Energy Efficiency: Challenges and Opportunities for Electric Utilities

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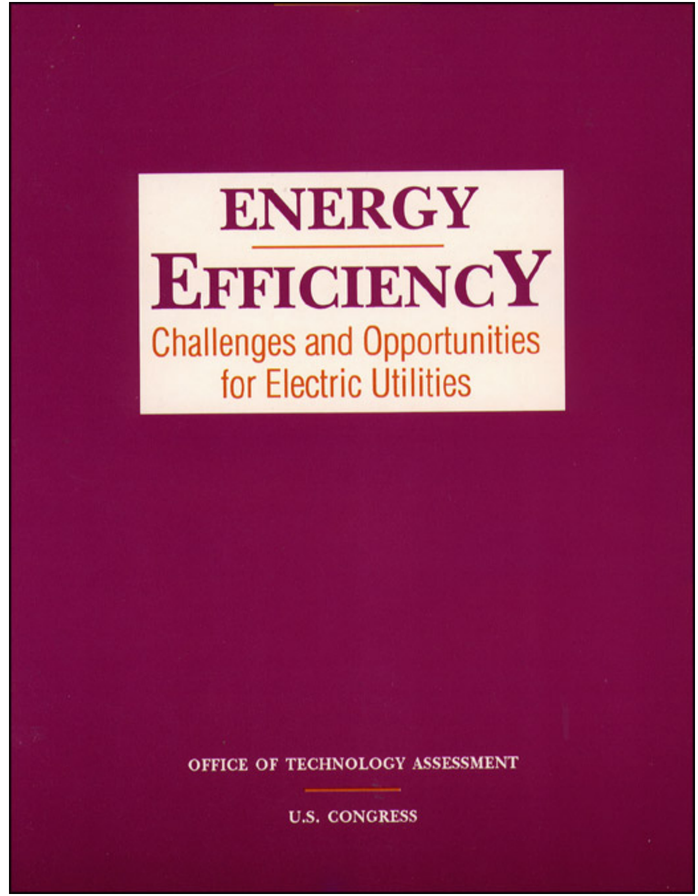

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Foreword

This Report on energy efficiency and electric utilities was prepared as part of OTA's assessment of U.S. Energy Efficiency: Past Trends and Future Opportunities. The assessment was requested by the Senate Committees on Governmental Affairs and Energy and Natural Resources and the House Committee on Energy and Commerce and endorsed by the Chairman of the Subcommittee on Environment of the House Committee on Space, Science, and Technology. Other reports in this assessment examine energy efficiency in residential and commercial buildings, industry, transportation, and the Federal Government,

This Report focuses on the opportunities for advancing the energy efficiency of the U.S. economy through technology improvements and institutional change in the electric utility sector. In particular, the Report examines the prospects for energy savings through expansion of utility demand-side management and integrated resource planning programs and related Federal policy options.

OTA appreciates the advice and assistance of the many individuals who contributed to this project, including the advisory panel, workshop participants, and reviewers.

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NOTE: OTA appreciates and is grateful for the valuable assistance and thoughtful critiques provided by the advisory panel members. The panel does not, however, necessarily approve, disapprove, or endorse this report. OTA assumes full responsibility for the report and the accuracy of its contents.

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OTA appreciates and is grateful for the valuable assistance and thoughtful critiques provided by the participants in OTA'S workshop on Energy Efficiency and Electric Utilities, September 9, 1992. The workshop participants do not, however, necessarily approve, disapprove, or endorse this report. OTA assumes full responsibility for the report and the accuracy of its contents.

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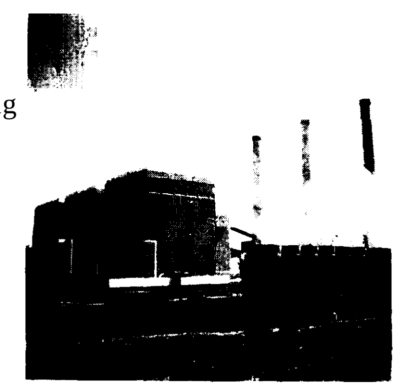
Introduction 1

Energy efficiency offers seemingly glittering promises to all-savings for consumers and utilities, profits for shareholders, improvements in industrial productivity, enhanced international competitiveness, and reduced environmental impacts. The technical opportunities are myriad and potential savings real, but consumers and utilities have so far been slow to invest in the most cost-effective, energy-efficient technologies available. The energy efficiency of buildings, electric equipment, and appliances in use falls far short of what is technically attainable. Energy analysts have attributed this efficiency gap to a variety of market, institutional, technical, and behavioral constraints. Electric utility energy efficiency programs have great potential to narrow this gap and achieve significant. energy savings.

But along with opportunities, greater reliance on energy efficiency as a resource to meet future electricity needs also entails risks—that efficient technologies will not perform as well as promised, that anticipated savings will not be truly cost-effective in practice, and that the costs and benefits of energy-efficiency programs will not be shared equitably among utility customers.

More than 30 States have adopted programs for promoting energy efficiency through utility integrated resource planning (IRP) and demand-side management (DSM) and programs are rapidly being developed and implemented in most of the remaining States (see box l-A). These programs reflect a recognition that increasing the efficiency of energy use by consumers to offset demand growth can be a financially attractive and reliable alternative to the addition of new generating plants. They also reflect a belief by policymakers that tapping the economic and technical resources of electric utilities can be an effective strategy for speeding the adoption of energy-efficient technology in all sectors.



Box I-A-Key Terms

- **Energy efficiency refers to the physical performance of specific end uses or energy services such as lighting, heating, cooling, and motor drive. Greater energy efficiency is achieved by replacing, upgrading, or maintaining existing equipment to reduce the amount of energy needed. Energy efficiency is usually measured by the output quantity per unit of energy input (miles per gallon or lumens per watt, for example). Because energy is one of several factors of production (labor, capital, and materials are others), energy efficiency improvements contribute to greater energy productivity and economic efficiency.**
- **Energy conservation refers to measures taken to reduce energy consumption. Conservation measures include substituting more energy-efficient equipment to produce the same level of energy services with less electricity and changing consumer behavior to cut energy use. The term is sometimes used interchangeably with energy efficiency.**
- **Demand-Side Management (DSM) refers to utility-led programs intended to affect the timing or amount of customer electricity use. These include energy efficiency programs aimed at reducing the energy needed to serve customer needs and programs that shift electricity demand to reduce peak loads or to make more economic use of utility resources. All utility DSM programs fit into one or both of following: 1) programs affecting the way energy-using equipment is operated, and 2) programs that focus on the installation of improved technologies. A variety of DSM mechanisms are in effect, including audit and information programs, rebates and other consumer financial incentives, direct installation programs, technical assistance, and energy performance contracting.**
- **Integrated Resource Planning (IRP) is a teohnique used by utilities and State energy regulatory agencies to develop flexible plans for providing reliable and economic electric power supply for customer needs. The process includes explicit comparisons of both supply-and demand-side resource options to meet a range of future electricity demand scenarios. Utility planners compare the lifetime capital and operating costs, availability, reliability, and environmental impacts of the various supply-and demand-side resource options in a consistent manner to develop an overall plan to meet Identified future needs at least cost. There are several competing methodologies for defining what resource chokes constitute "least-coost" mix. The IRP process usually includes public participation and comment and may require approval of State regulators before adoption. After adoption, the plan is used to guide utility chokes in acquiring new resources. IRP is sometimes also referred to as least-cost planning.**

SOURCE: Office of Technology Assessment, 1993.

With passage of the Energy Policy Act of 1992, the Federal Government also has adopted a policy favoring expansion of utility IRP and DSM programs and reaffirmed its support for development and commercialization of more energy-efficient technologies.[1]

Efficient use of electricity and changes in the electric power sector will play a vital role in any strategy for achieving a more energy-efficient society. If the threat of global climate change prompts concerted action to reduce carbon emissions, maximizing energy efficiency will be an imperative and a major overhaul of how energy services are provided and paid for will be required on a more accelerated schedule.

This report is part of the Office of Technology Assessment (OTA) ongoing assessment of *U.S. Energy Efficiency: Past Trends and Future Opportunities.* It examines mechanisms for achieving greater energy efficiency through electric utility planning, operations, and regulation. In particular, the report looks at the results of State

[1] Public Law 102486, 106 Stat. 2776, Oct. 24, 1992.

and utility IRP and DSM programs. The report also looks at the influence of State and Federal regulatory policies on utility investments in energy efficiency and presents a range of legislative policy options for encouraging energy efficiency through the electric utility sector.

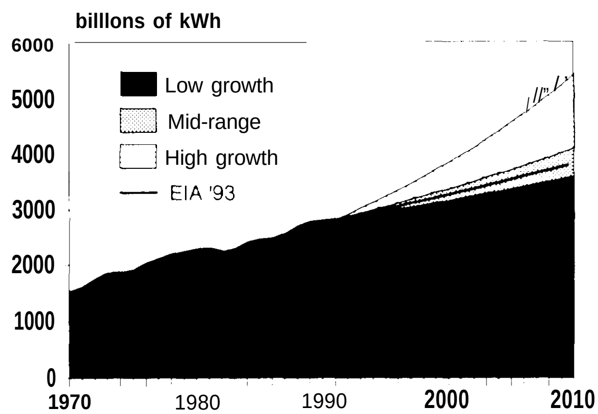
ENERGY AND ELECTRIC UTILITIES

Electric utilities are important as energy users, as providers of vital energy services, and as an economic force in the U.S. economy. Electric utilities are the Nation's biggest purchaser of primary energy supplies-coal, nuclear fuel, gas, and oil. Utility power generation accounted for 36 percent of total primary energy use in the United States or 29.6 quads in 1990.[2]

Energy efficiency improvements have slowed electricity demand growth, but electricity use is still increasing, Energy use for electric power generation as a share of the Nation's energy consumption has been growing-faster than growth in demand for other energy sources and that trend is projected to continue. Electricity demand growth over the past decade has slowed from the high (7 percent/year) annual growth rates that characterized the 1950s and 1960s to an average of 2.3 percent/year in the 1980s.[3]

Projecting future electricity demand is a highly uncertain art-adding to the risks that utilities face in planning and building for the future. Current estimates of 10-year electricity demand growth range from 1 percent to 3.5 per year (see figure l-l). Estimates of new powerplant construction needed to meet this new electricity demand and replace retired units range from 56 to 221 gigawatts (a gigawatt is one billion watts) in addition to the 700 gigawatts already installed.[4]

Figure 1-1—Electricit y Demand Growth, 1970-2010



SOURCES: Office of Technology Assessment, 1993, based on data from U.S. Department of Energy, Energy Information Administration, Annual *Energy Outlook* 7993, DOE/EIA-0383(93) (Washington, DC: U.S. Government Printing Office, January 1993); and Edison Electric Institute, "Meeting Electrcity Needs in the 1990s," September 1991 (briefing paper prepared for the Strategic Planning Executive Advisory Committee by Science Concepts, Inc.).

The U.S. Department of Energy uses a range of about 80 to 100 gigawatts for the new capacity needed by the year 2000--equivalent to construction of up to 100 new 1,000-megawatt coal-fired powerplants.[5] The differences in the estimates of new capacity needs reflect hundreds of billions of dollars in new capital equipment costs to ratepayers.

Efficiency advocates have long maintained that it is often cheaper for ratepayers and better for the environment and society to save energy rather than build new powerplants. This view is now embraced by many utilities, regulators, shareholders, and customers. The energy efficiency

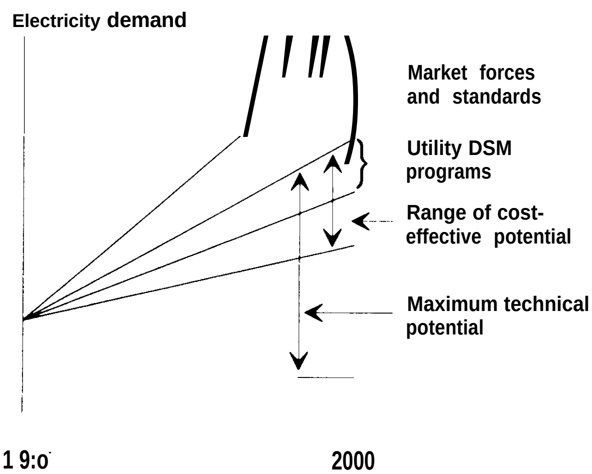
[2] U.S. Department of Energy, Energy Information Administration, *Annual Energy Review 1991,* DOE/EIA-0384(9 1) (Washington, DC: U.S. Government Printing Office, July 1992), p. 15, table 5.

[3] Edison Electric Institute, "Meeting Electricity Needs in the 1990s," September 1991 (briefing paper prepared for the Strategic Planning Executive Advisory Committee by Science Concepts, Inc.).

[4] Ibid.

[5] U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 1993, D0E/EIA-0383(93)* (Washington, *DC:* U.S. Government Printing Office, January 1993).

Figure I-2—impacts of Energy Efficiency Savings



This figure shows the different levels of projected energy savings impacts depending on what measure of energy efficiency is used.

SOURCE: Office of Technology Assessment, 1993, adapted from Barakat & Chamberlin, Inc., Efficient *Electricity Use: Estimates of Maximum Energy Savings,* EPRI CU-6746 (Palo Alto, CA: Electric Power Research Institute, March 1990).

strategy is already shaping our future-initial results are promising, but substantial uncertainties remain, and hundreds of billions of dollars are at stake.

FINDINGS

1. There are significant opportunities for cost-effective, energy efficiency savings in all sectors of the economy.

Analyses by OTA and others have consistently found that there are numerous cost-effective opportunities to use electricity more efficiently and to avoid the costs and pollution associated with new powerplant construction and still have the same energy services-warm showers, cold drinks, comfortable surroundings, and a vital economy.[6]

There is general consensus that the most promising technical opportunities for achieving more efficient use of electricity include:

- improvements in the thermal integrity of building shells and envelopes;
- improvements in the efficiency of electric equipment;
- lighting improvements;
- net efficiency gains from shifting energy sources from fossil fuels to electricity (electrification); and
- Optimization of electricity use through better energy management control systems, shifts in time of use, and consumer behavior and preference changes.

Estimates of the amount of cost-effective electricity savings that might be achieved through full adoption of currently available efficiency technologies vary, falling within a range of from 20 to 45 percent of present use by 2000 depending on the study. This wide range in the estimates reflects differing assumptions about technology availability, adoption rates, and cost-effectiveness (see figure 1-2). The high estimates would require replacing much of the entire stock of electricity-using equipment with the most-efficient models available and would require

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[6] *See the* following reports by U.S. Congress, Office of Technology Assessment: *Energy Technology Choices: Shaping Our Future,* OTA-E-493 *(Washington DC:* US. Government Printing Office, July 1991); *Changing by Degrees: Steps to Reduce Greenhouse Gases, OTA-O-482* (Washington, DC: U.S. Government Printing Office, February 1992); *Energy Efficiency in the Federal Government: Government by Good Example?,* OTA-E-492 (Washington, DC: U.S. Government Printing Office, May 1991); *Building Energy Efficiency,* OTA-E-518 (Washington, DC: U.S. Government Printing Office, May 1992); and *Industrial Energy Efficiency,* OTA-E-560 (Washington, DC: U.S. Government Printing Office, August 1993).

See also: *National Energy Strategy: Powerful Ideas for America, First Edition 1991/1992* (Washington, *DC:* U.S. Government Printing Office, February 1991); American Council for an Energy-Efficient Economy and New York State Energy Office, *The Achievable Conservation Potential in New York State from Utility Demand-Side Management Programs,* Energy Authority Report 9018 (Albany, NY: New York State Energy Research and Development Authority and New York State Energy Office, November 1990); American Council for an Energy-Efficient Economy et al., *America's Energy Choices: Investing in a Strong Economy and a Clean Environment,* (Cambridge, MA: The Union of Concerned Scientists, 1991): and Arnold P. Fickett, Clark W. Gellings, and Amory B. Lovins, "Efficient Use of Electricity," *Scientific American,* September 1990, pp. 65-74.

mobilizating of staggering amounts of capital to finance the transition even though it would result in significant long-term savings in energy costs. Even without aggressive retrofitting and replacement of electric equipment, it is projected that present trends in energy efficiency improvements due to energy prices, standards, and technological improvements, coupled with existing utility-sponsored resource planning, conservation, and DSM efforts will result in about a 9 percent reduction in electricity use by 2000 from what it would be without the expected efficiency savings.[7] Utility DSM programs are expected to offset about 14 percent of new electricity demand growth over the next decade.[8]

There is general consensus among energy analysts that we can cut electricity demand growth further and maybe even produce a net reduction in electricity demand over the next several decades. Doing so clearly offers substantial benefits. We believe with wise implementation of cost-effective measures, they likely will outweigh the costs and risks inherent in this strategy.

2. Investments in energy efficient technologies offer significant benefits to electric utilities and the Nation.

Improvements in energy efficiency through the electric utility sector offer the promise of savings for ratepayers and electric utilities, profits for shareholders, and societal benefits to energy security, international competitiveness, and environmental quality. Figure 1-3 illustrates the potential contributions of energy efficient technologies to national interests.

Increasingly, utilities are finding that energy efficiency programs make good business sense.

NICK CHRISTMAS, BPA

A home energy audit in progress.

Investments in energy efficiency through demand-side measures and enhancing the performance of supply-side options can provide reliable, flexible, and lower-cost alternatives to reliance solely on conventional generating options. Efficiency contributes to improved load factors for existing plants, reduces financial risks, and generates good will among customers.[9] In addition, energy efficiency improvements are becoming an important strategy for environmental compliance by reducing emissions and qualifying utilities for additional emissions allowances under the acid rain provisions of Clean Air Act Amendments of 1990. With the growth of State regulatory incentives for DSM investments, utilities are finding that energy efficiency programs offer new profit opportunities.

Improving the energy efficiency of electricity use contributes to greater productivity, lower energy costs overall, and more competitiveness in the international marketplace for U.S. businesses. Moreover, utility DSM investments tend to create more job opportunities for lower-skilled workers

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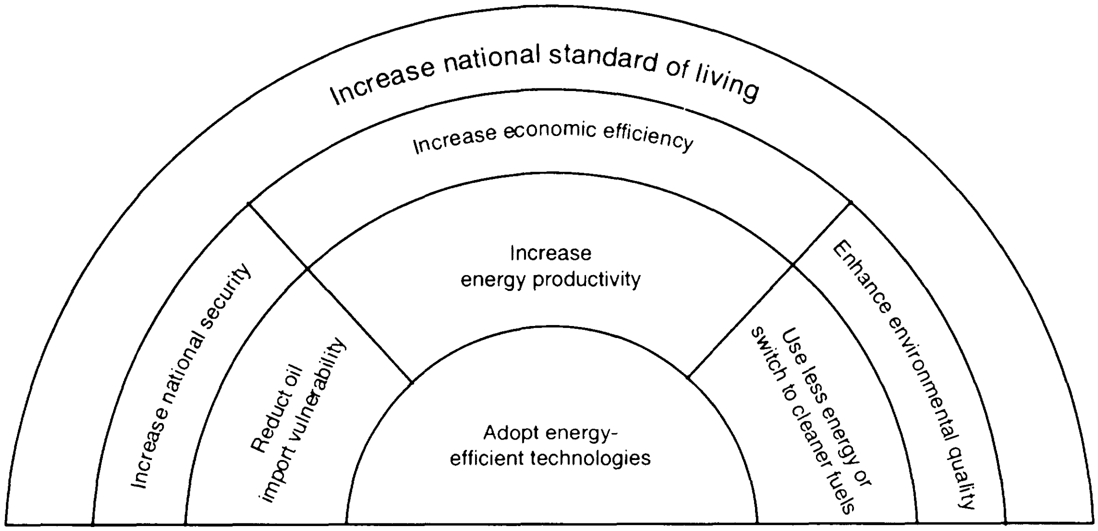
[7] Barakat & Chamberlin, Inc., *Estimating Efficiency Savings Embedded in Electric Utility Forecasts* EPRI CU-6925, *Project 2788,* Final Report (Palo Alto, CA: Electric Power ResearchInstitute, August 1990). Electric Power Research Institute and Edison Electric Institute, *Impact of Demand-Side Management on Future Customer Electricity Demand:* An *Update,* EPRI-CU 6953 (Palo Alto, CA: Electric Power Researc h Institute, September 1990)

[8] Eric Hirst, *Electric Utility DSM-Program Costs and Effects: 1991-2001,* ORNL/CON-364 (Oak Ridge, TN: Oak Ridge National Laboratory, May 1993).

[9] Brent Barker, "Energy Efficiency: Probing the Limits," *EPRI Journal,* March 1992, pp. 14-21.

Figure 1-3-Energy Efficiency and Energy-related National Policy Goals



SOURCE: Office of Technology Assessment, 1993, adapted from Energetics, Inc., Utility Enerrgy *Efficiency Srategies: The Role of Effiency, Productivity,* and *Conservation,* EPRI CU-6272 (Palo Alto, CA: Electrie Power Research Institute, February 1989), p. 2-2.

than construction programs for conventional supply--side generation and transmission additions.[10]

DSM measures also can help reduce our oil import vulnerability. Even though electric utilities today account for less than 5 percent of U.S. oil demand, oil-fried generation remains an important resource in the Northeast, California, Florida, and Hawaii. For utilities in these areas, accelerating the implementation of DSM measures to displace oil-fired generation is a key strategy for responding to potential oil import disruptions.[11]

3. Electric utility energy efficiency programs can produce cost-effective energy savings and help overcome economic, institutional, and behavioral impediments to investment in energy efficient technologies.

The potential of using the electric utilities sector and utility regulation to spur changes in the energy efficiency of America's homes, schools, and workplaces has captured the attention of energy efficiency advocates, utilities, entrepreneurs, State regulators, Federal policymakers, and consumers. Public utilities are well positioned to promote the adoption of more energy-efficient technologies. Their integrated operations, technical expertise, established ties to customers, and familiarity with customer energy use equip them with the technical skill, marketing tools, and information to identify energy-savings opportunities. Their special status as regulated public

10 Howard Geller, John DeCicco, and Skip Laitner, *Energy Efficiency and Job Creation: The Employment and Income Benefits from Investing in Energy Conserving Technologies (Washington DC: The American Council* for an Energy-Efficient Economy, October 1992).

11 See U.S. Congress, Office of Technology Assessment, *U.S. Oil Import Vulnerability: The Technical Replacement Capability,* OTA-E-503 (Washington, DC: U.S. Government Printing Office, October 1991), chs. 2 and 3.

utilities offers access to capital, a relatively secure cash flow, and a concomitant responsibility to provide cost-effective and reliable service to their customers. Their regulated status also makes them attractive targets for policy initiatives in pursuing energy efficiency, as it has in improving environmental quality. Utilities are by no means the only entities that can provide energy efficiency investments-the growth of energy service companies and energy management technology companies testify to this. Many of these companies owe much of their market to opportunities created by utility programs and rebates.

Utility efficiency programs can work—providing significant savings and profits for utilities. Energy efficiency and utility demand-side management and conservation efforts have become big business. An estimated $2 billion was invested by utilities in DSM in 1991 and this will grow significantly in years to come.

Initial results have demonstrated that well-designed and implemented utility energy efficiency programs can deliver sustained, reliable, and cost-effective electricity savings. Despite this promise, there have been early disappointments. In many programs, participation rates have been low and actual savings have been well below cost-effective technical potential. In part this is due to the fact that many utility programs are of recent vintage and are still limited in scope. Nevertheless, even the best programs have experienced gaps between technical potential and actual savings. In coming years, utility programs will have to narrow this savings gap and expand the degree of customer participation in order to make energy efficiency the true equal of new generating units and other supply-side options in meeting customer energy needs.

DSM programs entail some risks both in technology and the associated regulatory changes: that the savings will not be as high or as durable as expected, or that consumers will be asked to pay more than necessary to achieve them. DSM programs and IRP methods are evolving to take advantages of lessons learned and to target a broader range of electricity saving opportunities. The challenge is to assure that expanded utility and State programs achieve their goals and that Federal policies support, or at least not frustrate, those objectives.

4. State and Federal Governments will play key roles in overcoming the barriers and constraints to utility energy efficiency investments because of the regulated nature of utilities and government's influence over other sectors of the economy.

States and utilities are already well-advanced in establishing energy efficiency programs. The Federal Government has only limited direct influence over utility resource decisions, demand management programs, and retail operations. Most of these matters are regulated at the State and local level. Yet there is a strong Federal interest in energy efficiency arising from the importance of reliable and economic electric power production to the economy, concerns over the environmental impacts of power generation, and the Federal Government's roles as wholesale power producer, utility regulator, and utility customer.

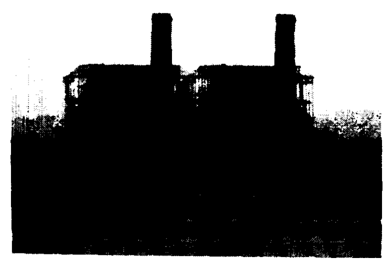
Our future energy path will be determined by choices made by utilities, consumers, regulators, and government. If we choose to pursue the energy efficiency alternative, success depends on cooperation by utilities, acceptance by consumers, and institutional change. The States and many electric utilities have already moved far ahead of the Federal Government in direct initiatives for more efficient electricity use through the utility sector. There are, however, a number of areas where the Federal Government can make a contribution in encouraging the development and availability of energy-efficient technologies for electric utilities and their customers. Moreover, Federal Government decisions in a number of areas could signicantly affect the success and cost-effectiveness of utility programs and investments.

Federal policy options for encouraging greater energy efficiency through the electric utilities sector are discussed in chapter 2 of this report. The overall strategies include: 1) support for expanded IRP and DSM programs and other State regulatory incentives for utility investment in energy efficiency; 2) continued support for commercializing energy-efficient technologies through tough energy efficiency standards for buildings and equipment; and 3) support for energy efficiency research, development, and technology transfer activities.

Policy Issues and Options 2

The Federal interest in encouraging energy efficiency throughout the U.S. economy rests firmly on three broad national policy goals: economic growth, environmental protection, and national security. The Federal Government has a long history of involvement in the utility sector, both as a regulator and as the builder and operator of large power systems. Following the energy crises of the 1970s, new Federal laws and programs were established to support energy conservation activities, minimum energy efficiency standards, utility regulatory reforms, and the research, development, demonstration, and commercialization of new and more environmentally friendly technologies for generating electric power.

Improvements in energy efficiency through the electric utility sector offer the promise of savings for ratepayers and electric utilities, profits for shareholders, and societal benefits to energy security, international competitiveness, and environmental quality. But, as discussed later in this report, the Federal Government has only limited direct influence over utility resource decisions, demand management programs, and retail operations. Most of these matters are regulated at the State and local level. Yet there are a number of areas where the Federal Government can make a contribution in encouraging the development and availability of energy-efficient technologies for electric utilities and their customers. Moreover, Federal Government decisions in a number of areas could significantly affect the success and cost-effectiveness of utility programs and investments.



This chapter discusses a range of legislative policy options for encouraging greater energy efficiency through the electric utilities sector. They include Federal policy options for supporting expanded integrated resource planning, demand-side management programs, and other State regulatory incentives for utility investment in energy efficiency. The chapter also presents options for new Federal energy efficiency standards for buildings and equipment and greater support for efficiency research and development and technology transfer.

This report was completed and sent to the ‘Technology Assessment Board before passage of the Energy Policy Act of 1992.[1] The policy options discussed include many that were adopted in whole or in part in recently enacted legislation. We have noted some of these new provisions in the text and in box 2-A. The recently passed legislation leaves many issues for subsequent Congresses. Decisions will have to be made about appropriations levels for newly authorized programs and the efficacy of agency implementation.

Box 2-A–The Energy Policy Act of 1992

The Energy Policy Act of 1992[1] was passed in October 1992 following 2 years of extensive legislative consideration and debate. The act contains a wide range of Federal initiatives intended to Improve the energy efficiency of the U.S. economy, encourage the commercialization of energy-efficient and renewable energy technologies, reduce oil import vulnerability, and lessen the environmental impacts of energy production and use. Provisions that aid utility energy efficiency efforts are highlighted below.

Energy Efficiency Policy Goals

National energy policy plans submitted after 1993 must contain a national least-cost energy strategy to meet the goals of increasing energy efficiency by 2010 by 30 percent over 1988 levels, expanding use of renewable resources by 75 percent over 1988 levels, and reducing greenhouse gas emissions.

Integrated Resource Planning

State utility regulatory commissions must consider adopting standards requiring utilities to adopt integrated resource planning (IRP).

The Tennessee Valley Authority (TVA) must establish a least-cost planning process to develop a resource plan with the lowest system cost. The process must consider a full range of supply and demand resources, including renewable resources, energy conservation and efficiency, and provide opportunities for involvement by TVA distributors.

The Western Area Power Administration (WAPA) must require its long-term firm power customers to implement IRP within 3 years. WAPA will provide technical assistance in developing IRP programs and review the plans prepared. Utility resource plans must select options that minimize life-cycle costs, including adverse environmental effects, and give priority to energy efficiency and renewable energy to the extent practicable. WAPA may impose penalties for failure to file or carry out IRP. Special provisions are included to aid small utilities in preparing resource plans.

DOE is to study the implementation of IRP and its impacts and report to Congress in 2 years.

Demand-Side Management

State utility regulatory commissions must consider standards giving utility energy efficiency investments a return at least as high as that given supply-side investments.

Federal grants of up to $250,000 each to State regulatory commissions are authorized to encourage utility demand-side management (DSM) measures and help weatherization grantees participate in State leascost planning processes.

TVA is directed to provide technical and financial assistance to its distributors in the planning and implementation of cost-effective energy efficiency options.

[1] Public Law 102-466, 106 Stat. 2776, Oct. 42, 1992.

[1] Public Law 102-486, 106 Stat. 2776, Oct. 24, 1992.

DOE will provide grants to States **to promote industrial energy efficiency and utility industrial energy efficiency programs.**

Utility subsidies to residential customers for energy efficiency measures are granted an exemption from Federal income tax **and payments to commercial and industrial customers are made partially exempt.**

Energy Efficiency Standards

Categories of electric equipment subject to standards are expanded to include: lamps; shower heads; electric motors; commercial heating, cooling, and water heating equipment; and utility distribution transformers.

Existing Federal efficiency standards for appliances and fluorescent ballasts must be upgraded to the highest levels that are technologically feasible and economically justified.

Federal energy testing and labeling requirements are expanded to cover light fixtures, office equipment, and major consumer appliances, and to disclose life-cycle energy costs, usage, and comparisons to the most efficient models. DOE will support industry efforts at voluntary ratings and labeling systems for windows, office equipment, and lighting fixtures, however, mandatory Federal standards are to be issued if the private efforts fail.

Federal cofunding will be made available to set up 10 regional centers to demonstrate efficient lighting, heating, cooling, and building technologies.

DOE will provide technical assistance to help States update and enforce commercial and residential building codes to incorporate model industry energy efficienccy standards.

DOE will issue voluntary guidelines for home energy rating systems and provide technical assistance to local officials.

The Department of Housing and Urban Development will establish a pilot program for energy-efficient home mortgages for new homes and improvements in existing homes.

Energy Efficiency Research, Development and Demonstration

Many existing DOE programs are reauthorized as part of a 5-year program to increase the use of energy-efficient and renewable technologies in the buildings, industrial, and utility sectors. Goals for the utility sector are to accelerate the development of technologies that will increase energy efficiency and the use of IRP. DOE is required to submit a plan for the 5-year program within 180 days of enactment.

Federal Energy Management

DOE must develop tough, new energy efficiency standards to be effective in 3 years for all new Federal buildings. Federal agencies must install cost-effective, energy and water saving technologies by 2005.

Authorization and conditions for Federal agency participation in utility DSM programs and energy savings performance contracts are clarified.

The Federal Energy Management Program is extended to the Congress and the U.S. Postal Service.

New public housing and new homes with Federal l-busing Administration and Veterans l-busing Administration mortgages have to meet Federal energy efficiency standards.

Expanding Utility Resource Options

New **wind or** closed loop biomass energy systems may qualify for an income tax credit of up to 1.5 cents/kWh generated for up to 10 years.

To encourage growth of independent power producers, qualifying wholesale generators are granted a new exemption from the limitations of Public Utility Holding Company **Act.**

The Federal Power Act is amended to expand Federal Energy Regulatory Authority to order utilities to provide transmission services to other utilities and power generators.

Several significant utility-related issues were left unresolved, especially in the delicate area of conflicts in Federal and State jurisdiction over utility planning on multistate systems, wholesale power transactions, and their effects on retail rates.

STRATEGIES FOR ENERGY EFFICIENCY

Efforts to harness the utility sector as a means to achieve greater energy efficiency have focused on three regulatory strategies: requirements for adoption of utility integrated resource planning (IRP), also called utility least-cost planning; expansion of utility demand-side management (DSM) programs; and rate reforms and other regulatory incentives for utilities to invest in energy-saving technologies. Programs for promoting energy efficiency through utility IRP and DSM measures are already entrenched in many States and are rapidly being developed and implemented in many others. These State and utility efforts could eventually involve the expenditure of billions of dollars of ratepayer funds. These programs reflect a recognition that increasing the efficiency of energy use by consumers can be a financially attractive and reliable alternative to the addition of new energy supplies to meet demand growth and a belief that tapping the economic and technical resources of electric utilities can be an effective strategy for speeding the adoption of energy-efficient technology in all sectors.

Initial results have demonstrated that well-designed and implemented utility energy efficiency programs can deliver sustained, reliable, and cost-effective electricity savings. Despite this promise, there have been early disappointments. Many programs have failed to achieve the significant electricity savings and high degree of participation needed to make DSM the true equal of new generating units and other supply-side options in meeting customer energy needs. DSM programs and IRP methods are evolving to take advantages of lessons learned and to target a broader range of electricity-saving opportunities. The challenge is to assure that expanded utility and State programs achieve their goals and that Federal policies support, or at least not frustrate those objectives.

Although energy efficiency through IRP was a keystone of the Bush Administration's National Energy Strategy, Federal financial commitments to energy efficiency are dwarfed by Federal investments in conventional supply-side technologies (fossil and nuclear power) and in renewable energy sources (see chapter 7). Part of the disparity can be explained by the fact that electric utility resource planning decisions and DSM programs are matters largely within the purview of State regulation and Federal regulatory influence is largely indirect. The Federal Government clearly lags far behind the States in programs and expertise in the utilities sector, particularly in the areas of resource planning and DSM. Moreover, at the same time, Federal policies and regulatory initiatives are promoting both the growth of a competitive bulk power sector that includes more unregulated nonutility generators and greater use of market-based rates in wholesale power contracts in place of traditional cost of service rates. To the extent that utilities rely on wholesale power purchases to supply future needs instead of investing in their own plant and equipment, Federal regulatory control over power supplies will increase and State regulators' influence over power supply costs will diminish and so too will their ability to enforce State-approved least-cost plans unless there is a change in law at the Federal level.[2]

The Federal Government has provided modest levels of financial support to State initiatives and supported research on IRP and DSM through the

2 The implications for greater conflict between Federal and State regulation of electric power is discussed in detail in U.S. Congress, Office of Technology Assessment, *Electric Power Wheeling and Dealing: Technological Considerations for Increasing Competition,* OTA-E-409 (Washington, DC: U.S. Government Printing Office, May 1989),

national laboratories. With the exception of programs by the Bonnville Power Administration and, to a lesser extent, the Western Area Power Administration, the Department of Energy (DOE) and the Federal Energy Regulatory Commission (FERC) at present are ill-equipped to provide substantive direction and technical support on increasingly sophisticated aspects of utility resource planning and evaluation of DSM efforts. New policy directions coupled with modest funding support, would, however, improve Federal capabilities to further utility energy efficiency programs and enhance cooperation with State and local governments.

The primary strategies available to Congress to advance energy efficiency through the utility sector include:

- Supporting, through Federal actions, expanded use of IRP, DSM programs, and State regulatory initiatives to increase utility investment in energy efficiency technologies, including legislation imposing new requirements on State regulators and electric utilities;
- Providing Federal financial and technical support to State regulatory agencies for implementation of utility energy efficiency initiatives;
- Providing Federal support for research, development and demonstration of energy efficiency technologies and technology transfer programs;
- Strengthening and expanding Federal energy efficiency standards and labeling and information requirements for a wider variety of electric products and equipment;
- Requiring the Federal Energy Regulatory Commission to advance IRP and energy efficiency in its direct regulatory responsibilities;
- Requiring the Tennessee Valley Authority to adopt IRP principles to guide its future resource acquisitions (including investment in cost-effective energy efficiency measures) and to assist its customer utilities in developing IRP and DSM programs of their own;
- Expanding the activities of Federal power marketing administrations to support IRP and DSM; and
- Requiring the Federal Government to “lead by example” by improving the energy efficiency of its buildings and operations and participating in utility sponsored energy efficiency programs.

The Energy Policy Act of 1992 includes provisions that commit the Federal Government to many of these strategies (see box 2-A). The challenges now lie in the implementation of new Federal policies and requirements. For Congress, this means decisions over appropriations levels for new energy efficiency initiatives and hard choices over competing demands for Federal funds in a time of financial difficulty and looming budget deficits. Congressional oversight of the pace and direction of agency implementation of energy efficiency measures and the successfulness of these programs also plays a role in assuring that the ambitious energy efficiency mandate is attained. Even given the breadth and detail of the recently passed energy act, there remain, however, several areas where additional legislation may be appropriate to further goals of increased energy efficiency and greater use of integrated least-cost planning methods.

Much of the success of these initiatives will depend on how they are implemented and will require continued congressional oversight and support.

INTEGRATED RESOURCE PLANNING

IRP is a technique used by utilities and State energy regulatory agencies to develop plans for providing reliable and economic electric power supply for customer needs. The process includes explicit consideration of both supply-side and demand-side resource options. The process begins with development of a range of projections of future electricity demand under alternative future scenarios. Next, the planners assemble a menu of potential resource options for meeting those energy service needs including both supply--side resources (new generation, transmission and distribution (GT&D) facilities, retrofit or improvement of existing GT&D facilities, and/or bulk power purchhases) and Utility-Sponsored demand-side resources (conservation, load management, and end-use efficiency improvements). The life-time capital and operating costs, availability, reliability, and suitability of the various supply- and demand-side resource options are then compared to develop an overall plan to meet identified future needs. There are several competing methodologies for defining what resource choices constitute a “least-cost” mix. In developing a least-cost plan, some planning processes require that environmental externalities be quantified and explicitly weighed in the resource selection process, others give preferences to certain technology choices, i.e., locally produced coal, DSM, low carbon emissions, or renewable resources. The planning process usually includes public participation and comment and may require approval of State regulators before adoption. After adoption, the plan is used to guide utility choices in acquiring new resources.

Many utility analysts and energy-efficiency advocates believe that, compared with past supply-oriented utility planning methods, IRP will favor the selection of more cost-effective, more efficient, and more environmentally-friendly energy technologies, including renewable energy technologies and demand-side options. Adoption of an IRP process alone will not automatically produce these results. What is even more important are the policy choices made in establishing the goals and in weighing the costs, reliability, and other attributes of alternative technology choices in resource plans.

Adopting formal utility IRP processes has certain clear effects that are usually deemed positive by State regulators. First, the IRP process opens up utility resource planning to review and influence by the public, potential resource suppliers, and regulators. IRP creates a mechanism for consideration of a wider variety of potential resources and future planning contingencies than might be the case under past internal supply-oriented utility planning procedures. Opening the process creates opportunities for developing broader consensus among utility decisionmakers, ratepayers, regulators, and other interested parties about preferred strategies-perhaps lessening some of the contentiousness of adversarial proceedings on capacity and rates. Indeed, some States and utilities have made collaborative consensus-building efforts a keystone of their overall IRP process. Open planning will perhaps avoid some of the problems of utility construction programs of the 1970s when unneeded capacity and cost overruns in a time of slower demand growth produced protracted, bitter rate hearings and disallowances of recovery for investments later found to be imprudent. Rigorous and open advance review of utility plans and periodic reassessments also encourages more flexible responses to changing conditions.

Among the potential disadvantages of broader application of IRP among States and utilities are the additional procedural burdens it could impose on smaller utilities and State regulatory programs. Many smaller investor-owned public power and cooperative utilities may not have the resources, personnel, or need to do extensive independent IRP. Their needs could perhaps be as well served by participation in State or region-wide planning exercises. For some utilities and financial analysts, more open planning processes and State IRP approvals may be perceived as diminishing the utility’s control over resource choices. There is no doubt that this is a goal of some IRP proponents. However, for many utilities, adoption of IRP with its more explicit consideration of planning uncertainties and inclusion of more flexible supply and demand alternatives is a natural response to the changes in the utility operating environment in the 1980s and 1990s. Expanded use of IRP will require some utilities to use longer plarming horizons than previously, and public and regulatory review will mean that resource planning may take longer than when it was a purely internal exercise. Offsetting this, of course, is the expectation that implementation of the plan will be smoother.

To encourage the expanded use of IRP, Congress could direct State regulatory agencies to consider adopting rules requiring jurisdictional utilities to use IRP. This option follows the approach established by the Public Utility Regulatory Policies Act of 1978 (PURPA) and upheld in the courts and avoids a direct clash between State and Federal powers or preempting State authority. State regulators can constitutionally be directed to consider a proposed action within a specific period of time, but the decision whether to adopt IRP and the precise form it would take is left to the States. The legislation might further provide that States consider requiring that utility investments in supply and demand-side resources be consistent with the State integrated resource/least-cost plan. The Energy Policy Act of 1992, indeed, took this approach and requires State regulators to consider several policies under PURPA section 111 on IRP, DSM, and supply-side efficiency investments.

More than half of the States have already adopted some form of IRP requirement without any Federal prodding-attesting to the attractiveness of the process to State regulators (see chapter 6). Many of the remaining States are already considering IRP proposals. These developments mean that utility IRP will grow even without Federal legislation. A key issue in formulation of added Federal requirements would be how existing State IRP programs should be treated. Should State regulators initiate new proceedings to consider IRP anew, or would the legislation exempt States that had already adopted plans? Imposing new procedural requirements could divert scant resources and personnel away from implementing existing initiatives. Utilities, too, would likely object to additional requirements. To minimize this outcome, legislation could provide for States to certify that they have already met the procedural requirements for IRP consideration.

The Federal Government could also provide additional inducements for State adoption of IRP with or without any direct Federal requirement for formal State rulemakings to consider adopting IRP.

- Federal financial and technical support could be provided for State development and implementation of IRP/LCP requirements through direct grants to State agencies, and funding of cooperative research on IRP methodology. This assistance could help offset the impact on State agency budgets and staffing of developing and implementing IRP programs. The Energy Policy Act of 1992 includes authorization for grants to State regulatory agencies of up to $250,000 to implement various efficiency initiatives.
- Congress could require that Federal actions including FERC rulings be consistent with State approved integrated resource plans. If FERC rulings are not consistent with approved regional or State least-cost plans, FERC actions should be subordinate to State actions needed to implement these plans.
- Congress could amend the Federal Power Act to delegate more authority over wholesale rates and intrastate electric power transactions from the FERC to States that have adopted IRP programs that meet certain minimum Federal standards.
- Congress could authorize States to enter into regional compacts for purposes of developing and implementing integrated resource plans for utilities that operate in more than one State or that are members of multistate tight power pools. Congress might further require that utility resource plans be consistent with these regional or multistate plans.

The comprehensive energy legislation passed in 1992 did not address issues of State and Federal regulation involving resource planning. Various proposals to clarify respective roles in regional planning and to close the regulatory gap created by recent developments have been offered. (See chapter 3.)

DEMAND-SIDE MANAGEMENT

DSM refers to utility-led programs intended to affect the timing or amount of customer electricity use. These include energy efficiency programs aimed at reducing the energy needed to serve customer needs and programs that shift electricity demand to reduce peak loads or to make more economic use of utility resources. A variety of DSM mechanisms are in effect, including audit and information programs, rebates and other consumer financial incentives, direct installation programs, technical assistance, and energy performance contracting.

Utility DSM programs are rapidly proliferating in extent and cost. Estimates of current annual utility DSM expenditures range from several hundred million dollars to almost $2 billion. One large California utility is poised to spend $1 billion on energy efficiency investments over the next decade and is awaiting the blessing of the State public utility commission. Equally ambitious efforts are being mounted in other jurisdictions as utilities announce plans to meet a significant portion of their demand growth in the 1990s through energy efficiency.

DSM programs have had mixed success to date. Many have delivered dramatic electricity savings at low cost-demonstrating their promise. However, many other programs have had low rates of customer participation, produced actual energy savings that were less than predicted, and lacked adequate evaluation and verification of energy savings over time (see chapters 5 and 6). For energy conservation and efficiency to become true alternatives to supply side resources, DSM efforts will have to be expanded in size and to a wider range of end-use applications, customer participation rates will have to increase, and actual savings will have to be closely monitored and evaluated.

There are several options available for Federal encouragement of utility DSM programs.

- Congress could direct State regulatory commissions to consider requiring their jurisdictional utilities to establish or expand cost-effective DSM programs.
- The Federal Government could provide additional financial and technical assistance to State agencies in developing, implementing and evaluating utility demand-side management programs. These could take the form of direct grants to State agencies, funding of cooperative research and demonstration program, sponsorship of training programs for State regulatory personnel, collection and dissemination of information on various State and utility DSM measures and their effectiveness.

As noted, the Energy Policy Act of 1992 does require States to consider financial incentives for DSM and conservation investments under PURPA, and authorizes Federal grants to State agencies. The legislation does not establish any new Federal program to aid in research and development and training in DSM evaluation.

U.S. DEPARTMENT OF ENERGY PROGRAMS

The DOE Integrated Resource Planning (IRP) Program, which has primary responsibility for advancing IRP and DSM, has a modest budget of a few million dollars and a very small staff. The program originally was established in response to congressional initiatives; its mission is to provide technical assistance and support on utility planning issues including DSM. It has primarily served as a conduit for funds to support research efforts at national laboratories, sponsor conferences, and provide small grants for cooperative efforts. Overall, the program results to date have received praise from utilities, regulators, and efficiency advocates. The growth of IRP and

DSM programs and the more sophisticated technical challenges they present for State regulators are rapidly outstripping the low budgets, modest research efforts, and limited expertise of the IRP Program. Despite the high profile given to electricity efficiency in DOE's energy policy pronouncements and budget submissions, the size and activities of the IRP office indicate the low priority actually attached to supporting utility IRP and DSM (see chapter 7). If Congress wishes DOE to provide leadership and support to State efforts and provide needed imputs to national energy policy debates, the IRP Program will have to be expanded and given adequate resources to establish a strong institutional presence to advance IRP and other utility energy efficiency programs.

There are clear opportunities for the Federal Government to be involved in research, development, and demonstration (RD&D) activities to advance utility efficiency initiatives. Utilities are funding significant amounts of resource independently and through the Electric Power Research Institute. Continued cooperative efforts with Federal agencies and national laboratories should be encouraged. The potentially large amounts of funds at stake in utility demand-side programs suggest that Federal policymakers and State regulators also have a need for independent and impartial assessments of IRP methods, DSM programs, and alternative regulatory incentives for efficiency investments. DOE-sponsored research can serve this public need by expanding RD&D efforts on DSM, supply-side efficiency technologies, IRP, conservation and load management methodologies, and on energy efficiency estimation, metering, monitoring, and evaluation technologies. Such research should include engineering, behavioral, and policy studies to assist improvement of DSM and IRP efforts. The research could be funded by redirecting a small portion of funds now devoted to supply technologies. opportunities for joint funding of research by the Federal Government, State agencies, utilities, trade associations and other interested parties could also be authorized and would allow leveraging of Federal research dollars.

UTILITY RATE REFORMS

Under traditional approaches to utility ratemaking, utility profits are based on sales of kilowatt-hours of electricity and total investment in generating, transmission and distribution equipment (see chapters 3 and 6). Almost without exception, every additional kilowatt-hour sold by a utility yields a profit.[3] Investments that promote energy efficiency and reduce electricity consumption, lower sales and threaten profits. States are currently experimenting with various regulatory mechanisms to decouple utility sales from profits and to make efficiency investments more attractive to utilities and their shareholders as detailed in chapter 6. To support these State efforts, Congress could:

- Direct DOE to expand funding for research on model State utility regulations and innovative ratesetting mechanisms such as decoupling profits from power sales, time of day pricing, interruptible rates, and performance incentives for efficiency; research results should be made widely available.
- Establish a DOE-supported multidisciplinary resource center to assist State regulators and utilities in developing and implementing innovative rate reforms and in evaluating the results.
- Provide grants to States for experiments in developing, implementing and evaluating innovative rate structures to encourage cost-effective supply and demand-side energy efficiency investment by utilities.

Congress could also follow the precedent of PURPA and direct States to consider the adoption

[3] David Moskovitz, *Profits and Progress Through Utility Least-Cost Planning (Washington DC: National* Association of Regulatory Utility Commissioners, 1989).

of ratemaking mechanisms that provide utilities with financial incentives for implementing cost-effective efficiency improvements and the Energy Policy Act of 1992 does this. Again, more than half of the States have already adopted some financial incentives for utility demand-side efficiency investments. Congress, could of course go further and require that State regulators adopt rate procedures that make demand-side efficiency improvements at least as profitable for utilities as investments in new supply-side resources. This direct, and obviously preemptive approach would likely be viewed with disfavor by many State regulators who believe that the choice of a proper incentive is a matter of State policy. Some consumer representatives would likely argue that such provisions could distort rates unnecessarily as utilities are already under some obligation to invest in cost-effective efficiency measures as a means of minimizing rates whether or not they are as profitable for shareholders as new generating plants.

FEDERAL REGULATION OF POWER TRANSACTIONS

While much Federal influence over utility planning and State ratemaking policies is indirect, there are three areas where the Federal Government can directly influence utility resource planning and energy efficiency investments:

1. FERC regulatory authority over wholesale power transactions and transmission arrangements.
2. Operation of five Federal power marketing administrations that supply power to local utilities and oversight of the operations of the Tennessee Valley Authority.
3. Rural Electric Administration loans and loan guarantees to electric cooperatives.

The Federal Government can provide leadership in adoption of IRP and cost-effective energy efficiency investments through its established regulatory and administrative authority in these areas.

The extent to which FERC on its own initiative and as a matter of policy could require utilities engaged in wholesale power transactions and multistate holding companies to develop integrated resource plans is not clear, even if FERC were inclined to do so (see chapter 3).[4] FERC has used its conditioning authority to induce utility compliance with various FERC economic policy initiatives, most recently open transmission access. Under the recent policy directions of FERC toward greater reliance on competition and market-based prices, it seems unlikely that the commission would advance new policies that would involve it more deeply in consideration of the details of resource planning and least-cost determinations of utilities that are either purchasing or selling power. Current FERC electricity policies could actually work to increase disincentives to investment in DSM. FERC could, however, use its rate design authority to eliminate biases against investment in DSM by wholesale power providers and purchasers. As a practical matter, FERC is largely bereft of the expertise that would allow it to pass on the merits of utility resource plans and DSM programs. Even if FERC does not become involved in promoting IRP and demand-side management, its preemptive jurisdiction over wholesale transactions and cost allocations in multistate holding companies has the potential to frustrate State initiatives at least-cost planning and DSM.

As mentioned above, if Congress wishes to support State implementation of IRP and DSM programs it could amend the Federal Power Act to require that FERC decisions be consistent with State-approved integrated resource/least-cost plans. To accomplish this, FERC could be directed to revise its procedures so that State regulators and other interested parties can effectively participate

[4] The Federal Power Act provides that FERC has no authority to order utilities to expand generating facilities or to buy or exchange power (16 USC 824f).

in wholesale proceedings to make regional or local interests known to the commission.

In the late 1980's the Tennessee Valley Authority (TVA) has discontinued its energy conservation and DSM programs and began to look at the need for adding new generating capacity in the later 1990s to meet the needs of its customers. Congress could require that TVA develop and implement its own least-cost planning program to direct its future resource acquisition strategies. It further could authorize and require TVA to invest in demand-side resources where it is cost-effective to do so as an alternative to construction of new generating capacity. TVA could also be directed to require its customer utilities to adopt IRP processes and to certify that purchases are in compliance with their plans. TVA could be directed to reestablish its programs in support of energy efficiency and conservation and provide technical assistance in these areas to its customers. The Energy Policy Act of 1992 does just this and requires TVA to adopt a least-cost planning program including participation by its distributors and the public.

Congress could require that the Federal power marketing administrations adopt an IRP approach and require their customer utilities to adopt IRP as a condition of power contracts. Under existing law, the Bonneville Power Administration already engages in extensive regional power planning and must give preference to conservation and renewable resources in its power procurement (see chapter 7). The Western Area Power Administration has already embarked on a regulatory effort to require its customers to engage in limited IRP as a part of its power supply contracts. The Energy Policy Act of 1992 incorporates much of this into statute. The much smaller Southwestern Power and Southeastern Power Administrations have not yet implemented planning or energy efficiency programs directed at their customers. Southwestern is cooperating with Western in development of programs and materials to help customer utilities implement IRP. Legislation has been introduced to approve the sale of the Alaska Power Administration.) Design of IRP and DSM requirements for power marketing administration customers must be done with care and sensitivity to the small size and limited resources of many public power utilities and cooperatives, and potential for Federal requirements overlapping with conditions imposed under State regulation.

Congress could require that cooperatives seeking REA loans or guarantees for new generation facilities demonstrate that they have adopted an IRP process that includes explicit consideration of energy efficiency alternatives and that the proposed facility is consistent with the least-cost plan. REA has already moved in this direction by rule. Legislation could reinforce and make permanent such conditions for REA transactions. Again, caution must be exercised in the design of requirements because of the size of many cooperatives and the possibility of overlap with State and other Federal agency requirements.

LEADING BY EXAMPLE: THE FEDERAL GOVERNMENT AS ENERGY CONSUMER

The Federal Government is the Nation's largest single energy consumer, in fiscal year 1989 it spent over $8.7 billion on direct energy purchases for its own facilities and operations and about $4 billion more subsidizing the energy expenses of low-income households under various programs. Not reflected in this direct energy expenditure of some $12.7 billion are the additional energy costs for leased space for which the Federal Government does not pay utilities directly. Payments to electric utilities accounted for an estimated $2.4 billion of the fiscal year 1989 Federal energy bill for government buildings.

The Office of Technology Assessment's (OTA) May 1991 report, *Energy Efficiency in the Fed-*

eral Government: Government by Good Example,[5] found that despite a wide array of programs and policies developed over the past 15 years, the Federal Government still has many opportunities to improve energy efficiency in its facilities and operations using commercially available, cost-effective measures. OTA estimated that total Federal Government energy consumption could be cut by 25 percent with no sacrifice to comfort or productivity. There are many measures with potential returns of 30 to over 100 percent. OTA's report found that existing Federal programs and present funding levels maintain program capabilities and will yield gradual improvements in Federal energy efficiency. However, the status quo is not sufficient to capture significant savings opportunities. At the present low level of energy efficiency funding and staffing for individual agencies, OTA estimated that it would take several decades to make all the economically attractive investments. During that time tens of billions of dollars would be unnecessarily spent to buy inefficiently used energy.

The Energy Policy Act of 1992 toughens energy efficiency standards for Federal buildings, sets a new deadline of 2005 for Federal agencies to install cost-effective, energy- and water-saving technologies, and contains a number of other measures to raise agency awareness and financial commitments to energy efficiency improvements. Nevertheless, taking full advantage of existing opportunities will require a higher priority for energy efficiency as reflected in adequate investment funding and staffing. One alternative is private sector financing in the form of utility rebate programs and shared energy-savings contracts that can be used to supplement direct Federal investments.

OTA found significant benefits associated with Federal actions to support energy efficiency.

- *Setting a good example* by demonstrating the cost and performance of a wide range of energy-efficient technologies and practices in its own facilities and operations,
- *Creating market pull for energy-efficient goods and services* through Federal purchasing power and promoting earlier introduction of high-efficiency technologies by specifying the most cost-effective energy efficiency products.[6]
- *Providing first-hand experience basis for national energy policy* on the technical and cost performance of energy efficiency measures from Federal projects.
- *Cutting Federal spending through energy efficiency savings;* and
- *Reducing the environmental, health and security costs of energy use.* Among the congressional policy options for making the Federal Government a leader in advancing cost-effective energy efficiency measures are several that would encourage Federal agency participation in utility-sponsored demand management programs.

Congress could use its oversight and appropriations processes to press Federal agency managers to give greater priority to funding and staffing to achieve the variety of existing congressional and presidential directives to cut building energy use and improve energy efficiency in operations. A 1991 Executive Order calls for a reduction in Federal building energy use by at least 20 percent by 2000 compared to 1985 and greater participation in utility DSM services.[7]

Congress could provide clear authorization and direction for Federal agencies to participate in utility demand management programs and shared

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[5] U.S. Congress, Office of Technology Assessment, *Energy Efficiency in the Federal Government:* Government by Good Example, OTA-E-492 (Washington, DC: U.S. Government Printing Office, May 1991).

[6] For example, about 10 percent of residential appliances are used in federally assisted or owned housing units, but are purchased by private individuals. Ibid., p. 106.

[7] Executive Order 12759, Apr. 17, 1991.

energy savings contracts, to accept payments, services, and goods associated with such energy efficiency programs, and to incur obligations for financing of efficiency measures. Confusion over agency eligibility and authority to enter into utility demand management programs was found to have deterred participation. Congressional legislation has already been enacted that specifies that Federal agencies (principally the Department of Defense and the General Services Administration may enter into shared energy savings contracts for federally-owned buildings and facilities.[8] The Energy Policy Act of 1992 expands that authority and specifically encourages agencies to participate in utility programs and to negotiate with local utilities for demand-side management programs specially tailored to the needs and characteristics of government facility loads.

Federal agencies could themselves become purveyors of energy efficiency savings to meet utilities' resource needs. Many Federal facilities would be attractive targets for energy efficiency savings under utility programs seeking cost-effective demand-side resources. Federal facilities managers should be authorized to enter agreements with energy services companies or directly with utilities to offer these potential resources in competitive procurements. Under such arrangements, utilities might install efficiency measures directly, the agency might pay for the measure and receive a rebate for some or all of the costs of the measures, or an energy service company would install the measure and recover its costs and profits from the utility. Such agreements at a minimum should provide that Federal payments for efficiency measures do not exceed the value of electricity bills that would have been due if the measure had not been installed.

Congress could assure that agencies devote sufficient funds and competent well-trained personnel to oversee and administer energy efficiency efforts, including those funded in whole or in large part by private funds through utility demand management programs or agreements with energy service companies. Several provisions of existing law and executive order attempt to do that through the budgeting process and reporting requirements.

As an additional incentive agencies could be allowed to keep some or all of the proceeds from energy efficiency rebates for either general program activities or for additional energy efficiency measures. Existing law authorizes retention of a portion of such energy savings in DOD facilities and allows them to be used for recreation.

Technical support could be provided to agency energy efficiency coordinators/personnel to aid them in identification of efficiency opportunities and provide assistance in negotiations with local electric utilities and energy service companies. These might include establishment of several regional model or demonstration energy efficiency facilities.

OTA's report on the Federal Government experience suggests that rewards for good performance in agency energy efficiency measures would also aid both agency management and energy efficiency staff deterrnination in capturing possible savings. In addition to the prior suggestion that agencies be allowed to keep all or a portion of savings, additional incentives might include establishment of well-publicized agency citations or awards for energy efficiency savings and bonuses for individual energy managers.

Improving the energy efficiency of Federal buildings and operations will require a long-term commitment and many novel approaches to new situations. It will be important that efforts be periodically evaluated and that successes and failures alike be analyzed and the results distributed among public and private energy managers so that needed modifications can be made, successes shared and failures avoided.

[8] Comprehensive Omnibus Budget Reconciliation Act, Public Law 99-272, Title VIII, 100 Stat. 42, Apr. 7, 1986.

SUPPORTING ENERGY-EFFICIENT TECHNOLOGIES

Federal support for improvements in the availability of energy-efficient equipment in the marketplace can complement utility energy efficiency programs. In addition to creating a market pull for efficiency by creating incentives for utility investment in DSM measures, Federal efforts can create a market push to raise the efficiency of new products.[9]

Information, Labeling and Efficiency Standards

Among possible approaches is strengthening and expanding Federal efficiency standards and labeling and consumer information requirements applicable to buildings and to household and commercial appliances, fixtures, and electrical equipment. These actions provide consumers with more information on energy use and can require that new buildings and products incorporate cost-effective efficiency technologies.

The Energy Policy Act of 1992 contains a number of provisions relating to increasing the efficiency of electric equipment. Specifically, it:

- Expands Federal energy efficiency standard legislation to major categories of electric equipment including: lamps; shower heads; electric motors; commercial heating, cooling, and water-heating equipment; and distribution transformers.
- Requires existing Federal efficiency standards for appliances and fluorescent ballasts to be raised to the highest levels that are technologically feasible and economically justified.
- Adopts expanded Federal energy testing and labeling requirements for light futures, office equipment, and major consumer appliances, including life-cycle energy costs and usage and comparisons to most efficient models.

The major share of residential and commercial energy use is for heating, cooling, lighting and providing hot water to buildings. Improving the energy efficiency of buildings offers significant opportunities for energy savings. Options for expanding and enforcing energy efficiency standards for buildings include:

- Developing and applying energy efficiency rating systems for new and existing commercial and residential buildings.
- Requiring DOE to work with national professional and trade associations to develop strengthened energy efficiency standards for new buildings to reflect the best cost-effective energy savings practices.
- Encouraging States to adopt these standards as part of State building codes and assisting them in strengthening building code compliance and enforcement procedures.
- Requiring sellers to provide information on energy efficiency features and energy use of buildings.
- Requiring compliance with the new Federal standards for federally assisted housing, mortgage guarantees, and Federal facility housing.

The success of such information, labeling and standards programs will require at least four conditions to be met. First, adequate funding and technical expertise must be available to develop standards for technically achievable and cost-effective energy-efficient technologies in a timely fashion and to revise them periodically to reflect technical advances. Second, mechanisms must be put in place to educate Federal, State and local officials, architects, manufacturers, wholesalers, equipment installers, and construction trades about new requirements. Third, monitoring and enforcement mechanisms need to be established

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[9] Various Federal market push policy options and the effectiveness of past Federal efforts are discussed in detail in U.S. Congress, Office of Technology Assessment, *Building Energy Efficiency, OTA-E-5 18* (Washington, DC: U.S. Gov ernment Printing Office, May 1992).

and adequately funded and staffed to backup the new standards. Lastly, the programs must be periodically evaluated to assess their effectiveness (including review of quantitative indicators of energy savings, costs, ease of administration, alternative implementation methods), improvements needed, and the continuing need for government involvement. Continuing congressional oversight and support will be key to assure that the new initiatives will be successful in attaining their goals.

