STABILIZING ELECTRICITY PRODUCTION AND USE: BARRIERS AND STRATEGIES

David Moskovitz
Steven M. Nadel
Howard S. Geller

American Council for an Energy-Efficient Economy
1001 Connecticut Avenue, NW Suite 801
Washington, DC 20036

American Council for an Energy-Efficient Economy
2140 Shattuck Avenue, Suite 202
Berkeley, CA 94704

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PREFACE

This issue paper builds upon *Energy Efficiency: A New Agenda,* an ACEEE book which examined energy problems and policies in the United States, and developed a twenty-one point action agenda. This prior work included an introduction to electricity policy issues, but given the complexities of many of these issues, a more in-depth treatment was called for.

This paper is the fifth in ACEEE's policy series, following upon:

1. U.S. Energy Demand: Back to Robust Growth?

2. National Energy Efficiency Platform: Description and Potential Impacts

3. Assessing Carbon Emissions Control Strategies: A Carbon Tax or a Gasoline Tax?

4. Light Vehicles: Policies for Reducing Their Energy Use and Environmental Impacts

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SUMMARY

Our focus is on the nation's energy policy as it relates to electricity.

We begin by examining the implications of staying with existing policies and find that our failure to invest more heavily in energy efficiency will increase consumption and consumer bills, thereby eroding the United States' competitiveness in the global economy, and worsening our standard of living. Under existing policies, a large number of new power plants will be needed, plants that are expensive to build, risky to finance, and difficult to site. Furthermore, existing policies leave emissions of carbon dioxide and nitrous oxides largely unaddressed, and do little to reduce imports of oil for use in power plants.

Next, we explore the causes for low investment in energy efficiency, including market barriers which inhibit the adoption of cost-effective efficiency measures, meager utility efforts to promote efficiency, regulatory processes which discourage utility investment in energy efficiency, low and poorly structured electricity prices, underinvestment in power plant efficiency, and low levels of federal and private funding of energy efficiency.

We then offer alternative policies -- policies which lead to a different future. These policies include:

* Adopt least-cost planning at the state level, allow states to join together to adopt regional least-cost plans, require federal regulatory decisions to be consistent with state and regional least-cost plans;

* Reform state and federal regulatory practices to remove disincentives to least-cost planning by decoupling utility profits from the level of sales. Also adopt positive incentives for pursuing implementation of least-cost plans.

* Increase utility efforts in efficiency including the number of utilities offering programs, and the breadth and quality of programs each utility offers;

* Amend federal laws to give energy efficiency vendors the same benefits currently possessed by cogenerators -- the right to sell power to utilities whenever the saved power is less costly than alternative power supplies;

* Reflect all costs, including environmental costs, in energy pricing and planning. Initially environmental costs may only be included for planning purposes, but over the long-term environmental costs should be included in all energy prices through the substitution of energy taxes for other taxes;

* Adopt innovative price structures including time-of-use rates, interruptible rates, and hook-up fees; abolish preferential price structures under which electricity is sold for less than its long-run marginal cost;

* Strengthen building codes and equipment efficiency standards including adoption by the states of current and improved state-of-the-art building codes,

adoption by the federal government of improved efficiency standards for products which are currently regulated, and adoption by the states and federal government of efficiency standards for new products such as lights and motors;

* Promote more efficient generation options through research, development, and demonstration efforts, a revenue-neutral system of fees for inefficient plants and incentives for efficient plants, and possibly, efficiency standards for new and/or existing power plants;

* Increase efficiency R&D efforts including efforts by DOE and EPRI; form development of state R&D centers in states which presently do not have such centers.

Finally, we conclude with an analysis of the savings that could result over the 1990-2010 period if our recommendations are adopted. In particular, we examine a mix of new power plant construction and increased investment in energy efficiency that can best meet the nation's economic and environmental needs. Our conclusions (which are summarized in Table 1 and Figure 1) are quite simple: relative to levels predicted by the U.S. Energy Information Administration in its most recent base case forecast, growth in electricity sales can be reduced by more than 70% (reducing the annual growth rate to 0.5%), the need for generating capacity will actually decline, carbon dioxide emissions from the electricity sector can be held to 1990 rates, and consumer electricity bills in 2010 will decline by 16% in real terms from present day levels, representing nearly $60 billion in savings in 2010.

Table 1. Summary of Estimated TWh, GW, and Carbon Savings from Adoption of Strategies Recommended in this Paper

	TWh Sales		GW Capacity		MT of Carbon		Consumer Bills (billion 1990$)	
	1990	2010	1990	2010	1990	2010	1990	2010
EIA Reference Case	2700	3985	689	830	522	755	$187.4	$287.7
Annual growth rate	--	2.0%	--	1.5%	--	2.0%	--	2.2%
Demand-side savings								
Codes and standards	0	407	0	157	0	77		
Utility DSM programs	0	568	0	158	0	108		
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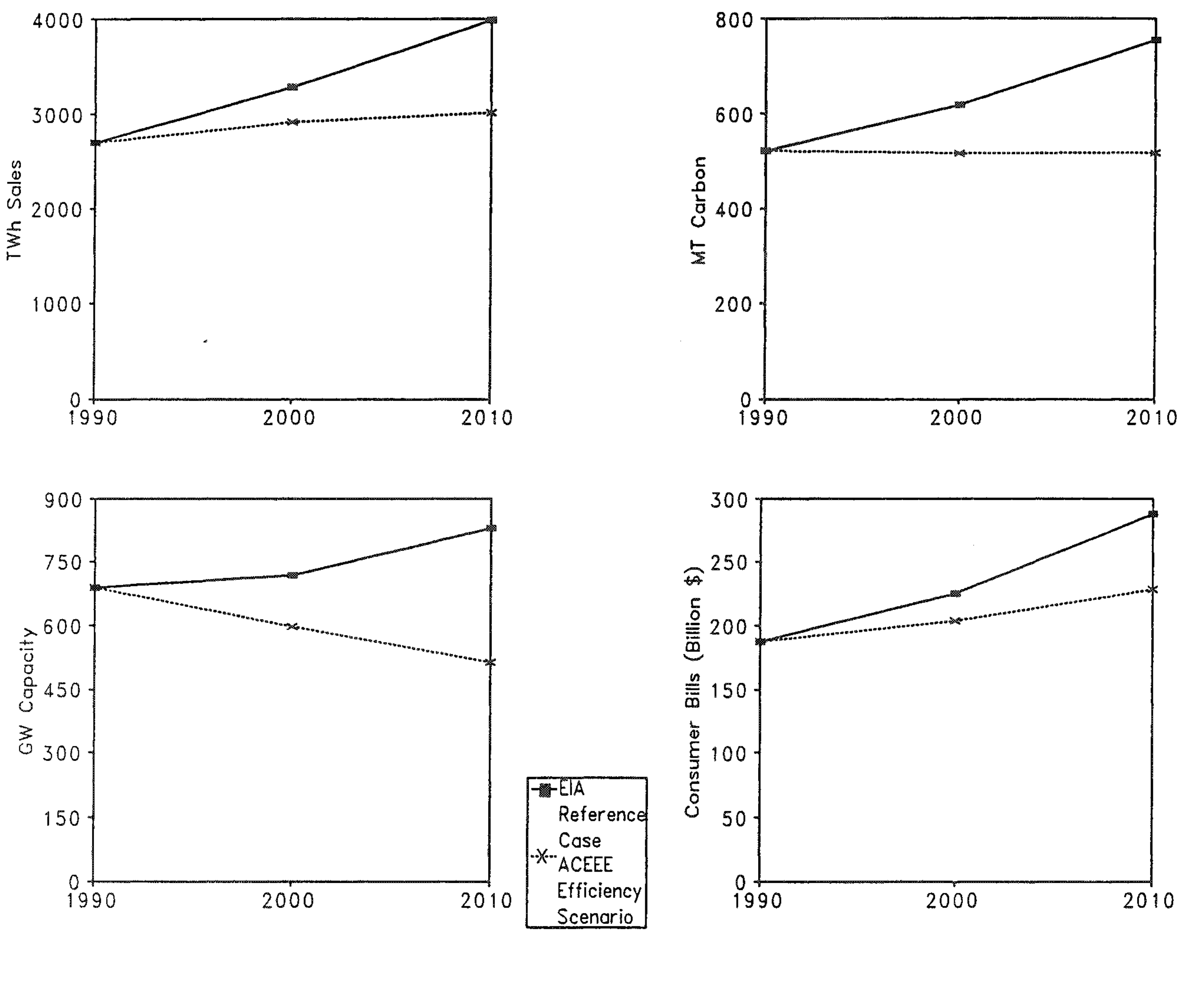
Total	0	975	0	315	0	185	$0.0	$59.5
ACEEE Post DSM Case	2700	3010	689	515	522	571	$187.4	$228.2
Annual growth rate	--	0.5%	--	-1.4%	--	0.4%	--	1.0%
Supply-side savings					0	53	$0.0	$4.9
ACEEE Efficiency Case					522	518	$187.4	$223.3
Annual growth rate					--	0.0%	--	0.9%

Figure 1. Comparison of EIA Reference Forecast with ACEEE Efficiency Scenario.



THE PROBLEM

With business-as-usual energy and regulatory policies, the demand for electricity is expected to increase 2.0% annually between now and the year 2010.[1] Based on this projected growth rate, the U.S. Energy Information Administration projects that 82,000 megawatts (MW) of new generating capacity will be needed by 2000, and 245,000 MW by 2010.[2] This is equivalent of 137 new 600 MW power plants (the size of a typical new coal-fired baseload power plant) by 2000, and over 400 such plants by 2010. Because it takes seven years or longer to license and build plants of this type, financial and regulatory commitments are being made today. The daunting prospect of having to build and operate 245,000 MW more generating capacity than exists today raises serious economic and environmental issues.

ECONOMIC

Consumer Costs

The U.S. Department of Energy (DOE) estimates that between $100 billion and $200 billion will be invested in new generating capacity over the next ten years.[3] Plant construction represents only about half the total cost of the new power supplies, the remainder being composed of fuel, operating, and maintenance costs. All of this investment and operating cost will ultimately be borne by the consumers. Will this be too high a cost for consumers to pay?

To answer the question we must first understand that consumers have no need for electricity directly, they need heat, light, refrigeration, motor drive, and other energy services.

Consider the example of using electricity to heat homes. Consumers want comfort -- not kilowatt-hours (kWhs). The same amount of comfort can be provided with more electricity and less insulation, or more insulation and less electricity. Likewise, the amount of electricity required depends on the efficiency with which it is converted to heat. To determine whether consumers are overpaying for energy services, we need to ask what mix

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[1] The current forecast cited here is that of the Energy Information Administration, *1991 Annual Energy Outlook*, DOE/EIA-0383(91), U.S. Department of Energy, Washington, DC, March, 1991. Similarly, the North American Electric Reliability Council forecasts 2.1% load growth for the 1990-1999 period in its report *1990 Electricity Supply and Demand*, Princeton, NJ, November 1990.

[2] Energy Information Administration, *1991 Annual Energy Outlook*, DOE/EIA-0383(91), U.S. Department of Energy, Washington, DC, March 1991.

[3] U.S. Department of Energy, *National Energy Strategy*, Washington, DC, February 1991.

of expenditures on electricity and efficiency will provide the consumer the desired level of comfort at the lowest cost.

The crux of the problem is all studies, whether performed by the utility industry, government, or independent analysts, show that significant energy efficiency improvements can be had at a fraction of the cost of new electricity supplies. (The results of our own studies and studies performed by others are discussed later in this paper).

Based upon these studies, as well as on recent experience, one can conservatively estimate that at least 20% of the forecasted electricity demand in the next two decades (which represents 70% of anticipated sales growth in the next two decades) can be satisfied at a lower cost by greater investment in energy efficiency. The average cost of the energy efficiency improvements is about 50% of the cost of building and operating new power plants.[4] It follows that by investing more in energy efficiency, consumers can save substantially.

International Competitiveness

Industrial and commercial consumers use about two-thirds of the nation's electricity to produce goods and services sold both here and abroad.[5] Without greater investment in energy efficiency U.S. businesses pay more for energy services than required; the goods and services produced in the U.S. will be less competitive in global markets; American jobs and productive capacity will be lost to overseas manufacturers; the Gross National Product will decline; and the balance of trade deteriorates.[6]

American producers are less competitive in part because we use energy in general, and electricity in particular, less efficiently than our principal competitors. Japan and West

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[4] An illustration of this general trend is provided in Geller and Nadel, "Electricity Conservation: Potential vs. Achievement," American Council for an Energy-Efficient Economy, Washington, DC, October 1989. However, costs of individual measures vary widely, ranging from negative costs (for long-lived efficiency measures that outlast conventional equipment, thereby reducing lifecycle equipment costs), to costs equivalent to the full cost of new power plants (for measures that are just barely cost-effective).

[5] Energy Information Administration, *Annual Outlook for U.S. Electrical Power*, U.S. Department of Energy, Washington, DC, 1989.

[6] In the base case scenario prepared by the Energy Information Administration for DOE's National Energy Strategy, the price of oil in 2010 is $37.14/barrel while GNP is $8,882 billion. In the high conservation scenario the comparable figures are $35.74/barrel and $8,905. In the very high conservation scenario, the figures are $34.47/barrel and $8,957 billion. Energy Information Administration, *Energy Consumption and Conservation Potential: Supporting Analysis for the National Energy Strategy*, SR/NES/90-02, U.S. Department of Energy, Washington, DC, December 1990.

Germany use about one-half the energy we use to produce one dollar of GNP.[7] This wide gap is due in part to actual energy efficiencies and in part to differences in level of energy services, geographic scale, and climate.[8]

Our competitors are also increasing their efficiency at a faster pace than the U.S. During 1973-1986, there was roughly no change in the overall intensity of electricity use by industries in the U.S. (i.e., electricity use per unit of real output remained about constant). In Japan electricity intensity declined markedly. In some major industries, including iron and steel, paper and pulp, chemicals, cement, and non-ferrous metals, Japanese manufacturers reduced their electricity intensity at least 20% more than U.S. manufacturers during this period. Greater technological innovation is one of the main causes of more impressive efficiency improvements in Japan.[9]

Investors' Cost

Raising $100-200 billion of new private capital over the next ten years to build new generating capacity also raises serious problems to investors who face the risk that all, or part of the investment might be lost.

During the past decade, investors suffered as more than $13 billion of private U.S. capital invested in power plants was denied cost recovery by state and federal regulators.[10] The reasons for the denials varied, but often regulators concluded that lower cost options (including investments in energy efficiency) were available and should have been pursued.

Investors are most certain to be at risk if regulators conclude that the utility's decision to pursue a new power plant was imprudent, a finding made increasingly likely by the fact that study after study reports that significant amounts of relatively low-cost energy efficiency potential can be achieved through electric utility action. More damning than studies are the growing number of leading utilities investing heavily in energy efficiency and demonstrating convincingly that energy efficiency investments are practical and inexpensive alternatives to

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[7] Flavin and Durning, *Building on Success: The Age of Energy Efficiency*, Worldwatch Paper Number 82, Worldwatch Institute, Washington, DC, March 1988.

[8] McDonald, S.C., *A Comparison of Energy Intensity Trends in the United States and Japan*, Pacific Northwest Laboratory, Richland, WA, December, 1990.

[9] Kahane, Adam, "Technological Change and Industrial Electricity Use" in Johansson, Bodlund, and Williams, eds., *Electricity, Efficient End-Use and New Generation Technologies and Their Planning Implications*, Lund University Press, Lund, Sweden, pp. 489-502, 1989.

[10] The North American Electric Reliability Council cites the disallowance of power plant costs as a major risk to future electricity reliability. North American Electric Reliability Council, *1990 Reliability Assessment*, Princeton, NJ, September 1990.

power plant construction. This contrasts with a much lower risk of regulators disallowing recovery of conservation costs.[11]

SECURITY

Our nation's heavy dependence on imported oil creates national security risks and costs, as indicated by our military presence in the Persian Gulf region.

The electric utility sector is not the country's largest user of oil and gas. Of the nearly 17 million barrels of oil consumed each day in the U.S., about 4% is used to generate electricity.[12] This is equivalent to about 9% of the nation's imported oil.

Of the 18.8 trillion cubic feet (tcf) of natural gas consumed in 1990, about 15% was used to generate electricity. About 1.5 tcf or 8% of our natural gas is imported, mostly from Canada.[13]

While the use of oil and gas to generate electricity is relatively restrained nationally, certain areas such as New York and New England are much more dependent on oil-fired generation, and most of New England's oil is imported.[14] Also, the relatively high operating costs of gas- and oil-fired power plants means that these fuels are used more extensively to provide <u>marginal or incremental</u> generation. Decreases in electricity use cause disproportionate decreases in the consumption of oil and gas.

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[11] A related problem for both investor and consumer is whether, given the amount of new capital required and the past decade's experience with denied plant expenditures, capital will be forthcoming on terms consistent with the assumed cost of new plant construction. Investors will demand returns that are commensurate with the perceived risk of the investments. If investment in utilities with large construction programs is perceived as being risky, investors will demand a higher rate of return for the use of their capital. Because financing costs are a major portion of new plant construction, investors demanding higher returns mean power plants may be more expensive than now assumed in utility cost-benefit analysis.

[12] U.S. Department of Energy, *Monthly Energy Review, DOE/EIA-0035(91/03)*, Washington, D.C., March 1991.

[13] *Ibid.*

[14] New York and New England rely on oil for about 32% of electricity generation. North American Electric Reliability Council, *1990 Reliability Assessment*, Princeton, NJ, September 1990.

ENVIRONMENTAL

Approximately two-thirds of sulphur dioxide emissions, and one-third of the nitrogen oxide emissions, in the U.S. are from the electric power sector. U.S. electric utilities are also the source of one-third of the national emissions and 11% of the global emissions of carbon dioxide, the principal greenhouse gas.[15]

In addition to air pollution impacts, the siting of electric generation plants and transmission lines have substantial land use impacts, as witnessed by the local opposition that is usually engendered whenever a new power plant or transmission line is proposed.

The connection between these environmental problems and the way we use energy is illustrated by a recent analysis on *Energy Consumption and Conservation Potential* conducted by the Energy Information Administration (EIA) for the National Energy Strategy. In this analysis, EIA compared a baseline business-as-usual consumption and conservation scenario to high and very high conservation scenarios. For the year 2030 (the end of the analysis), emissions of sulphur oxides, nitrogen oxides, and carbon were, respectively, 15%, 47%, and 27% higher in the baseline case than in the high conservation case, and 28%, 86%, and 52% higher in the baseline case than in the very high conservation case. GNP was higher in the conservation cases than in the baseline case because conservation lowered energy prices, thereby providing a stimulus to the economy.[16] The economic analysis did not include the economic costs and loss of national wealth that would result from higher levels of pollutant emissions in the base case.

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[15] Pace University Center for Environmental Legal Studies, *Environmental Costs of Electricity*, Oceana Publications, New York, NY, 1990.

[16] Energy Information Administration, *Energy Consumption and Conservation Potential: Supporting Analysis for the National Energy Strategy*, SR/NES/90-02, U.S. Department of Energy, Washington, DC, December 1990.

