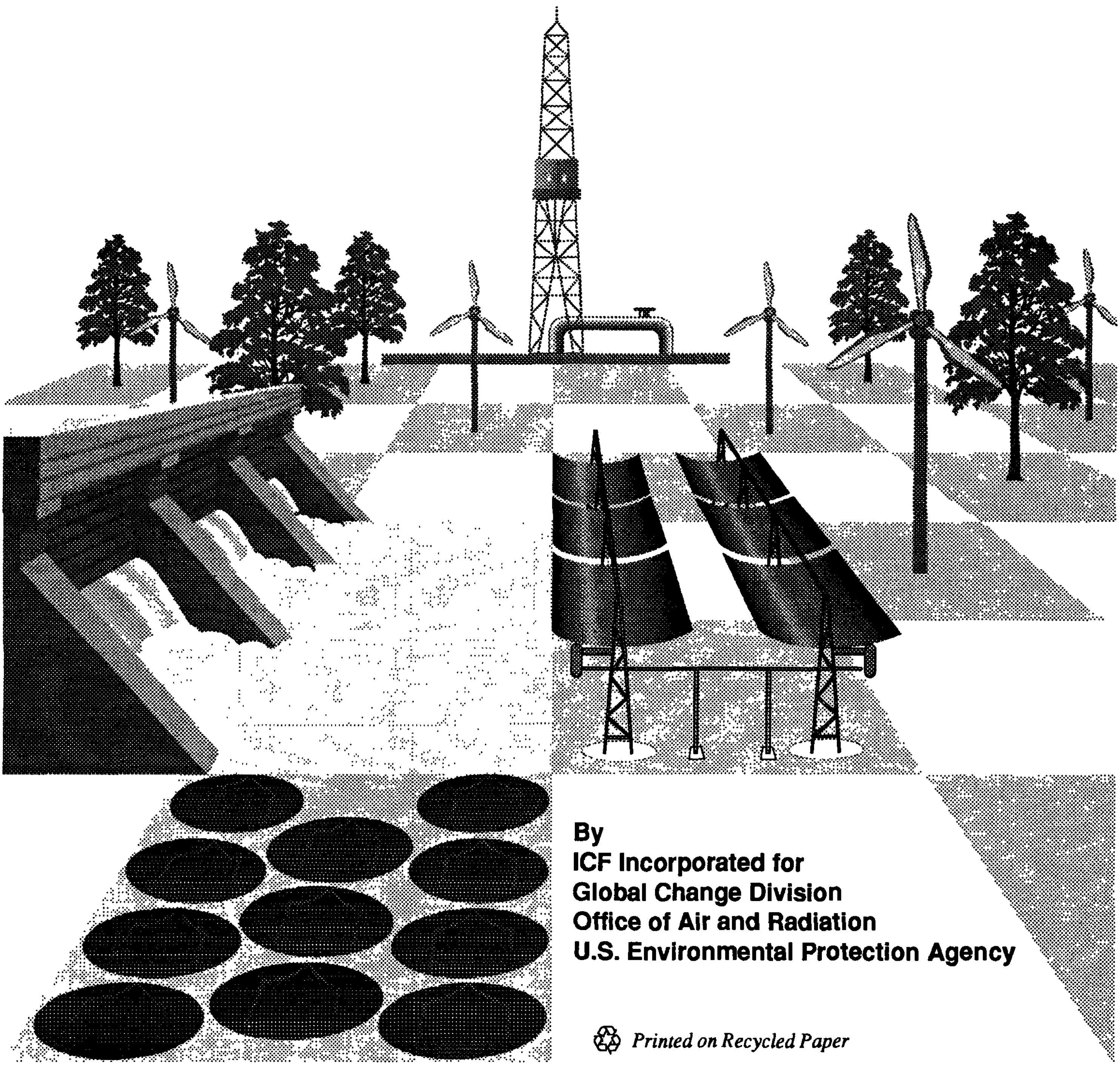
United States
Environmental Protection
Agency

Air and
Radiation
(ANR-445)

EPA/400/R -92/005
March 1992

Renewable Electric Generation

An Assessment of Air Pollution Prevention Potential



By
ICF Incorporated for
Global Change Division
Office of Air and Radiation
U.S. Environmental Protection Agency

Printed on Recycled Paper

RENEWABLE ELECTRIC GENERATION

An Assessment of

Air Pollution Prevention Potential

Final Report

By
Marc Chupka
David Howarth
ICF Incorporated

Cathy Zoi
Project Officer and Editor
Global Change Division
Office of Air and Radiation
United States Environmental Protection Agency

March 1992

Acknowledgements

The authors would like to thank Caleb Kleppner, Robin Langdon, and Dara O'Rourke of ICF Incorporated and David DeBusk and Brendan MacMillan of The Bruce Company for their contributions. We would also like to thank the many individuals who reviewed and provided useful comments on earlier versions of this report.

CONTENTS

CHAPTER III: THE EPA MARKET ASSESSMENT

CHAPTER IV: BIOMASS ELECTRIC GENERATION

CHAPTER VI: CONVENTIONAL HYDROPOWER

CHAPTER VII: PHOTOVOLTAICS

CHAPTER VIII: SOLAR THERMAL ELECTRICITY GENERATION

APPENDIX A: RENEWABLE ELECTRIC TECHNOLOGY PENETRATION SCENARIOS

APPENDIX B: 12 REGION MODEL RESULTS

APPENDIX C: MODEL DESCRIPTION

EXECUTIVE SUMMARY

The purpose of this assessment is to identify the air pollution prevention potential of renewable electric generation. During recent years environmentalists and members of the renewable energy community have been hailing the environmental benefits of renewable resources. With increasing attention on air emissions associated with electricity generation, as well as passage of the Clean Air Act Amendments of 1990, the U.S. EPA commissioned this analysis to help determine the near and mid-term potential of renewable electric resources to avoid increased air pollution.

The general approach of the analysis is "bottoms-up" -- that is, technology-by-technology, region-by-region, and seasonal/time-of-day. In order to assess the emissions reduction potential, technologies were examined individually based on their cost and operating characteristics in particular regions (see Appendix C for model description). In addition, the current regulatory and legal settings were examined closely to help gauge the likely contribution individual technologies could make.

Chapter I provides context by characterizing electricity generation and its relationship to the environment. Chapter II discusses the technical availability of renewables as well as the institutional barriers and opportunities. Chapter III integrates the important elements of Chapters I and II with the technical and regional assessments (discussed in detail in later chapters) to construct a scenario for increased penetration of renewable electric generation for the years 2000 and 2010. Chapters IV-IX provide detailed discussions of the current status of the individual technologies. Chapter X offers a brief discussion of some of the issues associated with the development of "hybrid" technologies, that are either a renewable/fossil combination, or a renewable/renewable system in tandem.

The assessment leads to the following findings:

1. Renewable electric generation has fewer environmental impacts than fossil fuel-fired electric generation. Expanded renewable generation can prevent pollution by displacing fossil fuels. For instance, using hydropower in place of fossil fuel-fired generation reduces NO_x emissions by about 4 kg/MWh based on national averages.

2. Renewable electric generating technologies are already competitive in a variety of regions and niche markets, providing roughly 370,000 GWh of electricity, approximately 12% of U.S. electric generation. Hydropower and biomass, both mature technologies, together account for over 90 percent of this generation.

3. With a few exceptions, renewable electric technologies are at earlier stages of technological development than fossil fuel competitors. Given the large number of different pathways and technological options for significant cost reductions, there is a high probability that some technologies will achieve much wider cost competitiveness with fossil fuels over the next twenty years.

4. A number of regulatory, economic, environmental and political trends will encourage increased public and private investment in renewables. Increased investment could accelerate cost reductions, making renewables more cost-competitive in the near term. Under conservative assumptions regarding renewable cost reductions through 2010, a portfolio of renewable "backstop" technologies for electricity generation will be available in most U.S. regions at a cost of between 7 ¢/kWh and 12 ¢/kWh. With intensified support consistent with a "level playing field," the cost of generating electricity using renewable resources could fall as low as 4 ¢/kWh to 7 ¢/kWh by 2010.

5. While a few states and utilities explicitly include environmental externalities in their resource planning activities, currently most utility and regulatory practices do not fully recognize the economic value of renewable electricity sources, thus inhibiting their market penetration. For example, they fail to reward renewables for preventing pollution below standards allowed for fossil fuel-fired generation. Some utilities also undervalue the contribution that renewables can make to minimizing fuel price risks, as well as minimizing the risks associated with future environmental regulatory compliance.

6. Innovative ways of integrating intermittent renewable resources such as solar and wind into electric utility systems could increase their value. These methods could include fossil fuel hybrid options, portfolio approaches that combine renewable technologies, demand side management techniques, and electric storage technologies. Current regulatory or utility practices may not adequately consider the full range of such options.

7. Renewable technologies have received less government R&D support than fossil fuels over the past decade. For example, in FY 1990 research for fossil fuels received over $410 million from DOE compared to about $140 million for renewable technologies. Additional investment in renewable R&D has the potential to realize larger social returns compared with fossil fuel R&D.

8. Renewable technology would compete more effectively with fossil competitors if the environmental benefits of renewable generation were explicitly considered in utility resource planning. Many PUCs are currently considering incorporating the environmental costs of fossil fuel-fired generation in the regulatory process.

9. Future economic competitiveness of renewable electric generation will be enhanced by offering renewable energy sources a "level playing field" with respect to the recognition of environmental benefits, greater accommodation of intermittent generation, and equitable levels of government R&D support.

CHAPTER I

ELECTRICITY GENERATION, ENVIRONMENTAL IMPACT, AND REGULATION

Expanded renewable electric generation could substantially reduce the amount of air pollution associated with electricity supply. In fact, this report estimates that substantially expanded use of renewable electric resources could reduce emissions of NO_x and CO_2 by 10 percent in the year 2010, relative to Base Case emissions from all energy sources projected under the National Energy Strategy (see Chapter III).[1] Renewable energy currently accounts for roughly 12% of electricity supply, a contribution that is expected to grow in the future to the extent that renewable energy costs continue to fall relative to fossil fuel energy sources. However, the increased use of renewable energy faces institutional and economic constraints. The prospects for significant increase in renewable electric generation will depend on how conditions evolve in electricity markets, including guidance by the policies of federal, state, and local authorities.

This chapter describes how electricity markets operate, highlighting the regulatory trends that may provide increased opportunities for air pollution prevention strategies. This broad perspective provides a useful context for understanding how renewable electric generation can help reduce the environmental impacts associated with energy production and use.

ELECTRICITY AS AN ENERGY SOURCE

Electricity provides essential services to the economy. Manufacturers, service providers and households depend on continuous electric power to operate; U.S. industrial productivity and general quality of life are tied to a reliable supply of electricity. Electric power provides roughly 15% of net energy consumed in the United States.

Electricity may seem expensive compared with other energy forms, but it provides great value in the form of light, heat, and mechanical power on demand. Electricity use can be adjusted instantaneously and requires no storage or inventory, with users paying only for energy actually consumed. To the end-user electricity entails no direct pollution (as compared to on-site use of coal

[1] Similar reductions in SO_2 (14% of the NES Base Case) are also estimated. Given the current system of tradeable SO_2 emission permits, however, these reductions would probably not occur. Rather, allowances would be created that could then be sold to SO_2 emitters.

or fuel oil). It is therefore viewed by many as the cleanest and most convenient energy form, although a complete fuel cycle analysis would be needed to determine electricity's total impact.

Sources of Supply

As noted above, electricity is not actually a source of energy, it is a form of energy. In conventional systems electric current is produced when a generator (dynamo) converts kinetic energy into electricity; the energy to turn the generator usually comes from the spinning blades of a turbine. Most electricity in the U.S. is steam-driven, where the primary thermal energy source is fossil fuel combustion or nuclear energy. Other thermal options include combustion turbines, which are similar to jet engines, and internal combustion engines.

However, converting fossil energy to electricity entails energy losses of between 60 and 70 percent. Therefore, electricity accounts for greater primary energy use than other forms of direct energy consumption; in fact, electric power production accounts for 36% of all U.S. primary energy consumption, with fossil fuels providing two-thirds of the primary energy input. Looking at current electricity fuel requirements, coal is the dominant fossil fuel, followed by natural gas and oil. Nuclear power provides 20% of the primary energy. Renewable resources - flowing water (hydroelectric), biomass fuels (wood and organic waste), geothermal energy, wind, and solar energy - provide the remaining 12%.[2] Table I-1 shows the current contribution of renewable energy to electricity supply.

Growth in Demand

Figure I-1 shows historical U.S. electricity demand and several different projections of electric demand growth. The growth rate projections range from 1.6% to 2.4% per year through 2010. Based on these projections and current utility reserve margins, electricity demand during the 1990s will outstrip current capacity to supply the load in most regions. The primary choices to meet increasing demand include the following:[3]

---

[2] DOE/EIA, *Annual Energy Outlook 1991*

[3] Over the time-frame of this analysis, nuclear energy has not been considered. There are a number of issues associated with nuclear power plant development that are beyond the scope of this report. Given the fact that a nuclear unit has not been ordered in almost 15 years, and that no utilities have publicly filed their intention build any new units, this does not appear to be a major omission.

TABLE I - 1

RENEWABLE ELECTRIC TECHNOLOGIES: 1990 CONTRIBUTION TO ELECTRIC SUPPLY

Technology	Capacity (MW)	Generation (GWh)	Share of Total Renewable Generation	Commercial Status
Conventional Hydropower[a]	71,270	298,010	80.6%	
Storage	50,380	197,500		Mature
Run-of-river & diversion	20,890	100,510		Mature
Biomass Electric[b]	7,844	45,730	12.4%	
Wood and wood waste[c]	5,728	32,600		Mature
Municipal solid waste	1,624	9,250		Relatively mature
Landfill and digester gas	492	3,880		Relatively mature
Geothermal[b]	2,929	23,070	6.2%	Relatively immature
Wind[b]	1,392	2,190	0.6%	Relatively mature
Solar Thermal Electric[b]	279	765	0.2%	
Hybrid (natural gas)[d]	274	753		Relatively immature
Non-hybrid peaking	5	12		Immature
Photovoltaics[b]	12	25	0.0%	Immature
Total Renewable Electric	83,726	369,790	100.0%	
Total U.S. Electric[e]	729,400	3,014,000		
Percent Renewable	11.5%	12.3%		

Notes:

a Hydropower data taken from Federal Energy Regulatory Commission (1990) based on average conditions, excluding Alaska.

b Based on data contained in The Power of the States (1990, Public Citizen). Generation based on 65% capacity factor for wood, wood waste, agricultural waste, and municipal solid waste, and 90% capacity factor for landfill and digester gas.

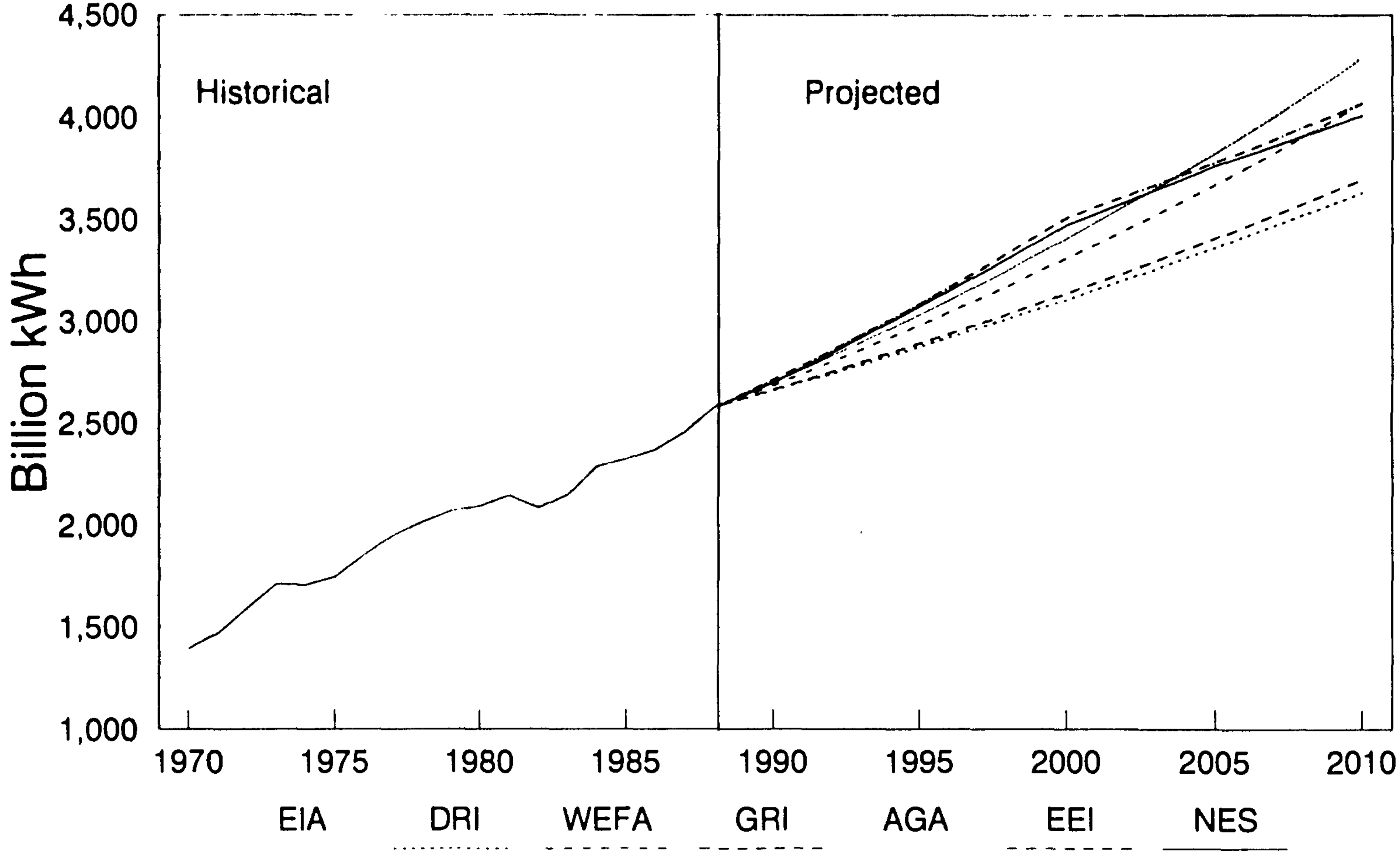
c Includes combustion of agricultural wastes.

d See *The Power of the States: State-by-State Supplement* p. 10.

e Capacity and generation taken from Tables A4 and A5 of *Annual Energy Outlook 1991* by the Energy Information Administration. Figures include utility and non-utility capacity and generation.

FIGURE I - 1

DOMESTIC ELECTRICITY CONSUMPTION
1970 - 2010



Sources:
DOE/EIA, "Annual Energy Outlook, 1990" Table 3
Edison Electric, "Electricity Futures" Fig. 12
DOE, National Energy Strategy, 1991

EIA = Energy Information Administration
DRI = Decision Research Institute
WEFA = Wharton Econometric Forecasting Associates
GRI = Gas Research Institute
AGA = American Gas Association
EEI = Edison Electric Institute
NES = National Energy Strategy Base Case

- Conventional and advanced coal power plants;
- Combined-cycle natural gas plants;
- Natural gas turbines (for peak loads);
- Investing in increased efficiency in supply, distribution, or end-use; and
- Renewable electric technologies.

These choices will have important consequences for air quality and the environment. Some options will increase the amount of air pollution produced each year in the U.S.; others will not. Because powerplants typically last a minimum of 30 to 40 years, with coal plants lasting for 50 to 60 years with refurbishment, these investment decisions will commit the U.S. to certain levels of air emissions well into the future.

ELECTRICITY AS A POLLUTION SOURCE

Most of the electricity used in the United States is generated by burning fossil fuels. Thus, while electricity is a clean and convenient source of power for users, electricity production incurs environmental costs.

Environmental Impacts

Environmental impacts from electricity generation include air, water, and land pollution which results from extracting, transporting, and burning fossil fuels. Although this report focuses on the direct emissions of air pollutants and greenhouse gases, many other impacts arise from the full fuel cycle. For example, coal mining operations emit particulates and methane into the atmosphere and cause water pollution in the form of acid runoff. Coal transport (primarily railroad) consumes energy and causes pollution. Oil and natural gas drilling and distribution also have environmental impacts. Although nearly all energy supply activities are regulated to mitigate environmental impacts, damage to environmental resources and health continue to occur as a result of energy consumption.

Fossil fuels are composed primarily of hydrogen and carbon, but also contain small amounts of sulfur, nitrogen and other impurities. In an ideal combustion reaction, the hydrocarbon fossil fuels quickly react with the oxygen in the air (oxidize) to form carbon dioxide (CO_2) and water, while giving off useful heat. What is commonly referred to as "air pollution" results from the incomplete combustion of hydrocarbon fuels (forming carbon monoxide, CO), the presence of impurities in the fuel (such as sulfur that forms sulfur dioxide, SO_2) or high combustion temperatures (which convert atmospheric or fuel-based nitrogen into nitrogen oxides, NO_x).

Air Emissions and Environmental Controls

Regulated Pollutants. Under authority of the Clean Air Act of 1970, the U.S. Environmental Protection Agency (EPA) has established ambient air quality standards for a number of air pollutants. These "criteria" pollutants include SO_2 , NO_x , CO, particulate matter, and reactive volatile organic compounds (VOCs). The EPA and individual states then set emission limits for individual stationary sources. Table I-2 shows the progress made in controlling pollutants from electricity generation between 1970 and 1988. During this period, overall emissions of air pollutants from electricity generation have gradually fallen, while electricity generation has increased by 77%. Despite these accomplishments, fossil fuel-fired electricity generation accounts for about 66% of total U.S emissions of sulfur oxides, 37% of total emissions of nitrogen oxides, 6% of total particulate emissions, and less than 1% of total VOC and carbon monoxide emissions.[4] Figure I-2 shows 1989 emissions of EPA's criteria air pollutants from U.S. electric utilities.

Sulfur Dioxide. SO_2 emissions from electric utilities peaked in the mid 1970s at nearly 17 million metric tons per year and currently stand at 14 million metric tons (66% of total U.S. SO_2 emissions). SO_2 can adversely affect human health and is the primary constituent of acid rain, which harms aquatic and terrestrial ecosystems. Over 95% of SO_2 emissions from electricity generation come from coal-fired facilities. New coal-fired utility sources are controlled with "scrubbers," which range in cost between \$70 and \$250 per kilowatt (\$120/kW average) and remove up to 95% of SO_2 from the flue gases.[5] Because of concern about SO_2 emissions from existing utility sources, the Clean Air Act Amendments of 1990 will limit overall annual SO_2 emissions from electricity generation to about 8 million metric tons by 2000. This emission "cap" will be sustained by a system of allowances that can be traded among emitters.

Nitrogen Oxides. NO_x emissions from utilities have increased from 4.4 million metric tons in 1970 to 7.3 million metric tons in 1989, an average annual growth rate of 1.7%. Utilities accounted for 37% of

[4] See National Air Pollutant Emissions Estimates, 1940-1989, Environmental Protection Agency. Tables 7 - 11.

[5] See *Electric Power Annual 1989* (Energy Information Agency, 1991) Table 47. Some of these technologies do not eliminate pollution, but simply transfer pollutants to other media. For example, scrubber sludge must be landfilled carefully to prevent groundwater pollution However, the pollutants may be more easily controlled in this form where they are more concentrated and less reactive.

TABLE I - 2

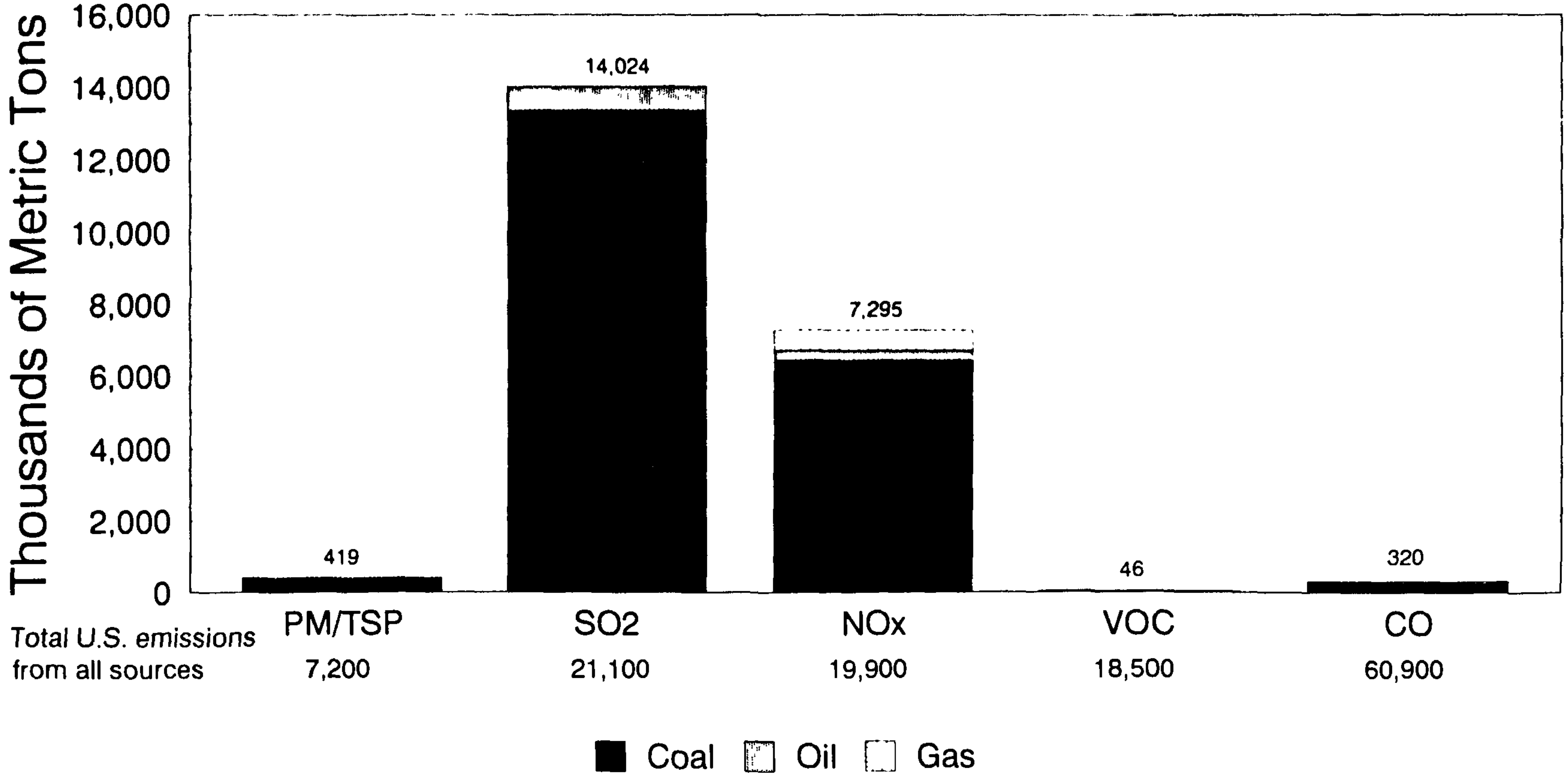
CRITERIA POLLUTANTS: 1970, 1980, 1989
(Thousand Metric Tons/Year)

PARTICULATE	1970	1980	1989
Coal	2,220	720	354
Oil	110	100	60
Gas	6	6	5
Total Utility	2,336	826	419
TOTAL PARTICULATE	18,548	8,522	7,154
SULFUR OXIDES	**1970**	**1980**	**1989**
Coal	14,330	14,190	13,345
Oil	1,450	1,300	678
Gas	1	1	1
Total Utility	15,781	15,491	14,024
TOTAL SULFUR OXIDES	28,422	23,377	21,092
NITROGEN OXIDES	**1970**	**1980**	**1989**
Coal	3,170	5,150	6,430
Oil	390	440	280
Gas	880	780	585
Total Utility	4,440	6,370	7,295
TOTAL NITROGEN OXIDES	18,510	20,919	19,887
VOC	**1970**	**1980**	**1989**
Coal	20	30	38
Oil	7	8	5
Gas	5	4	3
Total Utility	32	42	46
TOTAL VOC	24,951	21,117	18,527
CARBON MONOXIDE	**1970**	**1980**	**1989**
Coal	100	170	230
Oil	40	40	30
Gas	80	80	60
Total Utility	220	290	320
TOTAL CARBON MONOXIDE	101,420	79,617	60,816

Source: EPA/OAQPS, "National Air Pollutant Emission Estimates, 1989" March 1991, Tables 19-20

FIGURE I - 2

EMISSIONS OF CRITERIA POLLUTANTS FROM ELECTRIC UTILITIES, 1989



Source: EPA "National Air Pollutant Emission Estimates, 1940-1989" Tables 19-23.

U.S. NO_x emissions in 1989. NO_x is also a precursor to acid rain. In combination with volatile organic compounds (VOCs), NO_x forms tropospheric ozone (photochemical smog), which causes respiratory stress and other health problems. Low-NO_x burners can reduce NO_x formation by 50% from utility boilers, and more expensive selective catalytic reduction can remove about 90% of NO_x from the flue gas. The Clean Air Act Amendments of 1990 will reduce annual utility NO_x emissions to about 4.6 million metric tons by 2000.

Particulate Matter. Particulate emissions from electric utility generation have been steadily declining from 2.3 million metric tons in 1970 to 0.4 million metric tons in 1989, or 6% of total U.S. emissions. Particulates impair visibility and contribute to respiratory problems. Baghouse filters and electrostatic precipitators remove over 99% of particulate matter, and nearly all coal-fired sources apply these measures.

Carbon Monoxide. CO emissions are harmful to human health. CO emissions from oil and gas-fired generation facilities have decreased since 1970, but CO emissions from coal-fired generation have more than doubled. As a result, total CO emissions from electric generation rose from 0.2 million metric tons in 1970 to 0.3 million metric tons in 1989, a 40% increase. Putting this increase in perspective, utility CO emissions represented only 0.5% of the U.S. total in 1989.[6]

Volatile Organic Compounds. Non-methane volatile organic compounds (VOCs) are a broad class of pollutants that include evaporated gasoline, unburned hydrocarbons emitted from automobile engines, and a wide range of industrial and home solvents. These VOCs contribute to tropospheric ozone pollution. Total VOC emissions from electric generation have increased slightly from 32,000 tons in 1970 to 46,000 tons in 1989; coal VOC emissions have doubled over the same period. Utilities, however, directly contribute minor amounts (0.2%) to national VOC emissions.[7]

Unregulated Pollutants. Greenhouse gases, including carbon dioxide and methane, currently are not regulated by the EPA as criteria pollutants. They are included in this analysis, however, because utilities account for a significant portion of these emissions.

Carbon Dioxide. Although carbon dioxide is not regulated as a criteria pollutant, CO_2 is the primary "greenhouse gas" contributing to global warming. The amount of CO_2 released in combustion is related to the ratio of carbon to hydrogen in the fuel. Figure I-3 shows the molecular structure of coal

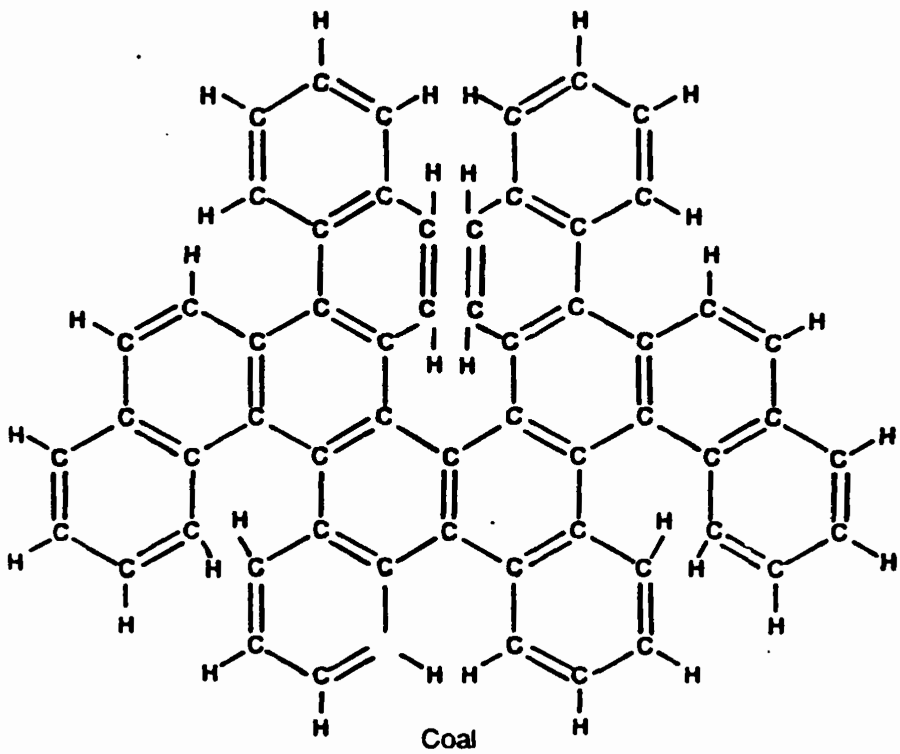
---

[6] The vast majority of CO emissions (66%) comes from transportation sources.

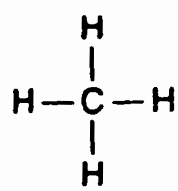
[7] Transportation and industrial processes account for 35% and 44%, respectively, of total VOC emissions

FIGURE I - 3

MOLECULAR STRUCTURES OF COAL AND METHANE



Coal
$C_{57}H_{32}$



Methane
CH_4

and methane (the primary constituent of natural gas). Coal emits about twice as much carbon per unit of heat released as does natural gas. The CO_2 emission rate for oil combustion is between that of coal and natural gas.

No practical abatement technologies exist to control CO_2 from carbon-based fuels, and CO_2 emissions from electric utilities will rise if current trends continue. In 1988, electric utilities in the U.S. emitted 1,800 million metric tons of CO_2, or 37% of U.S. CO_2 emissions.[8] U.S. electric utilities account for roughly 8% of worldwide CO_2 emissions. Over half of the electric power in the U.S. is generated from coal, and many forecasts project that the contribution of coal to U.S. electric power generation will continue to grow over the next decades. If coal remains the dominant electric generation fuel, then utility CO_2 emissions could account for even larger shares of total U.S. CO_2 emissions. For example, Figure I-4 shows the CO_2 emissions from a recent forecast made by the Energy Information Administration, where emission from all electric generation (utility and non-utility) increases roughly 75% over the next twenty years.[9]

Methane. Methane reacts more slowly than other hydrocarbons to form ozone, and is not included in the class of regulated VOCs. However, methane is a powerful greenhouse gas that contributes to global warming. As with other VOCs, utilities are directly responsible for a very small share of total methane emissions. However, natural gas extraction operations and pipelines that supply utilities with natural gas may contribute methane to the atmosphere, and coal mining operations routinely vent methane for safety reasons.

ELECTRICITY SUPPLY AND REGULATION

The most attractive feature of electricity -- instantaneous power on demand -- makes electricity supply a complex undertaking. Electric utilities must continually adjust electric supply to meet fluctuations in demand. Much of the demand follows fairly predictable patterns. For example, daily peak demand occurs during relatively predictable times in most utility systems, and utilities can anticipate increased air conditioning loads during hot summer days. However, other fluctuations are more random.

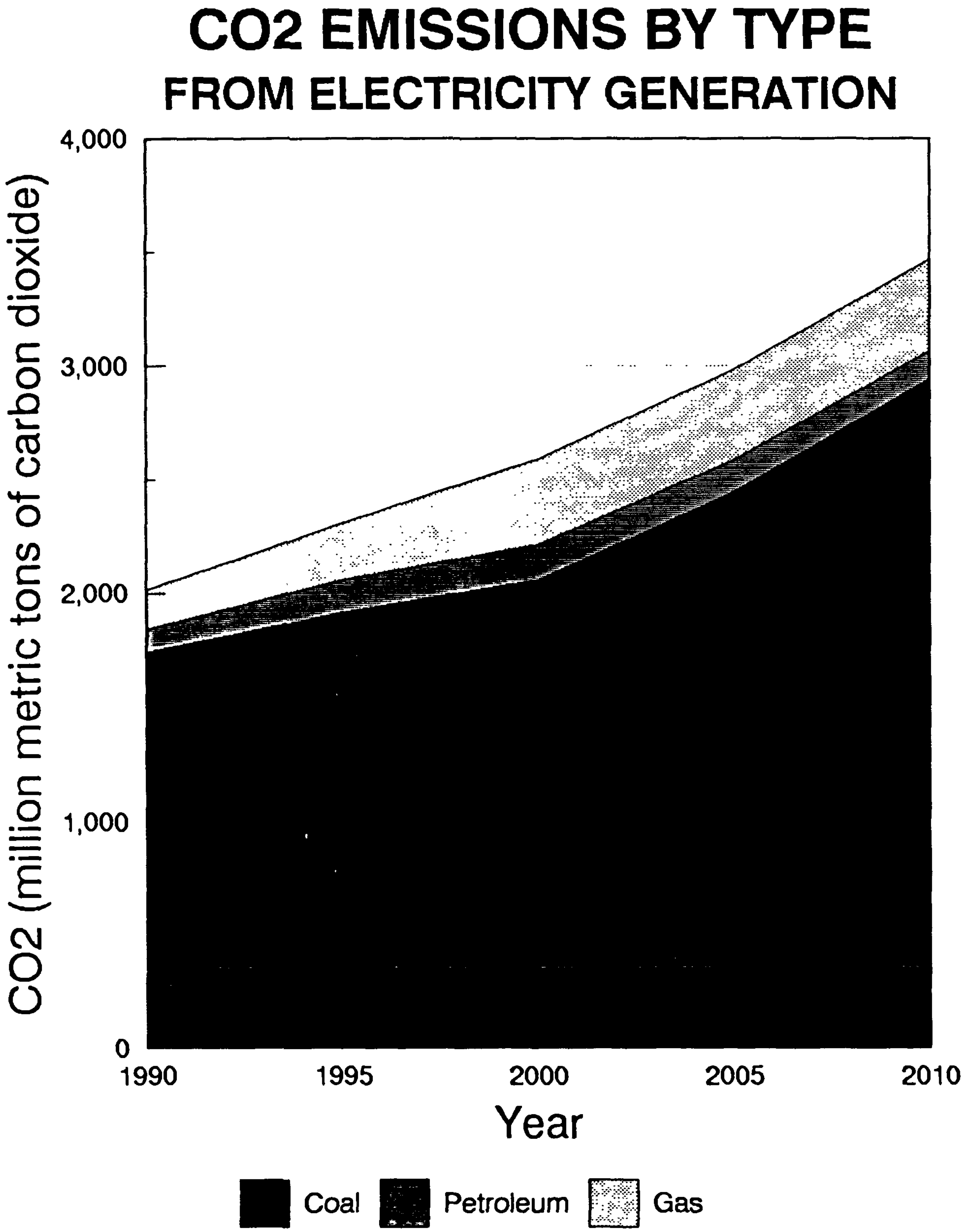
In order to provide reliable power, utilities must control the output of a mix of generating units to keep the system operating within certain parameters (e.g. voltage and frequency). Controlling the

---

[8] DOE/EIA. *Electric Power Annual, 1988*. Table 30. In addition to electric utilities, non-utility electricity generation emitted about 200 million metric tons of CO_2

[9] Figure I-4 is derived from forecast in *Annual Energy Outlook 1990*, DOE/EIA-0383(90).

FIGURE I - 4



Source: Energy Information Administration output of these units to supply power in the least expensive manner is called economic dispatch. Baseload plants (usually coal, nuclear, and hydroelectric capacity) operate continuously unless shut down for repair; intermediate load plants are cycled (generation varies through the day) or generate only during high demand seasons; and peaking units (usually natural gas turbines or internal combustion engines) are operated only for a few hours per day in the high demand season. In the short run, utility operation focuses on economic dispatch and maintaining generating units to keep them operational. Utilities must also maintain a cushion of reserve capacity to accommodate higher than anticipated demands and unscheduled shutdowns of generating units. Over the long run, utilities must decide how to meet growth in demand for electricity and maintain reserve margins. A utility's portfolio of power plants changes as new resources are required to meet growing loads, and as older generating units are overhauled or replaced by new, more efficient technologies.

Some renewable energy sources -- hydroelectric, solar, and wind -- cannot always provide dispatchable power due to the intermittent nature of the resources. These technical considerations pose some challenges to utility operations. The operation of specific renewable electric technologies are discussed in individual chapters, and Chapter X explores ways that intermittent renewable electric generation can be integrated into electric supply systems.

Rate Regulation and Traditional Supply Decisions

About 80% of U.S. electricity is generated by investor-owned utilities (IOUs), which operate under the rules and conditions set forth by the state Public Utility Commissions (PUCs).[10] Under the traditional regulatory compact, IOUs accept an obligation to provide reliable power on demand under electricity rates set by the PUC, in exchange for a monopoly license to generate, transmit, and distribute electric power within a specified service territory. The PUC sets electricity rates based on the operating and capital costs incurred in meeting service obligations (including an allowed return on investment), providing that the utility is investing prudently and operating efficiently.

Historically, electric utilities have responded to projected demand growth by constructing large central-station generating plants. Fuel choice was based on the type of capacity needed, regional fuel availability, and relative cost. After the PUC granted a "Certificate of Need" for a new generating facility, the utility constructed the powerplant. If upon completion of the plant the PUC determines that

[10] Various government agencies also generate and distribute electric power. For example, the federal government owns and operates about 65 GW (9%) of U.S. generating capacity, of which 40 GW is hydroelectric. States, district and regional authorities, counties, and municipalities own 2,000 utilities (about 10% of total capacity), and about 900 consumer-owned cooperatives (about 4% of capacity) also supply electricity. See *Electric Power Annual 1989*, DOE/EIA, pp 2-3.

the investment in the plant was prudent, the cost is then allowed into the "rate base," and the utility customers begin paying for it through electricity rates. Beyond conforming with federal and state environmental regulations and local pollution control or land-use ordinances, the environmental impacts of powerplant emissions are often not considered in traditional supply planning processes.

Demand-Side Options

Over the past fifteen years, utility planners have begun to develop programs to influence electricity demand as an alternative to building new supplies. These programs, called "demand-side management" (DSM), have been encouraged by PUCs and intervenors concerned about the rate impacts of adding increasingly expensive generating capacity. In utility DSM programs, utilities encourage investment in more efficient end-use technologies that can deliver the same level of electric services, such as light, heat, and mechanical power, while using less electricity. Typical program elements include direct investment by offering customer rebates for efficient appliances, lighting, or industrial motors; performing energy audits; and offering energy planning assistance or information. If enough consumers purchase efficient equipment in response to the incentives, then demand for electricity will not rise as quickly. These efficiency gains become a source of electricity "supply" that can be used to satisfy new demands for electric services, enabling utilities and ratepayers to avoid the costs of building new powerplants.

Many PUCs have required DSM evaluation as part of the normal supply planning process, a marked departure from the historical scope of PUC oversight. Where PUCs traditionally evaluated the economic viability of completed generating facilities, many PUCs now insist that utilities examine demand side measures prior to investing in generating capacity, a process known as least cost utility planning (LCUP) or integrated resource planning (IRP).

Emerging Competition and Supply Choices

The 1980s ushered in a period of growing non-utility investment in generation capacity. The emergence of non-utility owned power plants has ignited an extensive debate over the role of competition in electricity supply. The appropriate role of bidding, transmission access, and the influence of PUCs on investment decisions are among the issues that cloud the future of electricity markets in general, and renewable generation in particular. The outcome of this debate will determine, among other things, whether renewables can compete on a "level playing field" in which the environmental impacts of renewable electric generation are appropriately compared with the impact on the environment from fossil fuel generation.

Qualifying Facilities under PURPA. The Public Utilities Regulatory Policies Act (PURPA) of 1978 guaranteed a market for renewable power producers and cogenerators (facilities that produce electricity in conjunction with steam or waste heat) under certain conditions. PURPA was designed to create opportunities for non-utility energy developers to participate in the electric power market, and remains the regulatory foundation upon which most emerging renewable electric projects are built and operated. PURPA was quite successful in stimulating renewable energy development during the 1980s, as seen in Figure I-5. Under PURPA, renewable power and cogeneration projects are designated "Qualifying Facilities" (QFs) under rules established by the Federal Energy Regulatory Commission (FERC).[11] Utilities are required by law to purchase power from QFs and sell back-up power to QFs at non-discriminatory rates. The state PUCs set the electric power purchase rates at the "avoided cost" of the utility. PURPA grants states broad latitude in establishing the markets for QF generators, and a wide variety of approaches has emerged.