R&D and Technology Transfer

Federal programs promoting efficiency initiatives through the utilities sector are limited in scope and funding. Most federally supported efforts have been targeted at the buildings and industrial sector and weatherization assistance for institutions and low-income consumers. Between 1980 and 1990, Federal spending on conservation and efficiency technologies and programs was slashed. Only congressional steadfastness kept many programs alive. Funding of efficiency research and development has begun to rise. However, most of the DOE research and development funds allocated as promoting electricity efficiency in budget documents actually support conventional fossil technologies, nuclear power and nuclear waste disposal programs.[10] Less than 0.5 percent of the non-defense DOE research and development budget went to programs to improve energy efficiency in the utilities sector.

The Federal Government support for research, development, demonstration and commercialization activities can advance the availability of energy-efficient supply-side and demand-side technologies. For example, the DOE Clean Coal program could be redirected to give more preference to technologies that improve powerplant efficiency and reduce environmental impacts of burning coal. Similar objectives can be applied to funding of other advanced electric power technologies offering significant efficiency gains. (for example, advanced generating technologies such as advanced gas turbines, and fuel cells, improvements in automation, monitoring, and dispatch controls, and high-efficiency transmission and distribution technologies.) Efforts should be directed at technologies for new construction and for retrofitting/repowering old generating plants. Research efforts should yield information on the performance characteristics, and the capital and operating costs of these technologies to be made more available to State regulators and Utility planners.

INCREASING UTILITY RESOURCE OPTIONS

A wider range of cost-effective supply- and demand-side resources will increase potential benefits to utilities and customers from the full implementation of IRP. Proponents of greater competition in electric power supplies contend that competition will bring market forces to bear to force greater efficiency in resource selection and in the development of new power technologies. Allowing demand-side measures to compete against supply-side options can help foster selection of more cost-effective efficiency alternatives to new powerplant construction.

Utility resource planning and supply acquisition have largely been matters of State jurisdiction. However, if as seems likely, expanded competition results in more wholesale power transactions, Federal authority over resource acquisition will increase. This enlarged influence could hinder rather than encourage efficiency gains if utility transactions receive Federal approval without regard to State least-cost plans.

Expanding Competition

Congress could increase competition either directly or through FERC by:

10 General Accounting Office, “Energy R&D: DOE’s Prioritization and Budgeting Process for Renewable Energy Research” GAO/RCED-92-155, April 1992, pp. 13-16.

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- Requiring utilities to acquire new power resources through competitive procurement mechanisms and requiring the inclusion of demand-side options in the competition.[11]
- Amending the Public Utility Holding Company Act (PUHCA) to encourage participation in bulk power and energy efficiency industries by broader group of potential suppliers.

The Energy Policy Act of 1992 creates a new exemption to PUHCA for entities engaged in wholesale generation markets. The exemption is applicable to utility affiliates.

Transmission Access

Increased access to the transmission grid has been advocated as a means to expand utility resource options and to open additional markets for capacity and electricity made available through efficiency efforts. Greater access to transmission facilities increases opportunities for power producers to sell power and for buyers to choose from a potentially greater variety of sellers and a wider range of generating options. Among options Congress could consider for encouraging more open transmission access are:

- Authorizing voluntary transmission-sharing mechanisms through regional agreements and joint planning among all prospective transmission users—both utilities and independent generators-under nondiscriminatory guidelines to be established by the FERC.
- Requiring the FERC to consider conditioning approval of special rate treatment, mergers, etc. on the petitioning utilities offering expanded non-discriminatory access to their transmission services.
- Providing additional Federal authority to require utilities to provide transmission services with protection for system reliability and native customer loads.
- Directing the FERC to defer to State efforts to improve transmission access and transmission services by State jurisdictional utilities unless the State efforts were found to be unjust, unreasonable, or to confer undue competitive advantage.

The Energy Policy Act of 1992 gave FERC explicit authority to order transmission access for wholesale transactions. The controversial details of pricing policies and information requirements to carry out this mandate have been left to FERC and progress on these matters will have to be monitored to determine if additional mechanisms are needed. Many utilities have been pressing for legislative approval for organization of voluntary regional transmission groups as a more flexible alternative to mandatory wheeling orders.

LEVELING THE PLAYING FIELD IN RESOURCE PLANNING

Because most energy prices do not reflect all of the social and environmental costs of particular energy choices, many economists and energy analysts believe that market-based mechanisms alone cannot be relied upon to produce the most efficient options from a social, environmental, and economic perspective. (A similar imperfection is also introduced by the tax and other “subsidies” that some fuels enjoy.)

Energy Taxes

One way of correcting such market failures would be to impose taxes on various energy sources that reflected the costs they imposed on society and the environment. In fact, in Europe and Japan, high energy taxes perform this function in some respects. Energy taxes have proven to be a controversial and unpopular approach for attaining energy policy goals in the United States. Recently, there has been renewed interest in energy taxes, not only as a means to promote energy and environmental policy goals via the

[11] See OTA's report, *Electric power Wheeling and Dealing: Technological Considerations for Increased Competition*, supra note 2.

''market-based mechanisms' currently in vogue among some policy analysts, but also as a means of increasing Federal revenues to reduce budget deficits. The Clinton Administration's Btu tax proposal would have imposed a small tax on a broad range of energy sources, but was rejected by Congress in favor of an increase in the transportation fuels tax.

Internalizing Social and Environmental Costs

An alternative to energy taxes is to use a surrogate price adjustment in the resource planning process so that relative costs of energy options are more adequately reflected and energy choices compete on a more level playing field. One method, for example, would be requiring that States and utilities include consideration of social and environmental costs/' 'externalities' in evaluating supply- and demand-side resources in developing least-cost plans. Including adjustments for externalities in the planning process avoids most of the political and economic impacts of direct energy taxes, while offsetting market imperfections in energy choices. Many conservation and renewable energy advocates believe that consideration of externalities in cost-effectiveness determinations would boost prospects for these options being selected in utility resource plans. However, some economists would say that the choice of a perhaps higher-priced energy option would impose a hidden environmental/social energy tax.

Consideration of externalities in resource choices is already required in many States, but experience is limited and the State efforts have proved highly contentious and politically controversial. Moreover, economists are deeply divided over whether and how to fashion mechanisms to internalize such costs in energy decisionmaking. Some States, such as Massachusetts and California, have attempted to set a specific quantitative value on external environmental costs to be used in evaluating competing resource choices, while other States have opted for a more qualitative approach. Various legislative proposals have been made that would require Federal agencies and utilities to consider life-cycle costs of energy options, including environmental and social costs and benefits to the maximum extent possible, in developing least-cost energy plans.

Whatever the conceptual difficulties of attempting to include externalities in integrated resource planning, as a practical matter State regulators and utilities are already doing it to some extent and proposals for expanding this approach to other States and Federal actions will increase. Given experience to date, there is no clearly preferred or accepted method of addressing the externalities problem. This suggests that any Federal action to require explicit quantification of externalities is premature. Congress could direct DOE to support research on alternative methods for assessing and quantifying environmental, social, and other externalities in least-cost planning and to report back on the experience to date, additional research needs, and the feasibility of including external costs in Federal least-cost planning.

Electric Utility Industry Structure, Regulation, and Operations

3

Electric utilities occupy a unique place in the U.S. economy. Their activities touch virtually everyone. Their regulated status as public utilities imposes special responsibilities in return for assurances of the opportunity to recover their costs, and for investor-owned utilities, to earn a reasonable return on their investments. Maintaining the reliable operation of the Nation electric power systems requires a high degree of cooperation and coordination among sometimes competing utilities and adherence to stringent performance standards. Yet, there is great diversity in the structure and organization of the industry. The recent growth of unregulated, independent power producers and pressures from consumers and regulators for greater utility investment in electricity-saving technologies pose new challenges for utility operations and the regulatory compact.

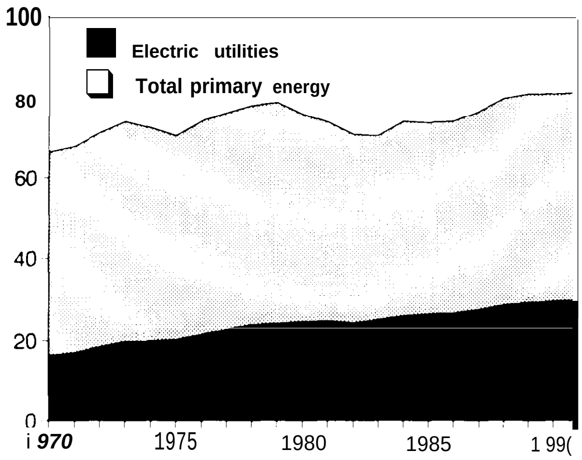
This chapter provides an overview of the electric utilities sector. It begins with a look at utility energy use, financial characteristics, environmental considerations, and an overview of industry structure. Next, it gives a brief introduction to State and Federal regulation of electric utilities. It concludes with an overview of utility system operations.

ELECTRIC UTILITIES IN THE US. ECONOMY

Energy Use

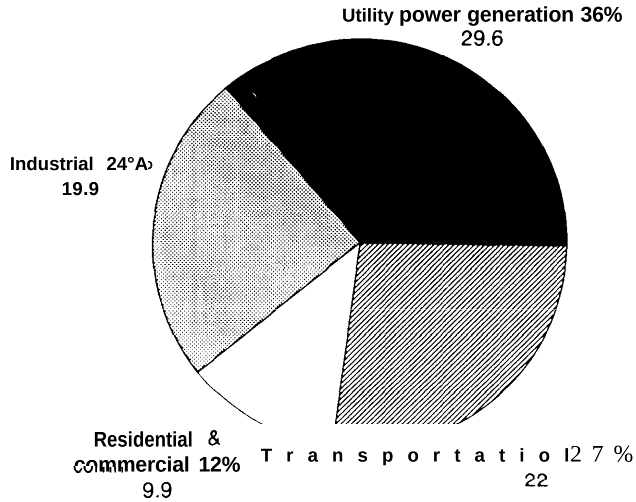
Electric utilities are among the Nation's biggest energy users and energy producers. Utility power generation accounts for 36 percent of total primary energy use in the United States or 29.6

Figure 3-1—U.S. Primary Energy Use, 1970-91 (quadrillion Btus)



SOURCE: Office of Technology Assessment, 1993, based on data from U.S. Department of Energy, Energy information Administration, Annual Energy *Review 1991,* DOE/EIA-0384 (91) (Washington DC: U.S. Government Printing Office, June 1992).

Figure 3-2—U.S. Primary Energy Consumption by Sector, 1990 (quadrillion Btus)



SOURCE: Office of Technology Assessment, 1993, based on data from U.S. Department of Energy, Energy Information Administration, *Annual Energy Review 1990,* DO/EIA-0384 (90) (Washington, DC: U.S. Government Printing Office, May 1991), p. 5.

quads in 1990.[1] (See figures 3-1 and 3-2.) Energy use for electric power generation as a share of the Nation's total energy consumption has been growing-faster than growth in demand for other energy sources—and that trend is projected to continue.

Utility fuel demand strongly influences the growth and structure of primary energy markets. In 1990 energy inputs for providing electricity accounts for virtually all nuclear power, 86 percent of coal use, 15 percent of natural gas, 3 percent of oil consumption, and over 40 percent of renewable energy production.[2]

Of the 29.6 quads of energy input to electric utilities to produce power, only 9.3 quads were delivered to retail customers as electricity.[3] On average only 31 percent of the primary energy input to electric power generation and transmission is available/delivered to meet customer needs. The rest is lost to inefficiencies in power generation processes-heat loss, incomplete combustion, and transformer and line losses in transmission and distribution. Thus, even modest gains in the efficiency of electricity production and delivery systems could make significant contributions to improving overall energy efficiency. And the impacts of demand-side electricity savings are magnified when they are translated

[1] U.S. Department of Energy, Energy Information Administration, *Annual Energy Review 1991,* DOE/EIA-0384(91) *(Washington DC:* U.S. Government Printing Office, July 1992) p. 15, table 5, hereinafter DOE, *Annual Energy Review 1991.* Because electricity can be considered an energy carrier, the means by which the energy content of fuels, falling water, sunlight, etc. is captured and converted to electricity that is then used to power other activities or energy services, electric utilities are at times categorized as energy producers rather than energy consumers. As a result, electric utilities would be omitted from profiles of energy consumera, and the primary energy inputs used by them to generate electricity is allocated proportionately to end-use sectors.

[2] DOE, *Annual Energy Review 1991,* supra note 1, various tables.

[3] Ibid.

Tables 3-1—Selected Utility Statistics by Sector, 1990

Sales to ultimate consumers (billion kWh)	2,713
Residential	924
Commercial	751
Industrial	946
Other	92
Revenue from sales to ultimate consumers ($billion)	178
Residential	72
Commercial	55
Industrial	45
Other*	6
Average revenue/kWh (cents)	6.6
Residential	7.8
Commercial	7.3
Industrial	4.7
Other	6.4
Emissions (million short tons)[b]	
Sulfur dioxide (SO_2)	16.5
Nitrogen oxides (NO_x)	7.1
Carbon dioxide (CO_2)	1,976.3

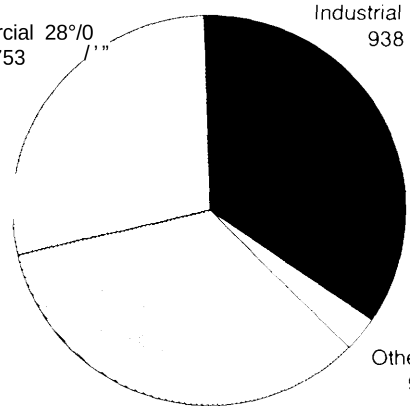
a includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.

bincludes only those power plants with a fossil-fueled, steam-e nameplate capacity (existing or planned) of 10 or more megawatts,

NOTES: Data on capabliity, generation, consumption, stocks, receipts, and costs of fossil fuels for 1990 are final; other 1990 data are preliminary. Totals may not equal sum of components because of independent rounding.

SOURCE: Office of Technology Assessment, 1993, based on information in U.S. Department of Energy, Energy Information Administration, *Electric Power Annual 1990,* DOE/EIA-0348(90) (Washington, DC: U.S. Government Printing Office, January 1992).

Figure 3-3-Electricity Sales by Sector (billion kWh)



SOURCE: Office of Technology Assessment, 1993 based on data from U.S. Department of Energy, Energy Information Administration, *Annual Energy Review 7990, DOE/ElA-0384 (90)* (Washington, DC: U.S. Government Printing Office, May 1991), table 94, p. 215.

into avoided fuel and capacity savings on the supply side.

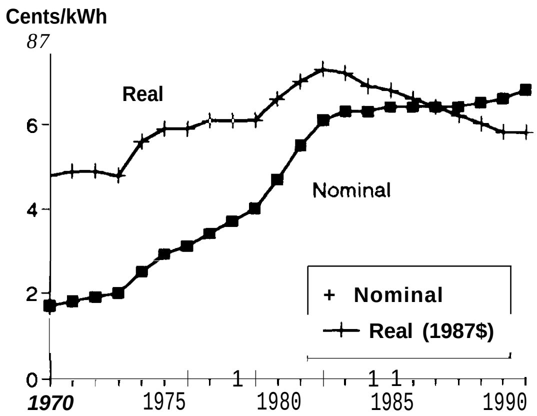
Revenues and Capital Investments

Electricity sales and capital investments make electric utilities an influential force in the economy. In 1990, consumers paid over $179 billion for electric power.[4] Table 3-1 and figure 3-3 show power sales and revenues by customer class, The retail cost of electricity varies significantly among the customer classes. Industrial customers generally are charged less per kilowatt-hour (kWh) than residential or commercial customers. Utilities justify this on the basis of lower costs incurred to serve industrial customers with large loads and often a single point of delivery, compared with residential service characterized by many dispersed customers with relatively low individual electricity sales volumes and higher associated transmission and distribution investment and electricity losses per kilowatt-hour sold. Lower prices are also justified to maintain market share and to discourage industrial customers from leaving the system by turning to natural gas or self-or cogeneration for energy needs—which could result in stranded investment costs that must be borne by remaining customers in the form of higher rates.

On a national average, the nominal price of electricity in 1990 was 6.6 cents/kWh, up from

[4] *Public Power*, Annual Statistical Issue, vol. 50, No. 1, January-February 1992, p. 56.

Figure 3-4-Average Retail Electricity Prices, Nominal and Real (1987 dollars)



SOURCE: Office of Technology Assessment, 1993, based on data from U.S. Department of Energy, Energy Information Administration, *Annual Energy Review* 1991, DOE/EIA-0384 (91) (Washington, DC: U.S. Government Printing Office, June 1992), table 102, p. 229.

4.7 cents/kWh in 1980. However, real electricity prices have, on average, declined during the last decade (as shown in figure 3-4). Adjusting for inflation, average retail electricity prices in 1990 of 5 cents/kWh are 10 percent less than they were in 1980.[5]

The utility industry is highly capital-intensive. Investor-owned utility capital investment in plant and equipment was valued at $379 billion in 1990.[6] Total assets of public power systems and rural electric cooperatives were estimated at $125.8 billion in 1990.[7] Estimates of new construction spending for investor-owned utilities were some $26.3 billion in 1990 according to one industry survey.[8] The largest share of this capital investment, $13.6 billion, was earmarked for transmission and distribution construction and improvements; only $8.9 billion was for building new generating plants-a shift from the massive new powerplant construction expenditures of the 1970s and early 1980s.

Environmental Impacts

Electric power generation is a significant source of air pollution and carbon dioxide (CO_2) emissions and thus has been a focus of environmental protection and cleanup efforts. In 1990 electric utilities' fossil-fired steam electric-generating plants spewed 16.5 million tons of sulfur dioxide (SO_2), 7.1 million tons of, nitrogen oxides (NO_x), and 1,979 million tons of carbon dioxide into the air.[9] According to data collected by the U.S. Environmental Protection Agency (EPA), burning of sulfur-laden coal and residual fuel oil by electric utilities accounted for over 80 percent of SO_2 emissions in 1989.[10] Electric utilities also were the source of some 60 percent of NO_x emissions in that year, Electric generation is responsible for about 35 percent of total carbon emissions in the United States and electric utilities account for almost all of these emissions.[11] Any strategy to limit carbon emissions to offset threats of global climate change will of

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[5] DOE, *Annual Energy Review 1991,* supra note 1, p. 229, table 102.

6 "SWcl~ Report: 1991 Annual Statistical Report Utility Construction Stirs as NUG Plans Grow," *Electrical World,* April 1991, pp. 9-14. See also U.S. Department of Energy, Energy Information Administration, *Financial Statistics of Selected Investor-Owned Electric Utilities,* DOE/EIA-0437(90)/1 (Washington, DC: U.S. Government Printing Office, January 1992).

[7] U.S. Department of Energy, Energy Information Administration *Financial Statistics of Selected Publicly Owned Electric Utilities 1990,* DOE/EIA-0437(90)/2 *(Washington DC:* U.S. Government Printing Office, February 1992).

[8] *Electrical World,* supra note 6, p. 9.

9 DOE, *Annual Energy Review 1991,* supra note 1, p. 227, table 100.

10 U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *National Air Pollutant Emission Estimates 1940-1989, EPA-450/4-91-004,* March 1991. According to the same report, utility emissions of sulfur oxides in 1989 would have been approximately 60 percent higher without the installation of pollution control equipment required by the Clean Air Act.

11 See U.S. Congress, Office of Technology Assessment, *Changing by Degrees: Steps to Reduce Greenhouse Gases,* OTA-O-482 (Washington DC: U.S. Government Printing Office, February 1991), p. 8.

necessity target electricity generation—and increase the attractiveness of energy efficiency alternatives through demand-side management (DSM).

The Federal Clean Air Act required installation of pollution controls at electric generating plants, reducing emissions and spurring the development of cleaner, state-of-the-art powerplants. Stringent new acid precipitation provisions of the Clean Air Act Amendments of 1990 will require electric utilities to make further reductions in their emissions of SO_2 and NO_x starting in 1995. These requirements will fall most heavily on Eastern and Midwestern utilities now burning high sulfur coal and potentially involves billions of dollars in new investment in control technologies to be paid for by ratepayers. One potential result could be the accelerated retirement or life-extending repowering of older plants. The 1990 Amendments also offered utilities another option for compliance. The option was to buy emissions allowances-a kind of license to pollute-from other utilities who have reduced their emissions below required levels, This innovative 'market-based' approach to environmental regulation-a new system of tradable pollution allowances-was included in the 1990 acid rain amendments and provides a further spur to utilities to install pollution control equipment, participate in integrated resource planning, and invest in energy efficiency in their operations.[12] The amendments established the Conservation and Renewable Energy Reserve to award additional emission allowances to utilities that cut emissions by installing electricity-saving DSM measures or by using renewable energy resources.[13]

In addition to air quality impacts, other environmental effects associated with electric power generation are the extraction and processing of fossil and nuclear fuel; construction and operation of hydroelectric, geothermal, solar, and wind facilities; and waste to energy plants.[14] Siting, construction, and operation of the plants can create local land-use conflicts, congestion and noise impacts on neighbors, and adverse impacts on natural habitats and wildlife. Power generation contributes to water and waste pollution. Nuclear power and handling and disposal of nuclear waste also entail a special set of serious, contentious, and long-term environmental issues because of the radiation hazards. Opportunities to use energy more efficiently are also opportunities to avoid associated environmental impacts of energy production.

Electric power transmission and distribution also have associated environmental impacts beginning with local land-use conflicts in the siting of power lines and substations. The construction phase contributes to erosion, soil compaction, destruction of forests and natural wildlife habitat in the right of way. During operation, nuisance effects include visual impacts, audible noise, corona effects, and interference with radio and television reception. Transmission systems can have deleterious effects on local bird life through collisions with powerlines and towers and electrocutions. Use of chemical herbicides and other vegetation management techniques along rights of way raises concerns about ecological impacts in some areas. In recent years, the as-yet-unproven possibility of human health effects from exposure to electric and magnetic fields has

12 Public Law, 101-549, sec. 404(f), Nov. 15, 1990, 104 Stat. 2601,42 U.S.C. 7651c(f).

13 See ch. 7 of this report.

14 Environmental impacts of electric utility activities are S ummarized in ch. 7 of U.S. Congress, Office of Technology Assessment, *Electric Power Wheeling and Dealing: Technological Options to Increase Competition,* OTA-E-409 (Washington, DC: U.S. Government Printing Office, May 1989), hereinafter OTA, *Electric Power Wheeling and Dealing.*

become a prominent concern in siting transmission and distribution facilities.[15]

Industry Structure

Electric utilities are the largest component of the electric power industry, a diverse patchwork of investor and publicly owned utilities; consumer cooperatives; Federal, State, and local government agencies; cogenerators; and independent power producers. The distinguishing characteristic of most electric utilities is that they are regulated monopolies that sell power to retail customers.

America's more than 3,200 regulated electric utilities supply electricity to over 110 million households, commercial establishments, and industrial operations. The differences among utilities in size, ownership, regulation, customer load characteristics, and regional conditions are important for policy. Table 3-2 shows selected statistics for the electric utility sector by type of ownership. Utility ownership and location determine regulatory jurisdiction over utility operations and rates.

Investor-Owned Utilities

The 267 investor-owned utility (IOU) operating companies dominate the electric power industry, generating 78 percent of the Nation's power in 1990 and serving about 76 percent of all retail customers. IOUS are private, shareholder-owned companies ranging in size from small local operations serving a customer base of a few thousand to giant multistate corporations serving millions of customers. Most IOUS are vertically integrated, owning or controlling all the generation, transmission, and distribution facilities required to meet the needs of the customers in their assigned service area.

IOUS can be found in every State except Nebraska. Their local operations and retail rates are usually highly regulated by State public utility commissions, however their wholesale power sales and wheeling (power transmission) contracts fall under the jurisdiction of the Federal Energy Regulatory Commission (FERC).

Control over IOUS is further concentrated because many of them are actually subsidiaries of utility holding companies. Nearly one-quarter of the IOU operating companies are subsidiaries of registered electric utility holding companies regulated under the Public Utility Holding Company Act of 1935 (PUHCA) by the Securities and Exchange Commission and FERC. The following are registered utility holding companies: Allegheny Power System, Inc., American Electric Power Co., Central and South West Corp., Eastern Utilities Associates, General Public Utilities Corp., Entergy Corp., New England Electric System, Northeast Utilities, and The Southern Co. In addition to the registered holding companies, many other utilities are also part of holding company systems consisting of affiliated utility subsidiaries operating intrastate or in contiguous States and, thus, are exempt from detailed oversight under PUHCA.

Publicly Owned Electric Power Systems

The more than 2,000 public power systems include local, municipal, State, and regional public power systems ranging in size from tiny municipal distribution companies to giant systems like the Power Authority of the State of New York. Publicly owned systems are in operation in every State except Hawaii. Together, local public power systems generated 9 percent of the Nation's power in 1990 but accounted for 14 percent of total electricity sales, reflecting the fact that

15 U.S. Congress, Office of Technology Assessment, Biological *Effects of Power Frequency Electric and Magnetic Fields,* Background Paper, O-IA-BP-E-53 (Washington, DC: Us. Gov ernment Printing Office, May 1989). Several epidemiologic studies have been published suggesting a link between magnetic field exposures in the vicinity of local distribution lines and increased risk of childhood cancer. Public health concerns have resulted in increased research funds for investigating this possible health hazard in hopes of determining what risks, if any, exist and how tbey might be mitigated. In the meantime, utility commissions and utilities are now increasingly including assessments of electric and magnetic field exposures and field reduction alternatives in the consideration and approval of new transmission facilities.

Table 3-2—U.S. Electric Utilities, Selected Statistics, 1990

Type of utility	Number	Ultimate consumer[a]		Sales to ultimate consumers		Revenues from sales to ultimate consumers		Installed generating capacity		Net generation[c]	
		Millions	Percent	Billion kWh	Percent	$billions	Percent	GW[b]	Percent	Billion kWh	Percent
Investor-owned	267	84	76	2,071	71	140	79	529	77	2,203	78
Publicly owned[d]	2,011	15	13	386	14	23	13	71	10	245	9
Cooperatives	953	12	11	201	7	14	8	25	4	126	4
Federal[e]	10	<1	0	55	2	2	1	65	9	235	8
Total	3,241	111		2,713		178		690		2,808	

a Ultimate consumers in most instances are retail customers.
b GW, or gigawatt, is 1 billion watts.
c Includes 116 billion kWh purchased from nonutility generators.
d Publicly owned utilities are local nonprofit government agencies including municipal, public power districts, irrigation districts, State power authorities, and other State organizations.
e Federal utilities include the electric power Operations of the Federal power marketing administrations and the Tennessee Valley Authority.

SOURCE: Office of Technology Assessment, 1993, based on information from the U.S. Department of Energy, Energy Information Administration, Electric *Power Annual* 1990, DOE/EIA 0348(90) (Washington, DC: U.S. Government Printing Office, January 1992).

many public systems are involved only in retail power distribution and purchase power supplies from other utilities.

The extent of regulation of public power systems varies among States. In some States the public utility commission exercises jurisdiction in whole or part over operations and rates of publicly owned systems. In other States, public power systems are regulated by local governments or are self-regulated. Municipal systems are usually run by the local city council or an independent board elected by voters or appointed by city officials. Other public power systems are run by public utility districts, irrigation districts, or special State authorities.

Rural Electric Cooperatives

Electric cooperatives are electric systems owned by their members, each of whom has one vote in the election of a board of directors. They can be found in 46 States and generally operate in rural areas. In 1990, rural co-ops accounted for 4 percent of total power generation and 7 percent of sales to ultimate customers.

Congress created the Rural Electrification Administration (REA) in 1935 to bring electricity to rural areas and subsequently gave it broad lending authority to stimulate rural electricity use. Cooperatives have access to low-cost govemment-sponsored financing through REA, the Federal Financing Bank, and the Bank for Cooperatives. Early REA borrowers tended to be small cooperatives that purchased wholesale power for distribution to members. Over the past 20 years, however, many expanded into generating and transmission cooperatives in order to lessen their dependence on outside power sources.

Regulatory jurisdiction over cooperatives varies among the States, with some States exercising considerable authority over rates and operations, while other States exempt cooperatives from State regulation. In addition to State regulation, cooperatives with outstanding Federal loans fall under the jurisdiction of REA, which imposes various conditions intended to protect the financial viability of borrowers.

Federal Power Systems

The Federal Government is primarily a wholesaler of electric power produced at federally owned hydroelectric facilities and has less than 25,000 retail customers directly served by its systems. Together, Federal systems had an installed generating capacity of approximately 65 gigawatts (GW) and accounted for 8 percent of the Nation's power generation in 1990. All Federal power systems are required under existing legislation to give preference in the sale of their output to other public power systems and to rural electric cooperatives.

Federally owned or chartered power systems include the Federal power marketing administrations, the Tennessee Valley Authority, and facilities operated by the U.S. Army Corps of Engineers, the Bureau of Reclamation, the Bureau of Indian Affairs, and the International Water and Boundary Commission. Wholesale power is marketed through five Federal power marketing agencies:

1. Bonneville Power Administration,
2. Western Area Power Administration,
3. Southeastern Power Administration,
4. Southwestern Power Administration, and
5. The Alaska Power Administration.

The Tennessee Valley Authority is an independent government corporation that sells power within its statutory service area. Jurisdiction over Federal power systems operations and the rates charged to their customers is established in authorizing legislation. More on these Federal utility systems can be found in chapter 7 of this report.

ELECTRIC POWER REGULATION

The electric utility sector is one of the most heavily regulated industries in the U.S. economy with virtually all aspects of power generation, transmission, and distribution under the oversight of State and/or Federal agencies. Like other businesses, the electric power industry is subject to laws and regulations governing financial transactions, employment practices, health and safety, and environmental impacts. But unlike other businesses, as a public utility, it (along with segments of the natural gas, telecommunications, and transportation industries) is subject to additional economic regulation. Economic regulation of public utilities encompasses organizational and financial structure, prices (rates), profits, allocations of costs, franchise territories, and terms and conditions of market entry and exit—matters that for unregulated entities are normally determined by management discretion and market forces. Economic regulation of public utilities is exercised by Federal, State, and local bodies. Which regulatory body has controlling jurisdiction typically depends on the type of utility, the transaction involved, and State and Federal law. It is not at all unusual for both State and Federal regulators to be involved in review of some utility decisions.

The Concept of a Public Utility

Public utilities enjoy a special status under State and Federal law because their activities provide vital services to businesses and communities (sometimes phrased as "affected with the public interest"). This status confers specific rights and obligations and distinguishes them from most other business enterprises. Generally, a public utility has an obligation to:

- serve all customers in its service area (within its available capacity limitations);
- render safe and adequate service, including meeting foreseeable increases in demand;
- serve all customers within each service class on equal terms (i.e., with no unjust or undue discrimination among customers); and
- charge only a' 'just and reasonable price for its services.[16]

In return for assuming these obligations, the public utility enjoys certain "rights." First, the utility has a right to reasonable compensation for its services, including a profit on capital investment to serve the public. Second, through its franchise and certificate of public convenience and necessity, the utility generally is protected from competition from other enterprises offering the same service in the same service territory. Third, the public utility has a right to conduct its operations and render service subject to reasonable rates and regulations. Finally, in many States public utilities can exercise the right of eminent domain to condemn and take private property for public use where necessary to provide adequate service, subject to the requirement of just compensation to the owner.[17]

Both State and Federal laws define any entity that sells electricity as a public utility,[18] thus bringing generators and retail distributors of electricity under regulation, unless provided with an explicit exception. Jurisdiction over the activities of electric utilities is split between the Federal Government and State agencies (including local governments). This division reflects both the historical growth of electric utility regulation in this country, which began at the State and local level, and the Federal Government's constitutional authority over interstate commerce. Many utilities are now directly or indirectly subject to both Federal and State rate regulation.

16 Charles F. Phillips, Jr., *The Regulation of Public Utilities: Theory and Practice* (Arlington, VA: Public Utilities Reports, Inc., 1984), p. 106.

17 Ibid., p. 107.

18 The definition of an electric utility in the Federal Power Act 1S: "any person or State agency which sells electric energy, " 16 U.S.C. 7%(22), and the definition of 'electric utility company' in the Public Utility Holding Company Act is ''any company which owns or operates facilities used for the generation transmission or distribution of electric energy for sale, " 15 U.S.C. 79b(a)(3).

State Regulation

State regulation of electric power is diverse, but four broad generalizations can be made about the form and extent of government oversight exercised.[19]

1. **State regulatory jurisdiction over utility rates** and operations is typically vested in independent multimember boards or commissions whose members are either appointed or elected.
2. State (or local government) regulators control market entry by granting certificates of public convenience and necessity to electric utilities--creating what are usually monopoly franchise territories.
3. All States regulate retail prices of electricity. In setting retail rates, State regulators must approve a level that covers the utility's cost of providing service and a reasonable rate of return to the utility and its shareholders. Under various formulations, many States require that utility investments be determined to be prudent and "used and useful" before they can be recovered through retail rates. Some States allow recovery for plants under construction, while others defer recovery until the plant is actually in operation.
4. State regulators also exercise control over utility securities (e.g., stock issuance, stock classifications) and financing arrangements (bonds, loans, and other debt transactions). This oversight was instituted because of the historical abuses by public utility holding companies and was intended generally to prevent use of utility assets for nonutility ventures and to protect the financial integrity of the utility.

The extent of State commission jurisdiction over utilities varies. Some States regulate all utilities, including public power systems and cooperatives, while others limit jurisdiction to investor-owned systems and leave regulation of municipal systems to local governments.

Many States also regulate other aspects of utility operations in some detail, including the planning and determination of resource needs such as new generation, bulk power purchases, and construction of transmission and distribution facilities.[20] A number of States regulate the siting of utility facilities either through the public utility commission or a separate siting agency.[21]

In some **States** public utility regulators have a more general mandate to protect and/or promote the public interest and welfare. This mandate has been interpreted as supporting other policy goals for utility regulation, such as economic development, universal electric service, minimum levels of service at equitable or affordable rates, and environmental protection.

RETAIL RATE REGULATION

Regulators establish the rates charged to customers, as well as their view of appropriate profit levels for utilities, through administrative proceedings. Under the most common ratemaking approach-variously referred to as rate-of-return regulation or cost-of-service regulation or traditional rate regulation-the utility commission sets retail rates based on estimates of the expected costs of service to meet projected customer demand (i.e., kilowatt-hour sales).

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19 For a more detailed discussion of State and Federal utility regulation, see Congressional Research Service, *Electricity: A New Regulatory Order?* Committee on Energy and Commerce, U.S. House of Representatives, 102d Cong., 1st sess., Committee Print 1O.2-F, June 1991.

20 For a summary of State requirements for utility planning and forecasting requirements, see Public Utilities Commission of the State of Ohio, *Transmission Line Certification and Siting Procedures and Energy Planning Processes: Summary of State Government Responses to a Survey by the National Governors' Association Task Force on Electricity Transmission,* contractor report prepared for the Office of Technology Assessment, July 1988.

21 For more information, see the discussion of State siting requirements in ch. 7 of OTA, *Electric Power Wheeling and Dealing,* supra note 13.

Box 3-A-The Revenue Requirement

A utility's revenue requirement is the total number of dollars required to cover its operating expenses and to provide a fair profit. This rate setting method is sometimes called the fair return on fair value rule. The revenue requirement is often expressed in a formula:

$$RR= OE + CD + (OC + 1- D)r$$

Where

RR. the revenue requirement (total dollars to be raised);

OE = operating expenses (e.g., fuel, maintenance, salaries, benefits, taxes, and insurance);

CD= current depreciation (on utility plant and equipment);

OC = original cost of capital employed in service to the public, sometimes partly adjusted for inflation;

I = Improvements in capital employed;

D - accumulated depreciation (in the value of capital employed); and

r. rate of return (percent earnings on the value of the capital employed in the business set by the regulators taking into account the utility cost of equity and debt capital, performance, and returns on similar investments).

In the above formula:

(OC-I-D) = rate base (net valuation)

(OG-I-D)r = profit expressed as earnings on the rate base.

SOURCE: Office of Technology Assessment, 1993, adapted from Congressional Research Service, Electricity:A New Regulatory Order? Committee on Energy and Commerce, U.S. House of Representatives, 102d Cong., 1st sess., Committee Print 102-F, June 1891, p. 137, citing Jones and Tybout, "Environmental Regulation and Electric Utility Regulaton: Compatibility and Conflict," Boston College Law Review, vol. 14, 1986, pp. 43-44 (1986).

Retail rates are typically set based on the utility's revenue requirement, i.e., the estimated revenues required to cover operating expenses. These expenses include: administrative, financing, and marketing costs; personnel, fuel, maintenance, purchased power, and other operating costs; plus recovery of capital investment in the rate base (plant and equipment committed to public service less depreciation). A percentage profit (rate of return) on all investments included in the rate base is also included in the revenue requirement for investor-owned utilities. (See box 3-A.) What capital investments are included in the rate base and what expenses are allowed are left to the broad discretion of regulators, as is judgment of what is a fair and reasonable rate of return. The utility too has some leeway in allocating expenses and capital costs in its submissions for ratemaking. State policies and regulations differ in formulations of matters included or recoverable through rates, including treatment of construction work in progress (investment in facilities that are not yet in operation). There are also variations in classes of customers, and related issues such as the availability of basic or lifeline rates for low-income customers.

After establishing the revenue requirement, State regulators must then determine how those funds will be collected from customers-referred to as the rate structure or the rate schedule. The revenue requirement is divided by estimates of expected sales to yield the rate per kilowatt-hour that is used to calculate the customer's bill. Typically, different rates are established for different classes of customers. The rate design for each class must yield a price (per kilowatt-hour) that will produce sufficient revenue to cover the costs of serving that class and contribute to meeting the overall revenue requirement. Rates are revised periodically to reflect changes in utility investments and performance and general economic conditions.

Because fuel prices can vary considerably in response to market conditions, most States have a separate fuel adjustment clause, a mechanism intended to insulate utilities from fuel price swings. The automatic fuel adjustment clause allows utilities to raise or lower fuel charges on customer bills to follow fuel costs as they are incurred instead of waiting for a rate case.

There is no single approved constitutional method of ratemaking. The U.S. Supreme Court has held that the Constitution gives States broad discretion to decide which rate-setting mechanism best meets their needs in balancing the interests of the utility and the public.[22] The rate base method for determining just and reasonable rates for public utilities as long as they are not confiscatory was upheld by the Supreme Court in *Hope Natural Gas Company v. Federal Power Commission*.[23]

With utility profits under traditional ratemaking based on the total value of capital invested and the amount of power sold, many analysts have concluded there is a tremendous financial incentive for utilities to invest heavily in capital-intensive plant and equipment and to sell as much power as they can at prices above their cost of service.[24] This incentive is counterbalanced by the threat of penalties and disallowances by their regulators. For example, regulators have developed certain general principles limiting investments included in the rate base:

- Negligent or wasteful losses that are the fault of the utility management cannot be included as operating charges.
- Investments must be prudent--i.e., reasonable under ordinary circumstances and at the time made. Recovery of costs from uncontrolled cost overruns, construction mismanagement, or plant abandonment can be disallowed as imprudent.

Some States further specify that the plant must actually be in service to the public to qualify for inclusion in the rate base.*

A utility's profits from electricity sales are supposed to reflect regulators decisions about appropriate returns on prudent capital investments in rate base. While regulatory authorities cannot force a utility to operate at a loss, recovery of a utility's authorized rate of return is not guaranteed. At times, the utility may not actually earn its authorized rate of return because of adverse economic conditions, poor business judgment, or because regulators overestimated actual sales. If a utility sells fewer kilowatt-hours than projected in the rate case, its actual revenues will be lower than assumed and, accordingly, its profits will be less than authorized. If, however, the utility sells more kilowatt-hours than projected, its revenues and profits will be higher, assuming that the marginal cost of generating the additional kilowatt-hours is less than the sales price. This is usually the case, because automatic

22 Congressional Research Service, supra note 18, pp. 619-620.

23 320 U.S. 591 (1944).

24 315 Us. 575 (1942).

25 In *Dusquenne Light Co. v. Barasch*, 109 S. Ct 609, Jan. 11, 1989, the U.S. Supreme Court upheld the Pennsylvania statutory requirement that a utility plant must be "used and useful in service to the public" to be includable in the rate base against claims that such a requirement in the case of canceled plants violated constitutional protections for due process and just compensation. The ruling affirmed the State utility commission decision precluding recovering initial costs of a canceled, unfinished nuclear plant even though the costs were prudently incurred by the utility at the time.

fuel adjustment clauses operate to reduce risks to utility profits from fuel price changes. This built-in incentive toward additional sales is what gives rise to the claim that traditional utility ratemaking is biased against utility investment in conservation and energy efficiency.

If the costs of serving additional consumption exceeded the established rates per kilowatt-hour, the financial incentives would change and utilities would profit by restraining demand, However, the immediate cost of procuring or generating additional kilowatt-hours usually falls well below the rates at which utilities are permitted to sell them, thus providing a powerful incentive for utilities always to increase power sales and to resist efforts to lower sales.

Under conventional rate-of-return regulation, short-term profit considerations favor increased sales of kilowatt-hours, especially in situations of surplus capacity that is cheap to operate. Recognition of this tendency has lead State regulators, spurred in large part by consumer and environmental activists, to adopt various measures to insulate or ''decouple' shareholder returns from the volume of kilowatt-hours sold.[26] One such device is the Electricity Revenue Adjustment Mechanism (ERAM) used in California and in variations in other States, in which customer rates are automatically adjusted upward or downward so that the utility meets, but does not exceed, its revenue requirement set in prior rate proceedings. These approaches are discussed in chapter 6 of this report.

Ratemaking is not an exact science, although, as practiced today, it relies heavily on economics, statistics, computer modeling, and expert testimony. Much of the regulators' work is political in nature. Fundamentally regulators seek tradeoffs among often competing policy goals of economic efficiency, adequate and reliable service, environmental quality, and equity.

Assuring Quality of Service

Most State commissions are expressly empowered to assure that utilities provide adequate and reliable service for their retail customers. The obligation generally means that a utility must provide safe, continuous, comfortable, and efficient electric service within its service area. However, the utility is not required to supply power under any and all conditions, such as during severe storms or power outages beyond their control. To provide reliable service, utilities are required to plan to meet reasonably foreseeable contingencies and load growth.

Regulators have several mechanisms for enforcing this obligation. They can punish chronically poor, unreliable, and inefficient service by denying or reducing rate increases. The commission can order the utility to take specific remedial actions to improve service, such as acquiring additional generation or transmission facilities, or executing power purchase contracts. Finally, under certain circumstances varying by jurisdiction, utilities can be held financially liable for injuries or damages to their customers caused by inadequacy, interruption, or failure of electric services.

Energy Efficiency, Resource Planning, and Demand-Side Management

With their plenary authority over retail rates and the construction of electric power facilities, State regulators can exercise considerable influence over utility resource planning and operations. In response to the sizable rate increases and disputes over new powerplant construction that arose in the late 1970s, many utility commissions adopted policies encouraging or requiring utilities to engage in demand-side management (DSM) programs and integrated resource planning (IRP). Several commissions have also adopted incentives or requirements for improvements in the energy efficiency of utilities' supply-side opera-

26 Ralph C. Cavanagh, ''Responsible Power Marketing in an Increasingly Competitive Era,'' *Yale Journal on Regulation*, vol. 5, summer 1988, pp. 331-366.

tions. These requirements are generally intended to lower electricity costs for consumers by encouraging the use of cost-effective energy efficiency measures as an alternative to higher-cost conventional generation. Some policies also have been adopted to support environmental protection, and promote diversity of energy sources. Chapter 6 of this report provides an overview of these State efforts.

The legal basis for requiring utility IRP and DSM varies by State. Some requirements are backed by legislation, others are the result of broad rulemakings by State regulatory commissions, and still others have arisen out of rate cases involving specific utilities. By the 1990s State regulatory requirements for utility planning activities were firmly established in more than 30 States and under development in many others. At the same time, a broad range of financial incentives intended to encourage utility investment in DSM programs had also been adopted by States. These changes are altering the relationship between utilities and their regulators and shifting the financial incentives in utility ratemaking.

Federal Regulation

JURISDICTION

The Federal Power Act gave the Federal Power Commission authority over the rates and conditions for interstate sale and transmission of electric power at wholesale.[27] Federal regulation of interstate and wholesale sales was initially seen as a supplement to State authority to fill a gap where existing State regulation had proven ineffective or unconstitutional. The creation of a Federal role in the regulation of interstate activities in electric power was prompted by the 1927 Supreme Court ruling in *Rhode Island Public Utilities Commission v. Attleboro Steam and Electric Co.* that State regulatory agencies were constitutionally prohibited from setting the prices of electricity sold across State lines because doing so would violate the Commerce Clause.** This decision created a gap in effective regulation of electric utilities that the Federal Power Act was intended to close.

Originally, it was perceived that there was a bright line between Federal and State jurisdiction—Federal regulators would have jurisdiction over wholesale transactions involving more than one State and State commissions would oversee utility operations, instate wholesale transactions, and retail rates. But, as interconnections among utilities grew and long-distance transmission increased, virtually all electric power moving over transmission lines was viewed as being in interstate commerce and, hence, subject to exclusive Federal jurisdiction. These ever-more expansive interpretations of Federal jurisdiction have now brought wholesale transactions between utilities in a single State, as well as most instate wheeling arrangements, under Federal law. These rulings and the fact that most utilities are interconnected with utilities in other States have arguably limited most State jurisdiction over prices and terms of wholesale sales and wheeling transactions, even when they involve instate parties--except in Alaska, Hawaii, and parts of Texas.[29]

27 Public Utility Act of 1935, Act of Aug. 26, 1935, c. 687, Title II, sec. 213,49 Stat. 863, 16U.S.C. 791a-825r, as amended.

28 This landmark Supreme Court case, *Rhode Island Public Utilities Commission* v. *Attleboro Steam and Electric CO., 273* U.S. 83 (1927), held that a State could not regulate the price of electricity generated in that State and sold in another. It reflected the then prevailing view that the Commerce Clause of the Constitution gave the Federal Government exclusive jurisdiction to regulate matters in interstate commerce and foreclosed State action to intrastate matters even in the absence of Federal regulation.

29 See *Federal Power Commission* v. Southern *California Edison Co., 376* U.S. 205 (1%8), also known as *City of Colton* v. *Southern California Edison Co, See also Florida Power & Light Co., 29* FERC *61,140 (1984), in* which FERC asserted exclusive Federal jurisdiction over virtually all transmission service in Florida. Because the power systems in the ERCOT region of Texas, and in Alaska and Hawaii, are not synchronously connected to power systems in other States, it has been widely assumed that FERC does not have jurisdiction over most power transactions in these States.

With the establishment of the U.S. Department of Energy (DOE), the responsibilities of the Federal Power Commission for regulating electric utilities, natural gas pipelines, and oil pipelines were transferred to a new agency, the Federal Energy Regulatory Commission.[30] Its five members are appointed by the President and confirmed by the Senate to staggered, fixed terms; no more than three commissioners may come from the same political party. Although within DOE, FERC retains its independent status. The Secretary may submit his or her views on energy policy to the commission, but the Secretary cannot direct the commissioners to reach a particular result.[31]

The Federal Power Act, as amended, gives FERC jurisdiction over the prices, terms, and conditions of wholesale power sales involving privately owned power companies and of transmission of electricity at wholesale.[32] It also oversees sales and mergers of public utilities,[33] the issuance of securities and indebtedness of electric utilities,[34] and power pools and utility interconnections.[35] In addition, FERC approves the rates for public power sold and transported by the five Federal power marketing administrations, and oversees and licenses nonfederal hydroelectric projects on navigable waters.[36]

The Public Utility Regulatory Policies Act of 1978 (PURPA) gave FERC expanded responsibilities for encouraging cogeneration and certain alternative power technologies.[37] PURPA required utilities to interconnect with and buy power from cogenerators and small power producers that met standards established by FERC at not more than the utility's avoided cost of power.[38] PURPA marked the frost major Federal move to open up electricity markets to nonutilities. At the same time, PURPA exempted these qualifying facilities (QFs) from most of regulatory burdens applicable to public utilities under Federal and State law in order to reduce the institutional barriers to QF development.

PURPA also imposed new requirements directly on State regulatory commissions relating to the consideration of regulatory policy initiatives and consumer protection and representation before State commissions. PURPA required State commissions to give formal consideration to adopting certain new Federal standards as part of State utility law and policy, but PURPA also expressly provided that States could, after such consideration, decline to implement the standard. Many of the proposed standards were already being used by State regulators to ensure that rates more accurately reflect the costs of providing service and to encourage energy conservation. The Federal standards included certain ratemaking methods: seasonal, time of use, and interruptible rate differentials; limiting declining block rate (e.g., large volume) discounts unless they involved lower service costs; and requiring utilities to offer load management technologies to their customers. Federal standards were also proposed

30 The Department of Energy Organization Act, Public Law 95-91, Title IV (1977), 42 U.S.C. 7101 et seq. FERC also regulates interstate natural gas pipeline transactions and oil pipelines.

31 Congressional Research Service, supra note 18, p. 129, citing Grenier and Clark, "The Relationship between DOE and FERC: Innovative Government or Inevitable Headache," *Energy Law Journal,* vol. 1, 1980, p. 325.

32 See secs. 201 and 205 of the Federal Power Act, 16 U.S.C. 824a and 824d, respectively.

33 Section 203 of the Federal Power Act, 116 U.S.C. 824b.

34 16 U.S.C. 824c.

3516 U.S.C. 824b.

36 Title I of the Federal Power Act, 116 U.S.C. 791a to 823.

37 Public Law 95-615, 92 Stat. 3117, Nov. 9, 1978.

38 Avoided cost generally means a price not exceeding the cost of electric energy that the utility would otherwise have to generate itself Or purchase from another source. Public Law 95-615, sec. 210,92 Stat. 3144, 16 U.S.C. 824a-3.

for consumer information, lifeline rates, and procedures for terminating electricity service. Not surprisingly, PURPA was challenged in the Courts. However, the Supreme Court ruled that this Federal intrusion into matters previously left to the States was found to be within the broad embrace of the Commerce Clause.[39]

FERC shares responsibility for enforcing the Public Utility Holding Company Act of 1935 (PUHCA) with the Securities and Exchange Commission (SEC).[40] PUHCA vests broad authority over the structure, finances, and operations of public utility holding companies in the SEC. PUHCA was enacted in response to widespread concern over the influence of a handful of large interstate utility holding companies that by 1932 controlled over 75 percent of the private electric utilities.[41] PUHCA was intended to limit severely the use of the holding company structure and to force the regional consolidation of the existing large multistate holding companies.

WHOLESALE RATEMAKING[42]

The Federal Power Act requires that rates charged for wholesale power sales and for transmission be "just and reasonable" and "not unduly discriminatory or preferential."[43] Utilities under FERC jurisdiction must file detailed, written tariffs and schedules of all rates and charges, which are available for public inspection. FERC has established detailed regulations and guidelines on rate requests, allowable costs, and matters considered in rate of return determinations. FERC also requires that electric utilities follow a uniform system of accounting.

Proposed new rate schedules must be filed with FERC 60 to 120 days before they are to go into effect. Utilities must submit detailed schedules of information, including actual and projected cost of service data to support the increases. When a proposed new rate is filed, FERC has several choices: it can reject the filing, approve the rate schedule immediately, or order a hearing and suspend the new rate for 5 months. If FERC schedules a hearing, the burden of proof is on the utility seeking the rate increase. The Commission must also consider evidence submitted by customers or other interested parties. Parties to proceedings can seek review in Federal Courts of Appeals, where the standard is whether the agency decision is supported by substantial evidence.

FERC decisions are made on a case-by-case basis. However, over the years a substantial body of administrative precedent has accumulated that guides the commission and applicants. FERC is not wholly bound by precedent, however. Within its broad and general authority under the Federal Power Act, the commission can establish new policies on electric power transactions through

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39 *Federal Energy Regulatory Commission* v. *Mississippi, 456* U.S. 742 (1982).

40 Act of Aug. 26, 1935, c. 687, Title I, sec. 33, 49 Stat. 438, 15 U.S.C. 79.

41 The holding companies' complex corporate structures and interlocking business arrangements had frustrated both State and Federal oversight of their activities, led to substantial investment fraud, and weakened or bankrupted many local gas and electric utilities. For more on the structure and influence of the holding companies, see Leonard S. Hyman, *America's Electric Utilities: Past, Present and Future,* 3d Ed. (Arlington, VA: Public Utilities Reports, Inc., 1988), pp. 71-83.

42 For more background on Federal power regulation, see Congressional Research Service, supra note 18, pp. 135-144.

43 16 U.S.C. 824d and 824e. The term "just and reasonable" as used by Congress in the Federal Power Act in 1935 had been established by decades of judicial review of administrative actions governing public utilities *Farmers Union Central Exchange, Inc. et al. v. Federal Energy Regulatory Commission*, 734 F2d 1486, at p. 1502 (D.C. Circuit, 1984). In that case, the court reviewed basic principles of rate regulation observing that Courts will uphold agency rate orders that fall within a "zone of reasonableness' where rates are neither "less than compensatory" nor "excessive." The zone of reasonableness requires striking a fair balance between the financial interests of the regulated company and "the relevant public interests. ' In determining the reasonableness of rates to a producer, the concern is whether the rate is high enough to cover the cost of debt and expenses and provide a return commensurate with investments in other enterprises with comparable risks in order to maintain credit and attract capital. In deciding the justness and reasonableness to the consumer, the concern is whether the rate is low enough to prevent exploitation by the regulated business.

individual case decisions or in new rulemakings. When FERC departs from past policies, however, it must provide ample justification and documentation of its decision in the face of possible court challenges.

In approving wholesale rates, FERC historically has followed a cost of service approach that is, in principle, similar to that used by State regulators. As with State rate regulation, Federal economic regulation is based, in part, on lack of effective competition in bulk power markets. However, during the Reagan and Bush Administrations, FERC chairmen and staff embraced the market deregulation rhetoric of the times and embarked on several initiatives with the goal of allowing utilities and independent power producers to charge ''market-based rates' for their wholesale services rather than cost-of-service rates established by regulators.[44] Under market-based pricing, wholesale power rates are not based on a detailed evaluation of costs of service plus an appropriate rate of return set by regulators, but rather on a price set through competitive bidding or arms-length negotiations between power sellers and purchasing utilities where market power is absent or mitigated. Some proponents expressed a preference for wholesale rates set by competitive market signals instead of regulators' projections, estimates, and judgments in the belief that such an approach would produce a more economically optimal result for society .45 Others also argued pragmatically that market-based rates with prospects of higher profits than those available to regulated utilities were needed to attract new entrants, so-called independent power producers, to build new powerplants because the pace of utility construction had slowed and some feared an impending capacity shortfall.[46] Still others supported the availability of market-based prices and the expanded participation of independent power producers in generation markets to provide utilities with a greater variety of options in resource planning and acquisition.

While FERC generally retains cost-of-service rate policies for bulk power sales, in a growing number of cases, the commission has accepted market-based prices. By May 1993 FERC had received more than 40 applications for market prices for wholesale power contracts and had approved 29 of these requests and rejected 9.[47] In approving these transactions, FERC imposed various conditions intended to establish that the applicant's market power has been mitigated. The preconditions for receiving market-based rates have been evolving on a case-by-case basis and FERC has not adopted any generic policy. In these and other cases, FERC has used its conditioning power to require applicants to expand access to transmission services to provide wider

44 In 1987, FERC solicited public comments on three notices of proposed rulemakings (NOPRS): 1) competitive bidding for new power requirements, 2) determinati'on of avoided costs under PURPA, and 3) treatment of independent power producers. See discussion in OTA, *Electric Power Wheeling and Dealing*, supra note 14, pp. 77-79. The FERC NOPRS proved controversial, and efforts to establish formal rules or policies were abandoned as commission membership changed. With the support of several co remission members and key FERC staff, however, the overall policy goals were still pursued on a case-by-case basis. See Congressional Research Service, supra note 18, pp 170-172.

45 For more discussion and references for the various deregulation proposals, see Congressional Research Service, supra nOte 18, pp. 232-303.

46 J. Steven Herod and Jeffrey Skeer, "A Look at National and Regional Electric Supply Needs," paper presented at the 12th Energy Technology Conference and Exposition, March 1985; U.S. Department of Energy, Deputy Assistant Secretary for Energy Emergencies, Staff Report, "Electric Power Supply and Demand for the Contiguous United States, 1987-19%," DOE/E-0011 (Springfield, VA: National Technical Information Service, February 1988); "Summary of Current Staff Proposal on PURPA-Related Issues, " Federal Energy Regulatory Commission Sept. 11, 1987. Other industry experts discount the shortfall theory, interpreting the slowdown as the natural result of aggressive overbuilding of large capacity baseload plants and slower economic growth. They also note that new capacity needs for many utilities are for smaller increments of peak-load power, which would be met by combustion turbines and other short-lead time resources.

47 Federal Energy Regulatory Commission Office of Economic policy, personal communication, June 2, 1993. One application is still pending and another was terminated for failure to respond to a deficiency finding.

opportunities for other buyers and sellers in bulk power markets.

TRANSMISSION ACCESS

Access to transmission services allows utilities opportunities to purchase and sell power in a wider area beyond their local host utilities and adjacent utilities. Within segments of the electric utility industry and regulators, there has been longstanding concern that some transmission "haves" might use their control over regional transmission systems to keep their wholesale utility customers captive and to deny competing wholesale power providers access to bulk power markets. Utilities that have been denied wheeling services have had only limited options.[48]

The extent of FERC'S authority to order one electric utility to transmit or "wheel" over its lines power produced by another generator has been a matter of contention for years. FERC'S authority under the original Federal Power Act to order wheeling was not explicit. PURPA, for the first time, provided explicit wheeling authority but placed such severe limitations on its exercise that made it all but impossible to obtain wheeling orders.[49] In recent years FERC has relied on its authority under other provisions of law to advance its policy goals of expanding access to transmission services to promote the growth of competitive bulk power markets. For example, FERC conditioned the approval of several large utility mergers on agreement that the merged utility system offer transmission services to other utilities.[50] FERC also has encouraged several utilities seeking acceptance of market-based rates for wholesale power transactions to file open-access transmission tariffs as a means of mitigating market power.

The Energy Policy Act of 1992 clarified and strengthened FERC'S wheeling authority.[51] Now utilities, independent power producers, and others can apply to FERC for mandatory wheeling orders to carry out wholesale power transactions. This change provides new impetus for the growth of competitive power markets and expands the options available to utilities in resource planning and acquisitions. The act restricted retail wheeling—provision of transmisson services to retail customers--but left State authority in such matters untouched. With the basic question of whether FERC can issue wheeling orders settled, new controversies are likely to arise as FERC struggles to establish fair and workable policies on transmission pricing and capacity determinations.

ASSURING QUALITY OF SERVICE

Unlike State regulatory commissions, FERC has only very limited authority under the Federal

48 In *Otter Tail Power Co.* v. *United States*, 410 U.S. 366, at 375 (1973), the U.S. Supreme Court noted in dicta that the Federal Power Act did not grant any authority to order wheeling, but that wheeling could be ordered by the Federal Courts as a remedy under the antitrust laws. A similar conclusion on wheeling authority is reached in National Regulatory Research Institute *Non-Technical Impediments to Power Transfers*, September 1987, pp. 52-68, although the author notes that FERC may have some as-yet-untested authority to order wheeling as a remedy for anticompetitive behavior under sees. 205 and 206 of the Federal Power Act, id. at note 45, p. 64. See also *Florida Power & Light Co. v. FERC*, 660 F. 2d 668 (5th Cir. 1981), p. 679. The report of the Conference Committee on PURPA is vague on the extent of any existing wheeling authority FERC might have outside of sees. 211 and 212 and notes that PURPA is not intended to affect existing authority, House Conference Report 95-1750, to accompany H.R. 4018, 95th Cong., 2d sess., Oct. 10, 1978, pp. 91-95, *U.S. Code Congressional and Administrative News, 1978, pp. 7825-7829.*

49 PURPA, secs. 203 and 204, amended the Federal Power Act to add new sees. 211 and 212, 16 U.S.C. 824j and 16 U.S.C. 824k.

50 In *Re Utah power& Light co. et al.* (Oct. 26, 1988), FERC approved the merger of Utah Power & Light Co. into Pacific Power & Light Co., subject to the condition that the merged companies provide firm wholesale transmission services at cost-based rates to any utility that requested such service. The condition was necessary to prevent the future exercise of market power by the new company to foreclose access by competitors to bulk power markets. The decision was reached under sec. 203 of the Federal Power Act, which requires commission approval of mergers and acquisitions. A more expansive 'open access" provision was included in the FERC approval of Northeast Utilities acquisition of the bankrupt Public Service Co. of New Hampshire.

51 Public Law 102-486, Oct. 24, 1992, 106 Stat. 2776. Expanded transmission access provisions are contained in Title VIII, Subtitle B, secs. 721-726, 106 Stat. 2915-2921, which amend sees. 211 and 212 of the Federal Power Act.

Power Act to remedy inadequate service.[52] If a State commission fries a complaint, and if FERC finds that interstate service of a public utility is inadequate or insufficient, the commission can order the utility to provide the proper level of service provided that the utility has sufficient capacity available .53 The commission has no authority to compel a utility to enlarge its generating facilities or to sell or exchange electricity when doing so would impair its ability to render adequate service to its customers.

There is no Federal rate penalty for failure to provide adequate and reliable service under Federal law, nor is there a basis to provide more favorable treatment to utilities providing superior performance. Rate treatment provides no incentive or disincentive for performance or to remedy inadequate service.

Nevertheless, there is a chain of decisions creating a Federal obligation to provide wholesale service. FERC can require a jurisdictional utility to provide wholesale service to another utility where the ability of the purchasing utility to meet its customer needs is threatened and the selling jurisdictional utility can provide the service without imposing an undue burden on service to its own customers. This has come into play when long-term power purchase contracts have expired, and the parties have not entered into new arrangements, and protects the purchasing utility from being left without power supplies. If, however, generating capacity is not available, FERC cannot enforce wholesale contracts or the obligation to seine.

Adequacy and reliability have been dealt with as planning tools for electric utilities and not as matters of regulatory concern. PURPA amended the Federal Power Act to include provisions dealing with interconnections and emergency power sharing arrangements. Utilities are required to report anticipated power shortages to FERC and contingency plans to State regulators. FERC is authorized to work with State commissions and local reliability councils to promote reliability in utility planning and coordination activities. Beyond this, there are no explicit responsibilities.

ENERGY EFFICIENCY, RESOURCE PLANNING, AND DEMAND-SIDE MANAGEMENT

Compared to the scope and extent of State regulation of utility activities, FERC leaves largely untouched many areas related to energy efficiency and resource planning. This has been primarily a matter of policy, but also reflects uncertainty over the extent of FERC power and influence over generating resources and retail operations under the Federal Power Act.