THE CAUSE

This section explores the principle causes of overinvestment in electricity supply and underinvestment in energy efficiency.

MARKET BARRIERS

Consumers currently invest in very few of the proven and cost-effective energy efficiency opportunities. Those efficiency techniques actively pursued are generally limited to the most obvious and lowest cost energy efficiency measures. Research by the Synergic Resources Corp. (SRC), the Electric Power Research Institute (EPRI), and others has shown that most consumers will adopt efficiency measures only if the payback on investment is rapid. Studies indicate that less than one-half of residential customers will undertake efficiency investments with a simple payback of three years, and less than one-quarter will invest in measures with a simple payback of more than five years. Less than one-half of commercial and industrial customers will undertake efficiency investments with a simple payback of 2.5 years, and only 10% or so of customers will undertake investments with a simple payback of more than four years.[17]

The pervasiveness of these problems are illustrated by the case of energy-efficient electric motors. Energy-efficient motors were introduced into the market in the late 1970's. Efficient motors reduce energy use by 2-15% (varying with motor size), and cost 10-30% more to purchase. Because the cost to operate a motor for a single-year is often several times its purchase price, in the overwhelming majority of cases (80% to 95%), energy efficient motors are cost-effective to the user and the local utility (as long as avoided costs are in excess of approximately 1.5 cents/kWh). Still, after more than ten years of effort by the motor industry to promote energy-efficient motors, the market share of these motors was only about 20% in 1988.[18]

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[17] Simple payback period is the cost of a measure divided by the annual savings from the measure. Simple payback measures the number of years it will take for measure savings to payback the original cost of the measure. Simple payback period is a simplistic financial analysis approach, as it ignores the life of the measure (a simple payback of one year is great if the measure lasts 20 years, but is undesirable for a measure with only a six-month life) and ignores the time value of money (the fact that a dollar invested in a measure is no longer available to earn interest). Despite these limitations, simple payback is used here because it is probably the economic analysis approach that is most widely used by consumers. The payback acceptance data described here is from Synergic Resources Corporation, *Comprehensive Market Planning and Analysis System, Version 1.2, User Guide*, Synergic Resources Corporation, Bala Cynwyd, PA, 1990.

[18] Market share is expressed in terms of the percentage of total motor sales in 1988. From Nadel, et. al., *Energy-Efficient Motor Systems: A Handbook on Technology, Program,*
(continued...)

participating customers by 10-30%.[26] The few utilities who have committed to investing in all cost-effective efficiency programs have found that financial commitments between 3% and 6% of utility revenues do not exhaust the efficiency opportunities (see Table 2). Even the low end of this range is at least twice as great as typical utility spending levels.

Utility expenditures on efficiency programs tell only part of the story. Of greater importance is the amount of savings that have been achieved, and the amount of savings utilities plan to achieve in coming years. For the industry as a whole, according to an EPRI-sponsored study, savings in 1990 amounted to 1.3% of 1990 electricity sales and 3.7% of summer peak demand. Projected savings in 2000 total approximately 3% and 7% respectively of what sales and peak demand would be if no conservation and load management programs were offered.[27]

In contrast the utilities with the most active demand-side programs have reduced their sales and/or peak demand by up to 7% in 1990 (Table 3), and plan to reduce sales and demand by up to 19% by 2000 (Table 4). These percentages are cumulative impacts from all utility DSM programs. Clearly, the average utility (as represented in the EPRI study) is lagging the industry leaders by a substantial margin.

UTILITY REGULATION

It is now clear that the financial incentives embedded in the current regulatory process are an important barrier to utility investment in energy-efficiency. The rate-setting processes used by most federal and state regulators are characterized by these inherent incentives:

1. Each kilowatt-hour an electric utility sells adds to the utility's profits, no matter how low the selling price or how high the cost to generate the power.

2. Each kilowatt-hour a utility saves, regardless of how little the efficiency costs, hurts the utility's bottom line.

3. The only financial incentive a utility has for investing in cost-effective energy efficiency is that failure to do so might be held against the utility by regulators, resulting in large revenue disallowances.

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[26] Nadel, Steven, *Lessons Learned: A Review of Utility Experience with Conservation and Load Management Programs for Commercial and Industrial Customers*, Report 90-8, New York State Energy Research and Development Authority, Albany, NY, April 1990.

[27] Faruqui, et. al., *Impact of Demand-Side Management on Future Customer Electricity Demand: An Update*, CU-6953, Electric Power Research Institute, Palo Alto, CA, Sept. 1990.

Table 2. DSM Expenditures of Selected Utilities Recognized as Leaders in Energy Efficiency

	DSM Expenditures (million $)			Spending/Revenue (%)		
Utility	1989	1990	1991*	1989	1990	1991*
Boston Edison	11	29	40	0.9%	2.4%	3.3%
Central Hudson	2	5	10	0.6	1.1	2.3
Central Maine Power	18	26	28	2.7	3.8	4.1
Consolidated Edison	25	31	76	0.6	0.6	1.6
Green Mt Power	2	3	4	1.7	2.2	3.8
Long Island Lighting	33	32	33	1.7	1.5	1.6
Madison Gas & Elec.	4	3	4	3.0	1.8	2.8
New England Elec.	42	71	85	2.6	4.1	4.9
NY State Elec & Gas	12	18	25	0.9	1.4	1.9
Niagara Mohawk	9	21	37	0.4	0.8	1.4
NE Utilities	22	49	75	1.0	2.2	3.3
Orange & Rockland	3	5	8	0.8	1.3	2.2
Pacific Gas & Elec.	55	92	154	0.6	1.0	1.7
Puget Sound P&L	20	25	35	2.3	2.7	3.7
Rochester Gas & Elec	2	6	7	0.4	1.0	1.1
Sacramento MUD	9	17	42	1.5	2.5	6.4
Seattle City Light	5	15	18	1.6	5.3	6.2
Southern Cal Edison	54	73	108	0.7	1.0	1.4
Wisconsin Electric	44	46	57	4.0	4.3	4.8
Wisconsin P&L	9	15	15	2.3	3.2	3.2

* 1991 data is estimated by each utility.

Source: Data was obtained by Moskovitz and Associates over the telephone from each utility listed.

Table 3. DSM Savings of Selected Utilities as a Percent of 1989 Sales and Peak Demand

		Cumulative Over Period		Avg. Year During Period		In Last Year	
Utility	Period	kW	kWh	kW	kWh	kW	kWh
Central Maine Power	1985-90	4.6%	5.8%	0.8%	1.0%	1.6%	2.1%
COMM/Electric	1988-90	1.9	4.7	0.6	1.6	1.9	2.3
Eastern Utilities	1988-90	2.1	1.7	0.7	0.6	1.7	0.9
LILCO	1987-90	7.2	1.7	1.8	0.4	1.3	0.7
New England Elec.	1987-90	4.1	1.9	1.0	0.5	1.2	0.7
Pacific Gas & Elec.	1980-90	5.6	5.3	0.5	0.5	0.5	0.4
So.Calif. Edison	1980-90	5.6	5.0	0.5	0.5	0.5	0.3
Wisc. Elec. Power	1987-90	4.0	3.3	1.1	0.9	1.5	1.2

Notes:

Data were obtained by ACEEE from the individual utilities. Peak demand savings are coincident with the system peak, and energy and demand savings are at the customer level. Data were adjusted to exclude free riders (customers who would have made conservation investments, even if the utility program was not offered), with the exception of COMM/Elec and Eastern Utilities. Savings for PG&E and So. Cal. Ed. are adjusted to eliminate savings from measures that have passed the end of their lifetimes. The level of program evaluation activity varies from utility to utility and program to program, so savings estimates vary considerably in accuracy.

Table 4. Role of Conservation and Load Management (C&LM) in the Year 2000 as Shown in Long-Range Resource Plans of Selected Utilities

Utility	State	Projected Savings as % of Demand	
		GWh	MW
Boston Edison	MA	7.4%	10.5%
Central Hudson	NY	5.3	8.9
Central Maine Power	ME	2.2	11.8
COMM/Electric (1995)	MA	18.8	n/a
Consolidated Edison	NY	9.1	13.8
Green Mountain Power	VT	7.9	7.1
Long Island Lighting	NY	8.8	7.6
New England Electric	MA/RI/NH	7.8	11.8
NY State Elec & Gas	NY	9.2	14.5
Niagara Mohawk	NY	5.3	7.4
Northeast Utilities	CT/MA	11.3	11.5
Northern States Power	MN/WI	7.4	17.0
NW Power Planning Council	WA/OR/MT	6.4	n/a
Orange & Rockland	NY	5.0	8.9
Pacific Gas & Electric	CA	7.8	10.9
Public Service E&G (1999)	NJ	4.4	9.9
Rochester Gas & Elec.	NY	8.9	8.2
Sacramento Mun. Util. Dist.	CA	17.7	19.2
San Diego Gas & Elec.	CA	8.6	14.6
So. Cal Edison (2001)	CA	17.6	16.7
United Illuminating	CT	4.0	13.6
Wisconsin Power & Light	WI	5.6	9.0

Notes:
Data were obtained by ACEEE from the individual utilities. The term "demand" is used loosely to connote projected GWh use and MW of peak demand in a utility's service territory. Transmission & distribution losses and reserve margin allowances are not included in figures. When a range of C&LM savings is given by a utility, the midpoint of the range is reported here. To the extent C&LM has occurred prior to the base year of the forecast, these C&LM savings are incorporated into the forecast and not into the savings estimates. Peak demand savings are coincident with the system peak, and all savings are at the customer level. Data for most utilities are adjusted to exclude free riders, with the exceptions of United Illuminating, COMM/Electric, and NW Power Planning Council.

In the electricity field, consumer requirements for rapid payback present a perverse situation. When consumers do not to invest in measures with moderate payback periods (3-5 years), electric utilities build power plants with a simple payback of ten years or more, resulting in a "payback gap" between what consumers are willing to pay for individual efficiency measures, and what they are forced to pay through their power bills.[19]

The reasons for this payback gap include the lack of information, lack of capital, lack of convenient product availability, a shortage of skilled personnel to properly specify, install, and maintain efficiency measures, the need to make purchases under near emergency conditions (e.g., the water heater breaking), and mismatches between those who make construction and purchase decisions (e.g., builders and landlords) and those who pay electricity bills (consumers). [20]

INADEQUATE UTILITY EFFORTS TO PROMOTE EFFICIENCY

As a general matter, the electric utility industry has not made a significant financial commitment to developing the energy efficiency potential. For example, in 1984, California utilities were spending about 1.5 percent of their gross revenues on energy efficiency

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[18](...continued)
and Policy Opportunities, American Council for an Energy-Efficient Economy, Washington, DC, 1991. Utility cost per kWh of $.015 comes from Nadel and Tress, *The Achievable Conservation Potential in New York State from Utility Demand-Side Management Programs*, Report 90-18, New York State Energy Research and Development Authority, Albany, NY, Nov. 1990.

[19] For example, New England Electric found that conservation and load management programs designed to promote conservation actions customers would not undertake on their own generally cost about half as much per unit of energy and power as a new coal generating plant. The conservation and load management programs were even less expensive than repowering existing inefficient generating plants with new high efficiency gas turbines. Destribats, Lowell, and White, "Dispatches from the Front: New Concepts in Integrated Planning," paper presented at EPRI Innovations in Pricing and Planning Conference, Milwaukee, WI, May 1990.

[20] These factors and others explain why the market fails to produce reasonable levels of investment in energy efficiency. For more detailed discussions of the issue, see Krause and Eto, *Least-Cost Utility Planning Handbook for Public Utility Commissioners, Volume 2, The Demand Side: Conceptual and Methodological Issues*, National Association of Regulatory Utility Commissioners, Washington, D.C., Dec. 1988. Also, see Marilyn Brown and Eric Hirst, "Closing the Efficiency Gap: Barriers to the Efficient Use of Energy," *Resources, Conservation and Recycling* 3(4), June 1990, pp. 267-281; Reddy, Amulya, "Barriers to Improvements in Energy Efficiency," paper presented at the Second International Workshop on Energy and Global Climate Change, Lawrence Berkeley Laboratory, Berkeley, CA, Oct. 4-6, 1990.

investments. By 1989, spending had dropped to about 0.5% of gross revenues.[21] Even at the 0.5% level, however, the California utilities were ahead of many utilities. In 1990 utility expenditures on demand-side management programs have been estimated to be $2 billion (although this figure also includes money spent to sell <u>more</u> electricity through marketing programs).[22] If we conservatively estimate that 75% of this $2 billion is for energy efficiency and peak load reduction programs (a number which some will say is too high), investment in these programs amount to approximately 0.8% of gross utility revenues in the U.S. of approximately $180 billion.[23]

Most utilities that have demand-side programs limit them to information and audit programs, financing arrangements, and financial incentives in the form of rebates. A recent review of more than 200 utility programs for commercial and industrial customers (including over 100 rebate programs), found that the typical rebate program features limited marketing (primarily occasional mailings), and rebates equal to less than half the cost of the efficiency measures being promoted. Programs of this type typically provided rebates to only 0-4% of eligible customers, even after a several year period, and resulted in energy savings of only a few percent per participant.[24]

Furthermore, even where utilities are operating demand-side programs, the actual savings achieved by the programs are often not adequately evaluated. As a result, savings estimates are frequently inflated.[25]

A few utilities are operating highly successful programs. For example, some programs are achieving participation rates of 30-70% and reducing energy use among

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[21] The California Public Utilities Commission initiated action to reverse this trend and, shortly thereafter, the California utilities agreed to increase investment to over $300 million per year, or about 2% of revenues. See *An Energy Efficiency Blueprint for California, Report of the Statewide Collaborative Process*, available from the California Public Utilities Commission, Sacramento, CA, January 1990.

[22] Veronika Rabl, EPRI, personal communication, February 1991.

[23] 75% is an ACEEE estimate. Utility gross revenues in 1990 were $179 billion; U.S. Department of Energy, *Monthly Energy Review, DOE/EIA-0035(91/03), March 1991*, Washington, DC.

[24] Nadel, Steven, *Lessons Learned: A Review of Utility Experience with Conservation and Load Management Programs for Commercial and Industrial Customers*, Report 90-8, New York State Energy Research and Development Authority, Albany, NY, April 1990.

[25] Nadel, Steven and Ken Keating, "Engineering Estimates Vs. Impact Evaluation Results: How Do They Compare and Why?", in *Energy Program Evaluation: Uses, Methods, and Results, Proceedings 1991 International Energy Program Evaluation Conference*, Chicago, IL, August 1991, pp. 24-33.

That these incentives are real and powerful has been confirmed by NARUC and numerous state regulatory commissions.[28] Little progress toward implementing large scale efficiency programs can be expected in an environment controlled by such powerful economic forces.

What is it about the traditional rate-setting process that produces all the wrong incentives? Several aspects of the regulatory process lead to the conclusion that under the existing regulatory scheme, electricity sales and utility profits are closely and needlessly coupled.

First, as regulated monopolies, utilities are entitled to have their prices for electricity set at a level allowing recovery of all prudently-incurred operating expenses and fixed costs. These fixed costs include such things as taxes, depreciation, interest, and a reasonable rate of return (or profit) on the rate base (calculated as the capital investment in power plants and other hardware, minus depreciation).

Actual profit levels earned by utilities, however, are not etched in stone. Instead, state public utility commissions examine utilities' historical and forecasted expenses and set the price of electricity at levels expected to earn the utility a specified rate of return. However, once the price is set, actual profits depend on the usual formula of revenues minus expenses. The utility profits from selling more electricity whenever its marginal revenue from a sale exceeds its marginal cost to produce and distribute the power.

But what is the utility's marginal cost of power? In the short-run, the marginal cost of power is the cost of fuel and other variable operations and maintenance expenses needed to generate the power. But, to insulate utility shareholders from the impact of fluctuating fuel prices, nearly all states allow utilities to adjust customer prices periodically so that the cost of fuel is fully recovered, and changes in fuel prices, or the quantities of fuel used, do not affect profits. The result is that the short-run marginal cost of power <u>to the utility's shareholders</u> is essentially zero.[29]

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

[29] Consider the following example. To meet increased demand during peak periods, a utility may operate a relatively inefficient diesel generator which consumes ten cents worth of fuel to produce one kilowatt-hour of electricity. The regulated price of power might be seven cents per kwh, which represents five cents in fixed costs and two cents allotted for the utility's "average" fuel costs. But the utility can recover the extra eight cents in fuel costs later (that is, the generator's ten-cent fuel cost minus the two-cent average fuel cost) by invoking the fuel adjustment clause to raise rates. In effect, the utility charges customers 15 cents for the kWh, seven cents now and eight cents later, through the true-up provisions of the fuel cost adjustment clause. Meanwhile, the five-cent non-fuel (or base) part of its rate remains in place, contributing to its bottom line.

The combination of price-setting, accounting practices, and automatic adjustment clauses means that each and every kWh sold adds to earnings. The converse is equally true. Each kWh not sold, or conserved, has a negative effect on earnings.[30] Under the existing regulatory scheme, utilities have good reason to avoid productive investment in helping to make energy consumers more efficient.

These same financial disincentives also apply to utility efforts to increase the efficiency of power generation, transmission, and distribution. In states with so-called fully reconciled fuel adjustment clauses, utilities are automatically compensated for changes in power plant efficiency or utilization, in addition to changes in fuel prices. For example, if a utility reduces the heat rate (Btu's of energy required to produce a kWh of electricity) of a particular power plant through better operation and maintenance, all of the cost savings flow through to ratepayers. Likewise, changing power plant dispatch in order to optimize energy efficiency does not affect utility profits in the short run.

ELECTRICITY PRICING

Growth in electricity consumption dropped from 7.5% per year during the 1960's to 2.6% per year during the 1980's.[31] As a result, generating capacity in 1990 was about 800,000 MW lower than it would have been had the 1960's growth rate continued. To be sure, part of the reduced demand can be attributed to the effects of price elasticity resulting from price increases following the 1973 oil shortage.[32] Corrected for inflation, the national average electricity price increased 53% during 1973-83.[33]

The fact that consumers respond to rising prices to some degree underscores the importance of ensuring that electricity prices reflect the full cost of power production.

Electricity prices generally reflect a utility's average cost of providing service. In some cases, this average cost is less than the full marginal cost of expanding power supply

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[30] A common misconception is that the disincentive to conserve exists only if the utility has sold less electricity than previously forecast. However, the incremental contributions to the bottom line occur whether the sale takes place before or after the utility has reached its projected level of sales. The incremental effect on earnings of sales is the same, regardless of the level of sales.

[31] Energy Information Administration, *Annual Energy Review 1989,* DOE/EIA-0384(89), U.S. Department of Energy, Washington, DC, May 1990.

[32] National Economic Research Associates, *Considerations of the Price Elasticity of Demand for Electricity,* Electric Power Research Institute, Palo Alto, CA, 1977.

[33] Energy Information Administration, *Annual Energy Review 1989*, DOE/EIA-0384(89), U.S. Department of Energy, Washington, D.C., May 1990.

options.[34] For this reason electricity prices are sometimes too low and, as a consequence, customer consumption too high from the perspective of economically rational resource allocation.