Although definitive statistics are not available, QFs account for most of the non-hydroelectric renewable electric capacity. Nearly all windpower and solar thermal capacity is non-utility owned, and about 65% of biomass capacity and 80% of geothermal capacity is non-utility owned. Private non-utility conventional hydropower represents only about 2% of the U.S. capacity.[12]

Independent Power Producers. Independent power producers (IPPs) are a rapidly growing class of non-utility private power developers that are not QFs under PURPA. In practice, IPPs resemble utility-owned generators except for the ownership and contractual relationship between the IPP and utility. IPPs can use any fuel and build generating capacity of any size, and thus have some inherent competitive advantages over renewable QFs, although IPPs are not guaranteed avoided cost payments.

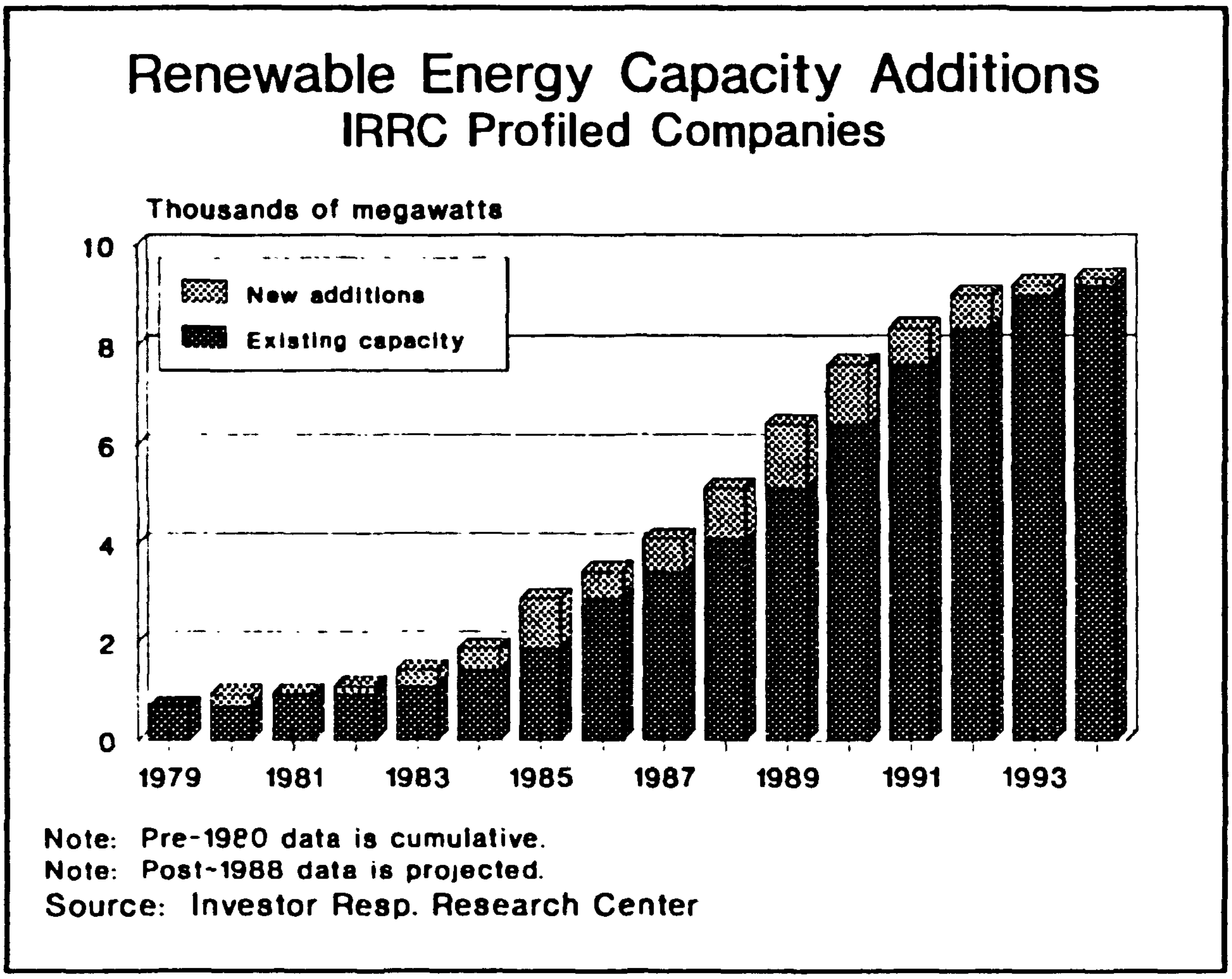
Competitive Procurement and Bidding. Utilities in several states have also established competitive bidding procedures for acquiring new capacity. The bidding process allows non-utility generators (and sometimes demand-side options) to compete for investments in new capacity expansion needs. Non-price factors, such as reliability, project viability, location, size, technology, and environmental impact are also evaluated for individual power supply bids. While early experience in competitive procurement has not been favorable for renewable energy developers, state regulators are beginning

---

[11] A renewable QF must derive at least 75% of energy input from a renewable energy source. An 80 megawatt (MW) size limitation on solar, wind, and geothermal projects was lifted in 1990 No size limit applies to cogeneration facilities Cogenerators can use any fuel, but at least 5% of the energy input must be consumed for non-electric use.

[12] See Susan Williams and Kevin Porter, *Power Plays: Profiles of America's Independent Renewable Electric Developers*, (Investor Responsibility Research Center, 1989), p. 15.

FIGURE I-5



Source: *Power Plays Profiles of America's Independent Renewable Electric Developers*, by Susan Williams and Kevin Porter (Invester Responsibility Research Center, 1989), p 25 to examine ways to increase the renewable energy share by assigning greater weight to non-price factors or setting aside capacity blocks for renewables.

Current and Planned Capacity

As of 1990, electric utilities in the U.S. had 690 gigawatts (GW) of generating capacity, with an additional 40 GW owned by non-utility generators.[13] The total capacity of 730 GW generated over 3 million gigawatthours in 1990. According to the Energy Information Administration, utilities have already planned to add 368 generators with a combined capacity of 41.2 GW between 1990 and 1999. These additions include 208 gas- or oil-fired units (14.9 GW), 39 coal-fired units (15.8 GW), 5 nuclear plants (5.8 GW) 100 hydroelectric generators (3.5 GW) and 16 "other" -- mostly renewable -- units (1.2 GW). Figure I-6 presents this breakout of planned capacity additions. Most of the announced capacity has not begun construction. In addition, EIA projects that utilities and non-utility generators will build an additional 66 GW of currently unannounced capacity by 2000, of which 52 GW will be natural gas-fired.[14]

REGULATION AND POLLUTION PREVENTION IN ELECTRICITY GENERATION

The two regulatory frameworks that govern electricity supply -- rate regulation and environmental control -- have traditionally operated as constraints on electric power generation. Environmental regulation constrained certain operating and investment decisions based on environmental impacts, while rate regulation constrains electricity prices and costs. These regulatory systems attempt to address different types of market failure: rate regulation checks the power of natural monopolies, and environmental regulation limits the adverse impact of electricity generation on human health and ecological resources.

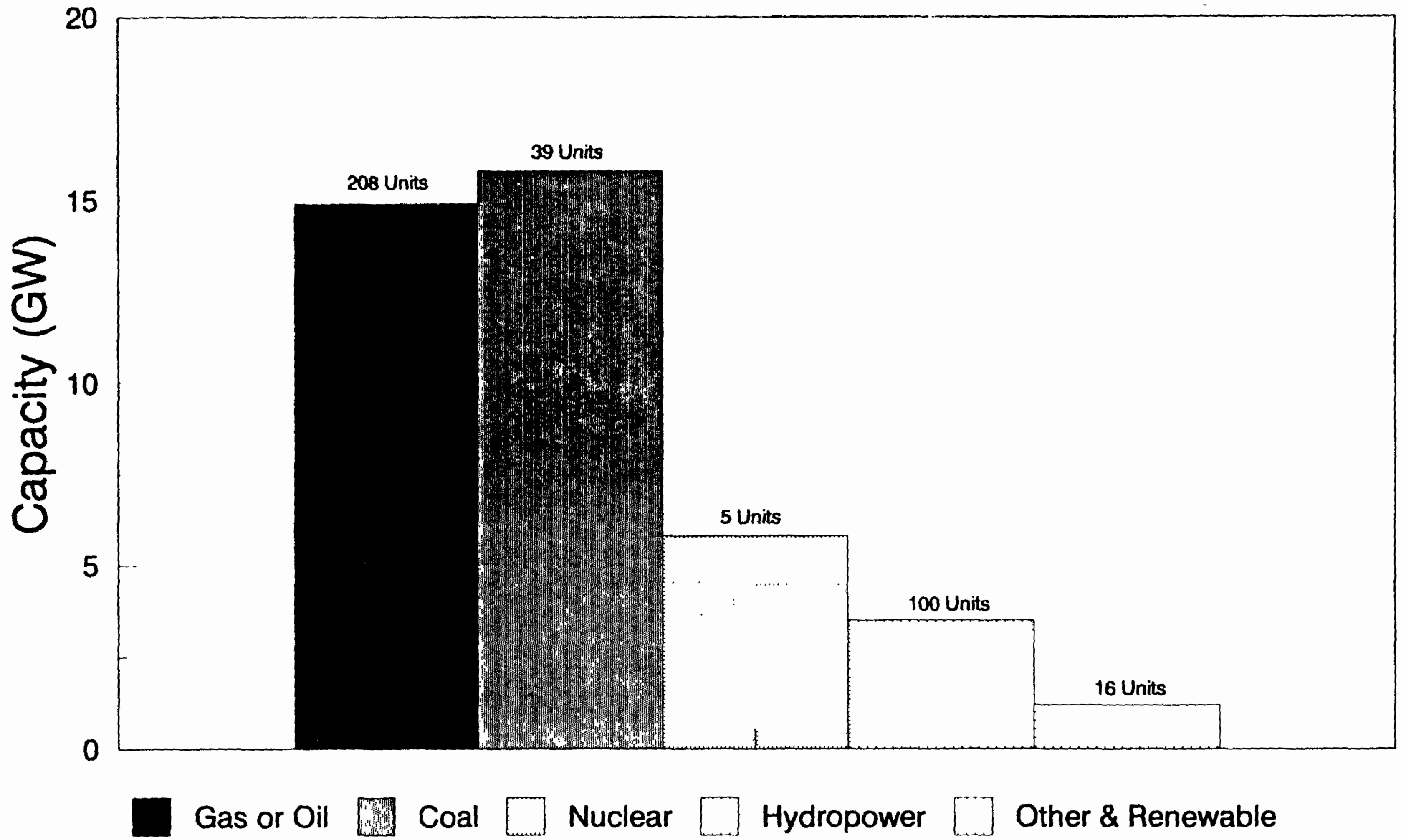
Over the past 20 years, the control of EPA criteria ambient air pollutants from electricity generation has evolved into a complex system of ambient standards, emission limits, and permits. These current regulatory systems give no credit for actions that reduce unregulated pollutants such as CO_2 or CH_4. Taken together, these regulations allow an "acceptable" amount of pollution from the production of electricity. The role of environmental regulation is to establish and enforce the amount

---

[13] Energy Information Administration *Annual Energy Outlook 1991*, Table A5. A Watt is a measure of power or capacity One kilowatt (kW) is 1,000 Watts, a megawatt (MW) is 1,000 kW, and a gigawatt (GW) is 1,000 MW. A kilowatthour (kWh) is a measure of energy equal to one kW of power over an hour. A megawatthour (MWh) is 1,000 kWh, and a gigawatthour (GWh) is 1,000 MWh As a rule of thumb, 1 MW of capacity can serve roughly 1,000 residences (assuming residential demand at 6,000 kWh/year and capacity operating at 68% capacity factor).

[14] Energy Information Administration, *Electric Power Annual 1989* (January, 1991) pp. 23-33.

FIGURE I - 6
PLANNED CAPACITY ADDITIONS
THROUGH 2000



Source: EIA "Annual Energy Outlook 1991," Table A-5.

of socially acceptable pollution at the time the regulation is put forth. What constitutes "socially acceptable" is determined by the scientific data available at the time a law is passed or a regulation is promulgated and the willingness of society to adopt a certain law or regulation. As new data become available, or as public attitudes shift, the "socially acceptable" amount of pollution may change.

Historically, the full environmental impact of generating options has not been considered in electricity investment decisions. A generating plant that produces no emissions (or emissions below the allowable limit) in most cases receives no additional credit compared to one that meets the emissions limit, even though the additional reductions may help to meet an ambient standard that required additional reductions elsewhere. Thus, a renewable plant with emissions far below the plant it competes against could reduce emissions even more than required, yet under the rate-setting system its higher cost would get no credit for additional pollution reduced compared to its competitor. In this instance it is possible that the resource chosen by the utility and approved by a PUC could lead to more stringent emission limits on other polluting activities that could result in higher total costs and greater pollution for society compared to an investment in the renewable plant. Thus, some opportunities for reduced pollution are not reflected in traditional environmental or regulatory planning activities.[15]

The Pollution Prevention Approach

The pollution prevention approach recognizes that altering activities (e.g. production processes) can often reduce the amount of pollution produced. Instead of applying control technologies "to the stack" or "on the tailpipe" to clean up emissions, it may be possible and more cost-effective to *prevent pollution* in the first place. Pollution prevention can reduce or eliminate three costs the cost of controlling the amount of pollution entering environmental media, the environmental damage that occurs from pollution actually emitted, and the cost to the government of regulations to control the pollutants. Because traditional regulation focuses on establishing and enforcing an acceptable emission level, existing regulations may not recognize or encourage fundamental changes. However, in many cases pollution prevention costs less than building emission controls and fixing the environmental damage that occurs under the traditional regulatory approach. Over the long run, pollution prevention is often less expensive than suffering environmental damages, mitigating adverse environmental impacts, or imposing additional controls.

[15] For acid rain reduction, a new system is being set up to achieve lower emission limits in which reductions by generating facilities below the "allowance" given to current units would be used as credits to offset emissions elsewhere

The pollution prevention approach views electricity as a means of providing beneficial services such as light, heat, and mechanical power. These same services -- though not necessarily fossil-fuel generated electricity -- could be provided in a more environmentally benign way if the full range of technological options were considered. For example, the same level of services could be attained with much less electricity if consumers bought the most energy efficient end-use equipment, such as lights and appliances, instead of equipment with average efficiency. This would prevent pollution by reducing the amount of generation required to provide the services.[16]

Many recent studies have identified vast potential for reducing electric demand by increasing end-use efficiency.[17] Depending on the analysis, between 20% and 45% of current (or projected) electricity consumption could be avoided by adopting the most efficient end-use technologies. Utility DSM programs target the cost-effective portion of this "supply," but do not necessarily take into account the pollution prevention benefits. Thus, while the emergence of DSM programs represents an historic shift toward pollution prevention, the emphasis on traditional economic impact on ratepayers and shareholders may limit the extent to which conventional DSM programs may prevent pollution. Moreover, increased efficiency can reduce, but not eliminate, the need for electric power. Thus, society still must choose among the technologies that provide electricity.

Pollution Prevention, External Costs, and Renewable Energy

Adopting the pollution prevention approach in the electric generating sector would encourage generating options that produce the needed electricity with the least pollution. Renewable energy sources produce much less air pollution than conventional fossil alternatives. Figure I-7 shows how much air pollution an advanced technology coal-fired generating facility will create per gigawatthour of electricity generated, compared with a photovoltaic generating plant. Advanced natural gas generating facilities would produce significantly less air pollution than would a coal-fired facility, and some renewable energy technologies would produce more air pollutants than PV stations. However, most renewable electric technologies produce far fewer air pollutants than fossil fuel electric generation.

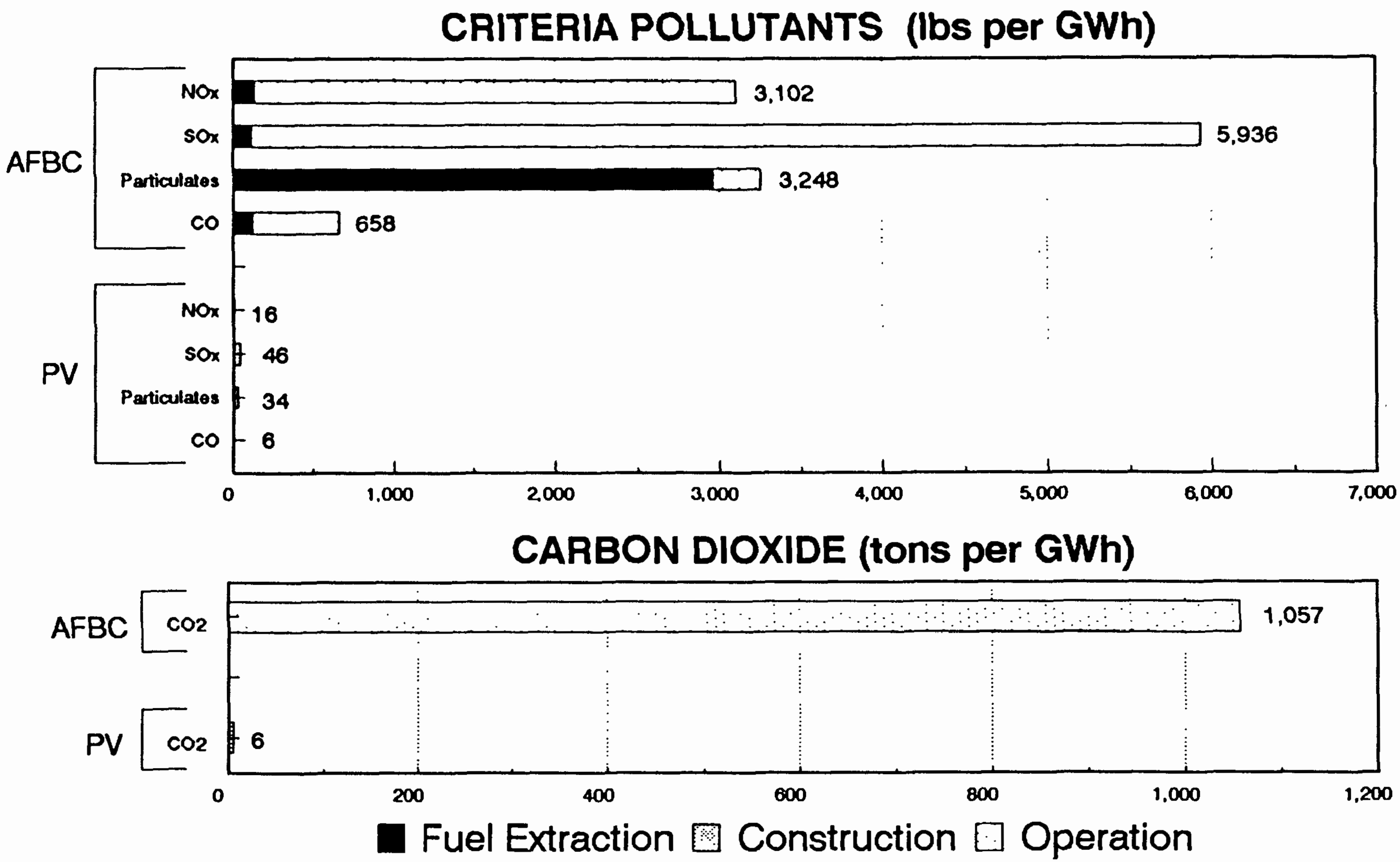
---

[16] Other changes in energy use could prevent pollution, such as substituting direct natural gas for some uses currently served by electricity. Since only about a third of the energy consumed in the production of electricity is returned as electric power, significant energy and pollution savings can be realized when direct fuel use can provide services with less energy lost.

[17] See *Energy Efficiency: How Far Can We Go?* by Roger Carlsmith, et al., prepared by Oak Ridge National Laboratory for the Office of Policy, Planning, and Analysis, U.S. DOE, 1990; *Efficient Electricity Use: Estimates of Maximum Energy Savings* by the Electric Power Research Institute, 1990, and *The Potential for Electricity Conservation in New York State*, prepared for the New York State Energy Research Development Authority, 1989.

FIGURE I-7

AIR EMISSIONS: AFBC* PLANT VS. PV† CENTRAL STATION



Source: Meridian Corporation, "Energy System Emissions and Materiel Requirements" 1989.

* AFBC = Atmospheric Fluidized Bed Combustion Coal
† PV = Photovoltaic

To the extent that renewable electric generating technologies displace fossil fuel-fired generation sources, these technologies would prevent air pollution. The major issue concerning the promotion of renewable energy is its cost relative to conventional alternatives. Most renewable electric technologies are currently more expensive than fossil technologies, as measured by market prices. However, market prices for fossil fuels do not reflect all of the environmental damages that result from their use. Economists call these damages "externalities," reflecting the notion that users of fossil fuels do not pay the full social cost of their choices (some costs remain external to their decision). If the price of fossil fuels included the external costs of environmental damages, many renewable energy alternatives become economically competitive with fossil fuel energy sources. This analysis projects the potential impact of quantifying carbon-related externalities and shows that, depending on the level, this valuation can significantly affect the ability of renewables to compete with fossil alternatives (see Chapter III -- Externality Penalty Cases).

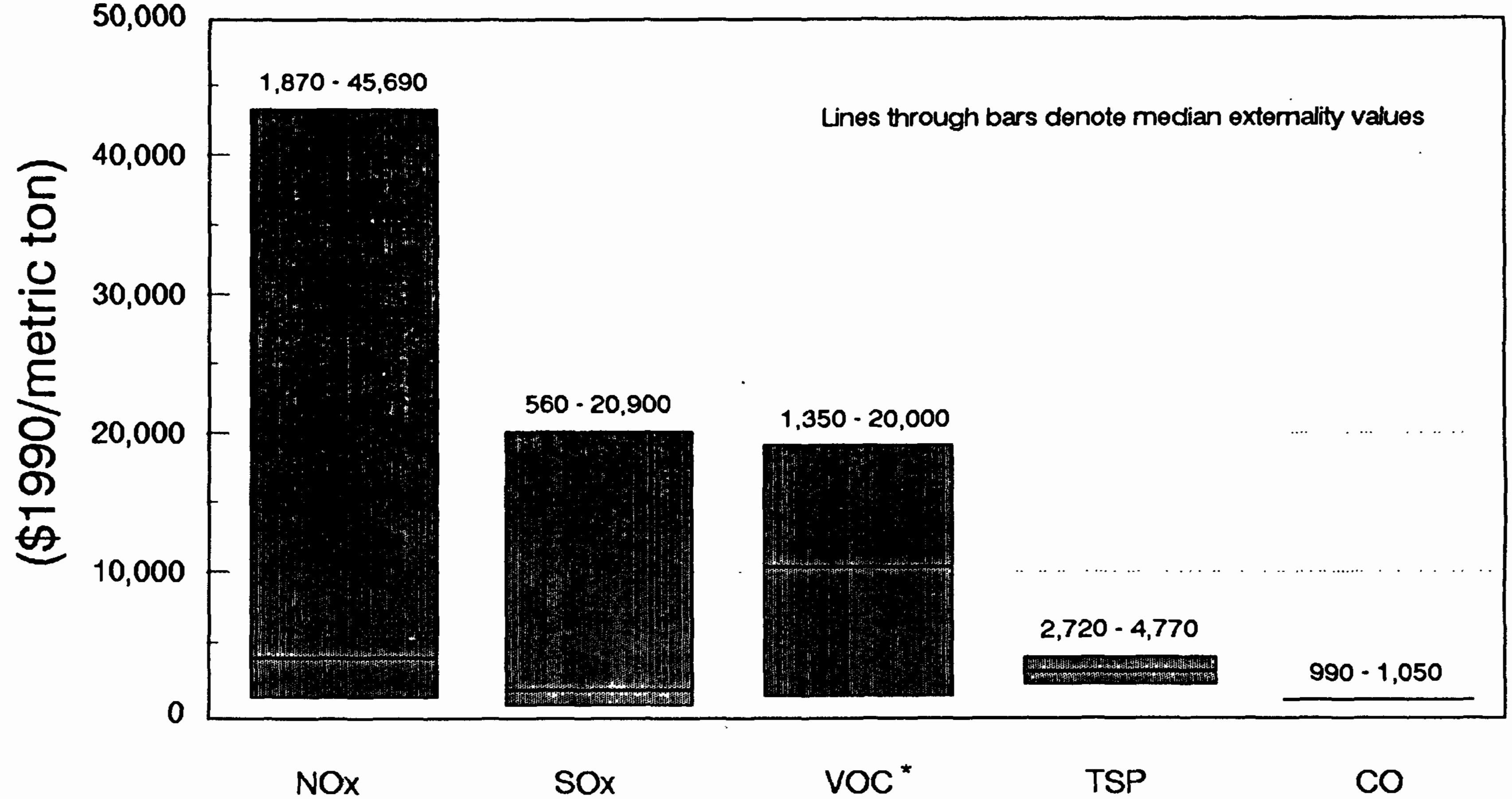
Figures I-8 and I-9 show a range of recent estimates of damages from pollutants and greenhouse gases arising from fossil fuel generation, on a per ton basis. Table I-3 summarizes several recent studies that quantify the external cost of electricity generation in cents per kilowatthour generated. The high social cost of fossil fuel electricity supply is another way of expressing the pollution prevention rationale for promoting renewable energy. Despite continued disagreement over the precise level of environmental damages from fossil fuel combustion, many analysts agree that these externalities are sufficiently large to be an important factor in rational economic choices regarding energy supply. Once quantified and incorporated into energy supply decisions, the external costs of fossil fuel electricity generation will enhance the market prospects of renewable energy resources.

REGULATORY REFORM AND RENEWABLE ELECTRIC OPPORTUNITIES

Rate regulation and environmental regulation continue to evolve. The inclusion of demand-side options into the electric resource planning has been an important step toward pollution prevention. Integrated resource planning methods can be extended to give more explicit recognition of the pollution impacts of various supply and demand choices, and rate regulators are examining several ways to incorporate environmental impacts into the regulatory planning process. Regulators are also beginning to examine how costs at the time of initial investment and the risks of future environmental controls and fuel supply should influence resource selection. On the environmental regulation side, elements of the Clean Air Act Amendments of 1990 reinforce these trends by adopting market-based mechanisms to allocate emission controls.

FIGURE I-8

RANGE OF ESTIMATED EXTERNALITY VALUES
CRITERIA POLLUTANTS

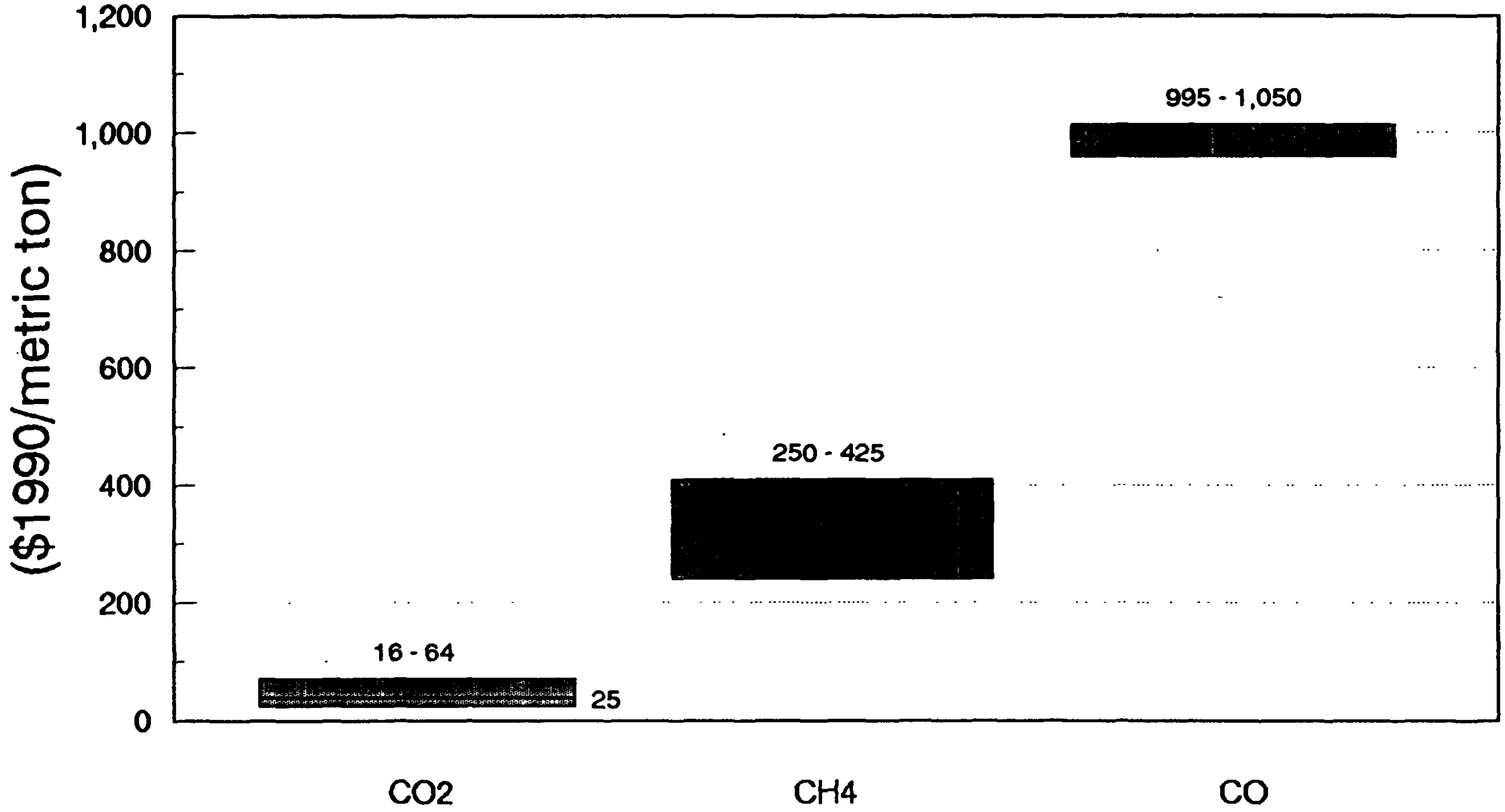


* Although VOCs technically are not criteria pollutants, they contribute to the formation of tropospheric ozone, which is a criteria pollutant.

FIGURE I-9

RANGE OF ESTIMATED EXTERNALITY VALUES

GREENHOUSE GASES



SOURCES FOR FIGURES I - 8 AND I - 9

South Coast Air Quality Management District (SCQAMD), "Draft Best Avaialable Control Technology Guidelines," October 7, 1988.

R. Thomas Beach, prepared testimony on behalf of Pacific Gas Transmission Co., CPUC 011, 88-12-027, June 1989.

Dennis Hertel, testimony for Southern California Edison Company. Hearing on SCAQMD Rules 1135, 1135. June 14, 1989.

W.B. Marcus, prepared testimony on Marginal Cost and Revenue Allocation on behalf of Toward Utility Rate Normalization CPUC App. 88-12-006, Exhibit 235, April 1989.

New York State Energy Office, Division of Policy Analysis and Planning, Environmental Externality Issue Report. February 1989.

Paul L. Chernick, unpublished paper on Externalities prepared for Boston Gas Company. January 1989.

Gayatri M. Schilberg, Jeffrey A. Nahigian, and William B. Marcus, "Valuing Reductions in Air Emissions and Incorporation into Electric Resource Planning: Theoretical and Quantitative Aspects," August 25, 1989. CPUC Docket 88-ER-8.

William D. Nordhaus, "Economic Policy in the Face of Global Warming," March 9, 1990 (unpublished).

H.C. Cheng and M. Steinberg, "Effects of Energy Technology on Global CO2 Emission," prepared for the Carbon Dioxide Research Division of Office of Basic Energy Sciences of U.S. DOE, November 1985.

W.B. Marcus, prepared testimony on behalf of the Small Power Producers Association of Nova Scotia, Nova Scotia Public Utilities Board, N.S. Power Corp. Work Order to Construct Point Aconi Coal Plant. March 1989.

Richard Ottinger, Paper on "Regulatory Processes: Legal and Institutional Barriers," NARUC National Conference on Environmental Externalities, Jackson Hole, WY. October 1-3, 1990 (hereafter referred to as NARUC, WY).

Stephen Bernow and Donald Marron, "Valuation of Environmental Externalities for Energy Planning and Operations," May 1990 Update, Tellus Institute.

Cynthia Mitchell, "State Regulatory Experiences in Attempting to Quantify and Incorporate Environmental Externalities," NARUC, WY

TABLE I - 3

EXTERNALITY ESTIMATES BY SOURCE AND GENERATION TECHNOLOGY ($1990 cents/kWh)

	Low - High	Hohmeyer (a)	Pace (b)	BPA (c)	Tellus (d)	JBS (e)
FOSSIL AND NUCLEAR						
Combustion Turbine: Gas	0.1 - 6.0	0.6 - 2.9	0.7 - 1.0	0.1	6.0	1.6 - 4.1
Combustion Turbine: Oil	0.3 - 10.3	0.6 - 2.9	2.6 - 6.9	0.3	10.3	X
Coal	0.6 - 10.0	0.6 - 2.9	2.6 - 5.9	0.7 - 1.1	4.5 - 10.0	2.8 - 8.2
Nuclear	0 0* - 5 7	0.6 - 5.7	3.0	0.0*	X	X
RENEWABLES						
Photovoltaic	0 - 0.4	0 - 0.2	0 - 0.4	X	X	X
Wind	0 - 0.1	0 - 0 0*	0 - 0 1	X	X	X
Biomass	(0.0*) - 0 7	X	0 - 0.7	(0.0*) - 0.6	X	X
Geothermal	0 - 0.0*	X	X	0 - 0.0*	X	X
MSW	(3.7) - 48.2	X	2.9	(3.7) - 48.2	X	X

* Numbers followed by an asterisk denote values less than one tenth of a cent
Numbers enclosed in parentheses denote a negative cost, or societal benefit

Sources: (a) Olav Hohmeyer, "The Social Costs of Energy Consumption" (Estimates reflect an average for all fossil technologies)
(b) Richard Ottinger, "Environmental Costs of Energy," Pace University
(c) Bonneville Power Administration: 1) "Estimating Environmental Costs and Benefits for Five Generating Resources," 2) "Generic Coal Study: Quantification and Valuation of Environmental Impacts," 3) "Environmental Cost & Benefits Case Study: Nuclear Power Plant--Quantification & Economic Valuation of Selected Environmental Impacts/Effects."
(d) Tellus Institute, "Full Cost Economic Dispatch: Recognizing Environmental Externalities in Electric Utility System Operation."
(e) JBS Energy, Inc., "Valuing Reductions in Air Emissions and Incorporation into Electric Resource Planning: Theoretical and Qualitative Aspects."

Integrated Resource Planning and Pollution Prevention

Utility investment decisions are increasingly influenced by state legislatures, regional planning authorities, and PUCs. Many state regulators have adopted the integrated resource planning framework to guide resource selection, and most states have at least considered this approach. Several states have ordered the explicit consideration of environmental externalities in IRP, notably in Massachusetts, New York, Oregon, Vermont, and Wisconsin.[18] Incorporating environmental impacts into IRP transforms least cost utility planning into least social cost utility planning, a more radical departure from the traditional utility regulatory objectives of reliability and low rates. Table I-4 shows which states are currently examining or implementing environmental criteria for air and water pollutants, and land-use impacts.

The environmental externalities associated with certain technologies are being assigned dollar values (or points in bidding systems) to account for environmental mitigation, health, and other costs over the long term. These externalities are then weighed in decisions between electric efficiency and various supply options. The effect is that the long-term externalities associated with a particular technology will be reflected in the initial cost, so that the advantages of technologies causing little environmental harm (e.g. conservation investments and renewable generation) would be considered in economic choices. When social costs govern investment decisions in an IRP framework, pollution prevention criteria influence utility resource selections.

Direct Environmental Valuation. Along with conventional cost data for demand and supply options, the IRP framework can accommodate environmental impacts. The most direct approach (from the perspective of IRP methodology) would be to assign dollar values for environmental damages from each option and simply count these costs in the conventional manner. California, New York, Massachusetts and other states are examining direct valuation approaches. Table I-5 shows proposed values of external cost valuation used in utility resource planning. The effect of these values on coal and geothermal generation costs in California are presented in Table I-6.

There are several methods used to value environmental externalities. The two most common approaches are to base external costs on estimated environmental damage or to value emissions on

[18] The diversity of state programs to incorporate environmental externalities is documented in Chapter X of *Environmental Costs of Electricity*, prepared by the Pace University Center for Environmental Legal Studies (New York Oceana Publications, Inc., 1990)

TABLE I - 4

STATES INCORPORATING ENVIRONMENTAL EXTERNALITIES

	Anticipated Capacity Needed within 10 years	Approach to Incorporating Environmental Externalities
Arizona	Peaking	Qualitative
California	Baseload & Peaking	Env. adder to bidding system
Colorado	Baseload & Peaking	QF bid evaluation
Connecticut	None	Higher ROR, qualitative
Idaho	Baseload & Peaking	Unspecified higher ROR
Kansas	Baseload & Peaking	Higher ROR
Massachusetts	Baseload & Peaking	Bid evaluation
Minnesota	Baseload & Peaking	Qualitative
Nevada	Baseload & Peaking	Qualitative
New Jersey	Baseload & Peaking	Bid evaluation
New York	Baseload & Peaking	Bid evaluation
Ohio	Baseload & Peaking	Qualitative
Oregon	Baseload & Peaking	Quantitative: resource planning
Pensylvania	Peaking	Qualitative
Texas	None	Qualitative
Vermont	Baseload & Peaking	15% adder
Wisconsin	Peaking	15% adder, quantitative

Source: "Environmental Externalities: A Survey of State Commission Actions"
NARUC, July, 1990

TABLE I - 5
EXTERNALITY VALUES PROPOSED BY STATES FOR RESOURCE PLANNING
($1990/metric ton)

	California [1]	Massachusetts [1]	New York [2]
SO2	13,140	1,710	950
NOx	13,250	7,430	2,090
TSP	8,910	4,570	380
VOC	3,770	6,050	N/A
CO2	8.00	25.10	1.25
CH4	N/A	250	N/A

Note: The values presented in this table reflect the marginal costs of pollution abatement or environmental damages for each state.

[1] California (per the California Energy Commission) and Massachusetts externality values are based on social cost estimates

[2] New York externality values reflect estimates of control costs

TABLE I - 6

THE EFFECT OF PROPOSED EXTERNALITY VALUES ON COAL AND GEOTHERMAL GENERATION COSTS IN CALIFORNIA

(levelized 1990¢/kWh)

	COAL	GEOTHERMAL
Estimated Levelized Cost	5.0 - 6.6	2.4 - 7.9
Externality Valuations		
SO_2	1.3	0.0
NO_x	2.0	0.0
TSP	0.1	0.0
VOCs	<0.1	0.0
CO_2	0.8	0 - <0.1
Total Generation Cost	9.3 - 10.9	2.4 - 8.0

Sources: Estimated levelized bid prices and emission rates for representative coal and geothermal plants are presented in *What Contribution can Environmental Valuation Make to the Cost Competitiveness of Renewables in Current Bidding Systems for the Electricity Business?*, prepared for EPA by Boston Pacific Company, Inc., Council for Renewable Energy Education, and ICF Incorporated. June 1991. The lower bound of coal costs does not come from this source, but is estimated based on inputs to the Renewable Electric Model used in the current study.

the marginal costs of controls.[19] As discussed above, however, current environmental valuation techniques are subject to much uncertainty. The scope of environmental valuation also affects the results. For example, complete analysis of entire fuel cycles (i.e extraction, distribution, combustion, and by-product management) gives a broader picture of environmental impact than an analysis of air emission impacts. Such studies are more expensive to perform and introduce additional uncertainty in the results

Other Valuation Options. Environmental factors could be incorporated into the competitive electric supply sector through environmental penalties for fossil fuel QFs or bid evaluation criteria. Instead of explicit environmental valuation, blocks of proposed capacity could be set aside for environmentally benign technologies such as conservation and renewables, either in utility plans or in competitive procurement. This would ensure that at least some capacity would be built with minimal environmental impact

For example, the California Energy Commission recently proposed to mandate that renewables provide half of new capacity needs over the next ten years. The Bonneville Power Administration grants preferential treatment in planning and competitive bid evaluation in the form of a 10% cost advantage for conservation and renewables. As a result of its recent "Green RFP" bid solicitation, New England Power Company expects to purchase up to 200 GWh of electricity annually from renewable energy sources. A review of utility competitive procurement experience found that environmental factors were given up to 15% of the total points in recent (self-scoring) request for proposals.[20]

Allocation of Future Regulatory and Cost Risk

Utility planning is inherently uncertain. Since electricity demand, fuel prices, future regulatory requirements, and emerging technology performance cannot be predicted with accuracy, regulators and utilities must rely on projections of future outcomes to make rational technology choices. Such choices implicitly expose ratepayers, utility shareholders, and environmental resources to different risks.

---

[19] Valuation based on the marginal cost of controls is sometimes referred to as the "revealed preference" approach, because the marginal control cost reflects the value that society (or regulators) currently attaches to environmental protection under existing regulatory policy

[20] See *Competitive Procurement of Electric Utility Resources*, prepared for the Electric Power Research Institute, (EPRI CU-6898) July, 1990, pp 97-98

Fuel Price Risk. Utility planners must use projections of future fuel prices in order to choose the most economic generating technologies. These projections are subject to PUC approval, but subsequent fuel price risk is generally borne by ratepayers through automatic fuel adjustment clauses. These were introduced in the 1970s to reduce the need for PUC rate-setting procedures during times of volatile fuel prices. In practice, this means that higher or lower fuel costs are directly passed on to consumers in the form of increased or lowered electricity rates, thereby insulating utilities from the risks associated with future fuel price volatility. As a result, utilities may have different perceptions of fuel price risk than consumers. To the extent that utilities discount the possibility of higher or volatile fuel prices because they can pass on the increased costs, technology choices will be biased against generating options like the renewable technologies that have low, stable, or virtually zero (in the case of solar and wind) fuel prices. Alternatively, to the extent that utilities and PUCs attach value to fuel diversity to lower risks from fuel price volatility, renewable energy sources would be favored over fossil-fired plants.

Regulatory Risk. The potential for more stringent environmental requirements could encourage utilities to choose options with fewer environmental impacts. Beyond conforming to existing environmental laws and regulation when making capacity decisions, utilities might also consider the potential for increased restrictions. Since fossil fuel generating facilities are long-lived, future environmental initiatives -- such as fossil fuel taxes (on a CO_2 or Btu basis) or CO_2 reduction targets -- would reduce the value of fossil fuel generating capacity and require additional investments to meet the demand for electrical services. Although not formally considered in traditional rate regulation, if the risk of incurring such costs can be reflected in the costs of those generating options most likely to face additional requirements, supply choices may tilt toward more environmentally benign technologies.

An alternative approach to explicitly considering risk now is to judge prudency of decisions later. If new regulations were required to address environmental concerns that arise in the future, PUCs could increase electric rates to cover the additional abatement expense. One possibility would have PUCs consider not allowing utilities to recover the full capital investment in fossil plants through higher rates if they determine that utilities should have anticipated such risks. For example, Figure I-10 presents an open letter to the U.S. utility industry from the National Association of State Utility Consumer Advocates and a coalition of environmental groups warning utilities that they will oppose future rate increases associated with reducing greenhouse gases if steps are not taken immediately to account for these risks in their long-term planning. Given these possible outcomes, utilities could begin to plan to minimize potential "regret" as compared with minimizing current and projected costs, by including the additional costs of potential CO_2 restrictions into current resource planning.

FIGURE I - 10

AN OPEN LETTER TO THE MANAGERS OF THE U.S. UTILITY INDUSTRY

Re: Implications of the Greenhouse Challenge for Utility Planning, Financial Risks, and Future Prudency Reviews

Dear Colleague:

This letter is a joint product of two communities with extensive involvement in utility issues: consumer advocates and environmental organizations. Recent scientific and policy developments convince us that the utility industry should be put on notice that its resource planning must take into account risks associated with continuing growth in greenhouse gas emissions. Our decision is based on a growing scientific consensus on the need to reduce emissions of greenhouse gases, as exemplified in recent reports from the Intergovernmental Panel on Climate Change (IPCC).