FERC regulations and rate procedures are focused on the costs of service of the entity selling electric power and not on the purchasing utility. Its concepts of just and reasonable rates, and the obligation to provide electricity at the lowest possible rates consistent with adequate service, have not been expanded into requiring that either the selling or buying utility demonstrate that the resource selected is the lowest cost alternative for meeting customer needs, considering both supply and demand-side alternatives.

PUBLIC UTILITY HOLDING COMPANIES

Under PUHCA any company that owns or controls more than 10 percent of the voting securities of a public utility is considered to be a public utility holding company. An electric utility company is any company that owns or operates facilities used for the generation, transmission, or distribution of electric energy for sale. The holding companies are subject to extensive regulation of their financial activities and operations. Public utility holding companies that operate wholly within one State or in contiguous States

52 Congressional Research Service, supra note 18, p. 157.

5316 U.S.C. Section 824 f.

can qualify for an exemption from the most stringent regulatory oversight of PUHCA. Exemptions also apply to companies primarily engaged in nonutility business and not deriving a material part of their income from the public utility business.[54] Nonexempt entities are registered holding companies and are limited in their operations to "a single integrated public-utility system, and to such other businesses as are reasonably incidental, or economically necessary or appropriate [there]to. ' Integration means that the utility operations are limited to a single area or region of the country. Registered holding companies must obtain SEC approval of the sale and issuance of securities; transactions among their affiliates and subsidiaries; and services, sales, and construction contracts. In addition, the companies must fide extensive financial reports with the SEC. In contrast, exempt companies need only file limited annual reports with the SEC.

With the growth of wholesale power markets in the late 1980s, PUHCA requirements were criticized as unfairly restricting entry into the competitive power industry and requiring unnecessarily complex corporate structures for independent power projects. These so-called "PUHCA pretzels' ' were created to avoid the geographic restrictions on holding company operations and/or the loss of the PUHCA exemption for qualifying facilities under PURPA. Even so, the independent power sector grew substantially over the period and among its major players are the independent power affiliates of regulated electric utilities.

The Energy Policy Act of 1992 amended PUHCA to create a new category, the exempt wholesale generator (EWG), for certain entities either building or operating generating facilities that sell electricity at wholesale to electric utilities.[55] The act also loosened restrictions on involvement of domestic registered holding companies' affiliates in power markets outside the United States.

Regulation of resource planning and affiliate transactions by registered holding companies has been a recurring source of tension between State and Federal regulators.

■ State and Federal Conflicts

While States have exclusive retail rate jurisdiction, under the *Narragansett* doctrine they must generally pass through wholesale rates previously approved by FERC.[56] The extent to which prior FERC determinations of the reasonableness of wholesale rates preempts State consideration of the retail impacts of those same rates is a matter of some controversy.[57] The strain arises because State regulatory programs and the considerations used in setting rates are generally far more extensive than FERC'S. In some cases, requiring States to adopt without question FERC'S wholesale rate determinations in setting retail rates would preclude States from exercising their own regulatory authority over issues normally within their jurisdiction, such as resource planning and acquisition and facility siting.

The major limitation on Federal preemption is found in the *Pike County* exception, which affirmed the right of a State commission to examine the prudence of a wholesale power purchase contract and to disallow the pass-

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54 15 U.S.C. 79c.

55 Public Law 102-486, Oct. 24, 1992, 106 Stat. 2776.

56 This rule was set forth in *Narragansett Electric* Co. v. *Burke,* 119 R.I. 559,381 A.2d 1358 (1977), *cert. denied, 435* U.S. 972 (1978), one of a series of State court decisions that recognized Federal preemption.

57 For discussion of these issues, see the following: Ronald D. Jones, "Regulations of Interstate Electric Power: FERC Versus the States,' 2 *Natural Resources & Environment 3,* Spring 1987; Lynn N. Hargis, "The War Between The Rates Is Over, But Battles Rem@' 2 *Natural Resources & Environment 7,* Spring 1987; and Bill Clinton, Robert E. Johnston, Walter W. Nixon, III, and Sam Bratton, ''FERC, State Regulators and Public Utilities: A Tilted Balance?" 2 *Natural Resources & Environment* 11, Spring 1987.

through of FERC-approved wholesale costs if lower cost power supplies were available elsewhere.[58] The issue of whether States can review the prudence of wholesale power contracts will become especially critical if, as a result of State least-cost planning initiatives and competitive procurement practices, utilities rely more heavily on bulk power purchases for new power supplies. Wholesale prices for power sales from utilities and independent generators, except for QF transactions, fall exclusively within FERC'S jurisdiction, as do the terms and conditions for transmission services. This creates a situation where States shape the initial consideration and choice of resources for their jurisdictional utilities through the planning process but have diminished control over wholesale power costs. The split jurisdiction increases the potential for utilities to escape State jurisdiction at the same time that the growth of competitive power' entities, including unregulated utility independent power affiliates, raises State regulator concerns over their ability to effectively control self-dealing, unfair competition, and other unfair practices.

The vitality of the *Pike County* exception has been cast into doubt by the Supreme Court's 1988 decision in *Mississippi Power & Light Co. v. Mississippi ex rel. Moore. In* this decision, the Court rejected State efforts to deny a rate increase based on FERC'S allocation of the costs of a nuclear unit built to meet the needs of an integrated interstate holding company system, on the grounds that the local subsidiary's participation in the project was imprudent.[59] The Court held that a State prudence inquiry was preempted even though FERC had not examined the issue during wholesale rate proceedings. The State regulators' only recourse is to challenge the prudence of the wholesale arrangements before FERC. Whether the *Mississippi Power & Light* decision is limited to the particular situation of interstate holding companies, or whether it marks further limitations on the powers of State regulators, is not yet known. Resolution of this controversy over conflicting Federal and State jurisdictional claims will be one of the major public policy issues in any transition to a more competitive electric power industry.

Note that the House and Senate versions of the Energy Policy Act of 1992 originally adopted different approaches to the Federal-State jurisdictional conflicts over competitive power transactions. Conferees failed to reach agreement on an alternative resolution, so the potential for conflict remains.

In an increasing number of cases, FERC'S efforts to expand competition in bulk power markets in pursuit of economic policies and streamlining g the bureaucratic process is moving Federal regulation away from detailed consideration of costs of service. At the same time, States though IRP, incentive rates, and DSM are moving toward greater oversight and involvement in utility planning and decisionmaking to promote least-cost energy plans. A number of State regulators see the potential for a clash between State least-cost plans and FERC (and SEC) preemptive regulation of wholesale transactions, particularly in the area of multistate utility holding companies. This has led to proposals for legislation to give States greater responsibility in resource planning areas, authorizing interstate plans for multistate utilities, and requiring FERC

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58 *pike County Light & power Co. v. Pennsylvania Public Utility Commission, 77* Pa. Comm'w. 268, 465 A. 2d 735 (1983). The potential exception was apparently accepted by FERC in *Pennsylvania Power & Light Co., 23* F. E.R.C. 61,005 (1983) and noted by the U.S. Supreme Court in *Nantahala Power & Light Co. v. Thornburg*, 106 U.S. *2349 (1986).*

59 *Mississippi Power & Light Co. v. Mississippi ex rel. Moore, 487* U.S. 354, 108 S. Ct. 2428, 101 L. Ed 2d. 322 (1988.)

rulings **to be** consistent with State plans or at least involve consultations with State regulators.[60]

Other observers argue that such legislation is not needed because in their view the potential for conflicts is minimal and existing law could allow cooperation and consultation among FERC and affected State regulators and holding companies before IRP approval.[61] Some also see **the potential** for regional integrated resource planning decisions to result in some unspecfied adverse impacts on bulk power markets and access to transmission services.[62]

OVERVIEW OF ELECTRIC UTILITY SYSTEMS AND OPERATIONS

Electric utilities provide much more than the commodity of kilowatt-hours of electricity. Their special obligations as public utilities require them to assure reliable, adequate, safe, and economic electric service on demand to customers in their franchise area. Utility customers value electricity for the energy services that it provides (e.g., lighting, heating, cooling, machine drive). The evolving perception of the role of utilities as providers of reliable and economic energy services to customers rather than purveyors of kilowatt-hours is evidenced in shifts both in internal utility organization and in regulatory policies. These changes reflect recognition of the potential contribution of utility conservation, load management, and efficiency programs in reducing electricity demand growth as an effective means of servicing customer needs and as an alternative to new powerplant construction.

As part of their obligation to serve, electric utilities must anticipate and match customer demand, while assuring system reliability, minimizing electricity rates, and maintaining financial health. To do this effectively—and for privately held systems at a profit-requires highly complex physical systems, specialized personnel, a myriad of operations, and extensive planning capabilities. Figure 3-5 shows a simplified electric power system. The structure and operations of electric utilities in the United States are shaped by the physical requirements of running reliable interconnected electric power systems and by the special institutional requirements imposed by their regulated monopoly status and service territories.

In particular, many features of the design and operation of electric power systems reflect two fundamental physical principles of electricity:[63]

1. Electricity must be generated as it is needed because it flows at nearly the speed of light with virtually no storage of power in the system.

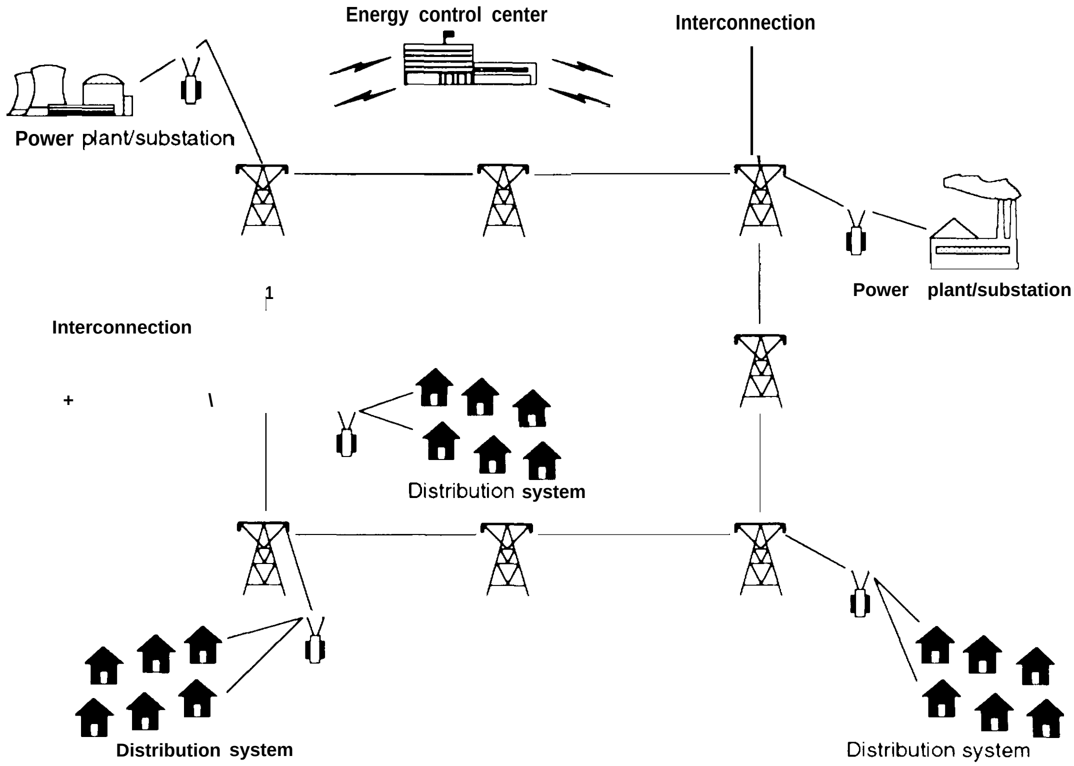
60 See, for example, Statement of Ashley C. Brown, Commissioner, Ohio Public Utilities Commission in Hearings on S. 2607, Legislation Authorizing Regional Integrated Resource Plarming before the Senate Committee on Energy and Natural Resources, May 14, 1992. Commissioner Brown, on behalf of the National Association of Regulatory Utility Commissioners, testified that as a result of Federal court rulings and FERC policies, ''under current law, holding company systems registered under PUHCA cannot be effectively regulated at any level of government—State, Federal, or local. " See also the Statement of Sam I. Bratton, Jr., Chairman, Arkansas Public Service Commission, Hearing on S. 2607 Before the Committee on Energy and Natural Resources, U.S. Senate, May 14,1992. Chairman Bratton testified that as a result of the U.S. Supreme Court decision in *Mississippi Power & Light v. State of Mississippi ex rel. Moore,* 487 U.S. 354 (1988), electric utility holding companies could avoid State regulatory review of retail rates by shifting generation from retail to wholesale subsidiaries. Bratton further observed that while commentators continued to debate the extent of the *Mississippi Power & Light* decision, ". . . participants in the debate seemed to agree on one thing: State regulators and registered holding companies cannot plan for additions of resources for their system and be assured that such plans will ultimately be overturned by FERC.'' He termed the situation "a major regulatory gap' and ''preemption without planning. " The State regulators were joined in their support of legislation on cooperative regional integrated resource planning by Entergy Corp., the registered holding company involved in the *Mississippi Power& Light case.*

61 See testimony of William S. Sherman, General Counsel, Federal Energy Regulatory Commission, before the Committee on Energy and Natural Resources, U.S. Senate, May 14, 1992.

62 Ibid.

63 For a more detailed treatment of utility operations and planning, see ch. 4 in OTA, *Electric Power Wheeling and Dealing,* supra note 14, from which this discussion was drawn.

Figure 3-5 Simplified Model of an Electric Power System



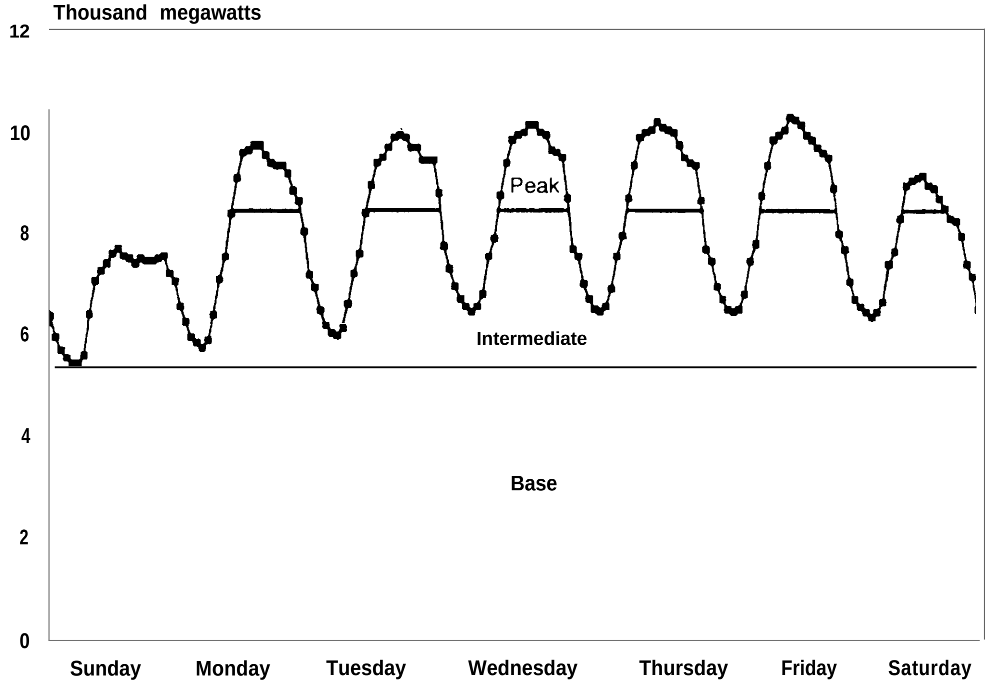
SOURCE: U.S. Congress, Office of Technology Assessment, Electric *Power Wheeling* and *Dealing: Technological Opportunities for Increasing* Competition, OTA-E-409 (Washington, DC: U.S. Government Printing Office, May 1989), p. 11.

2. Every flow of electricity from a powerplant to a distribution system affects the entire transmission system, not just the most direct path between them.

The first principle means that electric power systems must be planned and operated to follow customer demand (load) instantaneously. Following load requires that if customer demand for electricity increases, more generating units must be dispatched to meet the increase in load, and when load decreases, generation must also be backed down. Customer demands on the system change continuously, although they exhibit daily, weekly, and seasonal load cycles. Figure 3-6 shows a weekly load profile for a typical utility. Sudden failure of generating units or transmission components instantly affects frequency and voltage across the power system. Following load requires that utilities forecast likely patterns of customer demand and possible equipment failures and plan for and maintain adequate generating resources and transmission capacity in reserve and readily available to meet changes in demand and respond to contingencies on short notice. Moreover, power systems must be operated at all times to maintain narrow frequency and voltage standards to protect customer and power system equipment and to preserve system stability.

The second principle means that power transmission affects not only the transmission lines of the utility generating the power but also all the transmission lines of utility systems interconnected with it. When one utility transfers power to another utility, the receiving utility reduces its

Figure 3-6-Weekly Load Curve



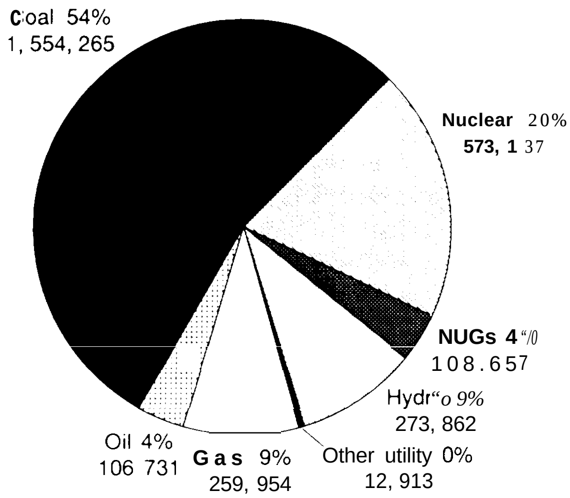
SOURCE: Office of Technology Assessment, 1883, based on Power Technologies, Inc., "Technical Background and Considerations in Proposed Increased Wheeling, Transmission Access and Non-Utility Generation," contractor report prepared for the Office of Technology Assessment, March 1988, pp. 2-3.

generation while the selling utility increases its generation, but the power flows over all paths available, not just the transmission lines of the two utilities involved. Part of the load may be carried by the transmission lines of other utilities hundreds of miles away, reducing the amount of power that those utilities can place on their own lines and, perhaps, overburdening a fully loaded line, and thus risking failure. Therefore, to maintain the integrity of the grid, each utility must control its operations and coordinate its transactions with neighboring systems to ensure that no components are overloaded on any of the possible paths available.

In addition to satisfying basic physical conditions, utilities must meet certain operational requirements. They must design and operate their systems to provide electricity with the correct frequency and proper voltage for customer equipment. The service must be reliable-sufficient to meet changing customer loads with an acceptable level of outages or service interruptions. In practice, voltage, frequency, and reliability are viewed as fundamental technical performance standards that must be met in system operation and planning. Planning and operating the power system in a manner that minimizes costs to the customer and maintains the profitability of the utility enterprise are additional objectives for utility decisionmakers and their regulatory overseers.

Satisfying these technical and operating conditions over seconds, hours, days, months, and years requires a high degree of coordination, planning, and cooperation among utilities, and detailed data and engineering analyses. This section reviews the major components of electric power systems infrastructure and operation and planning functions.

Figure 3-7—Electricity Generation by Fuel 1990 (millions of kWh)



SOURCE: Office of Technology Assessment, 1993, based on data from the North American Electric Reliability Council.

Electric Power System Components

The physical infrastructure of an electric power system consists of:

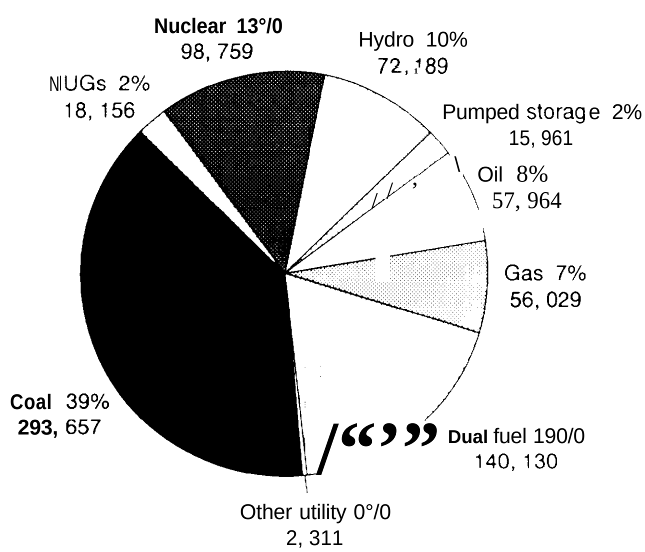
- generating units that produce electricity;
- transmission lines that transport electricity over long distances;
- distribution lines that deliver the electricity to customers;
- substations that connect the pieces to each other; and
- energy control centers to coordinate the operation of the components from moment to moment and in the near future.

A wide variety of other planning and engineering systems coordinate capacity utilization and expansion plans for the longer term. Figure 3-5 shows a simple electric system with two powerplants and three distribution systems connected by a transmission network of four transmission lines and is linked with neighboring utility systems by two tie lines.

Electric generators convert mechanical energy derived from fossil fuel combustion, nuclear fission, falling water, wind, and other primary energy sources to produce electricity. Utilities often have a mix of generating units that run on different energy sources and that are suitable for base, intermediate, or peaking loads. As shown in figure 3-7, about 56 percent of electricity generated in the United States in 1990 came from coal-fired generation and another 21 percent came from nuclear units. Installed generating capacity by fuel source is shown in figure 3-8.

Generators typically produce alternating-current (AC) electricity at a frequency of 60 cycles per second (60 Hertz or 60 Hz) with voltages between 12,000 and 30,000 volts. The frequency of all generating units on a system must be precisely synchronized. Automatic voltage regulators on generating units control the unit's voltage output, and speed governors monitor frequency and adjust power output in response to changing system conditions to maintain balance.

Figure 3-8—Electric Utilities Installed Generating Capacity 1990 (summer megawatts)



SOURCE: Office of Technology Assessment, 1993, based on data from the North American Electric Reliability Council.

A powerplant consists of one or more generating units on a site together with a generation substation that connects the generators to transmission lines. Power transformers at the substations raise the voltage to higher levels for efficient transmission. Substations also hold monitoring and communications equipment and control and protective devices for transmission and generation facilities.

Transmission lines carry electric energy from the powerplants to the distribution systems. To minimize losses over long distances, transmission lines operate at high voltages, typically between 69 and 765 kilovolts (kV). Most transmission in the United States consists of overhead AC lines, but direct current (DC) transmission lines and underground cables are used for special applications. Power transformers raise the generator voltage to the transmission voltage and back down to the distribution network level (typically under 35 kV) at the other end.

Transmission systems consist of interconnected transmission lines (the conductors (e.g., wires) and their supporting towers) plus monitoring, control, and protective equipment and devices housed in transmission substations and used to regulate voltage and power flow on the lines.

Most customers receive their electricity from a distribution system.[64] Distribution systems operate at lower voltages than the transmission system, typically under 35 kV, to transport smaller amounts of electricity relatively short distances. Power transformers reduce the high-voltage electricity from the transmission system to the lower distribution system level. The power transformers are housed together with control and protection devices in distribution substations.

The distribution system is divided into the primary distribution system, operating at between 2.4 and 35 kV, which moves power short distances and serves some moderately large industrial and commercial customers, and the secondary distribution system at 110 to 600 volts, which typically serves groups of customers in neighborhoods. The primary distribution system delivers power to distribution transformers, which reduce voltage to the secondary system voltage levels.

Protective apparatus in the distribution system includes circuit breakers in distribution substations that open automatically when a protective relay detects a fault (or short circuit) and fuses on the secondary systems that open when overloads occur. Many of the circuit breakers and switches in distribution circuits are manually operated devices, so restoring service after outages is usually done manually by dispatching a work crew to the site.

Utilities may have a dozen or more generating units and transmission lines, and hundreds of distribution systems serving hundreds of thousands of customers, each with a variety of energy-using devices. The energy control center coordinates the operation and dispatch of all power system components within a defined geographic region called a control area. One or more utilities may make up a control area. The control area in figure 3-5 is interconnected to two neighboring control areas through transmission lines. There are approximately 160 individual control areas in the United States.

Energy control centers use a variety of equipment and procedures: monitoring and communication equipment (telemetry) to keep constant watch on generator output and system conditions; computer-based analytical and data processing tools which, together with engineering expertise, specify how to operate generators and transmission lines; and governors, switches, and other devices that actually control generators and transmission lines. The control center equipment and procedures are typically organized into three somewhat overlapping systems:

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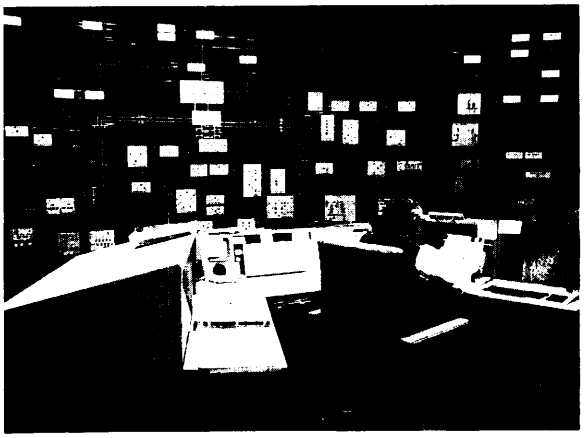
64 Some very large electric consumers, such as major industrial plants, take their power directly from the transmission system, typically at subtransmission voltage levels between 23 and 138 kV. A substation containing metering, protective, and switching apparatus connects these large customers to a transmission line.



CASAZZA, SCHULTZ & ASSOCIATES, INC.

Utilities monitor and direct power system operations within a control area from the energy control center show here.

1. automatic generation control (AGC) systems, which coordinate the power output of generators to balance supply with customer demand;
2. supervisory control and data acquisition (SCADA) systems, which coordinate the transmission line equipment and generator voltages; and
3. analytical systems, which monitor and evaluate system security and performance, and plan operations.

These three systems are sometimes integrated in a full energy management system (EMS).

Sophisticated coordinated operation and planning systems control the vast complex of generators, transmission lines, distribution systems, and substations that makes up the typical electric power system. Coordination operation systems include monitoring and communication equipment, devices that actually control generators and transmission lines, and engineering models and expertise that together specify how to operate generators and transmission lines. Planning systems focus on the selection of the technology requirements (generation, transmission, distribution, and energy conservation/efficiency resources and operating and maintenance practices) to **satisfy** predicted demand in an economic manner. Planning functions operate on several time horizons-from daily, weekly, or seasonal scheduling commitment of generation and transmission resources to long-term, 20- to 40-year system capacity expansion and maintenance plans. Integrated resource planning is one planning mechanism used to carry out utility intermediate and long-term strategic planning functions.

Backing the coordinated operation and planning systems are advanced software and engineering models, experienced technical personnel, and a host of engineering and technical standards and other institutional arrangements that together assure the safe, reliable, and economic operation of electric power systems and coordinate operations with other interconnected utilities. Carrying out these various operations requires detailed and extensive information on utility systems, load characteristics, and customer needs.

Operating and Planning Functions

Together the coordinated operating and planning systems and procedures aid utilities in the performance of three general functions: following changing loads; maintaining reliability; and coordinating power transactions.

In practice, utilities seek to perform these functions at minimum cost. Each of these basic functions focuses on different time horizons and different aspects of the power system. See table 3-3. Some procedures are performed continuously, such as coordinating the energy output of generating units to balance demand. Others, such as planning generation additions and DSM programs, are performed far less often. Each time horizon beyond a few seconds requires forecasts of customer demand and performance of system equipment. All require a tremendous amount of information, computing power, and communication capability, as well as extensive coordination within and among the various organizations involved.

Table 3-3-Electric Utility Operating and Planning Functions

Function	Purpose	Procedures Involved
Following load		
Frequency regulation	Following moment-to-moment fluctuations.	Governor control. Automatic generation control (AGC) and economic dispatch.
Cycling	Following daily, weekly, and seasonal cycles (within equipment, voltage, power limits).	AGC/economic dispatch. Unit commitment. Voltage control.
Maintaining reliability		
Security	Preparing for unplanned equipment failure.	Unit commitment (for spinning and ready reserves). Security constrained dispatch. Voltage control.
Adequacy	Acquiring adequate supply and DSM resources to meet demand.	Unit commmitment. Maintenance scheduling. integrated resource planning for supply and DSM.
Coordinating transactions	Buying, sailing, and wheeing power in interconnected systems.	AGC/economic dispatch. Unit commitment.

SOURCE: Office of Technology Assessment, 1993.

FOLLOWING LOAD

The ability to follow load is central to the operations of utility systems. Following load requires that at each moment the supply of power must equal the demand of consumers and that utilities maintain power frequency and voltages within appropriate limits across the utility system. Consumer demand for electricity changes continuously and somewhat unpredictably. Some load changes tend to repeat cyclically with the time of day, day of week, and the season. Others result from the vagaries of weather, economic conditions, and from the random turning on and off of appliances and industrial equipment. Because these load patterns cannot be forecasted accurately, utilities must plan for and secure generating, transmission, DSM, and control resources to meet a variety of future customer load patterns over the short, medium, and long term. Utilities rely on unit commitment schedules, economic dispatch, and automatic and operator control of generation to follow loads while maintaining frequency and voltage.

Utilities establish detailed unit commitment plans to ensure a sufficient supply of generation to follow loads and to provide backup power supplies for immediate operation in case of contingencies such as failure of a generating unit or transmission line. The schedules are based on forecasted load changes over daily, weekly, and seasonal cycles plus an allowance for random variations and equipment outages.

Unit commitment schedules specify which units Will be warmed up and cooled down to follow the load cycles and to provide spinning reserves.[65] Some generators in a unit **commitment** schedule increase or decrease their power output according to a schedule, following predicted loads; others are under AGC and economic dispatch to follow actual loads as required. Power

[65] Spinning reserves are generating units that are operating and synchronized with the power grid and ready to send power to the system instantaneously to meet additional demand or respond to outages.

purchases from other utilities are also specified. The unit commitment plan ensures that sufficient generation under governor control is available for regulating frequency in response to changing loads. Voltage control and reactive power devices on the transmission system and in generating plants are simultaneously coordinated to maintain system voltages as loads and supplies change.

Utilities calculate unit commitment schedules to minimize the total expected costs of power generation and maintaining spinning reserves for reliability and to meet expected changes in demand. New unit commitment plans are typically established each day or after major plant outages or unexpected load changes.

Unit commitment planning requires a vast amount of information. Virtually all the information about generation and transmission operating costs and availability required by the dispatch and security systems is also needed to develop the best unit commitment schedule. In addition, the time and cost to warmup generating units and the availability of personnel to operate generating units must be considered. These factors vary depending on the type of generating unit. Unit commitment schedules are typically developed using computers to perform the numerous calculations for identifying the minimum expected total costs.

Maintaining Frequency

The design of customer equipment such as motors, clocks, and electronics often assumes a relatively constant power frequency of 60 Hz for proper operation. Actual frequencies in U.S. power systems rarely deviate beyond 59.9 and 60.1 Hz, well within the tolerance of consumers' electronic equipment and motors. Power system equipment is more sensitive to frequency deviations than consumer equipment and the control systems of modem power systems function by monitoring slight frequency deviations and responding to them.

Frequency fluctuations result from an imbalance between the supply and demand for power in **a** system. In any instant, if the total demand for power exceeds total supply (e.g., when a generator fails, or as demand increases through the course of a day), the rotation of all generators slows down, causing the power frequency to decrease. A similar process occurs in reverse when generation exceeds loads, with the governors reducing the energy input to generators to maintain frequency. Speed governors on most generating units constantly monitor frequency and regulate those units' power output to help balance demand and restore the frequency.

The usefulness of a particular generator in regulating frequency varies from unit to unit because of differences in the vamp rate-the rate at which generator's power output can increase or decrease. Large steam generating units such as nuclear powerplants and large coal units generally change output levels slowly, while gas turbines and hydro units are very responsive. Power system operators and planners must consider the responsiveness and availability of generators to control frequencies in setting unit commitment schedules and planning new supply resources.

Controlling Voltage

Many types of customer equipment require voltage to fall within a narrow range to function properly. For example, if delivered power voltage is too low, electric lights dim, and electric motors function poorly and may overheat. Overly high voltages, on the other hand, shorten the lives of lamps substantially and increase motor power, which may, damage attached equipment.

Unlike frequency, which is the same at all locations in a power system, voltage varies from point to point. The voltages throughout a power system depend on the voltage output of individual generators and voltage control devices and the flows of power through the transmission system.

Maintaining voltage involves balancing the supply and demand of **reactive** power in the system. Reactive power is created when current and voltage in an alternating current system are not in phase due to interactions with electric and magnetic fields around circuit components.[66] Reactive power is often referred to as VARS (for volt amperes reactive).

Maintaining voltages within the standards required by system equipment is the function of VAR control systems which monitor voltages and adjust generation and transmission system components accordingly. Monitoring equipment at various locations in the system measures and telemeters voltages to the energy control center where voltage levels are checked to ensure they fall within the acceptable range. When voltages begin to deviate from the acceptable limits, both automatic and remotely controlled actions are taken using a variety of reactive power control devices. Supervisory control and data acquisition systems combine telemetry of voltage to the control center and remote control of VAR supplies.

Reactive power is regulated by adjusting magnetic fields within the generators either automatically or under the control of system operators. Control of generator VAR output and off-economy dispatch are common modes of voltage control on the bulk power system. Other automatic and manual voltage control devices include capacitors, shunt reactors, variable transformers, and static VAR supplies.

Planning and selecting generation and transmission resources and designing coordination and control systems must build in consideration of reactive power flows and VAR control to keep the system operating at the proper voltage.

Economic Dispatch

Economic dispatch is the coordinated operation of generating units based on the incremental costs of generation and is a key to minimizing cost. The incremental production cost of a generating unit is the additional cost per kilowatt-hour of generating an additional quantity of energy or the cost reduction per kilowatt-hour due to generating a lesser quantity of energy. Incremental production costs depend on the cost of fuel and the efficiency with which the unit converts the fuel to electricity, and any other operation costs that vary with the level of power output. In economic dispatch, units with the lowest incremental costs are used as much as possible to meet customer demand, consistent with system security requirements. Typically, economic dispatch is entirely recomputed every 5 to 10 minutes at the control area.

Automatic Generation Control

The dispatch of generators in a control area is handled by computerized AGC systems that calculate increases or decreases in each generating unit's output required to maintain the balance between supply and demand in the least costly way. AGC gives utilities the capability of controlling system operations for economic dispatch, load following, reliability, and coordinating transfers. An AGC system constantly monitors the power system frequency to determine whether increased or decreased output is required and automatically resets generator governors to maintain frequency. AGC systems also monitor and reset dispatch to use low-cost generating units to displace more expensive generation to the extent feasible given the availability of adequate trans-

66 In an alternating current system, voltage (electrical potential or pressure) and current (the number and velocity of electrons flowing) vary sinusoidally over time with a frequency of 60 cycles per second. The current and voltage, however are not necessarily in phase with each other-i. e., reaching the maximum at precisely the same time. Real or active power results from current and voltage in phase with each other, is measured in watts, and is the power delivered to a load to be transformed into heat, light, or physical motion. Reactive power results from that portion of current and voltage not in phase as the result of the interaction of real power flows with the electric and magnetic fields created around circuit components. When voltage and current are in phase with each other over a transmission line, there is no net flow of reactive power. An imbalance in the supply and demand of reactive power or VARs causes voltage to rise or drop across the power system, Understanding the pattern of voltages and reactive power flows is a complicated problem arising from the physics of electric systems.

mission capacity and system security (reliability) criteria. AGC systems control both the planned and inadvertent power exchange between control areas. The AGC system typically resets generator governors every 5 to 10 seconds based on an approximation of economic dispatch.

To perform effectively, an economic dispatch and AGC system needs detailed cost and performance information (unit efficiency, dispatchability, capacity utilization, contract rates and terms) about each of the power system's operable generating units. The economic dispatch-AGC system also must take account of possible transmission line losses, and the adequacy and availability of transmission capacity to transfer power within voltage and load flow limits in determining the order of dispatch.

The extent of generation dispatchable under AGC systems is another factor that utilities consider in scheduling unit commitment and in planning new resource additions.

MAINTAINING RELIABILITY

Reliability is a measure of the ongoing ability of a power system to avoid outages and continue to supply electricity at the appropriate frequency and voltage to customers. To preserve reliability, utilities must plan for and maintain sufficient capacity or power supply arrangements to cover unscheduled outages, equipment failures, operating constraints for generating units, powerlines and distribution systems, coordinating maintenance scheduling, and addition of new resources and growth in customer demand. There are two aspects of reliability-security and adequacy.

Preparing for continued operation of the bulk power supply after sudden system disturbances and equipment failures is called maintaining security.[67] Bulk system outages occur when generation and transmission are insufficient to meet total customer demand at any instant, such as when a lightning strike on a transmission line or sudden equipment failure suddenly reduces the availability of a critical generator or transmission line. Bulk system failures account for a relatively small portion of customer service outages—around 20 percent. Distribution system problems, often from storm damage to distribution lines, are the source of most power outages experienced by customers. Security is maintained by providing reserve capacity of both generation and transmission in unit commitment schedules and security-constrained dispatch. The order of economic dispatch will be overridden if the dispatch scheme would threaten system security. Together with the coordinated engineering of relays and circuit breakers used to isolate failed or overloaded components, they ensure that no single failure will result in cascading outages.

The second major element of reliability is maintaining adequacy, which is the ability of the bulk power system to meet the aggregate electric power and energy requirements of the consumers at all times, taking into account scheduled and unscheduled outages of system components. Maintaining adequacy requires utilities to plan for and operate their systems to accommodate a number of uncertainties and constraints on system availability. The major uncertainties that utilities must develop contingencies for include: the cost and availability of fuels, future operating costs for generating units, construction cost and schedules for new equipment, and the demand for power. 'Technical constraints on system availability that must be addressed to preserve adequacy include: unit commitment schedules and economic dispatch for load following and security requirements, scheduling maintenance requirements for system components, and transmission and distribution system capabilities.

Planning new generation and transmission capacity involves selecting the right mix and location of both generation and transmission to meet the needs of following load and maintaining

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67 As defined by the North American Electric Reliability Council (NERC), ''security is the ability of the bulk power electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components."

reliability under a variety of possible futures. In selecting an appropriate resource mix to meet customer needs, system planners are supposed to balance the value to the customer of having reliable service with minimal outages and the costs to the utility of providing this service. However, deriving quantitative estimates of the value of various levels of reliability to the customer and the costs to the utility of avoiding outages under a variety of conditions has proven difficult and intractable. Therefore, in practice, engineering planners assume a variety of rules of thumb or de facto reliability standards in system planning and operations. Three of the most common reliability-related goals are:

1. loss of load probability (LOLP) of 1 day in 10 years,
2. first (or second) contingency security, and
3. reserve margins of 15 to 20 percent. (See box 3-B.)

These reliability standards specify the amount of capacity to be installed (e.g., reserve margins and LOLP), and how that capacity must be operated (contingency security). Thus, they play a central role in determining the constraints and capabilities of modem power system operations and planning. The choice of which standard to use is a matter of experience and engineering judgment as well as system-specific characteristics for individual utilities.

A key to security-constrained dispatch is scheduling generation in a "defensive" mode so that the power system will have enough supplies ready to continue operating within emergency standards for frequency, voltage, and transmission line loadings should contingencies (such as generator or transmission failures) occur. Defensive operating practices entail holding generating units and transmission capability in reserve for the possible occurrence of a major failure in the system. Idle generating units and transmission lines with below-capacity power flows may mistakenly seem to be surplus, when in fact they are essential for reliability.

Emergency Operations

Reliability operations and planning also entails establishing procedures for system emergency operations and restoring power for reliability emergencies. System emergencies occur when there simply is not enough capacity available either within the utility or through neighboring systems to meet load. When voltages and frenquencies deviate too much as a result, relays and circuit breakers may isolate overloaded generators and transmission components from the system, exacerbating the imbalance between supply and demand. Emergency operations involve avoiding cascading outages by reducing the power delivered to consumers. In the extreme, this requires disconnecting customers from the system. Plans for load shedding must be coordinated with the automatic isolation of generating units that occurs under abnormal frequency and voltage conditions. Restoring power also requires coordination of the system components and the devices used to isolate the loads. Following system failures, restoration requires that some generating units be capable of starting on their own, called "black-start capability. " Not all generators have this capability, typically taking their starting power from the system, and must be taken into account in unit commitment schedules and resource planning.

COORDINATING TRANSACTIONS

The third major function of coordinated operating and planning systems is to carry out power transactions. Interutility transactions take a variety of forms, including: short- and long-term purchases and sales with neighboring systems; purchases from suppliers within a utility's service area (e.g., an independent power producer); operation of jointly owned powerplants; and wheeling of power. Coordinating transactions involves scheduling and controlling generation and transmission to carry out the power transfers, as well as monitoring and recording transactions for billing or other compensation. Coordination

Box 3-B-Common Reliability Standards

Loss of load probability (LOLP) is a measure of the long-term expectation that a utility will be unable to meet customer demand based on engineering analyses. Many utilities prescribe a standard LOLP **of 1 day in 10 years.** This means that given the uncertain failure of generation and transmission equipment and variations in customer demands, engineering analyses predict that there will be a bulk system outage for 1 day in a 10-year period.

Contingency security criteria **means** that sufficient reserves of transmission and generation are immediately available so that the power system will continue to operate in the event that the one (or two) most critical components fail. Usually the critical components are the largest generators or transmission lines, or some component at a critical location in the network. The reliability criterion applies at all times, even when some elements are already out of service. The criteria are established based on contingency studies and rely on engineering judgment to decide which types of failures are reasonable or credible.

Reserve **margin is the difference between generating capacity and peak load expressed as a percentage of peak load and is the oldest and most traditional measure of reliability.**[1] For example, in a system with a peak load of 4,000 MW and installed capacity of 5,000 MW, the reserve margin is calculated as follows:

(5,000 - 4,000) (divided by) 4,000 - 0.25, or 25%.

Reserve margins of about 15 to 20 percent typically have been considered sufficient to allow for maintenance and unscheduled outages. However, the appropriate reserve **margin to assure reliability is determined based on system-specific factors such as the number and size of generating units and their performance characteristics. For example, a system with a few large units will require higher reserves than a system with many small units.**[2]

[1] The North American Electric Reliability Council uses a similar measure called *capacity margin,* defined as the difference between capacity and peak load expressed as a percentage of capacity (rather than peak load). Because it uses a larger denominator, the capacity margin Is always smaller than reserve margins by a few percentage points. In practice, however, most utilities refer to their reserve margins. Capacity margins of 13 to 17 percent are commmonly considered acceptable.

[2] North American Electrlc Reliability Council (NERC), Reliability Concepts (Princeton, NJ: February 1985), p. 16.

may involve parties to the power transaction and third-party utilities that may be affected.

Interutility Coordination and Cooperation

The simple model of an electric utility system like that in figure 3-5 is of a stand-alone integrated utility that serves its own needs within an exclusive, geographically compact retail service franchise area. The model utility generates sufficient electric power from its plants to meet customer demand and delivers it via its own transmission and distribution systems to its customers. It exercises sole control over the operation and planning of all its system components and derives its profits from retail power sales and the return on capital investment in its rate base. It operates under the oversight of a single State ratemaking authority. The modern-day reality of electric utility systems, however, is far more complex.

Nearly all U.S. utilities operate as part of an interconnected regional grid and not as isolated systems. All these interconnected systems are multistate operations with the exception of Alaska, Hawaii, and utilities within the Electric Reliability Council of Texas (ERCOT). The transmission interconnections improve electric system reliability by allowing utilities to share generating and transmission resources, provide backup power supplies at peak loads and during emergencies, and engage in other bulk power transactions. While clearly conferring benefits, these interconnections also impose physical and legal constraints on utility systems. Utility operations and planning require a high degree of cooperation and communications among utilities on the system, and must satisfy technical performance standards and other formal and informal obligations imposed through control area and interconnections agreements, power pools, reliability councils, and various contractual arrangements for bulk power transfers.

Each utility is responsible for providing the power used by its customers without taking power from neighbors, unless alternate arrangements have specifically been made. Many utilities depend on wholesale purchases of electricity from other utilities or public power agencies or independent power producers for some or all of their power requirements. Utilities rely on wholesale transactions because they do not have enough generating capacity to meet the needs of their customers and/or because lower-cost power is available from others. Indeed, there are a large number of small municipal systems dependent on regional investor-owned or public power systems for their electricity supplies and transmission services. Many large investor-owned utility systems support generation and transmission facilities not only to serve their own retail distribution customers, but also to meet the long-term obligations to wholesale customers within their service areas, and to engage in short- or long-term wholesale power transactions with other utilities.

There are significant variations among utilities in different regions, and among utilities in the same region, that help shape planning and operations decisionmaking and regulatory policy. These include differences in industry structure, composition, and resource base characteristics that are traceable to patterns of population, climate, economic activity, and the history of electrification within each region. Among utilities, differences in generation reserve margins, fuel mix, load growth and coordination, and access to regional transmission systems will further shape power markets and resource options.

The structure of the electric power industry has been changing over the past decade as utilities have merged, reorganized into (exempt) holding company structures, and diversified into regulated and nonregulated ventures. One result of this diversification and corporate reorganization among investor-owned utilities is that traditional electric utility operations are no longer the only (or most profitable) source of corporate income. In some cases, the regulated public utility subsidiary serving retail distribution customers could find itself in competition with, or purchasing from, unregulated independent power and energy services subsidiaries or joint ventures of its parent holding company. These changes are introducing subtle and not so subtle influences into corporate decisionmaking--how will company officers and directors decide between providing for long-term, least-cost resources for the regulated electric utility and pursuing potentially higher returns on unregulated ventures. The changes create new challenges for utility regulators in policing the potential for self-dealing and cross-subsidization of unregulated ventures by utility ratepayers and, in many cases, transfer the regulatory venue from State to Federal jurisdiction.

The picture is further complicated by the growing presence of independent power producers and energy service companies as competitors with, and suppliers to, regulated electric utilities. These unregulated entities operate under different financial and regulatory regimes than traditional integrated utilities, and it remains to be seen if existing resource planning and regulatory approaches will be adequate to secure reliable and reasonably priced resources from these new entrants over the longer term.

The growing split in jurisdiction over electric utilities among States and between States and the Federal Government will undoubtedly influence resource decisions by individual utilities and by regulators. Greater reliance on bulk power transactions in utility resource plans will mean that

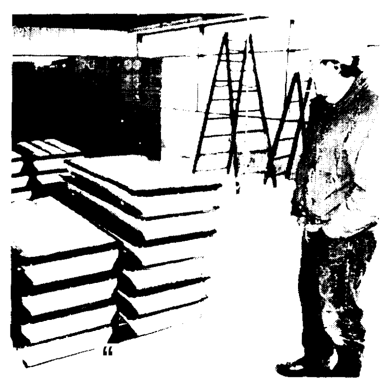
Federal regulators will have a more dominant role in determining electricity costs and that State regulators' control over utility costs, and ultimately retail electricity prices (rates), will be diminished.

As a result of these various influences, each utility system has a unique set of operational, structural, regulatory, and geographic conditions that drive its investment decisions and opportunities for enhancing energy efficiency. This diversity precludes easy generalizations and one-size-fits-all policy prescriptions for utility energy efficiency. Nevertheless, most utilities generally adhere to similar goals, performance standards, and operating and planning functions and procedures.

Using Electricity More Efficiently: Demand-Side Opportunities 4

Commercially available energy-efficient technologies offer abundant opportunities to cut electricity consumption in the residential, commercial, and industrial sectors. The major electricity uses across all sectors are lighting, space conditioning, water heating, motors, drives, and appliances. Studies of energy efficiency opportunities have identified a variety of technologies for each of these applications that offer cost-effective savings and rapid paybacks. Still other energy-saving technologies are not currently cost-effective in most applications, but could prove more financially attractive if economies of scale cut costs, if energy prices rise, or if policy interventions provide additional incentives to install them.

This chapter briefly examines some of the energy efficiency opportunities in the residential, commercial and industrial sectors, including a profile of electricity use in each sector, examples of electricity-saving technologies, estimates of potential savings, and major factors influencing technology adoption.



HOW MUCH ELECTRICITY CAN BE SAVED?

Estimates of how much energy can be saved through more efficient electric technologies vary. Some of the differences in the estimates are attributable to what measure of energy efficiency is used—maximum technical potential, cost-effective potential, or achievable or likely savings potential. (See box 4-A.) The studies vary in assumptions about technology penetration rates, energy demand, consideration of cost-effectiveness and discount rates,

The Electric Power Research Institute (EPRI) has estimated that if the existing stock of equipment and appliances were replaced with the most efficient commercially available technologies, projected U.S. electricity use in the year 2000 could be cut by 27 to 44 percent without any diminution of services.[1] (See

[1] Barakat & Chamberlin, *Efficient Electricity Use: Estimates of Maximum Energy Savings*, EPRI CU-6746 (Palo Alto, CA: Electric Power Research Institute, March 1990), hereafter referred to as EPRI, *Efficient Electricity Use*.

Box 4-A-Estimating Energy Efficiency Savings

Estimates of potential energy savings from efficient technololgies vary considerably. At least part of the difference in estimates can be attributed to what is being estimated. Most published estimates use one of the following measures:

Maximum technical potential, or MTP, is a measure of the most energy that could be saved if all possible efficiency improvements were made with the most efficient technologies adopted in all new and existing applications (i.e., 100 percent penetration reached. Achieving MTP savings assumes agressive government and private efforts and implementation of policies designed to make efficient alternatives attractive to everyone. Supporting policies rnight include, for example, increased R&D to lower costs, Information program, and rebates and other financial incentives.

Cost-effective potential is an estimate of the energy savings that could reobtained if efficient techndogies are installed in new and replacement applications whenever they are cost-effective. Cost-effective potential is lower than MTP and depends on projections of future marginal electricity costs and rates. Several cost-effectiveness tests are in common use in utility planning and rate regulation. See chapter 6 for more on cost-effectiveness tests.

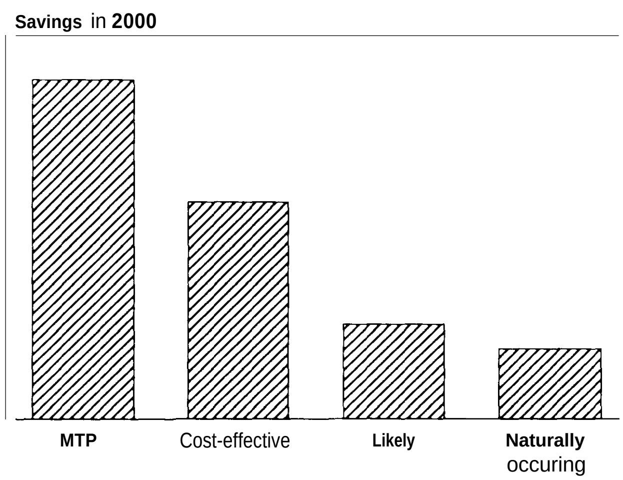
Likely energy efficiency savings estimates are used in utility planning and reflect judgments about the savings from efficient technologies adopted in response to utility programs. Likely impacts are lower than cost-effective potential because of the influenoe of various factors inducting, for example: lack of customer awareness of potential savings or utility programs, customer reluctance to convert with new or different technologies, and constraints on the supply or deliverability of the technology.

Natural occurring energy efficiency savings estimates reflect estimates about the penetration of energy efficient technologies in response to normal rnarketplace conditions and existing standards In the absence of new utility or other programs to encourage their adoption. The savings arise from installation of newer, more efficient technologies- but not necessarily the most efficient technologies commercially available--in new and replacement applications. Estimates of naturally occurring savings are used by utilities to evaluate the effectiveness of efficiency programs. Actual electricity use is compared to what consumption would have been if efficiency levels were frozen at a base year's level and then the effects of naturally occurring savings are subtracted to yieid the savings attributable to the utility program

The figure shows a conceptual comparison of the relative magnitude of different estimates of energy efficiency potential.

In this chapter, OTA has adopted the MTP estimates from efficient electric technologies published in a 1967 report for the Electric Power Research Institute (EPRI).[1] The EPRI analysis provides one of the few comprehen-

EPRI Base Case Usage and Maximum Technical Potential (MTP) From Electricity-Savings Technologies



[1] Barakat & Chamberlin, Inc., *Efficient Electricity Use: Estimates of Maximum Energy Savings*, EPRI CU-6746(PaloAlto, CA: The Electric Power Research Institute, March 1990).The Electric Power Research Institute Isa research organization supported by the electric utility industry.

sive and economy-wide examinations of the potential energy efficiency savings.

The EPRI MTP estimates of savings from efficient electric technologies in the year 2000, included savings from: 1) using the most efficent electricity-saving technologies available for new Installations and replacement of all the existing stock of installed electric equipment; and 2)replacing less-efficient fossil-fired equipment with more efficient electrotechnologies in industrial processes. EPRI's MTP estimates compared with current and projected electricity use by sector are shown in table 4-1.

The estimates of savings were developed using a baseline projection of eletricity demand in the year 2000, which includes naturally occurring improvements in efficiency and the effects of mandatory standards and a best ease scenario in which all applicable technologies are replaced instantaneously with the most efficient commercialty available electric equipment.

The MTP estimates are subject to a great deal of uncertainty including:

- the efficiency levels of new and existing equipment;
- the unknown impacts from naturally occurring efficiency Improvements; and
- physical constraints that limit the applicability, compatibility, or deliverability of efficient equipment.

To account for these uncertainties, the EPRI report used two scenarios reflecting a range of Impacts from technology adoption: an 'optimistic" or high impact scenario assuming adoption of all commercially available technologies (i.e., no prototypes, demonstration models, or lab bench-scale technology@, and a conservative" or low impact scenario reflecting possible constraints on the perpetration rates due to technology applicability and manufacturer capacity. Neither estimate reflects considerations of cost-effectiveness, the economic tradeoffs between efficiency improvements and equipment cost.

table 4-l.) (EPRI is the joint research institute supported by funds from America's electric utilities.) The EPRI analysis presents its best-case estimates of the most energy that could be saved through efficient technologies, further improvements in existing technologies, and policy initiatives such as information programs, rebates and other incentives that make the alternatives attractive to everybody. The range in their estimates from "conservative low impacts" to best-case, "high" impacts reflects uncertainties in technology applicability, manufacturing capabilities, and performance characteristics.

The analysis did not include assessments of the cost-effectiveness of the technologies in particular applications or projections of future electricity costs and rates that would strongly influence cost-effectiveness determinations. Considerations of cost, practicality, and capital availability may preclude attainment of the maximum savings potential, but nevertheless EPRI believes that many opportunities remain for substantial gains.[2] The EPRI maximum technical potential estimates are cited in this chapter to provide some measure of prospective energy savings that can be targeted.

Amory Lovins and others at the Rocky Mountain Institute have estimated the maximum technical potential of efficiency savings as high as 75 percent by 2010.[3] Other studies have included considerations of cost-effectiveness in their estimates.

2 OTA's own analysis concluded that cost effective, energy-efficiency measures could yield savings of one-third in total energy use in the residential and commercial sectors by 2015 over a business as usual scenario. In fact total energy use in these sectors would decline somewhat under an aggressive efficiency strategy. These two sectors combined are often dubbed "the buildings sector" because energy use for building systems (space heating and conditioning, ventilation% lighting, and water heating) has made up the overwhelming bulk of energy consumption in these two sectors. Reported energy use for the buildings sector includes building systems, appliances, office systems, and other electrical equipment. U.S. Congress, Office of Technology Assessment, Building Energy *Efficiency*, OTA-E-5 18 (Washington, DC: U.S. Government Printing Office, May 1992), p. 3, hereafter referred to as OTA, *Building Energy Efficiency*.

3 *See, e.g., the estimates* from Rocky Mountain Institute cited in Arnold P. Fickett, Clark W, Gellings, and Amory B. Lovins, "Efficient Use of Electricity," *Scientific Amen'can,* September 1990, pp. *65-74.*

Table 4-1—EPRI Base Case Usage and Maximum Technical Potential (MTP) From Electricity-Savings Technologies (gigawatt-hours)

	Elect ricity consumption		Electricit y savings			
Residential **end uses sector**	1987 Base GWh	2000 Base GWh	Low case GWh	% of base	High case GWh	% of base
Space heating.	159,824	223,024	71,915	32.20/.	122,285	54.8%
Water heating.	103,499	134,509	43,481	32.3	88,995	66.2
Central air conditioning.	78,127	90,134	26,265	29.1	30,996	34.4
Room air conditioning.	15,254	13,063	2,421	18.5	4,222	32.3
Dishwashers.	15,308	23,707	1,240	5.2	6,233	26.3
Cooking.	30,390	39,271	3,115	7.9	7,132	18.2
Refrigeration.	146,572	139,255	30,716	22.1	66,896	48.0
Freezer.	59,779	48,073	11,534	24.0	15,594	32.4
Residual appliances.	240,861	353,620	98,242	27,8	141,552	40.0
Total residential.	849,613	1,064,656	288,929	27.1%	483,904	45.5%
Industrial end uses						
Motor drives.	570,934	780,422	222,226	28.5%	351,040	45.0940
Electrolytic. ... , ...	98,193	138,273	25,950	18.8	41,124	29,7
Process heating.	83,008	125,274	9,928	7.9	16,606	13.3
Lighting.	84,527	114,097	19,016	16.7	38,032	33.3
Other.	8,453	9,192	0	0.0	0	0.0
Total industrial[a].	845,266	1,167,413	277,119	23.7	446,802	38.3%
Commercial end uses						
Heating.	77,245	128,322	16,335	12.7%	30,333	23.694.
Cooling.	154,299	208,106	62,432	30.0	145,674	70.0
Ventilation.	76,959	96,094	28,828	30.0	48,047	50.0
Water heating.	24,068	39,794	15,917	40.0	23,876	60.0
Cooking.	16,172	26,381	5,276	20.0	7,914	30.0
Refrigeration.	60,883	81,652	9,925	12.2	27,857	34.1
Lighting.	238,488	283,124	62,916	22.2	157,291	55.6
Miscellaneous.	108,447	177,254	32,228	18.2	64,456	36.4
Total commercial.	756,561	1,040,726	233,858	22.5940	505,448	48.6%
Total.	**2,451,440**	**3,272,795**	**799,905**	**24.4%.**	**1,436,154**	**43.9%**

[a]Sum of end uses may not add to total due to rounding.

SOURCE: Office of Technology Assessment, 1993, based on 8arakat and Chamberlin, Inc.,*Efficient Electricity Use: Estimate of Maximum Energy Savings*, EPRI CU-6746 (Palo Alto, CA: Electric Power Research Institute, March 1990), p. 3.

OTA's report *Energy Technology Choices: Shaping Our Future*[4] moderate-efficiency scenario assumes adoption of all cost-effective efficiency measures (defined as measures that repay their added incremental costs with energy savings over their lifetimes). The scenario also assumes adoption of a variety of government policy initiatives to overcome significant market, institutional, and behavioral barriers that have hampered full use of cost-effective, energy-savings opportunities. Under the moderate-efficiency scenario, electricity demand in 2015 would be 25 percent less than the baseline demand (which assumes some naturally occurring efficiency improvements, but no significant policy initiatives).[5]

[4]U.S. Congress, Office of Technology Assessment *Energy Technology Choices: Shaping Our Future,* OTA-E-493 (Washington DC: U.S. Government Printing Office, July 1991), hereafter referred to as OTA, *Energy Technology Choices.*

[5]Ibid., p. 130. See chs. 4 and 5 for details on the scenarios and government policy initiatives.

The 1991 National Energy Strategy projects that electricity consumption in 2010 will be about 12 percent less than the current policy baseline due to cost-effective energy savings from proposed initiatives to promote utility integrated resource planning (and associated demand-side management programs), building and appliance efficiency standards, and industrial conservation research and development.[6]

Other studies on energy efficiency opportunities in specific sectors or regions have yielded similar estimates of cost-effective savings potential.

There is considerable agreement among the various energy efficiency potential studies about the most promising strategies for achieving more efficient use of electricity. They include:

- improvements in the thermal integrity of building shells and envelopes;
- improvements in the efficiency of electric equipment;
- lighting improvements;
- net efficiency gains from shifting energy sources from fossil fuels to electricity (electrification); and
- optimization of electricity use through better energy management control systems, shifts in time of use, and consumer behavior and preference changes.

ENERGY-EFFICIENCY OPPORTUNITIES FOR RESIDENTIAL CUSTOMERS

The residential sector essentially consists of all private residences including single and multifamily homes, apartments, and mobile homes. Institutional residences, such as dormitories, military barracks, nursing homes, and hospitals are included in the commercial sector, About 22 percent of total primary energy consumption in the United States can be attributed to residential sector energy demand. Total energy expenditures by the residential sector in 1990 were $110.5 billion.[7]

Figure 4-1 shows direct on site energy consumption in the residential sector.[8] Electricity at present supplies about 30 percent of residential energy needs and this share is expected to grow as electric heating and appliance loads grow. Natural gas supplies 47 percent of residential energy use mostly for space and water heating. The remaining residential energy consumption consists of oil (15 percent), coal (1 percent), and other energy sources (7.6 percent), predominantly *firewood.*[9]

The residential sector accounts for about 34 percent of all **U.S.** electricity sales. In 1990, total residential electricity sales (exclusive of conversion and transmission losses) were 924 billion

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[6] *National Energy Strategy: Powerful Ideas for America, First Edition 1991/1992* (Washington, *DC: U.S.* Government Printing Office, February 1991), app. C, pp. C25-26.

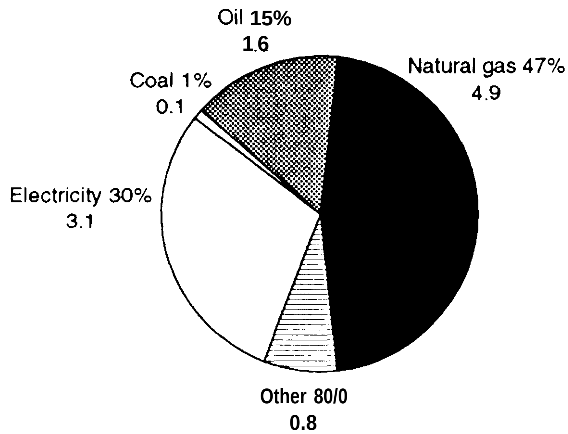
[7] U.S. Department of Energy, Energy Information Administration, ''Energy Preview: Residential Energy Consumption and Expenditures Preliminary Estimates, 1990, *Monthly Energy Review April 1992, DOE/EIA-O035(92/04) (Washington* DC: U.S. Government Printing Office, April 1992), p. 1.