Even when average costs and marginal costs are reasonably close, many utilities have adopted pricing structures that hide from customers the full incremental cost (long-run marginal cost) of power.[35] About one-half of the nation's largest utilities continue to charge customers using declining block rates, in which energy prices decline as customers' consumption increases.[36] Over one-third of the nation's largest utilities also offer special rates called "incentive rates," "economic development rates," and "cogeneration deferral rates." Although the public rationale for each of the rates differs, all aim to increase, or at least maintain, electricity sales by lowering the price of electricity to certain customers.[37] These prices are also well below the full cost of additional resources.[38]

Overall efficiency can also be greatly aided through innovative pricing options such as interruptible rates. Under an interruptible rate agreement the customer contracts with the utility to curtail a specified portion of its electricity consumption when called upon by the utility. The customer's agreement allows the utility to avoid the high cost of adding new resources to meet peak power demand. In return for its agreement to accept interruptible service, the customer receives a payment (or is given a rate discount).[39]

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[34] For example, average electricity costs in the Pacific Northwest are approximately 4.1 cents/kWh at present but marginal costs are approximately 7.5 cents/kWh. Northwest Power Planning Council, *1991 Northwest Conservation and Electric Power Plan, Volume 1*, Portland, OR, April 1991.

[35] The full cost of power is the cost of building and operating new power plants plus the cost of delivering, metering, and billing customers for the service rendered. Long-run marginal cost is the common industry and economic term used to describe the full cost of power.

[36] Duke Power, "1988 Annual Utility Survey," Rate and Research Department, Duke Power, Charlotte, NC.

[37] *Ibid.*

[38] For a thoughtful discussion of the problems brought on by these pricing practices, see Cavanagh, Ralph, "Responsible Power Marketing in an Increasingly Competitive Era," *Yale Journal on Regulation*, 5(2), Summer 1988.

[39] Maine utilities have been able to secure interruptible service contracts for about 9% of the statewide peak load. The rest of the nation lags far behind. Data for the nine electric reliability regions in the U.S. shows that only about 2.4% of the nation's peak electricity demand is subject to interruptible rates or other direct utility control (e.g. radio controlled air conditioners and water heaters). The range for the nine regions is 0.8% to 3.8%. The potential to improve this performance is enormous. Each 1% point represents a 7,500 MW

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ENVIRONMENTAL COSTS

Even where marginal-cost-based rates and other innovative price structures are used, energy production imposes significant environmental costs which are not included in utilities' costs, and are therefore not reflected in even the most accurate prices.[40]

Air pollution imposes costs that are borne, for example, by farmers who suffer crop damage and must spend heavily to correct overly acidic soils; by property owners whose steel, masonry, and paint require more frequent maintenance; by business owners who suffer when anglers give up fishing in dead or dying lakes and streams; and by all citizens who pay higher health care costs. These costs are ignored when computing the cost of energy and setting electricity prices.

There have been many attempts to quantify the most direct and immediate environmental costs associated with electricity production.[41] The most recent and comprehensive effort to assemble the information was performed by The Pace University Center for Environmental Legal Studies and the results are summarized in Table 5. It should be acknowledged, however, that quantification of environmental costs and their role in utility planning and regulation is subject to a great deal of uncertainty and controversy.[42] For example, other researchers suggest that the environmental costs are much lower than the values shown in Table 5.[43]

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[39](...continued)
reduction in national capacity needs. North American Electric Reliability Council, *1990 Reliability Assessment*, Princeton, NJ, September 1990.

[40] Recent amendments to the Clean Air Act require reductions in emissions from existing levels. The cost of achieving these reductions will be reflected in future electricity prices. The remaining lawful emissions, however, will continue to cause damage (albeit at lower levels), the costs of which will still not be reflected in electricity prices. For example, recent evidence indicates that substantial damage to soils and forests can be caused by nitrogen deposition, deposition that will be scarcely affected by these recent Clean Air Act Amendments (Flynn, John, "Forest Without Trees," *The Amicus Journal*, Winter 1991, pp. 28-33.

[41] The studies are limited to the effects of air and water pollution caused by power plant operation, and do not address any other environmental costs such as mining of coal, drilling, refining, or transporting oil, or producing steel and concrete for plant construction.

[42] Electricity Consumers Resource Council, *Profiles in Electricity Issues: Externalities*, Washington, DC, October 1991.

[43] Koomey, Jonathan, *Comparative Analysis of Monetary Estimates of External Environmental Costs Associated with Combustion of Fossil Fuels*, LBL-28313, Lawrence
(continued...)

According to a survey published in mid-1990, nine states have adopted rules governing the inclusion of environmental externalities into utility planning processes.[44] Several states, including Massachusetts and Nevada, adopted rules after this survey was conducted. New York, Massachusetts, and Nevada have adopted the most detailed and comprehensive programs.[45] Under New York's plan, the most polluting resources -- coal-fired power plants -- are assessed a 1.4 cent per-kWh penalty when evaluated against the least polluting resource, energy efficiency. Other, less polluting facilities are assigned smaller economic penalties. These penalties are added to the direct economic cost of each resource and the sum of the direct economic cost, plus the environmental penalty, is the "shadow price" for the resource.

Table 5. Estimated Environmental Costs for Selected Types of Power Resources

Types of Plants	Cents per kilowatt-hour
Existing coal plants	4.1 - 11.4
New coal plants	1.8 - 4.3
Existing oil plants	2.5 - 6.9
Existing natural gas plants (steam-electric)	0.9 - 1.8
New natural gas combined cycle	0.7 - 1.4
Demand-side management programs	Generally "not significant"

Source, Pace University Center for Environmental Legal Studies, *Environmental Costs of Electricity*, Oceana Publications, New York, 1990.

[43](...continued)
Berkeley Laboratory, Berkeley, CA, July 1990. See also New England Electric System, *NEESPLAN3: Environment, Economy and Energy in the 1990s*, Westborough, MA, 1991.

[44] Cohen, Eto, Goldman, Beldock, and Crandall, *A Survey of State PUC Activities to Incorporate Environmental Externalities into Electric Utility Planning and Regulation*, LBL 28616, Lawrence Berkeley Laboratory, Berkeley, CA, May 1990.

[45] New York Public Service Commission, *Opinion and Order Establishing Guidelines for Bidding Program -- Case 88-E-246 -- Proceeding on Motion of the Commission (established in Opinion No. 88-15)* as to the guidelines for bidding to meet future electric capacity needs of Orange and Rockland Utilities, Inc., 89-7, Albany, NY, April 13, 1989.

Massachusetts and Nevada have adopted similar shadow pricing mechanisms which assign specific dollar values to various air pollutants, including CO_2. In both states, the environmental cost of a typical new coal-fired power plant is about 4.4 cents per kilowatt hour, of which about one-half is associated with CO_2 emissions.[46]

In New York, Massachusetts, Nevada and elsewhere, environmental costs are considered only in conjunction with decisions relative to new resources. No state yet extends consideration of environmental costs for existing power plants, even though existing plants are far more polluting per unit of energy output than new plants.

UNDERINVESTMENT IN POWER SUPPLY EFFICIENCY

The average efficiency of fossil-fuel-based power plants reached its peak around 1960 and has declined slightly since. (see Figure 2). However, a wide range of more efficient power production technologies, including coal gasification and combined-cycle power production, advanced steam-injected gas turbines, and fuel cells are under development.[47]

Many of these technologies are being advanced under the Clean Coal Technology Demonstration Program to commercialize new power production technologies that emit much less SO2 (the major cause of acid rain) than conventional generating technologies. Unfortunately, the clean coal program ignores coal's substantial carbon dioxide emissions. Achieving maximum efficiency in the next generation of fossil fuel-based power plants will be critical to reducing primary energy consumption and carbon dioxide emissions in the United States.

Older fossil fuel-based power plants are relatively inefficient, due to both their original efficiency and because efficiency tends to deteriorate with plant age. A 30 year old fossil-fuel-based power plant consumes about 6% more fuel per kWh generated compared to the same plant when it was new.[48] About 15,000 MW of existing coal-fired generating capacity have a heat rate in excess of 12,000 Btu/kWh (equivalent to an efficiency of 28% or less) and about 47,000 MW have a heat rate of 11,000 - 12,000 Btu/kWh (28-31%

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[46] Massachusetts Department of Public Utilities, "Decision in Docket 89-239," Boston, MA, August 31, 1990. Wiel, Stephen, "Nevada Adopts Clean Power Rule," Nevada Public Service Commission, Carson City, NV, April 1991.

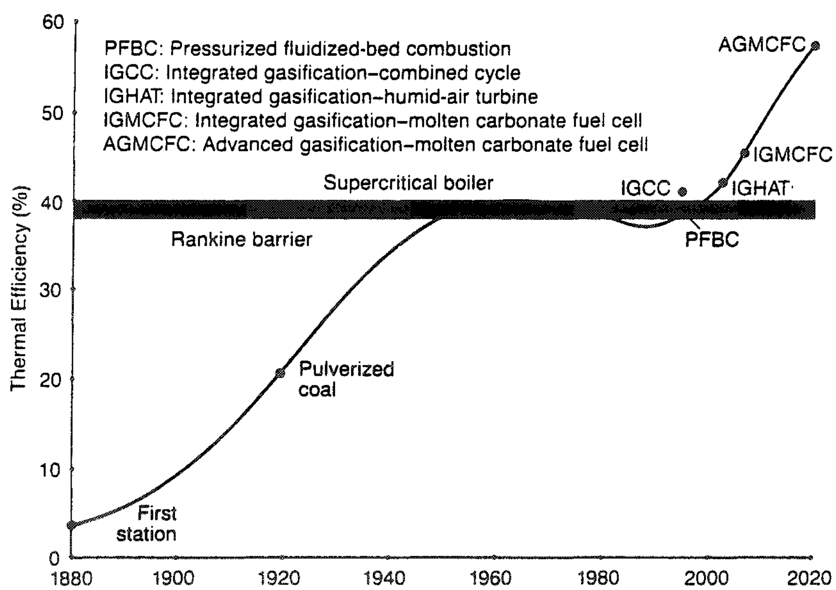
[47] "Beyond Steam: Breaking Through Performance Limits", *EPRI Journal*, 15(8), December 1990, pp. 4-11.

[48] Office of Technology Assessment, *New Electric Power Technologies: Problems and Prospects for the 1990's*, OTA-E-246, U.S. Congress, Washington, DC, July 1985.

Figure 2

Evolution of Coal-Fired Power Plants

The efficiency of steam-based (Rankine cycle) power plants increased steadily for 80 years, nearing theoretical limits in the 1960s. Since then, efficiency has decreased somewhat because of the need to use energy to remove pollutants formed during combustion. Breaking the Rankine barrier of practical limitations on efficiency will require innovative approaches based on chemical energy conversion, such as coal gasification, and electricity generation by means of advanced combustion turbines and fuel cell technologies.



Source: *EPRI JOURNAL*, December 1990.

efficiency).[49] Many of these plants could be replaced cost-effectively with new, high-efficiency generating technologies, cutting their fuel consumption per unit of power production by 30% or more.

New more efficient generation options are not being pursued for a variety of reasons. For example, risk-averse utilities generally prefer to extend the life of existing power plants rather than construct new power plants because of the fear that there will be long delays in construction of new plants, cost overruns, and possible disallowance of some costs when a new plant is placed in the rate base. Life extensions may also be preferred by utilities that perceive business risks from non-utility generators that may compete against utility construction. Finally, life extensions may present a less risky and expensive set of environmental and regulatory reviews.

RESEARCH AND DEVELOPMENT

Another cause of our slow efficiency gains is the research and development (R&D) priorities of the federal government and the Electric Power Research Institute (EPRI). Between 1980 and 1988, the federal budget for R&D in energy efficiency was cut by about 68% in constant dollars. As of 1992, the funding level for R&D into energy efficiency was $220 million, or equivalent to about 6% of the federal support for energy supply.

Low priority for energy efficiency R&D would be understandable if past efforts had yielded little or no progress. In fact, past investment in R&D on energy efficiency has been enormously effective. For example, seven technologies developed in part by the U.S. DOE: electronic ballasts for lighting, improved window coatings (low-E glass), absorption heat pumps, advanced electric heat pumps, high efficiency refrigerator compressors, high-efficiency refrigerators and freezers, and heat pump water heaters are expected to produce annual net savings at the time of product saturation of $16.65 billion. The return on DOE's R&D investment ranges from a low of 1500:1 to a high of 8000:1.[50] The net savings from sales during 1985-90 from two technologies -- electronic ballasts and low-emissivity windows -- already equals about $4 billion per year.[51]

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[49] Gluckman, M., "CO2 Emission Reduction Cost Analysis," Electric Power Research Institute, Palo Alto, CA, August 1990.

[50] Geller et. al., "The Importance of Government-Supported Research and Development in Advancing Energy Efficiency in the United States Building Sector," in Johansson, Bodlund, and Williams (eds.), *Electricity: Efficient End-Use and New Generation Technologies and Their Planning Implications*, Lund University Press, Lund, Sweden, 1989.

[51] Rosenfeld, Arthur, "The Role of Federal Research and Development in Advancing Energy Efficiency," testimony before the Subcommittee on Environment, Committee on Science, Space, Technology, U.S. House of Representatives, Washington, D.C., April 17, 1991.

Private sector energy R&D is also vitally important. Unlike other industries, most of the electric utility industry's research activities are conducted centrally, by the jointly funded Electric Power Research Institute. EPRI's annual research budget is about $270 million, of which about 14% or $36.2 million, falls under the broad category of demand-side management projects. Only about 60% of the DSM budget, however, relates directly to energy efficiency. The remaining programs involve monitoring and modeling projects aimed at environmental issues, and research devoted to load building and new electricity application opportunities.[52]

The level of funding for energy efficiency R&D (both federal and EPRI-based) is growing, albeit slowly. Still, the overall combined level of efficiency R&D funding is low and the lack of a more aggressive effort contributes to the problem of limited technology availability and implementation.

[52] *Electric Power Research Institute,* Research & Development Program, 1991-1993, Palo Alto, CA, 1991.

THE CURES

The previous sections set forth the causes and consequences of continuing low levels of electric energy efficiency. This section addresses the cure to these problems.

Action is needed in the following areas:

* Adopt least-cost integrated resource planning at the state and federal levels;
* Reform state and federal regulatory practices to remove disincentives to least-cost planning;
* Improve and increase utility efforts in efficiency;
* Amend federal laws to give energy efficiency vendors the same benefits currently possessed by cogenerators;
* Reflect all costs, including environmental costs, in energy pricing and planning;
* Adopt innovative price structures;
* Strengthen building codes and equipment efficiency standards;
* Promote more efficient power supply options; and
* Increase efficiency R&D efforts.

LEAST-COST INTEGRATED RESOURCE PLANNING

Least-cost planning (LCP -- also called Integrated Resource Planning -- IRP), is a process whereby a utility identifies and pursues the mix of supply and demand-side resources which meets energy service demands at the lowest total cost.[53]

As of 1991, only eleven states had fully implemented LCP.[54] Fifteen states have

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[53] See *Least Cost Utility Planning Handbook for Public Utilities Commissioners*, Volumes 1 and 2, for an excellent background on least-cost planning principles and process. (National Association of Regulatory Utility Commissioners, Washington, DC, Oct. and Dec., 1988).

[54] Mitchell, Cynthia from a survey of state activities in least-cost planning. See also: Mitchell, Cynthia and Jon Wellinghof, *LCUP Consumer Participation Manual*, National Association of State Utility Consumer Advocates, Washington, D.C., 1989. Also, Mitchell,
(continued...)

implemented some but not all aspects of LCP, and ten states are considering LCP. What is most disturbing is that 15 states were not even considering LCP as of May, 1991.[55] Action must be taken to assure that LCP becomes an integral part of the planning, regulatory, and acquisition process used in every state.

The adoption of least-cost planning is needed to ensure energy services are provided at the lowest total long-term cost to consumers. Positive steps must be taken to encourage more states to adopt and incorporate LCP principles in their utility review processes. Also, federal regulatory impediments to LCP need to be removed, and federal agencies which sell power should be required to prepare least-cost plans.

Recommendations:

1. a) Congress should amend the Federal Power Act to require utilities to show that wholesale power acquisitions are consistent with regional or state approved least-cost plans in order to receive approval from the Federal Energy Regulatory Commission (FERC).[56] Such an action will have two effects: (1) it will help states and regions to enforce their LCP's, and (2) it will encourage states and regions to adopt LCP's, because by adopting plans, they gain an important mechanism to affect FERC rulings.

   b) Proposed amendments to the Public Utility Holding Company Act (PUHCA) making it easier for utilities to construct new power plants outside of the purview of state regulatory commissions should require a demonstration that electricity purchased from independent producers or other PUHCA-exempt suppliers is consistent with approved least-cost plans at the state or regional

[54](...continued)
Cynthia, "Lagging in Least-cost Planning -- Not as Far Along as we Thought," *The Electricity Journal* 2(10), December 1989, pp. 24-31.

[55] The conclusions of the Mitchell/Wellinghoff survey show much less progress than reported in the U.S. Department of Energy, *National Energy Strategy*, at page 36, or a similar EPRI survey: *Electric Power Resource - Status of Least-Cost Planning in the United States*, EM 6133, 1988. The EPRI survey relied on a much less detailed questionnaire and did not use personal interviews. In some instances, the EPRI survey interpreted isolated load forecasts or the existence of energy efficiency programs as evidence of a full implementation of LCP. For these reasons, we have relied on the Mitchell/Wellinghoff study.

[56] *The National Energy Strategy* (U.S. Department of Energy, Washington, DC, Feb. 1991) at page 37, contains a similar provision allowing State commissions to disallow FERC-approved expenses at the retail level if the State commission determines that the transaction is not consistent with the State's LCP.

level before the cost of such purchases is allowed to be passed through to ratepayers. [57]

c) Federal actions relating to review of electric utility proposals under the National Environmental Policy Act (NEPA), and to any mandatory federal approval or permit required for utility facilities, should be required to be consistent with state and region approved least-cost plans.

2. Encourage regional least-cost planning where utility service areas cross state boundaries. A number of major holding companies and utilities cross state lines, and power planning for these utilities should strive to minimize energy service costs throughout the system.

   Congress should pass legislation authorizing and encouraging states to set up regional compacts, for the purpose of pursuing LCP on a multi-state basis.[58] The decision of whether to create such a compact would be at the discretion of the individual states. Requiring FERC actions to be consistent with approved regional least-cost plans would encourage states to enter into regional compacts.[59]

3. Adopt the "societal test" as the basis for all least-cost plans. The foundation of least-cost planning is selection of the proper planning criteria or cost-effectiveness test. That is, whose costs are being minimized? Most states and utilities use either the Utility Cost test (which seeks to minimize utility revenue requirements and ignores direct customer expenditures for efficiency measures) or the Total Resource Cost (TRC) test (which minimizes costs to customers, including money paid to the utility through rates, as well as money paid directly for efficiency measures). Increasingly, states are using the Societal Cost test, which is similar to the TRC test, but also includes consideration of environmental externalities. We recommend that all states and utilities use the

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[57] Hempling, Scott, "Confusing 'Competitors' with 'Competition'," *Public Utilities Fortnightly* 127(6), pp. 30-32, March 15, 1991.