The IPCC is the broadly representative international body charged by the U.S. and other governments with assessing prospects for global climate change. It has now determined that human activities are substantially increasing the atmospheric concentrations of greenhouse gases; that these increases will warm the earth's surface; and that "business as usual" emissions will result in a warming during the next century that is greater than that seen over the past 10,000 years.

The IPCC cannot rule out surprises that might worsen or moderate this trend, but it calculates with confidence that substantial reductions in current emissions of carbon dioxide and other greenhouse gases would be necessary to stabilize their concentrations in the atmosphere. The United States is the world's largest source of these emissions. Other major nations are already moving to stabilize or reduce carbon dioxide releases; examples include Germany, the United Kingdom, Japan, Denmark, and the Netherlands.

We do not pretend to be able to chart the future of the Earth's climate. We are convinced, however, that findings like those of the IPCC should prompt the utility industry to reassess its strategic plans to account for increased risks of fossil fuel use. Such findings will also likely result in steadily increasing international pressures to reduce fossil fuel use both here and abroad. Those pressures, in turn, suggest several likely consequences. For example, utilities contemplating substantial investments in long-lived fossil fuel technology should begin explicitly to take these risks into account, both in assessing these technologies and in evaluating alternatives. Second, failure to realign resource planning and investment in this way will open those responsible to prudency challenges, if identified risks and alternatives are not responsibly addressed. Third, utility plant extension and refurbishment programs may become less attractive compared with energy efficiency improvements and renewable energy resources.

As the most substantial sources of carbon dioxide per unit of energy produced, coal- and oil-fired generation clearly merit the closest scrutiny in terms of greenhouse risks. Both for new units and long-lived extensions of existing units, an invigorated search for alternatives clearly is needed. However, we do not believe that this imperative will or should result in a nuclear power revival, since that technology still fails tests of financial risk and cost-effectiveness. Its lower carbon dioxide emissions are unlikely by themselves to reassure investors. Moreover, still unresolved problems, including those related to high level nuclear radioactive waste disposal, can not be ignored. This conclusion is reinforced by an abundance of preferable alternatives on both economic and environmental grounds, including efficiency improvements in all sectors of energy use and numerous renewable energy technologies.

Ratepayers' income, utility shareholder investments, and environmental quality will all be at risk, if the utility industry fails to take into account future costs of greenhouse gas emissions in its resource planning. Conversely, all of our constituents stand to gain when utilities cost-effectively substitute what amount to climate defense technologies for additional greenhouse gas emissions. We jointly pledge our best efforts in helping regulators to gauge utilities' performance and to respond appropriately.

Sincerely,

Donna Sorgi, President
NASUCA
1133 15th Street, NW
Suite 575
Washington, DC 20005

John Adams, Executive Director
Natural Resources Defense Council
40 West 20th Street
New York, NY 10011

Recently, the Southern California Edison (SCE) and Los Angeles Department of Water and Power (LADWP) announced their intentions to reduce emissions of CO_2 by 20% over the next twenty years.[21] The president of SCE stated explicitly that "taking prudent steps today to reduce CO_2 emissions will ensure we have no regrets later if scientific research confirms that CO_2 and other greenhouse gases in fact do cause global warming." In Wisconsin, the Public Service Commission requires utilities to conduct sensitivity analysis on resource plans to determine the costs of future CO_2 limits, assuming that CO_2 is reduced by 20% from 1985 levels by the year 2000 and 50% in the longer term.[22] Such consideration would enhance the current value of conservation and renewable energy technologies.

Technology Risk. Some renewable technologies are relatively new, and utilities and PUCs are reluctant to invest in technologies perceived as economically risky. The recent experience with nuclear construction programs has made utilities and PUCs scrutinize future capacity plans to determine if the power is needed. Given the need, utilities must have assurances that a given technology can deliver the power reliably. Although renewable technologies have demonstrated improved reliability, negative experiences with emerging renewable technologies (especially intermittent technologies) during the 1970s and early 1980s have created unfavorable impressions with many utility planners. As the increased reliability of intermittent technologies becomes more apparent, however, utility planners obligated to incorporate environmental performance into resource planning will evaluate more recent commercial experience.

Technology risks can be shared among ratepayers, utilities, and taxpayers through federal support of RD&D projects, utility joint ventures (e.g., through EPRI), preferential tax treatment for emerging renewable technologies, and liberal PUC treatment of emerging technology investments through lenient prudency reviews. To the extent that technology risks are shared, in order to reduce societal risks like global warming, individual utilities would be more willing to invest in renewable energy projects. The potential environmental and other public benefits of expanded renewable electric generation may justify policies that limit financial exposure to technology risks in order to promote research and investment.

---

[21] "Utilities to Cut Carbon Dioxide Emissions 20%," Los Angeles Times, May 21, 1991.

[22] *Environmental Costs of Electricity*, p 591

The Clean Air Act Amendments of 1990

Two provisions of the Clean Air Act Amendments of 1990 will enhance the market for renewable electric technologies. The most important influence in the long run will be the limit ("cap") on aggregate SO_2 emissions from electric utilities, which will be administered through a system of tradeable SO_2 emission allowances. Utilities facing the emission cap will be forced to consider a wide range of methods to produce electricity with less SO_2, and in a very real sense, the cap will encourage utilities to adopt a pollution prevention stance toward producing electricity. Utilities could view conservation programs, generation efficiency improvements, and renewable energy sources as methods available to operate less expensively than installing expensive emission controls or purchasing emission allowances.

Additional near-term renewable energy incentives will come from the pool of 300,000 allowances (tons of SO_2) that has been earmarked for conservation and renewable energy options between 1992 and 2000. Initial projections indicate that allowances could be worth between $200 and $600 per ton of SO_2 (this amounts to 0.04 to 0.12 cents per kWh, based on an SO_2 emissions factor of $2x10^{-6}$ tons per kWh). Depending on eventual market prices, this pool represents allowances that may be worth up to $180 million to conservation programs or developers of renewable electric supply.

CHAPTER II
RENEWABLE ELECTRIC OPPORTUNITIES

The prospects for expanded renewable electric generation depend primarily on the economics of conversion, the extent to which environmental advantages are reflected in the market, and the evolving regulatory and competitive framework that governs electricity supply decisions. This chapter focuses on three issues: (1) the technical potential of renewable energy is far larger than its current contribution, (2) the economics of renewable resource conversion are improving, and (3) the regulatory and political climate is becoming more favorable for development of renewable energy. This report suggests that if these issues evolve favorably for renewables, the incremental contribution of renewable electricity could more than triple by 2000, and increase four-and-a-half times by 2010.[1]

THE RENEWABLE ENERGY RESOURCE BASE

The total potential renewable energy base is much larger than the total potential fossil fuel resource base. Fossil fuels began as organic material that stored solar energy (and atmospheric carbon) through photosynthesis millions of years ago. Only a fraction of the ancient biomass resource (mostly plant material) was transformed into useful chemical energy. However, this fossil energy is concentrated and, once extracted, is easily converted into useful energy forms such as liquid fuels and electricity.

All renewable energy is derived from the sun.[2] Biomass and hydropower are concentrated and storable solar energy forms. Biomass is the solar energy stored in plant and animal matter through photosynthesis and metabolic conversion. Hydroelectric power is solar energy stored when evaporated water is deposited in higher elevations, which gravity converts to kinetic energy. Other solar resources are more immediate, diffuse, and intermittent. Windpower is the result of uneven solar absorption that creates moving air masses. Solar thermal and photovoltaic energy use direct and indirect sunlight received during the day.

The amount of potentially useable energy from these renewable resources is quite large. Much research has been devoted to estimating the size of fossil resource bases that could be

---

[1] Based on incremental renewable generation in the EPA Enhanced Market scenario over the EPA Base Case (see Ch III, Tables III-2,4)

[2] Geothermal energy, which is heat that is stored in the earth and replenished through radioactive decay, is technically not a renewable resource It is included in this report because the resource is so vast that it shares many of the same properties as renewable energy sources

extracted and used under various technical and economic assumptions. Similar efforts for renewable resources have only recently been initiated. Figure II-1 shows a recent estimate of U.S. fossil and renewable resource bases prepared for DOE.[3] Of course, neither fossil nor renewable resource bases are fully exploitable, due to technological constraints and economic considerations. In order to make more meaningful comparisons, a distinction is made between the **resource base** (total potential), **accessible resources** (feasible potential under current or nearly developed technology), and **energy reserves** (economic potential under existing technology).

According to the DOE analysis, the U.S. renewable energy base is composed primarily of geothermal, solar, and wind resources. The renewable energy resource base is 14 times the U.S. fossil energy resource base, which is dominated by coal and shale oil. The picture reverses when only energy reserves are considered. Under current market prices and conversion technologies, fossil energy reserves are more economically exploited than most renewable energy forms. Reserves of natural gas represent about 25% of the total gas resource base and coal reserves make up about 15% of the total coal resource base. In contrast, only 1% of the geothermal and 0.06% of the photoconversion resources are currently economic to capture as renewable energy reserves according to the DOE analysis.

The prospects for renewable energy are more optimistic, however, when accessible resources are considered. Accessible resources are those that can be exploited with current technology or technology that will be available in the near future. The accessible direct solar resource base is eleven times larger than the accessible fossil fuel resource base; the biomass accessible resource base is larger than the domestic oil accessible resource base. Taken together, the accessible geothermal and wind resource base is over 70% of the entire domestic coal resource base.

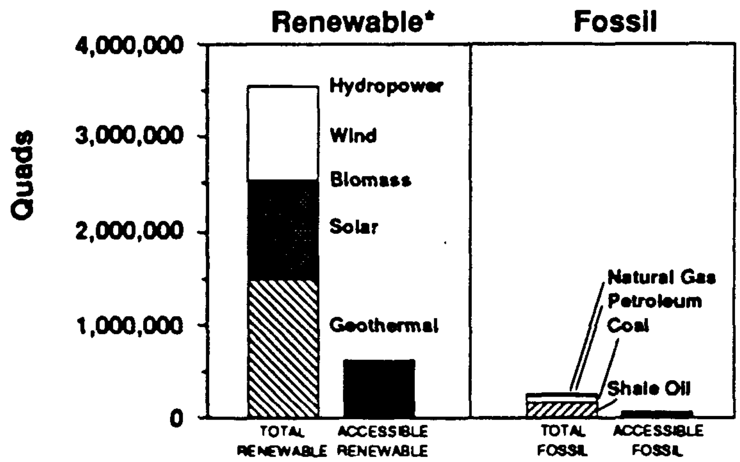
It must be noted that energy resource assessment is inherently inexact, and the definitional and measurement problems are especially severe for renewable energy forms. Thus, the figures are useful for comparing rough estimates and pointing out the magnitude of untapped renewable resource potential. While specific definitions of accessibility and "reserves" may vary from study to study, most estimates suggest that cost remains the main barrier to renewable energy development, not resource availability or technological feasibility. The extent to which renewable accessible resources are nearly economic (i.e. could be counted as reserves) will determine the long run potential for renewable energy supply.

---

[3] See *Characterization of U.S. Energy Resources and Reserves*, prepared by the Meridian Corporation for the Deputy Assistant Secretary for Renewable Energy, U.S. Department of Energy, 1989. The Meridian analysis multiplies annual renewable energy quantities (flows) by 30 years in order to obtain a comparable figure with fossil energy quantities (stocks).

FIGURE II-1

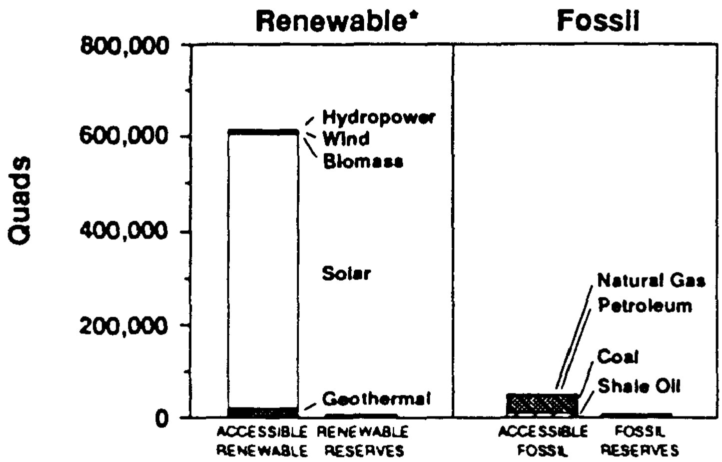
TOTAL & ACCESSIBLE RESOURCE BASE



Total Resource Base: The combination of undiscovered and identified, subeconomic and economic concentrations of naturally occuring solid, liquid, or gaseous materials in or on the Earth's crust.

Source: Meridian, "Characterization of U S Energy Resources and Reserves", 1989

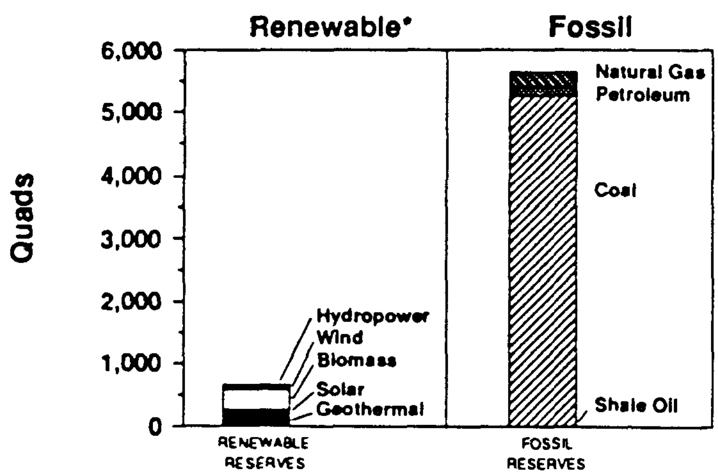
ACCESSIBLE RESOURCE BASE & RESERVES



Accessible Resource: That subset of the total resource base that can be captured, mined, or extracted by current technology or technology which will be available in the very near future (3-5 years)

Source: Meridian; 1989

RESERVES



Reserves: That subset of the accessible resource which is identified and can be economically and legally extracted to yield useful energy or an energy commodity.

Source: Meridian, 1989

***Renewable energy annual values are multiplied by 30 years to arrive at a generally comparable figure with fossil fuels**

IMPROVEMENTS IN CONVERSION TECHNOLOGIES

One important reason that renewable energy does not contribute more to the U.S. electric supply is that it often costs more per kWh than fossil fuel-fired generation. This economic disadvantage could diminish (or perhaps even reverse) if the market price of fossil fuels reflected environmental externalities. Other important factors also constrain the contribution of renewable energy:

- **First Cost** -- the tendency of the marketplace to prefer minimal initial costs for investment decisions in decision making, which biases options such as renewables that have little or no fuel cost and incur little, if any, escalation in costs over time;

- **Risk** -- the lack of demonstrated performance of some renewable options makes their initial use considerably more risky than conventional options;

- **Production Levels** -- the need for renewables to achieve a modest production level to achieve economies of production; and,

- **Information/Education** -- some renewables have demonstrated major cost/performance improvements during the 1980s, although this may not be widely known.

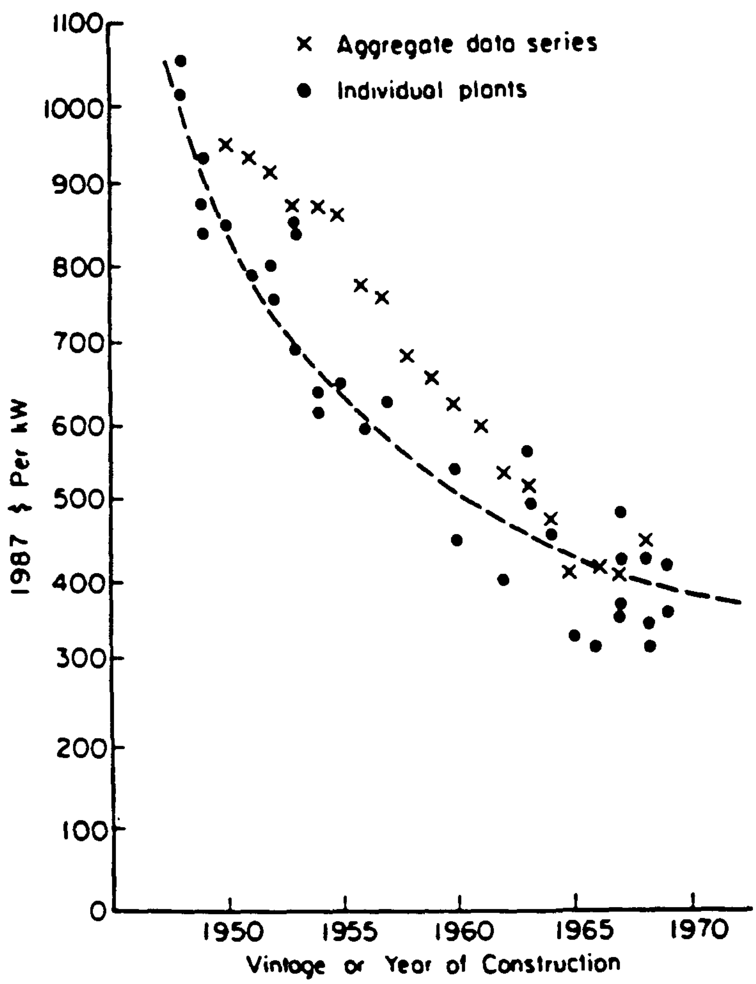
Recent Market Experience

Technologies to capture and convert renewable energy have been improving rapidly. The most mature technologies -- biomass combustors and hydraulic turbines -- are similar to fossil fuel technologies in that they convert relatively concentrated and stored solar energy into electric power. Accordingly, biomass and hydroelectricity currently contribute far more electricity supply than other renewable technologies. Geothermal technologies also exploit concentrated energy sources, but historically have been too expensive to locate and extract, given the amount of thermal energy geothermal resources could provide. However, the cost of exploiting geothermal energy will fall as exploration, drilling, and conversion technologies continue to improve. The technologies for capturing more diffuse intermittent solar energy sources, such as wind and sunlight, have only recently become commercial for producing electric power. However, these technologies have improved dramatically in the past decade, and analysts predict that efficiencies will continue to increase, bringing down conversion costs.

Compared with renewable technology costs, conventional fossil fuel generating technology costs have remained stable in recent years. Figure II-2 shows how cost reductions for fossil fuel-fired steam capacity nearly leveled out by the 1970s. While improvements in fossil fuel generation will continue to occur, especially for advanced natural gas generation, further cost reductions are more

FIGURE II - 2

HISTORICAL FOSSIL FUEL CAPACITY COSTS



Source: Robert H. Williams and Eric D. Larson, "Expanding Roles for Gas Turbines in Power Generation," in Johansson, et. al., eds, *Electricity: Efficient End-Use and New Generation Technologies, and Their Planning Implications*, (Lund University Press, 1989).

likely to be incremental rather than dramatic.[4] With a few exceptions, renewable electric technologies are at earlier stages of technological development than fossil fuel competitors, and are more likely to experience improvements that could significantly enhance their comparative economic competitiveness over the next decades.

Renewable Technology Research and Development

The renewable electric industry is relatively new -- particularly solar and wind -- compared to the mature, established fossil fuel industry. Renewable energy received generous R&D funding support during the late 1970s, but funding fell off abruptly in the early 1980s. As Figure II-3 shows, R&D funding for renewable energy continued to decline steadily during the 1980s. Renewable energy currently accounts for 5% of the federal research and development for energy supply and conservation.[5] Figure II-3 also shows that fossil energy R&D was also cut significantly in the early 1980s, but has since been restored to late 1970s levels.

Many renewable technologies continued to improve with limited federal R&D support during the 1980s. These improvements occurred as a result of expanded private R&D efforts and increased commercial experience, and as federal R&D conducted during the late 1970s translated into commercial cost reductions. As discussed in subsequent chapters, renewable energy R&D efforts continue along many technological pathways. Given the large number of pathways and technological opportunities for cost reductions, there is a high probability that some technologies will achieve much greater cost competitiveness with fossil fuels over the next decades.

Expanding International Markets for Renewable Technologies

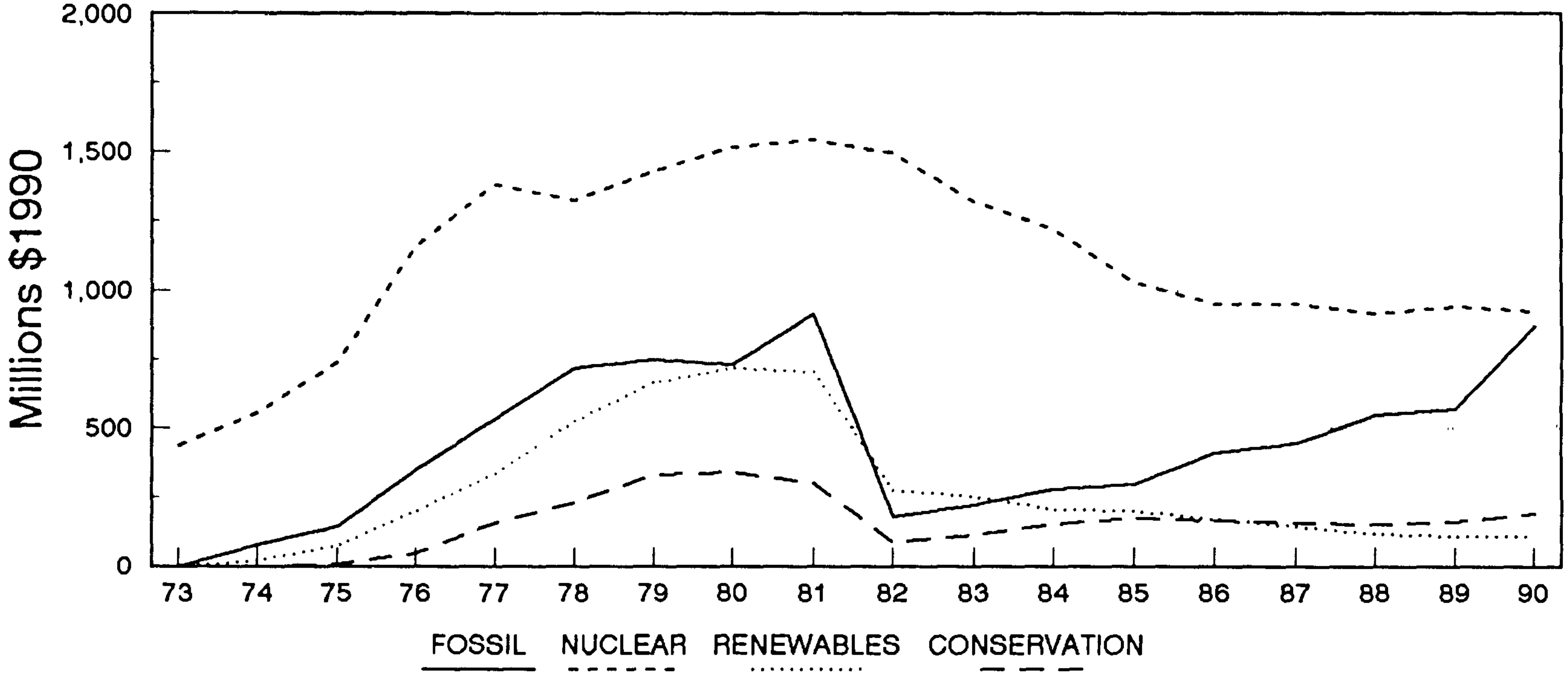
Developed nations that commit to greenhouse gas reductions will provide additional markets for renewable energy technologies. Taken together with the energy needs of developing nations, renewable energy technology industries are poised for significant growth in the coming decades. This growth could accelerate the cost reductions expected from U.S. demand for renewable electric technologies. To the extent that expanded domestic market growth is stimulated by U.S. environmental policies, the competitive stature of U.S. manufacturers and developers would be

[4] In fact, the area of greatest recent cost improvement for fossil fuel technologies has been for pollution control equipment, a market which was essentially created in the 1970s by the Clean Air Act. This demonstrates the ability for technologies to improve in a short period of time given sufficient market stimulus.

[5] See "Energy Use and Emissions of Carbon Dioxide Federal Spending and Credit Programs and Tax Policies," Congressional Budget Office, December 1990, Table 2.

FIGURE II - 3

DEPARTMENT OF ENERGY SCIENCE AND ENERGY FUNDING
FY 1973 TO FY 1990



"FOSSIL" includes all fossil energy technologies and the Clean Coal Technology Program

"NUCLEAR" includes both nuclear fission and nuclear fusion

Source: Congressional Research Service, "Renewable Energy: A New National Commitment?" October 1990.

enhanced further. Extending domestic market gains to growing markets abroad could help reduce the current U.S. trade deficit.

The growing economies of many populous developing nations have abundant renewable energy resources. As these nations attempt to meet the growing expectations of their citizens to raise living standards, they must decide on energy supply strategies. Many developing nations would prefer to exploit indigenous renewable energy resources than import fossil fuels for meeting energy needs, since such policies can serve as a buffer against oil price fluctuations and save scarce hard currency. Although definitive estimates of worldwide sales of renewable energy technologies do not exist, the current international market for renewable energy technology probably exceeds $2 billion annually.[6]

These potential markets have stimulated the governments and industries in some developed nations to finance renewable technology RD&D and export promotion programs. The U.S. leadership in several areas of technology development eroded during the 1980s, and the U.S. was a net importer of wind and solar electric energy systems in recent years.[7] While U.S. federal renewable energy RD&D expenditures were scaled back during the 1980s, other countries continued research support at steady levels. As shown in Table II-1, the United States was a leader in 1986 in terms of total dollars spent on renewable R&D with a budget of $177 million, however, it trailed other countries in the share of total energy R&D budget allocated to renewables and renewable R&D spending per capita.

FAVORABLE POLITICAL CLIMATE FOR RENEWABLES

A broad array of local, state, national, and international concerns and actions are operating to enhance the market potential of renewable electric generation. Some of these concerns are manifested in recent regulatory reform, while others are reflected in political debates. All of these factors indirectly increase the economic desirability of renewable energy options.

While it is difficult to predict the impact of political movements, they are likely to encourage renewable energy development over the next decades Much of the progress made in environmental regulation and rate regulation discussed in the previous chapter occurred as a result of public

---

[6] See "Renewable Energy Federal Programs" by Fred J Sissine (Washington, D.C.: Congressional Research Service, Issue Brief IB87140, April, 1990). p 12

[7] See "Renewable Energy. Federal Programs" p 13 Also, see *Energy R&D: Changes in Federal Funding Criteria and Industry Response* (Washington D C, U S. General Accounting Office, February, 1987).

TABLE II - 1
GOVERNMENT R&D SPENDING ON RENEWABLES
SELECTED COUNTRIES, 1986

Country	Renewable R&D Spending (million $)	Share of Energy R&D Budget (percent)	Spending Per Capita (dollars)
Sweden	17.3	21.8	2.06
Switzerland	10.2	14.7	1.57
Netherlands	17.0	10.6	1.17
West Germany	65.9	11.6	1.09
Greece	9.7	63.2	0.97
Japan	99.2	4.3	0.82
United States	177.2	7.8	0.73
Italy	29.5	3.9	0.52
Denmark	2.6	17.8	0.51
Spain	19.4	27.6	0.50
United Kingdom	16.6	4.4	0.29

Source: "Shifting to Renewable Energy" by Cynthia Pollock Shea in *State of the World 1988: A Worldwatch Institute Report on Progress Toward a Sustainable Society.*

pressure to minimize environmental impacts of energy supply. The public concern over environmental impact continues to promote renewable energy as an alternative to fossil fuels.

Public Environmental Concern

Support for renewable energy options has come from states and local communities concerned about the broad environmental impacts of a variety of activities. Recent polls of U.S. voters have shown consistently that citizens support and are willing to pay for additional environmental protection or improvement. One recent poll indicated that 75% of those surveyed believe that the U.S. should reduce energy demand through efficiency measures, and 59% favored accelerated development of renewable energy sources. Of those surveyed, 73% said that they would be willing to pay more for fossil fuels if the added cost was used to prevent serious consequences of global warming.[8]

State and local initiatives reflect the public concern over environmental damages, and a "quiet revolution" has emerged that addresses broader national issues at the state and local level. For example, Vermont has banned CFCs in automobile air conditioners by the 1993 model year, and the city of Irvine, California has enacted local ordinances prohibiting the manufacture, sale or distribution of products utilizing ozone depleting substances. Connecticut has enacted legislation to ensure that new buildings conform to strict energy efficiency codes, and Iowa has passed a bill to encourage alternative energy production.[9] Given the level of public support for environmental action, more state and local initiatives promoting renewable energy are likely to emerge during the 1990s.

Oil Dependence

The recent Iraqi invasion of Kuwait and subsequent U.S. military response have revived concern over oil dependence. Although oil provides only about 5% of electricity generation in the U.S., some regions in the Northeast and South rely on oil for 20% to 40% of generation. The economic cost of unreliable oil supplies could be high for electricity consumers in these regions. Beyond the environmental effects of oil use, the cost of maintaining the Strategic Petroleum Reserve and supporting military intervention suggest that the U.S. market price for oil remains below social cost. Because most oil is consumed as transportation fuel, DOE supports research and development

---

[8] See "America at the Crossroads: A National Energy Strategy Poll," sponsored by The Alliance to Save Energy and The Union of Concerned Scientists, January 1991.

[9] See *Selected Summary of State Responses to Climate Change*, report by the Bruce Company prepared for the Climate Change Division of the Office of Policy, Planning, and Evaluation, U.S. EPA January, 1991.

into renewable fuels such as biomass-derived ethanol and methanol. This research could have important spillover benefits for biomass generated electricity.

Greenhouse Gas Protocols

The Intergovernmental Panel on Climate Change (IPCC) sponsored by the United Nations Environmental Program (UNEP) has begun the process of identifying opportunities for greenhouse gas reductions in both developed and developing countries. The main emphasis is reducing fossil fuel emissions in the developed nations and stemming the potentially explosive emission growth in developing countries. Although the U.S. has not formally entered into agreements to reduce greenhouse gases, other developed countries have declared their intentions to stabilize or reduce emissions over the next decade and beyond. Table II-2 shows the current positions of these nations on CO_2 emission targets. Developed countries that import most of their fossil fuel supplies, such as the Scandinavian countries and Japan, have committed to CO_2 reduction targets; developed nations that currently exploit indigenous coal resources, such as the United Kingdom, Australia, and Germany, have also committed to reducing CO_2 emissions.

POLICIES TO INCREASE RENEWABLE ENERGY CONTRIBUTIONS

The political trends identified above and the regulatory reforms discussed in Chapter I enhance the prospects for renewable electric generation. Further enhancements, such as more widespread and stringent environmental valuation, new approaches for accommodating intermittent generation, additional R&D support, federal and state tax policy, and aggressive promotional programs could significantly increase the market penetration of renewable electric technologies in the future.

Greater Environmental Valuation in Resource Planning and Operation

According to the range of estimates shown in Table I-3 in Chapter I, the external cost of fossil fuel electric generation may exceed the production cost of electricity. A few states have incorporated external cost into the planning process, but at relatively modest levels. As more states adopt environmental valuation, and incorporate higher damage estimates, renewable generation technology will become more competitive, and its contribution could substantially increase. Policies that give greater weight to environmental performance in bid evaluations, provide set-aside blocks of energy to be met by renewables or conservation, or institute environmental adders (e.g. granting certain options a percentage value increase in planning) could be as effective as explicit quantification of environmental externalities.

TABLE II - 2

POSITIONS ON CO2 EMISSION TARGETS

		Base Year
Stabilization, 1995	Netherlands	1989-90
Stabilization, 2000	Australia	1988
	Austria	
	EC Commission	1990
	Finland	
	Italy	1990
	Japan	1990
	Norway	1987
	Sweden	1988
	Switzerland	
Stabilization at 10% by 2000	France	1990
Stabilization, 2005	Canada	1988
	United Kingdom	1990
3-5% reduction, 2000	Netherlands	1989-90
20% reduction, 2005	Austria	1988
	Denmark	
	New Zealand	1990
25% reduction, 2005	Germany	1987
Support targets for developed countries; weaker or no targets for LDCs	Brazil	
	China	
	India	
	Malta	
	Mexico	
	Saudi Arabia	
Oppose targets	USSR	
	Israel	
	Venezuela	

Source: Second World Climate Conference,
November 1990, Geneva, Switzerland

Environmental valuation can also be applied to short run dispatch decisions. Environmental impacts from one existing utility plant to another can differ significantly when generating electricity, but pure economic dispatch does not take into account these costs. However, operation of some units may be modified to attain existing environmental standards, which can affect the cost of generation. At the other end, pure environmental dispatch would give priority to the lowest emitting units, but would cost more. In between the two extremes of pure economic dispatch and pure environmental dispatch, a full social cost economic dispatch would take into account economic and environmental values. A recent analysis of utility dispatch including social cost has shown that environmental valuation could reduce SO_2 emissions by 67%, NO_x by 26%, and CO_2 by 19% in a typical utility system.[10]

Environmental Taxes and Penalties

Environmental taxes or penalties on fossil fuel or emissions have often been suggested as an efficient market-based policy to "internalize" the external costs associated with energy use. For example, a recent Congressional study examined the impacts of fossil fuel penalties based on carbon content of fuel as a policy to reduce CO_2 emissions.[11] Depending on the basis (e.g. fuel or pollutant emissions) and the tax levels chosen, such policies could obviate the need for environmental valuation in utility planning, since the costs of various supply options would reflect environmental damages associated with them. If such policies are enacted, renewable electric generation could increase substantially because its cost relative to fossil generation would decline.[12]

Regulation and Planning for Intermittent Generation

Three renewable electric technologies -- photovoltaic, solar thermal, and wind -- depend on intermittent renewable resources.[13] The premium placed on overall system reliability limits the interest of utilities in intermittent sources. Although most utility systems could accept larger portions of intermittent generation than they currently handle, thinning reserve margins in many regions may

---

[10] See "Full Cost Economic Dispatch Recognizing Environmental Externalities in Electric Utility System Operation" by Steven Bernow, et. al presented at National Conference on Environmental Externalities, National Association of Regulatory Utility Commissioners, October, 1990

[11] *Carbon Charges as a Response to Global Warming: the Effects of Taxing Fossil Fuels*, Congressional Budget Office, August, 1990

[12] See Ch III Externalities Penalties Case

[13] Hydroelectric is normally dispatchable, but seasonal water level variations or prolonged droughts limit availability Although it is also an intermittent resource, utilities have gained much experience at adapting to hydropower fluctuations

force utilities to value "firm" (reliable and dispatchable) capacity over technologies that may not deliver power during peak load periods. From a utility planning perspective, intermittent resources may not eliminate the need to build capacity to meet peak demands, reducing the value of intermittent generation. This is manifested in the PURPA market as power purchase terms for intermittent renewables based only on the avoided variable cost to the utility, i.e., intermittent renewables generally do not receive payment for avoided capacity costs.

The process of utility planning or competitive procurement may not give enough "capacity credit" to intermittent sources because of the narrow terms upon which individual projects are evaluated, and in some cases because it does not give enough weight to the coincidence factors (when power output from intermittent resources in some regions is highly correlated with utility peak demand). Adapting utility planning or bidding procedures to give more value to intermittent resources, when some capacity credit may be warranted, would increase the competitive status of these technologies. The Renewable Electric Model results provide partial capacity credits for wind energy where the data indicate that sufficient coincidence factors exist (see Ch. IX for details).

Another way to overcome intermittent resources is to develop hybrid technologies that utilize storage or fossil fuel backup to "firm" the resource.[14] A good example of this strategy is the solar thermal generating stations built by Luz in California, where natural gas backup fuel is used to provide power during cloudy periods and to extend operation into early morning and late evening hours. Likewise, fossil-fuel backup could firm wind or PV generation. The fossil energy contribution allowed for QFs under PURPA is currently limited to 25%, however, the administration has recently expressed support to raise the limit to 50%.[15] Chapter X discusses the potential for hybrid technologies to increase the energy value of intermittent renewable generation.

Additional Research, Development and Demonstration Support

As mentioned in Chapter I, renewable electric technologies would benefit from expanded RD&D support. A recent study conducted by the Department of Energy (DOE) and the Solar Energy

[14] To the extent that the renewable technology allows less fossil capacity to be developed, the renewable technology earns that capacity credit on its own In combination, fossil-renewable hybrids allow total costs to be lowered in addition to earning firm capacity credits The capacity credits may be due to a combination of fossil and renewable generating capacity

[15] See *National Energy Strategy: Powerful Ideas for America*, First Edition 1991/1992, (Washington, D.C. February 1991) p 125

Research Institute (SERI)[16] estimated the cost reductions and market gains from an aggressive RD&D program over the next 40 years. Table II-3 shows the DOE/SERI projections of the levelized generation cost in the accelerated RD&D case, expressed as the percent of "Business as Usual" costs for the years 2000 and 2010. Additional RD&D reduces projected generation costs by between 10% and 40% in most cases, with even greater reductions for most technologies after 2010.

A recent report by the National Research Council recommended that the DOE reallocate about $300 million of its energy research budget from fusion and fossil fuel programs to renewable energy and conservation technologies.[17] The advisory panel stressed the need for long-term energy R&D policy to take into account the potential climate change impact of research agendas, and argued that providing greater support to renewable energy technologies would help shift energy production away from fuels that emit greenhouse gases.

Cumulative Commercial Experience and Learning Curves

While difficult to predict or quantify, expanded commercialization of renewable energy technologies will accelerate cost reductions. Economists refer to the cost reductions gained through commercial production as "learning curve" impacts, where costs are a function of cumulative sales of a product. The relationship between production cost and experience is often stronger and more indicative of technology maturation than the reduction of cost through time. Whatever the causes, evidence abounds suggesting that cumulative commercial experience can lead to significant cost reductions.[18]

Since many renewable energy technologies serve a relatively small market, many of the gains from manufacturing scale, standardization, and learning curve improvements for newly commercial technologies lie in the future. Experience shows that the transition to a stable and mature market can significantly reduce manufacturing or construction costs of energy supply technologies, while improving efficiency and performance. As discussed in subsequent chapters, substantial cost reductions have already occurred for some renewable electric technologies during the 1980s.

---

[16] The Solar Energy Research Institute (SERI) recently changed its name to the National Renewable Energy Laboratory (NREL) References in this document reflect the time period prior to the name change and use the acronym SERI

[17] See *Confronting Climate Change: Strategies for Energy Research and Development* (Washington, D.C.: National Research Council, 1990).

[18] For example, the average price of computer equipment, based on a ratio of real price per unit of performance, declined by 87% between 1972 and 1985

TABLE II - 3 COST IMPACTS OF INTENSIFIED RD&D: DOE/SERI RENEWABLE ENERGY STUDY							
RENEWABLE TECHNOLOGY	Levelized Generation Costs (¢/kWh)					Percent Reduction From BAU Costs	
	1990	2000		2010			
		BAU	RD&D	BAU	RD&D	2000	2010
Biomass[a]							
Ethanol	17.4	13.0	7.2	10.0	7.2	45	28
Methanol	15.5	10.5	10.0	8.5	7.0	5	18
Geothermal							
Hydrothermal	4.4	4.2	4.1	4.1	3.7	2	10
Geopressured Brine	7.5	6.5	6.1	5.6	5.1	6	9
Hot Dry Rock	6 5	5 9	5.2	5.4	4.2	12	22
Magma	21.9	16.8	12.3	12.6	7.7	27	39
Photovoltaic							
Standard Case	32 0	15 0	10.0	9.0	7.0	33	22
Alternative[b]	32 0	15 0	8.0	9.0	5.0	47	44
Solar Thermal							
With Storage	15.8	7.5	6.0	5.5	5.0	20	9
Peaking	15.8	10.3	7.7	7.5	6.8	25	9
Windpower	8.3	5.3	4.6	4.7	3.8	13	19

Source: *The Potential of Renewable Energy: An Interlaboratory White Paper*, DOE/SERI, March 1990.
BAU = Business as Usual Scenario; RD&D = Intensified Research, Development, and Demonstration Scenario.

Notes: [a] Biomass costs are levelized $/MMBtu for fuel production; taken from Tables B-3a and B-3b.

[b] Alternative photovoltaic cost scenario as described on page G-10.

Continuing technological improvement will expand markets for renewable electric generating systems, and costs will continue to decline as renewable energy industries attract more investment.

The economics of learning curves suggest that rising market demand is a powerful force in commercial technology improvement. Broad-based policies to encourage near-term market demand for renewable electric technologies in the U.S. can stimulate cost reductions that will make renewables more competitive. Growing international demand for renewable electric technologies will provide further market stimulus for cost reductions, both for U.S. and foreign suppliers. For some products, especially advanced electronics used in military applications, federal procurement has been the driving force behind innovation and cost reductions, which later yielded benefits in the form of new and better civilian products. While private utilities are the main market for electric generating technologies, the federal government also owns generating capacity e.g., the Tennessee Valley Authority and the Bonneville Power Administration. Thus, some opportunity exists for federal procurement to nurture renewable electric learning curve economies. Overall, these cost reductions associated with scale economies are a key element in enabling renewable electric generation to increase its penetration in EPA's "Enhanced Market" scenarios for 2000 and 2010 (see Chapter III).

Tax Policies to Promote Investments in Renewables

Some renewable technologies qualify for investment tax credits. These tax credits have survived rather precariously from year to year in Congressional deliberations, and the current tax credits are due to expire in December 1991. In recent years, 10% tax credits have been available for solar thermal, photovoltaic, and geothermal investments. These credits could be extended to other renewable technologies, such as windpower; credits could be increased beyond the current 10% rate; and the program could be extended indefinitely in order to increase investor confidence in the early planning stages of renewable energy projects. To be effective, developers must be able to depend on the tax credits being available from the planning stage through construction, including the period in which capital is raised and the facility is sited. Tax credits that are renewed on an annual basis are often not reliable enough to justify investment commitments. Other tax-related proposals have included changing the basis of the credit from capital investment to energy production, in order to more effectively target renewable energy generation.

Energy Pricing and the "Level Playing Field"

Many energy analysts contend that energy markets are biased toward fossil fuels and against renewable energy. Aside from environmental externalities that remain unpriced in the market, they point to direct government support that favors fossil fuel supply, such as R&D, as well as indirect government subsidies through tax provisions. While such a bias may exist, no definitive measures of the magnitude of such biases has emerged. Some studies have cited direct and indirect subsidies worth tens of billions of dollars annually.[19]

A complete examination of direct and indirect subsidy for fossil energy is beyond the scope of this study. Some government support of fossil energy clearly promotes its use, while other forms of support, such as R&D into efficient conversion technologies, could help reduce fossil energy use. In either case, concern for the environmental impact of expanded fossil fuel use could motivate fundamental changes in direct support programs, tax policy, and R&D priorities that would make renewable resources more competitive with fossil fuels.

[19] See "The Real Cost of Energy" by Harold M. Hubbard, *Scientific American*, Vol. 264. No. 4, April, 1991, p. 36, and "The Hidden Cost of Energy: How Taxpayers Subsidize Energy Development," by Richard Heede, et.al, for the Center for Renewable Resources, Washington DC, 1985.

CHAPTER III

THE EPA MARKET ASSESSMENT

In order to estimate the air pollution reduction potential of renewable generating technologies, important features of the U.S. electricity markets and renewable resource bases must be taken into account. Because renewable technology operating characteristics and availability differ across regions, and because regional electric power systems differ with respect to capacity and fuels, some renewable electric generating options could prevent more air pollution than others. These same regional factors affect the relative costs of renewable and fossil fuel generating options. The market assessment analysis identifies those renewable electric power options that are most likely to reduce CO_2 and other emissions in the near term, and estimates the costs of substituting renewable energy for fossil fuels in electric power generation.