[8] Historical energy use statistics of the Energy Information Administration do not separate residential and commercial energy use. Residential energy use share is based on Gas Research Institute estimates from Paul D. Holtberg, Thomas J. Woods, Marie L. Lihn, and Annette B. Koklauner, Gas *Research Insights" 1992 Edition of the GRI Baseline Projection of U.S. Energy Supply and Demand to 2010* (Chicago, IL: Gas Research Institute, April 1992) hereafter referred to as 1992 *GRI Baseline Projection);* and U.S. Department of Energy, Energy Information Administration, *Annual Energy Review 1991*, DOE/EIA-0384(91) (Washington, DC: U.S. Government Printing Office, June 1992), table 17.

[9] If the residential sector's share of direct primary energy consumption is augmented by its pro-rate share of primary energy consumed by electric utilities in the generation, transmission and distribution of electricity for residential customers, electricity accounts for some 60 percent of primary energy consumption attributable to the residential sector. The existence of these sizable conversion and delivery losses associated with end-use electricity consumption means that energy savings at the point of use are magnified in their impacts on utilities and overall primary energy use.

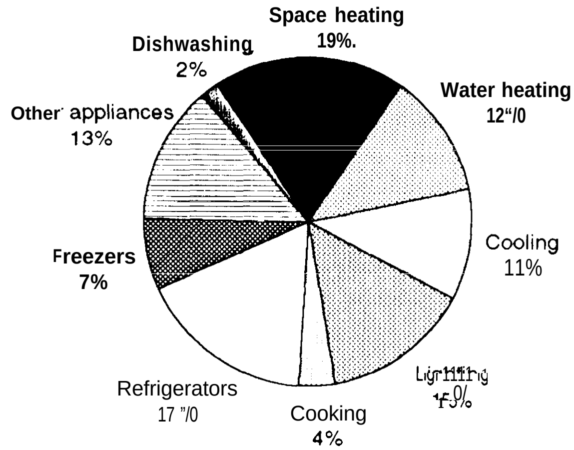
[10] U.S. Department of Energy, Energy Information Administration, *Electric Power Annual 1990*, DOE/EIA-0348(90) (Washington, DC: U.S. Government Printing Office, January 1992), table 1, p, 16, hereafter referred to as DOE, *Electric Power Annual 1990.*

Figure 4-1—Residential On-Site Energy Consumption by Source, 1990 (quadrillion Btus)



SOURCE: Office of Technology Assessment, 1993, based on data from the U.S. Department of Energy, Energy Information Administration, and the Gas Research Institute. Figure excludes generation and transmission losses.

Figure 4-2—Residential Electricity Use by Application, 1987



SOURCE: Office of Technology Assessment, 1993, based on data from the U.S. Department of Energy and the Electric Power Research Institute.

kilowatt-hours (kWh) at a cost of $72 billion.[10] Residential electricity demand growth is driven by population, climate, number of households, the number of persons per household, regional population growth patterns, increased demand for electricity-intensive services (e.g., air-conditioning, clothes-dryers) and size of residences.[11] Among factors that tend to limit growth are the decline in population growth, the increased efficiency of new housing stock and appliances, and retrofits of existing housing units.[12] Various forecasts peg expected growth in residential electricity demand at from 1 to 2 percent per year.[13]

Figure 4-2 shows household electricity use by application.[14] Within each of the categories shown there are a number of attractive and cost-effective options for cutting household electricity use, without diminishing the services provided.

EPRI's analysis of maximum technical potential estimated that residential electricity use in 2000 could be reduced by from 27 to 45 percent if the most efficient end-use technologies currently available commercially were used to replace the existing stock of electric appliances in homes. The EPRI study did not include estimates of total costs for achieving this maximum technical potential, nor any analysis of the cost-

10 U.S. Department of Energy, Energy Information Administration, *Electric Power Annual 1990*, DOE/EIA-0348(90) (Washington DC: U.S. Government Printing Office, January 1992), table 1, p. 16, hereafter referred to as DOE, *Electric Power Annual 1990*.

11 See OTA, *Building Energy Efficiency*, supra note 2, at 15 and 1992 *GRI Baseline Projection*, supra note 8.

12 1992 *GRI Baseline Projection*, supra note 8, p. 27.

13 U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 1993*, DOE/EIA-0383(93) (Washington, DC: U.S. Government Printing Office, January 1993) table 21, p. 78.

14 EPRI, *Efficient Electricity Use*, supra note 1, table 1-1, p. 3.

effectiveness of replacing working appliances with more efficient models. Other studies have included cost-effectiveness considerations in their analyses and generally found considerable opportunities for electricity savings in the residential sector at a cost less than that of supplying electricity .15

Residential Energy Efficiency Technologies

There are a variety of technologies available to cut residential energy use without diminishing the services provided. Some of these technologies are listed in table 4-2. The basic strategies for cutting electricity use in the residential sector are:

- Improving residential building shell efficiency through better insulation by cutting conductive heat losses and gains through ceilings, walls, and floors; installing storm doors and windows; and cutting air infiltration by caulking gaps and weatherstripping around doors, windows, joints and other spaces.
- Choosing more efficient appliances for new installations and accelerating the retirement of older less efficient appliances.
- Improving the management of residential energy use through better maintenance, energy management controls, load shifting, and changes in occupant behavior.

Improving the energy efficiency of existing buildings is one of the most promising and vital areas for energy savings. Space heating and cooling account for 30 percent of residential electricity use. Improved thermal integrity in new and existing residential buildings can reduce heating and cooling loads and save electricity.

Replacement of existing buildings by energy-efficient new buildings is slow and expensive; most of the existing housing stock will continue in use for the next 30 to 40 years or more. There are over 90 million residential units in the United States, and we are adding between 1 and 2 million units per year. Although by the year 2000 there will be 10 to 15 million new units, about 90 percent of the units existing in 2000 have already been built, and by the year 2010 it is estimated that about 70 percent of homes will consist of housing stock built before 1985.[16]

The most cost-effective time to incorporate energy-saving measures into buildings is when they are built, remodeled or rehabilitated. In fact, failure to make accommodation for energy-saving technology in material and design choices at this stage causes lost energy savings opportunities—for example, e.g., using the standard 2-by-4 dimension lumber in exterior walls instead of 2-by-6 construction that allows for more insulation, or not selecting the most energy efficient windows.

Careful attention to energy efficiency features in the design, siting, and construction of residential housing can save electricity. Over the past two decades, because of high energy prices, building code requirements, and greater attention to energy

15 See OTA, *Building Energy Efficiency*, supra note 2, at pp. 29-30. A study of electricity use in U.S. residences by researchers at Lawrence Berkeley Laboratories estimated that residential electricity demand in 2010 could be cut by 37 percent from a "frozen" efficiency baseline (i.e., excluding 'naturally' occurring efficiency gains over the period) by aggressive use of commercially available technologies with a cost of conserved energy below 7.6 cents/km using a discount rate of 7 percent. SeeJ. Koomey et. al, *The Potential for Electricity Efficiency Improvements in the U.S. Residential Sector,* LBL-30477 (Berkeley, CA: Lawrence Berkeley Laboratory, July 1991), pp. 35-36. Artother analysis of possible electricity savings in Michigan found achievable savings of 29 percent in residential electricity use by 2005 at reasonable cost over a business-as-usual baseline with aggressive conservation programs and commercially available technologies. F. Krause et al., *Final Report: Analysis of Michigan's Demand-Side Electricity Resources in the Residential Sector, vol.* 1, Executive Summary, LBL-23025 (Berkeley, CA: Lawrence Berkeley Laboratory, April 1988). Researchers estimated that current residential electricity use in New York State could be cut 34 percent at a cost below that of supplying electricity-less than 7 cents/kWh, assuming a 6-percent discount rate. American Council for an Energy Efficient Economy, *The Potential for Energy Conservation in New York State,* NYSERDA Report 89-12 (Albany, NY: New York State Energy Research and Development Authority, September 1989), pp. S-5-6.

16 Oak Ridge National Laboratory, Energy *Technology R&D: What Could Make a Difference?* vol. 2, p@ 1 of 3, ORNL-6541/v2/p1 (Oak Ridge, TN: Oak Ridge National Laboratory, December 1989) pp. 15,45.

Table 4-2-Selected Energy Efficiency Technology Options for the Residential Sector

Building envelope improvements

Cut conductive heat losses/gains; control infiltration
- ■ Weatherstripping and caulking
- ■ Insulation improvements
- ■ Storm windows and doors
- ■ Design and siting of new structures

Space heating

Use heat pumps instead of resistance heat

Air source heat pumps
- ■ More efficient models
- ■ Improved technology

Ground-source heat pumps

Solar heating

Energy management controls and systems
- ■ Set-back thermostats
- ■ Smart house/smart systems
- ■ Zoned heat systems

Air distribution systems
- ■ Improved insulation
- ■ Reduced duct leakage

Water heating

Blanket wrap of existing tanks

More efficient tanks

increased insulation for tanks and pipes

Low-flow devices

Thermal traps

Set-back thermostats

Heat-pump water heaters

Alternative water heating systems
- ■ Heat recovery water heaters
- ■ Solar water heat systems

Reduced thermostat settings

Alr-conditioners

Central air-conditioners
- ■ More efficient units
- ■ Frequent cleaning of filters and coils

Room air-conditioners
- ■ More efficient units
- ■ Frequent cleaning of filters and coils

Refrlgerators and freezers

Efficient motors and controls

Improved gaskets and seals

Improved insulation

Improved malntenance
- ■ Clean coils often

Lighting

Replace incandescent with fluorescent and compact fluorescent

Reduced wattage incandescent

Dimmers, controls, and sensors

Reflective fixtures

Cooking

More efficient ovens and stoves

Alternative cooking devices
- ■ Microwave ovens
- ■ Convection ovens
- ■ Induction cooktops

Dishwashers

Energy-saver cycles

No-heat drying

Reduced hot water usage

SOURCE: Office of Technology Assessment, 1993.

efficiency, newer residential buildings make greater use of energy-efficient features.[17] In fact, new houses built in 1985 were much more energy efficient than those built in 1973 and were better insulated and had more energy-efficient win-dews.[18] Design features to take advantage of passive solar heating and daylighting can also be incorporated into new units for additional savings.

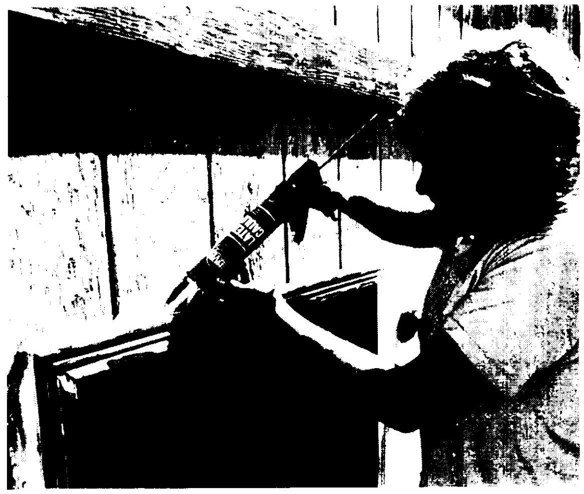
The rate of replacement of major appliances with newer, more efficient models has been slow and will continue to be so in the absence of policy initiatives or large changes in energy prices. Major electric appliances such as furnaces, heat pumps, central air-conditioners, water heaters, and refrigerators often are in use for 10 to 20 years or more and are unlikely to be replaced unless they fail. It could take as long as 20 years to realize potential savings from currently available

[17] OTA, *Building Energy Efficiency*, Supra note 2.

[18] Ibid., p. 18.

efficient new equipment.[19] Not installing the most energy-efficient model initially creates lost efficiency opportunities for a decade or more. Assuring the installation of the most efficient appliances and accelerating the replacement of older inefficient appliances offer prospects for reaping energy savings.

Building shell improvements in existing buildings are effective means of cutting heating and cooling costs and increasing occupant comfort. The most common weatherization retrofits include: installing more insulation in ceilings, walls, and floors; adding storm windows and doors, and weatherstripping and caulking windows and doors. One study of home retrofits found variations in savings attributable to climate and differences in individual building characteristics. Average savings of 12 to 21 percent in heating energy demand and payback periods of about 6 years were found for ceiling and wall insulation. Another intensive experiment in weatherization cut space heating electricity use by two-thirds.[20] According to DOE surveys many Americans have already taken some steps to improve the energy efficiency of their homes.[21] Even where some weatherization measures have been reported it is likely that additional efficiency upgrades are possible.



Caulking gaps around windows and doors can reduce infiltration, and thereby reduce energy use for space heating and cooling.

SPACE HEATING

About one-quarter of American homes (22 million units) depend on electric heat and each year more and more electrically heated units are added.[22] Electric space heating accounts for 19 percent of residential electricity consumption. There are two basic categories of electric space heating systems: electric resistance heat systems (including electric furnaces, baseboard heaters, and portable heaters) and electric heat pumps (including air-source heat pumps, and ground-source heat pumps). Electric resistance heating systems are virtually 100 percent efficient, that is 100 percent of the energy delivered to the system is converted to heat, so that there are few technical opportunities to improve on their performance.

Electric heat pumps use a reversible vapor compression refrigeration cycle to transfer heat from an outside source to warm indoor spaces in the winter; in summer, the cycle reverses to cool indoor spaces by removing heat from inside and discharging it outdoors. The most commonly used heat pump is the air-source heat pump that uses the ambient air as its heat source. On average heat pumps are twice as energy efficient as electric resistance systems. However, the performance of heat pumps is highly variable and dependent on sizing, climate, and the rated performance of the heat pump. At about 23° F, heat pumps begin to lose their heating capacity

19 Oak Ridge National Laboratory, supra note 16, p. 47 — projecting about 30 percent savings in total end-use energy.

20 OTA, *Building Energy Efficiency*, supra note 2, pp. 45-46 citing the Hood River Project.

21 OTA, *Building Energy Efficiency*, supra note 2, p. 46, citing a survey by the U.S. Department of Energy.

22 U.S. Department of Energy, Energy Information Administration, *Housing Characteristics 1987* DOE/EIA-0314(87) (Washington, DC: U.S. Government Printing Office, May 1989), hereafter referred to as DOE, *Housing Characteristics 1987;* OTA, *Building Energy Efficiency* supra note 2, p. 39 reports that 23 percent of new single family homes are equipped with heat pumps.

and in moderate to cold climates they must have a backup heat source, usually an electric resistance heater. There is a considerable range in the performance of residential heat pumps currently on the market. The typical heat pump has a heating efficiency (heating season performance factor, or HSPF) of about 6.9 Btus per watt-hour and a cooling efficiency (seasonal energy efficiency ratio, or SEER) of about 9.1 Btus per watt-hour. See box 4-B for a description of common energy efficiency measures. The best units currently on the market have efficiencies of 9.2 HSPF and 16.4 SEER.[23] Federal minimum efficiency standards for heat pumps sold after 1992 specify 6.8 HSPF and 10.0 SEER.[24]

Another variant of the heat pump, the ground-source heat pump uses groundwater, or the ground itself as the heat source. This technology offers an advantage over air-source heat pumps, in that ground temperatures seldom drop below freezing, thus there is no loss of heating capacity or resultant need for supplemental resistance heat.

For both heat pump and electric resistance heat systems, improving the thermal integrity of the building shell or envelope and insulating and plugging leaks in air distribution ducts can also cut heat losses and reduce the heating loads.

EPRI estimated that a combination of envelope improvements, a shift to electric heat pumps, and improvements in heat pump efficiencies could result in savings of 40 to 60 percent in space heating electricity demand in 2000 over 1987 stock.

SPACE COOLING

Air-conditioning accounts for about 11 percent of residential energy consumption and this demand is projected to grow as more homes are air-conditioned. Over two-thirds of U.S. homes are now air-conditioned; 40 percent have central air-conditioning and 29 percent have room units. Over three-quarters of new housing units have central air-conditioning. But this growth in air-conditioning demand has been offset by increases in the efficiency of both central and room air-conditioning units.

The most efficient central air units on the market today have a SEER of 16.9 Btus per watt-hour[25] and new Federal appliance standards in effect in 1992 will require a minimum SEER of 10 Btus per watt-hour. Just 10 years ago, the average efficiency for new central air systems was 7.8 Btus per watt-hour. These gains were due to more efficient fan motors and compressors, larger evaporator coils and condensers, and reduced airflow resistance. EPRI estimated that as of 1987, the stock of central air units in use had an average SEER of 7 Btus per watt-hour—considerably below the most efficient systems on the market. New installations and replacement of existing units with higher-efficiency central air units could cut electricity use by central air-conditioners in 2000 by 29 to 34 percent or more according to EPRI.

Room or 'window' air-conditioners have also improved with the addition of more efficient motors for fans and compressors, better fan blade design, larger heat exchangers, reduced airflow path resistance and better low-temperature refrigerant line insulation.[26] Efficiencies vary according to model sizes and features, but nevertheless new units today use about 30 percent less electricity to operate than units sold in 1972. The most efficient units available today, with SEERS of 12 consume half the electricity of 1972 models. EPRI estimated that the 1987 stock of room

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23 American Council for an Energy. Efficient Economy, The *Most Energy-Efficient Appliances 1989-1990* (Washington, DC: American Council for and Energy-Efficient Economy, 1989), pp. 18-19, hereafter referred to as ACEEE, *The Most Energy-Efficient Appliances.*

24 OTA, *Building Energy Efficiency*, supra nOte 2, p. 39.

25 ACEEE, The Most *Energy-Efficient Appliances 1989-90,* supra note 23, pp. 16-17.

26 Battelle-Columbus Division and Enviro-Management & Research, Inc., *DSM Technology Alternatives*, EPRI-EM-5457, Interim Report (Palo Alto, CA: Electric Power Research Institute, October 1987); hereafter EPRI, *DSM Technology Alternatives.*

Box 4-B-Measuring Energy Efficiency

Various measures are used to indicate the energy efficiency of electrical devices. The following are among the most common measures for residential and commercial equipment

The energy efficiency ratio (EER) Is used to measure the coding performa- of heat pumps and air-conditioners. EER is expressed as the number of Btus[1] of heat removed from the conditioned space per watt-hour of electricity consumed (i.e., the cooling output divided by the power consumption). Typical EERs for room air-conditioners are 8.0 to 12.0 Btus per watt-hour. The higher the EER the more efficient the air conditioner.

The seasonal energy efficiency ratio (SEER) is used to measure the seasonal coding efficiency of heat pumps. SEER is expressed as the number of Btus of heat removed from the conditioned space per watt-hour of electricity consumed under average U.S. climate conditions. Unlike the EER, the SEER incorporates seasonal performances under varying outdoor temperatures and losses due to cycling. Typical SEERS are 9.0 to 12.0 Btus per watt-hour.

The heating seasonal performance factor (HSPF) is a measure of the seasonal heating efficiency of heat pumps under varying outdoor temperatures, losses due to cycling, defrosting, and backup resistance heat for average U.S. climate conditions. HSPF is expressed as the number of Btus of heat added to the conditioned space per watt-hour of electricity consumed. Typical values are 7.0 to 12.0 Btus per watt-hour.

The efficiency factor (EF) is a measure of the energy efficiencyof water heaters based on the energy used to provide 84 gallons of hot water per day.

The annual energy coat (AEC), required by Federal appliance labeling regulations, reflects the cost of energy (usually electricity) needed to operate a labeled appliance for 1 year at a specified level of use. The AEC label provides information on the costs of operating the labeled appliance and similar models over a range of energy prices (e.g., cents per kilowatthour) to account for variations in local rates.

1 Btu is shorthand for British thermal unit, a basic unit of energy defined as the amount of heat needed to raise the temperature of 1 pound of water 1° F (at 39.1° F). A Btu is equivalent to 252 calories.

SOURCES: Office of Technology Assessment, 1993, based on U.S. Congress, Office of Technology Assessment Building *Energy Efficiency,* OTA-E-518 (Washington, DC: U.S. Government Printing Office, May 1882), p. *68* and American Council for an Energy-Effkient Economy, The *Most Energy-Efficient Appliances,* 1989-edition (Washington, DC: American Council for an Energy-Efficient Economy, 1989).

air-conditioners had average SEER of 6.5 Btus per watt-hour. Using the most efficient room units for new and replacement installations could cut room air-conditioner electricity use by 19 to 32 percent by 2000 according to EPRI's analysis.

Better maintenance of air-conditioners can also boost efficiency. A dirty filter can cut efficiency by 10 percent. Cleaning air-conditioner coils and cleaning or replacing dirty falters can preserve efficiency.

Heat pumps are also used for space cooling. Today's typical heat pump has a SEER of 9, but commercially available high-efficiency models have SEERS up to 16.4. New Federal standards effective in 1992 will set minimum cooling efficiency for new heat pumps at 10. Careful selection and sizing of heat pumps to match cooling loads, especially in hot climates, can increase efficiency.

WATER HEATING

Electric water heating is used in about 37 percent of American homes and makes up about 12 percent of residential electricity consumption. Electric resistance water heaters are the most common type of electric water heater in use today and new units incorporating better tank insulation and improved heat transfer surfaces, use 10 to 15 percent less electricity than models of 10 years ago. (On average, larger size hot water tanks are less efficient.) Other electricity-saving measures include wrapping the outside of the hot water tank with an insulating blanket, insulating hot water pipes, and installing devices such as low-flow showerheads, aerators, and self-closing hot water faucets. EPRI estimated that use of these energy-saving measures could cut water heating power needs by 20 to 30 percent in 2000.

Shifting to alternative electric water heating systems, such as heat-pump water heaters, heat-recovery water heaters, and solar hot water systems can achieve efficiencies of up to 70 percent. Overall, EPRI estimated that the range of efficient electric water heating technologies offered savings of from 40 to 70 percent.

REFRIGERATORS AND FREEZERS

Together, refrigerators and freezers make up about 24 percent of residential electricity demand. Both technologies have seen substantial increases in efficiency over the past 20 years, but opportunities for significant improvements in performance remain.

The typical refrigerator on the market today uses just 45 percent of the electricity needed to run the average 1972 model.[27] A combination of technological gains has produced these savings, including: more efficient fans, motors, and compressors; better and more compact insulation; improved door seals and gaskets; and dual compressors. DOE researchers believe that it is technically feasible to cut electricity needed to run today's average new model almost 50 percent further. EPRI's analysis estimates that more efficient refrigerators could cut energy use about 22 to 48 percent in 2000 over the 1987 stock. Even more efficient refrigerators are available today than those assumed in the EPRI report. so that the maximum potential savings probably understate the potential.

Freezers account for 7 percent of residential electricity use and are found in about 34 percent of U.S. households. Stand alone freezers also have seen significant efficiency gains over the past 20 years as a result of advances in refrigeration technology. The typical model sold today uses half the electricity of the average 1972 model and as with refrigerators, additional efficiency gains are probable.

More efficient freezers could save 24 to 32 percent over energy required for the 1987 stock according to EPRI analyses.

Complicating the drive for more efficient refrigerators and freezers is the need to find replacements for the chlorofluorocarbons (CFCS) used as refrigerants and in insulation that offer equivalent or improved performance. Box 4-C describes the ''Golden Carrot' award program—a contest sponsored by a consortium of electric utilities in cooperation with the U.S. Environmental Protection Agency to spur the commercialization of more efficient refrigerators.

As with air-conditioning, maintenance practices can affect the efficient operation of refrigerators and freezers. Cleaning refrigerator coils two to three times per year can save about 3 percent of annual refrigerator electricity use at little or no cost.[28]

LIGHTING

About 15 percent of household electricity load is lighting. As in other sectors, use of more energy-efficient lighting products can save electricity for residential customers. OTA's recent report *Building Energy Efficiency* estimated that efficient lighting could cut residential lighting electricity use by one-third if one-half of all residential incandescent lights were replaced by compact fluorescents.[29] Assuming the light is used 6 hours per day, OTA calculated a payback

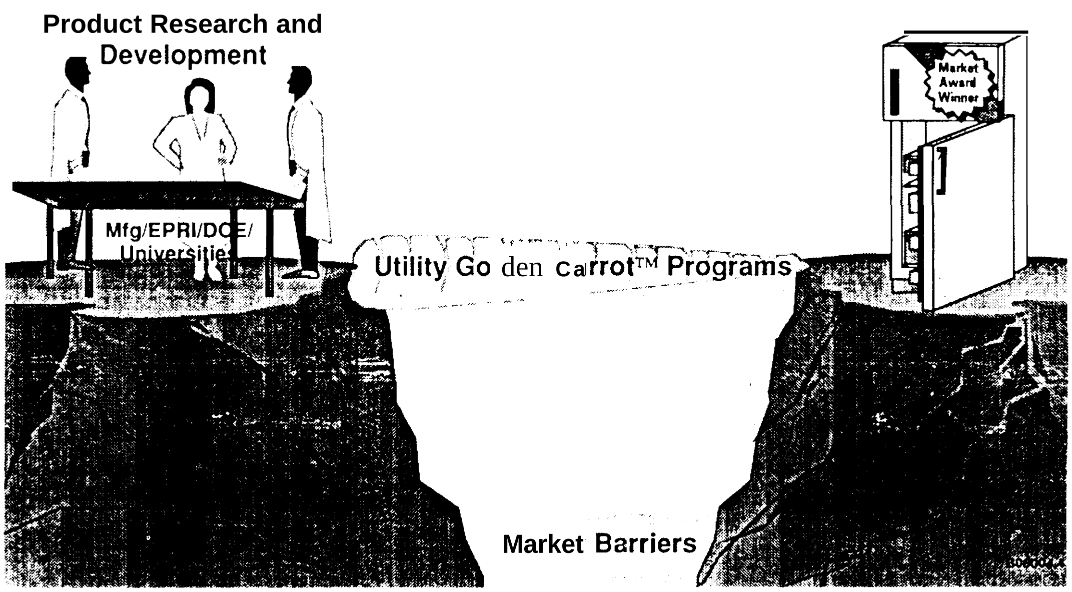
27 See OTA, *Building Energy Efficiency*, supra note 2, pp. 60-61, and table 2-13.

28 Stephen Cowell, Steve Gag, and Jackie Kelly, "Energy Fitness: Canvassing Urban Neighborhoods, " *Home Energy*, vol. 9, No. 2 March/April 1992, pp. 27-33, at p. 30.

29 OTA, *Building Energy Efficiency*, supra note 2, p. 50.

Box 4-C-The "Golden Carrot™" and the Quest for a Super-Efficient Refrigerator

In an innovative effort to overcome market barriers that have slowed the commercialization of more energy-efficient consumer appliances, 25 U.S. utilities joined to offer a "Golden Carrot™" in the form of a $30-miliion award to the winner of a design competition for an advanced, energy-saving refrigerator that is free of ozone-depleting chlorofluorocarbons (CFCS). The consortium, the Super-Efficient Refrigerator Program, Inc. (SERP), was formed in collaboration with the U.S. EPA Global Change Division's green programs, EPRI, and others. Its member utilities provide electric service to more than one quarter of the Nation's households. The award will provide the winning manufacturer with a subsidy of over $100 per refrigerator. In return, the new super-efficient refrigerator will be delivered in participating utilities' service areas before it is available to other distributors.



U.S. ENVIRONMENTAL PROTECTION AGENCY

Among the disincentives that the SERP program and possible future "Golden Carrot™" competitions are intended to counter are consumer reluctance to try new products and the higher first cost of more energy-efficient or green products. By offering a subsidy for development of the winning design and guaranteed orders for a sizable initial manufacturing run, SERP hopes to create a market pull for the energy-saving product, lower product development risks, and allow the manufacturer to achieve economies of scale in production. This should accelerate commercialization and result in a lower market price for the product than in the absence of the incentive. It will also help speed the commercialization of replacements of CFCS that are to be phased out of production by 1995.

The competition challenged manufacturers to commit to producing a CFC-free refrigerator at least 25 percent more efficient than the 1993 Federal energy efficiency standards require and to deliver them to participating utilities' service areas in 1994-97. The manufacturer must agree to assemble the refrigerators in North America. Additional points in the competition could be awarded for achieving greater efficiency levels.

Bids were due in October 1992 and all but 1 of the 15 major U.S. manufacturers entered the competition. Submittals were reviewed based on a number of key factors including proposed design, efficiency levels, incentive requested, marketing plans, and technological experience. In December 1992, Whirlpool Corp. and Frigidaire Co. were selected as finalists to design the new refrigerator.

(Continued **on next page)**

Box 4-C--The "Golden Carrot™" and the Quest for a Super-Efficient Refrigerator-(Continued)

The winner announced in June 1993 was Whirlpool Corp., which will deliver about 250,000 SERP **refrigerators in various models between 1994 and 1$97.** SERP **refrigerator will be priced the same as other models with similar features.**

EPA estimates that a super-efficient refrigerator has the potential to save 300 to 400 kWh/year over its its lifetime and save its owners a total of **aout $500 on utility bills. It also is expected to eliminate 9,000 dioxide emissions compared with current models.**

SOURCES: U.S. Enviromental Protection Agency, Office of Atmospheric ***Programs,1992Accomplishments*** **and Prospec for 1993, vol. 1 :Global Change Division, EPA 430-K_92-031 , November 1992, PP. 11-12. Gary Fermnstrom, "Buildinq a Better Refreigerator,' Environment, September/October 1992, p. 27;** "24 Utilities Sponsoring 'Super-Fridge' Contest to Get an Edge in Marketing,' **Electric Utility Week, July 5, 1993, p. 4.**

period of **1.7 years** for a $20 compact fluorescent bulb.[30] Compact fluorescent also last 10 to 13 times longer than standard incandescent bulbs. EPRI estimated maximum potential lighting related savings at from 20 to 40 percent in 2000.

Depending on applications, compact fluorescent bulbs can cut energy use per bulb by two-thirds over standard fluorescent. Even standard fluorescent offer energy savings over incandescent bulbs for equivalent lighting output. But consumers often find fluorescent lighting unacceptable or unattractive for some purposes. The extent to which energy-efficient lighting can cut electricity demand in the residential sector is highly uncertain and depends on consumer preferences and applications. Manufacturers of compact fluorescent continue to make progress on adapting these lamps for more common residential fixtures and to improve the quality of light provided, which may hasten acceptance by residential customers.

Other options such as lower-wattage "energy-saver' incandescent, reflector fixtures, task lighting, dimmers, and automatic lighting controls can also shave lighting energy use. Increased use of daylighting through windows, skylights, and clerestories can also reduce the need for interior lighting.

COOKING

Electric ranges and ovens account for 4 percent of household electricity demand. Newer models, particularly self-cleaning ovens are more efficient than current stock owing to a number of changes: more insulation, better seals, improved heating elements and reflective pans, reduced thermal mass, reduced contact resistance, and better controls. The penetration of microwave ovens, convection ovens, and induction cooktops also offer energy savings. It is uncertain whether microwave ovens, which cook food with one-third the electricity required for standard electric ranges and ovens, will actually result in reduced cooking loads as consumers may tend to use them more as an adjunct to conventional appliances. EPRI estimates that replacement of the 1987 stock of ranges and ovens with more efficient models could produce savings of 10 to 20 percent in electricity demand for cooking in 2000.

DISHWASHERS

Dishwashers account for about 2 percent of household electricity use and are found in 43 percent of households. Energy-saving features such as better insulation, water temperature boosters, water saver cycles, and air drying cycles can cut electricity consumption. Total savings are dependent on the customers use of energy-saving

30 Ibid., p. s3. Also assuming electricity at 7.8 cents/kWh, O labor costs.

cycles. EPRI estimates that improved dishwashers could cut dishwasher electricity demand in 2000 by 10 to 30 percent over 1987 stock.

OTHER APPLIANCES

The remaining household electric appliances, such as clothes washers and dryers, televisions, stereos and other electronic equipment, vacuums, small household appliances, power tools, and home computers account for about 13 percent of present residential electricity use. This portion of household electricity demand is expected to grow with greater saturation of clothes washers and electronic equipment. Newer models will be more energy efficient, and EPRI estimate, that this trend is expected to result in electricity consumption that is 10 to 20 percent less than equivalent 1987 models by 2000.

Estimating net efficiency gains from more efficient appliances is difficult, however, because energy services are growing, and households may use the energy savings to buy larger appliances or increase the utilization of the equipment.

Obstacles to Residential Energy Efficiency

Total residential energy use in 1990 was over 1 quad less than it was in 1978, even as the number of households grew from 77 million to 94 million, reflecting a steady improvement in residential energy efficiency.[31] Over this period the energy intensity of new living space has decreased and many older units were retrofitted with a variety of energy-saving measures. Major household appliances use significantly less electricity to operate than comparable models of 20 years ago.

Household electricity use also has grown from 24 percent of residential energy use in 1978 to 30 percent in 1990, but growth in residential electricity demand has been less than it might have been without energy efficiency gains. These gains are attributable to several factors in addition to evolutionary efficiency gains: higher energy prices during the 1970s and early 1980s; energy efficiency requirements in building codes; appliance labeling and efficiency standards; government and utility energy education efforts; utility conservation programs; and more awareness of energy efficiency by consumers, equipment vendors, and building professionals and tradespeople.

Even with the admirable gains that have been made in energy efficiency since the 1970s, there remains a sizable gap between the most energy-efficient products on the market to day and the products in use in American homes. More efficient options exist for almost all of the major electricity uses at home. The potential energy and cost savings from residential energy-efficiency investments are significant according to many efficiency proponents. For many measures the energy savings over the lifetime of the investment would exceed the initial cost, in some cases offering payback periods of 2 years or less.

If energy efficiency investments are such attractive investments, why then haven't they been enthusiastically embraced by American consumers? Analysts commonly cite a host of disincentives that have tended to dampen the pace and extent of efficiency savings. These include a number of institutional, economic, behavioral, and practical matters.

OTA's *report Building Energy Efficiency* found a confluence of factors resulted in underinvestment in residential energy efficiency. Decisionmaking affecting household energy efficiency is fragmented among: residents (homeowners and renters); architects; developers; builders; equipment manufacturers and vendors; and a host of Federal, State, and local government agencies. For all of these decisionmakers, energy efficiency is only one of many attributes considered in making choices that affect home energy use and

[31] U.S. Department of Energy, Energy Information Administration, *Annual Energy Review* 1991, DOE/EIA-0384(91) (Washington, DC: U.S. Government Printing Office, June 1992), tables 17 and 21, hereafter referred to as DOE, *Annual Energy Review 1991.*

it competes against such characteristics as lower first cost, appearance, convenience, features, and hassle-avoidance. For most decisionmakers, energy efficiency has not been a high priority. In all too many instances, residential consumers are effectively precluded from energy efficiency opportunities because design and major equipment choices are made by others-by architects, builders, and developers for new housing, and by landlords for the one-third of residential units that are rented.

Although energy-efficient residences and high-efficiency appliances offer electricity savings and lower life-cycle costs over less efficient versions, these potential cost savings provide only weak financial incentives for several reasons.

First, residential electricity prices seem to have only a weak influence on energy choices for most ratepayers, and almost no influence on third-party decisionmakers (developers, builders, equipment vendors and manufacturers, and landlords and tenants who do not pay monthly electric bills). Residential electricity prices have declined steadily in real terms over the past decade. Moreover, residential rates usually do not reflect the higher costs of using electricity at times of peak demand, nor the social and environmental costs (externalities) of generating electricity.

Future savings from energy-efficiency investments are heavily discounted. Studies have found that residential consumers demand a short payback period for efficiency investments-2 years or less for home appliances, for example.

Many decisionmakers are driven by the desire to keep first-costs low; few pursue the goal of minimizing life-cycle costs (the sum of capital and operating costs over the life of the equipment— or e.g., the initial purchase cost of an appliance plus the cost of annual electric bills, maintenance and repairs), This so-called first-cost bias is especially strong when energy-efficient equipment costs more and others (home purchasers or tenants) will reap the benefits of lower electric bills. First-cost bias is also strong for low-income consumers who lack either the cash or access to credit to pay for the more efficient and expensive equipment.

Reliable, understandable information on energy use and costs is often lacking or hard to use. Consumers that would like to give greater weight to energy efficiency in their decisions—whether motivated by lower life-cycle costs, environmental concern, technological fascination-have few alternatives. Government and private programs for energy-efficiency ratings of homes and apartments are only just beginning. The effectiveness of federally required labeling for major appliances is uncertain and has not been adequately assessed.[32]

Energy efficiency is often misperceived as requiring discomfort or sacrifice, rather than as providing equivalent services with less energy. The poor popular image of home energy efficiency as meaning cold showers, darkrooms, and warm beers hampers consumer acceptance and diminishes incentives for housing developers and equipment manufacturers to make efficiency a selling point for their products. Without a market pull for efficiency, equipment manufacturers and building suppliers give less emphasis to efficiency in product design and research.

The typical low turnover rate in the housing stock and slow rate of replacement of major appliances mean that efficiency improvements in the residential sector will significantly lag behind technical potential. Without aggressive efforts in response to government policy and/or an energy crisis, this lagging response will continue.[33]

From a somewhat different analytical perspective, the Bush Administration also found progress in residential energy efficiency unacceptably slow. President Bush's National Energy Strategy

32 See discussions in OTA, *Building Energy Efficiency*, supra note 2, ch. 4 and U.S. Congress, Office of Technology Assessment, *changing by Degrees: Steps to Reduce Greenhouse Gases, OTA-O-482* (Washington, DC: U.S. Government Printing Office, February 1992), ch. 4.

33 OTA, *Building Energy Efficiency*, supra note 2, p. 85.

(NES) found that "a number of institutional and market barriers' limited consumer responses to the higher energy prices of the 1970s and early 1980s. Strongly reflecting the economic policy framework of its analysis, the NES concluded that "Our stock of housing and appliances is still far less energy efficient than would be economically optimal.' '[34] Among the ''significant market barriers' in the residential sector identified by the NES were:

- Traditional energy price regulation and ratesetting that do not reflect the full costs to society of energy use, thus causing individual consumers to undervalue energy-efficiency investments and renewable resources.
- Failure of market mechanisms to induce adoption of economical energy-saving measures by residential customers, particularly in situations where those who must pay for such devices cannot expect any economic benefits.
- First-cost bias tendency of buyers (especially builders and homebuyers) to minimize upfront costs of residential property and major appliances.
- Mortgage lending practices that fail to consider the lower total cost of energy-saving homes in calculating mortgage eligibility.
- Low incomes of some energy users that often make them unable to finance energy-efficiency improvements no matter what the payback period is.
- Absence of credible data on reliability and cost of energy-saving technologies for builders, architects, utility programs, mortgage lenders, and individual consumers.
- Fragmented and cyclical nature of homebuilding industry that contributes to a reluctance to try innovative energy-saving designs, products, and construction techniques and makes concerted industry-led efficiency initiatives unlikely.
- Inadequate implementation and enforcement of energy building codes because of lack of resources to check actual plans and construction sites and to educate builders.
- Inadequate energy-efficiency investment in public sector housing because many local housing authorities lack funds and management incentives to improve efficiency.
- Slow turnover of residential structures and long lifetimes of heating and cooling systems.

The premise of institutional and market barriers to energy efficiency has wide acceptance among energy analysts, government policymakers, State regulators and utility executives. There are others, generally economists of the classical and neoclassical persuasions, who reject this conclusion of market failure, however. They adhere to a belief that present energy efficiency characteristics represent the informed decisions of knowledgeable consumers who have compared alternative investment opportunities and selected energy conservation that offers equal or better returns.[35]

As will be seen in the following sections, Federal, State, and utility programs have attempted to counter these constraints with varying degrees of success. Reducing these disincentives to energy efficiency will be key in attaining energy efficiency goals.

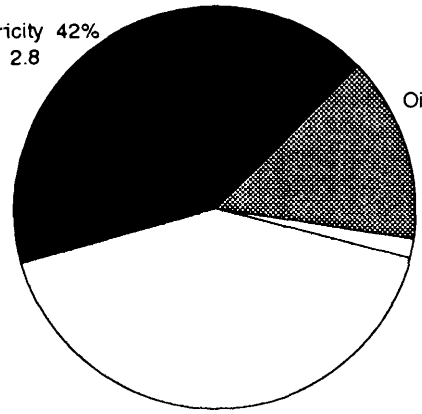
ENERGY EFFICIENCY OPPORTUNITIES IN THE COMMERCIAL SECTOR

The commercial sector consists of all businesses that are not engaged in transportation or industrial activity and includes, for example, offices; retail stores; wholesalers; warehouses; hotels; restaurants; religious, social, educational and healthcare institutions; and Federal, State,

34 *National Energy Strategy: Powerful Ideas for America*, supra note 6, p. 42.

35 See the discussion of failure of classical model to explain efficiency gap or consumer behavior as noted in Florentin Kraus and Joseph Eto, *Least-Cost Utility Planning: A Handbook for Public Utility Commissioners: Volume 2, The Demand Side Conceptual and Methodological Issues* (Washington, DC: National Association of Regulatory Utility Commissioners, December 1988),

Figure 4-3--Commerciai Sector On-site Energy Consumption, by Source, 1990 (quadrillion Btus)



SOURCE: Office of Technology Assessment, 1993, based on data from the U.S. Department of Energy, Energy Information Adminlstra-tlon, and the Gas Research Institute.

and local governments. In 1990 the commercial sector accounted for about 14 percent of total primary energy use.[36] Figure 4-3 shows energy consumption (excluding electricity conversion and transmission losses) in the commercial sector. Electricity and natural gas each supply about 42 percent of commercial sector energy needs, with oil (15 percent) and coal (1 percent) supplying the remainder.[37]

In 1990 the commercial sector consumed about 751 billion kWh of electricity at cost of $55 billion.[38] Commercial establishments made up about 28 percent of total electric utility retail sales in 1990. In addition to purchased electricity, a growing number of commercial facilities have resorted to cogeneration or self-generation to meet some or all of their electricity demand; this output is not included in commercial sector electricity consumption estimates, but fuels used to produce this power axe included in overall commercial energy consumption.[39]

Figure 4-4 shows commercial electricity use by application. Heating, ventilating, and air-conditioning (HVAC) dominates, comprising 37 percent of commercial electricity use (space heating, percent; cooling, percent; and ventilation, percent). Water heating accounts for an additional 3 percent. Lighting accounts for an estimated 29 percent of commercial load.[40] Refrigeration (7 percent); cooking (2 percent), and miscellaneous equipment including elevators, escalators, office computers, printers, telephone systems, and other commercial equipment (21 percent). Sixty percent of electricity use in commercial establishments is for nonspace heating purposes. These nonspace conditioning applications are projected to grow faster than commercial square footage to over 65 percent of electric load by 2010.[41] The heat generated by rniscellaneous equipment add to demands for cooling, but lowers space heating loads.

Electricity demand in the commercial sector is driven by the growth in square footage in commercial buildings and the intensity of service demand-for space cooling, lighting, and office

361992 *GRI Baseline Projection,* supra note *8.*

37 Adjusting for conversion and distribution losses of utilities for serving commercial loads, electricity accounted for 69 percent of total primary energy consumption by the commercial sector. OTA, *Building Energy Efficiency,* supra note 2, p. 24, note 37.

38 DOE, *Electric* Power *Annual 1990,* supra note 9.

39 Many commercial facilities are cogenerators—with natural gas the most common fuel. Opportunities to combine heating and or cooling plants with power generation abound in large institutions, and concentrated urban commercial areas. Cogeneration can add to overall efficiency of energy use in the sector, but in part means a shift of primary energy consumption from the electric utility sector.

40 Estimates of commercial ii@@ electricity use vary, some estimates place lighting at 40 percent of commercial load reflecting the high percentage Of lighting loads in office buildings. For purposes of this analysis we have adopted the estimates used in EPRI's analysis.

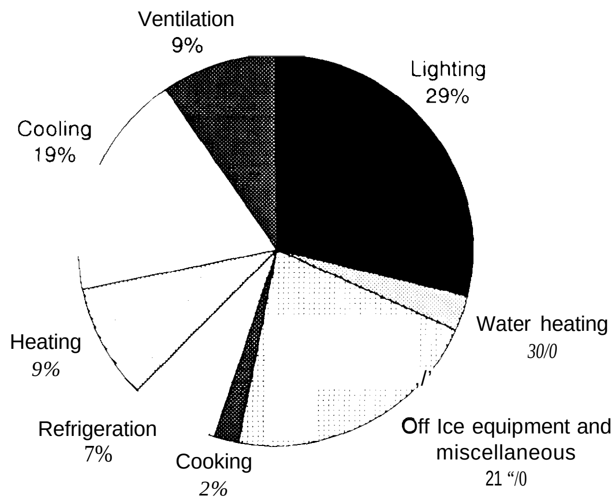
41 GRI 1992 *Baseline* Projection, supra note 8 and EPRI, *Efficient Electricity Use,* supra note 1.

equipment, for example.[42] On average, office, health care, and food service establishments are the most energy-intensive commercial buildings. Between 1970 and 1989, the amount of commercial square footage and electricity use each grew by 45 percent.[43] Even so, newer commercial buildings have tended to be more energy efficient incorporating more insulation, better windows, lighting and more efficient space-conditioning equipment, thus tempering the growth in electricity demand.

Commercial building energy intensity (i.e., energy use per square foot) has remained flat for the past two decades, even as demand for air-conditioning, computers and other equipment grew. Complicating this trend has been the growth in commercial electricity demand due to a shift from on-site use of primary fuels-oil, gas, and coal—to electricity. Thus primary fuel use transferred from the commercial sector to the utility sector, and may even have resulted in a net increase in primary energy consumption, because of the losses involved in electricity generation and delivery.

At present there are over 4.5 million commercial buildings in the United States with a total of over 61 billion square feet.[44] Each year about 1 billion square feet of new commercial space is added—10 to 15 billion total square feet will be added this decade. There is great diversity in the size and energy using characteristics of these commercial buildings. Smaller commercial building energy systems are similar to those in houses and small apartment buildings. Larger buildings, however, have complex HVAC systems and activities inside the building-lighting, occupancy, electric and other equipment-can add to energy demand and determine equipment choices. Buildings larger than 10,000 square feet make up almost 80 percent of building square footage and offer many opportunities for electricity savings.

Figure 44-Commercial Sector Electricity Use by Application, 1987



SOURCE: Office of Technology Assessment, 1993, based on data *from* the Electric Power Research Institute and U.S. Department of Energy.

Energy Efficiency Technologies for the Commercial Sector

Space-conditioning, lighting, and building shell weatherization are primary targets for improving energy efficiency and saving electricity in the commercial sector. In addition, large commercial buildings are suitable targets for utility load management programs designed to shift energy use away from peak hours, but not necessarily resulting in lower overall energy demand, through installation of technologies such as storage heating and cooling systems. There are also potential energy savings in other commercial applications. See table 4-3.

42 See OTA, *Building Energy Efficiency,* supra note 2, at p. 21.

43 DOE, *Annual Energy Review 1991*, supra note 31.

44 U.S. Department of Energy, Energy Information Administration, *Commercial Building Characteristics 1989,* DOE/EIA-0246(89) (Washington, DC: U.S. Government printing Office, January 1991) table 61, p. 122; hereafter DOE, *Commercial Building Characteristics 1989,*

Table 4-3-Selected Energy Efficiency Technology Options for the Commercial Sector

Heating, ventilation, and alr-condltlonlng (HVAC) systems	***WaterheatIng***
Building envelope efficiency improvements	Blanket wrap for water tanks
■ Weatherstripping and caulking	Commercial heat pump water heaters
■ Insulation	Integrated heating and hot water systems
■ Storm windows and doors	Heat recovery water heat systems
■ Window treatments	Increased insulation of tanks and pipes
Space heating	Flow restrictors
improved commercial heat pumps	Service/point of use water heaters
Air-source heat pumps	***Commercial lighting***
■ More efficient models	Delamping
■ Improved technology	Lighting fixture retrofits
Ground-source heat pumps	Electronic ballasts for fluorescent
Heat recovery systems	High-effidency lamps
Energy management controls and systems	Reflectors
■ Set-back thermostats	Increased use of daylighting
■ Smart buildings and smart systems	High-intermit y lighting applications
■ Zoned heat systems	Increased use of task lighting
Thermal storage systems	Compact fluorescent
Cogeneration systems	(LED) signs
District heating systems	Lighting control systems: timers, occupancy sensors, photocells, dimmers
Space cooling	***Commercial refrigerators and freezers***
More efficient cooling systems	Efficient motors and controls
Cool storage systems	Improved insulation and seals
District cooling systems	***Commercial cooking***
Vent//at/on	Energy+efficient commercial electric ranges, stoves, fryers, ovens and broilers
Air distribution systems	Microwave cooking
■ Improved insulation	Convection cooking
■ Reduced duct and damper leakage	Induction cooking
■ Separate make up airflows for cooling exhaust systems	***Miscellaneous electrical equipment and office machines***
■ Economizer controls	More efficient motors and drives for elevators, escalators, and other building systems
Improved HVAC maintenance	Improved hardware and software for office equipment
Integrated HVAC systems	Integrated building energy management and control systems

SOURCE: Office of Technology Assessment, 1993.

Analysis of potential efficiency opportunities by EPRI found that commercially available electric equipment could reduce commercial electricity in year 2000 by 22 to 49 percent from what consumption would be without the use of these technologies if efficiency were frozen at 1987 levels. Commercial applications with the most significant savings potential in the EPRI analysis were lighting, cooling, and miscellaneous electric equipment.

IMPROVEMENTS IN COMMERCIAL BUILDING EFFICIENCY

Turnover of commercial building space is more rapid than residential, but it is evident that a large portion of commercial space in use for the next few decades is already in place. Analysts estimate that one-half of the commercial space in 2010 has already been built, and 80 percent of the existing stock of commercial buildings will still be in use for the next 30 years.[45]

The pace of new commercial construction provides opportunities for efficiency gains in both building shell, equipment, and appliances. Measures to increase the efficiency of commercial buildings include improved design, siting, and construction techniques, better insulation, and more efficient equipment choices.

The remodeling and rehabilitation of commercial space offers additional opportunities. There is considerable potential for energy-efficiency improvements in existing commercial buildings. According to DOE surveys, while 84 percent of buildings are reported to have installed building shell conservation features, there remains a considerable pool of buildings that have not installed basic measures. The most frequently reported measure is ceiling insulation, 67.5 percent, weatherstripping or caulking, 61 percent, and wall insulation, 47 percent. Storm windows and multiple-glazing were reported in 32 percent of buildings, and shades and awnings and reflective shading glass or films were reported for 21 percent of buildings.[%]

HEATING, VENTILATION, AND AIR-CONDITIONING

Space Heating. Just under one-quarter of commercial buildings rely on electric heating systems.[47] Most of these buildings are located in the South and West.

Installation of more efficient electric heating equipment, such as heat pumps instead of resistance heat, coupled with a combination of measures such as building shell improvements, window treatments, heat recovery, and improved maintenance practices can cut electricity demand for space heating. Further savings are possible with integrated heat pump systems that provide heating, cooling and water heating. These potential savings are offset by the expected increase in heating load attributable to reduced internal heating gains from installation of energy-efficient lighting measures. Use of the best available energy efficiency measures could reduce space heating electricity demand in 2000 by 20 to 30 percent from what would be required from the 1987 stock of commercial buildings and equipment, according to EPRI.

District heat, in which a central plant provides heat, and often hot water for all buildings within a complex or downtown area, also offers efficiency opportunities, particularly if coupled with cogeneration.[48]

Cooling. Commercial cooling loads are the biggest component of summer peak load for most utility systems. Over 70 percent of commercial buildings have cooling systems and 96 percent of these systems are electric. Common commercial cooling equipment includes packaged cooling system, individual air-conditioners, central chillers, and heat pumps. Often these systems are integrated with the building ventilation and air transport systems. Commercial cooling load is driven by building size, external temperature, and internal heat gains from electric and other equipment and occupants. Over 6 percent of commercial buildings maintain separate cooling systems for computer areas.[49]

Energy-efficient cooling options for commercial buildings include more efficient air-conditioners, heat pumps, high-efficiency chillers, chiller capacity modulation and downsizing, window treatments, radiant barriers, energy management control systems, and improved operation and maintenance. Reduced internal heat gain

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45 O& Ridge National Laboratory, supra note 16, p. 45.

46 DOE, *Commercial Building Characteristics 1989,* supra note 44, table 103, pp. 198-199.

47 Ibid., table 66, p. 132.

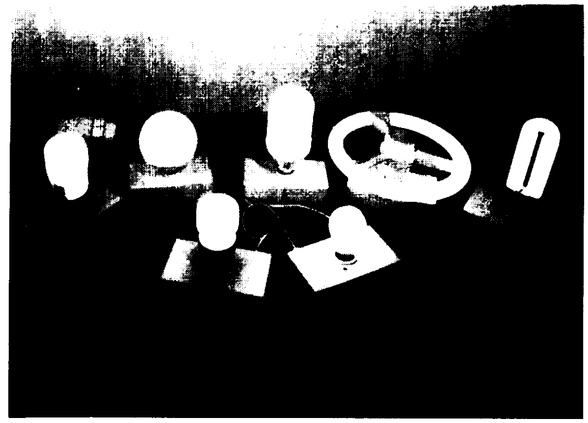
48 See discussion of district heat in OTA, *Building Energy Efficiency,* supra note 2, p. @.

49 DOE, *Commercial Building Characteristics 1989,* supra note 44, table 94, p. 183.

from installing efficient lighting systems also cuts cooling load. Excluding lighting-related savings, EPRI estimated that cooling requirements can be reduced by 30 percent or more in commercial buildings. Including lighting efficiency packages with cooling system improvements could provide total savings of over 80 percent according to EPRI estimates. However, the need to find replacements for CFCS now used in cooling systems could result in newer cooling technologies that may reduce some possible efficiency gains. EPRI therefore estimates maximum potential electricity savings in commercial space cooling in 2000 to be from 30 to 70 percent over 1987 performance levels.[50]

Another energy efficiency strategy for commercial cooling that may not always result in a net reduction in electricity demand is the use of cool storage systems that shift all or part of a buildings' air-conditioning electricity demand from peak to off-peak hours. Typically, ice or chilled water is produced in a refrigeration system at night and used to meet some or all of the next day's air-conditioning needs. Cool storage systems offer financial savings for customers through lower off-peak rates and peak reduction for utilities.[51]

Ventilation. Air transport and ventilation systems are a critical component of modern large commercial buildings. Improving the energy efficiency of ventilation and air transport systems can be attained through a variety of measures: viable air volume systems; low-fiction air distribution designs; high-efficiency electric motors; variable speed drives; heating, cooling, and lighting improvements; and improved operation and maintenance practices. EPRI estimates that ventilation electricity use can be reduced by 30 to 50 percent through a comprehensive package of measures.



U.S. DEPARTMENT OF ENERGY

Compact fluorescents, which use 75 percent less energy than standard incandescent lamps, are available in a variety of designs.

LIGHTING

About 29 percent of commercial electricity consumption is for lighting. Commercial lighting requirements are met with a combination of incandescent, fluorescent, and high-intensity discharge lamps and most commercial buildings have a mixture of these fixtures. Fluorescent lamps are already extensively used in the commercial sector. About 78 percent of commercial floorspace is lit with fluorescent and high-efficiency ballasts have been installed in about 40 percent of this space.[52]

A range of cost-effective technologies is available to cut lighting loads. Ready savings can be achieved in many commercial buildings by delamping to lower lighting levels, using lower wattage fluorescent, and replacing incandescent with more efficient fluorescent or compact fluorescent lamps where appropriate. More advanced lighting system efficiency upgrades include installation of high-efficiency electronic ballasts, aluminum and silver film reflectors, daylight dimming, occupancy sensors, use of high-

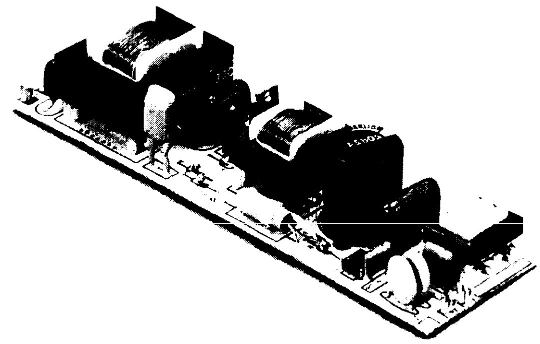
50 EPRI, *Efficient Electricity Use,* supra note 1, p. 50.

51 EPRI, *DSM Technology Alternatives,* supra note *26,* pp. B-394.

52 DOE, *Commercial Building* Characteristics *1989,* supra note 44, table 101, p. 195. It is not reported whether the high-efficiency ballasts have been installed in all fluorescent fixtures lighting these spaces.

pressure sodium lamps instead of mercury vapor lamps in high-intensity discharge fixtures. In new construction and remodeling, better lighting system design and greater use of daylighting can also cut lighting requirements.

Estimates of lighting savings involve interactions among package components and are not necessarily the sum total of individual measures. Building characteristics also influence potential savings. In addition lighting upgrades can cut cooling costs by reducing internal heat gain, but add to heating loads. EPRI estimates potential electricity savings from more efficient commercial lighting in 2000 to range from 30 to 60 percent over 1987 stock.[53]



ADVANCE TRANSFORMER CO.

Electronic ballasts can cut fluorescent lighting energy use by 20 to 25 percent.

COMMERCIAL REFRIGERATION SYSTEMS

Commercial refrigeration in retail stores, restaurants, and institutions can be a significant load. About 20 percent of commercial buildings are, equipped with commercial refrigeration systems; about 16 percent have commercial freezers. EPRI estimates that commercial refrigeration electricity use can be cut by 20 to 40 percent from 1987 performance levels by combining a variety of efficiency improvements. Examples include: more efficient fan motors and compressors, multiplex unequal parallel compressors, advanced compressor cycles, variable speed controls, evaporatively cooled condensers, floating head pressure systems, air barriers, food case enclosures, electronic controls, and improved maintenance practices. Electricity savings are highly site specific and depend on previous saturation of these technologies.

WATER HEATING

About 48 percent of commercial buildings with hot water systems[54] use electricity as the sole or supplemental water heat source. Hot water heating **accounts** for about 3 percent of commercial electricity use.

There are a number of efficiency measures for commercial hot water systems on the market. These measures include many also used in residential applications, such as water heater wraps, low flow devices, hot water pipe insulation, and installation of valves that reduce convection loses. Commercial heat-pump water heaters and heat recovery systems can provide energy savings of one-third or more over conventional resistance systems. Integrated heat pumps can provide heating, cooling, and hot water for commercial buildings. Lowering the hot water thermostat can reduce electricity use while still providing adequate water temperatures for most uses. EPRI estimates potential savings in water heating electricity use in 2000 of 40 to 60 percent over 1987 stock.[55]

COOKING

Commercial cooking equipment accounts for about 2 percent of commercial sector electricity use. Microwaves, convection ovens, and mag-

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53 OTA, *Building Energy Efficiency*, supra note 2, p. 50, for estimates Of savings in the commercial sector.

54 DOE, *Commercial* Building *Characteristics 1989,* supra note 44, table 76, p. 148.

55 EPRI, *Efficient Electricity Use,* supra *note* 1, p. 51.

netic induction cooktops can cook food with less time and energy than more conventional electric stoves and ovens and are seeing greater use in commercial establishments. A range of technological improvements are available to cut electricity use in commercial ranges, ovens, broilers, griddles, and fryers. Examples include: increased insulation, better heating elements, more precise temperature controls, reflective pans, reduced thermal mass, and less contact resistance. EPRI estimates that by incorporating a combination of efficiency measures, electricity use by commercial electric stoves and ovens in 2000 could be from 20 to 30 percent less than that required for 1987 stock.[56]

MISCELLANEOUS COMMERCIAL SYSTEMS AND EQUIPMENT

Residual electric systems and equipment (e.g. elevators, escalators, telephone systems, office machines, food preparation and other equipment) account for 21 percent of commercial sector electricity use and will continue to grow.

EPRI estimates that overall savings from expected efficiency advances in miscellaneous commercial sector equipment will range from 10 to 30 percent. Expected improvements in hardware, software, and system operations could offer maximum potential savings of up to 50 percent for office equipment in 2000. EPRI also calculates maximum potential savings of up to 35 percent in 2000 from the use of high-efficiency motors and adjustable-speed drives in elevators and escalators.[57]

The Federal Government, through the Environmental Protection Agency's green programs and Federal procurement policies, is seeking to overcome some of the market barriers to more energy-efficient computer equipment. (See box 4-D.)

Barriers to Energy Efficiency in the Commercial Sector

There remains a significant gap between the electricity-using characteristics of the present stock of commercial buildings and equipment and the energy-saving potential of the most efficient buildings and equipment marketed today. As with the residential sector, many economic, institutional, and behavior influences hamper greater commercial sector investment in energy efficiency.

Some influences are shared with other sectors. The normally slow turnover in commercial buildings and major equipment, albeit more rapid than in the residential sector, means that actual efficiency savings lag considerably behind technical potential. Relatively low energy prices that do not reflect all societal and environmental costs of energy production and use also lead to undervaluing of energy and underinvestment in efficiency by commercial consumers. (This persists even though commercial customers are in general more price-sensitive than residential customers, and utility bills for commercial establishments can be quite large.) Choices affecting commercial energy demand are made by a large number of decisionmakers — architects, designers, developers, building owners, tenants, equipment manufacturers and vendors, and local building authorities. The plethora of decisionmakers and the absence of any direct economic benefit in efficiency for many of them lessens the impact of existing weak financial incentives and fragrnents the potential constituency for efficiency improvements.

Several factors contribute to limited financial incentives to invest in efficiency. Energy costs of buildings can often be a small fraction of total business expenses and thus gain little management attention as a means of saving money .58

56 Ibid.

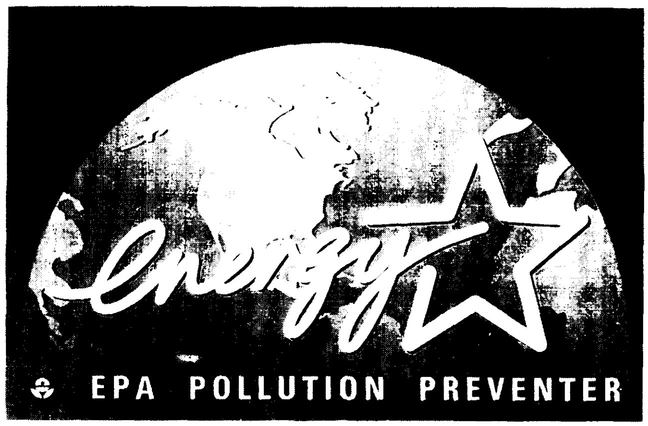
57 Ibid., p. 52.