[58] A constructive proposal has been jointly developed by Entergy, the Arkansas Public Utility Commission, and the City of New Orleans. See National Association of Regulatory Utility Commissioners, *Collaborative Jurisdiction in the Regulation of Electric Utilities: A New Look at Jurisdictional Boundaries*, Washington, DC, 1991.

[59] There is presently one precedent in the U.S. for a commission of this sort. In 1980 Congress established the Northwest Power Planning Council, with authority to pursue LCP in the states of Washington, Oregon, Idaho, and Montana. Utilities in the Northwest spent over $800 million on conservation programs during 1980-86 and acquired the capability to implement efficiency improvements on a large scale. Northwest Power Planning Council, "A Review of Conservation Costs and Benefits - Five Years of Experience Under the Northwest Power Act", Portland, OR, 1987.

Societal Cost test for all planning activities. Any other test focuses on only a subset of costs or benefits, and thus run the risk of advantaging one group of interests at the expense of society at large.

4. Congress should require federal power marketing agencies such as the Bonneville Power Administration (BPA), the Tennessee Valley Authority (TVA), and the Western Area Power Administration (WAPA) or the utilities who receive low-cost power from these agencies to prepare and implement least-cost plans. Legislation to this affect has been introduced into the 102nd Congress.[60]

5. New or existing federal benefits bearing a reasonable relationship to energy and the environment should be made contingent on the adoption of LCP. State participation in federal programs often depends on compliance with federally established minimum requirements. For example, federal highway funding is conditioned upon state-established and enforced speed limits. Because the nation's energy and environmental policies would be undermined by utility actions inconsistent with least-cost planning, conditioning energy and environmental benefits on the adoption of LCP is an effective way to leverage limited federal resources.[61]

6. Increase access to the transmission grid to facilitate power exchange among utilities and regions. Greater access to the transmission system will provide additional markets for capacity and electricity made available through efficiency efforts in a particular service area. A utility with excess capacity would be able to invest greater amounts in electricity conservation programs if the freed-up power can be readily sold to capacity-short utilities. Wisconsin, for example, is opening up its transmission grid in part to facilitate integrated least-cost planning and conservation efforts.[62]

7. The U.S. Department of Energy's Integrated Resource Planning (IRP) program's budget should be greatly expanded. The IRP program has carried

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[60] HR 776 introduced by Representative Sharp, HR 1543 introduced by Representative Lent, and S. 741 introduced by Senators Wirth and Hatfield.

[61] An excellent example of conditioning federal benefits on the utilization of LCP is a recently adopted provision of the Clean Air Act (in the Amendments of 1990), making the benefits of extra allowances for efficiency and renewable energy programs available to utilities in states with LCP processes in place. See Markey, Edward and Carlos Moorhead, "The Clean Air Act and Bonus Allowances," *Public Utilities Fortnightly* 127(10), May 15, 1991, pp.30-34.

[62] Arny, M.D. "The Transmission and Distribution System Planning in Least Cost Planning: The Link Between the Demand-Side and the Supply-Side", *Proceedings of the DSM and the Global Environment Conference*, Arlington, VA, April 1991.

out a successful, but limited, multi-year program supporting LCP. This program funds research and training on LCP issues, based on priorities identified each year by DOE in association with other interested parties.

In 1991 funding for these activities was only about $3 million per year. In 1992, this will be raised to $4 million. Many states that have not yet adopted LCP generally have very small staffs and little other technical support. Encouraging these states to adopt LCP will require a much more extensive program of training and technical assistance. Grants should be made available to states to offset the up-front costs of holding a LCP rulemaking, and of acquiring and training necessary staff.[63]

REGULATORY REFORM

Adopting least-cost planning is simply not enough if the regulatory system continues to reward utilities that ignore energy efficiency, and punish utilities that successfully implement least-cost plans. It is critical to reform the regulatory system so that the successful implementation of cost-effective energy efficiency opportunities is more profitable than other more costly resource options.

NARUC passed a resolution pointing out the inconsistencies between existing regulatory methods and LCP. The resolution urges states to adopt needed regulatory reform.[64] About 20 states have initiated the process to reform their regulatory systems and many states including California, Massachusetts, Rhode Island, New Hampshire, Maine, New York, Oregon and Washington, have implemented regulatory reform plans designed to make utility least-cost planning a profitable course of conduct.[65]

Experience shows that regulatory reform can have a significant and positive impact on utility planning and investment decisions.[66] For example, a late-1991 comparison between

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[63] This provision is included in both S. 1220, 102nd Congress, introduced by Senators Johnston and Wallop, and H.R. 143, 102nd Congress, introduced by Representative Lent and 30 other co-sponsors.

[64] For a copy of the text of the resolution, see Moskovitz, David, *Profits and Progress Through Least-Cost Planning*, National Association of Regulatory Commissioners, Washington, DC, Nov. 1989.

[65] For a summary of the regulatory reform plans adopted see Reid, Michael, "The Evolution of DSM Incentives" in Nadel, Reid, and Wolcott (eds.), *Regulatory Incentives for Demand-Side Management*, American Council for an Energy-Efficient Economy, Washington, DC, 1992 (forthcoming).

[66] Moskovitz, David, "Decoupling Sales and Profits: An Incentive Approach that Works," *The Electricity Journal* 4(6), July 1991, pp. 46-53.

WHY THE "NO-LOSERS" TEST IS WRONG

The "no-losers" test or ("rate impact test") focuses on the impact of utility actions on electricity prices rather than electricity bills (bills are the product of price and consumption; if prices go up due to a DSM program, bills often still go down because consumption is substantially lower). The no-losers test limits utility investment in end-use energy efficiency to programs that have no negative impact on electricity prices. Under the "no losers test" utility investment in demand-side programs is limited to the difference between the utility's retail rate and marginal cost. In many parts of the country this difference is small or even negative. This test should be rejected for several reasons:

a) The economic rationale of the no losers test is that electricity prices provide an adequate incentive and reason for customers to invest in energy efficiency without utility assistance. This is contrary to the overwhelming experience of market failure and low consumer investment in energy efficiency. In addition, without regulatory reform, energy conservation is contrary to a utility's financial interest even if the conservation is undertaken by customers and solely at the expense of customers.

b) The no-losers test ignores the overall cost savings of conservation. Even if the total benefits achieved by a demand-side program are many times greater than the costs to non-participants, under the no-losers test, the program would be rejected. Indeed, in many jurisdictions the "no-losers" test would reject even zero cost energy efficiency improvements (since reduced sales will sometimes increase rates).

c) Even when rate impacts occur, they are generally small and scarcely noticeable. For example, a recent ACEEE study examined the impacts of a very aggressive set of DSM programs on the rate payers of New York State's three largest utilities. The programs were assumed to operate for a twenty year period. For this period, rates were projected to increase by an average of 5% for the three utilities studied.[67]

d) So few customers have installed all cost-effective DSM measures, that nearly all customers can benefit from comprehensive utility efficiency programs. For example, as noted earlier, most customers will not invest in DSM measures if the simple payback for the measure is greater than 1-3 years. Many DSM measures with simple payback periods of five years or more are cost-effective to the utility and to society.

e) The no-losers test ignores the value of externalities such as environmental externalities. As is illustrated in Table 5, DSM programs generally have lower environmental costs than new power plants. Thus, even non-participants in DSM programs benefit from cleaner air and other environmental improvements.

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[67] Nadel, Steven and Harvey Tress, *The Achievable Conservation Potential in New York State*, New York State Energy Research and Development Authority, Report 90-18, Albany, NY, Nov. 1990.

16 utilities with incentive mechanisms in place and a group of neighboring utilities without incentives found that relative to the no-incentives utilities, the utilities with incentives increased their levels of DSM activity significantly after the incentives took effect.[68] Similarly, a recent review of incentives and DSM activity at Puget Sound Power and Light found that incentives had a dramatic impact on the utility's plans.

Although states must have the flexibility to adopt regulatory reforms that fit their individual conditions, two general changes should be pursued in all states.

Recommendations:

1. Profits should be decoupled from sales where this has not yet occurred. There are several ways to accomplish the needed decoupling of profits and sales.[69] For example, California adopted an "Electric Revenue Adjustment Mechanism" (ERAM) under which a balancing account is used to true-up revenues based on how actual sales compare to forecasted sales. The method is time tested and has widespread support in California.[70] A similar method was approved in New York in 1990 and 1991 for two utilities.[71]

   But the California and New York methods are not useful in the majority of states, which rely on historic test-year methods. A new decoupling approach adaptable to any state jurisdiction was approved in 1991 by the Oregon and Maine utility commissions.[72] With these modified methods, the annual true-

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[68] Nadel, Steven and Jennifer Jordan, "Will the Rat Eat the Cheese? -- A Preliminary Evaluation of DSM Incentives Provided to Utilities," in "The Evolution of DSM Incentives," Nadel, Reid, and Wolcott (eds.), *Regulatory Incentives for Demand-Side Management,* American Council for an Energy-Efficient Economy, Washington, D.C., 1992 (forthcoming).

[69] For a comprehensive discussion of the need for decoupling and alternative methods see David Moskovitz, *Profits and Progress Through Least-Cost Planning*, National Association of Regulatory Utility Commissioners, Washington, DC, November 1989.

[70] Marnay, C. and G.A. Comnes, *Ratemaking for Conservation: The California ERAM Experience*, LBL-28019, Lawrence Berkeley Laboratory, Berkeley, CA, March 1990.

[71] See "Agreement and Settlement Concerning Rate Plan, Performance Incentives and Revenue Decoupling Mechanism for Orange & Rockland Utilities, Inc.," New York Public Service Commission, Albany, NY, June 8, 1990.

[72] Moskovitz, David, "Decoupling Sales and Profits: An Incentive Approach that Works," *The Electricity Journal* 4(6), July, 1991, pp. 46-53.

up is based on variations in the number of customers, not variations in kWh sales.[73]

2. Consistent with the shift of focus from kilowatt-hours to energy services, revised regulatory schemes should reward a utility's successful implementation of a least-cost plan. Utilities satisfying customer energy service demands with low-cost energy efficiency investment should be rewarded by positive incentives, such as being permitted to keep a fraction of the net economic savings they produce.[74]

IMPROVE AND INCREASE UTILITY EFFORTS IN ENERGY EFFICIENCY

Cost-effective utility conservation and load management programs can reduce electricity use and peak demand by a substantial margin. For example, a recent study examined the amount of savings that could be achieved by New York State's three largest utilities from an aggressive set of conservation programs. Results are summarized in Table 6. As noted in Table 4, a number of utilities are now planning to achieve savings of this magnitude.

Savings goals on the scale shown in Table 6 should be adopted throughout the utility industry. Reaching these goals will require a significant increase in overall utility spending on demand-side management programs. The study of three New York utilities discussed previously found the cost of DSM programs would average about $320 million annually (1991 $), about 3.6% of the 1989 gross revenues of these companies, more than three times the actual DSM budgets of these companies in 1991.[75] Similarly, Oak Ridge National

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[73] Maine Public Utility Commission, "Investigation of Chapter 382 Filing of Central Maine Power Company," Docket Mo. 90-85, Augusta, ME, May, 1991. Also, Washington Utilities and Transportation Commission, "In the Matter of the Petition of Puget Sound Power and Light Company for an Order Approving a Periodic Rate Adjustment Mechanism and Related Accounting," Olympia, WA, April 1991.

[74] For example, states such as Rhode Island, New York, New Hampshire and California have adopted "shared savings" approaches whereby a utility is allowed to keep a portion of net societal economic benefits if it meets certain energy savings and cost-effectiveness goals. See also, Rowe, John, "Making Conservation Pay: The NEES Experience," The Electricity Journal 3(10), December 1990, pp. 18-25. Also, Schultz, Don and Joseph Eto, "Carrots and Sticks: Shared-Savings Incentive Programs for Energy Efficiency," *The Electricity Journal* 3(10), December 1990, pp. 32, 37-46.

[75] Nadel and Tress, *The Achievable Conservation Potential in New York State from Utility Demand-Side Management Programs*, Report 90-18, New York State Energy Research and Development Authority, Albany, NY, Nov. 1990; New York State Department of Public Service, *Financial Statistics of the Major Privately Owned Utilities in New York State, 1989*,
(continued...)

Table 6. Conservation Savings Possible from Cost-Effective Utility Conservation Programs in New York State as a Percent of Sales or Peak Demand in the Absence of Programs.[76]

Item	Con Ed	LilCo	NiMo	Wtd. Avg.
Electricity savings (kWh)				
2000	16.8%	12.0%	9.8%	13.0%
2008	16.9	11.9	11.0	13.5
Summer peak savings (kW)				
2000	14.0	9.3	10.6	11.9
2008	15.3	9.9	12.2	13.1

Source: Nadel and Tress, *The Achievable Conservation Potential in New York State from Utility Demand-Side Management Programs*, Report 90-18, New York State Energy Research and Development Authority, Albany, NY, Nov. 1990.

Laboratory found that to achieve 20% savings from DSM programs will require increasing DSM budgets nationwide from $2.1 billion per year (1990 $) in 1990 to $33 billion (2010 $) in 2010.[77] As shown in Table 2, a few utilities have DSM budgets of 3% or more of gross revenues, and the number increases each year, but hundreds of utilities will have to make commitments of this magnitude before the true savings potential of cost-effective utility programs can be realized.

Achieving savings of the magnitude shown in Table 6 also will require a fundamental change in the way most utilities offer demand-side management services to their customers. Successful programs generally feature extensive marketing, with an emphasis on personal one-on-one efforts, incentives which pay more than half the cost of measure installation, and extensive technical assistance helping customers to identify and install suitable efficiency

[75](...continued)
Albany, NY; Pace Center for Environmental Legal Studies, et. al., "Comments on the 1991-92 Annual and Long Range Demand Side Management Plans of the Major Electric Utilities," White Plains, NY, September 1990.

[76]For this study 21 different conservation programs were designed, based on the results of some of the most successful utility-operated programs now in place. These programs were then analyzed for savings and cost-effectiveness. Programs were limited to technologies that have already been commercialized, which limited the amount of savings achieved after 2000. The analysis did not include load management programs (programs which do not reduce energy use but instead shift use from one period to another, thereby reducing peak demand).

[77] Eric Hirst, *Possible Effects of Electric Utility DSM Programs, 1990 to 2010*, ORNL/CON-312, Oak Ridge National Laboratory, Oak Ridge, TN, January 1991.

measures.[78] In addition, because DSM measures are still relatively new in some regions of the U.S., sometimes an underlying infrastructure must be developed including knowledgeable utility staff, skilled designers and installers, and manufacturers and distributors who can supply efficient equipment in the quantities needed. When the infrastructure to support DSM programs is not properly developed, delays and quality-control problems can result.[79] Finally, programs must be periodically evaluated, in order to determine the actual savings achieved, and the results of these evaluations used to design program improvements. Without this feedback loop, problems with program design and implementation cannot be identified and solved.

Many successful programs have been developed in collaborative program design processes. Utilities work together with interested parties, including government officials, environmental and consumer groups, and customer representatives, to design an aggressive set of efficiency programs. Successful collaborative efforts have been undertaken in Connecticut, Massachusetts, California, and New York, and efforts have begun in a number of other states.[80]

The large savings that could be achieved by utility DSM programs leads to several recommendations:

1. Utilities should invest in all cost-effective energy efficiency opportunities costing less than marginal operating and capital costs of new power plants, including reasonable estimates of environmental externalities.

2. Based on the experience of leading utilities, utilities should target kWh and kW savings of at least 1% for each year of program operations. To achieve these targets will likely require an annual investment of at least 2% to 3% of the utilities' annual gross revenues. This would bring nationwide utility investment in efficiency to over $5 billion in 1991, almost triple the likely expenditures in 1991.

3. All DSM programs should be thoroughly evaluated by the sponsoring utility. Evaluations should examine actual savings and cost effectiveness, and should

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[78] Nadel, Steven, *Lessons Learned: A Review of Utility Experience with Conservation and Load Management Programs for Commercial and Industrial Customers*, Report 90-8, New York State Energy Research and Development Authority, Albany, NY, April 1990.

[79] For example, due to the impact of utility programs which promote compact fluorescent lamps and electronic ballasts, there is a nationwide shortage of this equipment which has caused delays for a number of utilities. See Rieger, Ted, "Supply Trails Demand for Compact Fluorescent Light Bulbs," *Home Energy* 8(6), Nov./Dec. 1991, pp. 7-8.

[80] See for example Cohen, Armond and Michael Townsley, "Perspectives on Collaboration as Replacement for Confrontation," *Public Utilities Fortnightly* 125(5), March 1, 1990, pp. 9-13.

identify ways of increasing program impact within the cost-effectiveness limits. Utilities and regulators should not be afraid of (or penalized for) identifying, modeling, or dropping unsuccessful programs. It is better to find and correct such mistakes before additional sums of money are spent on large-scale implementation.

4. DOE, EPRI, and other appropriate organizations, should provide increased assistance to utilities in the design and evaluation of state-of-the-art programs that maximize participation and savings while remaining cost-effective to the sponsoring utility. Among the activities that should be sponsored are the development and maintenance of a database of DSM program results that is in the public domain and periodic reports and workshops on how best to design programs for particular customer segments.[81]

5. Utilities should work together, with support from DOE, EPRI, and other appropriate organizations to develop the infrastructure needed to support DSM programs nationwide including skilled staff to plan programs and identify and install measures, and manufacturers who can produce the requisite equipment in the desired quantities.

6. Congress should repeal a recent IRS ruling that subjects utility rebates for energy efficiency measures to taxation. In 1989 the IRS issued a technical advice memorandum which held that cash rebates to customers from utilities are subject to taxation. This provides a significant disincentive to rebate program participation. Recently, several bills were introduced in Congress to restore the income tax exemption.[82] We urge speedy enactment so that electricity conservation programs sponsored by electric utilities are not set back.

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[81] A number of efforts along these lines have been undertaken, but all fall short of meeting utility's long-term needs. For example, a group of utilities in the northeast have developed a database on the programs they sponsor, but access to this database is primarily restricted to member utilities. Similarly, ACEEE developed a database in 1989 of commercial and industrial programs, but ACEEE does not have the resources to update this database on a regular basis. Likewise, DOE, EPRI, and others periodically put out reports on DSM subjects, but these efforts are often one-time efforts. Also, in some cases, these reports are short on information on program failures. This data is needed to complement data on program successes so utilities can avoid repeating mistakes made by others. The Lawrence Berkeley Laboratory has recently proposed a project to fill this niche -- funds are now being sought (Vine, Ed, personal communication, Lawrence Berkeley Laboratory, Berkeley, CA, Oct. 1991).

[82] Edison Electric Institute, "Tax Treatment of Energy Conservation Incentives," Washington, DC, April 1991.