CONSTRUCTION OF THE EPA RENEWABLE TECHNOLOGY PENETRATION SCENARIOS

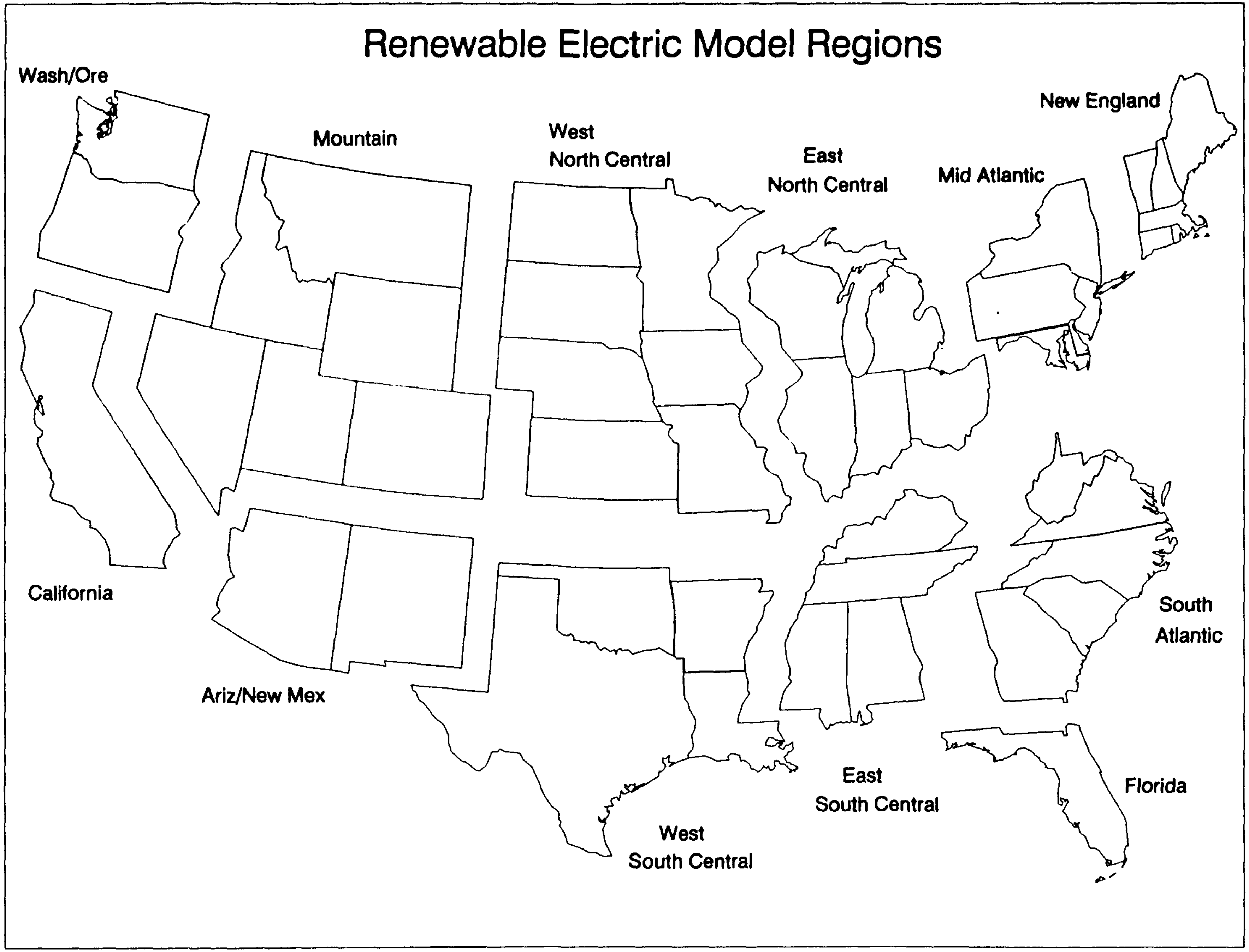
In order to analyze the cost and air pollution prevention impact of renewable electric technology, renewable technology penetration scenarios were constructed for the 12 regions shown on Figure III-1. Ten technologies are considered: biomass solid (primarily wood), municipal solid waste, landfill and digester gas, geothermal, hydroelectric run of river, hydroelectric storage, photovoltaic, solar thermal electric natural gas hybrid systems, solar thermal electric stand-alone systems, and windpower. The scenarios extend to the year 2010. Many of the scenarios are based on a recent study conducted by the Department of Energy (DOE) and the Solar Energy Research Institute (SERI).[1] Table III-1 summarizes the aggregate generation and capacity for the two EPA scenarios examined in the analysis, along with the three DOE/SERI projections.[2] The EPA scenarios bracket a wide range of possibilities, reflecting the uncertainty that exists regarding the technological and market penetration prospects for renewable electric generation.

---

[1] *The Potential of Renewable Energy*, Interlaboratory White Paper prepared for the Office of Policy, Planning, and Analysis, U S Department of Energy (Golden, Colorado: Solar Energy Research Institute, March, 1990). The Solar Energy Research Institute (SERI) recently changed its name tho the National Renewable Energy Laboratory (NREL) References in this document reflect the time period prior to this name change and use the acronym SERI.

[2] The 1990 figures are slightly different than those reported in Table I-1. This table displays the initial capacity and generation data used in the Renewable Electric Model (REM). Some small discrepancies occur because some capacity and generation figures were imputed using various data sources. Sources differ because of various survey sample years (1988 through 1990) as well as definitional and methodological differences.

FIGURE III - 1



Renewable Electric Model Regions
Wash/Ore
Mountain
West
North Central
East
North Central
Mid Atlantic
New England
California
Ariz/New Mex
West
South Central
East
South Central
South
Atlantic
Florida

TABLE III - 1 RENEWABLE ELECTRIC SCENARIOS				
Scenario	**Capacity 2000 (MW)**	**Generation 2000 (GWh)**	**Capacity 2010 (MW)**	**Generation 2010 (GWh)**
DOE/SERI				
Business as Usual	109,600	485,800	168,600	691,800
Intensified RD&D	129,000	549,300	282,700	1,050,100
National Premiums	136,600	585,300	290,900	1,144,500
EPA				
Base Case	103,700	454,200	146,200	616,000
Enhanced Market	147,400	668,000	379,000	1,393,100
1990:	84,000	371,325		

DOE/SERI Scenarios

The recent DOE/SERI Interlaboratory report contains renewable energy projections to the year 2030 under one trend scenario and two policy cases. Since the DOE/SERI report provided many of the assumptions and data used in constructing the EPA renewable electric scenarios, the DOE/SERI scenarios are briefly described here:

- The **Business as Usual** (BAU) scenario is based on current market trends. Renewable electric generation grows at an annual average growth rate of 3.2% between 1988 and 2010. Photovoltaic, solar thermal, and windpower are projected to account for the most growth under this scenario.

- The **Intensified RD&D** scenario reflects the impact of an increased program of federal research, development, and demonstration (RD&D) support over the next several decades. Renewable electric generation grows at an annual average growth rate of 5.3% between 1988 and 2010. All technologies respond to additional RD&D, but gains are especially large for geothermal, photovoltaic, solar thermal, and windpower.

- The **National Premiums** scenario is based on giving renewable electric generation a market premium of 2 ¢/kWh over fossil fuel-fired generation. Renewable electric generation grows by 5.3% annually between 1988 and 2010 (as in the RD&D scenario) but with slightly higher contributions by hydropower, biomass, and windpower than in the RD&D policy case.

For some technologies, the EPA scenarios are identical to one of the DOE/SERI projections. For those that differ, the DOE/SERI market projections provide a useful point of comparison to the EPA scenarios. Because the DOE/SERI study did not report regional cost and specific technology data in many cases, the pollution prevention and cost implications of the DOE/SERI scenarios are not examined in this report.

EPA Scenarios

EPA constructed a trend scenario and a policy case scenario to the year 2010. The basic assumptions underlying the renewable energy contributions are outlined in the individual technology chapters that follow, and Appendix A provides detailed scenario descriptions.

Base Case. Using information from the DOE/SERI report and other sources, EPA constructed a Base Case to reflect current trends. The EPA Base Case projects that renewable electric generation will grow at an annual average growth rate of 2.6% between 1990 and 2010, slightly less than the DOE/SERI BAU projections. The EPA Base Case is identical to the DOE/SERI BAU scenario for geothermal, photovoltaic and solar thermal electric, but slightly below the BAU scenario for biomass, hydroelectric, and wind. The EPA base case projects that annual renewable generation will increase by about 245 billion kWh between 1990 and 2010. This is somewhat higher than a recent Energy Information Administration (EIA) projection for renewable generation, which estimates that renewable generation will increase by 200 billion kWh over the same time period.[3]

Enhanced Market Scenario. The EPA Enhanced Market scenario represents the near term potential for renewable electric generation under both targeted and broad promotion policies, including increased RD&D, environmental penalties for fossil fuel-fired generation, tax incentives, or other targeted state or federal support. In some ways it resembles a combination of the DOE/SERI RD&D and National Priorities scenarios; consequently, the Enhanced Market scenario projects higher total renewable electric generation than either of the DOE/SERI policy cases. In the aggregate, the EPA

[3] Energy Information Administration, *Annual Energy Outlook 1991*, Table 6, p.31.

Enhanced Market scenario projects that renewable electric generation will increase by over 1,020 billion kWh between 1990 and 2010.

The EPA Enhanced Market scenario is derived differently for each technology, giving extensive consideration to mechanisms that would enhance electricity markets and stimulate the specific renewable electric technologies in particular regions. Some technology penetration scenarios are explicitly constructed from assumptions regarding future costs and renewable resource availability. Other penetration scenarios are based on previously published analyses. Cost reductions are assumed to be the product of increased private and public RD&D as well as expanded market activity, including additional project development, consumer awareness, and other issues, that realize manufacturing scale economies and learning curve impacts. These market responses are consistent with an increased emphasis on environmental impacts of electric generating technologies, either through state resource planning methods (bidding criteria, set-aside capacity blocks for renewable energy sources, etc.) or broader federal policy options such as fossil fuel price penalties.

EPA MODEL DESCRIPTION

EPA constructed a model that accounts for the impacts of increased renewable electric supplies. The Renewable Electric Model (REM) evaluates the emission and cost impacts of different scenarios of technology penetration in the 12 regions shown on Figure III-1. The time horizon for the evaluation extends to 2010. The model accounts for the fact that both electricity markets and renewable resource bases vary significantly across three dimensions:

- Region (12 regions of the U.S.)
- Season (winter, summer and spring/fall)
- Time of day (peak and off-peak)

The fossil fuel mix and generating costs of electric utility systems are depicted in these dimensions in order to estimate the utility resources that renewable electric options will displace. Estimates of avoided (fossil fuel) variable costs, capital costs, and emissions are based on the plants that otherwise would be dispatched to meet seasonal and daily loads in the absence of renewable generation.[4] The model incorporates judgments concerning the *marginal* (highest cost) fossil fuel-

[4] In this report, "avoided" emissions and costs always refer to the fossil fuel-fired generation displaced by renewables.

fired plants in the utility dispatch decision for each load segment, as these would be the most likely to be "backed down" to accommodate additional renewable generation.[5]

The model estimates avoided capacity costs by identifying the season and time of day that the annual system peak occurs in each region, the costs of incremental capacity (e.g. coal steam plants, natural gas combined-cycle plants), and the likelihood that renewable generating technologies can be relied upon to provide power at peak periods. Avoided variable cost plus avoided capital cost equal the total avoided costs of conventional alternative supply.

The model further calculates the levelized cost of renewable generation, which can be compared directly with avoided utility costs to give the net cost of renewable electric generation. Emission abatement costs can be calculated on a per-ton removed basis by combining the net costs with the avoided emissions. In this way, the most cost effective renewable energy pollution prevention strategies can be identified.

The REM approach represents an analytical compromise between (1) using a regional electricity dispatch and investment optimization (production simulation) model to estimate emission reductions, and (2) applying simple national average emission factors to aggregate renewable market projections. The former approach would represent a significant increase in analytical detail for modest and potentially misleading gains in accuracy, since the renewable electric projections are subject to more uncertainty than the capacity and operating assumptions that underlie utility optimization models.[6] The latter approach may not adequately capture some of the important characteristics of renewable and fossil fuel generation, such as regional, seasonal, and time of day variation. The compromise approach incorporates many of the important characteristics of renewable electric generation and regional electricity markets. By capturing these important regional and temporal variations, the REM can produce a fairly refined national profile of pollution prevention through renewable electric generation.

---

[5] This data was assembled by looking at the existing generating resources, fuel costs, and demand characteristics in each region. The generation data were available through DOE/EIA publications and data tapes; demand characteristics were based on data used in performing detailed simulations of utility system dispatching for particular utility systems within each of the regions. The simulation model that this detailed data had been prepared for was the Integrated Planning Model (IPM) developed by ICF Resources. Fuel costs were based on EIA's escalated 1990 forecast.

[6] However, as discussed below, such an approach could yield more robust conclusions regarding the impact of large increases in renewable electric technologies.

INTERPRETATION OF MODEL RESULTS

The REM evaluates the avoided cost and emission impacts of assumed renewable electric technology penetration scenarios. It does not, however, forecast renewable technology penetration in electricity markets. Projections of individual renewable electric technology contribution to electric supply and the future costs of renewable generating options must be derived independently, and such projections involve a great deal of uncertainty.

Since both the future costs of renewable electric technologies and the amount of generation projected are input assumptions in the REM, the model can evaluate scenarios that feature renewable electric generation growth despite renewable costs that are generally higher than fossil generating costs. The realism of such scenarios depends on the market and non-market factors assumed to contribute to increased renewable energy use, as described in previous chapters.

Avoided Costs

The fossil fuel generating costs and emissions avoided by increased renewable generation can differ among renewable technologies in the same region (on a per-kilowatthour basis). This occurs because generation from different renewable technologies will displace different fossil generating units during the day and throughout the year. Avoided fuel and operating costs depend on the annual generating profile of a renewable technology. Utility capacity costs are avoided only to the extent that renewable technologies provide reliable peak power.[7] Thus, the value of dispatchable renewable generation (as measured by avoided costs) will typically be higher than the value of intermittent generation.

Because the REM estimates the avoided emissions and costs through a set of linear coefficients that represent the marginal fuels displaced by renewable generation, the model becomes progressively less accurate when evaluating large increases in renewable generation; coefficients are based on relatively small increments. For example, the model implicitly assumes that (firm) renewable generation displaces new capacity builds, and thus avoids significant capital costs. If aggressive policies increase the contribution of renewable generation to the point of displacing significant generation from existing plants (which could occur if expanded DSM programs curb demand growth)

[7] The model assumes different "capacity credits" for renewable generating technologies. For example, one megawatt of biomass electric generation can fully displace one megawatt of conventional fossil capacity, and is given a capacity credit equal to one. On the other hand, the capacity credit for intermittent technologies such as windpower is calculated as the fraction of each megawatt of windpower capacity that utilities could count on to displace conventional power sources during peak demand hours. These are estimated separately for each intermittent renewable based on regional resource availability during the peak utility season.

then the avoided fossil fuel generation costs would be only the fuel and operating costs of existing fossil units. The REM estimate would overstate avoided cost in this case. (However, emission reductions may be underestimated to the extent that more coal-fired generation could be displaced compared to the fuel mix displaced by more modest increments of renewable generation.) A more detailed model of the electric generation sector would be required to analyze large changes.

The aggregate Base Case technology scenario represents a fairly modest fraction of overall projected load growth, about 20% of EIA projections between 1990 and 2010. Under the Base Case, therefore, the estimates of avoided emissions and costs are probably fairly accurate. However, the EPA Enhanced Market renewable generation represents over 75% of the projected growth in electricity demand through 2010. Given the limitations of the REM and the inherent uncertainty regarding demand projections, the avoided costs of the Enhanced Market scenario might be regarded as an upper bound, since this level of renewable penetration would likely displace only the variable costs (fuel and operation & maintenance) of fossil fuel generation in some regions. On the other hand, the intermittent renewables (solar and wind) are not assumed to fully displace conventional capacity, limiting the possible bias in comparing renewable and fossil (avoided) costs.

Emissions

Air pollution prevented from three biomass electric technologies (wood and wood waste combustion, MSW, and landfill gas) and solar thermal hybrid (natural gas backup) are computed on a net basis. Depending on the relative emission rates of biomass technologies and displaced conventional generation, therefore, some technologies will produce net emissions of NO_x, SO_2, CO, and particulates. These are reported as negative pollution prevented. CO_2 emissions from biomass sources are assumed to be zero, which implies that fuelstocks are either grown on a sustainable basis or that organic waste would eventually oxidize to CO_2.

Avoided SO_2 emissions are based on 1987 average regional emission rates for oil and coal plants, and NO_x emission rates are based on typical existing coal, oil, and natural gas capacity. These assumptions are likely to overstate the SO_2 and NO_x reduction potential, since average emission rates will fall (especially in the eastern U.S.) when the Clean Air Act Amendments of 1990 are fully implemented.[8] Moreover, to the extent that the emission cap of the Clean Air Act represents a

[8] While average emission rates will fall, it remains unclear which coal plants will operate at the margin. It is possible that historically high SO_2 emitters will install scrubbers and operate at maximum levels in order to earn allowances, and that historically "clean" plants would also operate in the same way. Thus, an "average" plant by 1987 standards could still be dispatched at the margin after 2000, and thus be displaced by renewable electric generation

binding constraint on national SO_2 loadings, renewable electric generation will not actually reduce SO_2 emissions at this rate. Instead, these figures could indicate the magnitude of emission allowances created (freed for purchase by other emitters) through increased renewable generation. As such, they represent an upper bound on either pollution prevented or, multiplied by the eventual market price of SO_2 allowances, the value of renewable generation in the allowance market. Allowances are estimated to cost between $300 and $1000 per short ton of SO_2 emitted, depending on market demand.[9]

In addition to the CO_2 emission results, a composite "CO_2 equivalent" measure is also reported. This measure is based on the global warming potential for greenhouse gases, integrated over a 100 year time horizon.[10] Carbon dioxide has a value of one, while other greenhouse gases are weighted by the relative global warming potential as follows: methane, 21; carbon monoxide, 3; and nitrogen oxides, 40. Thus, to the extent that greenhouse gases other than CO_2 are reduced, the CO_2 equivalent measure will be larger than the CO_2 emission figure.

Because the cost of greenhouse gas abatement has been the focus of considerable recent attention, the model presents a dollar per metric ton removed calculation for CO_2 and CO_2 equivalent.[11] Such abatement cost figures should be viewed with caution: to the extent that renewable energy would reduce many fossil-fuel emissions simultaneously, attributing the entire cost differential to one pollutant overstates the (unit) pollution prevention costs or savings. In addition, the pollution prevention benefits or costs of technologies that displace some fossil fuel emissions and create others will not be adequately expressed in single-emission abatement cost measures. A weighting scheme such as CO_2 equivalent gives a more complete picture, but only for the global warming potential of the greenhouse gases. An ideal system would be economic valuation, that is, weighting each unit of emission reduction by the dollar value of avoided damage. The total value (summing across emission types) would provide a measure of the gross economic benefit from reduced emissions. When divided by annual costs, such a measure would be a standard benefit/cost ratio that would represent a net gain to society when its value exceeded one. However, the externality

[9] However, the value of the emission offsets would not be independent of the amount of renewable electric supply, since the price of SO_2 offsets would be driven down under high penetration scenarios. Therefore, estimates of the value of SO_2 offsets produced are subject to more uncertainty as higher renewable penetration is assumed

[10] The derivation of this weighting scheme can be found in *Scientific Assessment of Climate Change* report prepared by the Intergovernmental Panel on Climate Change, June, 1990, Chapter 2.

[11] This is calculated by dividing the difference between annual renewable cost and avoided fossil cost by the annual tons displaced by renewable electric generation. Thus, if renewable generation costs $50 million per year, avoided costs are $40 million per year, and CO_2 is reduced by two million metric tons annually, then the abatement cost would be $5/ton, or ($50 - $40)/2

cost estimates for each pollutant discussed in Chapter I showed wide variation in absolute terms, limiting the accuracy of direct benefit/cost valuation.

On the other hand, these same externality estimates suggest that the *relative* environmental damages associated with coal-fired generation are larger than those incurred with oil or gas-fired generation, as Figure III-2 displays. This implies that CO_2 emissions could provide a useful proxy measure for the damages associated with a variety of pollutants arising from fossil fuel use. In other words, the external costs of fossil fuel generation appear to be correlated with the carbon content of fuel.

AIR POLLUTION PREVENTION ESTIMATES

The total air pollution prevented in the EPA scenarios is primarily a function of the overall level of renewable generation assumed. However, air pollution reduction also depends on the mix of technologies assumed in each scenario, and the geographic distribution of capacity additions.

Base Case Generation and Pollution Prevented

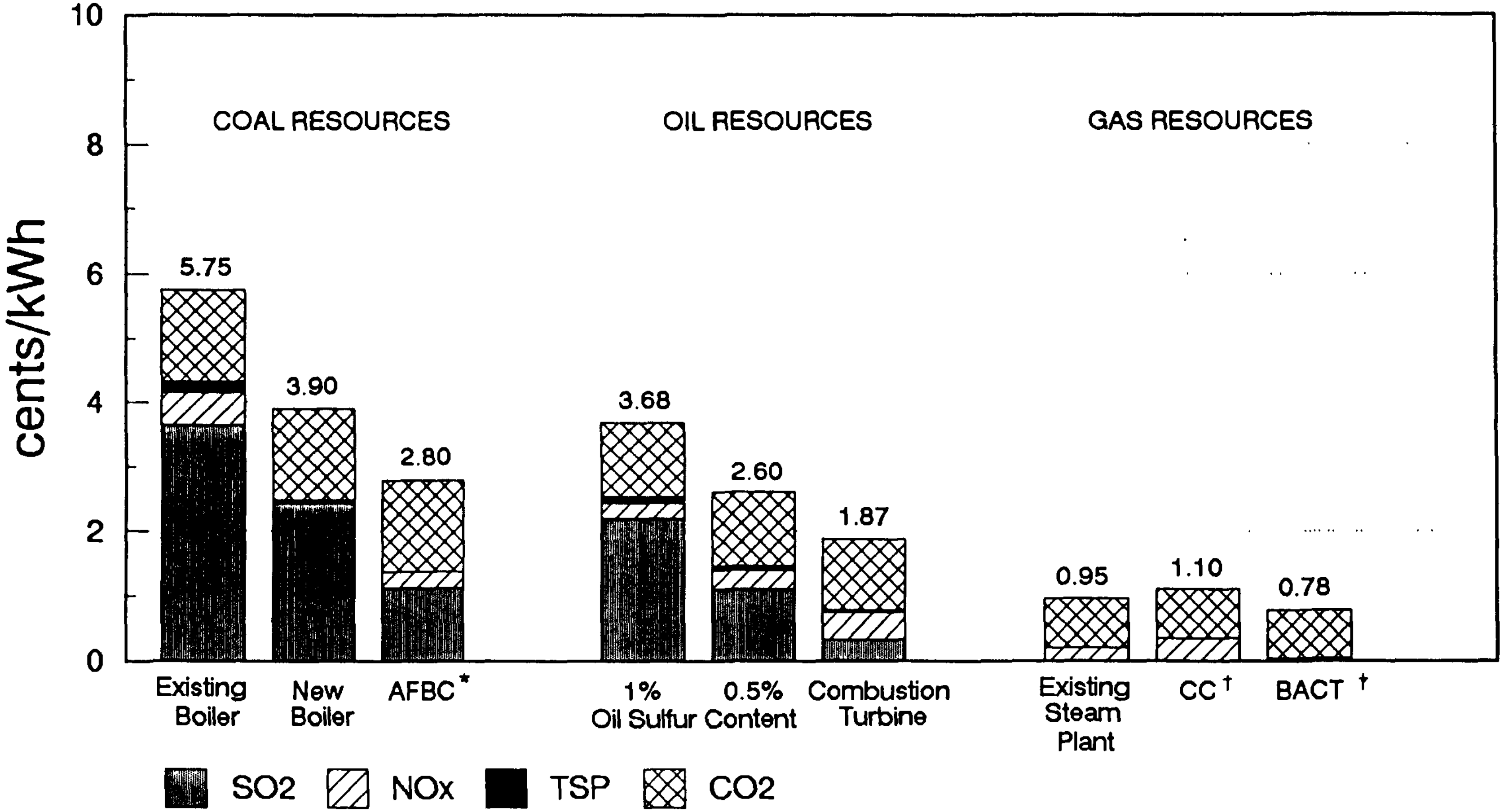
Tables III-2 and III-3 display Base Case results for renewable electric generation, costs, and air pollution prevented between 1990 and 2010.[12] In the Base Case, annual renewable generation increases by about 245,000 gigawatthours (GWh) between 1990 and 2010. Combustion of solid biomass fuels (wood, wood and agricultural wastes) account for 31% of the increased renewable generation, contributing an additional 77,000 GWh annually. Taken together, the three biomass technologies (solid, MSW, and gas) account for 45% of the increased renewable generation. Annual windpower generation grows by 46,000 GWh between 1990 and 2010, accounting for 19% of the increased renewable generation. Hydropower, facing increased environmental constraints, grows by only 14,000 GWh annually between 1990 and 2010.

Not surprisingly, the amount of air pollution prevented by each technology is roughly proportional to the amount of total generation assumed. Because biomass-gas is assumed to prevent emission of CH_4 at the rate of combustion (i.e. the methane would eventually escape to the atmosphere) it is the only renewable electric technology that eliminates methane in large quantities. As discussed above, SO_2 emission reductions must be viewed with caution: under the Clean Air Act

[12] Although treated separately in the model, run-of-river and storage hydropower plants are combined for reporting purposes, as are solar thermal (stand-alone) and solar thermal-natural gas (hybrid) systems.

FIGURE III - 2

Externality Values for Fossil-Fired Electricity Generation



* AFBC = Atmospheric Fluidized Bed Combustion
† CC = Combined Cycle Gas Plant
† BACT = Best Available Control Technology (assumes selective catalytic reduction and steam water injection)

Source: PACE UNIVERSITY, "Environmental Costs of Electricity"

TABLE III - 2

ELECTRICITY GENERATION COSTS

EPA BASE CASE
ALL REGIONS

TECHNOLOGY	INCREMENTAL GENERATION 1990 - 2000 (GWh/yr)	AVERAGE UNIT COST IN 2000 (cents/kWh)			TOTAL ANNUAL COST IN 2000 ($ millions)		UNIT COST OF EMISSIONS AVOIDED IN 2000 ($/metric ton)	
		AVOIDED FOSSIL	RENEWABLE	COST DIFFERENCE	AVOIDED FOSSIL	RENEWABLE	CO_2 Equivalent	CO_2
Biomass Electric - Solid	36,742	5.0	8.0	3.0	1,851	2,952	32	34
Biomass Electric - MSW	7,245	4.9	4.9	0.0	355	355	0	0
Biomass Electric - Gas	3,901	4.7	4.2	-0.4	183	166	-1	-6
Geothermal Electric	7,143	4.7	4.5	-0.2	334	323	-2	-3
Hydropower	6,948	4.3	4.4	0.1	298	307	1	5
Photovoltaic	1,925	4.2	19.1	14.8	81	367	145	170
Solar Thermal	10,939	7.1	11.4	4.3	781	1,252	49	58
Windpower	7,906	3.0	4.8	1.8	238	377	16	19
AVERAGE	**82,749**	**5.0**	**7.4**	**2.4**	**4,121**	**6,099**	**20**	**29**

TECHNOLOGY	INCREMENTAL GENERATION 2000 - 2010 (GWh/yr)	AVERAGE UNIT COST IN 2010 (cents/kWh)			TOTAL ANNUAL COST IN 2010 ($ millions)		UNIT COST OF EMISSIONS AVOIDED IN 2010 ($/metric ton)	
		AVOIDED FOSSIL	RENEWABLE	COST DIFFERENCE	AVOIDED FOSSIL	RENEWABLE	CO_2 Equivalent	CO_2
Biomass Electric - Solid	39,988	6.4	7.0	0.6	2,549	2,809	7	8
Biomass Electric - MSW	17,841	6.3	6.3	0.0	1,116	1,116	0	0
Biomass Electric - Gas	4,877	6.9	4.2	-2.7	337	207	-4	-37
Geothermal Electric	21,759	7.2	3.3	-3.9	1,559	718	-50	-59
Hydropower	6,690	5.3	4.8	-0.5	355	320	-5	-21
Photovoltaic	12,679	5.3	11.5	6.2	677	1,458	62	72
Solar Thermal	19,506	6.5	6.5	-0.1	1,276	1,265	-1	-1
Windpower	38,517	3.7	4.1	0.4	1,423	1,571	3	4
AVERAGE	**161,858**	**5.7**	**5.8**	**0.1**	**9,292**	**9,464**	**1**	**1**

TABLE III - 3

AIR POLLUTION PREVENTED

EPA BASE CASE
ALL REGIONS

REGION	INCREMENTAL GENERATION 1990 - 2010 (GWh/yr)	AIR POLLUTION PREVENTED 1990 - 2010 (thousand metric tons/yr)						
		SO_2	NO_x	Particulate Matter	CO	CH_4	CO_2	CO_2 Equivalent
Biomass Electric - Solid	76.731	457 4	146 2	-8 82	-110 04	0 58	66,608	72,138
Biomass Electric - MSW	25 086	148 1	32 1	-258 51	-10 25	0 18	21,639	22,897
Biomass Electric - Gas	8.778	34 9	-40 5	1 14	-25 15	2,337.57	6,401	53,796
Geothermal Electric	28 902	33 9	80 0	2 42	4 66	0.10	18,437	21,652
Hydropower	13.638	80 5	52 9	3 08	2 01	0.11	12,671	14,794
Photovoltaic	14.605	67 2	51 7	2 79	2 22	0.10	12,513	14,592
Solar Thermal	30.445	38 5	96 4	3 50	4 80	0 13	21,588	25,460
Windpower	46.423	189 5	183 5	10 66	6 85	0 37	43,659	51,026
TOTAL	**244,607**	**1,049.9**	**602.3**	**-243.75**	**-124.90**	**2,339.15**	**203,516**	**276,354**

Negative values indicate that the technology increases emissions for the pollutant indicated.

Amendments of 1990, these emission reductions would probably not occur under the SO_2 emission cap, but would be translated into financial gains in the form of allowances.

The 600,000 metric ton decrease in annual NO_x emissions by 2010 is about 33% of the 2 million (short) ton NO_x reduction required by the Clean Air Act Amendments by 2001. The 204 million metric ton reduction in CO_2 emissions represents about 10% of current CO_2 emissions from U.S. electric generation, and about 6% of the EIA projection for the year 2010 (shown in Figure I-4 in Chapter I). These emission results also show the tradeoffs encountered in increasing biomass generation in terms of additional CO, and particulate matter (PM): while net NO_x, SO_2, CO_2 and CH_4 emissions would decline, other environmental damage could occur. Nevertheless, the net increase in PM and CO are very small compared to current emission levels: the 244,000 metric ton increase in PM represents 4% of 1988 emissions (from all sources), while the 125,000 metric ton increase in CO is only 0.2% of 1988 emissions.

Enhanced Market Generation and Air Pollution Prevented

The combination of policies assumed in the Enhanced Market scenario would increase generation from all renewable technologies. Tables III-4 and III-5 display the Enhanced Market results for renewable electric generation, costs, and air pollution prevented between 1990 and 2010. The incremental renewable electric generation in the Enhanced Market scenario is 4.2 times the increased renewable generation in the Base Case by 2010. Solid biomass combustion accounts for 34% of the incremental generation between 1990 and 2010; generation is 4.5 times higher than Base Case levels in 2010. Photovoltaics provide 19% of the increase in annual generation between 1990 and 2010, while windpower and geothermal electric provide 14% and 13% of the incremental generation, respectively.

Because of the regional technology mix assumed in the Enhanced Market scenario, the increase in air pollution prevention is not always proportional to the incremental renewable generation. The implicit SO_2 reduction by 2010 in the Enhanced Market scenario is 4.7 times the Base Case reduction; NO_x reduction is 5.0 times the Base Case reduction; the CH_4 reduction is 1.3 times the Base Case, and the CO_2 reduction is 4.3 times the Base Case reduction. Compared to the Base Case, incremental renewable generation in the Enhanced Market scenario has 3.5 times the CO emissions, and 1.2 times the PM emissions.

The implicit reduction in annual SO_2 emissions in the Enhanced Market scenarios -- as much as 3.9 million metric tons -- could conceivably drive aggregate SO_2 emissions below the mandated cap (which would imply that the allowance price would be zero). The 2.4 million metric tons of NO_x

TABLE III - 4

ELECTRICITY GENERATION COSTS

EPA ENHANCED MARKET SCENARIO
ALL REGIONS

TECHNOLOGY	INCREMENTAL GENERATION 1990 - 2000 (GWh/yr)	AVERAGE UNIT COST IN 2000 (cents/kWh)			TOTAL ANNUAL COST IN 2000 ($ millions)		UNIT COST OF EMISSIONS AVOIDED IN 2000 ($/metric ton)	
		AVOIDED FOSSIL	RENEWABLE	COST DIFFERENCE	AVOIDED FOSSIL	RENEWABLE	CO_2 Equivalent	CO_2
Biomass Electric - Solid	150,529	4.9	7.8	2.8	7,448	11,714	28	31
Biomass Electric - MSW	19,871	4.8	4.8	0.0	960	960	0	0
Biomass Electric - Gas	6,671	4.7	4.0	-0.7	313	264	-1	-9
Geothermal Electric	31,877	4.6	4.1	-0.5	1,483	1,321	-7	-9
Hydropower	26,820	4.3	4.9	0.6	1,155	1,309	5	22
Photovoltaic	8,753	4.2	11.5	7.3	368	1,007	72	84
Solar Thermal	21,342	7.0	10.3	3.3	1,503	2,206	37	44
Windpower	24,344	2.9	4.3	1.5	704	1,058	13	15
AVERAGE	**290,206**	**4.8**	**6.8**	**2.0**	**13,934**	**19,839**	**19**	**23**

TECHNOLOGY	INCREMENTAL GENERATION 2000 - 2010 (GWh/yr)	AVERAGE UNIT COST IN 2010 (cents/kWh)			TOTAL ANNUAL COST IN 2010 ($ millions)		UNIT COST OF EMISSIONS AVOIDED IN 2010 ($/metric ton)	
		AVOIDED FOSSIL	RENEWABLE	COST DIFFERENCE	AVOIDED FOSSIL	RENEWABLE	CO_2 Equivalent	CO_2
Biomass Electric - Solid	193,936	5.7	6.4	0.7	10,993	12,444	7	8
Biomass Electric - MSW	17,200	6.3	6.3	0.0	1,076	1,076	0	0
Biomass Electric - Gas	4,877	6.6	3.7	-2.9	320	179	-5	-37
Geothermal Electric	102,057	6.9	4.0	-2.9	7,089	4,121	-35	-42
Hydropower	18,688	5.1	5.2	0.1	959	975	1	3
Photovoltaic	186,287	5.3	6.4	1.0	9,951	11,896	10	12
Solar Thermal	81,927	6.5	6.0	-0.5	5,356	4,946	-6	-7
Windpower	115,331	3.5	3.6	0.1	4,066	4,159	1	1
TOTAL	**731,357**	**5.6**	**5.6**	**0.0**	**40,791**	**40,738**	**0**	**0**

TABLE III - 5

AIR POLLUTION PREVENTED

EPA ENHANCED MARKET SCENARIO
ALL REGIONS

TECHNOLOGY	INCREMENTAL GENERATION 1990 - 2010 (GWh/yr)	AIR POLLUTION PREVENTED 1990 - 2010 (thousand metric tons/yr)						
		SO_2	NO_x	Particulate Matter	CO	CH_4	CO_2	CO_2 Equivalent
Biomass Electric - Solid	344.464	2,515 4	818 2	-28 90	-480 26	2 73	320,527	351,874
Biomass Electric - MSW	37.071	220 4	48 7	-381 98	-15 15	0 27	32,119	34,029
Biomass Electric - Gas	11 547	52 4	-50 0	1.87	-33 12	3,075.03	9,195	71,671
Geothermal Electric	133 935	225 2	389 6	13 52	21 36	0.55	90,213	105,874
Hydropower	45.508	271 7	176 6	10 32	6 70	0 36	42,368	49,461
Photovoltaic	195.040	891 7	689 5	37 06	29 64	1.36	166,713	194,412
Solar Thermal	114.323	142 4	361 3	13 00	18.14	0.50	80,995	95,511
Windpower	139 675	602 9	567 2	33 68	20.46	1.17	134,810	157,585
TOTAL	**1,021,563**	**4,922.1**	**3,001.3**	**-301.42**	**-432.23**	**3,081.97**	**876,940**	**1,060,417**

Negative values indicate that the technology increases emissions for the pollutant indicated.

emissions avoided annually would exceed the reduction requirements of the Clean Air Act Amendments by about 50%. Overall, the 670 million metric tons of CO_2 emissions avoided annually by 2010 in the Enhanced Market scenario are roughly 30% of the current level of CO_2 emissions from electricity generation, and would represent a 20% reduction from projected 2010 CO_2 levels according to the EIA forecast. In this scenario, renewables would cut the projected CO_2 emission increase by roughly 45%.

Additional context is provided by comparing EPA estimates of avoided emissions to projected levels of energy-related emissions in the National Energy Strategy (NES).[13] The NES projects energy production and consumption and energy-related emissions for a Current Policies Base Case (which does not include the Clean Air Act Amendments of 1990) and a Strategy Scenario. Avoided emissions in 2010 in the EPA Enhanced Market scenario (compared to those in the EPA Base Case) represent 9% of NO_x, 10% of CO_2, and 14% of SO_2 emissions from all energy sources projected for 2010 in the NES Current Policies Base Case.[14] The emissions avoided in the EPA Enhanced Market scenario also represent a substantial portion of the emission reductions projected in the NES Strategy Scenario (31%, 49%, and 74% of projected reductions in SO_2, NO_x, and CO_2, respectively).[15]

Air Pollution Prevention Rates

By taking into account how renewable electric generation would affect utility system operation in various regions, the REM can calculate specific air pollution prevention coefficients for each technology.[16] Table III-6 shows the average U.S. emission reduction rates per unit of renewable electric generation for the EPA Base Case and Enhanced Market scenario, calculated by dividing the total annual reductions of each pollutant by the incremental renewable generation. Since these

---

[13] *Technical Annex 2. Integrated Analysis Supporting the National Energy Strategy: Methodology, Assumptions and Results*, U S Department of Energy, First Edition 1991/1992 Tables 2-2 and 3-2.

[14] EPA estimates can be compared to the NES Base Case because neither includes the Clean Air Act Amendments of 1990, which substantially lower allowable SO_2 emissions. Given the current system of tradeable SO_2 emission permits, however, these reductions would probably not occur. Rather, allowances would be created that could then be sold to SO_2 emitters

[15] This points out that the EPA Enhanced Market scenario represents a more agressive estimate of renewable energy penetration than envisioned in the NES Strategy Scenario as a result of greater emphasis on pollution prevention and on renewable electric resource and technology potential rather than cost effectiveness

[16] The emission calculations do not take into account all aspects of utility system operation. For example, large penetration of intermittent renewable generation could increase a utility's need for spinning reserves (units operating at full or partial capacity but unconnected to load) An increase in spinning reserves could partially offset the pollution reductions from additional renewable generation

TABLE III - 6: AVERAGE EMISSION REDUCTION RATES 1990 - 2010

BASE CASE

TECHNOLOGY	SO_2 (kg/MWh)	NO_x (kg/MWh)	Particulate Matter (kg/MWh)	CO (kg/MWh)	CH_4 (kg/MWh)	CO_2 (kg/MWh)	CO_2 Equivalent (kg/MWh)
Biomass Electric - Solid	5.96	1.91	-0.11	-1.43	0.01	868	940
Biomass Electric - MSW	5.90	1.28	-10.31	-0.41	0.01	863	913
Biomass Electric - Gas	3.98	-4.61	0.13	-2.87	266.30	729	6,129
Geothermal Electric	1.17	2.77	0.08	0.16	0.00	638	749
Hydropower	5.90	3.88	0.23	0.15	0.01	929	1,085
Photovoltaic	4.60	3.54	0.19	0.15	0.01	857	999
Solar Thermal	1.27	3.17	0.11	0.16	0.00	709	836
Windpower	4.08	3.95	0.23	0.15	0.01	940	1,099

ENHANCED MARKET SCENARIO

TECHNOLOGY	SO_2 (kg/MWh)	NO_x (kg/MWh)	Particulate Matter (kg/MWh)	CO (kg/MWh)	CH_4 (kg/MWh)	CO_2 (kg/MWh)	CO_2 Equivalent (kg/MWh)
Biomass Electric - Solid	7.30	2.38	-0.08	-1.39	0.01	931	1,022
Biomass Electric - MSW	5.95	1.32	-10.30	-0.41	0.01	866	918
Biomass Electric - Gas	4.54	-4.33	0.16	-2.87	266.30	796	6,207
Geothermal Electric	1.68	2.91	0.10	0.16	0.00	674	790
Hydropower	5.97	3.88	0.23	0.15	0.01	931	1,087
Photovoltaic	4.57	3.54	0.19	0.15	0.01	855	997
Solar Thermal	1.25	3.16	0.11	0.16	0.00	708	835
Windpower	4.32	4.06	0.24	0.15	0.01	965	1,128

numbers remain fairly stable between scenarios, they could be applied to other renewable electric projections to estimate emission impacts.

These air pollution prevention rates indicate that, at the margin (and based on regional, seasonal, and time-of-day attributes), additional windpower generation would prevent more CO_2, NO_x, and particulates than other renewable technologies, while geothermal and solar thermal would be less effective at preventing air pollution than other technologies. Because biomass solid combustion mainly occurs in regions where high-sulfur coal has been traditionally used as utility fuel, wood-fired generation would be most effective at reducing SO_2 (or generating emission allowances). Solar thermal and geothermal electric generation, on the other hand, would tend to displace much less SO_2 because of their regional distribution.

RENEWABLE AND FOSSIL GENERATION COSTS

The cost comparisons generally indicate the growing competitiveness of renewable electric generating technologies compared with fossil fuel alternatives. However, a great deal of cost variation exists among renewable technologies, and the geographic distribution and operating characteristics (especially intermittency) of renewable technologies has a strong impact on the avoided costs.

Base Case Generation Costs

Table III-2 shows the electric generation costs under current cost trends (Base Case). Under these assumptions, the average renewable generating cost will be 2.4 ¢/kWh higher than fossil fueled generation in 2000, a difference that will narrow to 0.3 ¢/kWh by 2010.[17] Landfill gas and geothermal electric technologies are less expensive than fossil fuel alternatives by 2000, while solar thermal electric and hydropower technologies are also cost-effective by 2010 (as explained in Chapter IV, MSW generation costs are assumed to be equal to avoided fossil costs). Biomass solid combustion (wood and wood waste), photovoltaics, and wind are not projected to become broadly competitive on a market price basis by 2010. However, these national averages mask the regional results that indicate that biomass solid combustion and windpower will be less expensive than fossil fuel generation in some regions.

One of the key factors in the competitiveness of renewable generation is the cost of conventional supplies displaced. Avoided costs are a function of regional utility systems (generation

[17] This represents a weighted average cost of all technologies in all regions, using the Base Case generation projections as weights.

mix and fuel prices) and the operating characteristics of renewable energy sources, especially during peak load periods when renewable generation could reduce the need for building additional fossil capacity. For example, because intermittent windpower would displace little fossil fuel-fired capacity, the cost of avoided fossil generation is based primarily on avoided variable costs and is valued at only 3.0 ¢/kWh in the year 2000.[18] In contrast, "firm" renewable capacity such as biomass solid combustion, which receives full capacity credit, has an avoided cost of 5.0 ¢/kWh. Solar thermal electric hybrid generation (which is firm and operates exclusively during expensive peak utility demand periods) achieves an avoided cost of 7.1 ¢/kWh. Chapter X examines ways in which intermittent renewables such as PV and wind can earn capacity credit by using natural gas combustion turbine backup systems.

Enhanced Market Generation Costs

As shown in Table III-4, average renewable generating costs are only 2.0 ¢/kWh higher than fossil fuel generation in 2000, and are equal to fossil generating costs by 2010 in the Enhanced Market scenario. Most renewable electric technologies would cost less under the Enhanced Market assumptions, but average avoided costs are also lower as a result of additional renewable generation in low avoided cost regions. The Enhanced Market scenario features large contributions from biomass electric, photovoltaic, and windpower -- technologies that would continue to cost slightly more than the conventional generation they displace when valued at market prices. This highlights the assumed rationale behind the Enhanced Market scenario: renewable technology potential would be realized because of environmental advantages not necessarily reflected in market prices.