58 According to some estimates, for large office buildings and retail space energy costs are less than 5 percent Of total annual operating costs per square foot and are dwarfed by other business costs. OTA, *Building Energy Efficiency*, supra note 2, pp. 81-82,

Box 4-D-EPA and Green Computers

Computer equipment and other electric office machines are among the fastest growing components of commercial energy consumption. They now total about 5 percent and are expected to total 10 percent by 2000. Surveys have determined that most personal computers are left turned on when not in use during the day, overnight and on weekends. Desktop computers typically have been designed with little consideration for energy efficiency, unlike portable or laptop models that incorporate a number of energy-saving measures to save battery power. if desktops were equipped with technologies that allowed them to "nap" or shutdown when not in use and return quickly to full power capability when needed, EPA estimated that such computers could save 50 percent of the energy used to run them. Green computers thus became one of the first commercial consumer products targeted by EPA's pollution prevention programs to increase consumer and manufacturer awareness of energy efficiency benefits, and to create a new market for energy-efficient equipment.

Using a model similar to the Green Lights Program (see chapter 7), EPA entered into discussions with manufacturers of computers, peripherals, and microprocessors. Manufacturers agree to produce products that meet certain efficiency improvements and sign a mernorandum of understanding with EPA. The manufactures are then eligible to use the "Energy Star™-EPA Pollution Preventer" logo in the marketing and displaying of the products. For example, personal computers with the capability of switching to a low power mode of 30 watts or less (about 75 percent less than current models) qualify for the EPA logo that identifies new high efficiency equipment. EPA is expanding the use of such voluntary agreements for related computer products including printers, monitors and other pieces of office equipment.



U.S. ENVIRONMENTAL PROTECTION AGENCY

Energy Star Computers could save enough electricity each year to power Vermont and New Hampshire, cut electricity bills by $1 billion, and reduce CO_2 *pollution equivalent to emissions from* 2.5 *million autos.*

By May 1993 EPA had reached agreement with an impressive array of companies producing personal computers and related products. Charter partners in EPA's Energy Star™ computer program represent 60 percent of the U.S. market for computers and monitors, and 60 percent of the laser printer market. An Energy Star™ allies, program has been established enlisting agreements from components and software makers. Intel Corporation, one of the world's major microprocessor manufacturer, has committed to incorporating energy-saving technologies into all future microprocessors. The first products bearing the Energy Star logo will be available in 1993.

The widespread penetration of energy-saving computer technologies offers significant benefits to consumers, the economy, and the environment. The cost of operating a typical 150-watt personal computer 24 hours per day year round can be $105/year (assuming electricity costs at $0.08/kWh) and uses 1,314 kWh/yr. Turning the machine off at night reduces the operating cost to $35/year and cuts energy consumption to 433 kWh/year. Using technology that conserves power when the machine is not active during the day could cut costs to $1 7/year for 216 kWh/year. EPA estimates that green computers could save a total off $1.5 to $2 billion in annual electricity bills and avoid emissions of 20 million tons of carbon dioxide, 140,000 tons of sulfur dioxide, and 75,000 tons of nitrogen dioxide by 2000.

SOURCES: U.S. Environmental Protection Agency, Office *of Atmospheric Programs, 7992 Accomplishments* and Prospecft for *1993, vol.* 1: Global Change Division, EPA 430-K-92-031, November 1992, pp. 9-10. Brian J. Johnson and Catherine R. Zoi, "El% Energy Star Computers: The Next Generation of Office Equipment," in American Council for an Energy-Efficient Economy, *ACEEE 1992 Surnmer Study on Energy Efficiency in Buildings, vol. 6* (Washington DC: American Council for an Energy-Efficient Economy, 1992), pp. 6.107-6.114.

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Energy efficiency is only one consideration in decisions affecting energy use--first-cost, appearance, comfort, and other performance features may overshadow potential lifecycle cost savings from efficiency. Building owners and tenants tend to place greater emphasis on occupant comfort and productivity and may be reluctant to make any changes that might affect building operations. One-quarter of commercial space is leased and lower energy bills offer no incentives for building landlords when the tenants are responsible for paying electric bills. Where landlords pay utility bills and energy prices are included in rent, building occupants may have little financial incentive to choose high-efficiency equipment or to invest in energy-savings maintenance.[59]

When efficiency investments are considered, commercial sector decisionmakers also tend to require short payback periods of 1 to 3 years. Lack of resources or access to capital can discourage some possible commercial sector efficiency investments, particularly for nonprofit institutions and small businesses. Cost-effective, low-risk measures that could cut operating costs are often given low priority in government facility management. Even when government facility managers are aware of potential savings, budgetary and procurement constraints limit investments in efficiency for government owned or occupied facilities.[60]

The energy efficiency industry is still in its infancy and the small pool of trained vendors, installers, and auditors available to serve commercial establishments and utility programs can limit achievable energy savings at least in the short term. The relative newness of the industry and absence of a proven track record of delivering savings may make many in the commercial sector reluctant to make significant investments in energy efficiency. Indeed, savings from early building retrofit investments have been less than expected on average, and unpredictable for individual buildings, adding to the perceived riskiness of the investment.[61]

Nevertheless, the commercial sector remains a prime and potentially profitable target for utility, private sector and government efforts at improving energy efficiency.

ENERGY EFFICIENCY OPPORTUNITIES IN THE INDUSTRIAL SECTOR

The industrial sector includes both manufacturing enterprises (i.e., businesses that convert raw materials into intermediate or finished products) and nonmanufacturing enterprises, such as agriculture, forestry, fishing, construction, mining, and oil and gas production. The industrial sector is characterized by the diversity of energy uses, equipment, and processes and is the largest energy sector, consuming 37 percent of U.S. total primary energy use in 1990. Patterns of industrial energy use are further complicated by the use of oil, gas, and coal as feedstocks and for cogeneration. Figure 4-5 shows industrial energy use for fuel and power only.

Industrial energy use is variable, reflecting economic conditions, structural changes, interfuel competition, and rate of investment. Patterns of industrial energy use and energy intensity of industry also vary significantly by region. Price is the major determinant in most industrial energy choices, and head-to-head competition among fossil fuels is intense. Price however is not the sole consideration—availability, reliability, and quality also drive industrial energy decisions. Another trend is the growth in industrial cogeneration, which is generally viewed as a positive development for efficiency, but, which in effect transfers demand and losses between industrial

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59 Ibid., p. 54.

60 U.S. Congress, Office of Technology Assessment *Energy Efficiency in the Federal Government: Government by Good Example?* OTA-E-492 (Washington DC: U.S. Government Printing Office, May 1991).

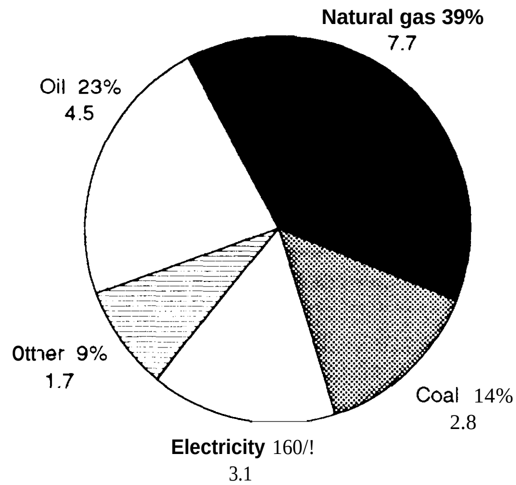
61 Oak Ridge National Laboratory, supra note 16, pp. 45-46.

sector and utilities. Moreover there has been a general trend toward electrifying many process technologies and a shift in energy and electric intensity of manufacturing. The relationship of efficiency gains and structural changes in U.S. industry was examined in detail in an OTA background paper, *Energy Use and the U.S. Economy.*[62] A companion new OTA report, *Industrial Energy Efficiency,* was published in summer 1993.

There are five major fuel and power demands in the industrial sector: process steam and power generation (36 percent), process heat (29 percent), machine drive (14 percent), electrical services(4 percent), and other (including off-highway transportation, lease and plant fuel use, and mining) (16 percent).[63] The industrial sector derives 40 percent of its fuel and power needs from natural gas, 25 percent from oil, 15 percent from purchased electricity, 9 percent from coal, and the remaining 9 percent from waste fuels and other sources. Electricity competes with other fuels, particularly natural gas, for direct heat applications.[64] For other uses, purchased electricity competes with the options of self-generation or cogeneration. It is estimated that in 1989, the industrial sector produced about 153,270 gigawatthours of electricity on-site. Surplus electricity production was sold to local utilities.[65] To avoid doublecounting, fuel used for industrial self-generation or cogeneration is usually attributed to primary fuels.

In 1990 industrial consumers purchased 946 billion kWh from electric utilities at a cost of $45 billion.[66] Sales to industrial users accounted for 35 percent of electric utility revenues from sales to end-users/ultimate customers. Electricity consumption in the industrial sector is divided among

Figure 4-5--industrial Energy Use for Fuel and Power, 1989 (quadrillion Btus)



SOURCES: Office of Technology Assessment, 1993, based on data from the Gas Research Institute.

the manufacturing enterprises (87 percent); agriculture (5 percent) and construction and mining (8 percent).

The major industrial electricity uses are motor drive, electrolytic, process heat, and lighting (see figure 4-6). Table 4-4summarizes EPRI estimates of 1987 industrial energy consumption for these applications by industrial subsectors (SIC codes), manufacturing loads and nonmanufacturing loads.

The most electricity-intensive manufacturing activities (including on-site generation) are chemical products, primary metals, pulp and paper, food, and petroleum refining, together accounting for more than half of manufacturing electricity use. The pulp and paper and chemical products

62 U.S. Congress, Office of Technology Assessment, *Energy Use and the U.S. Economy,* OTA-BP-E-57 (Washington, DC: U.S. Government *Printing* Office, June 1990).

63 1992 *GRI* Baselin, *Projection,* supra note 8, p. 36.

64 Ibid, p. 41.

65 Ibid.

66 DOE, *Electric power Annual 1990,* supra note 10, table 1.

Table 4-4—Industrial Electricity Use by Application and Industry, 1987 (gigawatt-hours)

Category SIC code	Total electricity consumption (GWh)	Motor drive (GWh)	Percent	Electrolytics (GWh)	Percent	Process heating (GWh)	Percent	Lighting (GWh)	Percent	Other (GWh)	Percent
Manufacturing											
Major electricity users[a]											
28 Chemicals	141,191	90,250	63.9%	36,810	26.1%	668	0.5%	13,464	9.5%	0	0.0%
26 Paper	83,219	74,364	89.4	0	0.0	1,870	2.2	6,985	8.4	0	0.0
20 Food	47,213	40,544	85.9	0	0.0	1,202	2.5	5,466	11.6	0	0.0
33 Primary metals	146,410	54,482	37.2	58,956	40.3	25,785	17.6	7,187	4.9	0	0.0
29 Petroleum	41,444	8,108	91.9	0	0.0	401	1.0	2,936	7.1	0	0.0
32 Stone, clay, and glass	34,019	27,192	79.8	0	0.0	5,077	14.9	1,822	5.3	0	0.0
37 Transportation equipment	37,560	21,539	57.3	101	0.3	13,895	37.0	2,025	5.4	0	0.0
35 Industrial machinery	33,194	16,598	51.1	101	0.3	12,692	38.2	3,442	10.4	0	0.0
34 Fabricated metal prod.	31,045	13,937	44.9	2,225	7.2	267	41.7	1,923	6.2	0	0.0
36 Electronics	32,299	27,679	85.7	0	0.0	267	0.8	4,353	13.5	0	0.0
22 Textiles	25,509	20,760	81.4	0	0.0	802	3.1	3,948	15.5	0	0.0
30 Rubber and plastics	28,809	26,510	88.9	0	0.0	1,069	3.6	2,227	7.5	0	0.0
Total all manufacturing	736,950	495,012	67.2%	98,193	13.3%	[illegible],959	10.7%	64,787	8.8%	0	0.0%
Nonmanufacturing											
Agriculture	44,541	23,283	52.3%	0	0.0%	[illegible]	91%	1,985	26.9%	5,132	11.5%
Mining	55,676	50,615	90.9	0	0.0	0	0.0	3,525	6.3	1,509	2.7
Construction	8,098	2,025	25.0	0	0.0	0	0.0	4,230	52.2	1,811	22.4
Total nonmanufacturing	10[illegible]315	75,923	70.1%	0	0.0%	4,049	3.7%	19,740	18.2%	8,452	7.8%
Total industrial	845,266	570,934	67.5%	98,193	11.6%	83,008	9.8%	84,527	10.0%	8,453	1.0%

[a] Industries using more than 25,000 (GWh) annually.

SOURCE: Office of Technology Assessment, 1993, based on data from Barakat & Chamberlin, Inc., *Efficient Electricity Use: Estimates of Maximum Energy Savings*, EPRI CU-6746 (Palo Alto, CA: Electric Power Research Institute, March 1990), p. 69.

subsectors have significant cogeneration capacity-mostly freed by waste fuels.

▮ Efficient Industrial Technologies

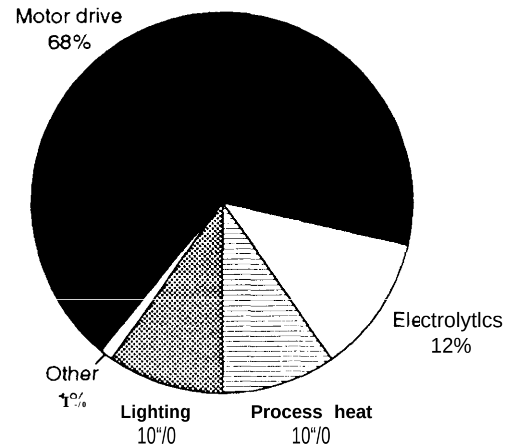
There are several strategies for improving energy efficiency in the industrial sector, including making existing electricity applications more efficient, shifting industrial processes from fossil fuel to electrotechnologies for net energy savings, and using more industrial cogeneration for net energy savings over purchased electricity.

EPRI estimates that application of more efficient industrial equipment and processes offers potential savings of from 24 to 38 percent of their projected base-case electricity use in 2000.[67] The most promising targets for potential efficiency gains are high efficiency electric motors and variable speed drives, improved electrolytic processes, industrial process waste heat recovery, and more efficient lighting technologies. (See table 4-5.) All but electrolytic technologies have a wide and diverse range of potential applications across the industrial sector.

ENERGY-EFFICIENT ELECTRIC MOTORS AND DRIVES

There is great diversity in industrial applications of electric motors and drives: pumps, fans, compressors, conveyors, machine tools, and other industrial equipment. Motor drive end-uses account for an estimated 70 percent of electricity load in manufacturing. High-efficiency electric motors combined with adjustable-speed drives (ASDS) offer significant electricity savings potential.

Figure 4-8-industrial Electricity Use by Application, 1987



SOURCE: Office of Technology Assessment, 1993, based on data from the Electric Power Research Institute.

Electric motors are available in standard and high-efficiency models and energy efficiency of both vary according to size. In general, larger motors are more efficient than smaller ones in both standard and high efficiency models. The high-efficiency models cost from 10 to 30 percent more than the standard versions,[68] but have efficiency increases of 8 percent for smaller motors and 3 percent for larger motors.[69] Energy-efficient motors typically have longer operating life than standard motors. The initial capital costs of electric motors are usually only a fraction of their operating costs. For example, annual energy costs for an electric motor might run as much as 10 times its initial capital cost; increasing its efficiency from 90 to 95 percent could mean

67 EPRI, *Efficient Electricity* Use, supra note 1, *p.* 61.

68 American Council for an Energy-Efficient Economy and New York State Energy Office, *The Achievable Conservation Potential in New York State from Utility Demand-Side Management Programs,* final report, Energy Authority Report 90-18 (Albany, NY: New York State Energy Research and Development Authority, November 1990), p. 48.

69 EPRI, *DSM Technology Alternatives,* supra note 26, p. C-41.

Table 4-5-Selected Energy Efficiency Technology Options for the Industrial Sector

Electric motors and drives
- High-efficiency motors
- Variable speed drives
- Optimal sizing of motors and loads, serial motors

Waste heat recovery systems
- Industrial process heat pumps
- Industrial heat exchangers
- Vapor recompression systems

Electrolytic processing

Chlor-alkali production
- Improved membrane and diaphram cells for chlor-alkali production

Aluminum smelting
- Improved efficiency in Hall-Heroult smelting process
- Alternative aluminum reduction technologies

industrial Lighting

Delamping
Lighting fixture retrofits
Electronic ballasts for fluorescents
High-efficiency lamps
Reflectors
Increased use of daylighting
High-intensity lighting applications
increased use of task lighting
Compact fluorescents
LED signs
Lighting control systems-timers, occupancy sensors, photocells, dimmers

industrial eiectro-technologies

Plasma processing
Electric arc furnaces
Induction heating
industrial process heat pumps
Freeze separation
Ultraviolet processing/curing

industrial cogeneration systems

High-efficiency industrial boilers
Integrated process heat/steam and power production

SOURCE: Office of Technology Assessment, 1993.

savings of 50 to 60 percent of its capital costs in a single year.[70]

Many industrial motors are often run at less than maximum power because of varying loads. Electronic adjustable speed drives allows an electric motor to operate at reduced speed when maximum power is not needed, saving energy. ASDS are appropriate in applications with high operating hours where motors are often operated at less than full load.

There are three targets for displacing standard-efficiency motors with high-efficiency motors: selecting new or replacement motors, rewinding of existing motors, and retrofitting of existing motors that do not need repair or replacement.

High-efficiency variable-speed motors offer tremendous potential for efficiency. Various studies have yielded estimates of potential savings of 20 to 50 percent depending on circumstances for application of ASDS. Use of high-efficiency electric motors can provide savings of an additional 3 to 10 percent. Overall efficiency improvements in motor drive of 35 to 50 percent over 1987 equipment were assumed in EPRI's analysis.[71] Motor drive improvements offered nearly 80 percent of estimated savings in their analysis, with over 90 percent of these savings in just a few industry categories.

WASTE HEAT RECOVERY

Waste heat recovery systems improve energy efficiency by using heat from fuel combustion or excess thermal energy from a process steam product. An estimated one quarter to one-half of the process heat used by industry is discharged as hot gases or liquids.[72] There are various approaches to capturing energy from these sources of waste heat. The choice depends on characteristics of the heat source, process needs, and economics. Heat exchangers are used to transfer heat from a high-temperature waste exhaust source, such as combustion gases, to a cooler supply stream such as steam for lower temperature uses. Low-temperature waste heat streams

70 U.S. Congress, Office of Technology Assessment, *Industrial Energy Use, OTA-B 198* (Washington, DC: U.S. Government Printing Office, June 1983) p. 50. (Available from the National Technical Information Service, Springfield, VA, NTIS Order #PB83-240606.)

71 EPRI, *Efficient Electricity Use*, supra note 1, p. 59.

72 EPRI, *DSM Technology Alternatives,* supra note 26, p. c-8.

can be upgraded to supply heat for higher temperature processes via industrial heat pumps or vapor recompression systems, Analyses for EPRI found that installation of heat recovery devices can reduce a plant's overall energy requirements by at least 5 percent with paybacks of less than 2 years. The most cost-effective time to incorporate the systems is during new construction or modernization projects and most applications have been custom designed. Heat recovery devices displace conventional energy sources (such as purchased electricity) and are used in processes requiring a constant heat source. Hence they are attractive to utilities as means to reduce base loads and peak loads,

Waste heat recovery in industrial process heat systems can provide electricity savings of 5 to 25 percent according to EPRI estimates. Very little waste heat recovery currently exists, so there is potential for significant improvement. EPRI assumed an average of 10 to 15 percent savings.

ELECTROLYSIS

An estimated 12 percent of industrial electricity use is used for electrolysis. Electrolysis is a method for separating and synthesizing chemicals or metals by using electricity to produce chemical reactions in aqueous solutions or molten salts. At present the two largest industrial applications of electrolysis are aluminum reduction in the primary metals processing industry and the production of chlorine and caustic soda from salt brines in the chemical products industry.

Electricity is the most costly material in aluminum production. In the century-old Hall-Heroult process alumina refined from bauxite ore is reduced via electrolysis to molten aluminum,[73] The smelting process is continuous. Alumina is dissolved in a molten electrolytic bath in carbon lined steel cells or pots, In each pot a direct current is passed from an carbon anode suspended in the cell through the bath to the carbon lining of the cell producing a chemical reaction. Molten aluminum is siphoned from the bottom of the pots and is then formed into aluminum ingots or further refined and/or alloyed into fabricating ingot. A single potline can consist of from 50 to 200 cells with a total voltage of 1,000 volts at currents of 50,000 to 250,000 amperes. U.S. smelters use from 6 to 8 kWh to produce each pound of aluminum.

The efficiency of aluminum production has improved steadily. Following World War II about 12 kWh of electricity was needed to produce one pound of aluminum; today, through greater economies of scale and process controls, the most efficient smelters use half that electricity per pound.[74] Further efficiency gains are promised by advanced electrolytic reduction methods including bipolar cells, inert anodes, and wettable cathodes. None of these technologies, however is currently installed, but EPRI estimates that they could potentially yield efficiency savings by year 2000 of some 30 to 50 percent over current methods. These improvements are highly attractive given the high electric intensity of aluminum production and are significant for regions where such production is concentrated, such as the Pacific Northwest.

Chlor-alkali production is second to aluminum in terms of electricity consumption and uses about 30 percent of electric power used for electrochemical production .75 Chlorine and caustic soda (sodium hydroxide) are produced from salt brine by electrolysis in either the diaphragm or mercury cell. Mercury cells account for about 20 percent of U.S. capacity. Throughout this century economies of scale have produced steady efficiency gains in chlor-alkali production as newer and larger cells required less energy to

[73] U.S. Congress, Office of Technology Assessment, *Nonferrous Metals: Industry Structure: Background Paper, OTA-BP-E-62* (Washington, DC: U.S. Government Printing Office, September 1990), pp. 25-26.

74 Ibid.

[75] EPRI, *DSM Technology Alternatives,* supra note 26, pp. c-5-c-6.

drive the chemical reactions.[76] In the membrane cell, different constituents of the solution are separated by selective diffusion through the membranes. EPRI analyses estimated that use of membrane cells to replace diaphragm cells could save 10 percent of electricity used in chlor-alkali production. Other analyses have estimated savings of up to 25 percent over current methods.

Adaptation and improvement of electrolytic separation methods, including electrodialysis which uses electric current to accelerate membrane separation, for other inorganic and organic processes also can yield efficiency gains over conventional methods.

LIGHTING

Lighting accounts for about 10 percent of electricity use in the industrial sector. As in the commercial and residential sectors, more efficient lighting technologies offer promises of electricity savings across the industrial sector too, Industrial lighting efficiency upgrades such as delamping, reduced wattage fluorescent, high-efficiency ballasts, reflective fixtures, occupancy sensors, replacing incandescent lamps with compact fluorescent, and greater use of daylighting. EPRI analyses estimate that lighting efficiency packages offer savings of from 36 to 49 percent. Lighting upgrades can also lower cooling loads, but increase heating loads.

ELECTRIFICATION OF INDUSTRIAL PROCESSES

Electrification offers the potential for net savings in fossil fuel use even as it increases electricity demand in the industrial sector. There has been a continuing trend toward electrification of many industrial processes and end-uses. Cost has been a major factor, but increasingly, reliability, flexibility, and reduced environmental impacts on-site have made electrification an attractive option for improving industrial productivity. There are a variety of electrotechnologies that could boost industrial electricity use over the next several decades, while providing net savings in fossil fuel consumption. EPRI looked at the possible net energy savings from five such technologies.

Freeze concentration uses refrigeration processes to separate and concentrate constituents from mixed dilute streams. Separation of constituents from process streams is a major energy use in the industrial sector and many techniques such as distillation rely on high temperatures produced by burning fossil fuels. It takes less energy (about 150 Btu) to freeze a pound of water than the 1,000 Btu needed to boil it.[77] Shifting to freeze separation could cut overall energy consumption and displace industrial fossil fuel use. More energy-efficient refrigeration technologies add to the attractiveness of freeze concentration as an alternative separation technique. Currently used for treating hazardous wastes, concentrating fruit juices, and purifying organic chemicals, the technique is being investigated for broader industrial application.

Industrial process heat pumps can replace indirect resistance heating for certain low temperature applications (below 280 to 3000 F) in lumber, pulp and paper, food, chemical, and petroleum subsectors.

Electric arc furnaces allow direct melting of raw steel and uses less energy than fossil-freed furnaces. Electric arc furnaces have already gained a significant foothold in the steel industry accounting for an estimated 34 percent of steel produced in 1985. Continuation of this trend to 56 percent or more by 2000 was projected. Electric arc furnace foundries are also used to produce steel castings and increased use of this technology also promises net fossil fuel savings.

Plasma processing uses a high intensity electric arc to generate ionized gases at temperatures up to 10,000° F and more, far exceeding the

76 OTA, *Industrial Energy Use,* supra note 70, p. 123-124.

77 Oak Ridge National Laboratory, supra note 16, p. 71.

2,800°F practical limit for fossil fuel combustion.[78] The technology offers high energy density and temperature capability, controllability, and fuel flexibility compared with conventional combustion technologies. Plasma processing can be expanded in already established uses for cutting, welding, heat treating, and burning and into promising new applications in electric arc furnace dust processing, cupola refits with plasma torches, ferroalloy production, and ore reduction. Use for chemical production also is said to have future commercial potential.

Ultraviolet **curing** uses ultraviolet radiation produced by ionizing gases in an electrical arc or discharge, such as in a high-pressure mercury vapor lamp, to change the molecular structure of a coating to make it a solid. UV curing offers large energy and cost savings compared with thermal curing and is expected to gain increasing market penetration especially in quickcuring applications. An additional and significant environmental and health benefit is the elimination of solvents in the curing process.

Potential Savings. EPRI estimates that all these technologies offer strategic load growth to electric utilities, while resulting in net savings in fossil fuel use overall. Maximum application of these technologies could add 319 trillion Btu of fossil fuel in electric utility generation, but at the same time yield a net savings of 290 trillion Btus in these industrial processes.

COGENERATION

Cogeneration is the simultaneous or sequential production of both electrical or mechanical power and thermal energy from a single energy source.[79] On-site industrial cogeneration has grown significantly since the late 1970s as a result of higher energy prices, volatile energy prices, and uncertainty over energy supplies. Implementation of the Public Utility Regulatory Policies Act of 1978 (PURPA), which required electric utilities to provide interconnections and backup power for qualifying cogeneration facilities and to purchase their excess power at the utilities' avoided cost, reduced institutional barriers to the expansion of cogeneration. PURPA was intended to promote industrial cogeneration as a means of improving efficiency especially in the use of premium fossil fuels (gas and oil) and encouraging the use of waste fuels.

In most industrial cogeneration systems, fuel is burned frost to produce steam that is then used to produce mechanical energy at the turbine shaft or to turn the shaft of a generator to produce electricity. The steam leaving the turbine is then used to provide process heat or drive machines throughout the host industrial plant and related facilities. From an energy policy perspective, the attraction of cogeneration is the ability to improve fuel efficiency. Cogeneration systems achieve overall fuel efficiencies 10 to 30 percent higher than if power and heat were provided by separate conventional energy conversion systems, i.e., less energy than if the fossil fuel were burned in an industrial boiler to provide process heat and at an off-site utility power plant to generate electricity to be transmitted to the industrial site. (This aspect of cogeneration efficiency depends on the fuel that is burned to produce electricity) Cogeneration can also be attractive as a means of quickly adding electric generating capacity at sites where thermal energy is already being produced.

Industrial cogeneration is concentrated in the pulp and paper, chemicals, steel, and petroleum refining industries. Often the industrial cogenerators can take advantage of waste fuels to fire their boilers for heat and power. Natural gas has been the fuel of choice for many qualifying cogeneration plants under PURPA.

Cogeneration does not always provide significant efficiency advantages, however. Almost the entire output of newer combined-cycle, natural

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[78] EPRI, *DSM Technology Alternatives,* supra note 26, p. C-21-22.

[79] OTA, *Energy Technology Choices,* supra note 4, p. 39.

gas-fired cogeneration systems is electric power generation with little steam for process applications. In this case, there is a much smaller efficiency gain from cogeneration and a net shift in primary fuel demand from the utility sector to the industrial sector. Thermal conversion losses in electric utility and industrial combined cycle generating units are similar, there are some small savings in avoided transmission and distribution losses. If a significant portion of the cogenerated power is sold to the local electric utility, these transmission and distribution gains would largely disappear.

Industrial cogeneration makes up the overwhelming bulk of the explosive growth of so called independent power producers in the past decade. While cogeneration was initially viewed by many utilities as a threat to their market share. It is increasingly accepted as an alternative power source and has been integrated into some utilities load management and resource plans. In fact a number of utility companies have independent power subsidiaries or affiliates that are partners in industrial cogeneration projects.

In 1989, Edison Electric Institute estimated that cogeneration accounted for about 73 percent of the operating capacity of nonutility power plants.[80]

Industrial cogeneration plants will benefit from many of the same efficiency improvements as utility generation as many use the identical technologies. In addition, better integration of industrial cogeneration and utility system operations through planning and dispatch offers net improvements to system efficiencies.

▮ Constraints on Efficiency Gains in the Industrial Sector

There have been significant energy efficiency gains in the industrial sector over the past two decades. Industrial energy use per unit of output (energy intensity) has been declining since 1970. At the same time, more and more industrial processes have been electrified. Even so, OTA found that opportunities for further gains in energy efficiency have by no means been exhausted.[81]

The industrial sector faces some of the same constraints as other sectors: low energy prices, failure of energy prices to reflect societal and environmental costs, multiplicity of decisionmakers, and reluctance to adopt unproven new technologies. Energy efficiency choices tend to be made in new investments and when equipment must be repaired or replaced which creates a normal lag time between the development of new electricity-saving technologies and their dispersion throughout industry. But certain barriers are less applicable-for example, the disconnect between those who pay for energy-efficient improvements and those who benefit is rarely present. Of all sectors, the industrial sector is probably the most responsive to price signals, so that the argument that there are market failures resulting in an underinvestment in energy efficiency here (from the perspective of myriad industrial consumers) is hardest to make. Nevertheless, certain characteristics of industrial decisionmaking about energy choices can result in lower adoption rates for energy-efficient equipment than might be desirable from a societal or utility perspective.[82]

80 Edison Electric Institute, *1989 Capacity and Generation of Non-Utility Sources of Energy,* Washington DC, April 1991, P. 29.

131 OTA, Energy *Technology Choices,* supra note 4, p. 38.

82 OTA has examined industrial energy investment decisionmaking in a number of reports. The most recent effort is in a forthcoming report *Industrial Energy Efficiency,* to be published in summer 1993. Other OTA reports include *Industrial Energy Use (1983),* supra note 70; *Energy Technology Choices,* supra note *79;* and U.S. Congress, Office of Technology Assessment, *Industrial and Commercial Cogeneration, OTA-E-192* (Washington DC: U.S. Government Printing Office, February, *1983).* (Available from the National Technical Information Service, NTIS Order #PB83-180457.)

Economic considerations dominate investment decisions in the industrial sector. For most industries energy costs and electricity costs are only a small part of operating costs and thus may not enjoy a high priority. Industries that are highly energy and electricity intensive have a stronger incentive to invest in efficiency, while others do not even though there may be substantial and cost effective opportunities. Most firms regard energy efficiency in the context of larger strategic planning purposes. Investments are evaluated and ranked according to a variety of factors: product demand, competition, cost of capital, labor, and energy. Energy-related projects are not treated differently from other potential investments and must contribute to increased corporate profitability and enhanced competitive position. As a result incentives aimed at reducing energy demand growth or improving efficiency in the industrial sector must compete with other strategic factors and therefore have to be substantial to make a significant impact.

In addition to lack of strong financial incentives and management indifference, industrial energy efficiency gains are also hampered by lack of information, and shortages of skilled designers, installers, and auditors. Highly specialized and plant- or application-specific analyses are often required to identify optimal and appropriate energy savings improvements because of the diversity of industrial processes, equipment, and energy applications. President Bush's National Energy Strategy report found that the industrial sector tended to underfund investment in energy efficiency R&D because of the belief that competitors could quickly adopt process or technology advances, thus minimizing any potential competitive advantage.[83]

overall, in past studies OTA has found that the best way to improve energy efficiency in the industrial sector is to promote general corporate investment in new plant and equipment-newer generally means more energy-efficient.

[83] *National Energy Strategy: Powerful Ideas for America*, supra note 6, p. 56.

Utility Energy Efficiency Programs and Experience 5

With ample untapped opportunities to save electricity, demand rising but long-term growth rates uncertain, and powerplant construction costs soaring, it is not surprising that energy efficiency has become the byword for cost-conscious consumers, regulators, and utilities seeking new ways to hedge future strategies. The potential of energy efficiency as a means to lessen the environmental impacts of energy use has also attracted the interest of conservationists. The prospective new business opportunities have garnered the attention of energy service companies and equipment manufacturers and vendors, as well as utilities.

This chapter looks at utility programs to influence customer energy use and how they are incorporated in utility resource options. State government efforts and regulatory treatment of utility-sponsored conservation and efficiency programs are discussed in chapter 6.

SCOPE OF UTILITY ENERGY EFFICIENCY PROGRAMS

U.S. utilities and State regulators have now had more than a decade's worth of experience with utility-sponsored energy efficiency programs. Broadly speaking, energy efficiency programs are aimed at reducing the energy used by specific end-use devices and systems without degrading the services provided. Such savings are generally achieved by substituting technically more advanced equipment to produce the same level of energy services (e.g., lighting or warmth) with less electricity.[1] Energy efficiency programs are sometimes referred to as energy conservation programs. However, because to some people the term

[1] *Eric* Hirst and Carol Sabo, *Electric Utility DSM Programs: Terminology and Reporting Formats,* ORNL/CON-337 *(Oak* Ridge, TN: Oak Ridge National Laboratory, October 1991).

conservation implies an overall reduction in electricity use and energy services, many industry analysts prefer to use the more neutral and inclusive term *energy efficiency*. Energy conservation measures can be included in efficiency programs.

Demand-side management (DSM) programs are organized utility activities intended to affect the amount and timing of customer electricity use. In theory, successful DSM programs can reduce the need to build powerplants by controlling demand for electricity and thereby creating room for expansion without providing additional supply resources.

Utility load management programs are closely related to energy efficiency DSM programs. Load management programs refer to utility programs intended to influence customer demand through economic or technical measures usually with the objectives of reducing demand during peak periods, and/or encouraging demand during off-peak periods).[2] In pursuit of the frost goal, load management programs can include many of the same technologies and measures used for overall reductions in electricity use. Load management programs usually employ a combination of load management incentives, metering to measure the time and quantity of customer electricity use, and load control equipment. Because of the time-shifting aspect of load management programs, they may be targeted at peak loads and not necessarily at an overall reduction in electricity consumption. Load management programs can also be directed at retaining load or customers, and expanding customer loads. Box 5-A shows common utility load management strategies and their load shape objectives. These same load shape objectives are used for utility DSM programs.

Electric utilities have used load control measures for more than 50 years, but interest in these measures increased significantly in the 1970s and 1980s. Over this period, interest in load control was high among utilities that purchase most of their power from others (primarily municipal utilities and rural cooperatives) because load control offered an additional means to reduce wholesale power costs.[3]

Utilities can have many goals for DSM and load management programs. Maximizing energy savings is one. Others, and perhaps more important to different utilities, are maximizing customer satisfaction, minimizing lost revenues (utility revenues lost when consumers reduce electricity use), mininizing free riders, or minimizing the cost per kilowatt (kW) or kilowatt-hour (kWh) saved.

The development of utility energy efficiency programs coincides with the trend toward adoption of integrated resource planning (IRP) processes by electric utilities. IRP involves a comprehensive and open utility planning process that includes greater consideration of potential demand-side measures on a par with generation and other supply-side additions in order to meet projected loads. The prospect of greater reliance on demand-side measures to delay the need for new powerplant construction requires that potential energy savings be estimated with greater certainty and that actual savings be validated. Adoption of IRP has created new challenges for electric utilities planners and their regulators in incorporating rapidly expanding DSM programs into the resource mix.

INFLUENCING CUSTOMER BEHAVIOR

Electric utilities, with the approval and encouragement of State regulatory bodies, have adopted a variety of mechanisms to influence customer electricity use: load controls, differential or incentive rates, rebates, loans, grants, shared-savings agreements, energy audits, technical as-

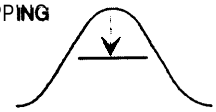
[2] U.S. Congress, Office of Technology Assessment New *Electric Power Technologies: Problems and Prospects for the 1990s, OTA-E-246* (Washington, DC: U.S. Government Printing Office, July *1985)*, p. 142.

[3] Ibid., p. 148.

Box 5-A-Load Shape Objectives

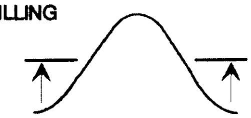
PEAK CLIPPING, or the reduction of the system peak loads, embodies one of the classic forms of bad management. Peak dipping is generally considered as the reduction of peak bad by using direct bad control. Direct load control is most commonly practiced by direct utility control of customers' appliances. While many utilities consider this as a means to reduce peaking capacity or capacity purchases and consider control only during the most probable days of system peak, direct load control can be used to reduce operating cost **and** dependence on critical fuels by economic dispatch.

PEAK
CLIPPING



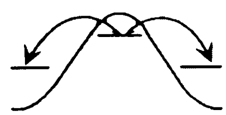
VALLEY FILLING is the second classic form of bad management. Valley filling encompasses building off-peak loads. This may be particularly desirable where the brig-run incremental cost is less than the average price of electricity. Adding properly priced off-peak bad under those circumstances decreases the average price, Valley filling can be accomplished in several ways, one of the most popular of which is new thermal energy storage (water heating and/or space heating) that displaces loads served by fossil fuels.

VALLEY
FILLING



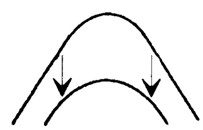
LOAD SHIFTING is the last classic form of load management. This involves shifting load from on-peak to off-peak periods. Popular applications include use of storage water heating, storage space heating, coolness storage, and customer load shifts. In this case, the bad shift from storage devices involves displacing what would have been conventional appliances served by electricity.

LOAD
SHIFTING



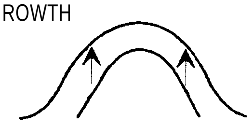
STRATEGIC CONSERVATION is the load shape change that results from utility-stimulated programs directed at end-use consumption. Not normally considered load management, the change reflects a modification of the bad shape involving a reduction in sales as well as a change in the pattern of use. In employing energy conservation, the utility planner must consider what conservation actions would occur naturally and then evaluate the cost effectiveness of possible intended utility programs to accelerate or stimulate those actions. Examples include weatherization and appliance efficiency improvement.

STRATEGIC
CONSERVATION



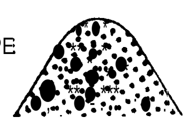
STRATEGIC LOAD GROWTH is the bad shape change that **refers to a general increase** in sales beyond the valley filling described previously. Load growth **may involve increased** market share of loads that are, or can be, served by competing fuels, as well as area development. in the future, load growth may include electrification. Electrification is the term currently being employed to describe the new emerging electric technologies surrounding electric vehicles, industrial process heating, and automation. These have a potential for increasing the electric energy intensity of the U.S. industrial sector. This rise m **intensity maybe motivated by reduction in the use of fossil fuels and raw materials resulting** in improved overall productivity.

STRATEGIC
LOAD
GROWTH



FLEXIBLE LOAD SHAPE is a concept related to reliability, a planning constraint. Once the anticipated load shape, including demand-side activities, is forecast over the corporate planning horizon, the power supply planner studies the final optimum supply-side options. Among the many criteria used is reliability, Load shape can be flexible-if customers are presented with options as to the variations **in quality of service that** they are willing to allow in exchange for various incentives. The programs involved can be variations of interruptible or curtailable bad; concepts of pooled, integrated energy management systems; or individual customer **load** control **devices offering service** constraints.

FLEXIBLE
LOAD
SHAPE



SOURCE: U.S. Congress, Office of Technology Assessment, 1993, adapted from Battalle-Columbus Division *and Synergic* Resources Corp., Demand-Side Management, Volume 3:Technology Alternatives and Market Impkmmntatkm Methods, **EPRI EAVEM-3597 (Palo Alto, CA: Electric Power Research Institute, 1984).**

sistance, direct equipment installation and replacement, comprehensive energy management programs, and so forth. Many of these programs are of recent vintage and limited in scope, but overall the initial savings have been promising even though not as high as expected. Certain issues have recurred in the design, implementation, and evaluation of these programs, including: cost-effectiveness determinations, choice of effectiveness tests, free riders, measurement of savings, persistence of savings, customer participation rates, utility cost recovery, and financial incentives.

All utility DSM programs fit into one or both of the following programs: 1) those affecting the way energy-using equipment is operated, and 2) those that focus on the installation of efficient technologies. Utilities typically operate separate programs for commercial, residential, and industrial customers.

Load control measures differ based on the degree of control and input exercised by the utility and the customer. They range from programs in which the utility asks customers to reduce load and the customer individually decides which appliances to turn off, to direct load control systems that are highly automated and have little customer input.

Direct control systems are by far the most common form of load control. They typically consist of a communications system that links the customer's equipment with the utility and a decision logic system (i.e., a computer program) that dispatches commands to the customer equipment in response to information on utility and/or customer loads. In a residential load management program, equipment might be installed to allow the utility to cycle participating home air-conditioners and water heaters on and off briefly during times of peak load with little or no disruption to the customer. With widespread participation, this represents a critical strategic tool for utilities to shave peak load. Typically the customer enters into an agreement with the utility that gives them either lower rates and/or a small monthly payment for participation in the program. For example, Potomac Electric Power Company (PEPCO) offers a credit of $110 to households that join its "Kilowatchers Plus Club" and allow the company to shutoff their air conditioning for short periods of time to offset summer peak loads if needed. Some 100,000 members of PEPCO'S "Kilowatchers Club" receive a $45 credit for allowing the utility to cycle their compressors off and on for brief periods. PEPCO estimates that by 1995, cycling will pare 170 megawatts from its summer loads.[4]

Utilities and regulators have experimented with various incentive rates in an attempt to encourage greater efficiency in electricity use. They have instituted variations in rates by charging more for peak load and higher volume usage to reflect the increased costs of providing such service. There has been a great deal of activity involving time of use rates for large industrial and commercial customers, but only limited experience with time of use rates for residential customers. Participation in time of use rates generally requires installation of meters that allow measurement of both the quantity and time of customer electricity use.

Information programs are intended to alert customers about potential electricity savings measures. Examples include informational advertising campaigns, energy audits, and bill enclosures. According to an analysis of utility DSM programs prepared by the American Council for an Energy-Efficient Economy (ACEEE) for New York State, information-only programs that provide customers with general information about energy efficiency opportunities and/or combine information with energy audits have low participation rates

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[4] "Utilities Field Peak Power Demand with Incentives for Homeowners," *Wall Street Journal*, June 6, 1991, p. Al.

and low energy savings[5] The most effective are the free energy audits coupled with post-audit followup. According to ACEEE, the programs can achieve high participation rates (60 to 90 percent) and energy savings among participating customers of 6 to 8 percent.[6] Revamped information programs are reported to be achieving greater levels of participation.

Rebate programs provide money to customers, contractors, homebuilders, vendors, or others who make equipment choices **to** help defray some or all of the cost of DSM measures. Rebate programs are the most *common* utility program offered. The form of rebate mechanism can be cash, discount coupons, or bill credits. ACEEE found that the most successful rebate programs in their survey reached about 10 percent of eligible customers (and about 25 percent of the larger customers with peak demand of 100 to 500 kW) over a period of 3 to 7 years. The most successful programs cut electricity use by 5 percent at utility costs of $0.01/kWh saved. The most effective targets have been lighting and heating, ventilation, and air conditioning (HVAC) equipment improvements. Rebate programs have not historically been very effective at promoting system improvements-those involving the interaction of many pieces of equipment. Generally, participation levels are moderate, as are energy savings. They effectively cut utility peak demand and electricity sales by about 1 percent/year in successful cases surveyed in the ACEEE study. Some analyses indicate that participation drops off after several years of aggressive program promotion; however, more analysis is needed of this possible pattern according to ACEEE'S study.

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The "Super Good Cents" Program, sponsored by the Bonneville Power Administration and northwestern utilities, provides certification for new residential buildings and manufactured homes that meet stringent energy efficiency standards. The program qualifies the buyers for rebates from participating utilities.

Loan programs provide cash to finance energy-savings investments and are attractive for customers who lack cash. The program may allow the customer to repay energy efficiency investments on the monthly utility bill, often at a low interest rate. They are offered by only a few utilities. Studies of consumer loan programs found that customers offered a choice of rebates or low-interest loans have generally opted for the rebates.[7]

Increasingly, utility programs bundle various DSM approaches into a single package. For example, the City of Fort Collins Light and Power offers residents of Fort Collins the Energy Score Home Energy Rating Service that combines information, audit, building efficiency standards, rebates, loans, and eligibility for energy efficient

5 American Council for an Energy Efficient Economy, *Lessons Learned: A Review of Utility Experience with Conservation and Load Management Programs for Commercial and Industrial Customers* Final Report, Energy Authority Report 90-8 (New York, NY: New York State Energy Research and Development Administration, April 1990). Hereinafter referred to as Lessons *Learned. This report* provides an analysis of utility industrial and commercial conservation and load management programs, including energy-savings, participation rates, costs, etc. The analysis covered some 200 utility commercial and industrial programs from 58 utilities and was based on comprehensive surveys and interview conducted circa 1987.

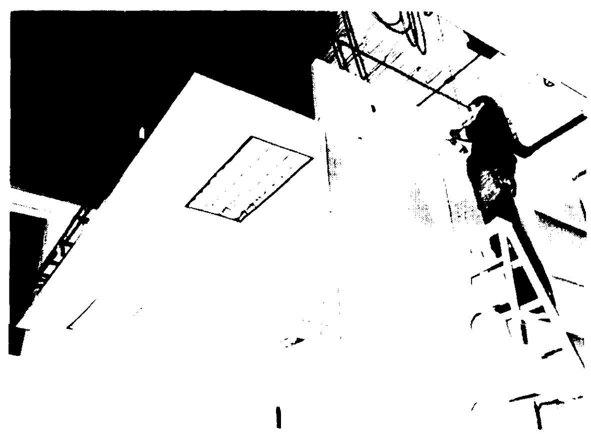
6 Ibid.

7 *Lessons Learned*, supra note 5, p. 5-5.

mortages. Homeowners, builders, sellers, or purchasers of new or existing homes can contact an independent utility-certified rater to inspect and report on a home. The rater provides a comprehensive home energy efficiency analysis covering the orientation of the lot, insulation, windows, doors, air leakage, heating and hot water systems, and other factors influencing energy use. The house is given a rating from O to 100, with 100 being the most efficient. The cost of the rating is $100 to $175 and the city utility picks up $50 of the cost. Homes with higher energy efficiency ratings (G-70 for gas-heated homes, and G-65 for electric heated homes) may be eligible for a 2 percent ratio increase on an energy efficient mortgage from participating lenders, increasing the purchaser's buying power. The rating also identifies opportunities for efficiency improvements and may qualify the homeowner for the utility's zero-interest "Zilch" home improvement loan to finance the upgrades.

Performance contracting programs offer payments based on the amount of energy saved as a result of efficiency improvements. They generally rely on energy service companies (ESCOS) or other vendors to recommend, install, and finance efficiency measures. Utilities can also contract directly with large customers. According to the ACEEE study, the most successful of these programs have included high incentives, but have achieved significant savings. On the whole these programs have been more costly than some other types of programs. Experience has indicated that ESCOS have tended to focus on the largest customers and the most lucrative measures (especially lighting and cogeneration) to achieve savings. ESCO contracts provide one mechanism for reaching some of the most cost-effective, energy-efficient opportunities with significant economies of scale. Other approaches can target and achieve these same savings opportunities. Initial experience with performance contracting and ESCOS has been mixed. Many utilities are substantially revising their performance contracting programs or are complementing them with other types of programs. Performance contracting with ESCOs or with large customers still remains an attractive alternative for financing and installing energy-saving technologies.

Comprehensive programs combine regular personal contacts with customers, comprehensive site-specific technical assistance, and financial incentives that pay the majority of the installation costs of efficiency measures. According to the ACEEE study, these programs were highly successful, but also tended to be among the most expensive at a typical cost of $0.03/kwh saved. There is little experience with large-scale programs over time. The analysis suggests that this type of program maybe particularly appropriate for serving small customers and for new construction (where there is a one-time opportunity to capture substantial savings at only the marginal cost of efficient equipment over standard equipment).



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Lighting Design Lab in Seattle. This resource center is supported by a consortium of Federal and State agencies, electric utilities, and conservation groups. It aids commercial designers, architects, engineers, contractors, facilities managers, and others in the design and selection of efficient lighting applications.

Request **for proposal** (RFP) and bidding programs have been in operation for several years. Under these programs, the utility issues a request for proposals to provide demand-side resources and receives and evaluates proposals from ESCOS and customers. After evaluating the bids, the utility negotiates contracts with the winning bidders for specific energy savings and load reductions. Based on preliminary results analyzed for the ACEEE New York study, these programs offer the promise of significant savings (up to 1.5 percent of peak demand after 2 years). The success has been tied to reaching large customers directly or through ESCOS who participate in the process. The programs generally are less than utility avoided cost, but a tendency has been noted for bids to approach utility avoided costs. Much of the initial experience with DSM bidding programs was in Maine and New York. As utility competitive resource procurements have expanded, so too have the number of bidders offering demand-side installations. Moreover, these demand-side bids are proving to have a higher success rate in winning bids than conventional supply options.[8]

Fuel switching programs involve incentives to utility customers to reduce load by switching to an alternative energy source for all or some of the service provided by electricity. Examples include the installation of a gas-powered air conditioning system in a large commercial office complex or switching from an electric resistance to a gas water heater. Fuel switching and electrification measures generally involve complicated site-specific tradeoffs, and no generalizations can as yet be made about their overall performances and costs.

MEASURING ENERGY SAVINGS AND EVALUATING EFFECTIVENESS

There has been over a decade of experience with utility load management and DSM programs around the country. Substantial dollar and energy savings have been claimed, but much remains to be learned.

To be successful from the perspective of least-cost planning objectives, the program should achieve maximum long-term, cost-effective net energy and demand savings (net of what would be required in absence of the utility program). Generally this means a long-term strategy aimed at serving the most customers (including all but the very smallest). This is to assure maximum savings and to minimize equity issues of cross-subsidization. In addition, the strategy should promote efficiency/load management measures that customers are unlikely to install without utility efforts in the short term and for longer-term measures with long-Lives or that have a high probability of replacement.

The ACEEE study found that utility DSM programs as a whole had not yet had a dramatic impact. The programs surveyed were reaching less than 5 percent of target customers on a cumulative basis and were reducing their energy use by less than 10 percent. As of 1989-90, it was estimated that utility peak demand had been reduced by less than 1 percent. They did find a number of highly successful programs, however. A few reached 70 percent or more of eligible customers—with customer energy savings of 10 to 30 percent, and reductions in utility peak demand of up to 5 percent. Many of the most successful programs, however, were still in pilot- or small-scale programs and had yet to be applied on a large-scale basis. The good news is that all of the energy savings reported came at a cost to utilities of less than $0.04/kWh saved even including free riders. These reported costs were less than many utilities' avoided costs to generate new power, making it likely that the programs would prove cost-effective using the utility cost test.[9]

Since the ACEEE study was published, utility DSM programs have continued to grow, and many utilities are now projecting significant savings from their efforts. A recent analysis by

[8] See discussion of bidding programs in ch. 6.

[9] Cost-effectiveness tests are described in ch. 6 of this report.

Oak Ridge National Laboratory, based on reports to the Energy Information Administration, found that existing utility programs are projected to offset 14 percent of the growth in electricity demand by the year 2000.[10]

Measuring Swings

The savings from a DSM program are estimated by comparing energy demand both before and after the program is implemented. Evaluating the success of utility DSM programs is difficult both on a local and a national basis. Most savings estimates reflect engineering estimates, and more sophisticated measured and validated **estimates of savings are rare.** Engineering estimates generally rely on simple rules of thumb calculations using manufacturers data, or engineering simulations. Engineering **estimates can** be fairly accurate for some simple DSM actions (e.g., domestic water heater wraps). However, in practice, engineering estimates have been found **to overestimate** actual electricity savings.[11] As experience with DSM programs increases, and energy savings are subjected to more rigorous impact evaluation, it should be possible to develop other techniques, or at least more accurate engineering rules of thumb, to support reliance on this technique to estimate potential savings. Until then, such estimates should be viewed with caution.

In order to show the effectiveness of efficiency measures, it must be determined how much electricity use is actually reduced over what it would be in the absence of the measure. Depending on the goal of the program, monitoring usage by the time of use (on-peak vs. off-peak) will also be important to determine impacts on load shape.

There are several means of measuring (collecting data on) electricity use and the impacts of efficiency improvements: monthly customer bills, spot metering (either on a short-term before and after retrofit or permanent basis), whole building load research monitoring, and end-use load research monitoring. See box 5-B.

Measuring exact savings is not necessary in all cases and could become prohibitively complex as the number and extent of DSM programs increase. For simple measures, where there is substantial experience (more efficient residential refrigerators, for example), past measurements and engineering estimates may suffice to calculate savings for the program. For more complex and site-specific DSM measures (e.g., retrofitting and relamping a large commercial building), detailed site-specific measurements of specific load shapes may be needed to estimate savings.

Comparison of customer billing data is the most straightforward and least expensive method for many applications, but is not adequate for new construction or for large and complex installations. In the former case, bill data will be absent, thus engineering calculations or comparisons with similar buildings for which data are available might be used. In the latter case, normal fluctuations in energy use could mask the effects of efficiency improvements and so specific end-use metering that tracks the time and quantity of electricity may be required.

Once total end-use savings have been determined, the impacts on utility load shape and supply must be calculated. In general, because of transmission and distribution losses, the actual kilowatts saved at the powerplant from customer efficiency measures are about 8 percent higher than that saved on site. Kilowatts saved by the customer may also reduce utility reserve margins, i.e., customer savings plus the reserve margin percentage (allowance for powerplant down-

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lo Eric Hirst, *Electric Utility DSM-Program Costs and Effects: 1991-2001,* ORNL/CON-364 (Oak Ridge, TN: Oak Ridge National Laboratory, May 1993).

11 S.M. Nadel and K.M. Keating, ''Engineering Estimates vs. Impact Evaluation Results: How Do They Compare and why,' *Energy Program Evaluation: Uses, Methods, and Results,* Proceedings of the 1991 International Energy Program Evaluation Conference, CONF-91OSO7, August 1991, cited in Hirst and Sabo, supra note 1, pp. 24-33.

Box 5-B-Methods Used to Measure Electricity Consumption

Approach	Explanation	Advantages	Disadvantages
Monthly electricity bills	Obtain electrtcity bills for a year before and a year after participation, adjust annual electricity use for weather and other relevant factors, and compute the difference between pre- and post-participation use in kWh/year.	Measures actual changes in electricity use, permits adjustment for changews in weather and other factors, and requires little primary data collection.	Provides no estimate of demand (kW) reductions unless customers face demand charges. Analysis of monthly billing data can yield ambiguous results. Estimates of kWh savings affected by changes in facility use unrelated to devices installed.
spot metering of electricity use	Monitor electricity use before and after participation for short times (e.g., a few days); also measure other relevant factors (e.g., operating hours for equipment and heating degree days) for a longer time (e.g., up to a year).	Measures electricitysavings (both kWh and kW) for well-defined, short time periods. Modest cost.	Could yield estimates of savings not realized if measurernents taken incorrectly or at atypical times, or if building use changes. Difficult to apply to devioes that are season-or weather-dependent.
whole-building load-research monitoring	Monitor electrlcity use of facility to record kW *demand use* before and after participation.	Measures actual electricity and demand (kWh and kW), Can be combined with other data to adjust for changes in weather and factors.	Expensive and time consuming. Large amounts of data produced. Results may be affected by changes in facili ment installed.
End-use, load-research monitoring	Monitor specific circuits affected by new systems to record kW demand before and after participation.	Measures actual electricity use and demand (kWh and kW) for specific end uses affected by program. Can be combined with other data to adjust for changes in weather and other factors.	Most expensive and time consuming method. Large amounts ofdata require sophisticated computer programs and analysts to interpret. Results may be affected by changes in facility use unrelated to equipment installed.

SOURCE: Eric Hlrst and Carol Sabo, Electric Utility DSM *Programs: Terminology and Reporting Formats,ORNL/CON-7(Oak Ridge,* TN: Oak Ridge National laboratory, October 1991), p. 36.

time). Improved measurement and monitoring of end-use efficiency savings and documentation of actual reductions in utility-generating demand over time may contribute to less uncertainty about demand-side measures in utility resource planning.

Tracking the persistence of energy savings from efficiency measures is also important. Some measures may prove to be fairly reliable and long-lived (for example building insulation that the customer is unlikely to remove). But other measures may be affected by declines in the technical performance of equipment, the lifetime of the measure, user replacement of measures when they wear out, changes in operating conditions induced by the DSM program, or market-related changes in electricity use.[12] The energy-savings benefits of a compact fluorescent light may disappear, if when it is worn out, the user replaces it with a standard incandescent lamp. Similarly, an occupant might be induced to raise thermostat settings to take advantage of improved building insulation or an efficient space heating system, thus, at least partially offsetting the efficiency gain. This phenomenon of losses in efficiency gains because of customer behavior is often referred to as takeback.

Participation Rates

The success of DSM programs often hinges on the number of customers and/or trade allies (businesses that sell or influence choices of energy using equipment such as architects, designers, builders, appliance dealers) that participate in the program. Participation rates are the ratio of the number of participants to the number of eligible customers. In many cases, determination of the pool of potential participants is fairly straightforward and based on information a utility readily has at hand (e.g., commercial office buildings, all residential customers). However, for more specialized programs, additional market research may be needed to identify potential participants, for example, homes with electric resistance heat, or industrial motor applications.

As a practical matter, most estimates of DSM program participation rates generally include free riders. Free riders are customers who participate in a program, but would have undertaken the same conservation actions even if the program were not offered.[13] (Some discussions also brand as free riders ratepayers who benefit from conservation programs, but do not participate; however in this report we include only program participants.) The presence of free riders tends to overstate program results. Some economists maintain that free riders should not be eligible for program incentives and will drive up program costs and ratepayer impacts to an unacceptable degree.[14]

The presence of free riders, setting aside the issue of whether they should be eligible for financial incentives, complicates evaluations of the effectiveness of utility DSM programs. In determining g whether the program has actually had an impact on customer energy use, the focus must be on net savings-calculated by determining the share of free ridership and excluding the associated savings.

But the presence of a high portion of free riders in a program is not necessarily an indication that the program is not effective for several reasons.

First, one should expect a high degree of free riders early in the program and then as the program becomes more successful and participation increases, the free rider share should approach a floor defined by the penetration of the efficiency measure in the market place or the market share of efficient devices versus standard devices in absence of the program.[15]

Second, many estimates of free ridership are based on self-identification by those who say they would have adopted the measure anyway, thus tending to overestimate actual free ridership. The bias problems with surveys are well documented and show a tendency of respondents to give the perceived "right" answer to the interviewer

12 Hirst and Sabo, supra note 1, p. 34.

13 Ibid.

14 Conversely, another complication is the general exclusion from participation rates of free drivers. Free drivers are customers who take DSM program-recommended actions, but do not participate directly in the program (i.e., claim rebates). The absence of free drivers will result in understating the program's effectiveness.

15 *Lessons Learned*, supra note 5, pp. 86, 167.170, (various utility programs estimated free riders at 5 to lo percent for replacement Of working motors and 5 to 35 percent for new motors).

rather than the ''true' answer. Additionally, while a participant might be favorably disposed to installation of the efficiency measure in the absence of the program, it is difficult to estimate with any accuracy how many of the self-identified free riders would actually have installed the measure without the program or the extent to which the existence of the program accelerated their actions.

Costs of DSM Programs

Monitoring and estimating the costs to utilities and customers is necessary to determine whether the costs of efficiency programs are outweighed by their benefits, and to provide for adequate cost recovery in regulatory proceedings.

For newly authorized programs, very little actual cost data may be available, but as experience increases, costs should be calculated with greater accuracy. The ACEEE review of 58 existing utility DSM programs found that reported cost figures per kilowatt and kilowatt-hour for efficiency measures were only approximate, and often ignored customer costs, and sometimes relying on rough estimates of indirect utility costs. The lack of accurate cost data is troubling when one considers that over $2 billion was invested in utility energy efficiency programs in 1991 and that by the end of the decade some experts estimate that DSM could be a $30 billion/year industry.[16] Moreover, more reliable and detailed cost data are needed for DSM resources to be more fully integrated into utility resource planning processes.

Determining Cost-Effectiveness

There is a wide variation in how different utilities and State regulators calculate the cost-effectiveness and costs of DSM programs. The cost-effectiveness of DSM measures is commonly estimated from either the utility, customer, or the societal perspective. For more on cost-effectiveness tests, see chapter 6 of this report.

The utility perspective considers the utility's costs and benefits for program, including rebate and other costs, avoided energy and capacity benefits. It excludes customer costs and the value of revenues lost by the utility because of energy savings.

The total resource cost perspective (adopted in New York State) includes money paid by program participants for materials, installation, and maintenance (including credits for reducing customer costs, such as reduced maintenance costs in addition to factors considered from the utility perspective). In practice, the total resource cost test suffers from the fact that extensive data on customer costs are not generally collected by utilities.

There are several alternative units used in estimating cost-effectiveness. Cost per kilowatt-hour saved simply uses program expenses divided by kilowatt-hours saved). Other measures calculate levelized cost per kWh saved (discounting the cost over time) to provide a long-term cost estimate. More rigorous approaches involve calculation of total levelized costs of the program and comparison with avoided total costs of the energy saved (avoided energy costs plus levelized value of annual capacity cost divided by 8,760 hours/year).

Evaluation of DSM Programs

Evaluation is the systematic measurement of the operations and performance of DSM programs and should rely to the extent possible on objective measurements and well-defined and executed research methods. Program and impact evaluations of DSM and load management programs are critical components of both utility and government assessments of the cost-effectiveness and success of efficiency measures. Program evaluation is a rapidly evolving specialty that

16 Eric Hirst and Jolm Reed (Eds.), *Handbook of Evaluation of Utility DSM Programs,* ORNL/CON-336 *(Oak* Ridge, TN: Oak Ridge National Laboratory, December 1991).

relies on social-science research methods and technical data to provide valid and reliable documentation and quantification of program results and costs and to analyze their usefulness. Good impact evaluation efforts are not cheap or easy to perform, and yet are an indispensable element of any expansion of efficiency programs. Adequate funding of evaluation and monitoring can amount to 10 percent of the costs of utility programs. As the costs, extent, and expectations of utility energy efficiency programs grow, the resources devoted to monitoring and evaluation will have to expand and the evaluation techniques must also become more technically sophisticated and reliable.