PUBLIC UTILITY REGULATORY POLICIES ACT (PURPA) REFORM

In 1978, the Public Utility Regulatory Policies Act (PURPA) was enacted to encourage the development of cogeneration and certain small power production facilities known as qualifying facilities or QFs.

Cogeneration facilities make efficient use of fuel by generating both electricity and other useful work, such as steam for heat or industrial purposes. Small power production facilities, as defined by PURPA, primarily utilize fuel from renewable supplies. PURPA was adopted to overcome the institutional and regulatory biases hampering the development of QFs. The solution was the removal of regulatory barriers and a federal mandate requiring utilities to buy power from QFs whenever it was no more costly than conventional power supply options. Implementation was left to the states.

State implementation of PURPA has led to the development of large amounts of new QF capacity at costs lower than conventional supply-side resources. Today, QFs account for a significant fraction of all new generating capacity.[83]

The valuable experience gained through PURPA should be harnessed to create a competitive energy efficiency industry. Just as utilities are required to purchase power from cost-effective QFs, so should they be required to invest in energy efficiency whenever efficiency costs less than other options.

Competitive bidding, now commonplace for QF acquisition, should likewise be expanded to include energy efficiency options to a great extent. Maine, New York, Massachusetts, Washington, New Jersey, Colorado, and several other states use competitive bidding systems to identify and acquire new demand-side resources as supplements to other utility programs; but, in general, bidding for supply of power is much more frequent and larger scale than bidding for energy efficiency improvements.[84] Expansion of these efforts will speed the development of a competitive energy efficiency market and allow efficiency opportunities to compete fairly with all supply options.

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[83] The North American Electric Reliability Council (NERC) now forecasts that QFs (or non-utility generators) will account for over 21% of all new generating additions by the year 1999. This represents about 5,000 MW more capacity from these resources than was forecast a year ago. Because most (73.2%) of the capacity additions expected by 1999 are not yet under construction, we expect that the fraction supplied by QFs will continue to grow as QFs are given the opportunity to compete against utility resources. North American Electric Reliability Council, *1990 Reliability Assessment*, September 1990.

[84] For a detailed breakdown of utility and state bidding programs see, National Regulatory Research Institute, "Implementing a Competitive Bidding Program for Electric Power Supply," Columbus, Ohio, January 1991. Also, "Financial Incentives to Make Power Purchases: Should It Pay to Buy?," *Current Competition 2(5)*, May, 1991, pp.1, 4-16.

EXAMPLES OF SUCCESSFUL UTILITY ENERGY-EFFICIENCY PROGRAMS

New England Electric Small C&I Program

New England Electric provides "soup to nuts" conservation services to small commercial and industrial (C&I) customers through its Small C&I Program. Under the program, contractors hired by the utility visit a customer's facility, identify cost-effective conservation measures, and install the measures at no cost to the customer. All the customer has to do is agree to participate and approve the specific measures prior to installation. In the first seven months of the program, over 2000 customers were served. Over 90% of the customers approached by the utility have elected to participate in the program. Based on program cost and savings estimates, the program is expected to cost the utility 3.6 cents/kWh saved (there are not customer costs).[83]

Northeast Utilities Energy Action Program

Northeast Utilities provides comprehensive conservation services to large C&I customers through its Energy Action Program. Under the program, "contractor/arrangers" hired by the utility work with customer staff to conduct comprehensive energy audits, prepare comprehensive specifications on recommended measures to be used to solicit installation bids, and oversee construction. The utility provides a financial incentive sufficient to buy down the cost to the customer to a 1-3 year payback (cost to the customer equals the value of energy savings in 1-3 years, varying by state and customer class). After three years, nearly 700 large customers have been served. Approximately half the customers approached have elected to participate. When all measures now under contract are installed, savings will total nearly 200 GWh/year, which amounts to a peak load reduction of approximately 50 MW. The average cost of these savings to the utility is estimated to be 4.4 cents/kWh.[84]

PG&E Commercial New Construction Program

Pacific Gas and Electric Company (PG&E) offers rebates for new commercial buildings whose efficiency exceeds state energy code requirements (and California's energy code is one of the strictest in the U.S.). Incentives are paid for lighting improvements; installing high performance glazing (windows), and installing high efficiency cooling, refrigeration, and motor systems. Incentives increase as the equipment efficiency increases. The utility also provides free technical assistance and blueprint review services. The program is marketed

[83] Horton, Michael, New England Electric, personal communication, May 1991. Also, Massachusetts Electric, "Integrated Resource Management Initial Filing, Technical Volumes," Westborough, MA, Aug. 1991.

[84] Connecticut Light and Power, *Conservation and Load Management Programs, Annual Report for 1990*, Rocky Hill, CT, April 1991. Also, "ECM Summary Report, 7/26/91," Northeast Utilities, Rocky Hill, CT. The MW savings figure assumes a typical facility operates 4000 hours/year.

SUCCESSFUL PROGRAMS (continued)

through extensive personal contacts with building owners, developers, and initial tenants. In the first year of the current program, buildings representing approximately 27% of new commercial floor area participated in the program. Preliminary estimates indicate that energy-use in participating buildings is 30% below code requirements.[85]

Bonneville Power Administration Residential Weatherization Program

The Bonneville Power Administration's (BPA) Residential Weatherization Program combines a free energy audit, arranging for measure installation (primarily insulation and storm windows), and a rebate averaging 75% of measure costs (rebates are based on engineering estimates of the annual kWh savings). In the first six years of program operation, 23% of eligible customers (electric space heat customers) received rebates. Due to the high rebate amount, the program has been popular with customers, so only limited marketing has been needed. Participation has been limited by available budgets. A variation on the program was offered in Hood River, Oregon where conservation improvements were installed in 85% of eligible homes by combining 100% grants with intensive, community-based marketing. Depending on the year and program variation being analyzed, net savings for BPA's weatherization programs have averaged approximately 12%. Based on statistical analyses of changes in electricity use in participating and non-participating households, utility costs for the basic weatherization program have averaged approximately 5.4 cents/kWh.[86]

Central Maine Power Lions Club Light Bulb Sale

Central Maine Power (CMP) used a novel approach to promote compact fluorescent bulbs. In the CMP territory, a public service organization (the Lion's Club) conducts an annual light bulb sale to raise money for charity. Normally the Lion's Club sells standard incandescent bulbs, but CMP enticed them to sell compact fluorescents. Under the program CMP purchased the bulbs in bulk and gave them to the Lion's Club, which sold them for $3 each. In the first year of the program, available bulbs were sold out in two weeks -- over

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[85] PG&E Energy Efficiency Services, "New Construction Programs, Presentation to the External Policy Advisory Group, December 20, 1990," San Francisco, CA. Also, PG&E, "New Construction Rebates, Commercial Program," San Francisco, MA, November, 1990; Furness, Robin, PG&E, personal communication, January 1991.

[86] White, Dennis, and Marilyn Brown, *Electricity Savings Among Participants Three Years After Weatherization in Bonneville's 1986 Residential Weatherization Program*, ORNL/CON-305. Oak Ridge National Laboratory, Oak Ridge, TN, Sept. 1990. Also, Nadel, Steven, "Electric Utility Conservation Programs: A Review of the Lessons Taught by a Decade of Program Experience," in Vine and Crawley (eds.), *State of the Art of Energy Efficiency: Future Directions*, American Council for an Energy-Efficient Economy, Washington, DC, 1991, pp. 61-104.

SUCCESSFUL PROGRAMS (continued)

20% of CMP's residential customers purchased bulbs through the program. Cost of the program to CMP was approximately 2.5 cents/kWh saved.[87]

[87] *Ibid.* Also, Schick, Birnbaum, Blagden, and Adelaar, *Review and Assessment of US Utility Experience with Residential Energy-Efficiency Programs (draft)*, Ontario Hydro, Toronto, Canada, March 1990, Section VII.

Also, while PURPA has largely been very successful, PURPA can provide a vehicle to further increase power plant efficiency. Under existing FERC regulations, a cogeneration facility can use as little as 5% of the thermal energy it produces for a purpose other than electric power production and still qualify for PURPA benefits as a cogeneration facility. During 1988-90, over half of the total cogeneration capacity proposed to FERC would use only 5-15% of available thermal energy.[90] A more restrictive threshold for thermal energy use would help improve overall plant efficiencies.

Recommendations:

1. PURPA should be amended to allow energy efficiency to compete against power supply options.

2. States should be encouraged to develop competitive bidding or other competitive systems to acquire new demand and supply-side resources.

3. DOE, EPRI, and other appropriate organizations should conduct additional research on how best to integrate utility-operated DSM programs with programs operated by successful DSM bidders, in order to minimize customer confusion from competing efforts, and maximize the amount, and cost-effectiveness of the savings achieved.[91]

4. FERC or Congress should require that cogeneration QFs use at least 30% of the thermal energy produced for a purpose other than electric power production and that at least 70% of the total thermal energy is used for heat plus electricity.

ENVIRONMENTAL TRUST FUND/FEDERAL AND STATE TAX POLICIES

Environmental costs should be considered when utilities acquire new resources or operate existing power plants. The shadow pricing systems implemented in some states are a commendable first step. However, shadow pricing systems have no effect on existing sources, and only to a small degree do they result in environmental costs being reflected in consumer prices. In fact, using shadow pricing only for the selection of new power plants

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[90] In contrast, only 12% of proposed capacity would use over 50% of available thermal energy. Capehart, Barney and Lynne Capehart, "Efficiency in Industrial Cogeneration: The Regulatory Role," *Public Utilities Fortnightly* 125(6), March 15, 1990, pp. 17-24. Also, Capehart, Barney and Lynne Capehart, "Efficiency Trends for Industrial Cogeneration," *Public Utilities Fortnightly 127(7)*, April 1, 1991, pp. 28-31.

[91] In cases of utilities with aggressive program efforts of their own, there may be less of a role for programs operated by bidders. For other utilities, bidder-operated programs may predominate. For many utilities, bidders and utilities will operate together, with some customer segments primarily served by utilities, and others by bidders.

could lead to greater use of dirtier existing power plants, thereby resulting in more rather than less pollutant emissions.[92]

Full consideration of environmental costs begins with estimates of the environmental costs associated with a unit of each major pollutant. On a phased-in basis, pollution fees should be charged to all new and existing resources in relation to the amounts of pollution actually emitted.[93] The cleaner the resource the less the pollution fee assessed. This would give utilities a financial incentive to reduce emissions below maximum allowed levels and operate power plants in a way that lowered overall emissions.[94]

All or part of the revenues collected by utilities as a result of the pollution fees should be deposited in an Environmental Trust Fund (ETF). The ETF would be used for mitigation, redress, restoration, or prevention of environmental degradation. For example, ETF funds might be offered to utilities on a cost-sharing basis for tree planting, energy efficiency and renewable energy R&D, or installing additional pollution control equipment beyond that needed to meet existing regulatory requirements. A particular target of ETF funds should be areas that are presently in non-compliance with The Clean Air Act and other environmental laws.

Recommendations:

1. Give high priority to the federal funding of studies to improve existing estimates of the cost of energy-related environmental discharges.

2. Adjust energy prices to reflect the <u>full</u> cost of producing and distributing power, including the cost associated in pollutant emissions.

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[92] Palmer, Karen and Hadi Dowlatabadi, "Implementing Environmental Costing in the Electric Utility Industry," Discussion Paper QE91-13, Resources for the Future, Washington, DC, May 1991.

[93] Emissions taxes have been adopted in some European countries (e.g., Sweden and The Netherlands). See Schmidt, Karen, "Industrial Countries' Responses to Global Climate Change," Environment and Energy Study Institute, Washington, DC, July 1991; Wiel, Stephen, "The New Environment Accounting: A Status Report, *The Electricity Journal 4(9)*, Nov. 1991. pp. 46-55.

[94] For example, one study that examined the New England and New York power pools found that by adding emissions costs to the normal costs of operating different types of power plants, plant dispatch changed significantly. As a consequence, regional SO2 emissions fell by 67%, NOx emissions fell by 26%, particulates fell by 65%, and CO2 emissions fell by 19%. Bernow, S., B. Biewald, and D. Marron, "Full-Cost Dispatch: Incorporating Environmental Externalities in Electric System Operation," *The Electricity Journal* 4(2), March 1991, pp. 20-33.

3. Direct part if not all of the incremental revenue associated with environmental externalities to an Environmental Trust Fund which would be established and managed by the EPA. Expenditures from the ETF should be limited to environmental mitigation, redress and R&D on technologies that would lower pollutant emissions.

4. State and federal policy makers should examine the environmental benefits of the revenue-neutral conversion of existing utility taxes (including sales, gross revenue, property and income taxes) to taxes based on environmental emissions. Detailed studies are needed of the environmental impacts of shifting utility taxes from sales revenue, profits, and the like, to pollutant emissions.[95]

ELECTRICITY PRICING

Electricity will be used most efficiently if it is priced to match the full social marginal cost at the time of use, and in the quantity used. Including environmental costs in consumer prices would allow consumers to take into account the broadest impacts of their actions when making decisions influencing energy use.

Pricing practices should include elimination of declining block, "incentive", "economic development", and "cogeneration deferral" rates, all of which are based only on short-run marginal fuel costs. Price structures should also make greater use of time-of-day and seasonal pricing structures, as well as increase the availability and marketing of interruptible rates.

Innovative pricing also means greater use of pricing structures such as sliding-scale hook-up fees that assess a fee or pay a rebate to new customers, based on the energy intensity and energy efficiency of the facility. Under current pricing practices the cost of new power plant construction is paid for by all consumers. As a result, many customers and home builders decide to save first-year capital costs and install too little insulation and low-initial-cost electric resistance space heat, even though more insulation and different heating sources would be more cost effective than building a new power plant to service the additional load. Assessing a portion of the cost of new capacity as an up-front charge provides the customer, or the builder in the case of construction for resale, with a more accurate electricity price to consider when making construction and design decisions.[96]

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[95] Sales and gross revenue taxes paid by utilities account for about 5% of existing utility revenue requirements, or about $10 billion per year. Collecting the same $10 billion on the basis of air emissions will cause shifts in fuel use, levels of investment in pollution control equipment, and energy conservation.

[96] The fee or rebate would typically be assessed on the basis of the estimated peak load relative to an energy-efficient structure (a structure incorporating most cost-effective

(continued...)

Utilities have been reluctant to implement innovative pricing structures because of risks to utility earnings. The direct linkage between profits and sales characterizing the existing regulatory scheme provides utilities with ample reason to resist implementing rate structures that cut sales and profits. Adoption of the regulatory reform recommendations described above should eliminate such resistance.[97]

Recommendations:

1. Eliminate pricing practices that encourage wasteful energy use such as incentive rates and declining block rates. These rates send the wrong price signals to consumers.

2. Pricing policies such as time-of-day rates, interruptible rates, and sliding-scale hook-up fees should be promoted by DOE, NARUC, EPRI, and the Edison Electric Institute. Also, DOE and EPRI should conduct evaluations and R&D that could extend the applicability of these mechanisms and increase utility confidence in their viability.

3. Congress should encourage entities such as Bonneville Power, Tennessee Valley Authority, and those utilities federally financed through regional Power Marketing Agencies and the Rural Electrification Administration, to become industry leaders in the adoption and demonstration of innovative pricing structures.

BUILDING CODES AND EQUIPMENT EFFICIENCY STANDARDS

Utility DSM programs are likely to capture only a portion of the available, cost-effective savings in a particular region. For example, aggressive utility DSM programs in New York state might reduce electricity use by 10-17% (see Table 6), while the cost-

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[96](...continued)
efficiency measures, even those that exceed building code requirements). For example, one proposal now pending in Massachusetts would establish a revenue neutral fee/rebate program for new large commercial buildings -- inefficient buildings will be charged a fee, and the funds collected used to pay rebates for buildings that exceed the program's efficiency targets (Commonwealth of Massachusetts, H. 6496, "An Act Reducing the Greenhouse Effect by Promoting Clean and Efficient Energy Resources," Boston, MA, 1990). A similar program directed at residential customers was implemented in Maine. Studies by Central Maine Power Company showed that the pricing scheme lowered the forecast of residential demand growth by about 15%. Legislation sponsored by electrical contractors prevented the charge from ever taking effect.

[97] Moskovitz, David, "Decoupling Sales and Profits: An Incentive Approach that Works," *The Electricity Journal* 4(6), July, 1991, pp. 46-53.

effective savings potential is on the order of 34%.[98] Achieving the remaining savings will require additional mechanisms. Two such mechanisms are building codes and minimum efficiency standards for new equipment.

Building codes have been adopted by most states in the U.S. and typically include energy efficiency provisions in the form of insulation requirements, equipment efficiency requirements, and limits on the connected power load for certain end-uses (lighting in commercial buildings for example).[99] Codes do not, however, require all efficiency improvements which are cost-effective over the life of the building.[100] Also, state code energy requirements are often not fully enforced, as busy code inspectors concentrate on fire and safety issues, and leave energy requirements up to engineers, architects, and builders to meet.[101] Nonetheless, energy codes can significantly raise the average efficiency of new buildings.[102]

Minimum efficiency standards have also been established by states and the federal government for a number of energy-consuming products. In 1987 and 1988, Congress adopted national efficiency standards on residential appliances (refrigerators, freezers, air

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[98] Nadel, Steven and Harvey Tress, *The Achievable Conservation Potential in New York State from Utility Demand-Side Management Programs*, Report 90-18, New York State Energy Research and Development Authority, Albany, NY, Nov. 1990.

[99] For a state-by-state description of energy requirements in state building codes see National Conference of States on Building Codes and Standards, *Energy Directory*, Herndon, VA, May 1991.

[100] Of the standards used as a basis for state building codes, only the yet-do-be-finalized ASHRAE 90.2 standard for residential buildings sets efficiency requirements based on a cost-effectiveness analysis, and even this code includes political compromises (e.g., the same efficiency requirements are used for electric-heated buildings as for oil- and gas-heated buildings, even though electricity is significantly more expensive per Btu of heat). Most state residential codes are less stringent than the proposed ASHRAE 90.2 standard, indicating the significant margin for code improvement. In the commercial sector, cost-effectiveness screening is not generally employed, although ASHRAE is planning to include cost-effectiveness analysis as it develops the mid-1990's version of its 90.1 standard for non-residential and high-rise residential buildings.

[101] See for example CMJ Engineering, *Special Issues Report, Compliance/Enforcement Problems, 1988-89 Monitoring*, California Energy Commission, Sacramento, CA, November 1989.