"Backstop" Technology Costs

A "backstop technology" is a long-run concept of limitless (at least in relevant ranges of demand) energy supply that is not subject to increasing costs over time due to progressive scarcity. Since the EPA technology assessment extends for only 20 years, the analysis does not specifically identify or estimate the costs of a single backstop technology. All of the renewable resources considered here have additional expansion potential (except landfill methane, hydropower, and to some extent MSW). PV is often mentioned as a backstop technology because PV uses ubiquitous sunlight, is manufactured from abundant materials, and could be widely deployed. Likewise, hot dry

---

[18] In the REM, windpower is given a capacity credit equal to: 1/2 of the regional capacity factor in 2000; and 2/3 of the regional capacity factor in 2010 (capacity factors rise between 2000 and 2010). Also, avoided costs for windpower are lower than for other technologies because some windpower is generated during the night when utility variable costs are low Windpower may have higher avoided costs in areas with relatively high levels of hydropower capacity, where windpower intermittency is less of an obstacle.

rock or magma geothermal technologies could theoretically provide immense amounts of useful energy, and the exploitation of wind resources remains far below estimates of technological feasibility. However, many of these energy forms face technological constraints, such as intermittence, and may have significant land-use impacts if universally deployed.

For these reasons, no single renewable technology is likely to provide pollution-free "backstop" electricity generation over the next two decades. Instead, a portfolio of renewable electric generation resources is likely to emerge if the U.S. undertakes significant shifts in energy production patterns in order to minimize environmental impacts. By the year 2010, generation costs in the Enhanced Market scenario range from 3.6 ¢/kWh (windpower), 3.7 ¢/kWh (biomass gas), and 4.0 ¢/kWh (geothermal) to 6.4 ¢/kWh (biomass solid combustion and photovoltaics). Since wind, geothermal, biomass solid combustion, and photovoltaics all have significant expansion potential beyond the levels in this report, backstop costs below 7 ¢/kWh could be expected if the market evolves in the direction of the EPA Enhanced Market scenario. Both biomass and PV are relatively free of geographic and resource constraints, compared with (hydrothermal and geopressured brine) geothermal, wind, and landfill gas, and these two technologies could serve as "backstop" technologies for most regions. If technical progress is limited to Base Case assumptions, then wind, landfill gas, and geothermal would still be the lowest cost technologies -- between 4.1 ¢/kWh and 4.4 ¢/kWh -- while biomass solid combustion would cost 7.0 ¢/kWh and PV generation would cost 11.5 ¢/kWh. If biomass and PV are considered as backstop technologies in this scenario, backstop costs would be between 7 ¢/kWh and 12 ¢/kWh in the year 2010.

ENVIRONMENTAL COSTS

The generation cost estimates discussed above are based on market prices for renewable and conventional technologies. The relationship between air pollution prevention and relative generation costs is further examined in two ways: constructing "air pollution abatement cost curves" for renewable energy options, and estimating the impacts of environmental penalties on fossil fuel generation.

Air Pollution Prevention Costs

Some of the air pollution prevented by renewable electric generation is obtained at a profit, while others would add cost to electric supply. Tables III-2 and III-4 report the cost per ton CO_2 removed, and Figures III-3 and III-4 show these costs as a function of CO_2 emissions avoided for each scenario in 2000 and 2010. The figures rank technologies by ascending costs, and are analogous to abatement cost curves familiar in pollution control analysis.

FIGURE III - 3

CARBON DIOXIDE ABATEMENT COST CURVE
2000

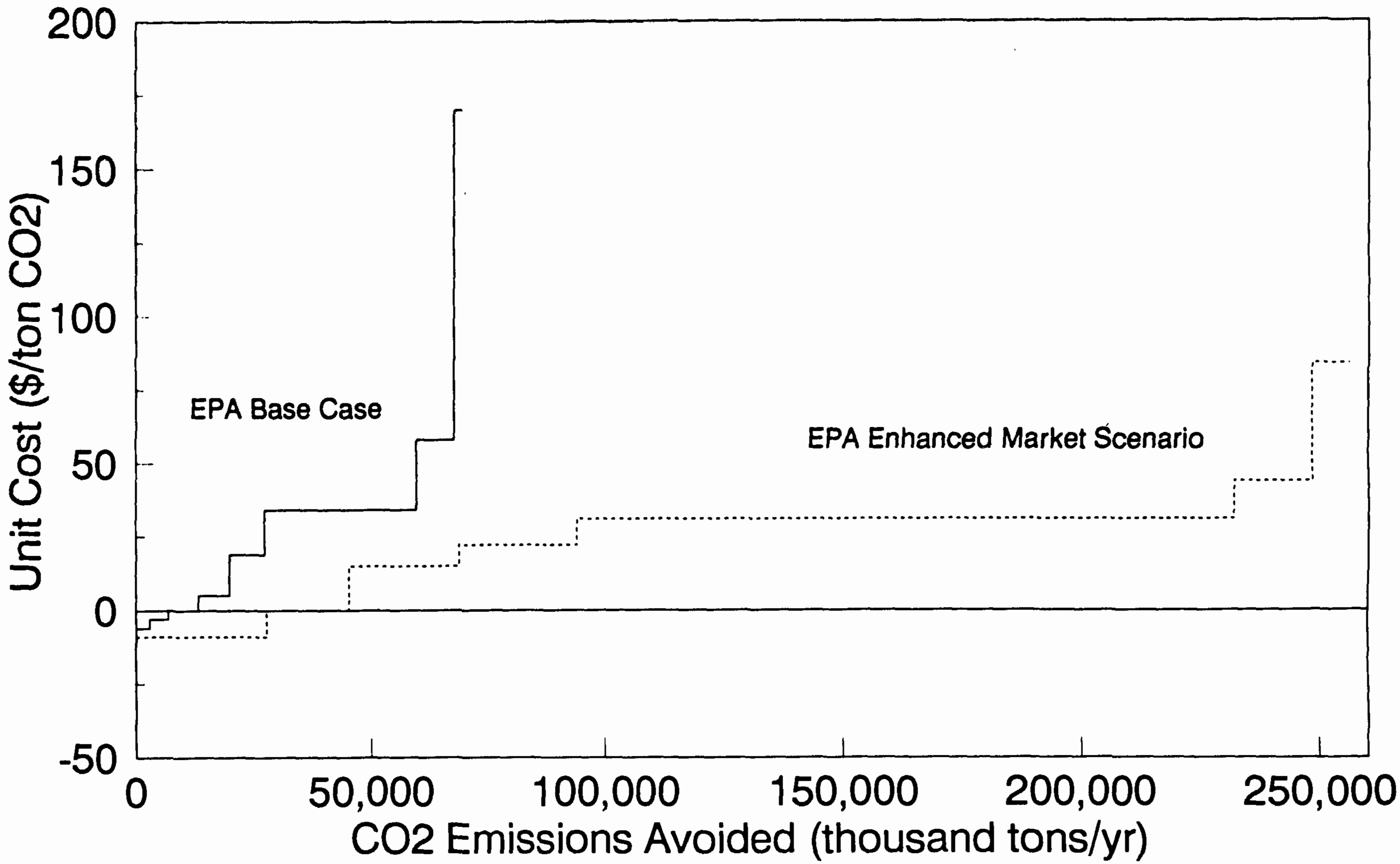
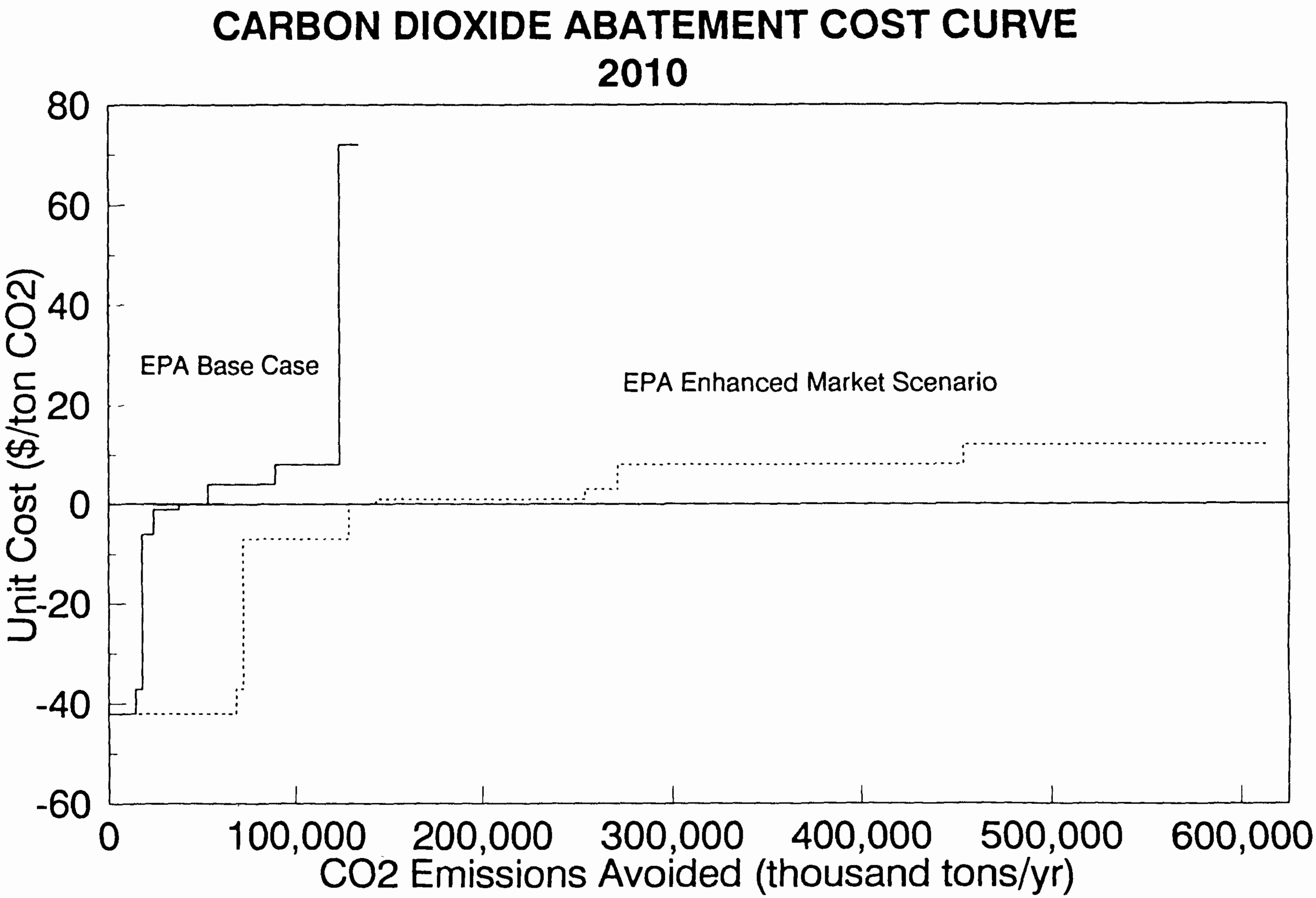


FIGURE III - 4


CARBON DIOXIDE ABATEMENT COST CURVE
2010
Unit Cost ($/ton CO2)
80
60
40
20
0
-20
-40
-60
EPA Base Case
EPA Enhanced Market Scenario
0
100,000
200,000
300,000
400,000
500,000
600,000
CO2 Emissions Avoided (thousand tons/yr)

The abatement cost curves for CO_2 show that Base Case conditions limit the cost-effective air pollution prevention potential for renewable electric generation. As seen in Figure III-3, CO_2 reduction costs quickly rise above $50/ton beyond 50,000 metric tons removed annually by 2000 in the Base Case. By the year 2010, CO_2 abatement occurs at negative cost (renewable electric technologies that eliminate CO_2 cost less than conventional generation) for the first 50,000 tons removed, but costs quickly rise beyond 100,000 tons per year prevented. The Enhanced Market scenario in 2000 shows that nearly 250,000 metric tons of CO_2 per year could be displaced by renewables at a cost of less than $50 per ton, while another 600,000 metric tons of CO_2 could be eliminated in 2010 for less than $20 per ton.

These summary figures highlight a key finding of this report: under the Enhanced Market assumptions, renewable electric generation can prevent significant amounts of air pollution at relatively low cost.[19] Market prices for most renewable electric generation technologies are unlikely to fall significantly below fossil fuel-fired generation costs over the next two decades. However, renewables could become broadly competitive during that period. If the environmental advantages of renewable energy over fossil fuel generation were taken into account, then renewable energy would become a cost-effective source of electricity supply.

<u>Externalities Penalty Cases</u>

If the environmental costs (externalities) of fossil fuel-fired electric generation were reflected in market prices, the market cost of fossil fuel generation would rise relative to renewable electric generation. This effect is demonstrated by applying environmental penalties to the price of fossil fuel generation displaced by renewable electric options in the Base Case (i.e. increase avoided fossil fuel costs). Penalties applied in proportion to the carbon content of fossil fuels could approximate external costs from a variety of pollutants. Three scenarios were examined:

- A penalty set at $50 per metric ton of carbon ($14/ton CO_2), which represents a low estimate on fossil fuel externalities;

- A penalty of $100 per metric ton of carbon ($27/ton CO_2) is close to the median estimate of CO_2 emission damages cited in Chapter I (shown on Figure I-7); and

[19] As discussed before, at higher ranges of renewable penetration and emission reduction, avoided costs could fall to variable fossil costs, which would increase abatement costs more steeply than shown in these figures.

- A penalty of $250 per metric ton of carbon ($68/ton CO_2) is near to the total externality costs of fossil fuel generation cited in the Pace University and Hohmeyer studies.[20]

Table III-7 shows the impact of these environmental penalties on the relative costs of renewable and fossil fuel electric generation. The $50/ton penalty would add an average of 1.1 ¢/kWh to the cost of fossil fuel generation displaced by renewables in 2000, and 1.2 ¢/kWh in 2010. Except for photovoltaics, every renewable electric technology costs less than fossil fuel generation that includes a $50/ton carbon penalty in 2010. This comparison does not rely on an optimistic forecast of renewable costs; the result is obtained using the Base Case cost assumptions. The $100/ton penalty would add an average of 2.3 ¢/kWh to fossil fuel generation in 2000, making fossil fuel-fired electric power cost the same as renewable generation. The $250/ton charge would more than double the cost of fossil-fuel electric generation, making all renewable energy sources except photovoltaic less expensive than fossil fuel generation.

The impacts of fossil fuel environmental penalties on the avoided costs of each technology is proportional to the average CO_2 emissions avoided (i.e. the pollution prevention rate discussed above).[21] Therefore, the $50/ton carbon charge adds 1.3 ¢/kWh to the avoided cost of windpower and hydropower, while the same penalty would add only 0.8 ¢/kWh (in 2000) and 0.9 ¢/kWh (in 2010) to the avoided cost of geothermal. Because renewable electric generating technologies have different pollution prevention potential, broad-based environmental policy would help promote some renewables more than others.

These results indicate that renewable electric generating options could compete extremely well with fossil fuel alternatives if environmental performance were valued in the marketplace. The $50/ton and $100/ton penalty for carbon emissions are within the range of penalties that some states are considering applying to various pollutants from fossil fuel sources. If such penalties help guide resource planning over the next decades, as the Enhanced Market scenario assumes, then renewable energy stands to make significant inroads to the electric supply sector.

---

[20] See *Environmental Costs of Electricity*, prepared by the Pace University Center for Environmental Legal Studies (New York Oceana Publications, Inc., 1990), and Olav Hohmeyer, *Social Costs of Energy Consumption: External Effects of Electricity Generation in the Federal Republic of Germany* (Heidelberg: Springer-Verlag, 1988).

[21] The penalties are applied to the fossil fuel mix displaced (at the margin) by specific renewable technologies. Because the assumed marginal fuel mix does not change by the imposition of the penalties, however, only a first-order estimate of the avoided cost increase is calculated.

TABLE III - 7: AVOIDED COST IMPACTS OF ENVIRONMENTAL PENALTIES - 2000 and 2010

YEAR 2000	Levelized Cost (¢/kWh) - 2000					Renewable Cost Difference (¢/kWh) - 2000			
	Base Case Costs		Carbon Charge Avoided Costs			Base Case	Carbon Charge Cases		
TECHNOLOGY	Renewable Technology	Avoided Fossil	$50/ MT	$100/ MT	$250/ MT		$50/ MT	$100/ MT	$250/ MT
Biomass Electric - Solid	8.0	5.0	6.2	7.4	11.0	3.0	1.8	0.6	-3.0
Biomass Electric - MSW	4.9	4.9	6.1	7.3	10.9	0 0	-1.2	-2.4	-6.0
Biomass Electric - Gas	4.2	4.7	5.7	6.7	9.7	-0.4	-1.4	-2.5	-5.5
Geothermal Electric	4.5	4.7	5.5	6.2	8.6	-0.2	-1.0	-1.7	-4.1
Hydropower	4 4	4.3	5.6	6.9	10.7	0.1	-1.2	-2.4	-6.3
Photovoltaic	19 1	4 2	5.4	6.6	10.2	14.8	13.7	12.5	8.9
Solar Thermal	11.4	7.1	8.2	9.2	12.4	4.3	3.3	2.2	-0.9
Windpower	4 8	3 0	4.3	5.6	9.4	1.8	0.5	-0.8	-4.7

YEAR 2010	Levelized Cost (¢/kWh) - 2010					Renewable Cost Difference (¢/kWh) - 2010			
	Base Case Costs		Carbon Charge Avoided Costs			Base Case	Carbon Charge Cases		
TECHNOLOGY	Renewable Technology	Avoided Fossil	$50/ MT	$100/ MT	$250/ MT		$50/ MT	$100/ MT	$250/ MT
Biomass Electric - Solid	7.0	6.4	7.5	8.7	12.3	0.6	-0.5	-1.7	-5.2
Biomass Electric - MSW	6.3	6.3	7.4	8.6	12.1	0.0	-1.2	-2.3	-5.8
Biomass Electric - Gas	4.2	6.9	7.9	8.9	11.9	-2.7	-3.6	-4.6	-7.6
Geothermal Electric	4.4	7.2	8.1	9.0	11.7	-2.8	-3.7	-4.6	-7.3
Hydropower	4.8	5.3	6.6	7.8	11.6	-0.5	-1.8	-3.0	-6.8
Photovoltaic	11.5	5.3	6.5	7.7	11.2	6.2	5.0	3.8	0.3
Solar Thermal	6.5	6.5	7.5	8.4	11.3	-0.1	-1.0	-1.9	-4.8
Windpower	4.1	3.7	5.0	6.3	10.1	0.4	-0.9	-2.2	-6.0

CHAPTER IV
BIOMASS ELECTRIC GENERATION

Biomass is a form of solar energy stored in organic matter through plant photosynthesis. The photosynthetic process is a complex chain of reactions that occurs in plants, where energy from sunlight fixes carbon (from carbon dioxide in the air) with hydrogen from water, producing glucose and oxygen. Glucose is used to synthesize longer chain hydrocarbons (polysaccharides), including cellulose and starch, for long-term energy storage. The only major difference between biomass hydrocarbons and the hydrocarbons that make up fossil fuels is that fossil fuels have been made much more energy dense through thousands of years of extreme pressure and temperature. Combustion of biomass hydrocarbons, which is essentially reverse photosynthesis, releases energy capable of performing work in the same way that fossil fuels provide useful energy.

As with fossil fuels, the combustion of biomass results in the production of carbon dioxide, a major greenhouse gas. However, there is no net emission of carbon when new growth of plants sequesters (through photosynthesis) an equal or greater amount of carbon as a part of the carbon cycle (shown in Figure IV-1). It is essential that biomass resources be properly managed to insure that new growth and organic buildup of soils offset carbon emissions from biomass combustion, making biomass a net sink of carbon. Combustion of biomass wastes also produces CO_2, but recovers useful energy that would otherwise be dissipated during slow oxidation (decay) which would yield CO_2 without providing useful energy.

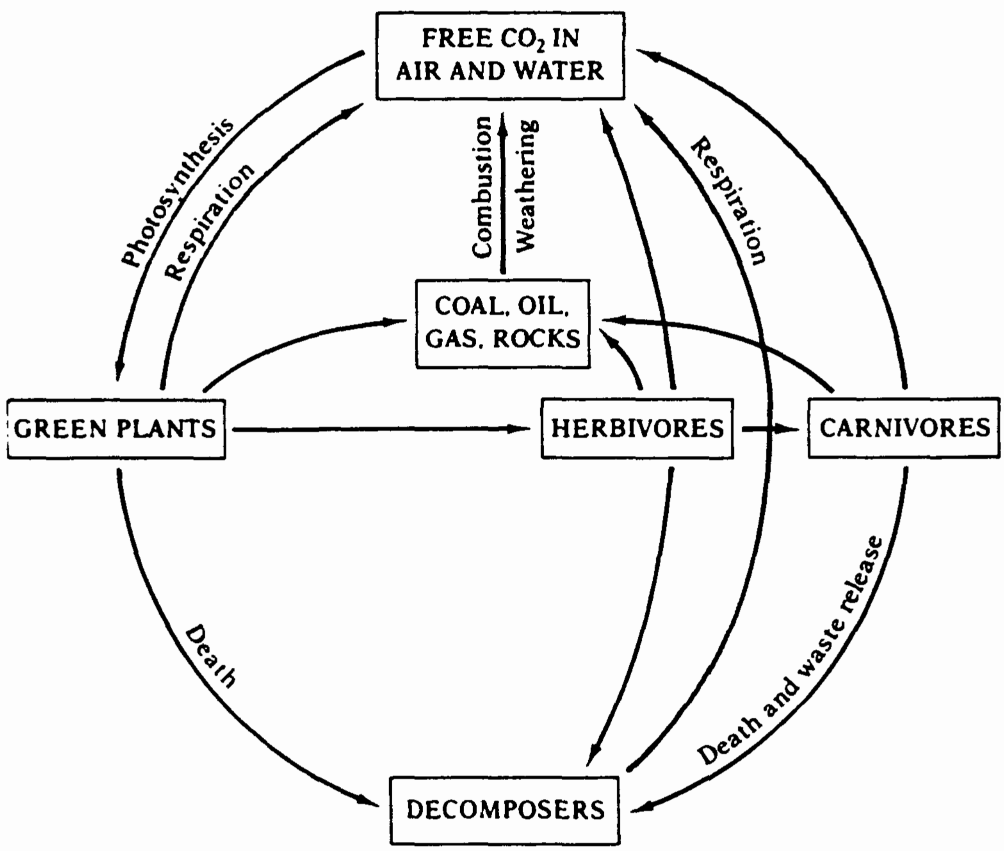
While biomass initially is formed as a solid (e.g., trees and other plants) the energy can be converted to liquid and gas forms. The primary thrust of the DOE biomass research program is the development of liquid transportation fuels, which are already used to some extent today. Anaerobic digestion of solid hydrocarbons by microbes produces biogas (whose primary component is methane) as a byproduct. Biomass is also gasified by thermal processes.

Traditional biomass fuelstocks used for the generation of electricity include wood, wood waste, and agricultural waste. Municipal solid waste (MSW) is a second major biomass fuelstock that is used for electricity production[1]. Biogas (methane produced by anaerobic digestion of organic matter) is

[1] MSW is considered to be a renewable biomass fuelstock here, even though it contains some amount of petroleum-based products, because it is composed largely of post-user biomass (mostly paper). It should become even more "renewable" in the near future as plastics and other petroleum products are separated from MSW for recycling

FIGURE IV - 1

The Carbon Cycle



Source: *Biological Science* by William T. Keeton, (New York, NY: W.W. Norton & Company, 1980).

the third type of biomass fuelstock considered in this analysis. Liquid fuels are not considered in this analysis of the potential contribution of renewable electric technologies because they are expected to be devoted primarily to providing energy for the transportation sector.

For each fuelstock there are a number pathways that can be taken for conversion to electricity. A number of technologies exist, or are being developed, for converting the energy stored in biomass to electricity. Figure IV-2 summarizes for the three fuelstocks the various conversion pathways that can be taken to produce electricity.

This chapter is divided into four main sections. The first section briefly describes the biomass resource bases considered in this study. The subsequent three main sections analyze the three biomass fuelstocks: (1) wood, wood waste, and agricultural waste; (2) MSW; and (3) landfill and digester gas. In each section, existing technologies for conversion to electricity are characterized, followed by a discussion of emerging technologies. Each section concludes with a market assessment of the fuelstock being considered and estimates of air pollution prevention potential.

BIOMASS RESOURCE BASE

The resource base for biomass is a function of the quantities of inputs, including land, machinery, and labor, devoted to biomass production as well as the productivity of the plant species and the land. Since biomass is a photoconversion process, like photovoltaic and solar thermal electric, its total resource base is limited in theory by the amount of solar insolation received by land upon which biomass can be grown (and by the availability of water and nutrients required for growth).

TOTAL U.S. RESOURCE BASE

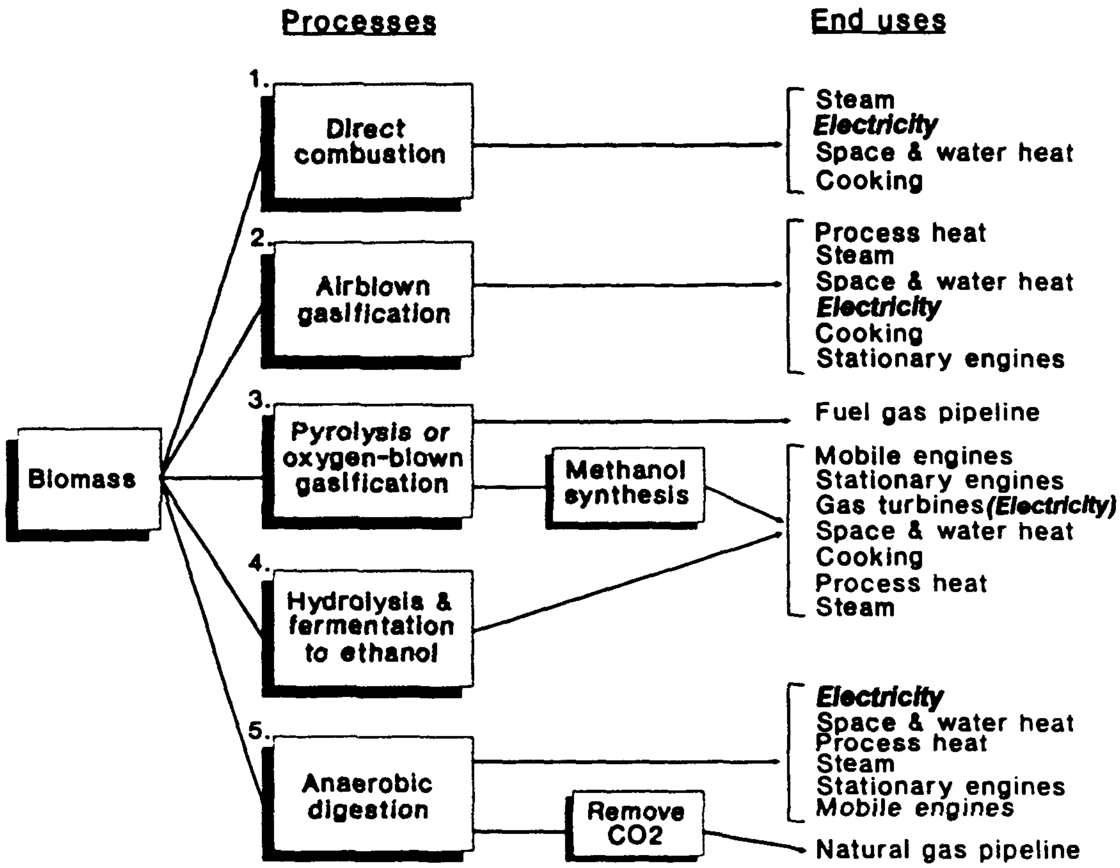
A recent study conducted by Meridian Corporation for DOE estimates the 30 year photoconversion energy resource at one million quads.[2] This value is the product of the average daily incident radiation on the surface of the U.S., about 4.32 kWh/m^2, and the proportion of the radiation which Meridian considers intense enough to be a potentially exploitable resource, which they estimate at 70%. Approximately 45% of the U.S. surface area is committed to uses such as national parks and cropland, which limits the accessible photoconversion resource base to approximately 600,000 quads. Biomass energy could account for only a portion of these totals, as the three photoconversion processes (PV, solar thermal, and biomass) are mutually exclusive. The estimated

---

[2] *Characterization of U.S. Energy Resources and Reserves*, prepared for the U.S. Department of Energy by Meridian Corporation, June, 1989. A quad is one quadrillion (10^{15}) Btu.

FIGURE IV - 2

Biomass Conversion Pathways



Examples of how biomass can be processed

Process number:	(see boxes above)
1,2,3,4	Wood & wood wastes
2,3,4	Agricultural crops
1,2,3,4	Crop residues
1,2,3,5	Municipal solid waste
5	Sewage sludge
5	Animal wastes
5	Aquatic plants

Source: *Changing by Degrees*, Office of Technology Assessment, 1991.

economic reserves of biomass represent a small fraction of this potential, amounting to about 10 quads per year.

An alternative estimation, based on more realistic assumptions concerning biomass photoconversion and the availability of biomass resources for energy production, places the theoretical maximum accessible resource base for biomass energy in the year 2000 at 54.9 quads. Approximately 14.6 quads, roughly 25 percent of the total, is potentially recoverable when considering the time and economic constraints that limit the installation of additional conversion equipment.[3] These estimates of the total and recoverable biomass resource base, and estimates for the various biomass sub-components, are presented in Table IV-1.

Biomass fuels generally come from one of two sources: (1) growing stocks of biomass, either trees or devoted energy crops, that are harvested specifically for conversion to electricity or (2) waste. Biomass as waste can exist in many forms, including municipal solid waste, agricultural and forestry residues, industrial waste (wood pallets), mill wastes (including waste wood and waste heat from mill operations used for cogeneration), and manure. While it is not desirable to maximize the production of by-products and waste for the sake of the energy they contain, the economic value of wastes ultimately generated can be maximized through conversion and/or recycling, often with positive environmental impact. The economic potential for transforming biomass wastes into useful energy is limited by the ability to collect and concentrate them for conversion. Growing stocks of biofuels, on the other hand, offer almost limitless potential for expansion. Maximization of this energy source can be achieved by dedicating more and/or better land to the production of dedicated energy crops and by increasing the productivity of species used. The widespread planting of Short Rotation Woody Crops (SRWC) is one way to increase output from this source, and has been estimated by DOE in a preliminary analysis to offer the annual potential for an additional 9 quads of energy, using conservative assumptions on land availability and economic feasibility.

In the U.S., biomass provides roughly 3 quads of primary energy, mainly for heat and steam. About 0.5 quads are used to produce electricity, with the bulk of current supply coming from cogeneration facilities in the wood, paper, and pulp industries. Many more resources are potentially available for expansion of biomass energy utilization. However, higher valued uses of these resources, inefficient resource management, and transportation constraints, among other factors, have all combined to raise fuel prices and add to supply uncertainties that compromise the economic viability of biomass electric generation.

---

[3] These figures are taken from "The U.S. Biofuels Industry" by Donald Klass found in *Energy from Biomass and Waste XIII*, (Chicago: The Institute of Gas Technology), 1990.

TABLE IV - 1 BIOMASS ENERGY CONSUMPTION AND POTENTIAL AVAILABILITY (quads)				
RESOURCE	1987	2000		
	Biomass Consumption	Biomass Consumption	Estimated Recoverable	Theoretical Maximum
Wood and Wood Wastes				
Industrial	1.85	2.1		
Residential	0.84	1.0		
Commercial	0.022	0.04		
Utilities	0.009	0.01		
Total	2.72	3.15	10.4	25.0
MSW (RDF and Mass Burn)	0.11	0.60	1.8	2.0
Agricultural & Industrial Wastes	0.04	0.08	1.2	17.1
Methane				
Landfill Gas Recovery	0.009	0.100	0.2	1.0
Digester Gas Recovery	0.003	0.004	0.15	1.1
Thermal Gasification	0.001	0.002		
Total	0.013	0.106	0.35	2.1
Other Biomass				
Ethanol	0.07	0.1		
Other Biofuels	0.0	0.1		
Aquatic Biomass			0.8	7.7
Miscellaneous Wastes			0.05	1.0
Total	0.07	0.2	0.85	8.7
TOTAL	2.95	4.14	14.6	54.9

Source: Adapted from "The U.S. Biofuels Industry," by Donald L. Klass in *Energy from Biomass and Wastes XIII*, ed. Klass, (Chicago: Institute of Gas Technology), 1990.

GEOGRAPHIC DISTRIBUTION

Table IV-2 presents current biomass electric capacity for wood and wood wastes, MSW, agricultural wastes, and landfill and digester gas for the twelve EPA model regions. As seen in this table, all regions have some biomass capacity, reflecting the maturity of this technology and the widespread availability of biomass fuels. The regional distribution of agricultural and silvicultural industries and MSW generation will determine the geographical range of future biomass fueled electric generation.

Wood and wood waste, the predominant biomass fuel, is available to some extent in all regions. However, these resources are generally concentrated in the traditional timber regions in the South, Northwest, and Northeast. Table IV-3 shows a projection of wood fuel use based on 1987 geographical patterns and a projection of total use in 2000. The South uses more than twice as much wood fuel as any other region. However, utility fuelwood use in all regions is currently very low compared with non-utility sources of generation (e.g., wood mill cogeneration); the national total was less than 0.01 quads in 1987. Limited commercial tree production for energy use occurs on roughly 50,000 acres in seven states, as shown in Table IV-4.

MSW resources (for mass burn, refuse-derived fuel, and landfill and MSW digester methane) generally follow regional population distribution. Regional estimates of current MSW generation and waste-to-energy capacity are presented in Table IV-5. Only Arizona/New Mexico, with some of the strictest air quality control standards in the country, currently lacks waste-to-energy capacity.

WOOD, WOOD WASTE, AND AGRICULTURAL WASTE

Wood and wood wastes together represent the single largest source of biomass fuel for electricity generation. Agricultural wastes (corn husks, rice husks, sugar cane residue, etc.) offer an additional source of fuel where they are geographically concentrated enough to be brought to a central site economically.

CONVERSION TO ELECTRICITY

Electricity has been produced from wood and, to a lesser extent, agricultural fuelstocks for many years. The technologies are well established and can be used to produce electricity economically in areas where biomass fuels are concentrated and available at low (or zero) cost.

TABLE IV - 2 BIOMASS ELECTRIC CAPACITY BY REGION IN 1990 (megawatts)					
REGION	Wood and Wood Waste	Municipal Solid Waste	Agricultural Waste	Landfill and Digester Gas	Biomass Total
New England	716	470	0	23	1,210
Mid Atlantic	90	442	*	110	642
South Atlantic	936	123	0	*	1,059
Florida	553	142	60	2	757
East North Central	387	172	0	55	614
West North Central	126	70	9	2	208
East South Central	967	7	25	3	1,002
West South Central	318	0	15	13	346
Mountain	82	32	0	8	122
Arizona/New Mexico	56	0	1	3	60
California	628	60	0	259	947
Washington/Oregon	567	66	0	10	643
Total	5,427	1,584	110	489	7,610

* Indicates electricity capacity of less than 0.5 MW.

Note: Totals may not equal sum of columns due to independent rounding.

Source: *The Power of the States*, by Nancy Rader, (Washington DC: Public Citizen) June, 1990.

TABLE IV - 3 WOOD FUEL CONSUMPTION BY END USE AND REGION IN 1987 (trillion Btu)						
Region	Residential	Industrial		Utility	Total	
	Total	Total	Electric[1]	Total	Total	Electric
Northeast	166	182	35	1.6	350	37
South	264	883	168	0.0	1,147	168
Midwest	250	222	42	2.1	474	44
West	172	290	55	4.9	467	60
Total	852	1,576	299	8.6	2,437	308

[1] Assuming that 19% of industrial cogeneration is for the production of electricity. Based on data in Table B-5 of *The Potential of Renewable Energy*, Interlaboratory White Paper, (Golden, CO: Solar Energy Research Institute, March 1990).

Source: *Estimates of Biofuels Consumption in the United States During 1987* (Washington, DC: Energy Information Administration), 1989.

TABLE IV - 4 COMMERCIAL TREE PRODUCTION FOR ENERGY USE					
State	Company/Municipality	Acres	Species	Rotation (yrs)	Comments
CA	Simpson Timber Co.	700	Eucalyptus	NA	NA
KY	West Vaco	16,000	Cottonwood, Sycamore	10	Primarily for pulp with some to fuel paper mills.
MI	Packaging Corporation of America	3,000	Hybrid Poplar	NA	NA
MD	Hagerstown	500	Hybrid Poplar	NA	Wastewater diposal site, energy use of wood planned.
NY	Reynolds Materials Co.	225	Hybrid Poplar	6	Captive energy use of wood planned.
NC	Union Corporation of North Carolina	22,000	Sweetgum	10	Captive for pulp with some to fuel paper mills.
NV	James River Corporation of Nevada	7,350	Hybrid Poplar	6	Captive for fiber and fuel for paper mills, larger plantings are planned.

NA: Not Available.

Source: "The U.S. Biofuels Industry" by Donald Klass in *Energy from Biomass and Wastes XIII*, (Chicago: The Institute of Gas Technology), 1990.

TABLE IV - 5
MSW GENERATION, WASTE TO ENERGY CAPACITY, AND TIPPNG FEES BY REGION

REGION	Biocyle Survey MSW Generation[1] (000 tons)	EPA/Franklin MSW Generation[2] (000 tons)	WTE Capacity[3] (000 tons/day)	Percent WTE	Tipping Fees[4] ($/ton)	WTE Tipping Fees[5] ($/ton)
New England	12,300	8,500	16.5	60%	$10 - 110	$63
Mid Atlantic	47,200	31,500	16.4	16%	$37 - 120	$72
South Atlantic	25,800	17,200	4.4	8%	$3 - 60	$39
Florida	16,000	10,700	9.3	27%	$10 - 65	$55
East North Central	48,700	32,500	8.5	8%	$8 - 29	$22
West North Central	15,300	10,200	4.8	14%	$4 - 90	$67
East South Central	14,700	9,800	2.3	7%	$5 - 20	$13
West South Central	25,800	17,200	1.8	3%	$0 - 42	$21
Mountain	6,000	4,000	1.5	12%	$10 - 50	$35
Arizona/New Mexico	4,100	2,700	0.0	0%	≤ $20	NA
California	44,000	29,300	1.2	1%	$3 - 30	$18
Washington/Oregon	7,600	5,000	1.3	8%	$26 - 75	$75
Total	267,900	178,600	67.9	12%	$0 - 120	$53

Sources:

1 "The State of Garbage in America" by J. Glenn, Biocycle (March 1990). State data aggregated to regions.

2 Characterization of Municipal Solid Waste in the United States: 1990 Update, Prepared for the Office of Solid Waste, Environmental Protection Agency by The Franklin Associates, June 1990. National totals allocated to regions according to distribution of MSW generation reported in Column 1.

3 Resource Recovery in the United States, National Solid Waste Management Association, September 1, 1989.

4 See Note 1. Range represents low and high costs of disposal options, including both landfilling and incineration.

5 Weighted average of incinerator tipping fees reported by state in Note 1. Where incinerator tipping fees was not available for a state, a value of 1.5 times the high landfill tipping fee for that state was used.

Existing Technologies

Direct combustion of wood and agricultural fuelstocks typically involves modifications of the technologies used to burn coal and include the following basic combustion system configurations: (1) **pile burners** involve the distribution of biomass fuel of variable dimensions to the furnace through an underfeed, overfeed, or spreader stoker with the fuel being piled on a grate to burn; (2) **cyclone and suspension burners** force the particulate biomass fuel into the combustion chamber with a pressurized air stream; (3) **fluidized bed burners** are similar to suspension burners but add a hot bed material such as sand or crushed limestone.

The DOE Clean Coal Technology Program (CCTP) has been exploring utility-scale atmospheric fluidized bed combustors (AFBC), a technology that has been used in smaller applications, primarily for coal, for many years. DOE expects utility-scale AFBC to be commercially available between 1995 and 2000, with widespread applications that could include biomass in addition to coal possible between 2000 and 2005.[4] In the near term, however, smaller scale AFBC offer the potential for immediate expansion of biomass electric capacity.

One of the key advantages of AFBC is fuel diversity, as demonstrated by successful operating experience at the Northern States Power French Island powerplant. French Island Unit 2 was retrofitted with AFBC in 1981, and Unit 1 was retrofitted in 1987; the plant currently burns a 50/50 mixture of wood waste and refuse-derived fuel.[5] A wide range of biomass/coal blends could also be burned in AFBC boilers. Utilities considering AFBC as a compliance option for revised Clean Air Act requirements may consider the partial or exclusive use of biomass fuels for these boilers. While CCTP funding of AFBC demonstrations is intended to expand the use of coal, stronger emphasis on biomass potential for demonstration projects is certainly consistent with the DOE goal of enhancing domestic energy capacity.[6]

As utilities face investment choices to maintain generation from older coal plants (about 200 gigawatts of coal-fired capacity -- more than two thirds of current capacity -- will be over 30 years old by 2010), repowering with AFBC boilers would represent a significant opportunity for expanding

---

[4] See *Clean Coal Technology: The New Coal Era* (Washington U.S. Department of Energy), November, 1989, p 36

[5] See "Waste Fuel Firing in Atmospheric Fluidized Bed Retrofit Boilers" by Jerome R. Zylkowski and Rudy J. Schmidt, in Klass, ed *Energy from Biomass and Wastes XIII*

[6] Although AFBC eliminates a large percentage of conventional air pollutants from coal, such as SO_2 and NO_x, the CO_2 emissions per kWh is actually slightly higher than a conventional coal plant because AFBC plants generally have slightly higher heat rates This underscores the need to consider co-firing coal with biomass fuels.

biomass utility generation and reducing coal use. Advancing biomass-compatible technologies would also promote U.S. technology export, since many countries have greater access to biomass fuels than coal.

Because biomass combustion technologies are based largely on existing coal combustion systems, direct combustion of biomass offers a unique opportunity of directly backing out coal consumption. The Santee Cooper electric utility in South Carolina has been cofiring waterlogged waste wood from hurricane Hugo at its Jeffries coal steam plant at a rate of 10 percent by weight without any decrease in efficiency.[7] Their experience suggests that wood fuel can be cofired with coal at a rate of up to about 20 percent by weight in some cases without derating the boiler. Throughput is limited by moisture content and chip size, so it is conceivable that smaller chips, dried using waste heat, could increase the potential for wood cofiring. Since combustion of wood fuel results in emissions of only trace amounts of SO_2 and NO_x, cofiring wood with medium to low sulfur coal could present a simple cost effective way of bringing existing plants that burn high sulfur coal into compliance with new Clean Air Act requirements. Refuse-derived fuel (RDF) processed from municipal solid waste represents another co-firing option that could reduce SO_2 emissions by displacing 10% to 20% of coal in an existing boiler.[8]

Wood has a heat content that is somewhat lower than most coal, with roughly 8 million Btu (mmBtu) per ton of green wood (about 17 mmBtu per dry ton)[9] compared to average values of 14 mmBtu for lignite, 18 mmBtu for sub-bituminous, and 24 mmBtu per ton of bituminous coal. Because the low energy density of wood requires a much greater volume of wood fuel than coal, burning only wood could limit total capacity due to constraints on transporting wood to the plant. The handling requirements of the two fuels are fairly similar once the wood fuel has been chipped. In fact, coal pulverizing equipment has been used at the Jeffries plant without any modifications to pound wood chips into particles for suspension burning, demonstrating that an existing coal-fired plant can use biomass fuelstocks with only minor modifications to fuel handling and processing equipment.

---

[7] See "Wood Chips Making Electricity" in *The Logger and the Lumberman*, May 1990.

[8] See "Effect of Co-combusting Refuse-derived Fuel and Coal on Emissions of SO_x, NO_x, and Ash from Coal-Fired Boilers," by Glenn A. Norton and Audrey D Levine, in *Energy from Biomass and Wastes XIII*, ed. Donald Klass, (Chicago Institute of Gas Technology). 1990

[9] The dry wood measure is used to normalize data and is defined as oven-dried wood having no water content, whereas green wood typically has a moisture content of 50 percent by weight. In practice, wood is not oven dried before being used, although in some systems it is dried to less than 25% water using waste heat.