MIXED RESULTS FROM UTILITY ENERGY EFFICIENCY PROGRAMS

While there are clearly successful utility energy efficiency programs with demonstrable energy savings, experience so far indicates that the energy savings achieved fall far short of the full technical potential that is cost-effective to end users.

The ACEEE review of 58 utility programs found evidence for this conclusion in low participation rates and in actual savings well below cost-effective technical potential.[17] programs with the highest participation rates reached only 10 to 70 percent of eligible customers. Among participating customers, the programs with the highest energy savings were found to yield only 20 to 60 percent of the cost-effective technical potential. Cost-effective technical potential was defined as measures having equipment and installation costs less than $0.05 kWh saved, i.e., less than the retail commercial and industrial electricity rates and/or utilities' long-run avoided costs. The gap between technical potential and actual savings was large for the best programs and larger still for typical programs.

Low participation and savings rates are typical of the startup stage of most programs, and many programs were still limited in scale and had only a few years experience. However, other utility programs have been operating for some time and it is reasonable to expect better performance.

No utility operates state-of-the-art programs in all areas. The largest commercial and industrial efficiency programs were found to have reduced kilowatt-hour sales by only 2 to 14 percent-far less than the estimated 35 percent cost-effective savings potential (from the consumer perspective) found in the ACEEE study of New York State potential.[18] These performance shortfalls raise questions about the viability of ambitious State and utility efficiency goals.

Some economic analysts are challenging utilities and regulators cost-benefit equations and questioning the claimed successes of DSM programs. One controversial analysis performed for the U.S. Environmental Protection Agency discarded the more commonly used cost-benefit tests and applied an alternative cost-benefit measure to DSM program savings calculated by two utilities. The report examined a total of 16 separate DSM programs operated by the two utilities and concluded that none of the programs passed its ''conventional' economic cost-benefit test if environmental benefits were excluded from the calculations .19

The New York State Energy Plan sets a goal for utility conservation and load management programs to reduce electricity use and demand by 15

17 *Lessons Learned*, supra note 5, pp. 181-196.

18 American Council for an Energy-Efficient Economy, and the *New York* State Energy Office, *The Achievable Conservation Potential in New York State from Utility Demand-Side Management Programs,* Energy Authority Report 90-18 (Albany, NY: New York State Energy Research and Development Administration, November 1990).

19 Albert L. Nichols, *Estimating* the *Net Benefits of Demand-Side Management Programs Based on Limited Information*, (Cambridge, MA: National Economic Research Associates, Inc., Jan. 25, 1993), p, 34, cited in Kennedy Maize and John McCaughey, "DSM at Mid-Passage: A Discussion of the State of the Art and Science of Demand-Side Management in Electric Utilities,' *The Quad Report, Special* Report, Spring 1993.

percent by 2008. To do this, ACEEE estimates that DSM programs will have to reach 50 to 70 percent of customers and achieve savings among participants of 20 to 30 percent.

Nevertheless, many utilities have now enthusiastically embraced DSM programs. The New England Electric System (NEES) has been an early leader in utility DSM programs, spurred in part by financial incentives adopted by State regulators in Massachusetts, New Hampshire and Rhode Island. For 1990, NEES reported that potential system profits from DSM programs were $10 million. Estimated savings were a total of 194,300 megawatt-hours saved and 116.5 megawatts of demand reduced.[20]

NEES'S third resource plan adopted in 1991 relies on DSM programs to displace a total of 850 megawatts by 2000, constituting more than 12 percent of the utility's capacity resources. NEES resource plan will also achieve a 45 percent reduction in net air emissions by 2000 through its resource strategies including DSM, converting/ repowering an existing plant to natural gas, accelerating environmental compliance, power purchases from nonutility generators and Canadian hydroelectric facilities, and various initiatives to offset greenhouse gas emissions.[21]

Pacific Gas & Electric Company, the Nation's largest utility, also has long experience in DSM programs. PG&E plans to spend about $2 billion on customer energy efficiency in the 1990s and cut their energy growth by half and peak demand by 75 percent (2,500 megawatts). PG&E projects that these savings can be achieved at a cost of from $0.03 to $0.04/kilowatt-hour-less than half the cost of building new fossil generation.[22]

Elements of Successful Programs

Even though no utility was found to perform at state-of-the-art levels in all of its efficiency programs, a number had demonstrated notable success.[23] They shared certain program elements that are believed to contribute to above-average participation and savings:

- *Marketing strategies that use multiple approaches (direct mail, media, etc.) combined with personal contacts with the target audience.* Particularly successful are those that develop regular, person-to-person contacts and followup contacts after installation to assure that the measures are working properly and to promote additional measures.
- *Targeting of program approaches and marketing strategies to different audiences* (customers, architects, equipment dealers, engineers, developers) and for different types of investment decisions (new construction, remodeling, replacement, retrofitting). Including target audiences in program design is especially successful in producing a program that meets consumer needs.
- *Technical assistance to help targeted customers assess efficiency opportunities and identify and implement DSM measures.* Assistance might include energy audits, advice on equipment, contractors, computer modeling of possible savings alternatives, information on new state-of-the-art technologies. Detailed technical assistance is generally only cost-effective when coupled with incentive programs that induce high levels of customer participation and savings.
- *Simple program procedures and materials that make it easier for the customer to*

20 Association of Demand-Side Management Professionals, 'NEES Credits Regulatory Incentives In 'Overwhelming' 1990 DSM Success,'' *Strategies,* vol. 2, No. 2, Spring 1991.

21 ''New England Utility Outlines Plans to Cut Greenhouse Emissions by 4570, " *Energy Conservation Digest, Dec. 23,* 1991, p.1.

22 Hirst and Sabo, supra note 1, p. 1.

23 Reviews of utility efficiency and conservation programs indicate that some utilities consistently do a better job than others in operating these programs. Among the most successful cited in the 1990 ACEEE study were: the City of Palo Alto, CA; Central Maine Power; New England Electric System; Pacific Gas and Electric; Southern California Edison; and Wisconsin Electric. See Lessons *Learned,* supra note 5.

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An energy audit team makes a site visit to a Pacific Northwest lumber mill to study operations to help development of an industrial energy efficiency program.

understand program potential and to participate. Examples are one-step application procedures, assistance in filling out forms, packaged rebate programs.

- *Financial incentives that attract customer attention and reduce first costs of implementin,q DSM measures.* Analyses of the effects of varying incentive rates are scanty. But initial results indicate that offering free measures produces the highest participation rate. High incentives (50 percent or more of a measure cost) generally appear to produce higher participation rates than moderate incentives (one-third of a measure's cost). Moderate incentives may not produce higher participation rates than low incentives, however.
- *Multiple measures available for customers to choose from that increase the likelihood that customers will find a measure or program that is appropriate for their needs and/or to implement more than one measure and gain more savings.* There are a plethora of programs limited solely to lamps and air conditioners, Including additional HVAC, efficient lighting, and motor measures and allowing customers to propose their own qualifying measures tend to boost participation rates and savings,
- *Programs promoting new technologies not yet widely adopted in the marketplace, These* programs for high-efficiency technologies tend to reduce free riders and achieve higher savings than available through first generation technologies. A high percentage of free riders (about 30 percent) have been found with <time technologies, especially when rebates are provided for products that are already being purchased by many customers, such as, reduced wattage lamps and moder-

ate efficiency air conditioners. Because customers may be unfamiliar with and wary of new, advanced energy-saving technologies, programs that focus on them may require substantial marketing efforts to boost typical low initial participation rates.

Additional factors that contributed to the success of utility DSM programs were: top management commitment to energy efficiency measures, staff and organizational commitment, skills, support, creativity, and flexibility. Personal contact marketing and followup by utility personnel are also key to successful programs. Lastly, the most successful utility programs have been those where utilities are offered incentives for successful programs.

■ Problem Areas

The ACEEE study identified several problem areas that must be addressed if DSM programs are to have a significant effect.

Most utility commercial and industrial DSM programs have had only a limited focus. The programs must expand beyond lighting and small HVAC improvements to include advanced lighting and motor technologies and comprehensive industrial system improvements. There is no one-size-fits-all comprehensive demand-side program. Regulators and utilities must develop packages of programs tailored for the utility, load, and customer characteristics if the initiative is to be a success. Many utilities in an effort to structure their services to enhance customer values are examining ways to provide more comprehensive energy efficiency services,

Participation rates have been low. Marketing efforts must be expanded to reach and persuade more customers to participate.

More data and research are needed to support DSM program development and evaluation. Program design and evaluation is hampered by the lack of credible data on energy use and target populations (building characteristics, motors and other equipment), and by the lack of accessible and useful documentation and evaluation of existing programs. Information on actual percentage reductions in energy use is rarely collected and yet would be of invaluable assistance to utilities, regulators, and consumers.

Additionally, because energy and load management efforts have been limited in scope and long-term experience is lacking, mistakes will be made. But utilities may fear to publicize mistakes and shortcomings for fear that regulators will punish them. There is, however, much to be learned from mistakes. Therefore unsuccessful program experiences should be investigated and the results publicized so that others might avoid these pitfalls.

■ Need for Complementary State and Federal Efforts

Even the best DSM programs cannot achieve all the cost-effective savings. Some customers won't participate, no matter what incentives utilities offer. Many will not adopt all cost-effective measures. Because of this tendency, utility programs need complementary approaches--e.g., building codes and appliance and equipment efficiency standards-in order to maximize the overall adoption of energy-efficient technologies. The California Energy Commission analysis of the effectiveness of utility DSM measures in 1983 found the reduced peak demand of 2,718 megawatts was due 45 percent to utility programs, 37 percent to building code requirements, and 16 percent to various appliance efficiency standards.[24] Federal and State efficiency initiatives can also boost the availability of energy efficiency products in the marketplace. See chapters 6 and 7 for discussion of these efforts.

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24 California Energy Coremission, Conservation *Report* (Sacramento, CA: 1986), p. II-11.

INCORPORATING ENERGY EFFICIENCY INTO UTILITY OPERATIONS-THE ROLE OF IRP

IRP has become the main process through which utilities incorporate DSM measures into their mid-and long-term resource planning. As a planning tool, IRP allows a utility to incorporate a variety of information about load, system characteristics, demand growth, resource options, and corporate goals into an analysis that explicitly evaluates supply- and demand-side resources in a consistent manner and expressly confronts the uncertainties inherent in utility planning to produce a flexible resource plan for meeting customer needs at least-cost. IRP also generally includes opportunities for public involvement and regulatory review, as well as consideration of environmental and other social impacts of utility resource alternatives.

By mid-1993 utilities in at least 41 States were actively involved in some sort of IRP process. At least 33 States require IRP or least-cost planning by their utilities. Under Federal law, utilities that purchase power from the Bonneville Power Administration, the Western Area Power Administration, and the Tennessee Valley Authority also must adopt IRP planning principles as a condition of their power contracts. Information on State and Federal IRP initiatives may be found in chapters 6 and 7 of this report.

Resource planning is an integral part of utility operations and is driven by the three fundamental goals-serving customer load reliably, minimizing customer costs, and maintaining the financial stability of the utility (see chapter 3). Today's IRP process evolved from traditional utility planning, which focused narrowly on supply-side resource additions to meet ever-growing customer demand. With experience, IRP planning processes are continuously evolving in both theory and application. Each utility's IRP process is different—reflecting its system characteristics and planning needs, corporate culture and organization, and regulatory environment. However, every IRP process follows a general framework in evaluating **a** broad range of resource options to develop along-term resource plan typically covering 20 to 30 years, and an action plan covering from two to five years. New or revised integrated resource plans are prepared on average every two to five years. Figure 5-1 shows a simplified IRP process.

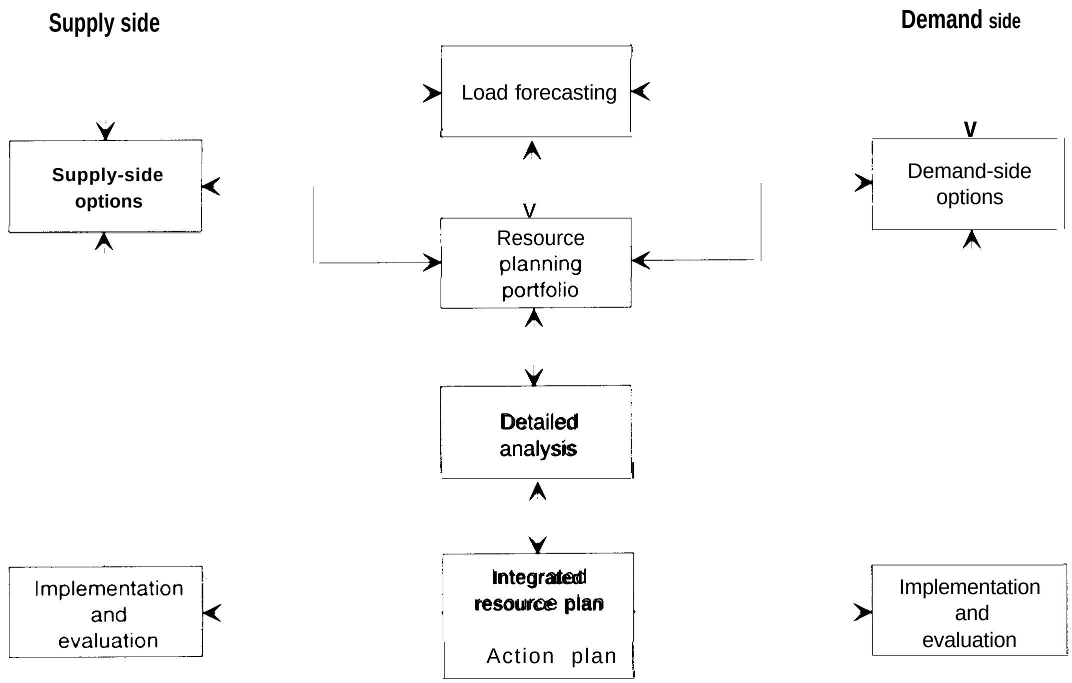
The process typically begins with preparation of long-term load forecasts projecting both energy sales (megawatt-hours) and peak demand (megawatts) over the planning period. The forecasts are based on historical consumption data, weather, population, and economic data, and electric equipment use. The load forecasts must also take into account expected load growth and potential changes in energy consumption patterns due to new technologies, DSM programs, and other conservation measures. The detailed forecasts are used for financia1 and resource planning to identify an appropriate mix of generation, transmission, distribution, power purchase, and energy efficiency options to meet system needs under a range of alternative future scenarios.

Using the initial load forecasts, utility planners then survey potential demand- and supply-side resource options to identify appropriate measures for inclusion in the integrated resource planning portfolio.

For supply-side options, planners will consider existing generation, transmission and distribution resources, utility generating plant additions, life extensions and efficiency upgrades, plant retirements, power purchases, and improvements to transmission and distribution facilities. During this initial evaluation, planners will compare the resources on considerations of: load profiles, reliability and dispatch capabilities; capital, fuel, operating, and maintenance costs; environmental and siting requirements; and capital availability. The result will be a supply-side resource stack.

Demand-side options will be identified based on considerations of existing customer use patterns, availability of energy-efficient technologies, demographic data, and evaluations of existing utility DSM programs. Planners will estimate

Figure 5-1-Simpl ified Integrated Resource Planning Framework



SOURCE: Office of Technology Assessment, 1993.

costs, load impacts, and participation rates to produce an initial stack of demand-side resources.

The IRP process then proceeds to detailed and iterative evaluation of the potential resource options to identify the best resource mix taking into consideration the utility's strategic goals, load profile impacts, production and capital costs, revenue requirements, rate impacts, environmental and other regulatory requirements, and other planning uncertainties. Planning uncertainties related to demand-side resources include participation rates, and the costs, effectiveness, durability, and verification of efficiency measures. For supply resources, uncertainties include construction time and costs, regulatory approvals, fuel availability and costs, operating and maintenance costs, and public attitudes towards the technology and the specific facility proposed. Overall uncertainties complicating resource planning affecting load growth and costs include impacts of inflation and interest rates, changing economic conditions, availability of purchased power, and changes in environmental and economic regulatory policies. During the process, resources may be added or removed from the portfolio based on the initial evaluation.

The typical IRP process includes opportunities for participation by the public and by regulators. The extent and type of participation vary. Some utilities have relied upon a collaborative consultation with interested parties over the entire course of plan preparation. Others may prepare a draft plan and then solicit public and regulatory comment before preparing a final plan.

The costs and benefits of alternative resource options are compared individually and in combination and they are ranked according to the appropriate cost-effectiveness test and planning goals. This cost-benefit ranking may be conducted under a number of separate scenarios with different assumptions about factors affecting energy demand, financial conditions, or regulatory requirements. In selecting a final integrated resource stack, planners must balance many different and sometimes competing goals and expectations about the future. Because resource planning involves many qualitative and strategic judgments, a least-cost plan will not always be the option that minimizes power production costs. Considerations of reliability, flexibility, resource diversity, and business strategy/policy may outweigh options that are the cheapest alternatives at the time the plan is developed.

The integrated resource plan lays out the utility's least-cost long-term strategy. It is coupled with a short- to mid-term action plan that details the specific actions and resource additions that the utility will take to carry out the plan objectives. Based on the plan, the utility, with any necessary regulatory approvals, will proceed to plan and acquire the preferred supply- and demand-side resources to meet customer loads. During implementation of the plan, adjustments can be made to reflect changing conditions using the plan as a guide. The utility's experience in implementing the action plan and evaluating its results are then used in the next round of the IRP process.

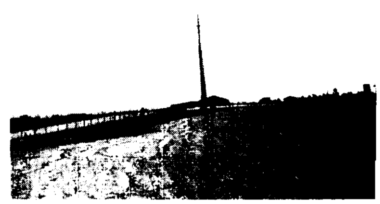
State Energy Efficiency Initiatives 6

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

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

PLANNING FOR FUTURE ELECTRICITY NEEDS

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



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

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

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

State Energy Plans

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

NEW YORK

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

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

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

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

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

Table 6-1—State Resource Planning Requirements

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

(Continued on next page)

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

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

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

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

CALIFORNIA

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

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

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

TEXAS

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

Collaborative Planning Efforts

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

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

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

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

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

Box 6-A--State Energy Plan Highlights

New York

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

California

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

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

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

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

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

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

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

IRP REQUIREMENTS

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

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

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

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

Box 6-B-The Massachusetts Collaborative

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

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

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

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

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

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

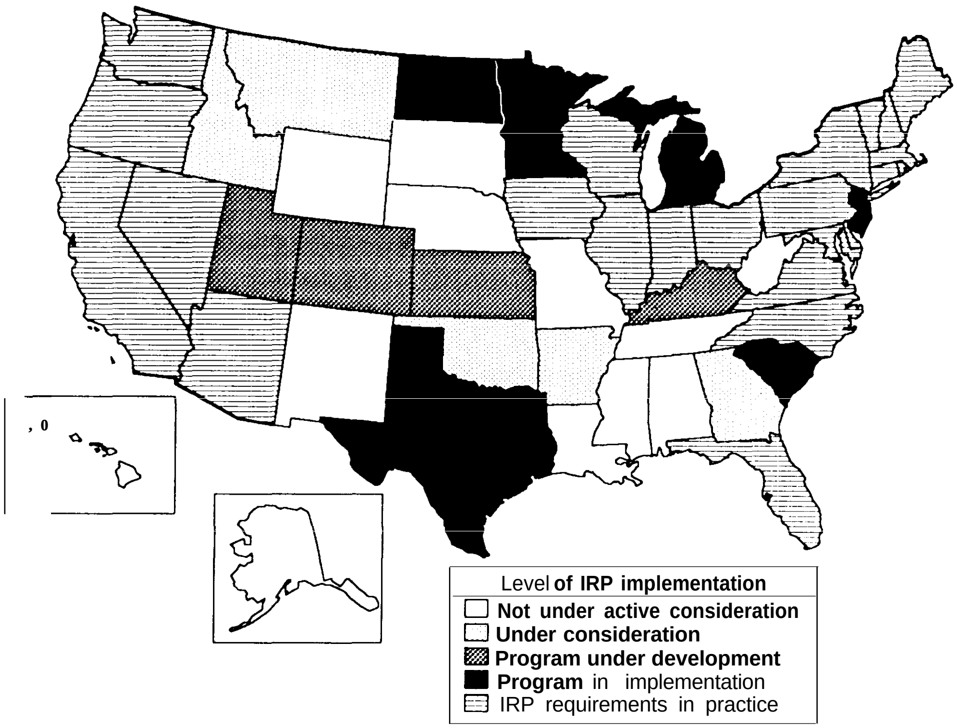
State resource planning requirements are usually coupled with incentives for DSM investment. Acquisition of supply-side resources has also changed. Increasingly, competitive bidding for new resources is allowed or required. Box 6-C and figure 6-2 show details.

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

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

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

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



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

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

What Makes a Least-Cost Plan?

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

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

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

Box 6-C-Competitive Bidding for New Utility Resources

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

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

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

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

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

ECONOMIC TESTS FOR EVALUATING DSM PROGRAMS

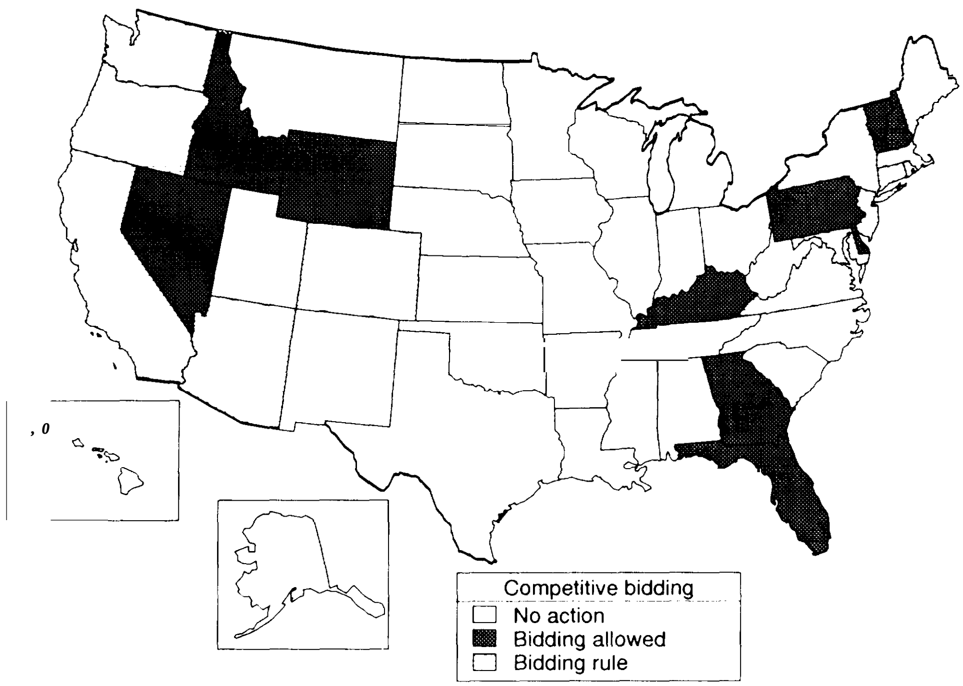
There are four commonly applied perspectives used for assessing the relative costs and benefits of resource options. The perspectives are the total resource cost, the rate-impact measure, the utility cost measure, and the societal cost measure (see box 6-D). Several other tests are available, but are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

Total Resource Cost Test

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

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

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



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

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

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

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

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

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

Total Resources Cost Test/All Ratepayers Test

Perspective

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

Benefits measured

Avoided supply costs of anticipated reduction in energy load.

Costs measured

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

Ratepayer Impact Measure (RIM)

Perspective

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

Benefits ***measured***

Utility avoided costs.

Costs ***measured***

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

Utility Cost Test

Perspective

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

Benefits measured

Utility avoided costs.

Costs *measured*

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

Societal Test

Perspective

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

SOURCE: Office of Technology Assemessment 1993.

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

Ratepayer Impact Measure

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

Utility Cost Test

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

Societal Cost Test

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

Cost Test Comparisons

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

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

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

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

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

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

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

16 Ibid.

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

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

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

STATE INCENTIVES FOR UTILITY DSM INVESTMENTS

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

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

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

Decoupling

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

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

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

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

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

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

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

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

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

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

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

21 Ibid. p. 35.

22 Ibid., pp. 16-21.

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

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

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

Recovering Demand-Side Energy Efficiency Investments

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

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

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

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

DEFERMENT TO RATE CASE

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

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

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

FLOW THROUGH TO RATES

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

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

RATEBASED RECOVERY

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

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

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

Status of State Cost Recovery Provisions

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

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

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

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

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

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

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

(Continued on next page)

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

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

30 Ibid., pp. 9-13.

31 Ibid., p. 149.

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

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

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

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

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

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

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

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

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

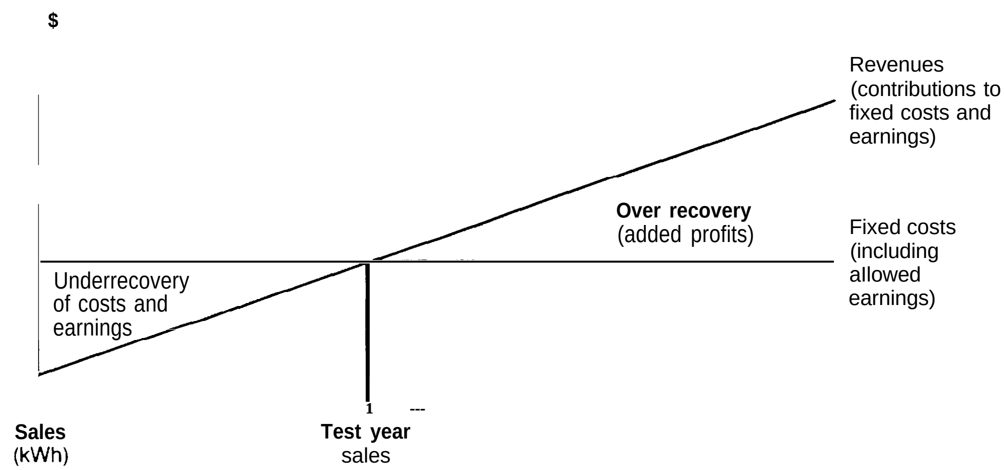
34 Ibid., p. 15

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

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

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

Figure 6-3-The Sales-Earnings Link



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

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

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

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

Lost Revenue Incentives

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

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

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

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

DSM SPECIFIC ADJUSTMENT

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

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

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

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

Performance Incentives

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

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

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

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

42 Ibid., p. 101.

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

that are historically receptive to regulatory innovation.[44]

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

RATE OF RETURN ADJUSTMENTS

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

Rate Base Premium

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

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

Return-on-Equity Adjustment

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

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

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44 Ibid., p. 8.23.

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

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

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

Bounty

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

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

Shared Savings

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

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

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

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

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

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

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

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

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

53 Ibid., pp. 30-34.

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

53 Ibid., p. 15.

56 Ibid., p. 15.

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

Penalties

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

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

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

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

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

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

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

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

60 Ibid., pp. 157, 177.

61 Ibid., p. 120.

62 Ibid., p. 232.

Table 6-Hate Energy Research and Development Programs

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

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

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

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

ENERGY EFFICIENCY RESEARCH AND DEVELOPMENT PROGRAMS

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

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

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

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

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

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

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

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

Federal Programs 7

The Federal Government sponsors a wide range of programs that support electric utility energy efficiency initiatives. Most of the programs are concentrated in the U.S. Department of Energy (DOE), however several other Federal agencies, including the Environmental Protection Agency (EPA), the Rural Electrification Administration (REA), and the Tennessee Valley Authority (TVA), also administer energy efficiency efforts. Federal programs include those that directly encourage the development and adoption of utility integrated resource planning (IRP) and demand-side management (DSM) efforts such as DOE's Integrated Resource Planning program and the initiatives of the Federal power marketing administrations. Other programs with a more indirect contribution to utility energy savings include energy supply and demand research and development (R&D) and technology transfer activities, mandatory energy efficiency standards and labels, and efforts to encourage voluntary adoption of energy efficiency technologies. This chapter provides an overview of the more notable Federal programs.

THE FEDERAL GOVERNMENT AND ENERGY EFFICIENCY

The strong Federal interest in energy efficiency arises from the importance of reliable and economic electric power production to the economy, concerns over the environmental impacts of power production, and the Government diverse roles of wholesale power producer, utility regulator, and utility customer. The Federal mission for encouraging energy efficiency through electric utilities is based on both legislative and executive actions. Over the past two decades, Congress has passed a number of laws that either directly or indirectly affect consumer electricity demand or utility resource planning and operations.

For example, electric utility involvement in helping customers to save energy was given impetus by the National Energy Conservation Policy Act,[1] which required utilities to provide information on energy conserving measures to their residential customers and to offer energy audits. The act also established Federal minimum energy efficiency standards for appliances such as refrigerators and fluorescent lamp ballasts, eventually contributing to lower electricity consumption per unit. Table 7-1 lists some of the major legislation shaping Federal energy efficiency programs and policies. The Energy Policy Act of 1992 builds on many of these existing programs, for example, expanding Federal support for State and utility energy efficiency efforts and extending building and appliance energy efficiency standards.[2]

On the executive side, President Bush's 1991 National Energy Strategy (NES) embraced energy efficiency as a key resource in meeting future energy needs. The NES set forth two goals for Federal programs related to electricity generation and use: to "encourage efficiency and flexibility in electricity supply and demand choices, " and to "promote diversity of electricity technology and fuel choices. "[3] It listed a variety of policy initiatives to achieve those goals. Among them were DOE-led efforts to support reform of Federal and State utility regulation to encourage wider use of IRP and DSM and an expanded commitment to R&D on improved methodologies for measurement and evaluation of IRP and DSM efforts. In other areas, Federal R&D and demonstration activities designed to improve the reliability of electrotechnologies and the cost-effectiveness of energy resources, including renewable energy technologies, could contribute to improved efficiency of electricity use and production.[4]

Federal support for energy efficiency R&D (as identified in the NES) is shown in table 7-2. Out of total funding of some $1.2 billion requested in FY 1993, only about $6 million was allocated to direct support for electric utility energy efficiency initiatives. Some indirect contributions to utility energy efficiency efforts may flow from the roughly $150 million in consumer energy efficiency under building energy R&D programs and from the hundreds of millions of dollars expended for R&D in fossil, nuclear, and renewable energy power generation.

The Clinton Administration has also given energy efficiency a high priority and has proposed increased spending on several Federal energy efficiency programs as part of its economic stimulus plan and budget requests

US. DEPARTMENT OF ENERGY PROGRAMS

DOE's responsibility for formulating national energy policy and implementing energy conservation and efficiency programs make it the lead Federal agency in promoting energy conservation

[1] Public Law 95-619, as amended, sec. 215, 42 U.S.C. 8216.

[2] Public Law 102-486, 102 Stat. 2776, Oct. 24, 1992.

[3] National *Energy Strategy: Powerful Ideas for America,* First Edition 1991/1992 (Washington DC: U.S. Government Printing Office, February 1991), p. 31.

[4] Ibid.

[5] The proposal calls for an additional $188 million in FY 1993 for DOE broad-based energy conservation programs including $47 million for the low-income weatherization assistance, and $19 million for model projects for commercializing building energy conservation technologies. The proposal would also allocate $14 million to improved energy efficiency in Federal Government facilities and $23 million for EPA's "Green Lights" program which encourages voluntary installation of energy efficient lighting. Steve Daniels and Steve Gorman, "Emergency Supplemental Appropriations Act of 1993—HR ?," *Energy andEnvironmental Study Conference Weekly Bulletin, Mar. 15,1993, pp.* A6-7.

Table 7-l-Selected Federal Legislation: Energy Efficiency and Electric Utilities

Legislation	Efficiency-Relatad Provisions
Energy Policy a nd Conservat ion Act (Public Law 94-163, December 22, 1975, 89 Stat. 870, 42 U.S.C. 6201 et seq., as amended)	Requires energy use labels for new appliances. Requires appliance energy efficiency standards (later made mandatory). Establishes State Energy Conservation Program. Provides Federal technical and financial assistance for development and implementation of State energy conservation plans.
Energy Conservation and Production Act (Public Law 94-385, August 14, 1976, 90 Stat. 1125, 42 U.S.C. 6801 et seq., as amended)	Establishes Weatherization Assistance Program to fund retrofits for low-income households. Required mandatory building energy efficiency standards for all new buildings (later made voluntary for nonfederal buildings). DOE to support innovative electric utility rate design initiatives and demonstrations to encourage energy conservation. At State request, authorizes DOE to intervene or participate in State ratemaking proceedings. Provides financial assistance for State consumer services offices to participate in State regulatory hearings.
National Energy Extension Service Act (Public Law 95-39, Title V, June 3, 1977, 91 Stat. 191, 42 U.S.C. 7001 et seq., as amended)	Establishes Energy Extension Service to fund State and local energy information, training, and demonstration programs.
National Energy Conservation Policy Act (Public Law 95-619, November 9, 1978, 92 Stat. 3206, 42 U.S.C. 8201 et seq. and elsewhere, as amended)	Establishes Residential Conservation Service and institutional Conservation Program. DOE to approve State plans requiring regulated utilities to implement residential energy conservation programs offering audits, information, and financing. Extends residential mortgage credit for energy conservation and solar energy improvements through Federal housing finance programs.
Powerplant and Industrial Fuel Use Act of 1978 (Public Law 95-620, November 9, 1978, 92 Stat. 3289, 42 U.S.C. 8340, as amended)	Imposed restrictions on use of natural gas and oil as primary fuels in existing and new powerplants (most provisions later repealed).
Public Utility Regulatory Policies Act of 1978 (Public Law 95-617, November 9, 1978, 92 Stat. 3117, 42 U. S. C.2601 et seq. and elsewhere, as amended)	Amends Federal Power Act to require State public utility commissions to consider adopting various energy conservation and ratemaking standards. Amends Energy Conservation and Production Act to provide Federal grants to States to carry out new requirements. Requires utilities to interconnect with and purchase power from qualifying small power producers and cogeneration facilities.
Energy Security Act *1980* (Public Law 96-294, June 30, 1980, 94 Stat. 611)	Amends National Energy Conservation and Production Act residential conservation programs to require warranties for conservation measures, cap audit fees at$15, and limit utility installation of conservation measures. Establishes DOE residential energy efficiency demonstration program. Establishes Commercial and Apartment Conservation Service (CACS).
Pacific Northwest Electric Power Planning and Conservation Act of 1980 (Public Law 96-501, December 5.1980, 94 Stat. 2697.16 U.S.C. 839)	Establishes the Pacific Northwest Power Planning Council to develop regional conservation and electric power plans to guide BPA resource acquisition.

(Continued on next page)

Table 7-l-Selected Federal Legislation: Energy Efficiency and Electric Utilities+Continued)

	Authorizes BPA to acquire new energy resources consistent with the regional plan and to encourage cost effective energy conservation and renewable energy resources. Gives priority to conservation and renewable energy sources in BPA resource plans. Requires Council and BPA to collaborate on and implement a fish and wildlife protection plan.
Omnibus Budget Reconciliation Act (Public Law 97-35, August 3, 1981,95 Stat. 357)	Amends the Powerplant and Industrial Fuel Use Act to allow DOE to ban the use of oil or natural gas in new powerplants where alternatives exist. Requires electric utilities using natural gas as a primary source to implement a conservation plan that will reduce at least 10 percent of electricity consumption attributable to natural gas over 5 years. Creates the imw-income Home Energy Assistance Program (LIHEAP). Makes building energy performance standards voluntary for non-federal buildings under the Energy Conservation and Production Act.
Hoover Power Plant Act of 1984 (Public Law 98-381, August 17,1984,38 Stat. 1333,43 U.S.C. 7275 et seq., as amended)	Requires Western Area Power Administration long-term firm power service contracts to require customers to develop and implement energy conservation programs.
Conservation Service Reform Act of 1986 (Public Law 99-412, August 28, 1986, 100 Stat. 932)	Amends National Energy Conservation Policy Act. Reforms the Residential Conservation Service and extends its expiration to 1989. Eliminates requirement that utilities arrange for conservation measures installation and related loans. Allows States to develop alternative conservation plan for residential buildings. Abolishes the Commercial and Apartment Conservation Service.
Powerplant and Industrial Fuel Use Act of 1978, Amendments (Public Law 100-42, May 21, 1978, 101 Stat. 310)	Repeals and amends certain sections of the 1978 Act restricting utility use of oil and natural gas. Requires that no new electric powerplant may be constructed or operated as a base load powerplant without the capability to use coal or other alternative to petroleum as a primary energy source, unless it receives an exemption.
National Appliance Energy Conservation Act of *1987* (Public Law 100-12, March 17, 1987, 101 Stat. 103)	In absence of DOE implementation, establishes mandatory minimum energy efficiency standards under Energy Policy and Conservation Act and requires DOE to update standards periodically. Adds additional appliance categories for which standards must be developed.
Renewable Energy and Energy Efflciency Technology Competitiveness Act of 1989 (Public Law 101-218, December 11, 1989, 103 Stat. 1859, 42 U.S.C. 12001-1 2007)	Directs DOE to participate in cost share joint venture demonstrations of renewable energy and advanced district cooling technologies. Establishes cost and performance goals for Federal wind, photovoltaic, and solar thermal research programs.

SOURCE: Office of Technology Assessment, 1993.

Table 7-2—National Energy Strategy Funding Levels for Energy Research and Development Fiscal Years 1991-93 ($ millions)

Research area	FY 1991 actual	FY 1992 enacted	FY 1993 requested	FY 1991-93 percent change
Surface transportation efficiency				
Transportation materials development	$21,6	$23.5	$26.4	22.20/0
Heat engine development	15.8	16.8	17.5	10,8
Electric and hybrid propulsion	25.0	42.9	75.3	201.2
Other transportation efficiency	7.6	9.6	11.5	51.6
Intelligent vehicle-highway systems	23.0	27.5	37.5	63.0
High-speed rail, maglev	12.0	20.0	28,0	133.3
High-performance communications	58.0	92.0	123.0	112.1
Total	$163.0	$232.3	$319.2	95.8%
Air transportation efficiency				
Energy-efficient aeronautics	$51.6	$63.0	$68.0	31 .8%
Air traffic control systems	35.0	32.0	46.0	31.4
Total	$86.6	$95.0	$114.0	31.670
New transportation fuels				
Alternative fuels utilization	$13.6	$ 17.4	$31.7	133.1 %
Fuels from biomass	28.7	34.8	46.4	61.7
Advanced oil recovery	31.7	36.9	46.5	46.7
Natural gas[a]	15.9	12.6	40.0	151.6
Total	$89.9	$101.7	$164.6	83.1%
Efficiency In buildings and Industry				
Integrated resource planning	$ 3.0	$ 3.9	$ 6.0	100.0%
Industry efficiency	78.9	92.2	95.7	21.3
Alternate industry feedstocks	0.3	0.5	2.0	566.7
Buildings energy technologies	44.9	49.4	54.5	21.4
Total	$127.1	$146.0	$158.2	24.50/.
Advanced electric technology				
Municipal solid waste	$ 0.0	$ 1.6	$ 4.0	NA
Cogeneration	4.1	3.2	3.5	-14.6%
Photovoltaics	46.4	60.4	63.5	36.9
Other solar and renewable	103.4	123.0	113,6	9.8
Superconductivity	18.6	22.0	22.5	21.0
Advanced light-water reactors	44.3	62.5	58.7	32.5
Advanced reactor concepts	61.3	59.5	50.0	-18.4
Advanced reactor facilities	91.1	97.8	95,1	4.4
Total	$369.2	$ 430.0	$ 410.9	11.370
Grand total	$835.8	$1,005.0	$1,166.9	39.60/0
Total DOE	$660.2	$ 782.5	$ 878.4	33.1%

a Includes only funding contained within the Fossil Energy appropriation.

SOURCE: Office of Technology Assessment, 1993, based on data from U.S. Department of Energy, "National Energy Strategy: Powerful ideas for America: One Year Later," DOE/S--92008000, February 1992, p. 5.

at electric utilities.[6] The primary DOE programs involving electric utilities are under the 0ffice of the Assistant Secretary for Energy Efficiency and Renewable Energy (formerly Conservation and Renewable Energy). The R&D and technology transfer efforts of the Office of Fossil Energy, the Clean Coal Technology Program, and the Office of Nuclear Energy, also offer some benefits for increasing the energy efficiency, cost-effectiveness, and environmental compatibility of utility power generation options.

Federal support for energy conservation and efficiency has varied significantly, usually reflecting shifting political priorities. From FY 1980 to 1990, appropriations for DOE conservation R&D, where much of the utility-related energy efficiency R&D is focused, fell by more than half. The Bush Administration and Congress reversed that trend, but in real terms, DOE's conservation R&D budget in FY 1991 was only 60 percent of what it had been in FY 1980.

In FY 1992, DOE budgeted an estimated $426 million on programs that the General Accounting Office (GAO) identified as promoting conservation and efficiency in the use of electricity and other forms of energy.[7] While marking an increase over prior years, this budget level was only 11 percent of the $3.8 billion in funds allocated to energy supply technology R&D. Adjusted for inflation, DOE's FY 1992 conservation R&D budget was some 18 percent lower than in 1980.[8]

Moreover, within the conservation R&D programs, the emphasis has shifted fro buildings and utility systems technologies to transportation and renewable energy technologies and to longer-term, high-risk research on industrial processes and materials, and superconducting materials.[9]

Determining g what portion of Federal spending actually supports electric utility energy efficiency initiatives or technology development is not easy. DOE programs have multiple goals, and improving energy efficiency is often a minor objective of DOE energy supply and demand technology programs. According to a GAO analysis, DOE's FY 1993 budget request to Congress reflected some $2.1 billion in civilian R&D identified by DOE as supporting the NES objective of "improving electric efficiency."[10] A more detailed breakout of the proposed spending showed $1.2 billion related to various DOE civilian nuclear programs (including light water reactors, high-efficiency and ultrahigh-efficiency power systems, fusion energy, first repository, monitored retrievable storage facility, and nuclear facilities). The Clean Coal program and renewable energy systems accounted for an additional $644 million. Altogether, demand-side efficiency programs (including $50 million for unspecified "utility demand efficiency," $26 million for industrial programs, and $27 million for buildings efficiency programs) made up less than 0.5 percent of the budget request for electric efficiency R&D.

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6 The Department of Energy Organization Act of 1977, 42 U.S.C. 7131 et seq., consolidated the energy functions of a number of agencies under a single department. DOE absorbed the Energy Research and Development Administration the Federal Energy Administration, the Federal power administrations, the power marketing functions of the Department of the Interior, as well as some functions of other agencies. A new independent agency established within DOE, the Federal Energy Regulatory Commission, took over the responsibilities of the Federal Power Coremission and the oil pipeline regulatory functions of the Interstate Commerce Commission.

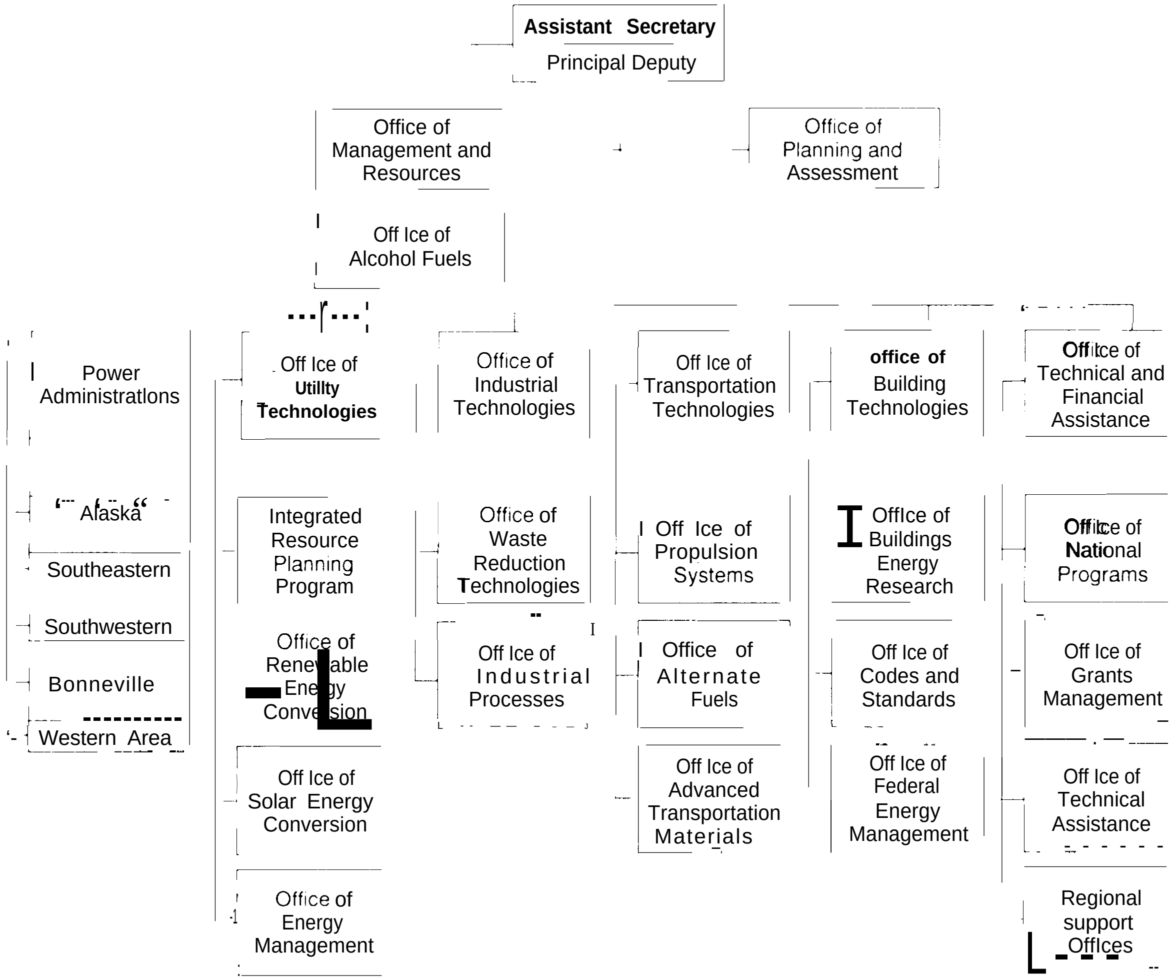
7 The GAO estimate excluded transportation sector efficiency programs, but did include DOE's conservation grant programs paid for by Petroleum Overcharge funds. General Accounting Office, "DOE's Efforts to Promote Conservation and Efficiency," GAO/RCED-92-103, April 1992, pp. 2-3.

8 Ibid.

9 For more on the fate of DOE energy conservation R&D, see U.S. Congress, Office of Technology Assessment, *Building Energy Efficiency, OTA-E-518* (Washington, DC: U.S. Government Printing Office, May 1992), pp. 104-107 (hereafter referred to as OTA, *Building Energy Efficiency). See also,* Fred J. Sissine, *Congressional* Research Service, "Energy Conservation: Technical Efficiency and Program Effectiveness," CRS Issue Brief 85130, April 1991.

10 General Accounting Office, "Energy R&D: DOE's prioritization and Budgeting Process for Renewable Energy Research," GAO/RCED-92-155, April 1992, pp. 13-16.

Figure 7-l-Organization Chart of DOE's Assistant Secretary for Energy Efficiency and Renewable Energy



SOURCE: Office of Technology Assessment, 1993, adapted from information provided by the U.S. Department of Energy, April 1993.

Office of Energy Efficiency and Renewable Energy

The Office of the Assistant Secretary for Energy Efficiency and Renewable Energy manages R&D and technology transfer programs for renewable energy technologies, end-use energy efficiency, and utility systems. It also oversees the operations of the five Federal power marketing agencies and Federal technical and financial assistance programs.[11] As shown in figure 7-1, the major program offices are organized by end-use sectors: Utility, Buildings, Industrial, and Transportation Technologies, plus Technical and Financial Assistance.

11 Office of Federal Register, United Stares *Government Manual,* 1991/92 (Washington DC: U.S. Government Printing Office, July 1991) pp. 279-280. Hereafter referred to as *U.S. Government Manual, 1991/92.*

Table 7-3-Program Funding for DOE Office of Utility Technologies, FY 1992

Programs:	Appropriations ($millions)
Office of Solar Energy Conversion	86.7
Solar thermal	21.1
Biomass power	4.4
Photovoltaics	60.4
Resource assessment	1.2
Integrated Resource Planning	4.0
Office of Energy Management	37.7
Transmission and distribution	3.1
Health effects of electric and magnetic fields	5.0
Energy storage	5.4
High-temperature superconductivity	22.0
Hydrogen fuels	1.4
District heating and cooling	0.8
Office of Renewable Energy Conversion	50.6
Wind	21.4
Hydroelectric	1.0
Geothermal	26.2
Ocean	2.0

SOURCE: Office of Technology Assessment, 1993, based on data from U.S. Department of Energy, Assistant Secretary for Conservation and Renewable Energy, "Conservation and Renewable Energy Tech nologies for Utilities," DOE/CH10093-865 (prepared by the National Renewable Energy Laboratory, Golden, CO), April 1992, p. 5.

The Office of Utility Technologies a dministers programs dealing with utility systems, IRP, DSM, and renewable energy technologies R&D. Other programs also fund activities that can contribute to utility energy efficiency efforts. The Office of Buildings Technologies and the Office of Industrial Technologies direct programs that are designed to improve the energy efficiency of building and industrial systems and related processes primarily through support of R&D and information projects. The 0ffice of Technical and Financial Assistance promotes the use of renewable energy and energy-efficient technologies and practices through technology transfer, grants, cooperative activities with State and local governments and private and nonprofit organizations.

Office of Utility Technologies

The Office of Utility Technologies, created in the FY 1990 DOE restructuring, manages various programs to encourage the development and adoption of cost-effective energy efficiency and renewable energy technologies (see table 7-3).[12] The office has four utility-related research, development, demonstration, and technology transfer programs:

- The Integrated Resource Planning Program, which deals with all aspects of utility planning and operations;
- The Office of Solar Energy Conversion, which promotes the development and adoption of solar thermal, photovoltaic, and biomass energy technologies;
- The Office of Renewable Energy Conversion, which promotes wind, hydroelectric, geothermal, and ocean energy systems; and
- The Office of Energy Management, which manages research to improve the efficiency and reliability of electricity delivery and storage systems.

All of the foregoing programs share the broad goals of ensuring that energy conservation and DSM programs are considered equally with new sources of supply, reducing institutional constraints deterring adoption of energy efficiency and renewable energy technologies, and expanding cooperative efforts with utilities and private industry to realize the large market potential of these energy resources.[13]

Integrated Resource Planning Program

The IRP Program was established to encourage the development and implementation of IRP processes to ensure that cost-effective energy

12 U.S. Department of Energy, Assistant Secretary for Conservation and Renewable Energy, "Conservation and Renewable Energy Technologies for Utilities," DOIVCH1OO93-86 (prepared by the National Renewable Energy Laboratory, Golden, CO), April 1992, p. 1, Hereafter referred to as DOE, "Conservation and Renewable Energy Technologies for Utilities. "

13 Ibid., p. 4.

conservation and DSM programs are considered equally with new sources of supply .14 The IRP Program encourages utilities and State regulators to use resource planning and regulatory approaches that emphasize electricity conservation and efficiency.

The IRP Program has evolved from the Least-Cost utility Planning Program (LCUP), established in 1986 in response to congressional directives. The LCUP Program was setup to aid the adoption of least-cost planning through technology transfer to utilities, regulators, consumers, and government agencies. [15] The current structure of the IRP Program has gradually evolved over the past 8 years to support three activity areas:

- *Planning* Processes--developing methods that will integrate regulatory and DSM programs into utility planning;
- *Demand-Side Management—working* to ease adoption of DSM by utilities; and
- *Regulatory Analysis--examining the eco*nomic regulatory environment and its barriers to demand-side investment.

The IRP Program has a very small staff (2 full-time equivalents in FY 1993), and thus, little institutional presence; its program efforts focus on channeling Federal funds for technical assistance and information transfer to State regulators and utilities. Program activities are primarily carried out through arrangements with several national laboratories to direct research, to manage grant applications and awards for cooperative research efforts and other cost-shared research.[16] The IRP Program has underwritten various conferences, workshops, publications, and training programs on IRP and DSM in collaboration with the National Association of Regulatory Utility Commissioners, the Edison Electric Institute, the Electric Power Research Institute, and similar organizations. The program has funded work evaluating and measuring utility DSM energy savings and the reliability of energy-efficient technologies. The program also is supporting development of analytical tools and methods for comparing the costs and benefits of various energy production and consumption options, including methods for incorporating total fuel-cycle analysis and consideration of environmental, social, and other external costs in utility resource planning. In recent years, the program has underwritten efforts to expand the application of IRP and DSM concepts to local gas distribution utilities. Table 7-4 shows selected projects supported in FY 1991. The program continues to support similar efforts today. According to IRP program representatives, requested budget increases will be passed through to support expanded activities through national laboratory programs and perhaps some additional direct research contracts.

Among its most successful early efforts according to program officials were the creation of organizations that have continued, independently of DOE funding, to promote LCP objectives. One of these projects, NORDAX, a regional utility-sponsored DSM data exchange is discussed in box 7-A.

For most of its history, the IRP Program has had an annual budget of some $1 million, rising to $3 million for FY 1992-93, as shown in figure 7-2. With this modest budget, DOE has defined its role as the gatherer and disseminator of information. DOE requested a 50 percent increase for the IRP program for FY 1993 for a total of $6 million to fund additional research and information activities. Actual funds received in FY 1993 were $4.9

14 Linda Berry and Eric Hirst, *Recent Accomplishments of the U.S. DOE Least-Cost Utility Program,* ORNL/CON—288 (Oak Ridge, TN: *Oak* Ridge National Laboratory, August 1989) p. 5.

15 *Hearing* on *Least Cost Utility Planning* before the Subcommittee on Energy Development and Applications of the House Committee on Science and Technology, 99th Congress, 1st sess., Sept. 26, 1985.

16 The major recipients of IRP program funds are the Oak Ridge National Laboratory in Tennessee; the Lawrence Berkeley Laboratory in California, and the National Renewable Energy Laboratory in Colorado.

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Table 7-4-Recipients, Research Topics, and Funding of DOE Integrated Resource Planning Program Projects, FY 1991

Lawrence Berkeley Laboratory
- Gas Integrated Resource Planning (IRP) ($180,000)
- Evaluation of Financial Incentives to Utilities ($100,000)
- Transmission Issues in IRP ($75,000)
- Environmental Externalities and IRP ($125,000)
- Analysls of Fuel Price Risk In All Source Bidding ($450,000)
- Competitive Bidding for Demand-Side Resources ($80,000)
- Integrated Resource Bidding in New York ($60,000)
- Database on Energy Efficiency Programs ($50,000)
- End-Use Resource Planning: Transferability of End-Use Load Shape Data ($25,000)
- Technical Assistance to National Association of Regulatory Utility Commissioners, Commissions, Utilities, and DOE ($80,000)
- Technical Assistance to Power Marketing Agencies (n/a)
- Technical Potential for Efficiency improvements in the Residential and Commercial Sectors (n/a)
- Advanced IRP Seminar ($50,000)

Oak Ridge National Laboratory
- Fundamentals of Electrlc-Utility IRP (n/a)
- Analytical Foundation for Demand-Side Management (DSM) Programs (n/a)
- DSM Planning Processes (n/a)
- Analysis of the Role of DSM as a Resource (n/a)
- DSM Collaboratives (n/a)

National Renewable Energy Laboratory
- Renewable Energy and IRP Strategy ($25,000)
- Renewable Energy Profiles ($40,000)
- Technical Assistance to National Association of Regulatory Utility Commissioners ($30,000)
- State Renewable Energy Policies and Incentives ($55,000)
- Utility Fuel-Cycle Analysis Requirements Review ($30,000)
- Net Energy Analysis Study ($25,000)
- Center for Clean Air Policy Analysis and Dialogue on Global Warming and Energy Policy ($85,000)
- Scoping Study of Renewable Energy-Related Utility Modeling Issues ($30,000)
- Scoping Study of IRP Needs in the Public Utility Sector ($25,000)
- IRP Definitional Study ($25,000)
- DSM Pocket Guides ($38,000)
- Compendium of Total Fuel-Cycle Studies for Use in IRP Processes ($5,000)
  - Residential technologies
  - Commercial technologies
  - Agricultural technologies
  - industrial technologies
- Renewable resource technologies IRP ($198,000)

Bangor Hydro-Electric
- Development of a Market Implementation Strategy for Water and Space Heating Technologies (n/a)

Burlington Electric Department
- Small Utility Approach to DSM (n/a)

Central Vermont Public Service Corp.
- innovative Approaches to Commercial Lighting for Rural Electric Customers (n/a)

Fitchburg Gas and Electric Light Co.
- Small Commercial Lighting Program (n/a)

Massachusetts Municipal Wholesale Electric Co.	
Electric Thermal Storage Lease/Loan Program for Residential and Small Commercial Customers (n/a)	
Niagara Mohawk Power Corp., NY State Electric& Gas, Rochester Gas & Electric	
Assessment of New York State Farmstead DSM (n/a)	
Northeast Utilities	
Evaluation of the Effectiveness of a Low-Income Weatherization Program for Rural Customers (n/a)	
Washington Electric Cooperative, VT	
Integrated Demand Control Project for Small Rural Utilities (n/a)	

KEY: n/a = funding level not published.

SOURCE: Office of Technology Assessment, 1993, based on data from the U.S. Department of Energy, Integrated Resource Planning Program, "Volume 1: IRP Program Reviews and Catalogue of Projects," 1991.

million. The budget request for FY 1994 is $6.8 million.[17]

Although the program is small (two full-time staff members) and expenditure levels practically invisible within the overall DOE budget, DOE, nevertheless, has projected significant energy savings from its investment. DOE has projected that in the next 10 years, the program will contribute up to 30,000 MW reduction in otherwise necessary supply options. (The estimates assume that adoption of IRP will spur utilities to greater investments in more efficient generating technologies and expanded electricity savings from utility DSM programs.) In the longer run, according to DOE, this could amount to 80,000 MW, with over 4 quads of primary energy saved annually.[18] DOE'S announced program goal 1992 was to increase the number of States with comprehensive IRP from 15 to 40 by the year 2000.[19] DOE was silent on the mechanisms for accomplishing its IRP implementation goals. As noted in chapter 6 of this report, State progress in adopting and implementing IRP requirements for their jurisdictional utilities has been accelerating, even in the absence of expansive Federal programs or Federal regulatory requirements. OTA estimates that more than 30 States have established IRP policies (see ch. 6).

Evaluation of the effectiveness of the IRP Program has been limited. A 1989 review by Oak Ridge National Laboratory (funded by the IRP Program), detailed the activities completed, and concluded that at the time the program was:

> .. playing a small but effective role in ensuring that the large potential of integrated utility planning is realized DOE's role has been primarily catalytic, providing the motivation for other organizations to join in cost-sharing and information-sharing projects. DOE's participation in these projects helps to publicize and legitimize the ideas of integrated planning and aids the technology transfer processes among utilities, commissions, and other interested groups.[20]

No formal evaluation has been done since. DOE continues to view its role primarily as publicizing and legitimizing IRP and DSM concepts.

Given the modest amounts devoted to the program and the lack of alternative sources of

17 Diane Pirkey, Manager, DSM Programs, Office of Utility Technologies, U.S. Department of Energy, personal communication, Apr. 8, 1993.

18 U.S. Department of Energy, *FY 1992 Congressional Budget Request,* vol. 4, DOE/CR-0001, February 1991, p. 438. Hereafter referred to as DOE, *FY 1992 Congressional Budget Request,* vol. 4.

19 Testimony of J. Michael Davis, Assistant Secretary, Conservation and Renewable Energy, U.S. Department of Energy, Hearings on FY 1993 Department of Energy Appropriations before the Subcommittee on Interior and Related Agencies of the House Committee on Appropriations, 102d Cong., 2d sess., Apr. 8, 1992, p. 5.

20 Linda Berry and Eric Hirst, supra note 14, p. 1.

Box 7-A--NORDAX: Sharing Utility DSM Experiences

NORDAX, the NortheastRegion DSM Data Exchange, is a cooperative projectsponsored by a kgroup of some 20 utilities in the northeastern United States and Canada. NORDAX is an example of DOE's institution building efforts. The Least-Cost Utility Planning Program (LCUP) provided money for development of a high quality DSM database and establishment of a regional organization to maintain and update the database. Participants in developing NORDAX included all of New York State's utilities, a number of other northeastern utilities, the New York Public Service Commission, State and city energy agencies, the Edison Electric Institut,the Electric Power Research Institute, the Alliance to Save Energy, several national laboratories, and DOE'S LCUP program NORDAX was incorporated as a nonprofit corporation in May 1989 to carry on the project and operates independent of DOE funds.

Development of the NORDAX data base required establishing standards for collecting and presenting data on actual DSM program experiences, technologies, and costs that allow utilities to exchange data for DSM programs and resource planning. The NORDAX database, created in 1988, provides comprehensive information on over 90 DSM programs from participating utilities plus detailed data on other utility system characterostocs, such as demographics, load and weather. The data is organized to assist utlilties compare and select future programs with abetter idea of their costs, market penetration, and load imparct.

From DOE's perspective, the NORDAX project helped toaddress the need for improved information on DSM technologies and programs. TheNORDAX experience will contribute to better methods for developinganddtahg DSM data to improve program effectiveness and to help incorporate real world load impacts and costs of DSM programs in IRP models. NORDAX also presents an organizational model for development of a regional DSM database that potentially could be replicated in other regions.

SOURCE: Office of Technology Assessment, 1993, based on Berry Linda and Eric Hirst, Recent tAccomplishments of the U.S. Department of Energy's Least-Cost Utility Planning Program, ORNL/CON--288 (Oak Ridge, TN: Oak Ridge National Laboratory, August 1989), pp. I5-18.

support, many of the program's clients have been reluctant to criticize it. Nevertheless, anecdotal information suggests that its emphasis on promotion of IRP and DSM as general concepts is rapidly falling behind the needs of client State regulators and utilities who are well advanced in implementing IRP and DSM programs. With growing reliance on IRP and DSM measures to meet future customer demand reliably and at least cost, the need increases for more sophisticated planning and evaluation methodologies and independent analyses of the cost and performance of various energy supply and demand-side efficiency options. With its current size and scope, it seems unlikely that the IRP Program will be able to provide institutional leadership or significant financial contributions to overcoming these challenges.