[102] See, for example, Brown, Kolb, Baylon, Haeri, and White, *The Impact of Bonneville's Model Conservation Standards on the Energy Efficiency of New Home Construction*, ORNL/CON-310, Oak Ridge, TN, Aug. 1991.

conditioners, water heaters, etc.) and fluorescent lighting ballasts.[103] In recent years, DOE has been reviewing and strengthening efficiency standards on products covered by federal legislation,[104] and states are starting to adopt efficiency standards on additional products including lamps, lighting fixtures, electric motors, and commercial heating and cooling equipment. Also, numerous states have adopted maximum flow rate restrictions on showerheads and faucets, which save both energy and water.[105]

Recommendations:

1. States should adopt state-of-the-art building codes. Presently, state-of-the-art codes include the DOE standard for commercial buildings (which is essentially the same as the ASHRAE 90.1-1989 standard, except that the DOE standard includes more stringent lighting requirements as of 1992), and the CABO 1990 Model Energy Code for residential buildings.[106]

2. The federal government (or states in the absence of federal action) should adopt efficiency standards on lamps, motors, transformers, showerheads, and commercial heating, cooling, and water heating equipment.[107] Also, the

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[103] "National Appliance Energy Conservation Act of 1987," P.L. 100-12. March 17, 1987 (42 USC 6291); "National Appliance Energy Conservation Amendments of 1988," P.L. 100-357, June 28, 1988.

[104] See for example, Turiel, Isaac, et. al., "U.S. Residential Appliance Energy Efficiency: Present Status and Future Policy Directions," in Vine and Crawley (eds.), *State of-the-Art of Energy Efficiency: Future Directions*, American Council for an Energy-Efficient Economy, Washington, DC, 1991, pp. 199-227.

[105] Nadel and Geller, "Efficiency Standards for Lamps, Motors, Commercial HVAC Equipment, and Showerheads," American Council for an Energy-Efficient Economy, Washington, DC, May 1991.

[106] Department of Energy, 10 CFR Part 435, "Energy Conservation Voluntary Performance Standards for Commercial and Multi-Family High Rise Residential Buildings; Mandatory for New Federal Buildings; Interim Rule", Washington, DC, January 1989; Council of American Building Officials, *Model Energy Code, 1990 Edition*, CABO, Falls Church, VA. The soon to be finalized ASHRAE 90.2 standard is likely to be more energy-conserving in cooling-dominated climates than the CABO code according to a recent analysis by the Alliance to Save Energy, Washington, DC (Bion Howard, personal communication, April 1991).

[107] Specific recommendations for state legislation can be found in Nadel and Geller, "Efficiency Standards for Lamps, Motors, Commercial HVAC Equipment, and Showerheads: Recommendations for State Action," American Council for an Energy-Efficient Economy, Washington, DC, July 1991. Similar standards are contained in H.R. 2451, "Energy (continued...)

federal government should establish testing and labeling requirements on light fixtures and office equipment, followed by minimum efficiency standards if this offers significant, cost-effective energy savings that cannot be achieved through voluntary mechanisms.

3. Base future energy code requirements and equipment efficiency standards on the highest levels of energy efficiency that are cost-effective to consumers. In assessing cost-effectiveness, life-cycle cost analysis should be employed, using a discount rate equivalent to average consumer interest rates.

4. Structure utility programs for new construction and for efficient equipment to build upon code and standards requirements. For example, if the code includes a schedule of insulation or lighting efficiency requirements, the utility can develop a more stringent schedule, using the same format, as a basis for eligibility for utility incentives.

5. Improve enforcement of building code energy provisions. Possible mechanisms include sponsoring training on code requirements for building designers and code enforcement officials, conducting periodic studies on the effectiveness of code enforcement, providing technical assistance to code officials on code enforcement matters, and/or making code compliance a condition of receiving service. [108]

6. Encourage technological innovation and the commercialization of new energy-saving technologies. For example, utilities could help convince manufacturers to introduce and market "super-efficient appliances" by offering financial incentives to either consumers or manufacturers. This type of "technology push" will pave the way for additional savings from utility programs, and for increasingly stringent minimum efficiency standards in the future.[109]

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[107](...continued)
Efficiency Standards Act of 1991," U.S. House of Representatives, Washington, DC, May 1991.

[108] This latter mechanism has been used by several utilities in the northwestern U.S. and is reportedly being considered by several major utilities in Canada. For example, Tacoma City Light and several other utilities in the Pacific Northwest require new homes to meet a set of regional model conservation standards as a condition for receiving an electrical hook-up. Huges, Guy, personal communication, Bonneville Power Administration, Seattle, WA, April 1990.

[109] The first such effort of this type is now being organized by a consortium of utilities and other interested parties to promote the development of refrigerators which will use approximately half the energy of units now on the market, without containing any CFC's. See, *The Golden Carrot News*, American Council for an Energy-Efficient Economy, Washington, DC, Sept. 1990, April 1991, and Oct. 1991.

MORE EFFICIENT SUPPLY OPTIONS

Federal and state officials can take a number of actions to encourage greater efficiency in electricity production and supply. The policies we recommend pertain to research and demonstration, financial incentives, state utility regulation, and federal standards. A combination of actions is needed to overcome the barriers described above and to have the greatest impact.

1. Expand R&D and demonstrations on advanced technologies that offer significant efficiency gains.

   Increasing efficiency should be a primary goal of R&D on fossil-fuel-based power plants sponsored by DOE or other federal agencies. Technologies such as advanced gas turbines, combined-cycle power plants, and fuel cells should be emphasized. Technologies that offer little or no efficiency improvement, such as atmospheric fluidized bed combustion, should be given lower priority. These criteria should be applied to the Clean Coal Technology Demonstration Program, a multi-year, $5 billion effort, as well as other relevant R&D programs. For example, only a small portion of the first three rounds of the Clean Coal Program were devoted to technologies that offer substantial efficiency improvements. With the fourth round the emphasis switched to efficiency improvements.[110]

   In particular, the federal government (together with private industries) should undertake a major project to demonstrate the feasibility of advanced aeroderivate gas turbines for power production. Intercooled, steam-injected gas turbines promise high efficiency (47% efficiency fired with natural gas, 42% efficiency fired with gasified coal), low capital cost, small and quickly-constructed facilities, and low pollutant emissions [111].

2. Reform state utility regulations so that utilities have financial incentives to increase "supply-side" efficiency.

   State utility commissions should establish an incentive to increase the efficiency of existing or new power supply, as long as these actions are cost-effective from a societal perspective. Modified fuel adjustment clauses that respond to unanticipated changes in fuel prices and not to changes in fuel quantity (i.e., limit the scope of reconciliation within fuel adjustment clauses) or shared savings approach are one way

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[110] Egan, John, "Clean Coal Round 4 Targets CO_2 Emissions," *The Electricity Journal 4(8)*, Oct. 1991, pp.6-7.

[111] Williams and Larson, "Expanding Roles for Gas Turbines in Power Generation," in Johansson, Bodlund, and Williams (eds.), *Electricity: Efficient End-Use and New Generation Technologies and Their Planning Implications*, Lund University Press, Lund, Sweden, 1989.

to accomplish this goal.[112] Another would be to allow a utility to keep a portion of the new economic benefits that result from investments in innovative highly efficient generating technologies.

3. Provide tax incentives to encourage more efficient power generation and supply

Federal taxes can be used to encourage supply-side efficiency improvements. For example, Congress should consider tax credits for the adoption of innovative, highly efficient generating or T&D technologies. To give utilities the greatest flexibility, the incentives should be performance-based. For example, all new fossil fuel power plants with an efficiency of at least 45% and emissions below certain levels could qualify, with the tax credit percentage increasing as power plant efficiency increases.

Another approach would establish a revenue-neutral system of taxes and tax rebates for utilities, based on average fossil-fuel heat rate. Utilities with heat rates below the average could be given a tax rebate, those with above average heat rates would have to pay a higher tax. The system could be implemented on a regional basis. The taxes and rebates should be implemented on a sliding scale to encourage maximum efficiency. Nuclear, hydro, and certain other plants could be excluded from the calculation of average heat rate, but utilities could be given credit for "other renewables" and district heating in order to encourage these environmentally sound technologies. For example, solar or wind generators could be averaged into a utility's heat rate at 0 Btu's of fossil fuel per kWh. Power plant waste heat utilized via district heating could be counted at its kWh equivalent (or some fraction of it).

4. Adopt power plant efficiency regulations

If R&D efforts, regulatory reform, and financial incentives fail to result in higher generating efficiencies, policy makers may choose to adopt efficiency regulations. Such regulations could take a number of forms. One approach would be to require all fossil fuel power plants to achieve some minimum efficiency level by a specific date. For example, a minimum efficiency of 31% (i.e., a maximum heat rate of 11,000 Btu/kWh) could be established. Less efficient plants would have to be refurbished and upgraded, or shut down.

A second approach would be to require utilities to meet an overall minimum efficiency, weighing each fossil-fuel plant according to its size and use (basically a "CAFE" standard for fossil fuel power plants). For example, utilities could be required to achieve an average generating efficiency of 34% initially (i.e., an average

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[112] The first supply-side incentive plan was recently approved by the Washington Commission. Under a plan agreed to by all parties, Puget Sound Power & Light can earn an incentive for new purchases from renewable or "high efficiency" cogeneration. "High efficiency" is defined to require that at least 20% of the heat produced be used for purposes besides electricity generation. See Moskovitz, David, "Prefiled Testimony, Docket UE-910689," Washington Utilities and Transportation Commission, Olympia, WA, June 1991.

heat rate of about 10,000 Btu/kWh) by a certain date. This approach gives utilities greater flexibility as less efficient plants could be operated if compensated for by highly efficient plants. As is the case with cars, the CAFE standard for power plants could be gradually increased over time.

A third approach would be to set minimum efficiency standards for new power plants only. This could force utilities (and possibly independent power producers) to adopt the most efficient new generating technologies. Such a policy could stimulate commercialization of some of the highly efficient advanced technologies, since vendors introducing these technologies would have more confidence that utilities would purchase such equipment. The minimum efficiency standards could be set according to fuel type and power plant size, and they should be updated periodically. Care needs to be taken to structure these standards so they do not provide an impediment to the desirable construction of new plants to replace old, inefficient plants.

RESEARCH, DEVELOPMENT, TECHNICAL ASSISTANCE, AND INFORMATION TRANSFER

The foundation for progress in energy efficiency is research and development (R&D) to bring new products and programs to market. In addition, technical assistance (TA) and information transfer to increase the market penetration of these products are very important.

In the U.S., in the electrical sector, R&D, TA, and information transfer efforts are undertaken by DOE, several state level R&D programs,[113] EPRI, individual utilities, and private industry. Efficiency represents just 8% of DOE's energy R&D budget and 14% of EPRI's.

We recommend that R&D funding for energy efficiency be tripled within a few years by reducing R&D funding for other energy technologies, such as nuclear fission and fusion. Such a change will raise the energy efficiency portion of DOE's R&D pie to around 24% for an energy source that can reduce U.S. electricity use by more than 20% over the next two decades not to mention the substantial amounts of oil, gas, and coal that would also be saved (as discussed in the next section).

Some states have established energy R&D centers that emphasize or even focus entirely on energy efficiency. In 1991, the energy R&D centers in California, New York, North Carolina, and Wisconsin have a combined budget of over $20 million. In each of these states a non-profit R&D center was established, with funding provided by local utilities. Programs in these states are a useful model for other states to follow.

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[113] Programs include the California Institute for Energy Efficiency, the New York Energy Research and Development Authority, the North Carolina Alternative Energy Corporation, and the Wisconsin Center for Demand-Side Management Research. These programs are funded by contributions from utilities within each state.

EPRI presently devotes about 14% of its R&D budget to demand side management ($36 million), of which about 60% is devoted to energy efficiency projects. Funding should be increased and more emphasis placed on analysis of what works and what does not work, even if the findings may reflect poorly on particular utilities. By learning from past mistakes, DSM programs operated by all utilities can profit.

Recommendations:

1. DOE, EPRI, and other appropriate organizations should undertake expanded research, technical assistance, and information transfer to promote energy efficiency, with a particular emphasis in the following areas (many of these areas were discussed in previous sections of this paper):

    * Expanded R&D on promising new energy-efficient technologies such as super-efficient lamps, windows, appliances, and low-cost variable speed drives for motors.[114]

    * An on-going database of utility demand-side management program results, with regular analysis and workshops on what works, and what does not.

    * Expanded technical assistance to states to adopt and implement least-cost plans.

    * Standardize demand-side definitions, measurement techniques and program evaluation techniques so that results are consistently reported and information can be readily exchanged and understood by utilities, regulators and other parties.

    * Additional work on how best to integrate utility-operated DSM programs with competitive solicitations to the private sector.

    * Work on innovative pricing structures, such as sliding-scale hook-up fees with an emphasis on evaluating schemes in actual operation.

    * Improve education and training for demand-side professionals.

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[114] For a discussion of many of the opportunities available see: Energy Conservation Coalition, "Alternative Budget for Energy Conservation FY 1992," Washington, DC, April 1991; Nadel, et. al., Energy-Efficient Motor Systems, American Council for an Energy-Efficient Economy, Washington, DC, 1991; American Council for an Energy-Efficient Economy, "The Golden Carrot News," Number 1, Washington, DC, September 1990; Lawrence Berkeley Laboratory, *Energy and Environment Division 1990 Annual Report,* Berkeley, CA, 1991.

In order to undertake all of these activities will require a significant increase in the energy efficiency budgets of DOE and EPRI.

2. Additional states should develop energy efficiency R&D programs modeled after efforts in California, New York, North Carolina, and Wisconsin. Smaller states may want to combine efforts by forming a regional center (e.g., in New England). State or regional R&D centers should focus on local conditions and obstacles to widespread implementation of cost-effective energy efficiency measures.

ANALYSIS OF ENERGY AND ENVIRONMENTAL IMPACTS

What savings would result if most of our recommendations were widely implemented and utilities, government, and consumers were to aggressively pursue efficiency improvements? To answer this question, we conducted an analysis to estimate the savings that would result from greatly expanded utility DSM programs, improved codes and standards, and greater attention to supply-side efficiency improvements.

APPROACH

Our analysis took as its starting point the Energy Information Administration's 1991 Reference Case forecast.[115] This forecast projects an average 2% rise in annual electricity sales over the 1990-2010 period, and a 0.9% increase in electric generating capability (the slower growth in generating capacity is due to an oversupply of capacity in some regions of the country). This forecast includes allowance for efficiency improvements that will result from pricing effects, and also incorporates appliance efficiency standards that were promulgated as of 1990. Few efficiency improvements from utility programs appear to be incorporated.[116]

To this forecast, savings from improved codes and standards are deducted first. Three classes of codes and standards are included in the analysis:

1. Savings from revised equipment efficiency standards for products presently covered by federal law, and for which DOE is scheduled to issue revised standards during the 1990's. These products include most major residential appliances, plus fluorescent light ballasts.

2. Savings from adoption of improved building codes for the residential and commercial sectors, including adoption of (a) standards developed in 1989-90 by the Council of American Building Officials (CABO) for the residential sector, and by the American Society of Heating, Refrigeration, and Air-Conditioning Engineers (ASHRAE) for the commercial sector (for those states that have not already adopted these standards), and (b) adoption of revised versions of these standards scheduled to be finalized in the mid-1990's.

3. Savings from enactment, nationwide, of efficiency standards and labeling requirements for products not presently covered by national standards including lamps; electric motors; commercial heating, cooling, and water heating equipment; showerheads; office equipment; and distribution transformers.

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[115] EIA, *1991 Annual Energy Outlook*, DOE/EIA-0383(91), U.S. Department of Energy, Washington, DC, March 1991.

[116] Hirst, Eric, *Possible Effects of Electric-Utility DSM Programs, 1990 to 2010*, ORNL/CON-312, Oak Ridge National Laboratory, Oak Ridge, TN, January 1991.

After accounting for the effects of improved codes and standards, additional savings that could be achieved by utility conservation and load management programs, if most utilities in the U.S. pursue an aggressive program, were estimated. These estimates are based on several recent studies on the amount of savings utilities can achieve, including resource acquisition plans prepared by several utilities, and on recent DSM results achieved by successful utilities.

Finally, opportunities to improve power supply efficiency were examined. For supply-side efficiency improvements, two opportunities were analyzed:[117]

1. Heat rate improvements at existing plants from low-cost operations and management measures.

2. Repowering of existing, inefficient coal and oil plants, with high efficiency gas combustion turbines.

For each efficiency measure on the demand-side, reductions in electricity sales, electric generating capacity, consumer bills, and emissions of carbon were calculated (as a measure of the amount of carbon dioxide emitted). For efficiency measures on the supply-side, savings in fossil fuels, and carbon were calculated. Additional details on the analysis are provided in an Appendix at the end of this paper.

RESULTS

The analysis shows that by implementing strengthened codes and standards and by substantially increasing utility DSM efforts, electricity sales in 2010 can be reduced by approximately 24% below the EIA Reference Forecast (see Table 7). Peak demand can be reduced by approximately 38% below forecasted levels. As a result of these savings, projected growth in electricity sales is reduced by 76%, lowering the average 2.0% compound growth rate predicted by EIA for electricity sales over the 1990-2010 period down to 0.5%. Power plant peak capacity needs actually decline by approximately 25% over the period, eliminating the need for new power plants during the analysis period (although, at some time in the future, new power plants will again be needed when plant retirements bring available capacity below capacity needs). These trends are illustrated in Figures 1 and 3. Of the energy and demand savings, approximately 50-60% are attributable to utility programs and 40-50% to codes and standards.

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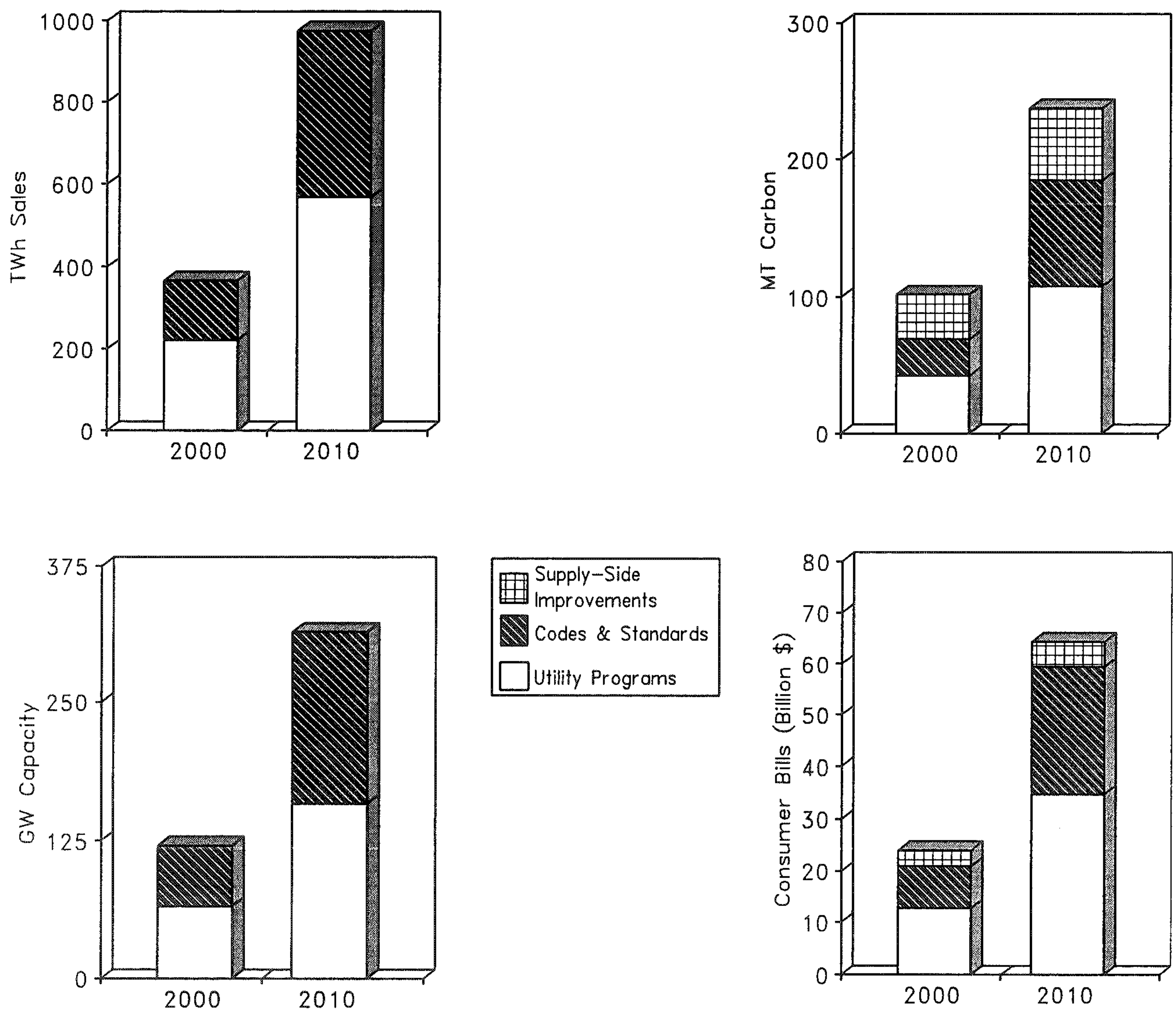
[117] At first, our analysis also included opportunities for upgrading the efficiency of new power plants built during the period, through the use of advanced, high-efficiency power plant designs. However, as discussed below, our analysis of opportunities to reduce electricity demand indicates that over the course of the analysis period, actions on the demand-side can eliminate the need for new supply-side resources.