Current Economics

Technologies for biomass conversion are well established, and are based on existing fossil fuel technologies. Competition with fossil resources for electricity generation is generally based on the relative prices of fuel inputs.

The capital costs of a conventional wood or agricultural waste fired electric generating plant range from $1,500/KW to $2,000/KW for plants between 30 MW and 50 MW. Because of the moisture content of biomass fuel, heat rates in the range of 12,000 to 16,000 Btu/kWh are typical. With the cost of biomass fuel in the range of $1.00 to $3.00 per million Btu, levelized generation costs are between 4 and 8 cents/kWh.

EMERGING TECHNOLOGIES

Biomass electric generation on a utility scale is not constrained by technology; in fact, biomass combustion technologies are very mature compared to some other renewable technologies. There are emerging conversion technologies that should make electricity generation from biomass more economic, including whole tree combustion and biomass gas turbines. The major factor currently constraining biomass electric generation is the economics of fuel supply. Emerging biomass production techniques, primarily the development of short rotation woody crops (SRWC), should dramatically increase the economic reserve of biomass fuelstocks in the coming decades.

Emerging Conversion Technologies

Continued advances in the fuel flexibility of coal technology may expand the amount of utility capacity that could use biomass fuels. Developing a whole tree combustion technology and a biomass gasifier driving a gas turbine or combined cycle steam turbine holds promise for increasing combustion efficiencies and minimizing costs of electricity generation from biomass. Examples of specific emerging biomass combustion technologies include:

Whole Tree Energy. A promising new approach to biomass combustion is the Whole Tree Energy (WTE) power generating plant developed by Energy Performance Systems, Inc.[10] This new technology lowers the overall generating costs for wood-fired generating plants by increasing the efficiency of wood handling and combustion, while also reducing emissions. Because the facility uses whole trees rather than processed wood chips, its fuel handling costs are less than traditional wood-

---

[10] See "Whole-Tree Combustion Avoids Fuel Preparation," by Jason Makansi in *Power*, October 1990.

fired plants. To improve the fuel, the WTE uses waste heat to dry the trees prior to combustion (reducing average moisture content from about 50% to under 25%). The boiler creates steam which is directed through a turbine to produce electricity in the conventional manner.

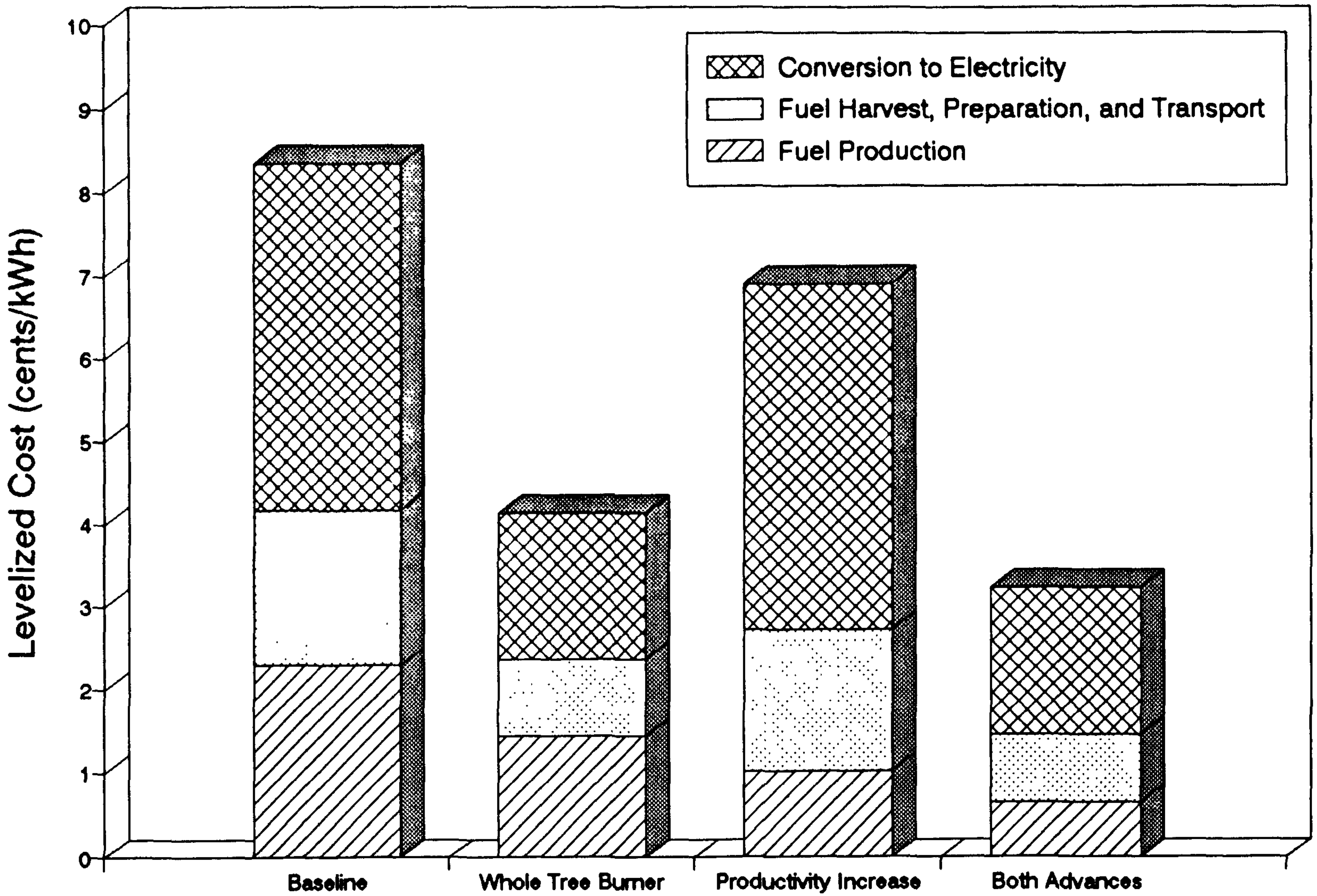
The pile-type combustor uses a three stage combustion process to burn the trees. The first stage of combustion occurs in the bed under oxygen-deficient (substoichiometric) conditions, during which volatile gases are emitted. These volatile gases are combusted in the second stage above the bed at very high temperatures (2700°F). Char produced in the first stage falls through the grate where it is combusted in the third stage. This combustion process results in a relatively high furnace efficiency (~87%) contributing to an overall power plant cycle efficiency of 33% - 36% as compared to conventional wood power plant cycle efficiencies of 20% - 30%. These increases in efficiency over conventional wood-burning technologies result in a much lower heat rate, about 10,000 Btu per kilowatt hour for WTE, compared to about 12,000 to 16,000 Btu per kilowatt hour for conventional wood-fired plants.

The lower heat rate, stemming from increased cycle efficiency, and lower capital and operating costs compared to conventional wood-burning plants, result in markedly lower levelized generation costs using WTE. Fuel costs related to harvest, preparation, and transport are reduced by using whole trees, rather than wood chips. Levelized fuel costs are reduced even further due to the lower heat rate for WTE. Relative electricity generation cost reductions associated with the use of WTE are illustrated in the first two bars of the graph presented as Figure IV-3.

New WTE plants could range in size from 25 to 400 MW, and the WTE system could also be used to retrofit old or out-of-service coal-fired plants. For both types of plants, fuel supply issues, such as the capacity for developing short rotation energy plantations nearby, are important factors involved in selecting plant sites. The WTE technology is in the development phase and has not currently been used commercially to generate electncity. Conversion of a coal-fired plant to a 60 to 80 MW WTE demonstration plant should be completed by the end of 1992. It is expected that once the technology is established, coal plant conversion would take about eighteen months and that construction of new plants will take two to three years.

Biomass Gasification and Combustion. The gas turbine is an existing technology widely used in natural gas power generation. Gas turbines are especially suited to biomass applications, because of their high thermodynamic efficiency compared to steam turbines, in small to medium size utility applications up to about 50 MW. In cogeneration applications, steam cycle generators have a thermal

FIGURE IV - 3
Wood Energy Cost Reductions



efficiency of 28 percent and a total efficiency of 35-62 percent, compared to 50 percent thermal efficiency and 76-81 percent total efficiency for gas turbines.[11]

The use of biomass fuelstocks does present some technical difficulties that require modification of existing gas turbine technologies. Currently, the major technical difficulty limiting the use of this technology is deposition on gas turbine blades. Hot gas cleanup technologies are advancing rapidly, however, and it is expected that over the next two decades these technologies will be refined to a point where deposition on the turbine blades no longer inhibits the use of directly-fired biomass gas turbines.

Thermal gasification involves heating biomass fuelstocks in a chamber containing air or pure oxygen, producing a low to medium Btu gas (100-250 Btu per standard cubic foot). Pyrolysis, an extreme form of thermal gasification, involves heating biomass fuelstocks at very high temperatures in the absence of any gases, producing a higher Btu gas (600-900 Btu/scf). Currently, air-blown reactors have the most potential for commercial application. The reactor can have either a fixed or fluidized bed. Fluidized bed reactors provide for more fuel flexibility, but result in higher levels of particulates in the hot gas. The hot gas is passed through cyclones to clean it of particles before being flashed in a combustion chamber to drive a gas turbine, generating electricity. Efficiencies can be increased by using combined cycle and steam-injected cycle technologies. In the steam-injected gas turbine (STIG), exhaust gas is used to produce steam that is injected into the pyrolytic chamber to augment power and efficiency by increasing hydrogen production. Figure IV-4 illustrates the processes involved in biomass gasification and combustion for a steam-injected gas turbine. STIG technology is especially useful in cogeneration applications where steam production is greater than the need for process heat. Gas turbine technology is commercially available now for fossil fuels, with ongoing research being conducted on improving hot gas cleanup technologies to increase operating efficiency with solid biomass fuels.

Costs

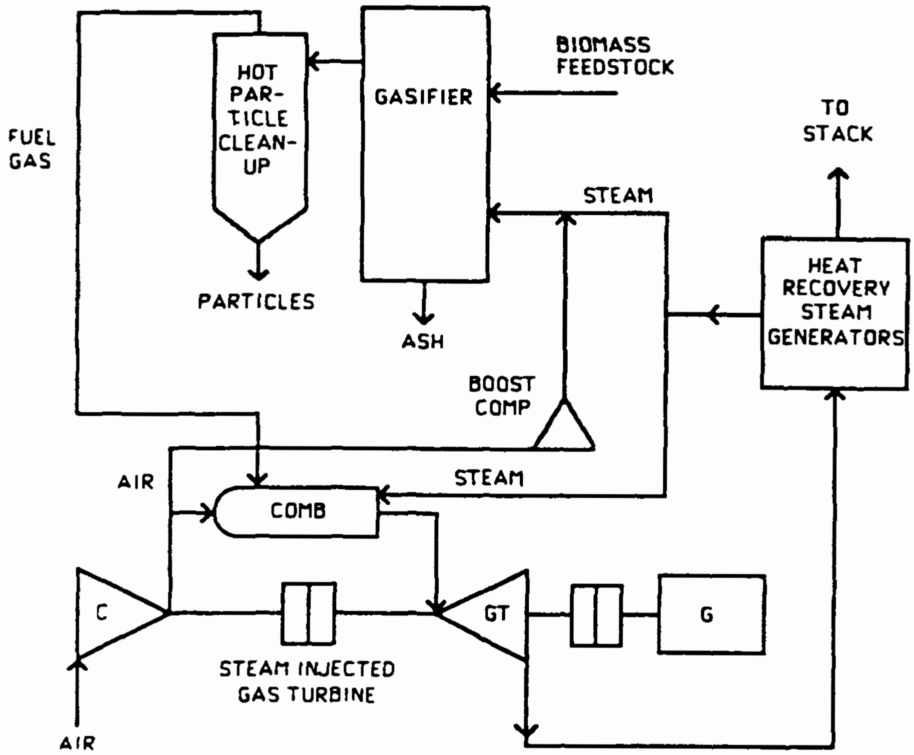
According to Energy Performance Systems, Inc, the developer of Whole Tree Energy, installed costs of a new WTE will range from \$800 to \$1100/KW. The installed costs for retrofitting an existing coal-fired plant range from \$300 to \$400/KW.

---

[11] See "Biomass Gasification for Gas Turbine Power Generation" by Eric Larson, et. al., in *Electricity: Efficient End-Use and New Generation Technologies and Their Planning Implications*, Thomas B. Johansson, Birgit Bodlund and Robert H Williams, eds (Lund, Sweden Lund University Press, 1989).

FIGURE IV - 4

Biomass Gas Turbine Schematic Diagram



C:	Compressor	G:	Generator
GT:	Turbine	COMB:	Combustor

Source: "Biomass Gasification for Gas Turbine Power Generation" by Eric Larson, et. al in *Electricity: Efficient End-Use and New Generation Technologies and their Planning Implications*, Thomas B. Johansson, Brigit Boblund and Robert H. Williams, eds. (Lund, Sweden: Lund University Press, 1989).

Biomass gas turbines generally have an installed cost between $900 - 1100/KW depending on the cycle configuration (i.e. combined cycle vs. steam injected). Depending on fuel costs (ranging from $2.50-3.00/mmBtu), generation costs for STIG range from 4.3 to 5.7 cents/kWh, roughly comparable to gas turbine costs for coal gasification and combustion.

Emerging Biomass Production Technologies

While advancements in biomass conversion technology will improve the economics of electricity generation, the primary obstacle confronting the biomass electric industry is the availability of inexpensive, reliable fuelstocks. Two means of increasing the availability of inexpensive biomass resources are: 1) increasing the recovery and use of wood, agricultural, and municipal solid wastes and 2) using short-rotation woody and herbaceous crops as feedstocks.

Increased Recovery of Biomass Wastes. Wood waste or logging residue is often produced from thinning of commercial stands, and from clear-cutting, where some waste must be removed in order to replant new trees. An estimated potential of 10.4 quads of energy could be recovered from wood waste by the year 2000. The cost of wood waste ranges from $1 to $3.30 per mmBtu and the cost of recovering logging residues is usually paid by the fuel user. In rural areas, slashing (open-air burning) of wood waste is preferred to disposal because of the cost of transporting the waste out of the forest. Possible future environmental regulations on slashing may force land managers to seek alternative waste disposal options, including increased utilization for energy.

Wood waste may also be generated from a secondary source such as mill residue, where waste transportation costs often keeps it on-site for use in cogenerating power for the mill. Mill wastes, however, are almost wholly utilized at present and are not expected to grow much in the future. In fact, residue factors (tons of residue per board feet) in the Pacific Northwest are expected to decrease by 30 percent over the next 20 years mainly because the pulp and paper industry is producing less waste and harvesting less old growth material.[12]

Agricultural waste includes the residues that remain after harvesting and the secondary residues that remain after the harvested crop is processed. About one quad of potential energy is estimated to be recoverable from agricultural residue in the year 2000. The use of agricultural residues as a feedstock for a stand-alone system faces the institutional problems and costs of collecting, storing, and delivery of residues from several individual farms to a power plant.

---

[12] See "Biomass Resources," by James D. Kerstetter, (Portland, OR: Northwest Power Planning Council, October 16, 1989).

While the use of existing biomass fuel sources can be expanded, especially the use of logging and construction waste wood and better management of underutilized forests, potential limitations and competing uses suggest that additional economic fuel sources will need to be developed in order for biomass electricity capacity to grow appreciably. Short-rotation woody crops (SRWC) offer the potential for dramatic growth in the supply of biomass fuels.

Short-Rotation Woody Crop (SRWC) Feedstocks. The potential for fast-growing, short-rotation fuel wood plantations is being explored as a means to develop a low cost, reliable fuel source. Biotechnology research seeks to improve the productivity of hybrid biomass energy crops through selection and genetic alterations. In demonstration stands and pilot projects, SRWC have been grown successfully in most regions of the U.S., using species tailored to each region and land type. Table IV-6 lists representative species for various regions of the country, presents aggregated data on current yields and costs, and defines SRWC program goals.

Currently, crops are harvested every 3 to 10 years with average annual yields of 3 to 8 dry tons per acre per year. The goal of the SRWC program is to achieve yields of 8 to 12 dry tons per acre per year. Although SRWC yields can be high on marginal croplands, optimum conditions and intensive culture are needed to achieve maximum yields.

The amount of land potentially available for SRWC plantations dedicated to energy crops depends on the economics of biomass fuels, including the relative prices of fossil fuels and other, higher valued uses, like food crops and fiber. The potential land base for energy crops is enormous, with estimates ranging from 78 to over 230 million acres, including both marginal land and surplus prime cropland.[13] If 230 million acres were planted with crops yielding 5 dry tons per acre per year (a conservative estimate of future SRWC yields), over 13 quads of primary energy equivalent could be produced each year.[14]

Even greater production can be achieved by increasing yields of SRWC species. For instance, increasing the yield per acre from 5 to 6 dry tons would boost the energy potential for planting on 230 million acres from 13 to 16 quads. All other things being equal, unit costs of production should decrease in proportion to the increase in productivity. Higher land and treatment

---

[13] See "Expanding the Market by Improving the Resource" by L.L. Wright, et. al, Biologue (June/July/August 1989)

[14] Assuming a heat content of 17×10^6 Btu per ton of dry wood and an electric conversion factor for wood of 15,000 Btu/kWh The current average fossil fuel conversion factor in the U.S. (10,253 Btu/kWh) is used to calculate primary equivalent Improvements in combustion technology to 10,000 Btu/kWh would bring the primary energy potential to almost 20 quads per year

TABLE IV - 6 SHORT ROTATION WOODY CROPS (SRWC) PROGRAM STATUS AND GOALS BY REGION				
	Current Research Status		Program Goals	
Regions/Promising Species	Average Yield Dry T/acre/yr	Average Cost $/mmBtu	Average Yield Dry T/acre/yr	Average Cost $/mmBtu
Pacific Northwest Black Cottonwood Hybrid Cottonwood Red Alder	8	2.20	12	1.90
Subtropics Eucalyptus	8	2.20	12	1.90
Lake States/Midwest Hybrid Poplar Alder Black Locust Willow Aspen Ailanthus Siberian Elm Silver Maple Autumn Olive	4	3.00	9	1.90
South Sycamore Black Locust Cottonwood Sweetgum	3	3.30	8	1.90
Northeast Hybrid Poplar Black Locust Maple	5	3.00	8	2.30
Semiarid Southwest Mesquite Fourwing Saltbush	NA	NA	NA	NA

NA: Not Available.

Source: Adapted from "Accelerating Energy Crop Growth Via Genetic Techniques," by Patricia Layton, et. al, in *Energy from Biomass and Wastes XIII*, ed. Donald Klass, (Chicago: Institute of Gas Technology), 1990.

"Short Rotation Intensive Culture for the Production of Energy Feedstocks in the US: A Review of Experimental Results and Remaining Obstacles to Commercialization," by R.D. Perlack, et. al, *Biomass* 9(1986) p. 145-159.

costs would most likely offset the reduction in unit costs, but in some cases the increase in productivity could be greater than the increase in input costs, causing unit costs of production to fall. Higher productivity could decrease fuel delivery costs as well, if a greater proportion of wood fuel is produced closer to the point of consumption. The relative effects of increased productivity on levelized electricity generation are illustrated in Figure IV-3.

There are many advantages of short rotation energy crops in addition to providing an abundant source of fiber or biomass energy fuelstocks. SRWC crops generally require less maintenance than traditional food crops, requiring weed control only through the first year or two of growth. Additionally, fewer chemical fertilizers and herbicides are needed compared to commercial food crops, reducing groundwater impacts. Woody crops can also be used to treat waste water and sewage sludge by recycling nutrients in these wastes. Organic wastes produced by municipalities and industries are often treated in large, capital intensive water treatment plants, with sewage sludge often landfilled in the end. An alternative organic waste treatment and disposal strategy is to couple waste water treatment with SRWC technology. Some cities, including Seattle, Washington and Edenton, North Carolina have already established SRWC plantations for waste disposal. SRWC waste treatment involves pumping organic wastes onto a SRWC plantation where the rapidly growing trees recycle the nutrients, preventing them from fouling surface and groundwater. Prior treatment of the waste may be needed in some instances to remove heavy metals and other pollutants that may not be adequately removed by the growing trees. If this practice is found to be environmentally acceptable on a large scale, SRWC production could increase considerably.

MARKET ASSESSMENT

Table IV-7 shows the DOE/SERI projections and EPA technology penetration scenarios for wood and wood waste generation. The EPA Base Case for wood and wood waste essentially equals the DOE/SERI Business as Usual Scenario, where electricity generation is projected to equal about 70 million MWh in 2000 and over 100 million MWh in 2010.

The EPA Enhanced Market scenario for solid combustion biomass electric generation builds on the DOE/SERI National Premiums projection. This assumes that market enhancement would stimulate existing markets for wood, wood waste, and agricultural waste fuel in much the same way as premiums placed on fossil fuel generation. Assuming that these traditional biomass sources are exhausted under the DOE/SERI National Premiums projection, the bulk of the increased biomass generation in the EPA Enhanced Market scenario comes from an aggressive short-rotation woody crop (SRWC) planting program for marginal or environmentally sensitive crop and pasture land. Most of this land is being eroded rapidly by either wind or water, and requires the planting of a cover crop.

TABLE IV - 7
WOOD AND WOOD WASTE SCENARIOS

Scenario	Capacity 2000 (MW)	Generation 2000 (GWh)	Capacity 2010 (MW)	Generation 2010 (GWh)
DOE/SERI				
Business as Usual	11,200	68,300	17,500	108,300
Intensified RD&D	12,800	78,000	18,800	116,100
National Premiums	17,500	108,300	18,000	111,200
EPA				
Base Case	11,200	68,300	17,500	108,300
Enhanced Market	28,800	182,100	71,200	376,000
1990:	5,500	31,500		

When managed properly, short rotation trees can provide adequate protection from erosion and provide a reliable source of fuel for power generation.

Over 260 million acres of crop and pasture land are presently eroding or are environmentally sensitive and would benefit from being enrolled in a program that takes them out of agricultural production, such as the Conservation Reserve Program (CRP).[15] EPA assumes that 25 percent of the available land base will be planted with SRWC over the next twenty years in all regions except for the Arizona/New Mexico and Mountain regions, where SRWC is not expected to be viable on a large scale. Slightly over 60 million acres are assumed to be planted nationwide over a twenty year period, averaging about three million acres per year. Given that SRWC technology is still developing, less land could be planted in early years; EPA assumes that 1.5 million acres are planted in the first year and that the acreage converted to SRWC each year increases linearly until 2010 when 4.5 million acres are planted.

Under these conditions, a total of roughly one quad of additional wood fuel will be available for electricity generation in 2000 rising to 3.5 quads in 2010 at an average price of roughly $2.70 per

[15] See "Costs of Sequestering Carbon through Tree Planting and Forest Management in the United States" by Robert Moulton and Kenneth Richards, USDA Forest Service General Technical Report, 1990.

million Btu (mmBtu). This assumes that all SRWC supply is utilized as fuel for electric power; other higher valued uses for the crops, such as pulp or liquid fuel production, could limit the fuel supply for electric power. Fuel prices for SRWC range from about $2.10/mmBtu in Washington/Oregon to almost $3.50/mmBtu in the Northeast. Costs and emissions for both EPA scenarios are calculated under the assumption that 75% of the wood-fired capacity built between 1990 and 2000 would be conventional plants, and the other 25% would be Whole Tree Energy (WTE) systems. Between 2000 and 2010, the Base Case assumes that conventional systems and WTE systems each gain 50% of the market, while in the Enhanced Market scenario, conventional systems account for 40%, WTE systems account for 40%, and biomass gas turbines account for 20% of new capacity built.

The incremental generation, costs, and air pollution prevention potential for wood fueled electricity generation are shown on Tables IV-8 and IV-9. The growth of wood-fired generation in the Base Case is concentrated in the South (South Atlantic, East South Central and Florida regions) and far West (California and Washington/Oregon). The increased generation in the Enhanced Market scenario reflects the vast potential for SRWC in the Central regions. More than two-thirds (68%) of the 1990-2010 incremental biomass solid generation occurs in East and West North Central and East and West South Central regions.

Costs

In the Base Case, the average cost of solid biomass combustion is roughly 8.0 ¢/kWh in 2000, or 3.0 ¢/kWh more expensive than conventional fossil fuel baseload generation. This cost falls to 7.0 ¢/kWh by 2010, when biomass solid combustion is only 0.6 ¢/kWh more expensive than conventional energy sources. Costs are similar in the Enhanced Market scenario, reflecting the fact that policies to stimulate a rapid expansion of wood-fueled electric capacity would be necessary to overcome the relatively high fuel prices for solid biomass fuels. In the Enhanced Market scenario, this stimulus comes from a recognition of the environmental benefits of biomass fuels (e.g. the 2 ¢/kWh premium assumed in the DOE/SERI National Premiums case) that results in increased use of traditional biomass sources as well as an aggressive SRWC fuel supply program. It is also important to note that these cost figures do not include the substantial environmental benefits obtained by reducing topsoil erosion from the SRWC planting program.

Costs variation is evident across regions in both scenarios. In the Base Case, traditional commercial wood product industries supply fairly low cost fuel in the Northeast and Northwest/Mountain regions. By 2010, biomass generation is less expensive than conventional generation in the Northeast and California, in part because of high avoided costs in those regions. Regional costs in the Enhanced Market scenario are somewhat different. The costs in the Northeast

TABLE IV - 8

ELECTRICITY GENERATION COSTS AND AIR POLLUTION PREVENTED

EPA BASE CASE

BIOMASS ELECTRIC - SOLID

REGION	AVERAGE UNIT COST IN 2000 (cents/kWh)			AVERAGE UNIT COST IN 2010 (cents/kWh)		
	AVOIDED FOSSIL	BIOMASS SOLID	COST DIFFERENCE	AVOIDED FOSSIL	BIOMASS SOLID	COST DIFFERENCE
Northeast	5.9	7.3	1.4	8.1	6.4	-1.7
Southeast	4.9	8.1	3.1	6.0	7.1	1.1
Southwest	5.1	8.6	3.5	6.7	7.6	0.9
North Central	4.8	8.6	3.8	5.3	7.6	2.2
Northwest/Mountain	4.9	7.3	2.4	5.1	6.4	1.3
California	4.6	8.6	4.0	7.8	7.6	-0.2
AVERAGE	**5.0**	**8.0**	**3.0**	**6.4**	**7.0**	**0.6**

REGION	INCREMENTAL GENERATION 1990 - 2010 (GWh/yr)	AIR POLLUTION PREVENTED 1990 - 2010 (thousand metric tons/yr)						
		SO_2	NO_x	Particulate Matter	CO	CH_4	CO_2	CO_2 Equivalent
Northeast	11,181	52.4	8.6	-1.78	-16.00	0.08	8,173	8,470
Southeast	35,206	267.5	76.1	-2.82	-50.60	0.30	33,068	35,966
Southwest	5,402	6.4	9.1	-1.09	-7.68	0.02	3,894	4,235
North Central	7,244	77.7	19.6	-0.41	-10.42	0.06	7,307	8,060
Northwest/Mountain	8,996	54.0	26.2	-0.24	-13.00	0.09	9,539	10,550
California	8,702	-0.7	6.6	-2.47	-12.33	0.02	4,628	4,857
TOTAL	**76,731**	**457.4**	**146.2**	**-8.82**	**-110.04**	**0.58**	**66,608**	**72,138**

TABLE IV - 9

ELECTRICITY GENERATION COSTS AND AIR POLLUTION PREVENTED

EPA ENHANCED MARKET SCENARIO

BIOMASS ELECTRIC - SOLID

REGION	AVERAGE UNIT COST IN 2000 (cents/kWh)			AVERAGE UNIT COST IN 2010 (cents/kWh)		
	AVOIDED FOSSIL	BIOMASS SOLID	COST DIFFERENCE	AVOIDED FOSSIL	BIOMASS SOLID	COST DIFFERENCE
Northeast	5.6	7.5	1.9	6.1	6.6	0.5
Southeast	4.9	7.9	3.0	5.7	6.4	0.7
Southwest	5.1	7.7	2.6	6.9	6.1	-0.7
North Central	4.8	7.8	3.1	5.3	6.5	1.2
Northwest/Mountain	5.0	7.1	2.2	5.0	5.8	0.7
California	4.6	8.5	3.9	7.8	7.1	-0.7
AVERAGE	**4.9**	**7.8**	**2.8**	**5.7**	**6.4**	**0.7**

REGION	INCREMENTAL GENERATION 1990 - 2010 (GWh/yr)	AIR POLLUTION PREVENTED 1990 - 2010 (thousand metric tons/yr)						
		SO_2	NO_x	Particulate Matter	CO	CH_4	CO_2	CO_2 Equivalent
Northeast	24,299	154.6	37.9	-2.73	-34.86	0.20	20,716	22,133
Southeast	96,148	785.1	234.7	-6.21	-136.26	0.84	93,528	102,526
Southwest	45,220	45.9	71.8	-9.62	-61.63	0.17	30,671	33,363
North Central	144,741	1385.2	398.6	-6.53	-198.26	1.27	145,326	160,702
Northwest/Mountain	22,810	145.5	67.2	-0.50	-32.73	0.22	24,305	26,899
California	11,245	-1.1	8.0	-3.31	-16.52	0.02	5,980	6,252
TOTAL	**344,464**	**2515.4**	**818.2**	**-28.90**	**-480.26**	**2.73**	**320,527**	**351,874**

are higher than Base Case costs in 2010 (primarily because SRWC land prices are high), but are lower in other regions. Avoided costs are lower in the North Central region (where a large amount of SRWC fuel can be grown) than in other regions, resulting in a cost differential of 1.2 ¢/kWh for wood-fired generation in this region.

Air Pollution Prevented

An expansion of biomass solid fuel-fired electricity would reduce NO_x, SO_2 (or create emission allowances under the new Clean Air Act), CH_4 and CO_2, but would slightly increase CO and PM from electricity generation. In the Enhanced Market scenario, 818,000 metric tons of NO_x could be prevented annually in 2010, and allowances for 2.5 million metric tons of SO_2 could be obtained. About 321 million metric tons of CO_2 could be prevented, assuming that solid biomass fuels are grown on a sustainable basis. Although the increased emissions of CO and PM warrant concern, they are relatively small compared to other sources of these pollutants. For example, the 29,000 metric ton increase in PM represents only 7% of 1988 utility PM emissions (and a negligible fraction of PM from all sources), while the 480,000 metric ton increase in annual CO emissions represents only 0.8% of CO emission from all sources in 1988.

MUNICIPAL SOLID WASTE

Characteristics of MSW vary considerably by regional demographics, local waste management laws (i.e. recycling programs), season, relative contribution of commercial and residential wastes, among other things, but can be described generally as being composed of about 70-75 percent organic matter (mostly paper) and containing about 4,500 Btu/lb. The organic component of MSW, comprised mostly of wood and paper wastes, can be separated from the waste stream in a resource recovery plant and processed to form refuse-derived fuel (RDF). RDF is a higher energy fuel (about 6,000 Btu/lb) that can be burned alone or with other biomass fuelstocks.

CONVERSION TO ELECTRICITY

Existing Technologies

"Mass burn" MSW combustion systems are similar to coal combustion technologies, although significant modification of these technologies is required because of the unique characteristics of MSW fuelstocks. RDF combustion systems are similar to conventional coal or wood-waste boilers, and some RDF plants can utilize RDF mixed with coal or wood waste. With both RDF and mass burn, flue gases must be cleaned to remove pollutants. The flue gases pass from the incinerator through a lime spray dry scrubber that removes sulfur dioxide (SO_2), hydrochloric acid (HCl), and other gases and then to a bag house that captures fly ash containing heavy metals, dioxins, furans, and other toxic compounds. Fly and bottom ash, because they contain these toxins, must be treated as a special waste. One way to dispose of incinerator ash is to place it in a lined landfill dedicated to incinerator ash and to monitor for any leaching that might occur.

Current Economics

MSW combustion is relatively costly due to the need for extensive pollution controls, ash landfilling costs, higher fuel handling costs due to the bulky nature of the fuel, and low energy content of the MSW. Waste disposal needs, and not the economics of energy production, determine whether waste-to-energy plants are built. However, if a community decides to incinerate waste, revenues from electricity sales can help offset the costs of waste disposal so that waste-to-energy plants can provide for waste disposal at a lower cost in certain areas.

The cost of a municipal solid waste-to-energy plant can range from $4,750/KW to $5,100/KW for capital and fixed operating costs and from 10 to 20 mills/kWh for operating costs, depending on whether mass burn or RDF technologies are used. Costs for RDF facilities are generally at the high end of these ranges because of the greater plant complexity and fuel handling requirements. The high cost of waste-to-energy facilities is partially offset by the negative fuel cost, i.e the cost of alternative waste disposal options. As shown on Table IV-5, tipping fees for MSW disposal range from over $100/ton in some urban areas of the Northeast to less than $20/ton in less densely populated areas. Tipping fees are generally set by the municipality with the intent to cover a portion of the costs of a waste-to-energy plant, with tax revenues and electricity sales revenue accounting for the remaining costs and profit for the operator.

EMERGING CONVERSION TECHNOLOGIES

The primary emerging conversion technology for combustion of MSW is the atmospheric fluidized bed burner (described in the preceding section on wood and agricultural fuelstocks). The development of "clean" burning technologies for MSW combustion is paramount to its future viability. Many of the pollution-related institutional barriers surrounding MSW combustion can be overcome by combining source separation and RDF production with combustion technologies like AFBC.

Thermal gasification of RDF fuelstocks for gas turbine electrical generation is an additional conversion pathway currently being developed for MSW. Development of this technology is following the same path as described in the preceding section and could provide a viable alternative to direct combustion technologies.

The amount of municipal solid waste available for energy conversion is much larger than current use, which is a little more than 0.1 quads. Only about 12% of MSW is incinerated, and not all incinerators have waste-to-energy conversion equipment. The remainder is currently landfilled, sequestering carbon in the short to medium term and producing biogas in the future. Many communities face rising costs of waste disposal, and state and federal waste minimization policies are likely to be implemented in the future. Even with successful waste minimization, however, future MSW electricity production will be limited by the capacity of plants, not by availability of MSW fuel.

MARKET ASSESSMENT

The Base Case and Enhanced Market scenarios for electricity production from municipal solid waste (MSW) are based on EPA projections of available MSW. MSW generation is expected to rise from the current 180 million tons per year to 216 million tons in 2000 and 250 million tons in 2010. In the Base Case, the share of MSW generation accounted for by waste-to-energy in 2000 and 2010 is expected to equal 15% and 25%, respectively. In the Enhanced Market scenario, these percentages are assumed to increase to 25% in 2000 and 33% in 2010. MSW could supply roughly 33 million MWh in 2000 and 50 million MWh in 2010. These are compared with the DOE/SERI projections on Table IV-10.

Tables IV-11 and IV-12 summarize the model results for MSW combustion. Increases in MSW generation are concentrated in regions with significant urban populations. In the Base Case, 70% of 1990-2010 incremental MSW generation occurs in the Northeast, Southeast, and North Central regions. These regions also account for 68% of the incremental MSW generation in the Enhanced Market scenario.

<u>Costs</u>

With construction costs around $5,000 per kilowatt of capacity, MSW facilities are extremely expensive to build. However, MSW fuel is obtained at negative costs. The cost of MSW generation is difficult to forecast due to uncertainty over future tipping fees charged by operators to dispose of the waste. Because of dwindling landfill space, such fees could easily rise sufficiently to dramatically reduce the cost of MSW generation.

TABLE IV - 10 MSW SCENARIOS				
Scenario	**Capacity 2000 (MW)**	**Generation 2000 (GWh)**	**Capacity 2010 (MW)**	**Generation 2010 (GWh)**
DOE/SERI				
Business as Usual	3,400	19,500	7,700	43,900
Intensified RD&D	4,500	25,400	9,800	55,600
National Premiums	5,800	33,200	14,400	81,900
EPA				
Base Case	3,200	19,900	5,600	37,800
Enhanced Market	4,900	32,600	7,200	49,800
1990:	2,200	12,700		

EPA did not attempt to forecast regional tipping fees in this analysis. The overall cost of MSW generation was assumed to equal the avoided conventional cost, reflecting the widespread practice of setting tipping fees at rates high enough to cover the MSW facility costs not recovered in electricity sales. To the extent that the cost of alternative disposal methods rise above these implicit tipping fees, however, the costs reported here represent high estimates of MSW generating cost.

Air Pollution Prevented

Although MSW combustion creates emissions and expanded MSW generation has only modest net air pollution prevention potential, additional MSW generation would provide a net decrease in NO_x, SO_2, CH_4, and CO_2. The CO_2 result assumes that MSW combustion creates no net CO_2 emissions because the organic component of MSW would eventually oxidize and escape from landfills. By 2010, roughly 50,000 metric tons of NO_x, 220,000 metric tons of SO_2, and 32 million metric tons of CO_2 are prevented in the Enhanced Market scenario. On the other hand, net CO emissions would increase by 15,000 metric tons and PM emissions could increase by over 380,000 metric tons

TABLE IV - 11

ELECTRICITY GENERATION COSTS AND AIR POLLUTION PREVENTED

EPA BASE CASE

BIOMASS ELECTRIC - MSW

REGION	AVERAGE UNIT COST IN 2000 (cents/kWh)			AVERAGE UNIT COST IN 2010 (cents/kWh)		
	AVOIDED FOSSIL	BIOMASS MSW	COST DIFFERENCE	AVOIDED FOSSIL	BIOMASS MSW	COST DIFFERENCE
Northeast	5.0	5.0	0.0	6.4	6.4	0.0
Southeast	5.0	5.0	0.0	6.1	6.1	0.0
Southwest	5.1	5.1	0.0	6.7	6.7	0.0
North Central	4.8	4.8	0.0	5.3	5.3	0.0
Northwest/Mountain	4.9	4.9	0.0	5.1	5.1	0.0
California	4.6	4.6	0.0	7.8	7.8	0.0
AVERAGE	**4.9**	**4.9**	**0.0**	**6.3**	**6.3**	**0.0**

REGION	INCREMENTAL GENERATION 1990 - 2010 (GWh/yr)	AIR POLLUTION PREVENTED 1990 - 2010 (thousand metric tons/yr)						
		SO_2	NO_x	Particulate Matter	CO	CH_4	CO_2	CO_2 Equivalent
Northeast	6,252	43.5	7.9	-64.23	-2.58	0.05	5,699	6,008
Southeast	5,349	36.6	6.9	-54.95	-2.20	0.05	4,887	5,159
Southwest	2,591	2.5	2.5	-26.91	-1.03	0.01	1,855	1,954
North Central	5,884	61.3	11.8	-60.28	-2.44	0.05	5,901	6,365
Northwest/Mountain	1,248	5.2	2.7	-12.76	-0.52	0.01	1,296	1,402
California	3,762	-1.1	0.3	-39.38	-1.48	0.01	2,001	2,009
TOTAL	**25,086**	**148.1**	**32.1**	**-258.51**	**-10.25**	**0.18**	**21,639**	**22,897**

TABLE IV - 12

ELECTRICITY GENERATION COSTS AND AIR POLLUTION PREVENTED

EPA ENHANCED MARKET SCENARIO
BIOMASS ELECTRIC - MSW

REGION	AVERAGE UNIT COST IN 2000 (cents/kWh)			AVERAGE UNIT COST IN 2010 (cents/kWh)		
	AVOIDED FOSSIL	**BIOMASS MSW**	**COST DIFFERENCE**	**AVOIDED FOSSIL**	**BIOMASS MSW**	**COST DIFFERENCE**
Northeast	4.8	4.8	0.0	6.4	6.4	0.0
Southeast	4.9	4.9	0.0	6.1	6.1	0.0
Southwest	5.1	5.1	0.0	6.7	6.7	0.0
North Central	4.8	4.8	0.0	5.3	5.3	0.0
Northwest/Mountain	4.9	4.9	0.0	5.1	5.1	0.0
California	4.6	4.6	0.0	7.8	7.8	0.0
AVERAGE	**4.8**	**4.8**	**0.0**	**6.3**	**6.3**	**0.0**

REGION	INCREMENTAL GENERATION 1990 - 2010 (GWh/yr)	AIR POLLUTION PREVENTED 1990 - 2010 (thousand metric tons/yr)						
		SO_2	NO_x	Particulate Matter	CO	CH_4	CO_2	CO_2 Equivalent
Northeast	8,517	61.5	11.6	-87.44	-3.52	0.07	7,909	8,364
Southeast	7,838	55.2	10.8	-80.48	-3.23	0.07	7,260	7,682
Southwest	4,065	3.9	4.0	-42.23	-1.62	0.02	2,919	3,076
North Central	8,818	93.6	17.9	-90.30	-3.65	0.08	8,911	9,616
Northwest/Mountain	1,868	7.9	4.0	-19.09	-0.78	0.02	1,947	2,106
California	5,965	-1.8	0.5	-62.44	-2.34	0.01	3,172	3,185
TOTAL	**37,071**	**220.4**	**48.7**	**-381.98**	**-15.15**	**0.27**	**32,119**	**34,029**

LANDFILL AND DIGESTER GAS

Anaerobic digestion of MSW and agricultural wastes (including crop residues and animal manure) and the capture of naturally occurring methane from landfills also contribute to energy production from biomass. Anaerobic digestion of biomass fuelstocks produces medium Btu biogas that can be upgraded to pipeline quality gas, although it is often more economical to burn the biogas on site to produce electricity. Biogas is produced under anaerobic conditions as organic matter is broken down by microorganisms. By providing optimal conditions (i.e. temperature and nutrients) biogas production can be maximized in a digester. The design of anaerobic digesters is advancing rapidly, with recent designs linking a number of digester tanks in series to maximize efficiency.

Landfill methane is a volatile organic compound (VOC) as well as a potent greenhouse gas (having 20 times the impact on warming per kilogram compared to carbon dioxide over a 100-year timeframe). Captured methane can be flared (converted to CO_2), burned on-site for process heat or steam, upgraded to pipeline quality gas, or used to generate electricity. Capturing landfill methane that otherwise would have escaped to the atmosphere and using it to produce energy effectively reduces greenhouse gas emissions by the amount of carbon dioxide that would have otherwise been emitted to produce that amount of energy and the amount of methane that is captured.

CONVERSION TO ELECTRICITY

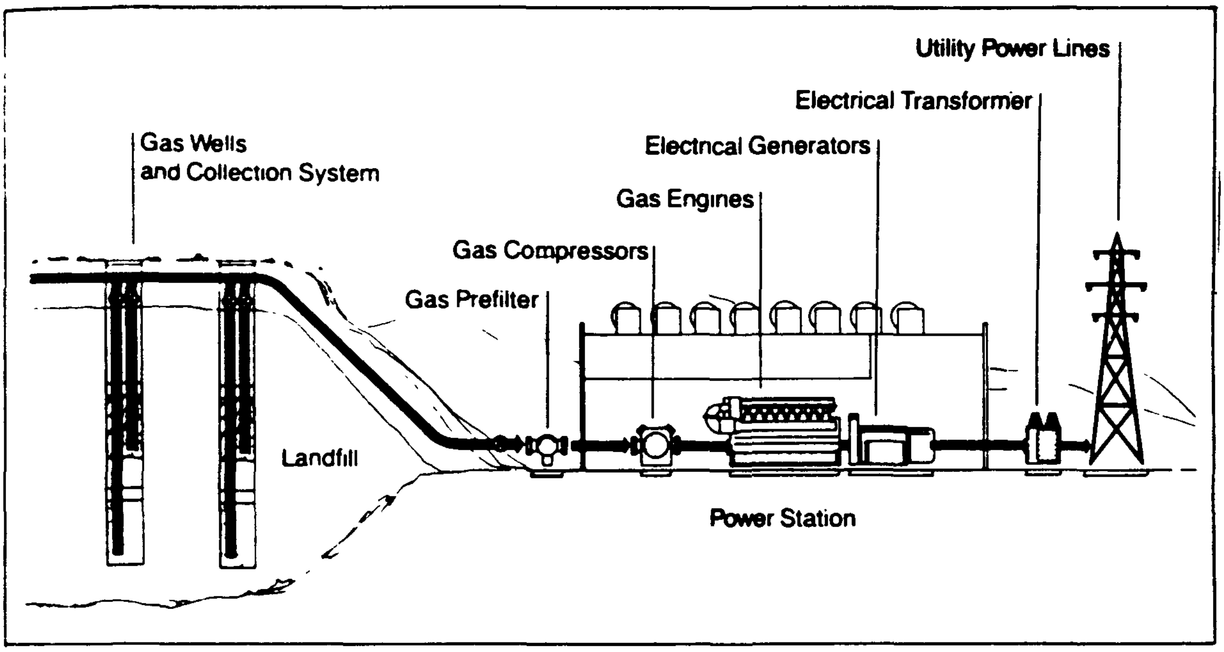
There are two stages involved with the generation of electricity from biogas. First, the biogas must be produced and collected, then delivered to an appropriate conversion technology for electricity generation. Figure IV-5 presents a diagram of a typical landfill gas collection and conversion facility.