Federal funds and technical assistance are not the sole sources for financing or directing research and education efforts on IRP and DSM methodologies. As utility involvement in these programs has expanded, so too has the institutional expertise within the industry and the regulatory community. The Electric Power Research Institute maintains active research and information programs on utility planning methods, DSM programs and efficient end-use technologies. Professional and trade associations, including such specialized groups as the Association of Demand-Side Management Professionals, sponsor seminars, conferences, publications, and other educational efforts. A plethora of consulting firms offer analytical services to utilities and regulators.

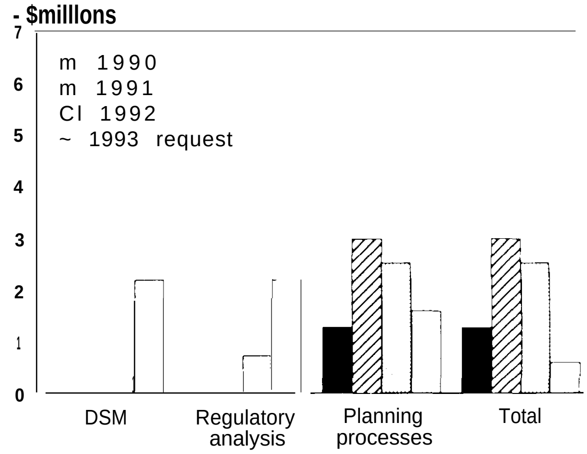
Solar and Renewable Energy Conversion Research Programs

The bulk of the Office of Utility Technologies annual budget is devoted to DOE-funded R&D to accelerate the development, demonstration, and commercialization of advanced renewable technologies for electric power generation. The major potential benefits to utilities from these research efforts are increased diversity in technology and fuel choices, reduced costs and increased confidence in the performance of solar, wind, biomass, hydro, and geothermal power technologies.[21] DOE also supports activities that target institutional factors influencing potential markets for and commercial deployment of renewable energy technologies.

Renewable energy technologies offer several significant benefits as part of utility resource plans including opportunities to reduce the operating and maintenance costs and planning uncertainties. In particular, renewable power generation technologies have the advantages of reduced fuel costs and fewer adverse environmental impacts on-site than fossil fuel alternatives.[22] Another attractive feature is that renewable energy generating technologies are available in small, modular units offering utilities capacity additions in smaller size increments and with shorter construction lead times than more conventional generators.[23]

The Office of Solar Energy Conversion manages projects to encourage solar thermal, biomass, and photovoltaic technologies. The Office of Renewable Energy Conversion oversees geothermal, wind, hydroelectric and ocean energy technologies. Both offices support research aimed at lowering the costs of renewable energy technologies in the mid- and long-term to make them more competitive economically with conventional fossil energy resources, As part of market-development for renewable energy technologies, DOE is supporting resource assessments of U.S. solar radiation and wind power potential and participates in cooperative efforts to boost U.S. renewable energy technology exports. Many renewable energy research projects are carried out on a cost-shared basis with private industry. Box 7-B shows some of the recent research efforts supported by these programs.

Figure 7-2—Funding for Integrated Resource Planning Program, FY 1990-93



SOURCE: Office of Technology Assessment, 1993, based on data from, U.S. Department of Energy, FY 1993, Congressional Budget Request, vol. 4, January 1992, p. 468.

Office of Energy Management Programs

The Office of Energy Management supports development of technologies to increase the efficiency and reliability of energy transmission, distribution, and storage and to increase the flexibility, and safety of utility systems. The Office administers research programs on transmission and distribution technologies, power systems and materials, high-temperature superconductivity, energy storage technologies, and

21 U.S. Department of Energy, DOE/CR-0006, January 1992, pp. 17-23. Hereafter referred to as DOE, *FY 1993 Congressional Budget Request, vol.* 2.

22 "Conservation and Renewable Energy Technologies for Utilities," supra note 12, p. 5.

23 Ibid., at pp. 11-26.

Box 7-B-Renewable Energy Technologies R&D Projects of DOE

DOE participates in a variety of cooperative, cost-shared research, development demonstration, and teohnology transfer activitiesbencourage the expanded use of renewable energy technogies. These efforts by the solar and renewable energy programs of the Office of UtilityTechnologies are directed at overcoming both the technical and institutional constraints that have slowed market penetration by renewable energy technologies. These programs also support activities designed to build the international competitiveness of the U.S. renewable energy industry and establish technological leadership in the marketplaoe.

Renewable Energy Conversion Programs

The core of the Wind Energy Program is research on materials, components, devices, and systems to increase power output and lower costs of wind energy systems. The program goal for the year 2000 is development of wind pow systems that can compete economicaiiy with conventionai power systems by producing electricity at a cost of $0.04/kWh (in 1990 dollars) in moderate wind speeds. The program is emphasizing cost-shared development of utility-scale advanced wind turbines and working to resolve critical reliability and performance issues by examining wind/airfoil interactions and turbine structural response. DOE also continues to support assessments of U. S. wind resources to assist State and utility energy planners and power producers in identifying new opportunities for deploying wind energy systems. Funding for the program was about $21 million in FY 1992.

The Geothermal Energy Program emphasizes cooperative R&D on technologies for reducing the cost of exploration development, and conversion to make more of the domestic geothermal resource available and economic, The program is examining the peak load following capabilities of existing geothermal plants, and exploring technologies for tapping the energy potential of hot dry rooks, and geopressurized brines. Geothermal Energy Program activities were budgeted at $26 million in FY 1992.

The Hydropower Program sponsors research on the costs, benefits, and effectiveness of environmental mitigation practices with the goal of reducing the uncertainties in the regulatory review of proposed hydropower development. FY 1992 funding was about $1 million.

the health effects of electric and magnetic fields. The major recipients of R&D funds under these programs are the various national laboratories.

Long-term goals for DOE research on transmission and distribution (T&D) technologies are to reduce energy losses on T&D systems (now estimated at 8 to 9 percent) by 10 percent, to reduce nuisance outages by 20 percent, and to increase post-outage recovery speed by 50 percent.[24] DOE is engaged in cooperative R&D on higher capacity transmission and automated control systems incorporating advanced electronics, communications, and computer technologies to increase power systems flexibility, efficiency, and reliability .25 To improve the cost-effectiveness of higher efficiency transmission technologies, for example, the DOE program is looking at the technologies necessary for converting alternating-current (AC) transmission lines to high-voltage direct current (DC) effectively doubling the capacity over the same right-of-way. Development of new technologies for improved real-time control of utility T&D will result in more efficient transmission and increased transmission capacity utilization.

[24] Ibid., pp. 27-28.

[25] DOE, *FY* 1993 *Congressional Budget Request, vol. 2,* pp. 119-123.

The Ocean Energy Technology program with a budget of $2 million is cooperating with the State of Hawaii in the design and construction of an experimental ocean thermal energy conversion (OTEC) facility using seawater as its working fluid.

Solar Energy Conversion Programs

The Photovoitaic (PV) Program is pursuing efforts to aid development of more cost-effective PV energy systems and to expand the market potential for PVS in utility applications. The program has set a goal of cutting the cost of PV systems from today's $0.25 to $0.35/kWh to $0.12 to $0.20/kWh by the late 1990s. The long-term goal is PV power generation at $0.06/kWh (in 1990 dollars). The PV Program is targeting improvements in PV materials, components, and system design to boost the solar conversion efficiency of thin-film and concentrator materials, and to advance the development of mass-production manufacturing capability. DOE also is participating in a PV demonstration project called Photovoltaics for Utility-Scale Applications (PVUSA), a joint-venture with EPRI, the California Energy Commission, and several utilities to test PV arraysfromseven manufacturers in a utility setting. The FY 1992 budget for the PV program was $60 million.

The SolarThermai Program is sponsoring research on improving basic thermal conversion technology and is supporting cost-shared development of central receiver systems for grid-connected electric generation and dish concentrators for remote-site power generation. The program is participating in joint ventures with industry in development and commercialization of solar thermal systems for remote applications at $0.1 to $0.2/kWh as a stepping stone to less-costly utility applications. Funding for solar thermal activities was $ 21 million in FY 1992.

The Biomass Power Program, budgeted at $4 million in FY 1992, is focused on research on biomass gasification and high-efficiency turbine conversion to expand the range of applications and performance of biomass power generating systems. The long-term goal is producing electricity at $0.04/kWh (in 1990 dollars) allowing biomass power systems to compete with conventional fuels for utility baseload applications.

SOURCES: Office of Technology Assessment, 1993, based on information from U.S. Department of Energy, FY 1993 Congressional *Budget Request, vol.* 2, *January 1992,* pp. 15-23; and US. Department of Energy, Assistant Secretary *for* Conservation and Renewable Energy, Conservation and Renewable Energy Technologies for Utilities," DOE/CH10093-86 (prepared by National Renewable Energy Laboratory, Golden Colorado), April 1992, pp. 11-26.

DOE's support of R&D on high-temperature superconductivity (HTS)[26] offers several potential long-term efficiency benefits for utilities, including lower power losses on T&D systems, more efficient generators, and advanced magnetic energy storage systems. Development of a strong domestic HTS industry could prove of strategic importance to U.S. industrial competitiveness. Significant technical challenges stand in the way of realizing any of this potential, however. DOE's collaborative research program is focused on improving the performance of high-temperature superconducting materials to allow fabrication of HTS wires, coils, and cables for long-term utility applications and is budgeted around $21 million a year.

Research on thermal energy storage systems includes the District Heating and Cooling (DHC) Program supporting joint ventures to develop technical strategies to cut the capital costs and increase the energy efficiency of major DHC components.[27] DHC technologies offer utilities

26 High-temperature superconductivity refers to materials that can conduct electricity with zero resistance and expel magnetic fields (dimagnetism) at temperatures substantially higher than liquid helium (4 degrees Kelvin(K) or 4 degrees C above absolute zero which is minus 273 degrees C). Sustaining superconductivity of high electric currents in high magnetic fields at temperatures of liquid nitrogen (about 77 degrees C above absolute zero) now commonly used in industrial applications could make HTS motors generators, magnets, and similar devices potentially practical. Ibid, p. 122.

27 The DHC program was mandated by the Renewable Energy and Efficient Technology Act, Public Law 101-218, sec. 6, Dec. 11, 1989.

opportunities **to** lower electricity peaks and improve energy efficiency and fuel flexibility. The DHC program was budgeted at $4.2 million in FY 1990-92 with more than $1 million expected from nonfederal sources for demonstration projects in FY 1992.[28] Because DOE views the technology as sufficiently mature to permit commercial growth of DHC systems, it proposed termination of the program and documentation of research results during FY 1993.[29] DOE also supports research on improved battery storage systems for utility applications and technologies for future hydrogen energy systems.

The Electric Energy Systems program also oversees DOE's research efforts on potential health effects of exposure to electric and magnetic fields. DOE is supporting research on characterizing EMF exposures, potential biological mechanisms of EMF interaction with living systems, and epidemiological studies. DOE is also expanding efforts on public information and engineering research on EMF mitigation options.

Office of Utility Technologies programs are geared specifically towards utilities. However, several other programs in DOE perform work that is potentially beneficial to utilities. This includes other programs under the 0ffice of Energy Efficiency and Renewable Energy and in the 0ffices of Fossil Fuels and Nuclear Energy, to be discussed later in this chapter.

Demand-Side Energy Efficiency Programs

The Office of Energy Efficiency and Renewable Energy also adminis ters programs that promote energy-efficient demand-side technologies through R&D, technical and financial assistance, and energy codes and standards. With buildings and industry contributing 30 percent each to U.S. energy use, the potential contributions from efficiency improvements in these sectors is substantial. DOE support for the development and commercialization of energy-efficient buildings and industrial technologies yields products that in turn create energy-saving opportunities for utilities and consumers.

Office *of Building Technologies*[30]*—The* commercial and residential sectors are frequently referred to as the buildings sector because most of their energy use is for building systems (i.e., heating, cooling, lighting, and appliances). Building energy use accounts for more than a third of all U.S. energy use and is continuing to grow even as the efficiency of buildings and appliances is improving. DOE-supported buildings R&D have provided several energy-efficient technologies successfully in use today, including solid-state fluorescent lamp ballasts, advanced refrigerator and freezer technologies, and low-emissivity window coatings. These technologies, resulting from R&D efforts initiated in the late-1970s, produced results that will save energy into the next century. Advances in fluorescent lamp ballasts aided by $3 million of DOE research funds, are expected to save billions of dollars in lighting energy costs in the coming decades. DOE-funded research efforts in improved insulation and wall and ceiling structures have also yielded successful energy-saving applications.

The Office of Building Technologies is currently supporting research to develop cost-effective technologies to reduce building energy loads by 30 percent in the near-term and by as much as 80 percent in the long-term. Major emphasis is given to development of high-efficiency lighting systems, energy efficiency HVAC conversion and distribution systems, advanced building materials, more energy-efficient appliances and replacements for chlorofluorocarbons in building systems. Advances in these areas will contribute to the technology base for utility

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28 DOE, *FY* 1992 Congressional *Budget Request,* vol. 4, pp. 440-441.

29 U.S. Department of Energy, *FY* 1993 *Congressional Budget Request,* vol. 4, DOE/CR-0006, January 1992, pp. 478-79. Hereafter referred to as DOE, *FY* 1993 *Congressional Budget Request,* vol. 4.

30 For more information on DOE's building technology research, see OTA, *Building Energy Efficiency,* supra note 9.

DSM programs. Buildings Technologies is also supporting R&D on cost-effective solar technologies to meet some or all of the energy needs of new buildings.

Office *of Industrial Technologies*[31]*-DOE* efforts to improve industrial efficiency have zeroed in on reducing the waste streams generated in industrial processes to improve energy efficiency and eliminate harmful environmental pollutants. DOE is also supporting development and adoption of more energy-efficient technologies and processes in energy-intensive industries and more extensive use of industrial cogeneration and municipal solid waste energy systems. These efforts could offer benefits to utilities in more diverse opportunities for new energy supplies as well as a stream of efficient industrial electric technologies for DSM programs.

Among the successes from DOE-funded industrial research are a control mechanism for a high-efficiency transformer used in the welding process, biomass grain driers, and slow-speed diesel motors for cogeneration systems. Present DOE industrial research is focused on improving the efficiency of electric motors, which now account for some 70 percent of industrial electricity use. DOE's cooperative efforts to spur adoption of adjustable-speed drives and high performance electric motors for new and retrofit applications include efforts to develop and provide information to justify including industrial motor programs in utility integrated resource plans.[32]

Technical and Financial Assistance Programs

Federal efforts to save energy and promote energy efficiency and renewable energy technologies have led to a variety of programs that offer technical assistance and Federal funds to government and private entities. Many of these programs were originally established during the energy scares of the 1970s and they have had varying degrees of success. Among the most notable are the various programs administered by the Office of Technica1 and Financial Assistance, the now expired Residential Energy Conservation and Institutional Energy Conservation Programs, and the Federal Energy Management Program.

The Office of Technical and Financial Assistance (OFTA) administers a variety of programs that provide technical advice and grants to States, local governments, nonprofit institutions, and low-income individuals. OFTA also oversees State programs funded from the petroleum overcharge violations settlements. OFTA'S portfolio consists of various State and local partnerships, information and technical assistance programs, and energy management programs .[33] The State and local partnerships encompass the State Energy Conservation Program, the Energy Extension Service, the Weatherization Assistance Program, and the Institutional Conservation Program.

The State Energy Conservation Program, established in 1975 under the Energy Policy and Conservation Act, provides financial and technical assistance to States and localities to develop and implement comprehensive energy conservation plans to encourage energy efficiency and reduce energy demand growth. All States have implemented the act's mandatory energy conservation programs (including lighting efficiency, insulation, and thermal efficiency standards for nonfederal public buildings) and most now include supplementary programs in energy education, technology demonstration, and technical

31 Technical opportunities for energy-saving technologies for industrial application and relevant Government programs are examined in detail in U.S. Congress, Office of Technology Assessment, *Industrial Energy Efficiency*, released in April 1993 and to be published in summer 1993.

32 DOE, *FY 1993 Congressional Budget Request,* vol. 4, p. 365.

33 OFTA also administers a number of modest programs providing technical and financial assistance for small energy inventors and innovators, technology transfer and information programs, and international market development and energy technology information exchange programs. These programs are not particularly relevant to utility energy efficiency efforts and are not discussed here.

Table 7-5-Budgets for DOE Energy Grant Programs, Fiscal Years 1991-93 (thousands of dollars)

Grant program	1991	1992	1993 request	1993 actual
Weatherization Assistance Program	198,952	193,925	80,000	187,000
State Energy Conservation Program	16,620	16,194	45,000	15,600
Institutional Conservation Program	31,022	30,246	30,000	29,200
Total	246,594	240,365	155,000	231,800

SOURCE: Office of Technology Assessment 1993, based on data from U.S. Department of Energy, FY 1993 *Congressiona Budget Request, vol.* 4, January 1992, pp. 28&281, and other sources.

assistance reflecting local priorities. A major goal of the program is to build State and local institutional capabilities for energy conservation planning and implementation.

Funds are provided in the form of formula grants (requiring a 20 percent State match) and incentive awards for innovative State/industry cooperative programs. While appropriations for the program have decreased since 1979, overall funding of State program activities has ballooned because of the availability of oil overcharge funds.[34] See table 7-5 for a summary of funding. DOE technical assistance to State energy agencies focuses on education and information exchange and has included publications, training manuals, an information clearinghouse, seminars, workshops, and conferences. States have used the funds to support a variety of energy conservation activities, including demonstration projects installing energy-efficient lighting, HVAC, and energy management systems and solar technologies in public buildings.[35] Beginning in FY 1992, DOE has supported an initiative aimed at encouraging States to attract nonfederal resources to supplement the grants provided by offering additional incentives to support State-led joint ventures with industry to encourage the near-term adoption of emerging renewable energy and energy-efficient technologies.[36]

A companion program, the **Energy Extension Service (EES) was** created in 1977 to provide information, technical assistance, and training tailored to the needs of small energy users such as homeowners, municipalities, and small businesses. Under the program, State energy agencies or other designated entities design projects serving specific local information needs. Cost-share funds are disbursed from DOE through State agencies to local programs.

Among the successful projects have been energy on-site audits, self-help workshops, and auditor-training programs. The program is intended to be flexible and responsive to local needs and leveraging of private funds is encouraged.

In Rhode Island, grant funds were used in a cooperative effort with local electric utilities and a nonprofit group to conduct energy audits of State buildings and recommend lighting efficiency retrofits. The utilities provided rebates of up to 82 percent of relamping costs, with State

34 Funding for the program in FY 1989 was about $60 million (in current dollars), by 1989, total funding including oil overcharge funds was in excess of $300 million. OTA, *Building Energy Efficiency*, supra note 9, figure 4-6, p. 121, citing various DOE reports to Congress.

35 A detailed report on the diversity of State use of oil overcharge funds made available through various Federal/State partnerships by 1989 is provided in Consumer Energy Council of America Research Foundation A *State-by-State Compendium of Energy Efficiency Programs Using Oil Overcharge Funds,* EPRI CU-7541 (Palo Alto, CA: Electric Power Research Institute, March 1991). By 1989 over $7 billion in various oil overcharge settlements had been collected and additional eases (with anticipated recoveries of $0.5 to $1.0 billion) were still under negotiation. Expenditures of funds from the escrow amounts from the Exxon settlement were limited to various Federal and State programs including the State Energy Conservation Program, the Energy Extension Service, Institutional Conservation Program, Weatherization Assistance Program, and Low-Income Home Energy Assistance Program. Funds from other settlements can be used for other ways as well. By 1989 about half of the overcharge funds had been expended, but a huge pool of funds remains to be tapped by State and local governments.

36 Office of Management and Budget, *Budget for Fiscal Year 1993*, Appendix One, p. 472.

funds paying the remainder. The State estimates that the project will result in a 20-percent reduction in total annual State electric costs.[37]

EES funds have also supported providing training for school districts in Washington on how to reduce energy use through lighting changes on school grounds and installation of a cogeneration demonstration at a community and business center, in Taos, New Mexico expected to save $10,000 annually in energy costs.

The Energy Policy Act of 1992 repealed the National Energy Extension Service Act that established EES.[38] The repeal is unlikely to result in lost energy savings given the overlap with other programs.

OTA's *Building Energy Efficiency* report noted that both the Energy Extension Program and the State Energy Conservation Programs lack evaluations of cost-effectiveness or reliable energy-savings estimates. However, OTA observed:

> . . . IB]oth programs are important networks for conveying Federal monies and expertise to the State and local level, and both programs are connected to small-scale energy users that could help DOE demonstrate technologies emerging from its energy conservation research and development projects. In addition, the auditor and other training offered by these programs help establish and sustain local expertise and markets for weatherization and other conservation services.[39]

The experience in Rhode Island also demonstrates that the programs provide opportunities for State/utility/private partnerships that can leverage Federal grant funds and expand the reach of utility-sponsored efficiency programs. With the large pool of oil overcharge funds still remaining, these opportunities should prove attractive to States and utilities.

The Weatherization Assistance Program (WAP) was originally established in 1976 under the Energy Conservation and Production Act to help weatherize the homes of low-income families. The program aims to reduce the energy costs of low-income families.

WAP allocations to States are made under a formula reflecting the number of low-income households, residential heating and cooling energy use, and local climate conditions. Families qualify for weatherization assistance if they meet certain eligibility conditions, including a household income at or below 125 percent of the poverty level. The weatherization assistance programs are usually carried out by local community organizations that provide energy audits and installation of cost-effective weatherization measures. In addition to the grants for weatherization activities, DOE also provides funds for training, technical assistance and client education.

According to DOE, energy savings of 25 percent or more are possible at residences eligible for WAP funds. Families earning less than $5,000 a year consume an average of 68 percent more energy to heat a square foot of living space than higher-income families. This difference is attributable in part to the fact that lower-income residences are old and in disrepair, and hence less energy efficient than the homes of higher-income households.

An early national evaluation of WAP found that the average energy savings is 10 percent per household from WAP retrofits.[40] However, since there have been many program changes since 1981, the evaluation may no longer be valid. DOE

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37 U.S. Department of Energy, The *Secretary's Annual Report to Congress 1990*, DOE/S-0010P(91), p. 58. Hereafter DOE *Annual Report to Congress* 1990.

38 Public Law 102-486, 102 Stat. 2776, Oct. 24, 1992, section 143.

39 OTA, Building *Energy Efficiency*, supra note 9, pp. 122-123.

40 G.E. Peabody, U.S. Department of Energy, Energy Information Administration, *Weatherization Program Evaluation*, service report, SR-EEUD-84-1, Washington, DC, August 1984, pp. 1, 18.

has initiated a new evaluation and anticipates a final report at the end of 1993.[41]

In recent years, the WAP program has also shifted more of its emphasis to encourage leveraging of Federal funds to increase the number of clients it can serve. Agreements were made with two utilities to augment WAP funds with additional financial and in-kind services.[42]

The Institutional Conservation Program (ICP) was established by the National Energy Conservation Policy Act in 1978 as a matching grant program that provided funds for both detailed energy audits and the suggested energy-saving capital improvement in nonprofit institutions, such as schools and hospitals. Projects are funded on a 50 percent cost-share basis and are administered through State agencies. Since 1978, the program has awarded over $800 million in grants while saving over $2 billion in energy bills at participating institutions.[43]

New rules adopted as a result of Public Law 101-440 will streamline the program and encourage leveraging, and third-party financing options (such as utility demand-side management programs and energy savings contracts). The new rules will allow a State to use up to 100 percent of its funds for program and technical assistance activities and up to 50 percent of its Federal funds for marketing and other costs associated with leveraging nonfederal funds.[44]

The DOE Weatherization Assistance Program and the Institutional Conservation Program (ICP) are financed in large part from the petroleum overcharge fund. An additional beneficiary of these funds is the Low-Income Home Energy Assistance Program (LIHEAP) at the U.S. Department of Health and Human Services (HHS) **that** helps poor households in meeting their energy bills. LIHEAP is described in box 7-C.

Past Technical Assistance Efforts-Building Energy Audits

During the 1980s Congress discontinued two legislatively-mandated building energy audit programs that included utility participation. The Residential Conservation Service (RCS), which expired in 1989, and the Commercial and Apartment Conservation Service, repealed in 1986, were designed to provide building owners and occupants with building-specific information on energy use and savings.[45] The centerpiece of the program was the requirement that utilities perform an on-site energy audit that included actual measurements by an auditor and an individualized written report for its customers.

The enabling legislation for RCS estimated that the program would contribute to the insulation of 90 percent of the Nation's homes. However, at the conclusion of the program 7.3 million audits had been performed, achieving only 11 percent participation.[46]

As designed, the programs did not address either the availability and costs of financing conservation retrofits nor the regional availability of conservation supply and installation services. Additionally, under most State ratemaking formulas then in use, participating utilities lacked sufficient incentives to conduct the program as the costs of the program were merely passed through to customers without any added profit and resulting energy-savings potentially reduced utility revenues.

Despite these drawbacks, the programs, like other federally-mandated technical assistance and

41 OTA, *Building Energy Efficiency*, supra note 9, pp. 97-99.

42 DOE, *Annual Report to Congress 1990*, p. 61.

43 OTA, *Building Energy Efficiency, supra* note 9, pp. 99-100.

44 DOE, *FY 1993 Congressional Budget Request*, vol. 4, p. 506.

45 For more on the history and effectiveness of these programs see OTA, *Building Energy Efficiency*, supra note 9, pp. 117-121.

46 Centaur Associates, *Update of the Evaluation of the Residential Conservation Service program*, vol. 1, report prepared for the U.S. Department of Energy, DOE/CS/10097, 1987, p. 2-19.

Box 7-C-Helping the Poor Pay Their Electricity Bills: The Low-Income Home Energy Assistance Program

LIHEAP, established in 1961 by the Imw-income Home Energy Assistance Act (Public Law 97-35), is a block-grant program administered by the Department of Health and Human Services. The program provides funds to States to help eligible low-income households meet heating and cooling bills, such as utility bills. Up to 15 percent of State LIHEAP grants (25 percent with a special waiver) can be used for home weatherization.

In 1990, with funding of about $1.6 billion, LIHEAP reached about 6 million households; weatherization services were provided to only 146,000 homes. On average, States spend from 7 to 10 percent of their LIHEAP funds on weatherization. The bulk of the funds are spent on energy assistance, averaging about $200 per household. In contrast, average weatherization expenditures under the program are about $l,600 per household. For the Federal Government and State agencies, helping poor families pay their energy bills allows thereto reach more households with available funds than weatherization efforts, even though weatherization could cut household energy bills.

OTA's report, Building *Energy* Efficiency found that there was little assessment of the cost-effectiveness of LIHEAP weatherization efforts and no dear program policies encouraging cost-effective weatherization. Moreover, utilities benefit substantially from Federal LIHEAP outlays by collecting payments that otherwise would have been lost or delayed. (Utility arrearages from delays in paying residential bills amount to hundreds of millions of dollars annually; LIHEAP funds help offset these liabilities.) The report noted that new Federal policies or requirements to leverage LIHEAP weatherization funds with State and utility resources could boost the number of low-income households that receive energy efficiency measures under the program.

SOURCE: U.S. Congress, Office of Technology Assessmens, Building Energy *Efficiency,* OTA-E-518 (Washington, DC: U.S. Government Printing Office, May 1992), pp. 99-100.

reformation programs, helped to create the institutional infrastructure and expertise in State government, utilities, and energy conservation service providers that now help sustain active energy efficiency and technical assistance efforts.

The Federal Energy Management Program

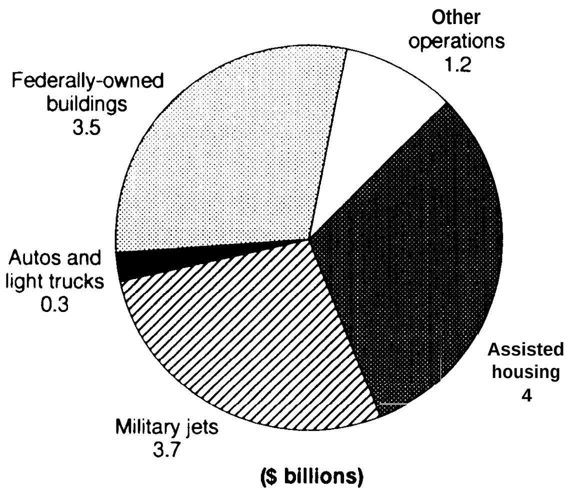
The Federal Energy Management Program (FEMP), located in The Office of Building Technologies, is an outreach program designed to assist Federal agencies in adopting energy efficiency measures in buildings, transportation and operations (see box 7-D). The program was established in the mid- 1970s in response to legislation and Executive Orders directing Federal agencies to reduce energy use. The program has a small staff (six people in 1991) and a modest budget ($4 million in FY 1992). FEMP has four areas of operations: 1) reporting on the energy management efforts of Federal agencies; 2) providing information training, and technical support to Federal agency personnel; 3) hosting interagency meetings to develop new Federal initiatives; and 4) awarding annual certificates of achievements to Federal facilities and personnel for demonstrating exemplary performance .[47]

As part of its efforts to assist Federal agencies in implementing energy-saving measures, FEMP has been evaluating agency participation in utility-sponsored DSM programs and is assisting in administrative reforms that would encourage greater use of shared energy savings contracts by Federal agencies as an alternative means of funding efficiency improvements. DOE estimates

[47] U.S. Congress, Office of Technology Assessment, *Energy Efficiency in the Federal Government: Government by Good Example?*, OTA-E-492 (Washington DC: U.S. Government Printing Office, May 1991), pp. 24-25.

Box 7-D--Federal Energy Management Program

Federal Spending on Energy, FY 1989



SOURCE: Office of Technology Assessment, 1993, adapted from U.S. Department of Energy, Federal Energy Management Program, "Report on Federal Government Energy Management and Conservation Programs," October 1990.

The Federal Government is the Nation's largest single energy consumer. In FY 1989, the Federal Government spent over $8*7 billion on direct energy purchasesfor its own facilities and operations and another $4 billion subsidizing the energy expenses of low-income households (see figure). Not reflected in this direct energy expenditure are some $12.7 billion for energy costs for leased space for which the Federal Government does not directly pay utility bills. Payments to electric Utilities accounted for an estimated $2.4 billion of the FY 1989 energy bill for Federal buildings. Electricity accounts for around 70 percent of total energy costs.

OTA'S report Energy Efficiency in the FederalGovernmentby Good Example? concludes that much Federal energy is inefficiently used OTA estimated that the Federal Government could profitably conserve at least 25 percent of the energy used in Its buildings by adopting commercially cost-effeotive measures such as high-efficiency lighting and carefully operated heating, ventilation, and air conditioning equipment-with no sacrifice of comfort or productivity.

The constraints to Improved Federal energy efficiency are real and significant (see table.) Implementing efficiency improvements will require overcoming several hurdles, including finding sufficient funds to pay for retrofits in an era of tight budgets.

OTA's ease studies found a large potential for savings. However constraints, notably the lack of funding and staff, limited action at the facilities. For example, the General Services Administration's (GSA) Suitland Complex has about 2 million square feet of commercial building space. Electricity accounts for over 90 percent of the $5-million annual energy bill. The facility has increased effiencyof the heating, ventilation, and airconditioning system, improved lighting efficiency, and improved the building envelope. Most Improvements consisted of low first-cost measures because the funds for more capital-intensive measures were unavailable.

In spite of these efforts, energy use at the facility has risen since 1985. Changes in the building's use, such as greater use of computers and increased occupancy, offset the gains. Further measures have not been implemented for several reasons. The complexity of the procurement process creates significant lag time, and inhibits selection of innovative equipment and participation in local rebate programs. Current policy restricts replacement of functional equipment in spite of technological advances that would reduce energy use. Lastly, building personnel often lack training in energy conservation and some new technologies may be too sophisticated to run without it.

OTA found that there are mechanisms in place to promote greater energy efficiency in Federal buildings including sanctioned private-sector financing options available to assist funding of energy efficiency measures.

[1] U.S. Congress, Office of Technology Assessment, Energy Efficiency the Federal Government: Govemnent by Good Example?OTA-E-492 (Washington, DC: U.S. Government Printing Offioe, May 1991).

The first of these are shared energy savings (SES) contracts. Under the Comprehensive Omnibus Budget Reconciliation Act of 1985 (Public Law 99-272), all Federal agencies can seek private financing from energy service companies. These companies perform conduct energy audits and install efficiency measures using their own capital and personnel. Their costs and profits are paid for out of the monies that previously went to higher energy bills. However, this procurement practice is rarely used by Federal agendas. The complexity of the procurement process and uncertainty over who keeps the savings discourage interested agencies from initiating such contracts. Legislation was passed to assist the Department of Defense (DOD) overcome constraints in SES contracting. DOD is permitted to retain two-thirds of energy savings at the installation with the SES contract. One-half is to be used for further energy conservation measures, while the other half is available for other projects. Additionally, provisions in the act simplify the contracting procedures for DOD.

Utility rebates are another important source of funding. Large Federal installations offer significant energy savings for interested utilities.Therebates offered by utilities are likely to bring borderline efficiency measures within financial reach. For example, the GSA and Potomac Electric Power Company in the Washington, DC, metropolitan area have been working on a Federal Lighting Initiative. In 1991, GSA committed $10 million towardthis effort with PEPCO offering an additional $10 million in rebates. As of early 1991, only DOD and DOE had an explicit policy on receiving utility rebates. DOD is allowed to retain two-thirds of rebate, while the remaining third is returned to the general fund at the Treasury. DOE is allowed to retain the entire sum and credit the rebate to energy cost appropriation. Pacific Northwest Laboratory, a national laboratory, is working with FEMP to develop a generic Federal utility rebate program.

Efforts to improve the energy efficiency of Federal buildings received further stimulus under the Energy Policy Act of 1992. The act toughens energy efficiency standards for Federal buildings and sets anew deadline of 2005 for Federal agencies to install cost-effective technologies to save energy and water. Also enacted were a number of other measures to raise energy awareness among Federal managers and financial commitments to energy efficiency.

Constraints on Improved Federal Energy Efficiency

Resource constraints

Priorities favor other agency needs
- Energy efficiency is not central to most Agencies' missions
- Energy is a small component of most agendas' expenditures
- Little senior management interest

Many measures require initial capital spending

Many measures require personnel
- Many facilities have no energy coordinator

Information constraints

Opportunities have not been systematical!y assessed

Agencies are uncertain of technical and economic performance
- Does this technology really work?
- Would the facility be better off waiting for next year's model?
- Lack of metered energy-use data
- %0 little information sharing between agencies

Energy-use decisions are dispersed, made by thousands of individuals
- Implementation requires coordinated effort from diverse parties
- Too little training and education for diverse parties

Lack of incentives

- Dollar savings often do not acrue to energy savers
- Energy costs are readily passed through budgets

Federal procurement policies often favor status quo
- Procurement practices am complex often restrictive

SOURCE: U.S. Congress, Office of Technology Assessment, Energy *Efficiency in theFederal Government: Government byGood Example?* OTA-E-492 (Washington, DC: U.S. Government Printing Office, May 1991), p. 10.

SOURCE: Office of Technology Assessment, 1993.

that aggressive implementation of energy efficiency measures in Federal buildings, such as lighting retrofits, could cut Federal energy use by 10 percent from 1985 levels and yield savings of $400 million per year by 1995.[48]

ENERGY EFFICIENCY INFORMATION AND STANDARDS

The Federal Government has had almost 20 years of involvement in various programs involving building energy codes and standards, and appliance labeling and efficiency standards. In addition to DOE, the Federal Trade Commission (FTC) and the U.S. Department of Housing and Urban Development (HUD) have been involved in these efforts. The programs have required Federal agencies to work in cooperation with trade and professional organizations and manufacturers.

OTA'S report *Building Energy Efficiency* examined the history and efficacy of these programs for commercial and residential energy technologies.[49] OTA found that although there has been limited evaluation of the effectiveness and energy-savings attributable to these efforts, there is some consensus that they help reduce information-related constraints to energy efficiency improvements, and they provide accepted benchmarks used by electric utilities in determining and advertising energy-efficient products in their DSM programs.

Federal Building Energy Codes and Standards

While building energy codes generally are adopted and enforced locally, most localities rely on model codes published by national building organizations .50 The DOE and HUD have been **active in** developing model and mandatory building energy codes and standards. In cooperation with States and various national organizations, Federal agencies have issued voluntary guidelines for nonfederal buildings. DOE and HUD have promulgated energy efficiency standards for Federal buildings and manufactured homes (e.g., mobile homes). Although the number of new Federal buildings constructed annually is small, the Federal Government potentially has the ability to influence about 27 percent of new home construction through eligibility requirements for Federal mortgage insurance programs of the Federal Housing Administration, the Veterans Administration, and the Farmers Home Administration.[51] Table 7-6 shows the status of Federal efforts.

Appliance Efficiency Standards

The National Appliance Energy Conservation Act[52], as amended, establishes Federal minimum efficiency or maximum energy use standards for certain appliances, including refrigerators, air conditioners, and furnaces. DOE is required to update the standards to reflect technological changes every 3 to 10 years depending on the appliance. Federal efforts to promulgate efficiency standards for consumer appliances were initiated in the 1970s under the National Energy Conservation Policy Act. Implementation of that act's mandatory efficiency standards was slow because of opposition within the Executive Branch and from manufacturers, and litigation. Pressure for uniform national standards helped break the logjam after California and several other States adopted appliance efficiency stand-

48 DOE, *FY 1993 Congressional Budget Request,* vol. 4, p. 327.

49 OTA, *Building Energy Efficiency,* supra note 9, pp. 107-116.

50 The major organimations are: the Building Officials & Code Administrators International the International Conference of Building Officials, the Southern Building Code Congress International, and the Council of American Building Officials, a federation of the first three organizations. The American Society of Heating, Refrigeration and Air-Conditioning Engineers (ASHRAE) promulgates standards for building HVAC systems tbat are often incorporated into building codes.

51 OTA, *Building Energy Efficiency,* supra note 9, pp. 107-109.

52 Public Law 100-137, Mar. 17, 1987, amended by Public Law 100-357,42 U.S.C. 6292.

Table 7-6-Federal Energy Standards for New Buildings 1992

Code	Applicability	Status
HUD Minimum Property Standards (1950s)	Residential buildings receiving Federal mortgages	To be replaced with Council of American Building Officials 'Model Energy Code'
National Manufactured Housing Construction and Safety Standards (1974)	All manufactured housing	Active
DOE Building Energy Performance Standards (1979)	All new construction	Never implemented; supplanted by performance standards listed below
DOE Mandatory Performance Standards for New Federal Residential Buildings (1989)	Federal residential construction (95 percent is military housing)	Active
DOE Energy Performance Standards for New Commercial Buildings (1990)	Mandatory for Federal commercial buildings. Voluntary for private-sector commercial buildings.	Active
DOE Voluntary Guidelines for Nonfederal Residential Buildings	Voluntary standards for nonfederal residential buildings	Underdevelopment; issuance pending

NOTE: New Federal Building Energy standards adopted in Energy Policy Act of 1992 (Public Law 102-488) are not included above.

SOURCE: Office of Technology Assessment, 1993, adapted from U.S. Congress, Office of Technology Assessment, *Building Energy* Efficiency, OTA-E-518 (Washington, DC: U.S. Government Printing Office, May 1992), p. 109.

ards of their own in the absence of Federal action. Table 7-7 shows selected appliance standards established before 1992, The Energy Policy Act of 1992 added additional energy and water-using devices to the list of products for which minimum Federal energy efficiency standards have been established .53

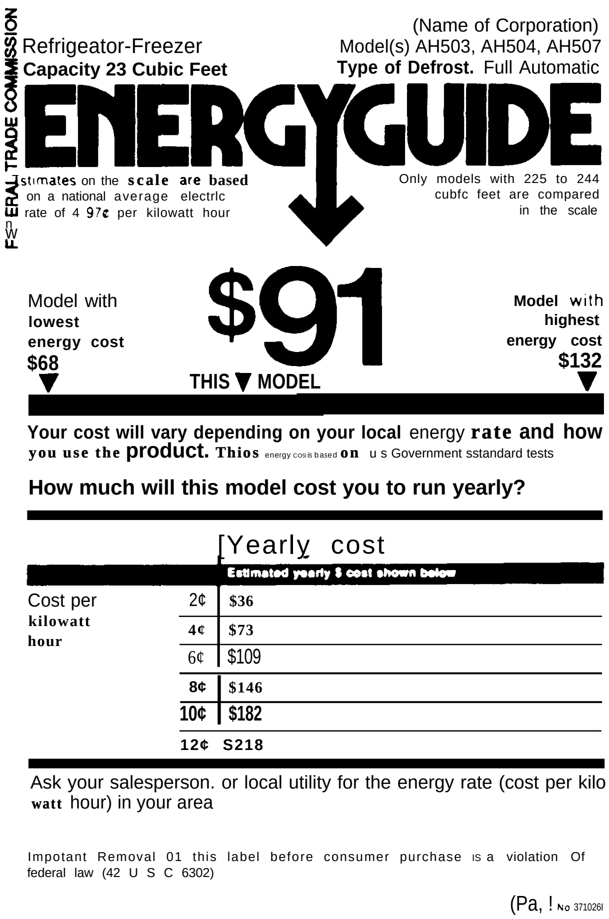
Appliance Labels

The Federal Government has also mandated labels showing energy use for the appliances covered by the standards under the Energy Policy and Conservation Act.[54] The requirement is based on the belief that consumers will purchase more efficient appliances if given information about operating costs and comparative product efficiencies. Labels now exist for refrigerators, freezers, dishwashers, water heaters, clothes washers, room air conditioners, and furnaces.[55] The labels include estimated operating costs for the product, as well as the range of operating costs for other available products in the same class. Appliance labeling requirements are the responsibility of the FTC.

53 Public Law 102-486, Subtitle C, 106 Stat. 2805, Oct. 25, 1992. The product categories added were @S, motors, commercial heating and cooling equipment, plumbing products, distribution transformers, windows, luminaries, and office equipment. The dates for promulgation of standards vary, but most must be published over the next 10 years.

54 The Energy Policy and Conservation Act (Public Law 95- 163), as amended, requires the Federal Trade Commission to develop and issue appliance energy-use labels for: 1) refrigerators, 2) freezers, 3) dishwashers, 4) clothes dryers, 5) water heaters, 6) room air conditioners, 7) home heating equipment (other than furnaces), 8) television sets, 9) kitchen ranges and ovens, 10) clothes washers, 11) humidifiers and dehumidifiers, 13) furnaces, and 14) any other type of consumer product defined as covered by the Secretary of Energy. Swimming pool heaters and fluorescent lamp ballasts were added to the list by the National Appliance Energy Conservation Act.

55 The Federal Trade Commission determined that labeling the remaining classes of appliances (clothes dryers, home heating equipment other than furnaces, television sets, kitchen ranges and ovens, and humidifiers and dehumidifiers). was economically unfeasible and would not assist consumer purchasing decisions. 44 Fed. Reg. 66466 (Nov. 19, 1979).



The Federal Trade Commission requires many new appliances to display labels that indicate the units' expected energy use of efficiency.

Other DOE Supply-side Research

The Office of Energy Efficiency and Renewable Energy administers a variety of programs with potential benefits for electric utility energy efficiency efforts. Three other DOE programs also sponsor R&D and demonstration projects dealing with energy efficiency in utility power generation and operations and cleaner generating technologies for new utility plants or repowering of existing plants. Energy efficiency is at present a minor consideration among the many objectives of these programs, which appear to be primarily directed at advancing particular fuels or technologies. DOE-funded activities could also provide cost and performance information on advanced power technologies that could aid consideration of these options in utility IRP programs. It is not clear, however, whether such information is effectively made available to the utility sector or to DOE's own 0ffice of Utility Technologies.

FOSSIL ENERGY R&D PROGRAMS

Fossil fuels contribute 60 percent of the fuel for the production of the Nation's electricity. The **Office of Fossil Energy (FE)** supports a wide range of basic R&D and demonstration projects involving coal, oil, and natural gas. One of the strategic goals identified for the fossil energy research program is to "provide environmentally, economically superior technology for the generation of electrical and thermal energy, and for the production of fossil-fuel-based chemicals and products for the electric utility market. . ."[56] Other goals include encouraging utilization of domestic resources, improving international competitiveness of U.S. technologies and technology-based products, and environmental protection. In recent years, consistent with these goals, greater emphasis has been given to cost-shared research and technologies for near- and mid-term commercialization by the private sector.

DOE-sponsored efforts with potential applications for electric utilities include R&D on coal combustion and control technologies, waste reduction, and fuel cells.

The coal program activities are focused on reducing emissions and boosting the energy efficiency of coal-fried powerplants. Low-cost coal cleaning methods will reduce costs for utilities' compliance with clean air regulations.

The fuel cell program, involving both coal and gas resources, is working to realize the potential of highly efficient, clean, and competitive generation of electricity and heat in the major sectors of the economy and is proposed to be shifted toward

56 DOE, *Congressional Budget Request, Fiscal Year 1992,* vol. 4, p. 15.

gas applications. By the year 2000, the program expects to demonstrate high-efficiency, natural gas fuel cell powerplants for on-site applications and low-megawatt electric utility powerplants that are economically competitive with conventional technologies.

The Clean Coal Technology program provides Federal funds to spur demonstration of advanced coal power generation technologies offering higher efficiencies, reduced emissions, and cost savings that can help coal compete with other resources (see box 7-E).

Cost and performance data from the Clean Coal Technology Program and other Fossil Energy R&D projects could aid utilities in resource planning for future power needs. Figure 7-3 shows the Fossil Energy R&D Budget.

NUCLEAR ENERGY R&D PROGRAMS

Nuclear power currently provides about 20 percent of the Nation's electricity. The Office of Nuclear Energy supports research projects in fission energy, including commercial nuclear reactor development. Preserving the viability and economic competitiveness of commercial nuclear power generation is a major priority of these efforts.

Much of the DOE nuclear R&D is targeted at the development of standardized designs for new nuclear plants. The $200-million program is shared equally between industry and the Federal Government. The goal of this partnership is to develop advanced light-water reactor designs for commercial application. Another focus is continued R&D in advanced nuclear power systems. DOE requested $50 million in FY 1993 for systems that show ''promise of potentially significant breakthroughs in economics, safety, licensing, and waste management.''[57] The early site permit program, a joint program started in 1992 between DOE and three electric utilities, will demonstrate the effectiveness of the early site permits procedure established by the Nuclear Regulatory Commission. The procedures are designed to approve sites for nuclear powerplants before both construction and substantial financial investment in an effort to improve industry standing.[58] Nuclear R&D funding requests were at $307 million in FY 1993, down from $332 million in FY 1992.

The energy efficiency related goals for nuclear power plants differ somewhat from those for

Table 7-7-Selected National Appliance Energy Conservation Act Standards 1992

Covered product	NAECA standard
Refrigerator-freezers[a]	960 kWh/yr (1990) 688 kWh/yr (1993)
Freezers[b]	706 kWh/yr (1990) 533 kWh/yr (1993)
Room air conditioners[c]	9.0 EER (1990)
Heat pumps[d]	10.0 SEER (1992) 6.8 HSPF (1992)
Water heaters[e]	
Electric	88.4% EF (1990)
Natural gas	52.5% EF (1990)
Furnaces	78.0% AFUE (1992)
Fluoresoent lamp ballasts	See 42 U.S.C. 6295(g)(5)-(6)

KEY: kWh/yr - kilowatt-hours per year; EER - energy efficiency ratio; SEER - seasonal energy efficiency ratio; HSPF - heating seasonal performance factor; EF = eff iciency factor; AFUE = annual fuel use (or utilization) efficiency.

a Automatic defrost units with top-mounted freezers, no through-the-door ice, and with adjusted volumes of 20.8 cubic feet.

b Uprighf, manual defrost units with an adjusted volume of 26.1 cubic feet.

c Room air conditioner units without reverse cycle, with louvered sides, and with capacities ranging from 8,000 to 13,999 Btu.

d Applicable to split (rather than single package) heat pump systems. SEER standard also applicable to central air conditioning systems.

e Standads shown here apply to 50 gallon units. NAECA water heater standards are less stringent for larger volume heaters.

SOURCE: Office of Technology Assessment, 1993, adapted from U.S. Congress, Office of Technology Assessment, Building Energy Efficiency, OTA-E-51 8 (Washington, DC: U.S. Government Printing Office, May 1992), p. 112.

[57] U.S. Department of Energy, ''National Energy Strategy: Powerful Ideas for America--One Year Later,' DOE/S—92008000, February 1992, p. 35.

[58] Ibid., pp. 33-36.

Box 7-E—The Clean Coal Technology Program

The Clean Coal Technology Program was established as an outgrowth of U.S.-Canadian agreements on add rain control (Public Law 99-190, Dec. 19, 1965). The program provides Federal funds for up to 50 percent of the cost of building and operating facilities demonstrating the future commercial feasibility of dean coat technologies that burn coal more efficiently, with lower emissions, and at a lowercostthan existlng technologies. The program was envisioned as a $5 billion effort with $2.5 billion in Federal funds to be matched with $2.5 billion in private funds. The Federal investment would be paid back over 20 years from sales of the technologies. Private-sector participation has exceeded expectations, and the overall investment in projects funded under the program is now anticipated to top $6 billion.

Clean Coal Program appropriations rose from $99.4 million in FY 1966 to $415 million in FY 1992. The program has encountered a number of difficulties and delays. Obligations have lagged behind the amounts appropriated. Awarding, negotiating, and obligating Federal funds for joint-venture arrangements proved to take longer than originally anticipated. A number of projects fell behind schedule and faced higher than expected costs.

The objectives of the Clean Coal Program have shifted over time. Originally, the program was envisioned as a means to spur practical technologies that would allow expanded coal use by reducing the adverse environmental impacts of burning coal and lowering costs for various industrial and commercial applications. As it has evolved, greater priority was given to technologies that can be used for retrofitting or repowering existing plants. (Repowering technologies c an also be used for new plants.) In later rounds, emphasis shifted to energy efficiency, environmental compliance, international competitiveness, and technologies with potentlal tocontribute to reducing global warming through lowered carbon dioxide emmisions. The fifth round targeted super-dean, high-efficiency power generation systems needed for coal to compete as an energy source under the more stringent post-2000 standards for sulfer dioxides and nitrogen oxides under the Clean Air Amendments acid rain controls. Information from dean coal demonstration projects will be collected by DOE for use by the industry, energy users, policy makers, regulators, and equipment vendors.

DOE has held five rounds of solicitations for clean coal Projects with the winners of the fifth round announced in May 1993. As of late 1992 there were 41 projects from the first four rounds of competition that were either underway (pre-construction or construction, or operational phases) or completed. Total value of these products is *nearry $4.6 billion* with 60 percent of the funding coming from nonfederal Sources.

Five projects were selected in the fifth round to share in sores $568 million available In cost-sharing. According to DOE, all five projects propose significant improvements in powerplant efficiencies, achieving conversion efficiencies of 45 percent of the energy content in the fuel, compared with the 33 to 35 percent efficiencies of conventional coal powerplants.

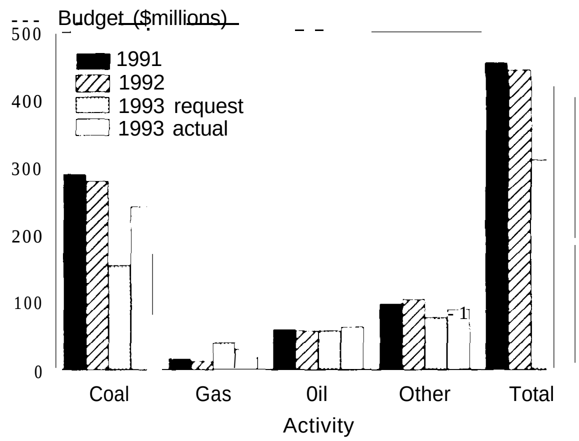
Among the technologies that have been funded under the demonstration program in early rounds are advanced coal cleaning, co-firing ofcoal with other fuels, advanced scrubbing technologies, underground coal gasification, atmospheric and fluidized bed combustion, slagging combustion, sorbent injection, integrated gasification combined-cycle, and advanced nitrogen oxide control and other flue gas cleanup technologies. Proposed projects selected in the fifth round include: a 480-MWadvanced integrated combined-cydepowerplant coupled with a 2.5 MW-molten carbonate fuel cell, a combined-cycle plant created by repowering an existing plant with an external gas turbine, a second-generation pressurized circulating fluidized bed powerplant, a small diesel power system fired by a coal-water slurry and equipped with a heat recovery boiler-steam turbine, and an advanced integrated steelmaking-power generation process.

The Energy Policy Act of 1992 calls for DOE to consider additional solicitations under the Clean Coal Technology Program

SOURCES: Office of Technology Assessment, 1993, bawd on information from U.S. Department of Energy, *"National Energy* Strategy: One Year Later," DOE/S--92008000, February 1992, pp. 27+32; and U.S. Department of Energy, Office of Fossil Energy, Clean Coal *Today, No.* 9, winter 1992.

fossil-thermal plants. The industry is interested in reducing the downtime that nuclear plants have experienced, improving load-factor and capacity availability, and refining predictive maintenance methodologies, as well as improving the energy efficiency of individual plant components. Improvements in the energy efficiency of nuclear powerplants is not a driving force in DOE commercial nuclear programs. Efforts supporting standardized nuclear reactor designs and permitting procedures could enhance the viability of nuclear options in utility resource plans.

Figure 7-3-Fossil Energy Research and Development Budget, FY 1991-93



SOURCE: Office of Technology Assessment, 1993, based on data from U.S. Department of Energy, FY 1993 *Congressional Budget Request,* vol. 4, January 1992, pp. 1$17.

FEDERAL POWER SYSTEMS

There are 10 Federal "electric utilities"—Government-owned and, operated power systems that generate and sell electricity. They include the Tennessee Valley Authority (TVA), the five Power Marketing Administrations (PMAs), the U.S. Army Corps of Engineers, the Bureau of Indian Affairs and the Bureau of Reclamation in the Department of the Interior, and the International Water and Boundary Con-mission in the Department of State. Together, they operate over 150 powerplants and generate 8 percent of the Nation's electricity supply .59 Much of the power is generated at Federal darn projects initially designed to control flooding and improve irrigation.

These Federal utilities are primarily generators and wholesalers of electricity, although some also serve as retail power distributors to ultimate customers. Most of the power is sold for resale to municipalities, electric cooperatives, and other nonprofit customers under preferences required by authorizing statutes. In 1990, Federal power systems sold 197.9 million MWh to wholesale customers, while sales to ultimate or retail customers totaled 52.1 million MWh. Federal system operating revenues totaled $8.2 billion and operating expenses were $5.4 billion for 1990 (see table 7-8). Pricing of Federal power is not intended to make a profit, but rather to recover operating costs and ultimately the capital costs of the facilities plus interest. Long-term debt and liabilities totaled some $31.9 billion in 1990.[60]

The major Federal power producers are TVA, the Army Corps of Engineers, and the Bureau of Reclamation. TVA markets its own power. Most of the electricity produced at Corps of Engineers and Bureau of Reclamation projects is marketed and transmitted by five power marketing administrations: the Bonneville Power Administration (BPA), the Western Area Power Administration (WAPA), the Southeastern Power Administration (SEPA), the Southwestern Power Administration SWPA), and the Alaska Power Administration (APA).[61] The PMAs also purchase power from other electric utilities in the United States and

59 U.S. Department of Energy, Energy Information Administration, *Financial Statistics of Selected Publicly Owned Electric Utilities 1990,* DOE/EIA-0437(90)/2 (Washington, *DC:* U.S. Government Printing Office, February 1992), p. 337.

60 Ibid.

61 The Bureau of Indian Affairs markets power for its Mission Valley Power and San Carlos dams. The Corps markets power from its North Central Division in Sault Ste. Marie, Michigan.

Table 7-8-Statement of Income of Federal Power Marketing Administrations and the Tennessee Valley Authority, 1990 ($ thousands)

Item	APA	BPA	SEPA	SWPA	WAPA	TVA	Total
Operating revenues.	9,602	2,070,265	136,569	95,326	517,259	5,338,721	8,167,742
Operating expenses.	3,867	1,554,260	26,500	84,845	514,954	3,216,460	5,400,886
Total income.	5,735	516,256	110,069	10,482	2,305	2,117,557	2,762,404
Income deductions.	2,983	201,950	110,081	830	44,918	2,845,175	3,205,937
Net income.	2,752	315,605	0	9,652	(44,598)	(387,588)	(104,177)

KEY: APA . Alaska Power Adminstration; BPA - Bonneville Power Administration; SEPA - Southeastern Power Administration; SWPA - Southwestern Power Administration; TVA - Tennessee Valley Authority; WAPA = Western Area Power Administration.

SOURCE: Office of Technology Assessment, 1993, from data in U.S. Department of Energy, Energy Information Agency, Financial Statistics of *Selected Publicly Owned Electric Utilities 1990, DOE/EIA-0437(90)/2* (Washington, DC: U.S. Government Printing Office February 1992), table 24, p. 338.

Canada to help meet customer demand, especially during periods of drought. ARA is an exception; it operates its own powerplants and distributes power to ultimate customers. Figure 7-4 shows a map of the areas served by the PMAs. With their broad customer base, PMAs are in a position to influence almost 30 percent of retail electricity sold.[62] Although all of the PMAs have authority to encourage their utility customers to invest in conservation, only Bonneville and Western have express legislative authority to link power sales to their customers with energy efficiency. Without this "conditioning authority," the other smaller PMAs have been limited in their ability to require their customers to participate in DSM activities.[63]

Individually, TVA and the PMAs have supported a number of energy conservation initiatives. Energy efficiency improvements offer several opportunities, including reduced agency costs and increased ability to satisfy varied uses of river systems.

Tennessee Valley Authority

TVA was created by Congress in 1933[64] as a government-owned corporation with the broad mission of resource and economic development for the Tennessee Valley region, an 80,000 square mile area extending to parts of seven States (figure 7-5).[65] TVA conducts a wide range of resource development programs including improvement of flood control, navigation, and recreation for the Tennessee River system, forestry and wildlife development, and electric power production. TVA also provides technical assistance in such areas as industrial development, regional waste management, and tourism promotion and has set up high-tech skill training centers to meet the needs of regional businesses and industries. TVA supports a fertilizer research facility and a bioenergy research program at Oak Ridge, Tennessee. TVA is governed by a three-member board of directors who are appointed by the President and approved by the Senate to serve 9-year terms.[66]

TVA is the largest Federal power producer. It serves some 110 municipal and 50 cooperative utilities that distribute power to some 3.3 million customers. TVA also provides power to about 50 retail customers. In 1990, TVA generated 116 million MWh, accounting for one-half of total net

62 General Accounting Office, "Utility Demand-Side Management Programs Can Reduce Electricity Use," GAO/RCED-92-13, October 1991, p. 33.

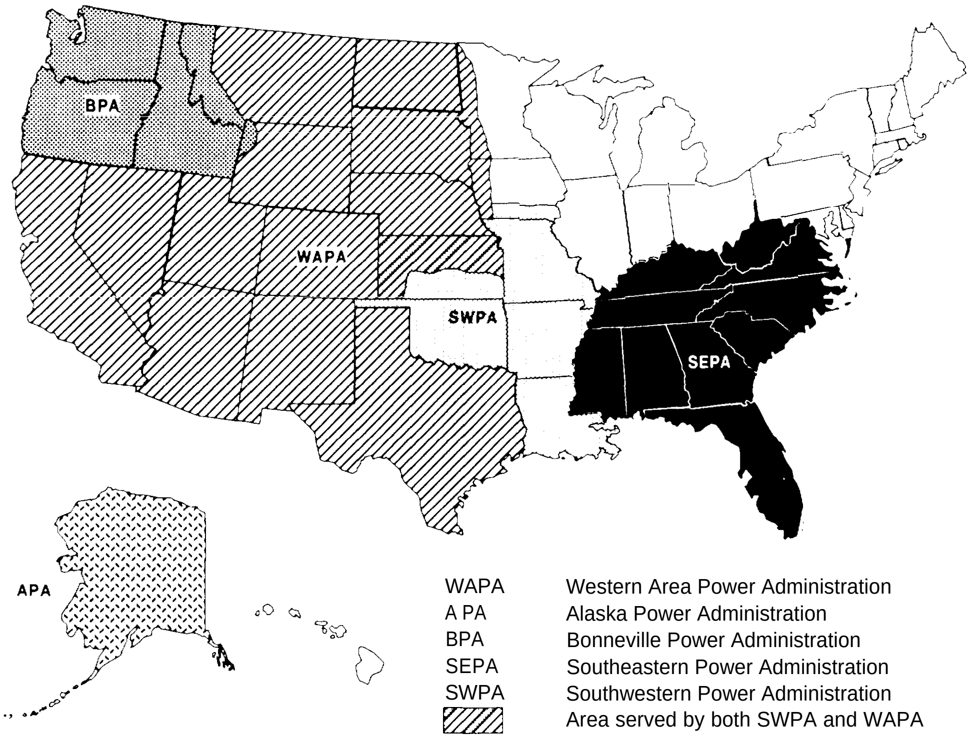
63 Ibid., pp. 37-38.

64 16 U.S.C. 831-831dd.

65 The Tennessee Valley region consists of Alabama, Georgia, Kentucky, Mississippi, North Carolina, Tennessee, and Virginia.

66 *U.S. Government Manual* 1991192, supra note 11, pp. 728-731.

Figure 74-Federal Power Marketing Administrations Service Areas



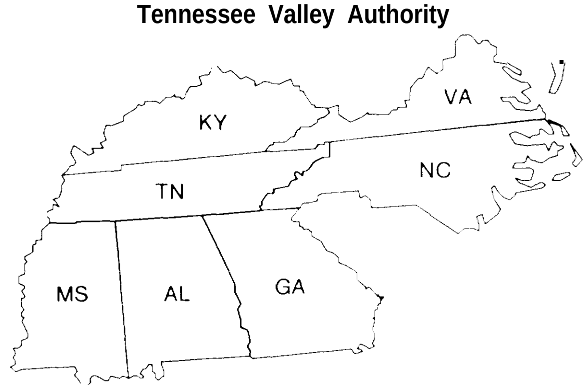
SOURCE: U.S. Department of Energy, The Secretary's Annual Report to Congress 1990, DOE/6-OO1OP (91), p. 160.

generation and over two-thirds of the electric operating revenues reported by the Federal electric utilities.[67]

While TVA's regional development programs are financed by congressional appropriations, the power program is required by law to be financially self-supporting through power sale revenues. Rates are to be set to cover capital and operational costs. Power system operations account for over 95 percent of the TVA budget.