Table 7. Estimated TWh, GW, and Carbon Savings from Adoption of Strategies Recommended in this Paper

	------ TWh Sales ------			----- GW Capacity -----			MT of Carbon Emitted			Consumer Bills (billion 1990$)		
	1990	2000	2010	1990	2000	2010	1990	2000	2010	1990	2000	2010
EIA Reference Case	2700	3282	3985	689	718	830	522	618	755	$187.4	$224.8	$287.7
Annual growth rate	--	2.0%	2.0%	--	0.4%	1.5%	--	1.7%	2.0%	--	1.8%	2.2%
Demand-side savings												
Revised appliance stds.	0	35	146	0	15	73	0	7	28			
Building codes	0	50	175	0	12	43	0	9	33			
Stds. on add'l products	0	60	86	0	29	40	0	11	16			
Subtotal	0	145	407	0	56	157	0	27	77			
Utility DSM programs	0	222	568	0	65	158	0	42	108			
Total	0	366	975	0	121	315	0	69	185	$0.0	$21.1	$59.5
ACEEE Post DSM Case	2700	2916	3010	689	597	515	522	549	571	$187.4	$203.7	$228.2
Annual growth rate	--	0.8%	0.5%	--	-1.4%	-1.4%	--	0.5%	0.4%	--	0.8%	1.0%
Supply-side savings												
Heat rate improvements							--	24	22			
Repowering							--	9	30			
Subtotal							0	33	53	$0.0	$3.1	$4.9
ACEEE Efficiency Case							522	517	518	$187.4	$200.6	$223.3
Annual growth rate							--	-0.1%	0.0%	--	0.7%	0.9%

Source: Table 12.

Figure 3. Savings from ACEEE Efficiency Scenario Relative to EIA Reference Case by Measure.



Consumer electricity bills decline by over $60 billion in 2010 (in 1990 $), despite an assumed 10% increase in electricity prices (half of this increase is included in the EIA Reference Case while the other half is needed to pay for DSM programs). This is a 22% reduction in electricity bills relative to the EIA Reference Case. In other words, the value of reduced kWh use is substantially greater than the value of the rate increase required to pay for this efficiency improvement.

The DSM efforts included in our analysis also have a substantial impact on carbon emissions relative to the EIA Reference Case. Under the EIA Reference case, annual carbon emissions from the electrical sector increase by 45% over the 1990-2010 period. After this forecast is adjusted for the impacts of our DSM efforts (including codes and standards), electrical sector carbon emissions in 2010 are just 11% over present levels. Furthermore, when modest supply-side efficiency improvements are factored into the equation, sector carbon emissions are essentially level with 1990 levels. If efforts to improve supply efficiency were more aggressive, including efforts to upgrade typical existing supply resources, significant additional savings on the supply-side appear possible.

While the reductions in carbon dioxide emissions from our efficiency scenario are dramatic, additional reductions in fossil fuel use and carbon dioxide emissions would also occur if adoption of renewable energy technologies occurs at a faster rate EIA projects. EIA's 1991 reference case forecast assumes that electricity supply from renewable energy sources expands from 370 TWh's in 1990 to 572 TWh's in 2010, a 2.2% average annual growth rate. While we have not analyzed the potential for accelerating implementation of renewables, the shift to renewables could occur more rapidly. This is especially true if strong policies supporting renewable energy sources are pursued (similar to the policies proposed here for stimulating efficiency improvements).

Several recent studies back up this contention. For example, a study by Public Citizen based on government and industry sources concluded that renewable energy-based electric generating capacity will expand 2.6%/yr during the 1990's and possibly much faster during 2000-2010.[118] Similarly, DOE recently estimated that accelerated cost and performance improvements and regulatory changes could lead to about 850 TWhs of renewable-based power by 2010 and 1,250 TWh's by 2020.[119] Likewise, with a financial incentive (tax credit) of 2 cents/kWh for renewable-based electricity production, the potential renewable contribution by 2010 was estimated by federal research laboratories to be about 1,000 TWh's.[120] If this renewables target is achieved along with very low demand growth

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[118] Rader, Nancy, "Power Surge: The Status and Near-Term Potential of Renewable Energy Technologies", Public Citizen, Washington, DC, May 1989.

[119] Energy Information Administration, *Renewable Energy Excursion: The Status and Near-Term Potential of Renewable Energy Technologies*, SR/NES/90-04, U.S. Department of Energy, Washington, DC, December 1990.

[120] Solar Energy Research Institute et. al., *The Potential of Renewable Energy-An Interlaboratory White Paper SERI/TP-2603674,* Golden, CO, March 1990.

as indicated by our scenario, renewables would provide about 30% of total power generation by 2010 and carbon emissions could fall to about 420 Mt that year, 20% below carbon emissions from the electricity sector as of 1990.

CONCLUSION

This paper has identified the many problems inherent in a business-as-usual national electricity policy, and the many causes of these problems. We make a number of recommendations to cure these problems and estimate that if most of our recommendations are adopted, growth in electricity sales can be reduced to 0.6% per year, power plant capacity needs can actually decline by 24% relative to EIA projections, consumer electricity bills can decline by 22% from forecasted levels, and carbon emissions from the electricity sector could remain at 1990 levels. More aggressive renewable energy initiatives combined with increased efforts to promote power plant efficiency improvements and advanced high-efficiency end-use technologies could lead to even more reductions in carbon emissions by utilities.

The goal of dramatically reducing the nation's cost of energy services by substituting energy efficiency technologies for many existing and forecasted inefficient uses of electricity is a radical departure from past history. Electricity demand in the United States grew faster than gross national product throughout this century. During 1950-70, electricity generation by electric utilities increased about 8.0%/yr on average, over twice the average GNP growth.[121] During 1970-89, the rate of growth of electricity generation moderated to 3.2%/yr on average, about 1.1 times the average GNP growth rate. Based on these trends, the "conventional wisdom" is that there is an ironclad coupling between electricity growth and economic growth.[122]

The experience with overall energy use in the United States demonstrates that energy and economic growth are not inextricably linked. Total primary energy consumption increased nearly as fast as GNP during 1950-75, and many energy experts in the mid- and late-1970's projected that this trend would continue.[123] However, primary energy use in 1986 was no higher than that in 1973 while GNP increased 2.4%/yr on average. Price signals, policies such as automobile efficiency standards, and the introduction of new technologies enabled our nation to reduce its overall energy intensity by 26% in a relatively short period. These same mechanisms, if aggressively pursued, could be used to decouple electricity demand from economic growth in the future.

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[121] Energy Information Administration, *Annual Energy Review* 1989, DOE/EIA-0384(89), U.S. Department of Energy, May 1990.

[122] The most recent forecast by the U.S. Department of Energy projects that electricity demand will increase 2.0%/yr while GNP increases 2.1%/yr on average during 1989-2010. See Energy Information Administration, *Annual Energy Outlook* 1991, DOE/EIA-0383(91), U.S.Department of Energy, March 1991.

[123] In the 1975-79 period, leading governmental and industrial organizations projected that primary energy use in 2000 would reach 131-163 Quads. See Ross, Marc and Robert Williams, *Our Energy: Regaining Control*, McGraw-Hill, 1981, p. 19.

Achieving these savings will require concerted effort by the electric utility industry, regulators, and government agencies. Priorities for action include the following:

Electric Utility Industry:

* Prepare and implement least-cost plans, using the "societal cost test" as the basis for cost-effectiveness determinations.

* Increase investments in demand-side management programs, with the objective of reducing electricity sales and peak demand by at least 1% for each year of program operation, relative to what sales and demand would have been in the absence of DSM programs.

* Routinely evaluate all DSM programs and use the results of these evaluations to improve program designs and operations.

* Adopt innovative pricing structures such as time-of-use rates, interruptible rates, and hook-up fees that send improved price signals to the market.

* Expand efforts by EPRI to conduct research on technologies and programs to increase efficiency on both the demand- and supply-sides.

* Support efforts at the state and national levels to improve state building codes and appliance efficiency standards, and to adopt new efficiency standards for lamps, electric motors, commercial heating, cooling and water heating equipment, showerheads, and distribution transformers. Also, work with states to improve enforcement of energy sections of state building codes.

* Work with private industry to encourage technological innovation and the commercialization of new energy-saving technologies.

* Expand R&D and demonstrations on advanced generating technologies that offer significant efficiency gains.

State Regulators:

* Develop least-cost planning processes.

* Make the "societal cost test" the basis for cost-effectiveness determinations in least-cost plans. This includes incorporating the costs of environmental externalities into economic analyses.

* Decouple profits from sales, including abolishing or reforming existing fuel adjustment clauses.

* Provide incentives for utilities that save consumers money by successfully implementing least-cost plans.

* Develop competitive systems to acquire new demand and supply-side resources.

* Eliminate preferential rates, such as declining block rates, incentive rates, and economic development rates, that encourage load-building by selling electricity at less than the long-run marginal cost of production and delivery.

* Encourage the development of innovative pricing structures such as interruptible rates and hook-up fees that send improved price signals to the market.

Federal Regulators:

* Take actions consistent with state approved least-cost plans.

* Apply LCUP principles to the approval of interstate and wholesale power transactions currently subject to federal regulation.

* Revise requirements for qualifying facilities so that the overall efficiency of cogeneration systems is increased.

Congress:

* Authorize states to enter into regional compacts for purposes of developing and implementing least-cost plans.

* Require that federal actions, including FERC rulings, be consistent with least-cost plans approved by states and regions. 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.

* Direct BPA, TVA, WAPA, and other federal power marketing agencies to prepare and implement least-cost plans.

* Amend PURPA to allow energy efficiency vendors to compete against utility power supply options.

* Enact efficiency standards on lamps, electric motors, commercial heating, cooling and water heating equipment, showerheads, and distribution transformers. Adopt testing and labeling requirements for light fixtures and office equipment.

* Limit the Clean Coal program to technologies that improve power plant efficiency.

* Direct states to adopt least-cost planning, decoupling profits from sales, and providing utilities with financial incentives for implementing cost-effective

efficiency improvements. Provide additional incentives or disincentives to encourage states to adopt rules in these areas.

* Encourage efficiency improvements on the supply-side through tax incentives and/or power plant efficiency regulations.

* Expand DOE R&D on demand-side and supply-side efficiency, and DOE programs to promote least-cost planning.

* Increase access to the transmission grid to provide additional markets for capacity and electricity made available through efficiency efforts.

* Consider pollution taxes as a substitute for some existing taxes. Deposit some if not all of the money from pollution taxes in an Environmental Trust Fund. Direct EPA to use the Trust Fund to fund projects designed to reduce pollution and pollution impacts.

U.S. Department of Energy:

* Expand its Integrated Resource Planning program, which provides technical assistance and support on utility planning issues, including demand-side management.

* Complement existing program efforts by making grants available to states who pursue least-cost planning.

* Upgrade efficiency standards for appliances and fluorescent ballasts to the highest levels that are technologically feasible and economically justified.

* Work with ASHRAE and CABO to develop strengthened energy efficiency standards for new buildings. Encourage states to adopt these standards as part of state building codes, and assist states in strengthening building code compliance and enforcement procedures.

* Expand R&D and demonstrations on advanced generating technologies that offer significant efficiency gains.

* Limit the Clean Coal program to technologies that improve power plant efficiency.

* Expand R&D efforts on conservation and load management technologies and programs.

State Governments:

* Direct utility commissions to undertake a least-cost planning process.

* Establish regional least-cost planning authorities that would oversee planning for multi-state holding companies.

* Enact efficiency standards on lamps, electric motors, commercial heating, cooling and water heating equipment, showerheads, and distribution transformers.

* Adopt and enforce strong energy efficiency standards as part of state building codes.

* Establish state energy R&D centers which emphasize energy efficiency, modeled after programs in California, New York, North Carolina, and Wisconsin.

* Consider pollution taxes as a substitute for some existing taxes.

Pursuing these policies will enable the United States to levelize utility-sector carbon emissions, reduce power plant capacity requirements, substantially reduce consumer bills for electricity consumption, and enjoy more of the benefits of a well-functioning, competitive economy.

APPENDIX: SAVINGS ANALYSIS DETAILS AND CAVEATS

METHODOLOGY

Codes and Standards

Our analysis of savings from codes and standards uses a basic methodology for all types of equipment and construction. In each case we estimate annual production of each type of equipment or building, the proportion of production that will be affected by codes and standards,[124] the number of years production will be affected by the standards, savings per unit on a kW or kWh basis, and a conversion factor to convert kW savings into kWh (or visa-versa). By multiplying each of these factors together, savings are estimated. Details of these analyses are provided in Tables 8, 9 and 10.

Utility Programs

Savings from utility programs are assumed to take place over a 19-year period, between 1991 and 2010. For this analysis, we assume that utilities will reduce kWh sales by 0.75% of the EIA reference forecast for 2010 during each year of the analysis period (total savings of 14.25% (19 times 0.75%). Peak demand savings are assumed to average 1% per year (19% over the period). These estimates are based on four sources which are briefly reviewed below.

The first source is the ACEEE study on the achievable conservation potential from utility programs in New York State. Results of this analysis were summarized in Table 6. This analysis found that utility programs could reduce electricity sales 13% below projected levels in 2000, a simple average of 1.3% each year. Savings in peak demand were slightly lower (about 12%) because the analysis did not include any load management programs. In this analysis, savings leveled off during the 2000-2008 period, due to rising electricity demand (which means greater savings are needed to get the same 13% reduction in sales) and due to the fact that the analysis did not include new technologies developed during the 1990-2010 period. Still, even with the limitation to existing technologies, the study estimated that utility programs could reduce electricity sales by 13.5% in 2008 -- a simple average of 0.77% per year. It should be noted that this analysis included codes and standards very similar to those analyzed in this paper, and savings from utility programs began where the codes and standards left off.

The second source is an ACEEE analysis of the savings that have actually been achieved by the utilities with the most aggressive demand-side management programs. These data were summarized in Table 3, and show that programs operated by several utilities are reducing kWh sales and/or peak demand by at least 1% each year, with cumulative kW

[124] In many cases, specialty products are exempted from standards. Likewise, some equipment or buildings are already in compliance with likely standards, either as a result of existing state standards, or as a result of market forces.

Table 8. Estimated Savings in the U.S. from Revised Appliance Efficiency Standards

Product	Effective Year of Standard	Standard Level Assumed	Annual Sales (1000's)	# Years Affected by Standards: Thru 2000	Thru 2010	kWh Saved Per Unit	Total GWh Savings: In 2000	In 2010	Summer Peak MW to GWh Ratio	Summer MW Savings: In 2000	In 2010
Refrigerators	1998	DOE Level 5	7,536	2	12	197	2,969	17,816	0.153	454	2,722
Freezers	1998	DOE Level 5	1,179	2	12	124	292	1,755	0.139	41	243
Clothes washers	1994	DOE Level 1	6,441	6	14	52	2,010	4,689	0.167	335	782
Clothes washers (in homes w/ elec water htrs)	1998	DOE Level 4	1,353	2	12	351	950	5,697	0.167	158	950
Electric clothes dryers	1994	DOE Level 2	3,270	6	16	75	1,472	3,924	0.173	254	677
Electric clothes dryers	1998	DOE Level 4	3,270	2	12	209	1,367	8,201	0.173	236	1,415
Dishwashers	1994	DOE Level 4	3,872	6	13	33	768	1,664	0.167	128	277
Electric water heaters	1995	EF >= .94	3,761	5	13	152	2,865	7,450	0.101	290	753
Room air conditioners	1995	EER >= 10	3,708	5	15	55	1,017	3,052	1.699	1,728	5,185
Ranges	1995	See notes	2,179	5	15	135	1,470	4,411	0.283	416	1,248
Central air conditioners	1999	SEER >= 14	2,514	1	11	783	1,969	21,661	1.006	1,981	21,791
Central heat pumps	1999	HSPF >= 9	849	1	11	1,691	1,436	15,792	0.424	608	6,691
Ballasts	1995	Electronic	68,108	5	15	49	16,687	50,060	0.276	4,598	13,795
TOTAL							35,272	146,172		11,227	56,530

Notes:

* Annual sales generally from U.S. Census Bureau reports for 1988.
* Number of years affected by standards is the year being analyzed (e.g. 2010) minus the year the standards take effect, up to the average rated life of that appliance.
* Refrigerator, freezer,clothes washer, clothes dryer and dishwasher standards based on standard levels studied by DOE as part of 1989 and 1991 rulemakings. Range standard from Miller, et al., "The Potential for Electricity Conservation in New York State," NYSERDA, 1989, p. 132. Ballast standard requires either an electronic or hybrid electronic/magnetic ballast. Air conditioner and heat pump standards estimated by ACEEE based on discussions with industry experts.
* Unit energy savings estimated by ACEEE based on data from DOE and ACEEE reports.
* Total energy savings equals annual sales times number of years affected by standards times unit savings.
* Peak MW to GWh ratios from Geller et. al., "Residential Conservation Power Plant Study," PG&E, 1986 and Miller et. al., "The Potential for Electricity Conservation in New York State," NYSERDA, 1989.
* Savings are calculated at the end-user level and do not include adjustments for T&D losses or reserve margin requirements.