Gas Production/Collection

Municipal solid waste landfills produce a gas produced through microbial degradation of the organic component of MSW under the anaerobic conditions that commonly occur in landfills. This gas typically consists of 55 percent methane, 44 percent carbon dioxide, and one percent other trace gases. Landfill gas is tapped by drilling recovery wells 30 to 100 feet deep and connecting plastic pipes from the wells to a central collection facility. The gas can then be used as a fuel source for industrial burners, boilers or electric generation. The carbon dioxide and moisture can be also be removed to upgrade the gas to pipeline quality, which in some cases may be a higher valued use of biogas than electricity production.

FIGURE IV - 5

Landfill Gas Collection and Conversion



Source: *Power Plays*, by Susan Williams and Kevin Porter (Investor Responsibility Research Center, 1989).

Municipal solid waste, agricultural and food processing wastes, and animal manures can be anaerobically digested by microbes to produce biogas, consisting primarily of methane and carbon dioxide. Current designs generally consist of a tank or trough into which organic matter is pumped. The waste is mixed to insure contact with microorganisms that are found naturally in wastes. In some cases digesters are seeded with additional microbes that have been grown in culture. As these microbes break down complex organic molecules, they produce biogas that can be purified to contain a higher percentage of methane. There are less than 100 animal waste digesters in the U.S., most of which produce a medium Btu gas for on-site energy use for heat and/or electricity.

Conversion Technologies

Biogas conversion technologies are similar to those currently used for natural gas. Gas turbines are the primary conversion technology. The gas turbine technology used for biogas combustion is very similar to that described previously, except for gasification of the biomass feedstock. Some amount of processing is required, especially for landfill gas, to remove contaminants from the gas that may damage the gas turbine.

In some cases where gas production rates are not high enough to make gas turbines economical, reciprocating internal combustion engines are used for electricity generation. In the internal combustion engine, combustion of the gas drives pistons that turn the armature of an electrical generator. The technology is very similar to that used in conventional diesel engine generators.

Current Economics

Landfills with sufficient methane production rates can use gas turbines for electric generation. These units cost about $1,700/KW and operate at high capacity factors. For large landfills, electricity generation with turbines is becoming the preferred alternative to upgrading the gas to pipeline quality; two gas supply projects have announced plans to install turbine generators.[16] However, turbine efficiency declines markedly when the units are operated below maximum output. In cases where landfill methane production rates cannot support a turbine at full output, or when space constraints at the site do not allow a turbine generator, a reciprocating engine may be used. These engines can, in some cases, be less expensive (at $1,100 - 2,500/KW), but have higher heat rates and operating

[16] The Calumet City project (6 6 MW) and the Pompano Beach project (16 MW) as noted in *Power Plays* (Investor Responsibility Research Center, 1989), pp 149-150.

costs, and produce higher levels of combustion emissions. At landfills where there are limited methane production rates, however, these engines are the most economical choice.

EMERGING TECHNOLOGIES

Research on ways to increase utilization of biogas energy is currently progressing on two fronts. Methods for increasing biogas production and collection are being refined and additional conversion technologies are under development.

Gas Production

Current research in the area of digester gas production is focusing primarily on increasing digester solids concentrations (the component that is converted to methane), improving mixer designs to increase the surface area exposed to the microbial population, and optimizing conversion efficiency of the microorganisms. Much research into the basic biochemistry and physiology of these microorganisms is still needed. Once these mechanisms are understood and the rate limiting steps identified, selection or genetic improvement can be undertaken to increase conversion efficiency.

Conversion Technologies

The primary emerging fuel conversion technology for biogas is the fuel cell.[17] Fuel cells are very efficient electricity generators that rely on an electrochemical reaction between hydrogen and oxygen, rather than combustion, to convert stored energy to electricity. Figure IV-6 shows a schematic representation of how a fuel cell works. A hydrogen-rich gas is introduced into the fuel cell containing an electrolyte where it releases electrons at the anode. The hydrogen ions then react with oxygen at the cathode to form water, combining with electrons returning from the electrical circuit. This is an exothermic reaction that produces heat as well as electricity.

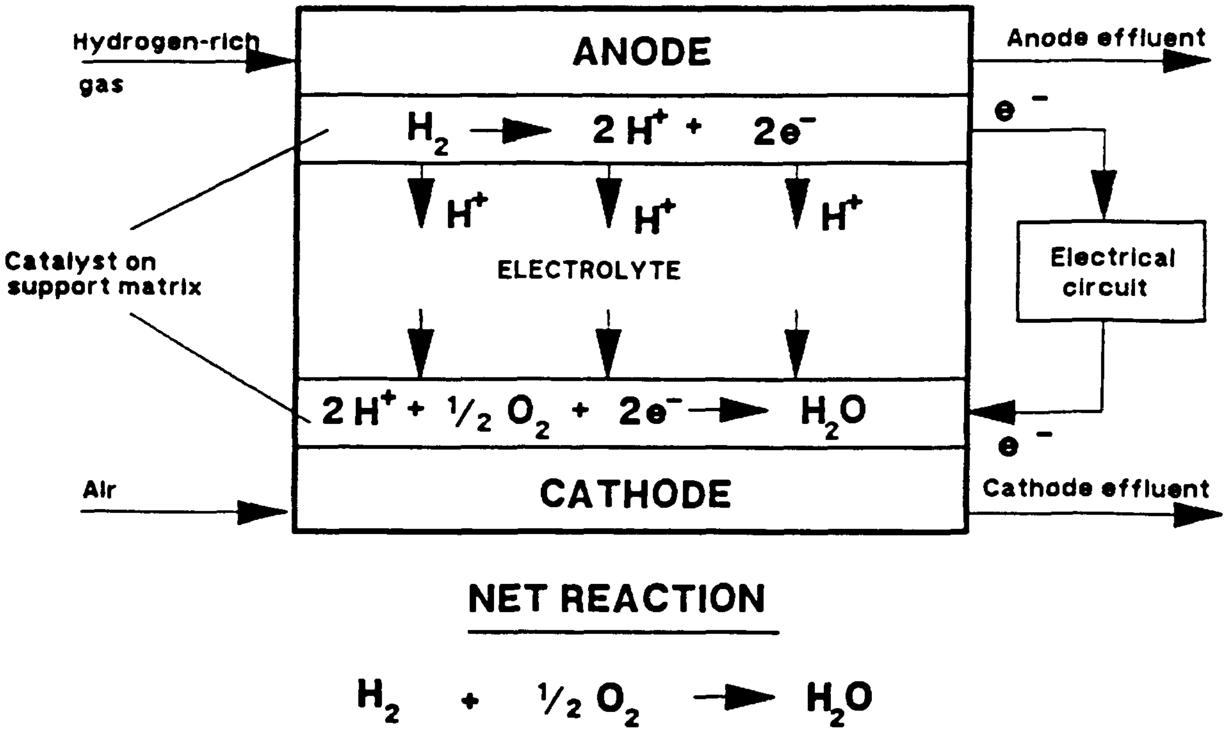
Fuel cells can be used with any hydrocarbon fuel, which includes all biomass fuels, but are currently most efficient when methane is used as a fuel source. Hydrocarbon fuels are broken down in a fuel processor to produce a hydrogen rich gas, much like the gas used for gas turbines. Waste heat from the fuel cell is used to raise the temperature in the processor and anode off-gas, consisting

---

[17] For an introduction to fuel cells see "Fuel Cells: A Review of Fuel Cell Technology and its Applications," by Leo J M J Blomen, in *Electricity: Efficient End-Use and New Generation Technologies and their Planning Implications*, Thomas B. Johansson, Birgit Bodlund and Robert H. Williams, eds. (Lund, Sweden: Lund University Press, 1989).

FIGURE IV - 6

Fuel Cell Schematic Diagram



Source: "Fuel Cells" by Leo J.M.J. Blomen in *Electricity: Efficient End-Use and New Generation Technologies and their Planning Implications*, Thomas B. Johansson, Brigit Boblund and Robert H. Williams, eds. (Lund, Sweden: Lund University Press, 1989).

of hydrogen, carbon monoxide, and unreacted hydrocarbons, is used in the burner to lower NO_x formation.

Fuel cells produce direct current (DC) that must be converted to alternating current (AC) in order to contribute power to the electricity supply grid. The power conditioner converts the DC that flows from the fuel cells into grid-compatible AC. Figure IV-7 shows the design of a complete fuel cell power plant. The fuel processor, fuel cells, and power conditioner are tightly integrated, using waste heat from one process in another, to reduce energy loss and increase efficiency.

Electricity conversion efficiencies of fuel cells range from 40 to 70 percent. Fuel cell systems are modular in nature and can be linked to build plants as small as a few kilowatts or as large as a few hundred megawatts. They can be used to produce electricity for utilities, or to provide electricity in conjunction with useful heat. For instance, fuel cells could be used in a housing complex to provide heat and electricity to all the units.

Costs

Total installed costs for a fuel cell power plant range from $1500 to $2500 per KW depending on production volume. The largest single cost component is the fuel processing equipment. It is this step in the process where costs must fall for this technology to become competitive with other conversion technologies.

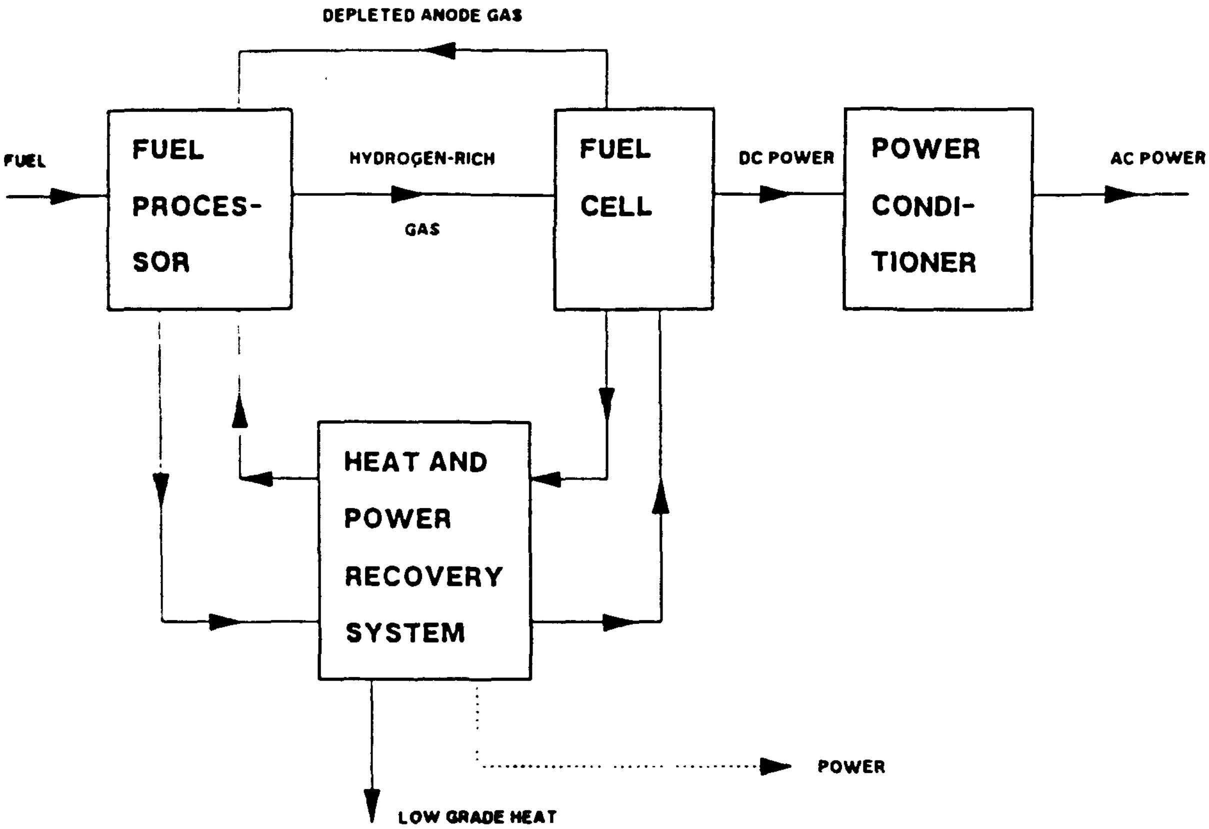
MARKET ASSESSMENT

Aggregate totals of landfill gas electricity generation for DOE/SERI and EPA scenarios are shown on Table IV-13, and the regional estimates of electric generation, costs, and air pollution prevented are shown on Tables IV-14 and IV-15. The incremental generation in the EPA Base Case scenario was assumed to be identical to the incremental generation in the DOE/SERI Business as Usual Scenario. Three-fourths of the landfill methane electricity capacity growth between 1990 and 2010 in the Base Case occurs in California (53%) and the Mid Atlantic region (22%).

Since landfill gas currently accounts for about 98% of electricity generation from landfill and digester gas, the EPA Enhanced Market scenario focuses on potential growth in this energy source. Assuming that 65% of landfill gas from the 850 largest landfills is captured, approximately 0.1 quads of energy will be available for electricity generation in the Enhanced Market scenario. For comparison, it is estimated that if all landfill gas emitted annually in the U.S. were captured, approximately 0.25 quads of energy would be available for use. According to the DOE/SERI report, increased research

FIGURE IV - 7

Fuel Cell Powerplant Schematic Diagram



Source: "Fuel Cells" by Leo J.M.J. Blomen in *Electricity: Efficient End-Use and New Generation Technologies and their Planning Implications*, Thomas B. Johansson, Brigit Boblund and Robert H. Williams, eds. (Lund, Sweden: Lund University Press, 1989).

TABLE IV - 13 LANDFILL METHANE SCENARIOS				
Scenario	**Capacity 2000 (MW)**	**Generation 2000 (GWh)**	**Capacity 2010 (MW)**	**Generation 2010 (GWh)**
<u>DOE/SERI</u>				
Business as Usual	800	4,900	1,500	9,800
Intensified RD&D	1,200	7,800	2,300	14,600
National Premiums	900	5,900	1,900	11,700
<u>EPA</u>				
Base Case	1,100	7,000	1,900	11,900
Enhanced Market	1,500	9,800	2,300	14,600
1990:	500	3,100		

and development should increase the use of digester gas, especially from MSW digestion. This growth brings the Enhanced Market fuel supply to 0.15 quads of primary energy equivalent in 2010. Roughly two-thirds of the additional landfill gas electric capacity in this scenario is built in the Northeast and California.

<u>Costs</u>

Where landfill gas is available, electric generation costs are typically lower than conventional generation.[18] In the Base Case, landfill gas generation averages 0.4 ¢/kWh less than conventional fossil generation in 2000, and is 2.7 ¢/kWh less by the year 2010. The average cost advantage of landfill gas generation reaches nearly 3 ¢/kWh by 2010 in the Enhanced Market scenario.

[18] Landfill gas recovery systems were not included in the costs, however, reflecting the assumption that they would be required for non-methane VOC control reasons. Once collected, gas can also be upgraded to pipeline quality or simply flared.

TABLE IV - 14

ELECTRICITY GENERATION COSTS AND AIR POLLUTION PREVENTED

EPA BASE CASE
BIOMASS ELECTRIC - GAS

REGION	AVERAGE UNIT COST IN 2000 (cents/kWh)			AVERAGE UNIT COST IN 2010 (cents/kWh)		
	AVOIDED FOSSIL	BIOGAS ELECTRIC	COST DIFFERENCE	AVOIDED FOSSIL	BIOGAS ELECTRIC	COST DIFFERENCE
Northeast	4.7	4.2	-0.5	6.2	4.2	-2.0
Southeast	5.1	4.2	-0.8	6.1	4.2	-1.8
Southwest	5.1	4.2	-0.8	6.6	4.2	-2.3
North Central	4.8	4.2	-0.6	5.3	4.2	-1.1
Northwest/Mountain	4.9	4.2	-0.7	5.1	4.2	-0.9
California	4.6	4.2	-0.4	7.8	4.2	-3.5
AVERAGE	**4.7**	**4.2**	**-0.4**	**6.9**	**4.2**	**-2.7**

REGION	INCREMENTAL GENERATION 1990 - 2010 (GWh/yr)	AIR POLLUTION PREVENTED 1990 - 2010 (thousand metric tons/yr)						
		SO_2	NO_x	Particulate Matter	CO	CH_4	CO_2	CO_2 Equivalent
Northeast	2,388	18.9	-9.5	0.57	-6.87	635.95	2,249	15,204
Southeast	92	0.7	-0.4	0.02	-0.26	24.39	85	581
Southwest	287	0.5	-1.2	0.04	-0.82	76.52	213	1,768
North Central	1,031	12.1	-3.5	0.27	-2.97	274.67	1,039	6,658
Northwest/Mountain	328	1.6	-1.1	0.09	-0.95	87.36	342	2,131
California	4,651	1.1	-24.8	0.15	-13.28	1,238.68	2,474	27,454
TOTAL	**8,778**	**34.9**	**-40.5**	**1.14**	**-25.15**	**2,337.57**	**6,401**	**53,796**

TABLE IV - 15

ELECTRICITY GENERATION COSTS AND AIR POLLUTION PREVENTED

EPA ENHANCED MARKET SCENARIO
BIOMASS ELECTRIC - GAS

REGION	AVERAGE UNIT COST IN 2000 (cents/kWh)			AVERAGE UNIT COST IN 2010 (cents/kWh)		
	AVOIDED FOSSIL	BIOGAS ELECTRIC	COST DIFFERENCE	AVOIDED FOSSIL	BIOGAS ELECTRIC	COST DIFFERENCE
Northeast	4.6	4.0	-0.7	6.1	3.7	-2.4
Southeast	4.9	4.0	-0.9	6.0	3.7	-2.3
Southwest	5.0	4.0	-1.1	5.9	3.7	-2.2
North Central	4.8	4.0	-0.8	5.3	3.7	-1.6
Northwest/Mountain	4.9	4.0	-0.9	5.1	3.7	-1.5
California	4.6	4.0	-0.6	7.8	3.7	-4.1
AVERAGE	**4.7**	**4.0**	**-0.7**	**6.6**	**3.7**	**-2.9**

REGION	INCREMENTAL GENERATION 1990 - 2010 (GWh/yr)	AIR POLLUTION PREVENTED 1990 - 2010 (thousand metric tons/yr)						
		SO_2	NO_x	Particulate Matter	CO	CH_4	CO_2	CO_2 Equivalent
Northeast	3,141	25.9	-12.0	0.78	-9.04	836.58	3,027	20,087
Southeast	279	2.2	-1.1	0.07	-0.80	74.22	263	1,775
Southwest	597	1.4	-2.2	0.13	-1.71	158.87	555	3,799
North Central	1,357	15.2	-4.6	0.36	-3.90	361.32	1,373	8,765
Northwest/Mountain	1,356	6.5	-4.4	0.38	-3.91	361.00	1,415	8,807
California	4,818	1.1	-25.7	0.16	-13.76	1,283.05	2,562	28,437
TOTAL	**11,547**	**52.4**	**-50.0**	**1.87**	**-33.12**	**3,075.03**	**9,195**	**71,671**

Air Pollution Prevented

The most significant air pollution prevention impact is the elimination of direct emissions of methane, a powerful greenhouse gas. Nearly 3.1 million metric tons of annual methane emissions could be avoided by 2010 under the Enhanced Market scenario. This represents roughly 20% to 40% of current estimated methane emissions from U.S. landfills (estimates of current emissions range from 8 to 18 million metric tons per year). Small reductions in SO_2, PM, and CO_2 would also occur, but net CO and NO_x emissions would rise slightly.

CHAPTER V

GEOTHERMAL ELECTRICITY GENERATION

Geothermal energy is the heat contained beneath the earth's surface. This heat may be harnessed where hot water or steam naturally percolate to the earth's surface or where human-made wells are drilled into the earth's crust. Geothermal energy can be used directly for process or space heat, aquaculture, or agriculture; or it can be used to generate electricity.

RESOURCE BASE

Resource Base, Accessible and Reserves

Geothermal resources fall into four categories: hydrothermal, geopressured brine, hot dry rock, and magma. Hydrothermal systems are vapor- or liquid-dominated with water temperatures ranging from 90-360 degrees Celsius (°C). Geopressured brines are high temperature (usually between 100 and 200 °C) salt water reserves containing dissolved methane, which are found at depths of approximately 10,000-30,000 feet in permeable sandstone. Hot dry rock (HDR) is hot water-free rock found in natural or human-made fractures several hundred to 10,000 feet below the surface, while magma is molten or partially molten rock within the earth's crust. Hydrothermal and geopressured brine resources carry heat to the surface in liquids that originate in the reservoir. HDR and magma energy would be harnessed by injecting water at high pressure through a well, forcing the water or steam through man-made cracks into a second well and then to the earth's surface for energy conversion. The water is then re-injected into the first well; additional water must be added to make up for losses below ground.

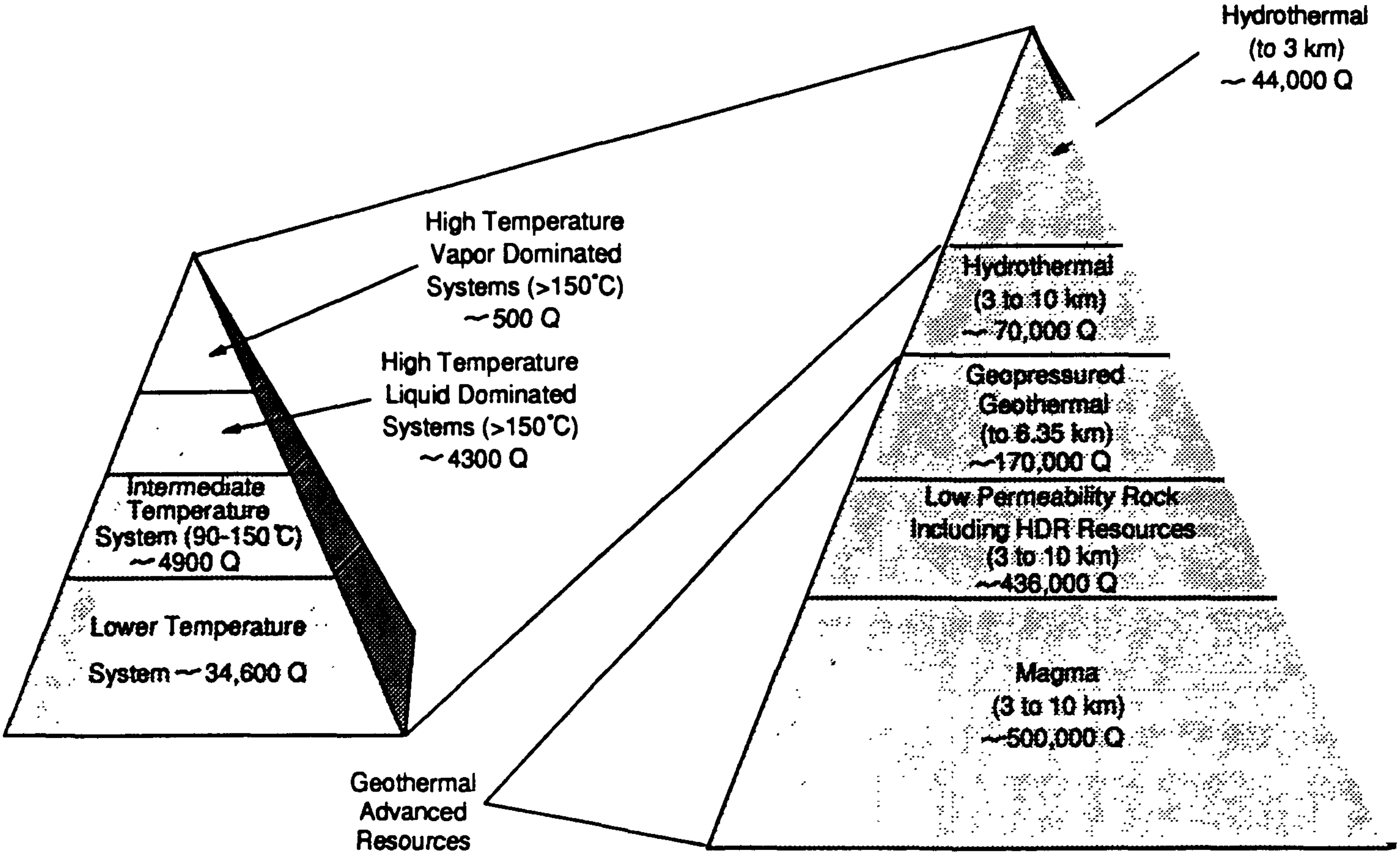
Estimates of the availability of geothermal resources vary widely. Figure V-1 shows a pyramid breakdown of geothermal resources with estimates of total resource potentials. Only hydrothermal resources have been exploited on a commercial basis thus far -- the United States Geological Survey (USGS) estimates available domestic hydrothermal resources above 90 °C to be 2400 quads -- 400 quads identified, 2000 quads undiscovered (compared to 1988 U.S. electricity consumption of 29 quads of primary energy).[1] These high-temperature hydrothermal resources represent a small fraction of the total estimated geothermal resource base.

---

[1] *United States Geological Survey Circular 790*, quoted in the U.S. Geothermal Energy R&D Program Summary, U.S. Dept. of Energy, 1988, p. 2.

FIGURE V - 1

Pyramid Breakdown of Geothermal Resources



Source: Idaho National Engineering Laboratory

The Meridian Corporation report defines geothermal energy resources more broadly than does the USGS.[2] Meridian defines geothermal resources as the amount of thermal energy above 80°C and at depths less than 6 kilometers (km), plus hydrothermal resources over 40 °C to a depth of 3.2 kilometers in areas where the temperature gradient is at least 25 °C/km.[3] The total resource excludes geothermal energy reservoirs in the National Parks, because legislation bars energy development there. By these criteria, the geothermal resource in the U.S. is over 1.5 million quads, over 99% of which comes from hydrothermal resources.

Meridian Corporation considers the following geothermal resources accessible: hydrothermal resources above 80 °C to a depth of 6 km; on-shore geopressured resources over 50 °C to a depth of 6 km, excluding the dissolved natural gas; heat at temperatures over 80 °C which results from the normal temperature gradient, and hot dry rock and magmatic energy to a depth of 6 km. Using this definition, Meridian calculates the accessible geothermal resource at 23,000 quads, of which 98% is in the form of hydrothermal resources. The economic subset of the accessible reserves comprises the hydrothermal resources over 150 °C and at depths of less than 3 km, which is estimated at 250 quads.

Technically, geothermal is not a "renewable" energy source, but because the resource is so extensive, it is considered essentially unlimited. Some geothermal reservoirs do in fact recharge themselves with liquid and heat, and are thus truly renewable. However, pressure in certain geothermal systems decreases with use. For example, the Geysers geothermal field in northern California has experienced a decrease in pressure over time, resulting in a loss in energy production ability.[4] Tests are currently underway to determine a predictable level of decline in well pressure in geopressured and hot dry rock resources.

<u>Geographic Distribution</u>

Figure V-2 shows the known and potential U.S. hydrothermal and geopressured resources. Hydrothermal reservoirs are located primarily in the western part of the U.S., with the most easily accessible high-temperature resources in California, Nevada, and Utah. The five states reporting

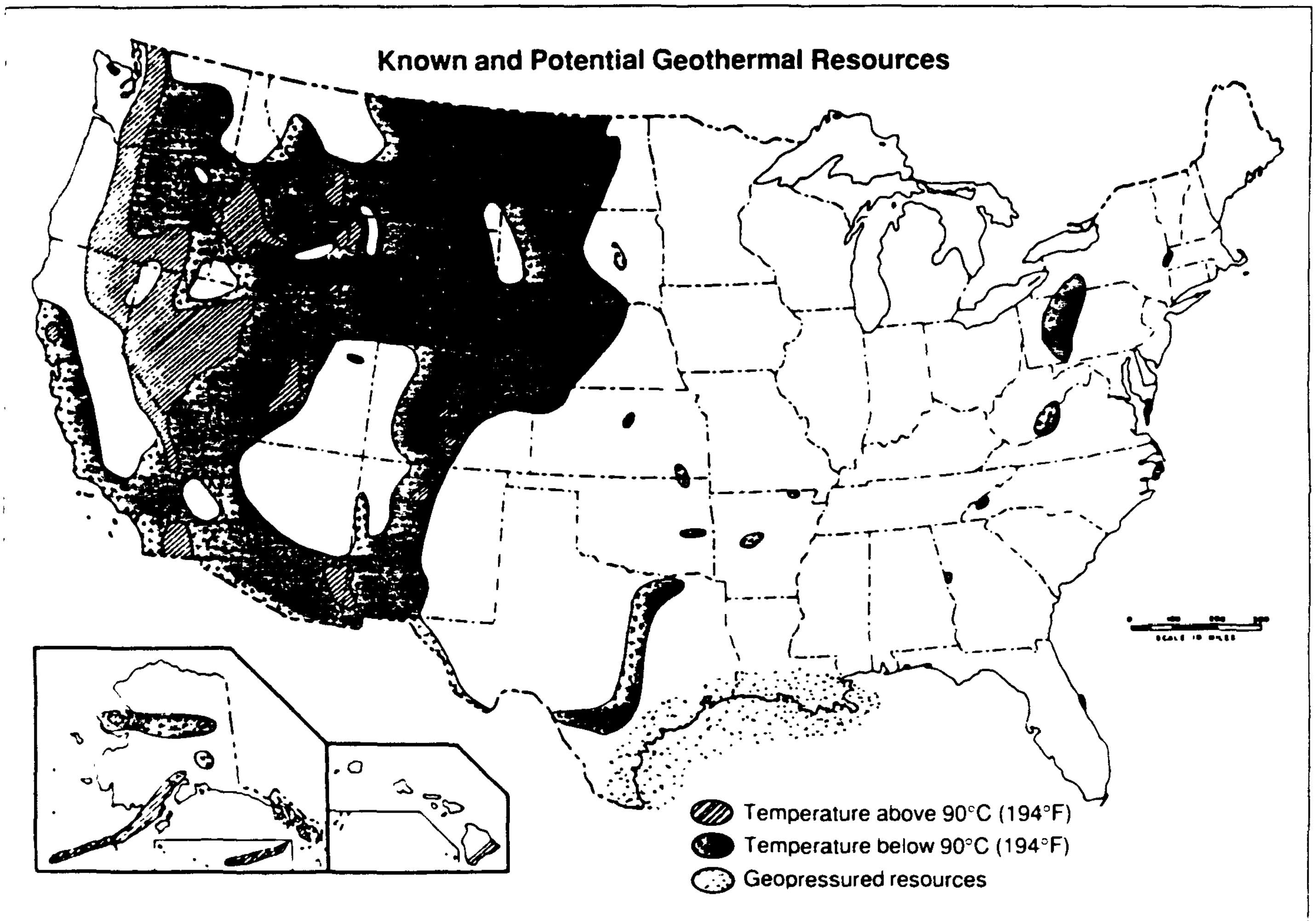
---

[2] *Characterization of U.S. Energy Resources and Reserves*, prepared for the U.S. Department of Energy by Meridian Corporation. This report does not distinguish between geothermal resources as a whole and geothermal resources sufficient to generate electricity. Geothermal electric resources are significantly less than the amounts cited in this report.

[3] Temperature gradient is the measure of how quickly temperature rises with depth.

[4] *Geothermal Progress Monitor*, December 1989. pp 23-24.

FIGURE V - 2



Source: *Geothermal Energy Program Summary*, Volume 1: Overview, Fiscal Year 1989, U.S. Department of Energy, January 1990.

geothermal electricity production in 1989 were: California, Nevada, Utah, Hawaii and New Mexico. Most of the untapped hydrothermal resources also occur in these states, but these resources are frequently remote, making transmission cost and access a significant but not insurmountable issue.

Geothermal energy development in other regions depends on how quickly technologies develop to exploit non-hydrothermal resources. If commercial technology emerges to utilize geopressured brine resources, development could extend into Texas and Louisiana; potential geopressured resources also exist off the Gulf Coast of these states.

Technology utilizing hot dry rock could extend geothermal development into the Northeast and North Central states. Figure V-3 shows the regional potential for HDR based on temperature gradients. Because the technology of HDR is still in the experimental stage, it is unreasonable to forecast costs of HDR electricity, but the least expensive electricity will probably come from the areas with the greatest temperature gradients. The geographic distribution of potential magma resources is only speculative at this point, but prospects are probably best in the western portion of the U.S.

CONVERSION TO ELECTRICITY

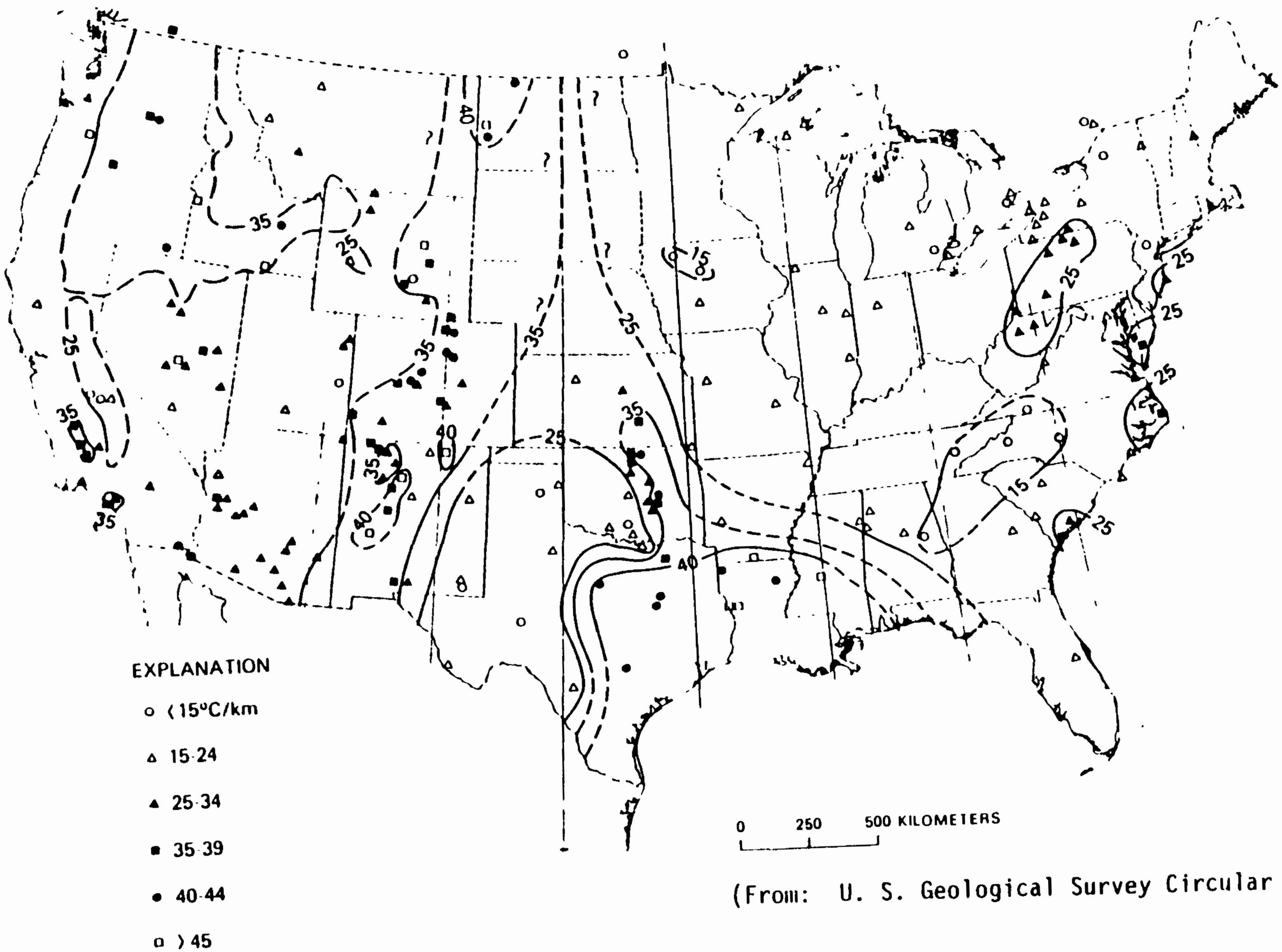
Existing Technologies

The three components of a geothermal system are: (1) the production well; (2) the energy conversion system; and in many systems, (3) the injection well. These are shown on Figure V-4. Four types of electricity generating technologies have been developed to exploit geothermal resources. Their design is based on the temperature and pressure characteristics of the geothermal fluids: (1) dry-steam plants use high-temperature vapor-dominated resources to drive a turbine which generates electricity; (2) flash plants tap high-temperature liquid-dominated resources; as the pressure decreases during the flow to the surface, part of the water vaporizes into steam (called "flashing"), which is separated at the surface to drive the turbine; (3) binary cycle plants extract useable energy from lower temperature liquid resources by passing the geothermal fluid through a heat exchanger, which transfers energy to a separate "working fluid" loop (with a lower boiling point than water) that powers the turbine; and, (4) hybrid plants employ fossil or biomass fuels to raise the temperature of a geothermal brine before transferring it into heat exchangers.[5] Figure V-5 shows schematic diagrams of flash and binary cycle geothermal conversion plants. Binary conversion technology will also be

[5] For a brief description of geothermal technologies see the U.S. DOE "Geothermal Energy Program Summary," 1988.

FIGURE V - 3

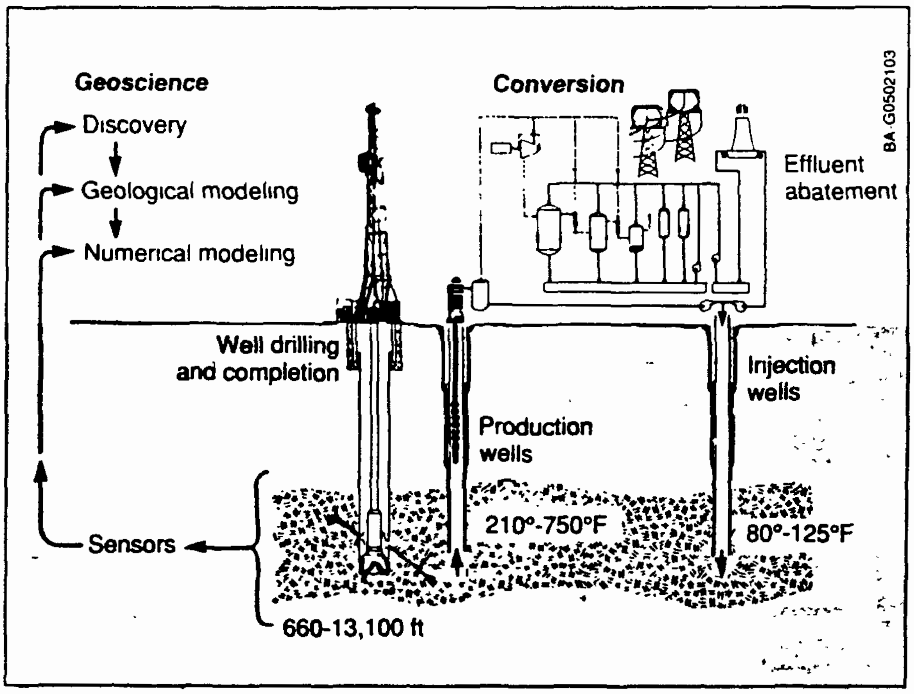
Map of Hot Dry Rock Potential by Temperature Gradient



(From: U. S. Geological Survey Circular 892)

FIGURE V - 4

Components of a Geothermal System

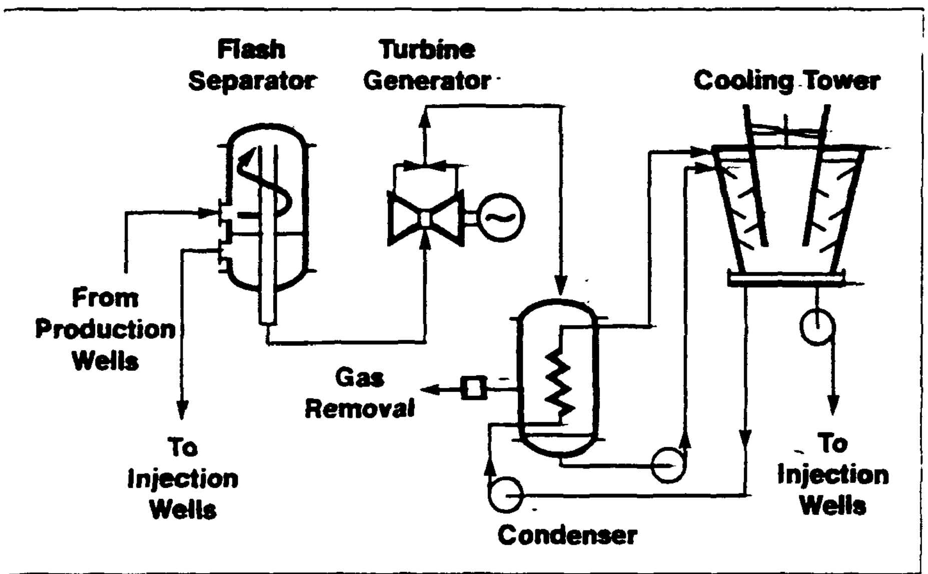


Geothermal power project components

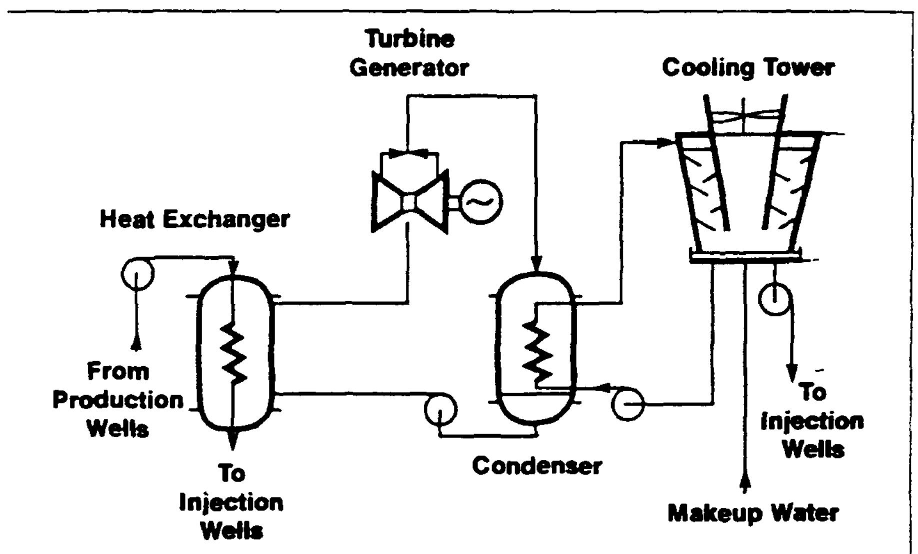
Source: *Geothermal Energy Program Summary*, Volume 1: Overview, Fiscal Year 1989, U.S. Department of Energy, January 1990.

FIGURE V - 5

Schematic of Flash and Binary Cycle Geothermal Plants



Flash steam technology



Binary technology

Source: *Geothermal Energy Program Summary*, Volume 1: Overview, Fiscal Year 1989, U.S. Department of Energy, January 1990.

used to generate power from geopressured brines, hot dry rock, and magma resources. Figure V-6 shows the water injection and steam production well configuration of an HDR plant.

Resources Recovered

Installed geothermal capacity of 2800 MW produced about 23,100 GWh of electricity in 1990. All of the generation comes from hydrothermal resources. Dry steam plants at the Geysers in California produced roughly two thirds of the electricity, double flash hot water plants produced about one fourth, and binary and single flash hot water plants made up the remaining 10%.