In addition to hydroelectric plants, TVA maintains coal-fired powerplants, nuclear powerplants, combustion turbines, and pumped storage systems in its capacity base.[68] Table 7-9 provides statistics

Figure 7-States in the Service Area of the Tennessee Valley Authority



SOURCE: Office of Technology Assessment, 1993, based on data from the Office of Federal Register, The *United States Government Manual 1991/92* (Washington, DC: U.S. Government Printing Office, 1991).

67 *Financial Statistics of Selected Publicly Owned Electric Utilities 1990*, supra note 59, p. 337.

68 Coal-fired steam plants now account for 55 percent of TVA's capacity and provide about 70 percent of the daily load. To comply with regulations required by the 1990 Clean Air Act Amendments, TVA estimates that it will invest more than $1 billion on new pollution control technologies by 2000, increasing annual operating costs by $300 million. William Malec, "TVA Re-Examines the Nuclear Option," *Forum for Applied Research and Public Policy,* winter 1991, p. 89.

Table 7-9-Tennessee Valley Authority Power System Statistics, 1990

Power system operators	Million kWh
System sales	
Municipalities and cooperatives.	96,748
Federal agencies.	2,336
Industrial customers.	17,134
Total sales.	116,483
Power delivered under cogeneration agreement.	1,168
Losses, etc..	3,135
Total system output.	120,768
System generation by source	
Hydro (includes pumped storage)....	21,654
Coal-fired.	78,504
Nuclear.	15,275
Combustion turbine.	203
Total net generation.	115,636
Purchased power.	959
Net Interchange and wheel ing.	4,191
Total system Input.	120,786

SOURCE: Office of Technology Assessment, 1993, based on data from *Tennessee Valley Authority 1990 Annual Report,* November 1990.

on the TVA power system. TVA also coordinates power output from Corps of Engineers dams in the Cumberland Valley and from Aluminum Company of America dams.

In the recent past TVA ran extensive energy conservation programs. However, in 1989 most of these efforts were terminated by TVA's board, citing the financial stresses facing the system. From 1985 to 1988, TVA rate hikes averaged 4.5 percent a year as the result of a combination of a problematic nuclear program, expensive repairs on coal-fired plants, and diminished hydroelectric production because of drought.[69] TVA's management felt its customer base was threatened as some of TVA's largest customers, including Memphis Light Gas & Water, which then accounted for 10 percent of kilowatt-hour sales, began to explore alternative power supply options.

To secure its base of distributors, TVA promised to freeze electricity rates for three years beginning in 1988. Among the various actions taken to reduce operating costs was elimination of most energy conservation programs. TVA officials gave two reasons for discontinuing conservation programs. First was the pledge not to raise rates for the 3-year period. TVA's managers reasoned that if sales declined because of successful conservation efforts, rates would likely have to increase as fixed costs were spread over fewer sales. TVA feared that increased rates would induce large customers to leave the system, leading to further decline in sales. Second, TVA cited an internal analysis that concluded that it had exhausted cost-effective conservation options.[70] In TVA management's view, finishing the partially complete nuclear plants offered more cost-effective options than continuing conservation programs to meet future electrical supply. In the summer of 1988, the TVA board of directors approved a transition program that began cutting the conservation staff. In 1989, then TVA Chairman Marvin Runyon stated: ''Conservation will add to our rates. ' '[71] In spring 1989, the board voted to terminate residential conservation programs, cut personnel from 600 to 280, and reduce the budget from $40 to $20 million.[72]

Prior to termination, TVA conservation programs were among the most extensive in the country, saving an estimated 913 MW in an 8-year period from home weatherization programs alone.[73] Average annula electricity use for

69 Roger L. Cole and Larry A. Pace, "The Power to Change: The Case of TVA, " *Training and Development,* August 1991, p. 59.

70 Tennessee Valley Authority, TVA Power Group, *Power Planning,* attachment in *Hearings on TVA Conservation Programs* before the Subcommittee on Energy and Power of the House Committee on Energy and Commerce, 101st Cong., 1st sess., June 29, 1989 (serial no. 101-60), pp. 190202.

71 Testimony of Marvin Runyon, Chairman, Tennessee Wiley Authority, ibid., p. 148,

72 Jim Cooper, U.S. Representative, ''What Is TVA's New Policy on Energy Conservation, " ibid, pp. 16-21.

73 Tennessee Valley Authority, ''Energy Services Report '87,' ' TVA/OP/CEM—88/17, 1988, p. 43.

Table 7-10-Tennessee Valley Authority Major Energy Conservation Programs, Fiscal Years 1977-87

Energy services	Number of Installations	Dollars loaned	Estimated annual savings (kWh)	Estimated cumulative savings (MW).
Residential				
Home weatherization.	601 ,282[b]	$375,001,000	1,802,300,000	913.0
Sunscreens.	2,626	490,000	2,100,000	1.0
Heat pumps. , ...	53,103	166,555,000	188,500,000	58.4’
Heat-pump water heaters.	1,504	1,108,000	4,100,000	0.8
Wood heaters.	16,246	4,484,000	79,100,000	55.4
“Cycle and Save”				
Air conditioner cycling.	53,287’	—		54.0
Water heater cycling.	57,037[d]	—	—	79.4
“Energy Saver” homes.	22,518	—	99,900,000	30.8
Commercial and Industrial				
Energy management surveys. .	26,500	4,947,000	838,600,000	173
Other programs, ...	n/a	n/a	50,200,000	14
Total.	834,103	$552,585,000	3,064,800,000	1,411

[a]Values shown are maximum seasonal reductions.
[b]Includes residences weatherized with TVA loans, without TVA loans, and residences weatherized in a joint effort with Community Action Agencies.
[c]Does not include switches installed on 12,324 heat pumps.
[d]Does not include 2,882 switches installed on solar water heaters Or 75 switches on heat pump water heaters.
‘Refers to number of buildings surveyed.
Includes savings attributable to "Cycle and Save” switches.

SOURCE: Tennessee Valley Authority, “Energy Services Report, 1987,” TVA/OP/CEM-88/17, p. 43.

TVA residential customers was 50 percent higher than the national average due to the large number of homes heated by electricity .74 Residential customers received services ranging from free audits to interest-free loans to financing for installation of conservation measures. In 1987, TVA celebrated the completion of 1 million home energy surveys. TVA had an extensive engineering staff assisting individual commercial and industrial customers with tailormade conservation programs. Additionally, industrial customers were eligible to receive information on relevant new technologies from TVA representatives. TVA also participated in a number of energy efficiency R&D efforts. TVA demonstration programs showcased innovative home designs, new water heaters, radiant barriers, and photovoltaics and helped confirm the cost, reliability, and availability of these emerging technologies.[75] Table 7-10 highlights the major conservation programs pursued by TVA.

After 1989, the programs remaining in TVA’s conservation budget are primarily educational and information programs and strategic load management. The information programs include distributing energy sourcebooks and other teaching materials, and operating a TVA energy center for teachers and students. The consumer energy efficiency information program provides brochures to customers on appliances. The Energy Management Program provides technical assistance to Tennessee county governments in identi-

74 About 40 percent of TVA residential customers rely on electric heat compared with 20 percent of homes nationally. Ibid., p. 6.

75 Ibid., pp. 1-34.

fying opportunities for installation of energy-saving measures financed with State and Federal conservation funds.

The load management programs are designed to maintain and expand TVA's customer base load. In the industrial sector, TVA is encouraging the use of electrotechnologies. In the residential sector, the focus is on promoting construction of all-electric homes. TVA "energy conservation" programs have effectively shifted in focus from saving kilowatt-hours to strategic load marketing and demand growth.

The Industrial Energy Services program is a technical assistance program that works with the largest industrial customers to determine their energy requirements. TVA personnel then identify how to meet energy requirements cost-effectively and promote use of electrotechnologies. TVA estimates that 20 percent of activity in this program is concentrated on energy efficiency improvements.[76]

In 1989 TVA established the Residential Energy Service Program (RESP), which provides technical and financial assistance for installation of energy-efficient electric heat pumps, and information on electric hot water heating systems. RESP is currently budgeted at $10.5 million. TVA offers bounty payments to distributors who successfully encourage construction of new all-electric homes.[77] RESP was designed to "help TVA maintain a desirable balance between summer and winter peaks by helping maintain winter water heating and space heating loads."[78] TVA provides the loans and support materials to its distributors which are responsible for the administrative costs. If a distributor does not participate, customers in its service area are not eligible for the loans.[79]

Under the stewardship of Marvin Runyon, TVA was poised to expand its generating capacity and "committed itself to nuclear power as an integral source for meeting the energy needs of its service area."[80] TVA demand is growing 1.5 to 4 percent a year according to TVA load forecasts. TVA plans have called for completing four nuclear powerplants currently in the construction or licensing stage by 2000.[81] With the five units already licensed, TVA anticipates that nuclear power will supply 40 percent of its annual generation by 2000. This additional power will be used to meet projected growth in demand.[82]

With passage of the Energy Policy Act of 1992, TVA's determination to eschew energy efficiency and build new nuclear generating capacity may be stalled and its future path redirected. Section 113 of the act requires TVA to establish a least-cost planning program to develop a resource plan with the lowest system cost.[83] The planning process must consider supply and demand resources, including renewable resources, energy conservation and efficiency, on a consistent and integrated basis. TVA must incorporate opportunities for its distributors to recommend cost-effective energy efficiency opportunities,

76 Tennessee Valley Authority, attachment to testimony, in *Hearings on TVA Conservation programs,* supra note 70, at p. 160.

77 Report submitted by Representative Jim Cooper, *Hearings on TVA Conservation Programs,* supra note 70, pp. 17-21.

78 Ibid, p. 17.

79 Ibid, p. 16-25.

80 William Malec (Senior Vice President and Chief Financial Officer, Tennessee Valley Authority), "TVA Does Not Need To Be Privatized," *Public Utilities Fortnightly,* Feb. 15, 1991, p. 28.

81 In early 1993 TVA's board voted to proceed with construction of the mothballed unit of the Bellefonte nuclear plant, finish work on two units at Browns Ferry, and bring Watts Bar Unit 1 on line in 1994. Ed Lane, "In Debt and Off Line: Uncertain Future Faces Nuclear-Driven TVA," *Energy Daily, May 4,1993, pp. 3-4.*

82 William F. Malec, "TVA Re-examines the Nuclear Option," *Forum for Applied Research and Public Policy,* winter 1991, pp. 87-90.

83 Public Law 102-486, Oct. 24, 1992, sec. 113, 102 Stat, 2798, 16 U.S.C. 831m-1. Section 113(b)(3) defines system cost as "all direct and quantifiable net costs for an energy resource over its available life, including the cost of production transportation, utilization waste management, environmental compliance, and in the case of imported energy resources, maintaining access to foreign sources of supply."

rate structure incentives, and renewable energy proposals for inclusion in the program.

In planning and selecting new resources, TVA must evaluate the full range of existing and incremental resources (including new power supplies, energy conservation and efficiency, and renewable energy resources) in order to provide adequate and reliable services to its customers at the lowest system cost. The act further requires TVA to provide opportunity for public review and comment before selection of any major new energy resource and include a description of the action in its annual report to the President and the Congress

TVA was also directed to encourage and assist distributors in the planning and implementation of cost-effective energy efficiency options and authorized to provide a range of technical and financial services to advance these efforts.

The impact of these requirements on TVA's nuclear plans and its conservation programs remains to be seen. The act set no schedule for TVA's least-cost planning process and did not include any explicit mechanisms for enforcement or 'review. TVA is moving forward to develop expanded energy conservation programs and preparing comprehensive DSM analyses for the upcoming integrated resource planning process.[84]

Bonneville Power Administration

BPA, established in 1937, is the Federal electric power marketing agency in the Pacific Northwest.[85] BPA markets hydroelectric power from 21 multipurpose water resource projects of the U.S. Army Corps of Engineers, and 9 projects of the Bureau of Reclamation, plus power from nonfederal generating plants. These generating stations and BPA's 14,794 miles of transmission lines and 389 substations make up the Federal Columbia River Power System. In marketing its power, BPA must give preference to publicly-owned utilities and electric cooperatives.

BPA is the largest power wholesaler in the Northwest, supplying half of the electricity and operating almost 80 percent of the region's high-voltage power transmission capacity. BPA sells power at wholesale to local utilities and also provides power to a small number of large direct-service industrial customers[86] and to other Federal agencies. It participates in seasonal power exchanges and maintains power coordination and transfer agreements with utilities in other regions and in Canada.

Under its authorizing legislation, BPA may build and operate transmission facilities and market power, but it is not authorized to build or own power generation facilities. To meet its firm power contracts with its customers, BPA supplements its Federal hydropower supplies with purchases from other utilities. Under the Pacific Northwest Power Planning and Conservation Act of 1980, BPA's selection of nonfederal supply and demand resources to meet its customers energy needs is guided by a collaborative planning process.[87] The act also gave BPA responsibility for technical and financial assistance for energy conservation and renewable resource development, and for fish and wildlife protection in the Columbia River drainage basin.

84 Meg McKnight, TVA Government Relations Office, Washington, DC, personal communication, Apr. 14! 1993.

135 Act of August 20, 1937 (The Bonneville Project Act), as amended, 16 USC 832 et seq. BPA serves Oregon and Washington and parts of Montana, Nevada, Utah and Wyoming.

86 There are currently fewer than 20 direct service customers, but when they are operating at capacity, they account for some 17 percent of BPAs power sales. They include a number of electricity-intensive industries: aluminum smelters, electroprocessing plants, pulp and paper mills, and chemical companies. Northwest Power Planning Council, *1991 Northwest Conservation and Electric Power Plan*, vol. 1,91-04 (Portland, OR: Northwest Power Planning Council, April 1991), p. 9.

87 Public Law 96-501, 94 Stat. 2697, Dec. 5, 1980, 16 U.S.C. 839-839h.

88 House Report No. 96-976, Part I, 96th Cong., 2d sess., May 15, 1980, pp. 23-30.

The House Report provides some of the background history that led to the legislation.[88] For over 40 years, the Columbia River system was able to provide the power requirements of BPA's preference customers, Federal agencies, investor-owned systems, and direct-service industrial customers. The region enjoyed some of the lowest electric rates in the country. In the 1970s, growing power demand was outstripping BPA's ability to meet customer needs from available hydroelectric resources. Extensive hydroelectric development also was blamed for declines in the region's fish and wildlife, and corrective measures to protect salmon and other species would reduce water flows for power generation. The BPA administrator warned that threatened power shortages could force it to curtail firm-power sales to investor-owned utilities and direct-service customers and to allocate available resources among the preference customers. To avoid this, BPA and the region's utilities then set forth on an effort to add nuclear and coal-fired generating plants owned by nonfederal entities to the Federal system. To help finance this capacity expansion, BPA entered into agreements with its preference customers that obligated BPA to purchase power generated from the new plants. In return, the selling utilities would receive credits on charges for power purchased from BPA.[89] However, this financing mechanism was foreclosed for additional resources by an adverse ruling by the Internal Revenue Service. Subsequent efforts also were derailed. The region's utilities and regulators scrambled to find some way to preserve their shares of BPA's low-cost hydro resources. At the same time, the cost of building new generating resources was climbing. By the late 1970s, BPA was selling wholesale electricity at 8 mills per kWh ($0.008/kWh) while power from new thermal powerplants would cost 10 times as much. The alternative of energy conservation, was being ignored, despite the existence of several successful programs demonstrating cost-effective electricity savings. Desperate for a solution, the actors turned to Congress.

The prescription was the Northwest Power Act of 1980. The House Committee report diagnosed the region's problems as follows:

> The opportunity for conservation of electric power in the region is great. Kilowatts saved cost a small fraction of the cost of producing an equivalent amount of kilowatts. All concede that a vast potential for energy conservation is being wasted in the region.
>
> As the costs of new generation have increased the potential for cost-effective conservation programs in the region have also increased. Unfortunately, the region appears to lack mechanisms to undertake an effective regional conservation effort. BPA has limited authority to carry out conservation programs, and no authority to borrow or underwrite funds to finance these programs. Individual utilities (particularly publicly owned systems) face many legal and practical problems which limit their conservation efforts. Further, under current conditions it could be several years before many customers of BPA preference customers will face the kind of price signals that would encourage them to invest money in cost-effective conservation measures.
>
> . . . In the absence of a coordinated regional power program, it is probable that conservation efforts in the region will be too slow, too scattered, and too modest to be effective; and the region would thus lose a good portion of conservation's potential economic benefit.[90]

The report concluded:

> The certain inability of the region to resolve its problems without legislation represents a serious economic, social, and environmental threat to the

88 House Report No. 96-976, Part I, 96th Cong., 2d sess., May 15, 1980, pp. 23-30.

89 This mechanism was used to finance three nuclear units of the ill-fated Washington Public Power System with BPA effectively guaranteeing repayment of bonds issued to pay for construction.

90 House Report 96-976, supra note 88, p. 26.

> region, and by implication to other regions of the country. The continued failure to use existing resources and conservation effectively and to plan efficiently for future needs raises the potential of severe regional electrical power shortages in this decade.[91]

The solution was to create a public planning process enabling States, localities, consumers, BPA customers, fish and wildlife agencies, Indian tribes, users of the Columbia River System, and the public to participate in the region's electric power decisionmaking process. The act authorized BPA to acquire additional resources on a long-term basis, consistent with the regional plan, and giving frost priority to conservation and renewable resources. It also clarified BPA's authority to enter firm power sale contracts with investor-owned utilities and direct service customers.

In form and practice, the regional planning process used by the Pacific Northwest Planning Council and BPA resembles utility IRP processes in wide use today. In 1980, however, the act marked a bold innovation in Federal and State collaboration. The act also required that conservation be treated as a resource, and that all resources be evaluated to determine the best and lowest-cost alternatives to meet the region's electricity needs. In planning and selecting resources, priority was to be given first to conservation; second, renewable resources; third, generating resources utilizing waste heat or generating resources with high fuel-conversion efficiency; and fourth, all other resources, including conventional thermal powerplants.[92] Box 7-F summarizes the planning process created by the act and the results of BPA's most recent resource plan.

BPA CONSERVATION ACTIVITIES

The Northwest Power Act of 1980 directed Bonneville to use conservation to the fullest extent possible in its resource mix and authorized a wide range of technical and financial assistance to encourage energy efficiency and renewable energy development.

BPA has had more than a decade of experience in developing, administering, and evaluating energy conservation programs. Its programs are extensive and serve customer utilities, residential, commercial, and industrial consumers, and State and local governments. Customer outreach provides technical and financial assistance for conservation measures. BPA pays part of the cost of residential weatherization. Hotlines inform commercial and industrial customers about emerging energy-efficient technologies. BPA has assisted State and local governments with the development and implementation of model energy conservation codes, and offered financial incentives to jurisdictions that adopt and enforce the codes. BPA also has underwritten extensive demonstration programs to test energy-efficient technologies and provide cost and performance information to their utility customers and others.

BPA's resource plans and energy conservation experience also contribute to the system's flexibility in responding to changing conditions. In April 1993 BPA outlined a number of emergency measures intended to head off or reduce a potential 25 percent rate hike on October 1, 1993. Among the circumstances that have contributed to the financial crisis were a drought that decreased sales and required BPA to purchase replacement power to meet its loads and the loss of one-quarter of its direct sales to aluminum companies. In an attempt to hold the price increase below 20 percent, BPA announced that

91 Ibid, p. *27.*

92 Northwest Power Planning and Conservation Act, Public Law 96-501, 1980, Sec. 4(e)(1). The definition of cost-effective in the act provides a 10 percent cost advantage to conservation resources. Section 3(4)(D) provides: "A conservation measure or resource shall not be treated as greater than that of any non-conservation measure or resource unless the incremental system cost of such conservation measure or resource is in excess of 110 per centum of the incremental cost of the non-conservation measure or resource. " 16 U.S.C. 839a(4)(D).

Box 7-F--Regional Power Planning: The Bonneville Power Administration and the Pacific Northwest Power Planning Council

'Ten years ago, the Pacific Northwest embarked on a grand experiment It was a test initiated by the Northwest Power Act of 1960, to determine whether four states, sharing common needs and assets, could coordinate their efforts to ensure their people energy services at the lowest possible cost."[1]

Northwest Power Planning Council, April 1991

The Northwest Power Planning Council

The Pacific Northwest Electric Power Planning and Conservation Act of 1980[2] created the Northwest Power Planning Council to develop a long-term regional conservation and electric power plan to guide the Bonneville Power Administration's resource planning and selection. The act requires that BPA's resource acquisition be consistent with the council's recommendation and resource acquisition proposals must have council approval.[3] The plan is to be updated at least every 5 years. The Council is authorized to monitor and report on implementation of the resource plan and efforts at depbyment of conservaton and renewable energy resurces in the region. The act also gave the Council responsibility for developing a program to protect and enhance fish and wildlife and related spawning grounds and habitat on the Columbia River and its tributaries.[4]

Collaboration between State and Federal agencies and public review and involvement are key features of the Northwest planning process. The Council consists of two members each from Washington, Oregon, Idaho, and Montana Council members are appointed by the Governor of each State. The act provides for public hearings on the proposed plan and for an ongoing public information and outreach program to involve State and Federal agendas, Indian tribes, customers, and the public In the planning process.

The Planning Process

The act specifies that the regional conservation and electric power plan must contain:

1. an energy conservation program, including model energy Conservation standards;
2. recommendation for research and developmet,
3. a methodology for quantifying environmental costs and benefits in evaluating the cost-effectiveness of resource options;
4. a 20-year demand forecast covering the amount and types of resources needed to rneet BPA obligations impacts of fish and wildlife protection, and estimates of the resources to be acquired on a long- term basis;
5. an analysis of the resources required to assure adequate and reliable electric power at the lowest probable cost and the met-effective means of providing them;
6. the fish and wildlife protection, mitigation, and enhancement program; and
7. recommendations, if any, for surcharges to be imposed on customers not implementing energy conservation standards.[5]

Energy conservation and renewable energy resources are given the highest priority for new resources. The act provides that conservation resources are to be given a 10 percent advantage in cost-effectiveness determinations. The Council has developed three regional power plans. The most recent one was released in April 1991.

The 1991 Northwest Conservation and Electric Power Plan sets forth the planning council's estimates of power needs and recommendations for resource acquisition.[6] The early plans weredeveloped during a timewhen

[1] Northwest Power Planning Council, *1991 Northwest Conservation and Electric Power Plan*, vol. 1, 91-04 (Portland, OR: Nortwest Power Planning Council, April 1991), p. 3.

[2] Public Law 96-501, 94 Stat. 2697, Dec. 5, 1980, 16 U.S.C. 839-839h.

[3] Any resources that Bonneville wants to acquire that aren't consistent with the plan must be approved through an Act of Congress.

[4] Public Law 96-501, sec. 4, 94 Stat. 2705-2706, 16 U.S.C 839b.

[5] 16 U.S.C. 839b(e).

[6] Northwest Power Planning Council, *1991 Northwest Conservation and Electric Power Plan*, vol. 1, 91-04 (Portland, OR: Northwest Power Planning Council, April 1991).

the region faced an energy surplus from the overbuilding in the 1970s. The 1991 plan addresses a tightening power supply. The plan forecasts a potential for a capacity deficit by the turn of the century unless new resources are acquired.

The plan analyzed a number of electricity demand growth scenarios ranging from one where average demand declines at a rate of-0.4 percent per year to one with a high growth rate of 2.5 percent per year, however more emphasis was placed on mid-range growth levels of 0.6 to 1.7 percent per year.[7] The council developed several alternative resource portfolios containing various mixes of supply and demand resources capable of meeting the full range of energy demand reflected in the scenarios. Potential supply and demand resources were evaluated by examining total costs including direct costs and environmnental impacts, and reliability. Other evaluation criteria included lead times, size, and capital cost. Based on its analysis and public comment, the council plan adopted four objectives for a regional energy strategy.

1. *Acquiring all low-cost resources-The* plan recommends that BPA and regional utilities acquire 1,500 average megawatt (aMW)[8] of conservation and energy efficiency improvements at a total cost to utilities and customers of $7 billion (see figure on next page). This would entail aggressive efforts to install efficiency measures in the residential, commercial, industrial and agricultural sectors at a level many times greater than current DSM and conservation programs. Efficiency improvements in powerplants, transmission, and distribution facilities would contribute 360 aMW of conservation savings. In addition, the plan callsfor 150 aMWof new, low-cost hydropower and 650 aMWof low cost industrial cogeneration by the year 2000.[9]
2. *2. Shortening lead times needed to bring new resources into operation to enable quick and flexible responses to rapid load growth. The* plan would reduce lead times by beginning inexpensive pre-construction preparations such as siting, permitting, licensing, design, contracts, and other approvals to enable addition of 100 aMWof new hydropower and up to 750 aMW of cogeneration to resource plans if demand growth is higher than anticipated. These pre-construction activities often are among the most time-consuming in developing new power resources. The council also recommends that BPA and utilities investigate cost- effective backup power supplies for 1,500 aMW of the region's non-firm hydropower to accommodate potential impacts of fish and wildlife protection programs. Good candidates for "hydrofirming" include interregional energy transactions, increased interruptible loads and gas fired combustion turbine plants.[10]"
3. *Confirming* the cost and *availability of additional resourocs that could be incorporated into future* plans--The plan callsforsupport of research, development, and demonstration efforts for resources that are not yet ready for utility-scale deployment including new energy conservation and renewable energy technologies (such as geothermal, wind, and solar generating technologies). Additionally, the council requests that BPA determine whether the continued preservation of its two uncompleted nuclear power plants remains a prudent insurance policy.[11] The council also suggests that BPA investigate

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7 Ibid., p. 17.

8 An average megawatt (aMW) is 8,760 megawatt-hours of_ or the amount of energy produced by continuous operation of 1 megawatt of generating capacity over a year. It Is distinct from a megawatt or MW used to refer to capacity, the maximum output of an electrical generator. Because most generators do not run continuously, securing 1 aMW of resources may require acquisition of more than IMW of capacity.

9 Ibid., pp. 31-36

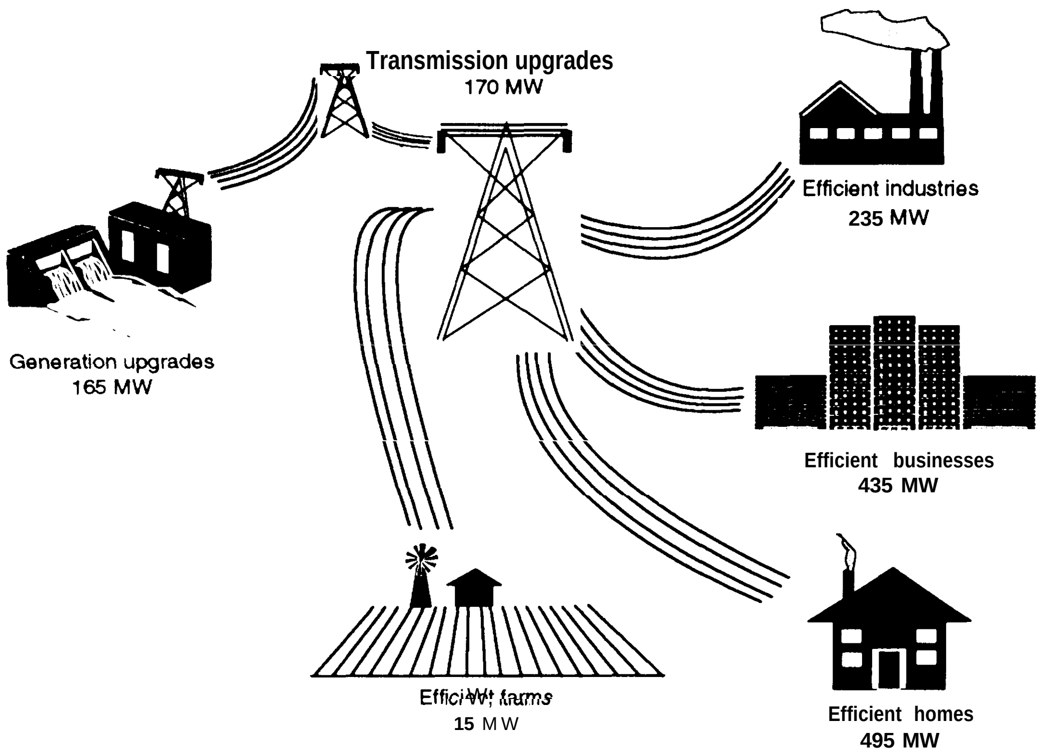
10 Ibid., pp. 36-38.

11 ibid., pp. 38-43. in April 1993, the Washington Public Power Supply System began proceedings to formally terminate *partially completed nuclear power plant that had been preserved in an unfinished condition since 1983. BPA is guaranteeing repayment of some $4.6 billion In revenue bonds sold to finance construction, It Is estimated that more than $3 billion would be necessary to complete the plants. BPA and regional planners have concluded that more than 5,000 MW from other sources at prices of $0.03/kWh making electricity from the two nuclear plants at an estimated $0.04/kWh uneconomic.

(Continued on next page)

Box 7-F–Regional Power Planning: The Bonneville Power Administration and the Pacific Northwest Power Planning Council--Continued)

Recommended Resource Acquisitions of the 1991 Northwest Conservation and Electric Power Plan



SOURCE: Office of Technology Assessment, 1993, from Northwest Power Planning Council, 1991 Northwest *Conservation and Electric Power Plan, vol.* 1, 91-04 (Portfand, OR: Northwest Power Planning Council, April 1991), figure 17, p. 33.

rapid-response resources replace 500 to 1,000 aMW of existing generating capacity should the need arise. Rapid-response resources include acquisitions through bidding, and alterations to existing combustion turbine resources. The council states that “if sufficient rapid-response resources cannot be identified, it may be necessary to seek interruptible loads and develop curtailment strategies until resources with longer lead times can be added.”[12]

4. *Encouraging regulatory and other Institutional changes to help implement theplan--The plan* details recommendations for a variety of actions by BPA State regulators, utilities and local governments to ease the implemental’bn of the council plan. Among the suggestions are that regulators consider changes to decouple profits from the energy sold and relink profits to energy saved and review policies to ease the siting and acquisition of generating resources. Regulators were encouraged to consider appropriate rate treatment for investing in activities that reduce resource lead times, and for participation in research activities to confirm/deny potential resources. Lastly, the council urged cooperation between regulatory

12 Ibid., pp. 31-43.

agencies and Bonneville **in the** issue of transmission access for non-utility generators.[13]

Responsibility for implementing the plan is shared by BPA and region's regulators and utilities backed by support of environmental, consumer groups and the public. The Council notes that it will monitor progress in addressing these recommendations.

BPA's 1992 Resource Program

Every two years BPA issues a 10-year resource program outlining its proposals for meeting electricity loads. The November 1992 resource program was the first adopted after the 1991 **Northwest Power Plan and identifies conservation as its preferred resource.** BPA assumed a 1 percent annual growth rate and proposed acquiring 1,530 **aMW.** In doing its part to meet regional electric needs, BPA proposes to:

- acquire all cost-effective conservation-targeting 880 aMW of conservation and 120 aMW of power system efficiency improvements through 2003 in its public utilities service areas (estimated cost $2.8 billion);
- acquire an additional 400 aMW of new generating resources to meet the most likely range of need through 1998; and
- purchase 250 aMW of options (rights to buy firm power at a specific time) to cover the outer range of need.[14]

BPA also plans to secure 1,050 aMW in options and contingent resources to provided needed capacity if demand growth is higher than forecast. BPA will reserve the right to cancel selected projects on option in exchange for reimbursing the sponsor's pre-development costs.

To accomplish its goal of accelerated acquisition of conservation resources, BPA is making major changes in the operation of its conservation programs and how it pays for energy savings. Program development and decisionmaking will shift from headquarters to BPA area offices which will collaborate with utilities and local communities in designing and implementing **local** conservation plans. Under the Northwest Power Act BPA can pay utilities and others for conservation resources that reduce BPA's loads. BPA anticipates securing conservation resources through:

- **utility adoption of BPA-sponsored programs;**
- **utility reimbursement** for costs of program administration and conservation measures installed; and
- utility or energy service company compensation for installation of conservation measures based on kwh saved.[15]

Instead of paying up-front, BPA plans to shift to pay-for-performance contracts that purchase measurable savings over time. Verification of energy savings will be required in the performance contracts. BPA expects utilities to provide a substantial portion of the necessary capital for installing conservation measures rather than relying on BPA to provide financing. BPA also will continue to require utilities that own generation to pay **a percentage** of the cost of conservation in their service area, based on the percentage of the utility's load supplied by BPA. This cost-sharing is required so that nongenerating utilities do not **pay** a disproportionate share of conservation program costs. For some utilities, current cost-sharing percentages have, however, created a financial impediment to meeting accelerated conservation targets and BPA is investigating alternative mechanisms for an equitable sharing.

The accelerated conservation path and will face several challenges. There will have to be unprecedented cooperation among all groups in the region to identify and install all commercially available cost-effective conservation measures. Utilities and governments will need greater staff, technical, and financial support from BPA to develop and carry out local conservation programs. Regulators will have to review policies and rate structures for possible conflicts with conservation goals.[16]

13 Ibid., pp. 43-44.

14 Bonneville power Administration, 1992 Reset.mx Program--10 Year Plan, *Draft II DOE/BP-1874* (Portland, OR: Bonneville Power Administration, May 1992), p. i, Draft II insubstantially identical to the final resource program released in November 1992.

15 Ibid., p. 48.

16 Ibid., pp. 26-33.

(Continued on next page)

Box 7-F–Regional Power Planning: The Bonneville Power Administration and the Pacific Northwest Power Planning Council--(Continued)

Savings to Date

In the view of the Northwest Power Planning Council, the act's grand experiment has been a clear success for the people of the Pacific Northwest:

> 'This region is convinced! Every Northwest utility is promoting efficiency through marketing programs and incentives. They have already saved more than 350 megawatts at a cost less than half of the power from a new generating plant Aluminum companies also have cut their consumption. And state energy office programs brought us another 200 megawatts.
>
> New energy-efficient building codes and appliance standards already adopted by Federal, State and local governments can save the region more than 1,300 average megawatts by the year 2010.
>
> In addition, if the region captures all the energy savings described in thisplan over the next 20 years, it could add another 4,600 megawatts of conservation."[17]

[17] 1991 Northwest Conservation *and Electric* Power *Plan* p. *20.*

SOURCE: Office of Technology Assessment, 1993.

it is cutting all programs by 25 percent, including conservation and fish and wildlife activities, and administrative programs by 50 percent. The cuts are not expected to change BPA's resource program goals, but likely will result in deferrals and slowdowns in prgram growth.

Western Area Power Administration

WAPA was established in 1977 under section 302 of the Department of Energy Organization Act to market power in a 15-State area generated from federally-owned powerplants operated by the Bureau of Reclamation, Corps of Engineers, and the International Boundary and Water Commission.[93] It also markets Federal entitlement power from the coal-fried Navaho Generating Station. WAPA operates and maintains 16,500 miles of transmission lines, plus associated substations to deliver power to its customers. Like BPA, Western's transmission resources are an important link in regional power systems. Westem serves some 532 wholesale customers, mostly public power systems and electric cooperatives supplying over 10 percent of the region's needs.[94] Other purchasers include investor-owned utilities and Federal and State agencies. Western supplies an average of 35 percent of its customers' power needs.[95]

In 1981 WAPA established its own conservation and renewable energy program with three objectives:

1. reducing wasteful uses of electricity through energy conservation;
2. enhancing the place of electricity in the energy market by making uses of electric power more efficient; and
3. ensuring that conservation and renewable energy technologies are fairly compared

[93] 42 U.S.C. 7152.

[94] States include Arizona, California, Colorado, Indiana, Kansas, Minnesota, Montana, Nebraska, Nevada, New Mexico, North Dakota, South Dakota, Texas, Utah, and Wyoming.

[95] Bill Clagett, Administrator, Western Area Power Admlhistration, letter to O'IX, Sept. 18, 1992.

with conventional resources when additional power is required.[96]

Title II of the Hoover Power Plant Act of 1984 essentially confined Western's conservation and renewable energy program and its pre-existing authority to condition contracts for Federal hydropower on customer adoption of conservation programs.[97] Indeed, the act explicitly requires new firm power contracts with WAPA to contain provisions obligating the purchaser to implement energy conservation programs. Unlike BPA, Western is not required to meet wholesale customer load growth, however, it must purchase power to make up for short-term power shortages in drought periods in order to meet its firm power contractual commitments. Western can withhold power from a customer that has not implemented conservation programs or that do not submit a plan within a year of signing a power contract.

Following the 1984 legislation, WAPA published amended guidelines and criteria for evaluating the adequacy of customer utilities' conservation programs.[98] Long-term firm power customers must submit a plan describing qualifying program activities, the implementation schedule, targeted goals, and energy savings estimates where feasible. Qualifying customer programs, include: energy consumption efficiency improvements; production efficiency improvements, load management, cogeneration, rate design improvements, and renewable energy resources (wind, solar, biomass, small-scale hydro, and geothermal technologies). Western allows considerable flexibility in program design. The acceptability of customer conservation and renewable energy plans is determined based on utility type and total system sales. For example, most customers with over 100 gigawatt-hours (GWh) per year in sales have been required to implement five individual programs. Customers with sales of less than 50 GWh per year need only submit three programs for acceptance.

Western provides additional support to customer utilities through a variety of information and technology transfer activities: workshops, information services, publications, direct technical assistance, onsite visits, equipment loans, and IRP computer software. Under a "peer matching' effort, Western has matched small customer utilities to others with first-hand experience and expertise in conservation and renewable energy technologies. This has been particularly helpful to small rural communities with limited staff and resources.

Estimates of energy or capacity savings resulting from the Western's requirements are not available at present. Western measures program accomplishments by the number of approved ongoing annual customer conservation and renewable energy activities. For FY 1992, Western reports almost 100 percent participation by the nearly 800 customers, with a total of 3,200 separate approved activities.[99] In any event, Western believes that because Federal hydropower is a low-cost resource, customer conservation activities would likely not be used to reduce their power purchases from WAPA, but rather to offset their own higher-cost thermal power supplies from utilities' own generation or from others. In 1990 electricity savings from operating conservation programs were insufficient to offset the power loss caused by drought conditions. Western spent an additional $267 million for power purchased during the drought.[100] Because

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96 Ibid.

97 Public Law 98.381, Aug. 17, 1984, 98 Stat. 1333-1342, 42 U.S.C. 7275. Pre-existing conditioning authority was derived from the Department of Energy Organization Act, 42 U.S.C. 7101, et seq., and the Reclamation Act of 1902, as amended.

98 50 Fed. Reg. 33,892-33,899, Aug. 21, 1985.

99 Bill Clagett, Administrator, Western Area Power Administration, letter to OTA, Sept. 18, 1992.

100 General Accounting Office, "Utility Demand-Side Management Programs Can Reduce Electricity Use,' GAO/RCED-92-13, October 1991, p. 33.

of Western's statutory responsibility to market available Federal hydropower and contractual obligations to supply power to its customers (including replacement power supplies in times of drought), customer DSM programs will not reduce the amount of power that Western markets. They may, however, allow that low-cost resource to serve a higher portion of customer requirements and to be shared more equitably.

Proposed revisions to WAPA'S conservation program begun in 1990 and now under review would add requirements for adoption of IRP programs and also would require customers to quantify energy and capacity savings from their programs. Changes would also directly link allocation of hydro resources to long-term planning and efficient use of resources and impose surcharges on customers that did not comply.[101]

Many elements of WAPA'S proposed Energy Plannin g and Management Program were adopted by section 114 of the Energy Policy Act of 1992, which amends the Hoover Power Plant Act of 1984 to add a new title on IRP. WAPA must promulgate rules within 1 year amending renewable resource and conservation plan requirements for its long-term firm power customers to include provisions calling for customer utilities to implement IRP within 3 years. WAPA is to provide technical assistance to customer utilities in developing IRP programs and review the plans prepared. Definitions of IRP, system costs, and least-cost resource options in the act require evaluation of supply and demand resources in a consistent, integrated manner to select options that minimize life-cycle costs including adverse environmental effects, and give priority to energy efficiency and renewable energy to the extent practicable. Failure to submit a plan or to comply with an approved plan will trigger surcharges of from 10 to 30 percent on purchases from WAPA. Alternatively, the Administrator can curtail power allocations by 10 percent until a customer complies. No penalties will be imposed if the Administrator determines that the utility has made a good faith effort to comply. Several provisions were added in recognition of the diversity of Western's customer utilities and to avoid duplication of requirements by State regulators or others. For example, two or more utilities can collaborate to submit joint IRP plans, and plans prepared under State or other IRP programs can also be accepted by WAPA.

Southwestern Power Administration

SWPA operates as the marketing agent for Federal hydroelectric power in a six-State area.[102] It was created in 1943 by the Secretary of the Interior for the transmission and sale of electric power from certain Corps of Engineers reservoir projects and assumed responsibilities under the Flood Control Act in 1944. SWPA has been under the direction of DOE since 1977.[103] Under various authorizing legislation, SWPA'S mandate is to market Federal hydropower to encourage the most widespread and economical use at the lowest possible cost, consistent with sound business principles.[104] SWPA supplements its power supplies with power purchased from public and private utilities to meet its contractual obligations. By law, publicly-owned utilities and cooperatives receive preference in power allocations. SWPA operates and maintains some 1,380 miles of transmission lines, 24 substations and switching stations, and 39 radio and microwave stations.[105] With these facilities, SWPA sells power wholesale to public utilities and cooperatives. SWPA is also responsible for scheduling and

101 *Western Area Power Administration Update*, June 1992, pp. 1-2.

102 The States are Arkansas, Kansas, Louisiana, Missouri, Oklahoma, and Texas.

103 Department of Energy Organization Act, 91 Stat. 578, 42 U.S.C. 7152.

104 16 U.S.C. 825s.

105 U.S. *Government Manual* 1991/92, supra note 11, p. 283.

dispatching power, negotiating power sales contracts and constructing facilities, and participating in comprehensive planning of water resource development. Rates to its customers are adjusted to ensure full recovery of Federal investment.

According to a GAO report, SWPA sought to clarify its authority to require its customers to adopt DSM programs. DOE's Office of Conservation and Renewable Energy responded that ''SWPA has implicit authority under Section 5 of the Flood Control Act of 1944 to encourage conservation programs among customer utilities, and could propose in the absence of more explicit legislative authority, conservation programs through rule-making actions, subject to departmental approval. '[106] DOE noted, however, that any attempts to implement programs could be subject to challenge in the courts.

SWPA supports various activities to encourage DSM and IRP. It maintains a program to loan energy-efficient equipment for its customers and provides technical assistance through workshops. Together with WAPA and others, it is jointly funding a project to prepare detailed IRP manuals to assist utilities in developing and implanting IRP programs.

Southeastern Power Administration

SEPA was created in 1950 by the Secretary of the Interior to carry out the functions of the Flood Control Act.[107] SEPA operates under the general mandate to encourage widespread use of electricity from Federal hydro projects at the lowest possible rates consistent with sound business principles and to give preference to publicly-owned utilities. Responsibilities include providing for the transmission and sale of surplus electric power generated at Corps of Engineers reservoir projects in a 10-State area of the Southeast.[108] SEPA does not own or operate any transmission facilities of its own; transmission lines owned by other utilities deliver the power. SEPA markets power from a total of 22 Federal multipurpose water projects, giving preference to public bodies and cooperatives. Using the region's large private utilities, SEPA negotiates wheeling and pooling arrangements to provide firm power to its customers. Rates charged to customers are adjusted to ensure that the Federal Government recovers its investment plus interest. Oversight of SEPA programs was transferred to the newly created DOE in 1977.[109]

SEPA does not have any explicit statutory mandate to promote DSM, IRP, or regional cooperation in power planning. However, like SWPA its authorizing legislation has been interpreted to support initiatives to promote energy conservation.[110] Southeastern is offering energy-efficient training programs for cooperatives and municipalities.

Alaska Power Administration

APA is responsible for the operation and maintenance of the Snettisham and Eklutna hydroelectric generating projects in Alaska and markets the power produced. APA also operates associated transmission systems serving Anchorage and Juneau.

For the past several years, DOE has been negotiating with the State of Alaska to sell the assets. The Alaska Power Administration Sale Authorization Act submitted to Congress by DOE

[106] General Accounting Office, "Utility Demand-side Management Programs Can Reduce Electricity Use," GAO/RCED-92-13, October 1991, p. 37.

[107] 53 Stat. 890.

[108] The States include Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee, Virginia, and West Virginia.

[109] Department of Energy Organization Act of 1977, Public Law 9s-91, as amended, sec. 302, 42 U.S.C. 7152.

[110] General Accounting Office, ''Utility Demand-Side Management Programs Can Reduce Electricity Use," GAO/RCED-92-13, October 1991, p. 37,

in June 1992 would sell the 78-MW Snettisham project to the Alaska Energy Authority and the 30-MW Eklutna project to three electric power utilities serving the Anchorage area. Over 90 percent of the State's electricity is now provided by nonfederal generating sources leading DOE to conclude that there is no longer a need for APA.[111]

APA has been assisting a customer utility with evaluating and testing demand as well as supply--side energy efficiency measures.

RURAL ELECTRIFICATION ADMINISTRATION

REA is a credit agency within the U.S. Department of Agriculture (USDA) that makes loans and loan guarantees to finance the construction and improvement of electric power systems to serve the needs of rural areas. The agency was established during the New Deal to extend electric service to remote areas not served by private utilities.[112] REA loans enabled borrowers to form electric cooperatives to build power lines for transmission and distribution of wholesale power purchased from private utilities or from Federal hydroelectric facilities. REA also guarantees loans made by others, and approves security arrangements that permit borrowers to obtain financing from other lenders without a guarantee.[113] Since the 1960S, REA has made loans for the construction of generating and transmission facilities "to protect the security and effectiveness of REA-financed systems. ' '[114] REA is also authorized to provide technical assistance to its borrowers to aid system development and to protect loan security. In 1990, there were 897 cooperative borrowers; 838 were distribution borrowers and the remaining 56 were generation and transmission cooperatives. (See table 7-12.)

Loans are made through the Rural Electrification and Telephone Revolving Fund created in 1973. By law, REA loans are made at a 5 percent interest rate and as low as 2 percent for extreme hardship, and for years REA rates were below the prevailing market rates for direct borrowing.[115] REA requires most borrowers to obtain 30 percent of their financial needs from outside sources to comply with a statutory requirement added in 1973 directing REA to encourage rural electric systems to enhance their ability to obtain financing from their own financial organizations or other sources.[116] Many cooperatives obtain this financing from the National Rural Utilities Cooperative Finance Corporation and the Bank for Cooperatives.

REA loan guarantees have been made primarily to large-scale facilities and are subject to the same requirements as direct loans. Interest rates on guaranteed loans are established at rates set by the borrower and the lender with REA concurrence. Since 1974, the Federal Financing Bank (FFB) has purchased obligations guaranteed by the REA, although all borrower dealings were with REA. A 1981 amendment to the Rural Electrification Act required the FFB to make loans under an agency guarantee if requested to

111 "Federal Power Projects in Alaska Will Be Sold to Private Owners," *Inside Energy with Federal Lands*, June 29, 1992, p. 7. Proposals for privatizing the PMAs have been circulating for more than a decade through both the Reagan and Bush Admiistrations and have met stiff resistance from members of Congress and the PMAs customers. Of all the proposals, the one to sell APA has been the least controversial.

112 Rural Electrification Act of 1936, 7 U.S.C. 901-950b.

113 *U.S. Government Manual 1991192,* supra note 11, p. 114.

114 *Financial Statistics of Selected Publicly Owned Electric Utilities 1990*, supra note 59, p. 347.

115 *U.S. Government Manual 1991/92*, supra note 11, p. 114. Interest rates on the direct borrowing have historically been several points higher than the 5 percent maximum charged on loans. More REA funds have been lent out than repaid since 1973 and the deficit is made up by direct borrowing and sale of Certificates of Beneficial Ownership to the Federal Financing Bank in the U.S. Treasury.

116 ". . . that rural electric and telephone systems should be encouraged and assisted in developing their resources and ability to achieve the financial strength needed to enable them to satisfy credit needs from their own financial organimations and other sources at reasonable rates and terms consistent with the loan's applicant's ability to pay. ' Ibid.

do so by a utility who held a guarantee. Now, most REA-guaranteed loans are made by the FFB.[117]

In January 1992, REA issued a final rule revising the requirements for general and preloan procedures for insured and guaranteed electric loans.[118] These regulations were in large part a recodification of many of REA's existing policies and rules. REA loan requirements contain several provisions that encourage IRP and utility energy efficiency programs. All borrowers are encouraged to promote energy efficiency and load management to improve system load factors, reduce losses, and reduce the need for new generating capacity.[119] Most REA borrowers must prepare and maintain power requirements studies (PRS) and construction work plans (CWP) for review and approval by REA. Together the PRS and CWP require a borrower to establish a comprehensive and integrated planning system to guide operations and resource acquisition, effectively an IRP process.[120] To qualify for new loans, a borrower must demonstrate to REA that it has explored all practical and feasible alternatives to adding new capacity, including improved load management, energy conservation, and power purchases from other suppliers, including independent power producers. REA believes that the rule changes are expected to lead to a more effective power planning process.

Table 7-1 l—Rural Electrification Administration Cooperative Distributor Borrowers: Consumers, Sales, and Operating Revenue 1990

Number of consumers on December 31	
Residential	9,732,694
Commercial and industrial	915,363
Other sales to ultimate consumers	153,324
Total ultimate consumers	10,801,381
Sales for resale,	203
Total consumers	10,801,584
Sales for the year (mWh)	
Residential	111,776,522
Commercial and industrial	65,794,723
Other sales to ultimate consumers	5,814,007
Total sales to ultimate consumers	183,385,252
Sales for resale	3,095,647
Total Sales	186,480,899
Operating revenues for the year ($000)	
Residential	8,403,275
Commercial and industrial	3,806,505
Other sales to ultimate consumers	374,504
Total sales to ultimate consumers	12,684,284
Sales for resale	121,008
Total revenue from sales of electricity	12,805,290
Other operating revenues	196,248
Total operating revenues	13,001,538

NOTES: Totals may not equal sum of components because of independent rounding. This table does not included in 1990 the 56 Power Supply Borrowers. Data for 1990 represents 838 Distribution Borrowers.

SOURCE: Office of Technology Assessment, 1993, based on data from U.S. Department of Energy, Energy Information Administration, *Fhancia/Stat/sties of Selected Publicly Owned Electric Utilities 1990, DOE/EIA-0437(90)/2* (Washington, DC: U.S. Government Printing Office, February 1992), table A4, p. 349.

FEDERAL ENERGY REGULATORY COMMISSION

FERC regulates prices, terms, and conditions of wholesale power sales and rates involving privately-owned power companies and of transmission of electricity at wholesale.[121] With the growth of wholesale transactions in the utility sector, FERC now regulates about one-third of electricity sold. FERC also approves rates for power sold and transported by the five power marketing administrations.

There have been suggestions that FERC could as a matter of policy under its existing broad authority over wholesale transactions require utilities selling power at wholesale to engage in IRP and offer DSM programs and require sellers to demonstrate that a proposed sale is consistent

117 Ibid.

118 57 Fed. Reg. 1,0441,068, Jan. 9, 1992.

119 7 CFR 1710.118, 57 Fed. Reg. 1061, Jan. 9, 1992.

120 7 CFR 1710.200-1710.206 and 7 CFR 1710.2501710.254, 57 Fed. Reg. 1062-1066, Jan. 9, 1992.

121 16 U.S.C. 791a, 824a, and 824d. FERC authority is discussed in ch. 3 of this report.

with the buyer's approved IRP program. For example, President Bush's National Energy Strategy suggests FERC promote utilities' use of IRP through its rulemaking authority and its regulatory powers.[122] To open discussions, from 1991 to 1992 FERC held several workshops with State regulators to explore IRP, transmission, and market-based pricing issues. However, FERC has not yet defined any potential role in promoting IRP or DSM, nor has it been actively pursuing issues related to energy efficiency or least-cost planning for utilities engaged in wholesale power sales and transmission.

ENCOURAGING VOLUNTARY EFFORTS

In recent years, there has been growing interest in mechanisms that the Federal Government can use to provide various incentives to utilities and others to implement energy efficiency programs voluntarily. These efforts are in addition to, and not a replacement for, the variety of programs that establish more or less mandatory requirements for utilities or that offer technical and financial assistance to aid utility energy efficiency and planning. Examples of this approach include the "green programs" in EPA's office of climate change, the conservation and renewable energy emissions allowances reserve under the Clean Air Act Amendments, and energy efficiency awards programs for Federal facility managers.

EPA's Green Programs

The EPA Office of Atmospheric Programs has embarked on several initiatives designed to encourage the voluntary adoption of energy-efficient and pollution-reducing technologies as part of EPA's global climate change activities. EPA's green programs marshall the agency's stores of good will, credibility, and visibility in combination with market forces to attract commercial, industrial, utility, and government participants to cooperative efforts to overcome some of the barriers that have hampered investment in energy-efficient and environmentally-friendly technologies. Among the goals most of these programs share are:

- Changing corporate and consumer purchasing patterns to favor efficient products through information availability and exhortation;[123]
- Creating a market pull and lower prices for efficient products through aggregated purchases (group buys) and changes in long-term procurement patterns;
- Encouraging utility rate reforms to reward investments in energy efficiency;
- Expanding international markets for high-productivity and energy-efficient products; and
- Changing industrial practices and processes to reduce emissions of greenhouse gases.[124]

The **Green Lights Program** is the largest and most prominent of EPA's green programs. It was established in 1991 as a voluntary program designed to encourage U.S. corporations to retrofit their buildings with cost-effective lighting measures. According to EPA estimates, commercial and industrial lighting amounts to some 20 percent of total electricity consumption. By reducing energy use from lighting, EPA anticipates a lower amount of pollutants associated with fuels from electricity generation. In particular, EPA estimates that more efficient lighting could lower greenhouse gas emissions by 22 to 55 million metric tonnes of carbon. EPA is relying on the lure of cost-savings, and higher profits, and the promise of technical assistance to attract participants.

122 *National Energy Strategy: Powerful Ideas for America*, supra note 3, p. 7.

123 Eileen Claussen, Director, Office of Atmospheric and Indoor Air Programs, Office of Air and Radiation, U.S. Environmental Protection Agency, testimony before the Joint Economic Committee, 102d Cong., 2d sess., April 28, 1992, p. 5.

124 John Hoffman, Office of Atmospheric Programs, Environmental Protection Agency, briefing for congressional staff sponsored by the Environmental and Energy Study Institute, Aug. 7, 1992.

As of May 1993, more than 900 corporations, and organizations have joined the program.

The over 450 “partners” have each signed a “memorandum of understanding’ ’(MOU) with EPA committing to survey their U.S. facilities and install all profitable lighting retrofits in 90 percent of total square footage within 5 years. In return, EPA offers encouragement, information, product testing, technical assistance, and public recognition to organizations. Green Lights helps partners overcome barriers to energy efficiency by providing technical assistance as well as information on products and financing. EPA-provided software and training help businesses identify the retrofit options that maximize savings. The National Lighting Product Information Program provides reliable information about lighting technologies and options to corporations concerned about product claims or potential employee response to lighting changes. EPA also supports participants through a registry of utility rebates, energy service companies, banks and leasing companies providing financing.

The over 350 Green Lights “allies” include lighting manufacturers and energy management companies, and electric utilities that agree to educate customers about energy efficient lighting. EPA’s utility ally program promotes cooperation in publicizing the many benefits of energy efficient lighting, EPA invites utilities to sign a MOU under which the utility agrees to:

- complete profitable lighting retrofits in 90 percent of the square footage of its own facilities;
- assist EPA in marketing Green Lights and energy-efficient technologies to its industrial and commercial customers;
- participate in the ongoing lighting product and employee information programs; and
- assist EPA in documenting savings from lighting upgrades in their service area.

In return EPA agrees to:

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- provide tools and methodologies for pollution prevention calculations, energy savings, dollar savings, and lighting upgrade designs;
- provide materials to help the utility’s efforts to promote high quality energy-efficient lighting; and
- enhance the energy-efficient lighting market by working with the lighting industry to improve consumer confidence in product availability, quality, and value.

EPA also promises utilities that participation in Green Lights will enhance their corporate image by showing their concern and involvement in environmental protection. Green Lights also offers utilities support for their own DSM objectives and access to a national network providing a timely exchange of information on program effectiveness, experience, and decision-support tools.[125]

EPA has also enrolled the assistance of various trade, conservation, and professional associations as Green Lights endorsers.

Green Lights builds on the realization that protecting the environment has become an attractive product marketing angle. As an additional incentive, EPA authorizes participating compa-

125 “U.S. EPA Green Lights, Utility Ally Program, ” flyer, April 1992.

nies and allies to use the EPA Green Lights logo in advertising and promotional materials. EPA also displays corporate logos of participants in its own publicity and recruitment materials and advertising.

As of May 1993, some 2300 Green Lights projects encompassing over 220,000 square feet were in the process of being surveyed and retrofitted. Approximately, 40,000 square feet of retrofits were complete. EPA estimates that if all participants enrolled as of May 1993 complete the upgrading of their facilities, more than 3.3 billion square feet will have been retrofitted.[126] Annual savings on participants' electric bills will total over $1 billion annually, according to EPA, and more than $6 billion in new powerplant investments will be avoided. Lighting upgrades will prevent emission of some 21,378 million pounds of carbon dioxide annually-the equivalent of removing over 2.1 million cars from the roads. Additionally, EPA estimates that program investments in lighting upgrades will create some 66,000 job years.

Because the agreements are voluntary, there are no enforcement mechanisms under which EPA can compel participants to fulfill their promises. EPA, however, is monitoring the pace of installations and has indicated that if participants fail to follow through, EPA will bring added pressure on them to do so.

Green Lights advances several objectives. First, it helps overcome informational barriers to installing more efficient lighting through advertising and technical assistance provided by EPA. Second, by expanding the pool of customers for energy-efficient lighting services, EPA is helping to create a market pull for efficient products and services. Third, this market expansion could eventually help lower prices of these products through improved economies of scale in manufacturing and distribution. Lastly, the program can help lower first-cost barriers to participation by collaborating with various utility and government programs that provide loans and rebates for installing efficient lighting.

EPA is also creating a partner lighting program for the Federal Government, entitled Federal Green Lights. A similar program dubbed Green Buildings, which will launch a cooperative effort to incorporate energy-saving construction and building, ventilation, and air conditioning technologies in commercial buildings, is under development.

Building on the success of Green Lights, EPA has launched an energy efficiency labeling program designed to sell consumers and manufacturers on the advantages of energy efficient products. The first application, the EPA Energy Star Computers program is a voluntary partnership with EPA and the computer equipment manufacturers to manufacture and market computer equipment incorporating energy-saving technologies. In return the participants gain the right to use the EPA pollution preventer logo in marketing and advertising. For more on this program see chapter 4. Other cooperative efforts under consideration are showerheads, residential room air conditioners, and cooking equipment.

Another innovative initiative is the "Golden Carrot" program-a consortium of 25 utilities that is sponsoring a contest for the development and production of a super-efficient regrigerator that is free of ozone-depleting CFCS. The winning manufacturer will receive a bonus of $28 million and orders to deliver up to 300,000 units to participating utilities for use in their DSM programs. The award will be announced in summer 1993. For more on the Super Efficient Refrigerator Program (SERP), see chapter 4.

Conservation and Renewable Energy Reserve

The Clean Air Act Amendments of 1990 acid rain title provides for allocation of up to 300,000

[126] John S. Hoffman, Director, Global Change Division, Office of Air and Radiation Programs, U.S. Environmental Protection Agency, presentation to congressional staff, June 3, 1993.

sulfur dioxide (SO_2) emissions allowances to a conservation and renewable energy reserve.[127] The EPA Administrator can make allowances from the reserve available to eligible utilities that have reduced SO_2 emissions by installing qualified cost-effective conservation measures or renewable energy generation after January 1, 1992. These allowances will be made available beginning January 1, 1995, and can be used for complying with the acid rain emissions limitations. The amendments set a number of requirements for eligibility. The utility must adopt **a** least-cost planning process that evaluates a full range of resources including conservation and renewable energy sources to meet future demand at the lowest system cost. The plan must be approved by the utility's State regulatory authority and the qualifying measures must be consistent with the plan. For conservation measures, State-regulated utilities must obtain DOE certification that State regulators have adopted rate provisions that assure that the utility's net income after installing the qualified conservation measures is at least **as** high as it would have been without the energy efficiency measures.i[n]

DOE certification of this "net income neutrality status' for DSM investments involves review of the regulatory treatment of conservation program expenditures, such **as** decoupling adjustments, lost revenues, and performance incentives.[129] DOE certification must be obtained before the utility implements the qualified conservation measure. DOE is processing certifications on a "first-come, first-served" basis, and must also certify that the utility is actually implementing the conservation measures it developed in qualifying for the emission allowances.[130]

Federal Energy Efficiency Awards

Two awards programs administered by the Federal Government recognize Federal employees and/or facilities for energy efficiency achievements. The first is the Federal Energy Efficiency Awards at FEMP, and the other is the awards program at the U.S. Department of Army.

Each year the FEMP awards 15 certificates of achievement to individuals and facilities for exemplary performance in promoting conservation in Federal facilities.[131] The award does not include any financial compensation, but it does provide recognition and favorable publicity for the winning individuals and organizations.

The U.S. Army in Europe (USAREUR) has an award component in its energy program. The awards recognize both small and large facilities for saving energy in a variety of ways. The strenuous review of the nominees includes scoring on elements like efficiency measures, short-term measures, long term plans, numeric performance, mobility fuel savings, special considerations, and a day-long inspection of finalists. The value of the program is multifold. In addition to showing the interest and commitment of USAREUR, it creates publicity for energy programs, recognizes deserving communities, and reduces energy use. Prior to FY 1991, the award included a monetary component: $500,000 for first place, and a total $1.2 million in cash awards to be used on a ''welfare, morale, and recreation' item for the winning communities.[132]

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127 Clean Air Act Amendments of 1990, Public Law 101-549, title IV, sec. 404, 104 Stat. 2592-2605, Nov. 15, 1990, 42 U.S.C. 7651b.

121742 U.S.C. 404(f)(2) @)(iii).

129 Diane B. Pirkey, Manager, DSM Programs, Office of Utility Technologies, Energy Efficiency and Renewable Energy, U.S. Department of Energy, "Demand-Side Management Activities of the U.S. Department of Energy-A National Perspective," Mar. 25, 1993, p. 6.

130 Ibid.

131 U.S. Congress, Office of Technology Assessment, Energy *Efficiency* in *the Federal Government: Government by Good Example?*, *OTA-E-492,* (Washington DC, U.S. Government Printing Office, May 1991) p. 27.

132 Ibid, p. 97.

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