Table 9. Estimated Electricity Savings in the U.S. from Building Codes

Code	Assumed Average Effective Year	New Homes or Comm'l Sq.ft. (millions) from Effective Year to:		Percent Already in Compliance	Baseline kWh Per Unit	Average kWh Savings Per Unit	GWh Savings		Summer Peak MW to GWh Ratio	MW Savings	
		2000	2010				2000	2010		2000	2010
Residential CABO - 1989	1993	10.70	28.04	64%	2,375	845	9,035	23,685	0.054	485	1,271
Residential ~1996	1999	1.60	18.94	37%	1,530	500	799	9,471	0.054	43	508
Comm'l ASHRAE 90.1-1989	1993	11,878	32,487	40%	17.74	2.68	31,833	87,065	0.224	7,122	19,480
Comm'l ASHRAE 90.1-1995	1998	3,589	24,198	5%	15.06	2.26	8,107	54,663	0.224	1,814	12,231
TOTAL							49,773	174,885		9,464	33,490

Notes:

* New homes and comm'l sq. ft. based on 1990 stock and annual growth rates from EIA, "1991 Annual Energy Outlook", and a building demolition rate from EIA, "Energy Consumption and Conservation Potential: Supporting Analysis for the National Energy Strategy."
* Residential sector data for the CABO-1989 code estimated by Bion Howard, Alliance to Save Energy based on a detailed state-by-state report to be published in 1991.
* Residential sector data for the 1996 code based on estimates by Bion Howard, Alliance to Save Energy, with the exception of savings from the code which was estimated by ACEEE based on an analysis of savings from the Massachusetts building code for homes with electric heat.
* Percent already in compliance with the commercial code estimated by ACEEE based on states that have already adopted ASHRAE 90.1-1989, plus an allowance for buildings that are in compliance with this standard, even though their local stat code does not require compliance.
* Commercial building electricity use before and after ASHRAE 90.1-1989 based on preliminary data provided by Steven Schliesing, Pacific Northwest Lab, from a forthcoming report by Schliesing, Crawley, and Shrivastava titled "Analysis of the Impacts of New Building Standards on Energy Consumption and Demand," Gas Research Institute.
* Savings from ASHRAE 90.1-1995 is a "guesstimate" by ACEEE.
* Summer peak MW to GWh ratio based on data for residential and commercial new construction programs in N.Y. City as estimated in Nadel and Tress, "The Achievable Conservation Potential in New York State from Utility Demand-Side Management Programs," NYSERDA, 1990.
* Savings are calculated at the end-user level and do not include adjustments for T&D losses or reserve margin requirements.

Table 10. Estimated Savings from National Lamp, Motor, Commercial HVAC, Showerhead and Distribution Transformer Minimum Efficiency Standards and from Office Equipment Labeling Requirements

Type of equipment	Annual Sales (10^6)	Effective Year	Percent Covered by Stds	Percent Complying w/o Stds	Avg. Life (yrs)	Watts Saved Per Unit	Total Savings in 2000 (MW)	Avg. Annual Op.Hrs	Total Savings in 2000 (GWh/yr)	Cummul. Savings 1990-2000 (GWh)	Total Savings in 2010 (MW)	Total Savings in 2010 (GWh/yr)	Cummul. Savings 1990-2010 (GWh)
Lamps													
Fluorescent	461	1994	87%	50%	5	7	7,020	3,500	24,570	98,280	7,020	24,570	343,980
Gen'l service incand.	793	1994	90%	30%	1	9.2	4,600	1,000	4,600	27,600	4,600	4,600	73,600
Reflector incandescent	100	1994	90%	15%	1	28	2,140	2,000	4,280	25,680	2,140	4,280	68,480
HID	19.8	1995	95%	60%	6	67	2,520	3,500	8,820	26,460	3,020	10,570	132,125
Subtotal - lamps							16,280		42,270	178,020	16,780	44,020	618,185
Motors													
Polyphase	1.85	1994	64%	20%	15	280	1,590	2,676	4,250	14,875	3,980	10,650	95,850
Single-phase	113	1995	50%	5%	10	51	1,280	250	3,430	10,290	2,560	6,850	71,925
Subtotal - motors							2,870		7,680	25,165	6,540	17,500	167,775
Commercial HVAC													
Unitary A/C	0.518	1994	100%	75%	15	1,501	1,170	1,100	1,290	4,515	2,910	3,200	32,000
Air-source heat pumps	0.016	1994	100%	75%	15	958	20	2,200	40	140	60	130	1,300
Water-source heat pumps	0.098	1994	100%	75%	15	522	80	2,200	180	630	190	420	4,200
Packaged terminal A/C	0.135	1994	100%	75%	15	130	30	2,200	70	245	70	150	1,500
Packaged terminal HP	0.098	1994	100%	75%	15	209	30	2,200	70	245	80	180	1,800
Recip. chiller/air-cool	0.012	1994	100%	75%	16	5,328	90	2,200	200	700	250	550	4,675
Recip. chiller/wtr-cool	0.004	1994	100%	75%	16	5,000	30	2,200	70	245	80	180	1,530
Rotary chiller/air-cool	0.001	1994	100%	75%	16	15,792	20	2,200	40	140	70	150	1,275
Rotary chiller/wtr-cool	0.001	1994	100%	75%	16	25,010	50	2,200	110	385	130	290	2,465
Centrif chiller/air-cool	0.000	1994	100%	75%	16	26,321	20	2,200	40	140	50	110	935
Centrif chiller/wtr-cool	0.002	1994	100%	75%	16	26,010	70	2,200	150	525	180	400	3,400
Subtotal - HVAC							1,610		2,260	7,910	4,070	5,760	55,080
Showerheads - elec.						(W/day)							
Old --> 3 gpm	0.94	1994	100%	36%	16	1,143	260	365	1,500	5,250	690	4,030	34,255
3 --> 2.5 gpm	0.94	1994	100%	18%	16	381	110	365	600	2,100	290	1,690	14,365
Subtotal - showerheads							370		2,100	7,350	980	5,720	48,620

Table 10 (continued)

Type of equipment	Annual Sales (10^6)	Effec-tive Year	Percent Covered by Stds	Percent Complying w/o Stds	Avg. Life (yrs)	Watts Saved Per Unit	Total Savings in 2000 (MW)	Avg. Annual Op.Hrs	Total Savings in 2000 (GWh/yr)	Cummul. Savings 1990-2000 (GWh)	Total Savings in 2010 (MW)	Total Savings in 2010 (GWh/yr)	Cummul. Savings 1990-2010 (GWh)
Office equipment labeling													
PC's	12.3	1994	100%	NA	5	10	620	2,000	1,200	4,800	620	1,240	17,360
Printers	8.8	1994	100%	NA	5	7.5	330	1,500	500	2,000	330	500	7,000
Copiers	1.4	1994	100%	NA	5	18	130	3,000	400	1,600	130	390	5,460
Subtotal - office equip.							1,080		2,100	8,400	1,080	2,130	29,820
Luminaire labeling	45	1994	90%	NA	16	0.72	170	3,500	600	2,100	470	1,650	14,025
Distribution transformers	1.2	1995	100%	25%	15	80	360	8,760	3,150	9,450	1,080	9,460	75,680
TOTAL							22,740		60,160	238,395	31,000	86,240	1,009,185

Notes:

* Number installed generally based on sales in 1988 as reported to the U.S. Census Bureau.
* Commercial HVAC sales and average unit sizes from Chiu and Zaloudek, 1987.
* Office equipment sales, energy use and operating hours estimated from Norford et. al., Annual Review of Energy, 1990.
* Distribution transformer sales and savings based on data provided by Allied Signal.
* Showerhead sales assume 1.5 showerheads/hh and an annual replacement rate of 3% (from Brown & Caldwell). 21% of showerhead sales allocated to electric based on EIA, 1989a.
* Percent covered by lighting standards based on Nadel et. al., 1989, and Nadel, 1991. Other coverages estimated by the authors.
* Avg. life estimated from manufacturers catalogs. Life capped at number of years between standard effective date & 2010.
* Savings and operating hours per unit for lamps and motors from Nadel et. al., 1989; Nadel, 1991; Nadel et. al., 1991; and Nadel and Tress, 1990.
* Luminaire and office equipment labeling assumed to reduce average electricity use 1% and 10% respectively.
* Showerhead savings based on HUD study on impacts of low-flow showerheads.
* Commercial HVAC savings generally assume improvement from ASHRAE 1989 level to 3% above ASHRAE 1992 level.
* Commercial HVAC operating hours generally based on Tecogen, 1986.
* Savings from commercial water heater standards are not included in this analysis because of lack of adequate data upon which to base estimates.
* kW savings are non-coincident and are the product of all of the previous columns (adjustments are made for single-phase motors and showerheads).
* kWh savings are at the end-user level and are product of kW savings and operating hours (adjustments are made for single-phase motors and showerheads).

savings as high as 7.2% over a four-year period (for Long Island Lighting) and cumulative kWh savings as high as 4.7% over a three-year period (for Commonwealth Electric).

The third source is an ACEEE analysis of the savings that several utilities are planning to achieve in the future. These data were summarized in Table 4, and show that at least 12 utilities are planning to reduce their summer peak demand by at least 10% over the next ten years (simple average 1.0-1.9% each year). Planned kWh savings are slightly lower, ranging from 2.2-17.7% over the ten year period (median of 7.8% -- a simple average of 0.78% each year). Most utilities are predicting that utility demand-side management programs will have a greater impact on peak demand than on electricity sales.

The final source is a study by Oak Ridge National Laboratory which estimates that utility programs can reduce forecasted electricity sales in 2010 19.2% below the EIA (1990) reference forecast, a simple average of 0.96% each year.[125]

In summary, these studies indicate that utility DSM programs can reduce electricity sales by from 0.6 to 1.3% each year. Based on this range, we assume an average reduction of 0.75% each year, in order to allow for the fact that some utilities will refuse to undertake programs along the lines suggested here. Similarly, DSM plans and results indicate that DSM programs can reduce peak demand by 1-1.5% each year. We assume 1% per year for this analysis.

Supply-Side Efficiency Improvements

Savings from efficiency improvements on the supply-side are calculated by estimating the amount of capacity that is affected by each measure, the average load factor for affected power plants, and the typical improvement in heat rate that can be expected. The product of these variables is energy savings, in BTU's. Details of this analysis are provided in Table 11.

Changes in Consumer Electricity Bills

Consumer electricity bills for the EIA Reference Case were estimated using EIA Reference Case estimates of average consumer electricity prices in 2000 and 2010.[126] Electricity bills in the ACEEE Efficiency Scenario were estimated by modifying the EIA Reference Case price forecasts to account for the impact of efficiency efforts on electricity prices. As discussed previously, as electricity sales decline the price per kWh increases slightly because (a) the costs of utility-sponsored programs are included in electric rates, and (b) fixed costs must be spread over fewer kWh of sales. For our analysis, we assumed that efficiency activities would increase electric rates by 2% in 2000 and 5% in 2010. These

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[125] Hirst, Eric, *Possible Effects of Electric-Utility DSM Programs, 1990 to 2010*, ORNL/CON-312, Oak Ridge National Laboratory, Oak Ridge, TN, January 1991.

[126] Average cost per kWh is projected by EIA to be 6.85 cents/kWh in 2000 and 7.22 cents/kWh in 2010. Both prices are in constant 1990 dollars.

Table 11. Estimated Savings from Efficiency Improvements on the Supply-Side

Option	Heat Rate Improvement 2000	Heat Rate Improvement 2010	Repower Inefficient Plants 2000	Repower Inefficient Plants 2010	TOTAL 2000	TOTAL 2010
Capacity affected (GW)	582 a	470 a	15 h	45 h		
Capacity factor	0.594 b	0.698 b	0.594 b	0.698 b		
Heat rate						
Before	10,535 c	10,242 c	12,804 i	12,804 i		
After	10,219 d	9,935 d	8,500 j	8,500 j		
Energy savings (quads)	0.96 e	0.88 e	0.34 e	1.18 e	1.30	2.07
Avg. MT Carbon/Quad	24.92 f	25.21 f	25.73 k	25.73 k		
Carbon savings (MT)	23.83 g	22.27 g	8.87 g	30.48 g	32.70	52.74

Notes:

a Total capacity after DSM (from Table 12) minus capacity repowered in the 1990-2010 period (from columns to right).

b Calculated for post-DSM case electricity sales and capacity in Table 12, assuming 8% T&D losses.

c Derived from EIA "1991 Annual Energy Outlook", Reference Case.

d Gluckman, in "CO2 Emisssion Reduction Cost Analysis", EPRI, Aug. 1990, estimates 2-4% savings are readily available. We assume 3% here.

e Capacity affected * capacity factor * 8760 hrs/yr * (heat rate before - heat rate after) / 10^9.

f Weighted average based on fuel shares for power sector from EIA, "1991 Annual Energy Outlook," Reference Case. Assumes 28.2 MT/Quad for coal, 20.7 for oil, and 14.5 for natural gas.

g Energy savings * MT carbon/quad.

h Gluckman (see note d) estimates that 30 GW of existing coal capacity is attractive for repowering. To this we add 15 GW of oil and gas steam turbine capacity (based on ratio of existing coal steam capacity and oil and gas steam capacity).

i Average heat rate of plants with a heat rate of 12,000 or more. Figure calculated by ACEEE based on data presented in Gluckman (see note d).

j Based on data presented in EIA, "1991 Annual Energy Outlook" and Gluckman.

k Assumes 67% displaced capacity is coal, 33% is oil -- see note h.

estimates are based on a detailed analysis by ACEEE and the New York State Energy Office on the rate impacts of an aggressive set of efficiency programs and policies along the lines suggested here.[127] This analysis was based on the assumption that the utility typically pays 80% of equipment and installation costs, and 100% of program installation costs. Remaining equipment and installation costs are paid directly by consumers out of the money they save on their electric bills. In addition, consumers also directly pay for efficiency improvements mandated by codes and standards. Typically benefits achieved by consumers from utility programs, codes, and standards are approximately five times greater than consumer costs.[128]

Reductions in Carbon Emissions

Carbon savings for efficiency measures were estimated based on the generating fuel mixes for 2000 and 2010 as estimated in the EIA Reference forecast, and a carbon emission value of 28.2 megatons (MT) per Quad (quadrillion Btu -- 10^{15}) of coal, 20.7 MT/Quad of oil, and 14.5 MT/Quad of natural gas.

Overall Results

The different components of our analysis are brought together in Table 12, which summarizes our overall results.

CAVEATS

The analysis presented here is subject to a few limitations. First, it uses the EIA forecast of future electricity needs as an initial baseline. If the EIA forecast ultimately proves to be too high or low, the savings estimated here will change.

Second, our scenario incorporates ratios of energy sales to peak power demand based on current data. In the future, these ratios may change, which will affect the savings estimates. For example, if load factors improve in industry (that is, if average loads and peak loads converge), peak load savings from equipment efficiency standards will be less than we predict. On the other hand, more new power plants would be built if peak load savings are not as great, providing additional opportunities for savings on the supply-side.

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[127] Nadel, Steven and Harvey Tress, *The Achievable Conservation Potential in New York State from Utility Demand-Side Management Programs*, Report 90-18, New York State Energy Research and Development Authority, Albany, NY, November 1990.

[128] *Ibid.*; Nadel, Shepard, Greenberg, Katz, and de Almeida, *Energy-Efficient Motor Systems*, American Council for an Energy-Efficient Economy, Washington, DC, 1991, p.223; Nadel, Geller, Davis and Goldstein, *Lamp Efficiency Standards for Massachusetts: Analysis and Recommendations*, American Council for an Energy-Efficient Economy, Washington, DC, June 1989, pp.92-95.

Table 12. Estimated TWh, GW, and Carbon Savings from Adoption of Strategies Recommended in this Paper

	TWh Sales			GW Capacity			MT of Carbon Emitted			Consumer Bills (billion 1990$)		
	1990	2000	2010	1990	2000	2010	1990	2000	2010	1990	2000	2010
EIA Reference Case	2700	3282	3985	689	718	830	522	618	755	$187.4	$224.8	$287.7
Annual growth rate	--	2.0%	2.0%	--	0.4%	1.5%	--	1.7%	2.0%	--	1.8%	2.2%
Demand-side savings												
Revised appliance stds.	0	35	146	0	15	73	0	7	28			
Building codes	0	50	175	0	12	43	0	9	33			
Stds. on add'l products	0	60	86	0	29	40	0	11	16			
Subtotal	0	145	407	0	56	157	0	27	77			
Utility DSM programs	0	222	568	0	65	158	0	42	108			
Total	0	366	975	0	121	315	0	69	185	$0.0	$21.1	$59.5
ACEEE Post DSM Case	2700	2916	3010	689	597	515	522	549	571	$187.4	$203.7	$228.2
Annual growth rate	--	0.8%	0.5%	--	-1.4%	-1.4%	--	0.5%	0.4%	--	0.8%	1.0%
Supply-side savings												
Heat rate improvements							--	24	22			
Repowering							--	9	30			
Subtotal							0	33	53	$0.0	$3.1	$4.9
ACEEE Efficiency Case							522	517	518	$187.4	$200.6	$223.3
Annual growth rate							--	-0.1%	0.0%	--	0.7%	0.9%

Notes:

* Base case numbers from EIA, "1991 Annual Energy Outlook". "Capacity" is electricity generating capability.
* Derivation of savings from codes and standards described in Tables 8, 9, and 10. Derivation of savings from utility programs explained in text.
* Capacity equivalents for DSM calculated by taking savings at the customer level, and adding an extra 8% for T&D losses, and an extra 20% for reserve margin requirements. In addition, for savings from standards on additional products, MW savings from Table 10 are multiplied by an assumed 70% coincidence factor.
* Supply side savings from Table 11.
* Distribution transformers are included in the list of additional demand-side standards, although technically distribution transformers are a supply-side measure.
* Estimates of carbon savings based on fuel mix in EIA Reference Case. Average carbon emissions assumed to be 14.5 MT/Quad of gas, 20.7 MT/Quad of oil, and 28.2 MT/Quad of coal.
* Consumer electricity bills for basecase based on retail rates from EIA Reference Case. Consumer bills for efficiency case assume rates go up 2% in 2000 and 5% in 2010 in order to pay for the DSM programs and recover the fixed cost portion of lost revenues (these estimates are based on work described in Nadel and Tress, "The Achievable Conservation Potential in New York State," NYSERDA, 1990. Savings from supply-side improvements based on average fuel costs for power sector from EIA Reference Case.

Third, while our scenario incorporates a set of aggressive actions to promote efficiency, the actions by no means exhaust opportunities for efficiency improvements. For example, the analysis includes changes to codes and standards during the early and middle 1990's, but does not include changes in the late 1990's and beyond. Similarly, the analysis is generally built around conservation and load management technologies that are on the market today. As new technologies are developed, opportunities for savings will increase. Likewise, the analysis includes modest efficiency improvements to power plants, but much larger improvements are possible. In fact, if future laws regulate carbon dioxide emissions of power plants, additional efficiency improvements on the supply-side are likely.