Current Economics

Geothermal project construction time is on average 22 to 28 months, including drilling and installation of production wells, injection wells, and piping; and construction of steam and/or brine handling equipment.[6] The construction time on the actual power plant is generally 6-24 months, depending on size and location. For instance, a recent 20 MW plant in East Mesa, California was brought on-line only seven months after construction began. Generally, however, the process of obtaining permits, securing financing, and completing construction takes about 36-52 months.

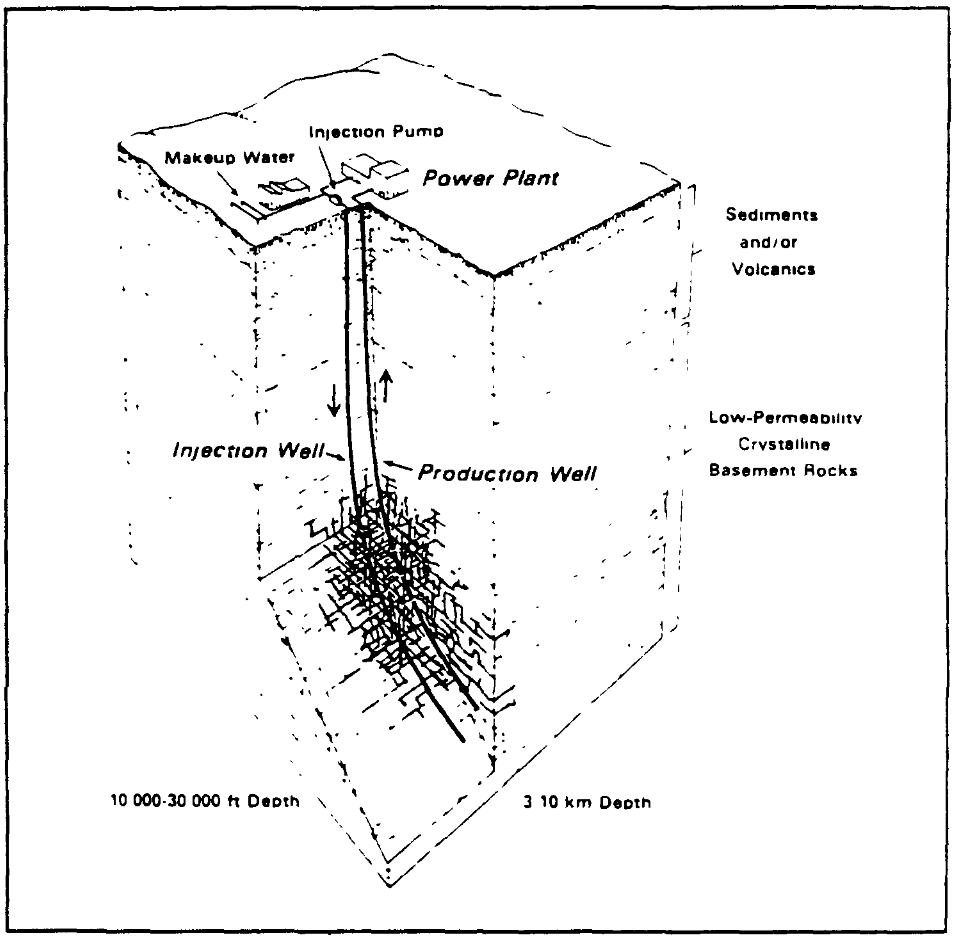
Geothermal operating costs and efficiencies are directly related to the temperature of the resource, and site-specific characteristics cannot always be easily compared. In general, the higher temperature resources will be the most economic to develop. Other factors, including the depth of the resource and the flow rate affect the costs of the system. Representative costs and performance of current hydrothermal systems are shown on Table V-1. However, these numbers should not be used to compare the relative merits of each type of conversion technology. The cost of exploiting geopressured brine resources are speculative at this point, and since such resources provide multiple products (heat, pressure, and methane) the cost of electricity generation is difficult to calculate separately. The cost of hot dry rock development will depend highly on both the exploration and drilling expenses and conversion equipment cost.

When good geothermal sites are far from existing transmission systems, lines must be extended to access the power from these sites, and the proximity of the resources to the demand for power or "load center" will affect generation costs. Building transmission lines to geothermal sites adds to the capital cost of geothermal development. The costs of high power transmission lines depend on terrain and design capacity, but range between $100,000 and $500,000 per mile of line

[6] California Energy Commission, *Energy Technology Status Report*, 1988.

FIGURE V - 6

Water Injection and Steam Production Well Configuration



Hot dry rock geothermal system concept for low-permeability formations

Source: *Geothermal Energy Program Summary*, Volume 1: Overview, Fiscal Year 1989, U.S. Department of Energy, January 1990.

TABLE V - 1
REPRESENTATIVE HYDROTHERMAL CONVERSION COSTS[a]

	DRY STEAM PLANT	FLASH PLANT	BINARY PLANT
Resource Temperature (°C)	>175	>150	>90
First Law Efficiency[b] (%)	15	10	11 - 14
Second Law Efficiency[c] (%)	50	35 - 40	40 - 50
Wellfield Development ($/KW)	550	550	660
Installed Capital Cost ($/KW)	1550	1550	1860
Fixed O&M ($/KW/year)	30 - 40	60	60
Variable O&M (¢/kWh)	0.3	0.3	0.6
Capacity Factor (%)	90	90	90
Levelized Cost (¢/kWh)	3 - 4	3 - 4	4 - 6

Sources: Based on "Geothermal Resources," Northwest Power Planning Council staff paper 89-36, and information provided by Greg Mines, Idaho National Engineering Laboratory.

[a] Values can vary widely depending on a number of factors, including resource quality.

[b] Fraction of energy output to heat transfer. Technologies are rated for a similar resource temperature.

[c] Fraction of available energy (temperature differential between the resource and the cooling fluid) converted to work. Technologies are rated for similar resource temperature.

required to transport geothermal electricity.[7] These costs add roughly $80/kW for a 100 mile line. In light of the high cost and various obstacles to siting and building transmission lines in the U.S., transmission could potentially impede geothermal development. Even if geothermal resources are close to transmission lines, remote generation may incur moderate transmission and distribution (T&D) losses.

[7] See "Geothermal Resources" Northwest Power Planning Council Staff Issue Paper, October, 1989, p 27 ($110,000 per mile for a 115 kilovolt line that could serve a 150 MW power plant); and *Power Plays*, by Susan Williams and Kevin Porter, Investor Responsibility Resource Center, 1989, p. 170, ($520,000 per mile for a 230 kilovolt line that serves 600 MW of capacity).

EMERGING CONVERSION TECHNOLOGIES

Efficiency/Performance

Further hydrothermal development will occur in California as the economics of geothermal energy improve. DOE expects that most hydrothermal reservoirs in the western U.S. have been identified; developing these resources will depend on reducing the risks of exploiting them. Geopressured brines and HDR resources will probably be developed in the West after available hydrothermal resources. Technologies to tap magma are speculative now, but would offer a potentially enormous base-load energy source (initially) in the western regions of the country.

The long-term reliability of geothermal resources will play an essential role in determining the market prospects for eventual development. There exist numerous examples of significant resource degradation over relatively short time frames (5-15 years).[8] The degree to which geothermal resources might recharge themselves is unclear and depends on the type of geothermal field involved. In the case of the Geysers, a vapor-dominated reservoir which has been producing electricity since 1960, neither external water nor water from depth has significantly recharged the reservoir. Long-term flow tests are currently underway or are planned in California and Texas to examine the performance of hydrothermal and geopressured resources respectively, under base-load conditions. With proper well management techniques, including variations in well locations and depths; maximized production rates and methods; fluid injection locations and rates; and production/injection control strategy, scientists are confident that these resources will offer stable base-load energy supplies for 20 to 30 years. Verification of resource dependability is required to decrease risks for energy companies to expand geothermal development.

Costs

As shown in Table V-2, costs of electricity are projected to drop slightly for hydrothermal, the most established technology, and most precipitously for magma, the least developed one.

Potential Technology and Multiple Pathways

The primary technological constraints inhibiting development of geothermal resources include the risk associated with exploration, specifically identification of well sites, verification of size and performance of the reservoir, and maintenance of well integrity. Improvements in fluid production (the ability to extract geothermal fluids for energy conversion) from all geothermal resources will include:

---

[8]See for example, Michael A. Grant *et al* Geothermal Reservoir Engineering, pp. 211, 151-158, 218-219.

TABLE V - 2

PROJECTED COSTS OF GEOTHERMAL ELECTRICITY

	Capital Cost ($1988/KW)		O&M (¢/kWh)		Levelized Cost (¢/kWh)	
	BAU	R,D&D	BAU	R,D&D	BAU	R,D&D
<u>1989</u>						
Hydrothermal	1800	1800	1.8	1.8	4.4	4.4
Geopressured	3200	3200	2.9	2.9	7.5	7.5
Hot Dry Rock	2800	2800	2.5	2.5	6.5	6.5
Magma	8300	8300	10.0	10.0	21.9	21.9
<u>2000</u>						
Hydrothermal	1700	1600	1.8	1.8	4.2	4.1
Geopressured	2700	2600	2.6	2.4	6.5	6.1
Hot Dry Rock	2500	2200	2.3	2.0	5.9	5.2
Magma	6100	5100	8.0	5.0	16.8	12.3
<u>2010</u>						
Hydrothermal	1700	1500	1.7	1.5	4.1	3.7
Geopressured	2200	2100	2.4	2.1	5.6	5.1
Hot Dry Rock	2300	1800	2.1	1.6	5.4	4.2
Magma	4600	2600	6.0	4.0	12.6	7.7

Source: *The Potential of Renewable Energy: An Interlaboratory White Paper*, March 1990.

(1) optimizing drilling techniques by upgrading drill bits, downhole instrumentation, downhole motors and properties of drilling fluids; and (2) improving reservoir management.

Conversion of hydrothermal resources to electricity has been commercial since 1960 in the U.S., and although the technologies are relatively mature, increases in conversion efficiencies are still possible in the future. Improvements in conversion technologies such as heat exchangers in binary plants will also increase energy production efficiency. Other improvements in geothermal technology include computer modeling of reservoir well behavior, optimization of injection well scheduling, prediction and elimination of scaling, and waste treatment biotechnology to reduce waste problems.[9]

The Geothermal Division of DOE currently supports R&D efforts into all phases of geothermal development. Further geothermal development will focus on increased exploration of hydrothermal resources which have been generally identified, and on the technical potential for exploiting currently uneconomic or inaccessible resources such as geopressured brines, hot dry rock, and magma.

Hydrothermal Resources. Although hydrothermal is the most mature of the geothermal technologies, further technology development is required to achieve the full potential of the resource. The Department of Energy (DOE) has broken its geothermal research program into four categories: reservoir technology; hard rock penetration; conversion technology; and industrialization.[10]

- Reservoir Technology. The goal of research on reservoir technology is to improve geothermal energy utilization by developing and testing methods to more effectively locate, develop, and utilize hydrothermal resources. Research on reservoir technology takes three paths: 1) reservoir analysis, which will develop tools for determining reservoir characteristics and performance; 2) brine injection technology research, which will assess effective and environmentally acceptable injection systems; and 3) exploration technology designed to locate and characterize geothermal resources. The Geothermal Technology Organization, a cooperative research agreement coordinated by DOE and industry representatives, is involved in these three areas of research.

- Hard Rock Penetration. Hard rock penetration research seeks to reduce the cost of drilling in "hostile" environments through development of three areas: 1) lost circulation control, which targets technologies for detecting and characterizing loss zones and then mitigating their effects; 2) rock penetration mechanics; and 3) instrumentation which can increase well siting accuracy at a reduced cost. The Geothermal Drilling Organization, a cooperative research program with industry, plays an active role in these research areas.

---

[9] "DOE Research and Development for the Geothermal Marketplace," *Proceedings of the Geothermal Program Review VII*, March 21-23, 1989.

[10] Kenneth Taylor, "An organized effort to develop the hydrothermal energy resources," *Proceedings of the Geothermal Program Review VII*, March 21-23, 1989, p 25.

- Energy Conversion. Energy conversion technology research is broken into three projects, all aimed at increasing the efficiency and economics of resource conversion: 1) heat cycle research; 2) material development; and, 3) advanced brine chemistry. Second generation binary plant designs will improve the energy conversion potentials of moderate temperature hydrothermal and geopressured resources. Since geopressured brines, hot dry rock, and magma resources all require binary cycle conversion systems, improvements in hydrothermal binary systems will also greatly facilitate the advancement of other resources as well. Advances in hybrid power plant design may also permit commercialization of low to moderate temperature geothermal resources.

- Industrialization. Industrialization research is intended to promote the use of geothermal energy throughout the U.S. and the world. This is currently achieved through joint government/university/industry programs in Alaska, Hawaii, Idaho, Nevada, New Mexico, North Dakota, Utah, Washington, Wyoming, and elsewhere. State coupled grants, one program within the industrialization efforts, distributes funds to organizations to study aspects of geothermal energy that are not being studied by industry.

Geopressured Brines. Current research on geopressured brines is concentrated in three areas: well operations, geoscience and engineering support, and energy conversion.[11] Long-term resource management experiments have been conducted by DOE at the Pleasant Bayou wells in Brazoria County, Texas. DOE programs focus primarily on demonstrating of electricity generation potential from geopressured resources, and operating test wells over varied conditions to obtain data useful for future commercial ventures.[12] DOE goals for 1989 included: proof of long-term injectability of spent brine; minimization of fluid production expenses; development of automated operations; and, development of modified scale inhibitor treatment procedures.

Hot Dry Rock Research in hot dry rock systems focuses on resource evaluation, and exploration techniques aimed at more effectively and efficiently locating high temperature resources in

---

[11] Kenneth Taylor, "The Development of the Geopressured Resource: A Status Report," *Proceedings of the Geothermal Program Review VII*, March 21-23, 1989, pp.99-101.

[12] Dr. B.A. Eaton, et. al., "Pleasant Bayou Operations Brazoria County, Texas," *Proceedings of the Geothermal Program Review VII*, March 21-23, 1989, pp.103-108.

underground rock fracture systems.[13] Hydraulic fracturing experiments have been conducted in deep wells to advance understanding of human-made fractures. Other tests are currently underway at Fenton Hill, New Mexico including geochemistry and tracer studies, microseismic response analysis, water requirements and flow impedance tests. A long-term flow test is to be conducted by Los Alamos National Laboratories in Fenton Hill, New Mexico to determine the viability and economics of HDR resources.[14] Resevoir management issues will be explored at Fenton Hill. Exploration techniques for locating fractures with HDR potential (such as deep seismic surveys, acoustical telemetry, and radar fracture mapping) must also be improved to decrease the risks of developing these systems.

Magma. Magma research is still in the analytical stages; key issues include cheaper and improved drilling techniques as well as better understanding of reservoir dynamics.[15] DOE activities in this area are currently on hold, but may focus on drilling and evaluating a deep exploratory well in Long Valley, New Mexico and studies at the Kilauea Iki lava lake in Hawaii.

MARKET ASSESSMENT

Estimates of future geothermal electric technology penetration depend on the rate of development of exploration and drilling methods and conversion technologies. Table V-3 shows the DOE/SERI and EPA scenarios, and Tables V-4 and V-5 show cost and air pollution prevention results of the geothermal market analysis. The EPA Base Case is identical to the DOE/SERI BAU scenario. The Enhanced Market scenario assumes that policies are put into place to encourage geothermal development: under these policies, almost 20,000 MW of capacity and 157,000 GWh of generation can be obtained from geothermal electric development by 2010. The technology breakout of this scenario includes: 16,120 MW of capacity and 127,000 GWh of generation from hydrothermal resources, 990 MW of capacity and 7,800 GWh of generation from geopressured brines, and 2,845 MW of capacity and 22,400 GWh of generation from hot dry rock systems. No development from magma resources is assumed.

---

[13] Michael Berger and Robert Hendron, "Hot Dry Rock Overview at Los Alamos." *Proceedings of the Geothermal Program Review VII*, March 21-23, 1989, pp.147-151.

[14] George Tennyson, Jr. "Hot Dry Rock Research Program Objectives Session: Introduction," *Beyond Goals and Objectives: Proceedings of the Geothermal Program Review VI*, 1988, p.111,

[15] "DOE Research and Development for the Geothermal Marketplace," Proceedings of the Geothermal Program Review VII, 1989, pp.127-131, James Dunn, "Magma Energy Overview and Status Report."

TABLE V - 3 GEOTHERMAL SCENARIOS				
Scenario	**Capacity 2000 (MW)**	**Generation 2000 (GWh)**	**Capacity 2010 (MW)**	**Generation 2010 (GWh)**
DOE/SERI				
Business as Usual	3,800	30,200	6,600	52,000
Intensified RD&D	5,200	41,100	11,300	89,400
National Premiums	5,000	39,100	8,700	68,200
EPA				
Base Case	3,800	30,200	6,600	52,000
Enhanced Market	8,200	61,400	19,900	157,000
1990:	2,800	23,100		

Estimates of regional generation are based on resource availability. Hydrothermal resources are available only in the Western U.S. (including Hawaii). Geopressurized brines are accessible in the West and the Gulf states of Texas and Louisiana, and hot dry rock technologies could extend geothermal development into the Northeast and North Central states.

Costs

Where available, geothermal resources could supply relatively inexpensive electric generation. In the Base Case, geothermal generation costs average 4.5 ¢/kWh in 2000, and 4.4 ¢/kWh by 2010. The hydrothermal resources in the West provide the least expensive generation, at 4.2 ¢/kWh in 2000 and 4.1 ¢/kWh in 2000, while small amounts of geopressured brine generation in the Southwest is more expensive, at 6.5 ¢/kWh in 2000 and 5.5 ¢/kWh in 2010. Because geothermal generation can fully displace conventional baseload fossil capacity, avoided costs average 4.7 ¢/kWh in 2000 and 7.2 ¢/kWh in 2010, making geothermal 2.8 ¢/kWh less expensive than fossil fuel generation by 2010. Geothermal costs in the Enhanced Market scenario drop as a result of additional RD&D: in 2000, geothermal costs average 4.1 ¢/kWh, falling to 4.0 ¢/kWh in 2010, when geothermal is 2.9 ¢/kWh cheaper than fossil fuel generation. As a result of HDR penetration in the Enhanced Market scenario, geothermal generation is also more geographically dispersed.

TABLE V - 4

ELECTRICITY GENERATION COSTS AND AIR POLLUTION PREVENTED

EPA BASE CASE
GEOTHERMAL

REGION	AVERAGE UNIT COST IN 2000 (cents/kWh)			AVERAGE UNIT COST IN 2010 (cents/kWh)		
	AVOIDED FOSSIL	GEOTHERMAL	COST DIFFERENCE	AVOIDED FOSSIL	GEOTHERMAL	COST DIFFERENCE
Northeast	NA	NA	NA	8.4	5.3	-3.1
Southeast	NA	NA	NA	NA	NA	NA
Southwest	5 1	6 4	1.3	6.2	4.8	-1.4
North Central	NA	NA	NA	NA	NA	NA
Northwest/Mountain	4 8	4 1	-0.7	5.1	4.1	-1.0
California	4 6	4 2	-0.4	7.8	4.3	-3.5
AVERAGE	**4.7**	**4.5**	**-0.2**	**7.2**	**4.4**	**-2.8**

REGION	INCREMENTAL GENERATION 1990 - 2010 (GWh/yr)	AIR POLLUTION PREVENTED 1990 - 2010 (thousand metric tons/yr)						
		SO_2	NO_x	Particulate Matter	CO	CH_4	CO_2	CO_2 Equivalent
Northeast	975	4.4	2.1	0.14	0.15	0.01	680	764
Southeast	0	0.0	0.0	0.00	0.00	0.00	0	0
Southwest	4,869	9.0	17.3	0.75	0.76	0.03	3,901	4,595
North Central	0	0.0	0.0	0.00	0.00	0.00	0	0
Northwest/Mountain	3,115	15.9	13.8	0.87	0.44	0.03	3,250	3,803
California	19,943	4.6	46.8	0.65	3.31	0.04	10,606	12,489
TOTAL	**28,902**	**33.9**	**80.0**	**2.42**	**4.66**	**0.10**	**18,437**	**21,652**

TABLE V - 5

ELECTRICITY GENERATION COSTS AND AIR POLLUTION PREVENTED

EPA ENHANCED MARKET SCENARIO
GEOTHERMAL

REGION	AVERAGE UNIT COST IN 2000 (cents/kWh)			AVERAGE UNIT COST IN 2010 (cents/kWh)		
	AVOIDED FOSSIL	GEOTHERMAL	COST DIFFERENCE	AVOIDED FOSSIL	GEOTHERMAL	COST DIFFERENCE
Northeast	NA	NA	NA	7.1	4.2	-2.9
Southeast	NA	NA	NA	NA	NA	NA
Southwest	5.1	6.1	1.0	6.0	4.3	-1.7
North Central	NA	NA	NA	5.3	4.2	-1.1
Northwest/Mountain	4.9	4.1	-0.8	5.2	4.0	-1.2
California	4.6	4.1	-0.5	7.8	4.0	-3.8
AVERAGE	**4.7**	**4.1**	**-0.5**	**6.9**	**4.0**	**-2.9**

REGION	INCREMENTAL GENERATION 1990 - 2010 (GWh/yr)	AIR POLLUTION PREVENTED 1990 - 2010 (thousand metric tons/yr)						
		SO_2	NO_x	Particulate Matter	CO	CH_4	CO_2	CO_2 Equivalent
Northeast	5,852	37.9	18.0	1.16	0.87	0.05	4,910	5,632
Southeast	0	0.0	0.0	0.00	0.00	0.00	0	0
Southwest	15,597	33.7	59.4	2.99	2.38	0.11	13,626	16,010
North Central	5,852	58.1	24.8	1.48	0.85	0.05	5,820	6,814
Northwest/Mountain	18,418	75.1	80.5	5.01	2.61	0.17	18,942	22,172
California	88,215	20.5	207.1	2.88	14.64	0.18	46,915	55,246
TOTAL	**133,935**	**225.2**	**389.6**	**13.52**	**21.36**	**0.55**	**90,213**	**105,874**

Air Pollution Prevented

The amount of geothermal generation that could be developed in the Enhanced Market scenario would provide significant emission reductions. However, because geothermal resources are located primarily in California and the Southwest (where gas-fired generation is common), emission reduction per kWh generated is lower than most renewable resources by 2010 (see Table III-6 in Chapter III). In the Enhanced Market scenario, geothermal electric generation could prevent almost 390,000 metric tons of NO_x emissions by 2010, and could reduce SO_2 by 225,000 metric tons per year (or generate an equivalent amount of allowances). Over 90 million tons of CO_2 emissions could also be eliminated from the electricity supply sector. These emission reductions are relatively modest compared to other renewables, but, unlike most other renewables, these emission reductions would occur at negative cost.

CHAPTER VI
CONVENTIONAL HYDROPOWER

Hydropower has been a significant energy source for many years due to the extensive network of rivers throughout the United States. Nearly 71,300 MW of conventional hydroelectric capacity had been developed by 1990, and in a good year hydro can generate nearly 14% of U.S. electricity. Table VI-1 displays the developed conventional hydroelectric capacity in the U.S. by region and facility type. Of all renewable resources, hydropower contributes the most to U.S. electricity supply, and much potential still remains undeveloped. However, the environmental impacts of hydropower development and operation -- on aquatic and terrestrial ecosystems, fish populations, wildlife habitats, and on certain types of recreation -- are becoming increasingly regulated by state and federal laws. The result is that hydropower development has been slowed, and possibly halted, in the last few years. However, reductions in airborne pollutants and greenhouse gases are not generally taken into account when assessing the benefits of hydroelectric power.

RESOURCE BASE

The total resource base for hydropower consists of all the potential energy contained in precipitation falling on the United States as it flows to sea level, adjusted for evaporation and consumption. This total is estimated to be roughly 30 quads per year.[1] Because of technical constraints and environmental concerns, only a small portion of this potential is currently accessible for conversion to electricity; DOE estimates that the potential from hydropower at new and existing sites in the U.S. is slightly over 5 quads per year. The Meridian report counts approximately 2 quads as economic reserves, which represents electricity generation at existing dam sites.

Hydropower resources are available to some degree throughout the entire United States. Development of these resources is currently concentrated in the West and Middle to South Atlantic States. The Pacific Northwest alone accounts for 40 percent of installed hydropower capacity. This area of the country consistently receives large amounts of precipitation, much of which falls on higher elevations. Because water often travels great distances from its source to the sea, it is not necessary for a particular site to experiences great amounts of precipitation in order to have hydropower resources. Changes in elevation are important, however, because the energy used is the kinetic energy of water in motion which results from the potential energy of water received in higher

[1] *Characterization of U.S. Energy Resources and Reserves*, prepared for the U.S. Department of Energy by Meridian Corporation, June 1989.

TABLE VI - 1
DEVELOPED CONVENTIONAL HYDROELECTRIC CAPACITY AND GENERATION

REGION	RUN OF RIVER		DIVERSION		STORAGE		TOTAL	
	MW	GWH	MW	GWH	MW	GWH	MW	GWH
New England	1,487	6,346	43	160	350	1,084	1,880	7,589
Mid Atlantic	2,592	10,083	78	247	2,705	15,952	5,374	26,282
South Atlantic	999	3,020	216	1,088	4,727	10,519	5,942	14,627
Florida	12	26	0	0	30	250	42	276
East North Central	594	2,650	48	322	512	2,389	1,154	5,362
West North Central	149	911	80	400	2,622	9,819	2,851	11,130
East South Central	780	3,808	139	530	4,950	18,238	5,869	22,577
West South Central	799	2,703	4	14	1,673	4,150	2,475	6,867
Mountain	970	7,014	278	1,106	5,178	19,138	6,426	27,258
Arizona/New Mexico	0	0	14	63	2,491	8,000	2,505	8,063
California	486	1,762	5,633	26,234	2,640	11,381	8,760	39,376
Washington/Oregon	3,008	21,068	2,482	10,959	22,501	96,584	27,991	128,611
TOTAL	11,876	59,392	9,016	41,121	50,378	197,505	71,270	298,018

Source: Federal Energy Regulatory Commission (FERC) database, 1990.

elevations. This explains why Florida, which experiences much rainfall but has relatively flat terrain, has only limited hydropower resources.

CONVERSION TO ELECTRICITY

Hydroelectric power plants convert the kinetic energy of water flowing downstream into electricity by passing the water through a hydraulic turbine. Hydroelectric projects vary along several dimensions: the amount of water storage, hydrostatic head, turbine type, and mode of operation.

Types of Hydroelectric Projects

Hydroelectric projects are usually categorized into three types: storage, run of river, and diversion. The geographical and hydrological characteristics of specific sites determine the appropriate type of hydroelectric development.

Storage Projects. Storage facilities use a dam to create an artificial lake from incoming stream flow. Storage hydroelectric projects are often rated in terms of storage capacity, usually in acre-feet of water available for power generation. A profile of a typical storage plant is shown on Figure VI-1. Storage is typically allocated to several uses, such as flood control, water supply, irrigation, and power generation, and the reservoir management plan dictates how much water can be passed through the turbines at given times during the year. The larger reservoirs may contain several weeks, and even months, of average stream flow. Table VI-2 shows the distribution of plants by storage capacity based on a sample of 35,330 MW of hydroelectric projects.

Some storage projects (excluded from Table VI-2) feature reversible turbines that can be used to pump water back through the penstock (the pipe or conduit that normally channels the water into the turbine) so that the plant can be operated in pumped storage mode. Pumped storage hydro plants capitalize on the difference between base load and peak load generating costs by using cheap base load electricity to pump water up behind a dam or into a separate storage reservoir, and then release it through the turbines to generate power during higher demand periods. Pure pumped storage projects are usually separate reservoirs (either high valleys or excavated ponds) that are not replenished by streamflow. Other than collected runoff, the water contained in these reservoirs has all been pumped uphill.

Run-of-River Projects. Run of river hydroelectric projects involve little or no water impoundment, so natural streamflow completely determines the amount of water available for power generation. Figure VI-2 shows a typical run of river hydroelectric project. At some projects, only a portion of the flow is

TABLE VI - 2
DISTRIBUTION OF PLANTS BY STORAGE SIZE AND HEAD

Plants by Storage Size					
Live Storage (Days of Average River Flow)	**No. Plants**	**Percent of Total**	**Total Capacity (MW)**	**Percent of Total**	**Average Plant Size (MW)**
Less than 0.3	54	(21)	6,040	(17)	112
0.3 to 2.9	69	(27)	11,230	(32)	163
3 to 49	61	(24)	7,850	(22)	129
50 to 240	50	(20)	6,270	(18)	125
250 and over	20	(8)	3,940	(11)	197
Total Sample	254	(100)	35,330	(100)	139

Plants by Head					
Normal Net Head (Feet)	**No. Plants**	**Percent of Total**	**Total Capacity (MW)**	**Percent of Total**	**Average Plant Size (MW)**
50 or less	45	(12)	3,080	(8)	68
50 to 100	92	(24)	9,380	(25)	102
101 to 200	86	(23)	8,850	(24)	103
201 to 500	83	(22)	10,240	(28)	123
501 to 1000	36	(10)	2,980	(8)	83
over 1000	34	(9)	2,570	(7)	76
Total Sample	376	(100)	37,100	(100)	96

Source: *Increased Efficiency of Hydroelectric Power*, Electric Power Research Institute, June 1982.

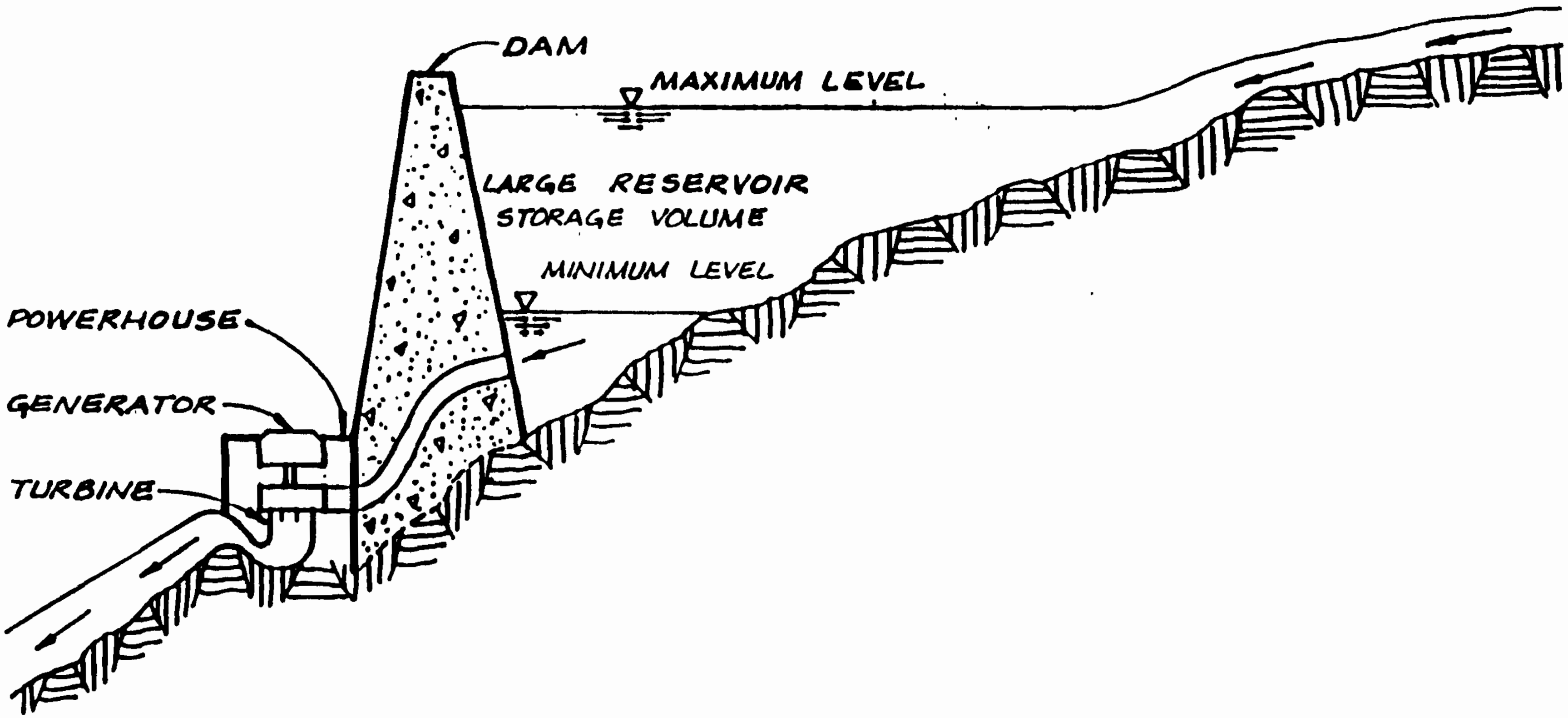


Figure 1. TYPICAL STORAGE HYDROELECTRIC PROJECT – PROFILE VIEW
Source: Federal Power Commission, 1976.

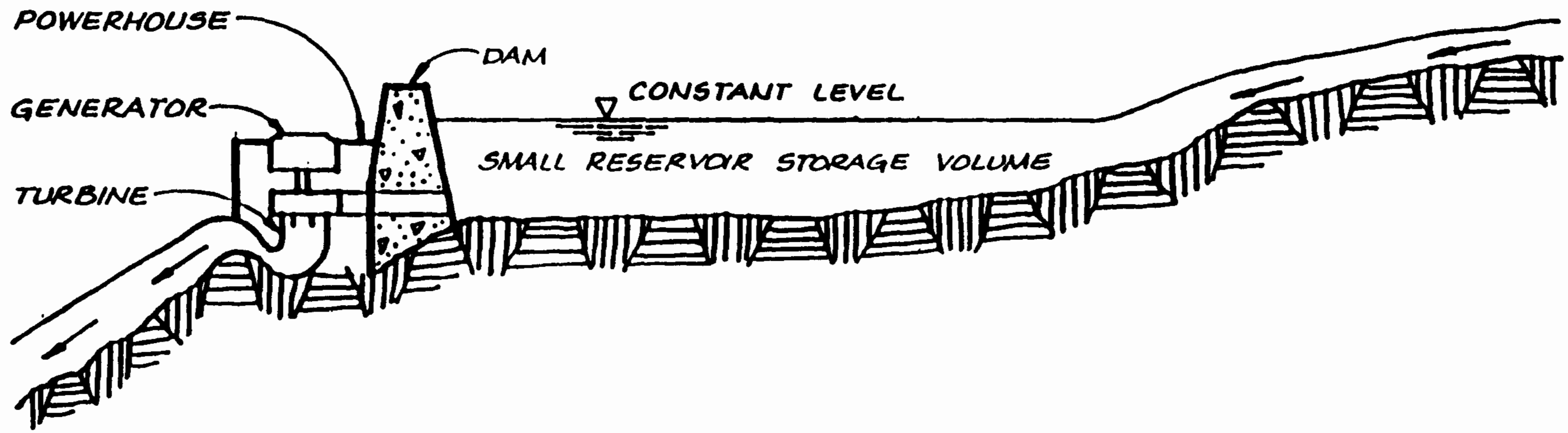


Figure 2. TYPICAL RUN-OF-RIVER HYDROELECTRIC PROJECT – PROFILE VIEW

Source: Federal Power Commission, 1976.

diverted to turn the turbines, while other plants employ "pondage," which is limited impoundment intended to store enough energy (perhaps a few hours of streamflow) to shift maximum power output to peak electric demand hours. Run-of-river plants tend to be smaller than reservoir storage projects, although run of river projects on large rivers can produce several hundred megawatts of power.

Diversion Projects. Another type of hydroelectric project is a diversion or conduit, which is a man-made channel or aqueduct of sufficient slope to create hydrostatic head. Some of these structures are built solely for hydroelectric power, although many diversion projects are sited at existing irrigation or municipal water supply conduits. Although diversions have no storage capacity, some diversion projects are associated with reservoirs and can be operated like storage plants.

Head

Hydrostatic head is measured as the difference in elevation between the impounded and downstream water levels. Head is usually rated under specific conditions, but actual head changes throughout the year based on seasonal waterflows, reservoir management schedules and rules, and electric generation. The Federal Energy Regulatory Commission (FERC) defines dams with gross static head above 20 meters (66 feet) as high head dams, and those below as low head dams. Some facilities attain over 1,000 feet of hydraulic head, with the highest exceeding 2,000 feet. There is no specific correlation between head and capacity. The highest head facility (2,736 feet) is the 1.5 megawatt Upper Manti Canyon project, while the largest hydroelectric project, Grand Coulee Dam, at 6,180 megawatts, is rated at 343 feet of head. Table VI-2 shows the distribution of plants by design head, based on a 37,100 MW sample of plants (plants over 10 MW installed by 1975).

Turbine Type

There are two basic hydraulic turbine types in widespread use: impulse turbines and reaction turbines. Very high head facilities with low flows typically use an impulse turbine (sometimes called a Pelton turbine) where water from the penstock is propelled against a series of buckets around the periphery of a wheel. Lower head facilities generally have short penstocks and sometimes none at all. Lower head facilities are more common and employ reaction turbines. These are usually either Francis turbines, which use bladed rotors similar in appearance to conventional steam turbines, or propeller turbines. Most propeller turbines, called Kaplan turbines, have runners (the blades of the turbine) that can be adjusted for maximum power output for a given head level. These turbines have replaced fixed-blade propeller turbines in new installations, and predominate in projects built after the 1940s. Francis turbines are used on facilities with head between 50 and 1,000 feet, while Kaplan turbines can be used in plants rated between 10 and 100 feet of head. Tubular turbines are ultralowhead turbines used between 5 and 50 feet of head. Figures VI-3 through VI-5 show schematic views of turbine types. Table VI-3 shows turbine characteristics by installation date and design head.

Operating Modes

Utilities have often used hydropower to meet baseload energy demand. In addition, the quick power response time of hydropower generation, compared to longer start-up time for conventional fossil fuel boilers, makes it attractive for load following (varying power output to match daily demand patterns). Many hydroelectric plants are operated as peaking units, where stream inflows are stored behind the dam during the night and released through the turbines during the day.

Storage projects are usually operated in peaking and load following mode. However, during the high flow season, reservoirs often have insufficient storage to operate less than full time, and are operated continuously or in a modified peak mode. Even when operated around the clock, many projects do not have the turbine capacity to use all of the high season flow. In these periods, some water must be "spilled" without passing through the turbine, foregoing potential electricity production.

Run of river plants are typically operated as baseload capacity, running continuously when sufficient water is available. In low seasons, however, many run of river plants operate as peaking units, since on-peak energy is more valuable than off-peak generation, and limited storage capacity can contain small overnight inflows. Other plants have insufficient flow during low seasons to operate at all. Diversion projects associated with reservoirs can be operated as peaking or baseload units, although most diversions are operated as run of river plants.

Environmental Impacts

A broad range of environmental impacts result from hydroelectric development and operation. These include the effects of dams and diversions on surrounding land, water quality issues, recreation opportunities, and fishery impacts. All hydroelectric projects can degrade downstream water quality because the temperature and dissolved oxygen content of water passed through turbines is often lower than natural streamflow. Tailrace waters (water directly exiting the turbine or spillway) can also trap excess nitrogen from the surrounding air, excess amounts of which can be lethal to trout and salmon. Recent spillway designs that deflect water flow can minimize nitrogen saturation. Fish are often killed when they pass through turbines, and dams prevent migrating fish from swimming upstream. This can significantly impede the spawning activity of anadromous fish (species that hatch in fresh water, swim into the ocean, and return to rivers to spawn). Many anadromous fish, such as

TABLE VI - 3
EXISTING TURBINE CHARACTERISTICS

Installation Date	No. Units	Total MW	Average Unit MW	Francis Turbines	Propeller Turbines	Impulse Turbines	Other/ Unknown
Turbines by Installation Dates							
Pre 1910	95	192	2.0	78	0	11	6
1910 - 1924	390	2,795	7.2	345	5	25	15
1925 - 1930	260	4,997	19.2	177	45	17	21
1940 - 1954	354	11,812	33.3	198	118	6	32
1955 - 1980	602	37,496	62.3	271	271	28	32
Total	1,701	57,292	33.7	1,069	439	87	106
Total MW		57,292		27,413	19,843	2,539	7,507
Turbines by Design Heads							
Design Head (Feet)	**No. Units**	**Total MW**	**Average Unit MW**	**Francis Turbines**	**Propeller Turbines**	**Impulse Turbines**	**Other/ Unknown**
50 or less	373	3,853	10.3	199	169	0	5
50 to 100	545	19,823	36.4	257	256	0	22
100 to 200	326	10,170	31.2	300	11	0	15
200 to 500	283	16,365	57.8	233	0	4	46
over 500	179	7,213	40.3	70	3	83	23
Total	1,706	57,425	33.7	1,069	439	87	111

Source: *Increased Efficiency of Hydroelectric Power*, Electric Power Research Institute, June 1982.

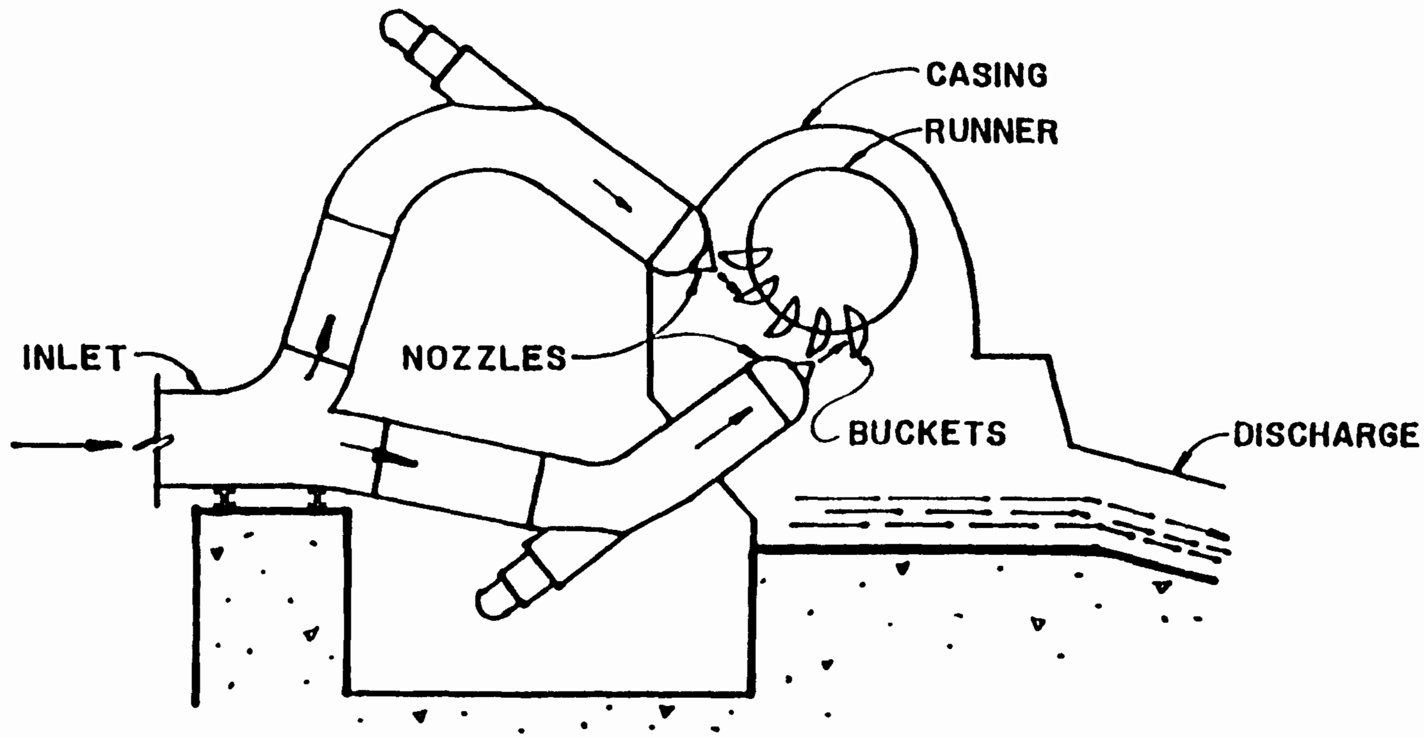


Figure 3. IMPULSE TURBINE

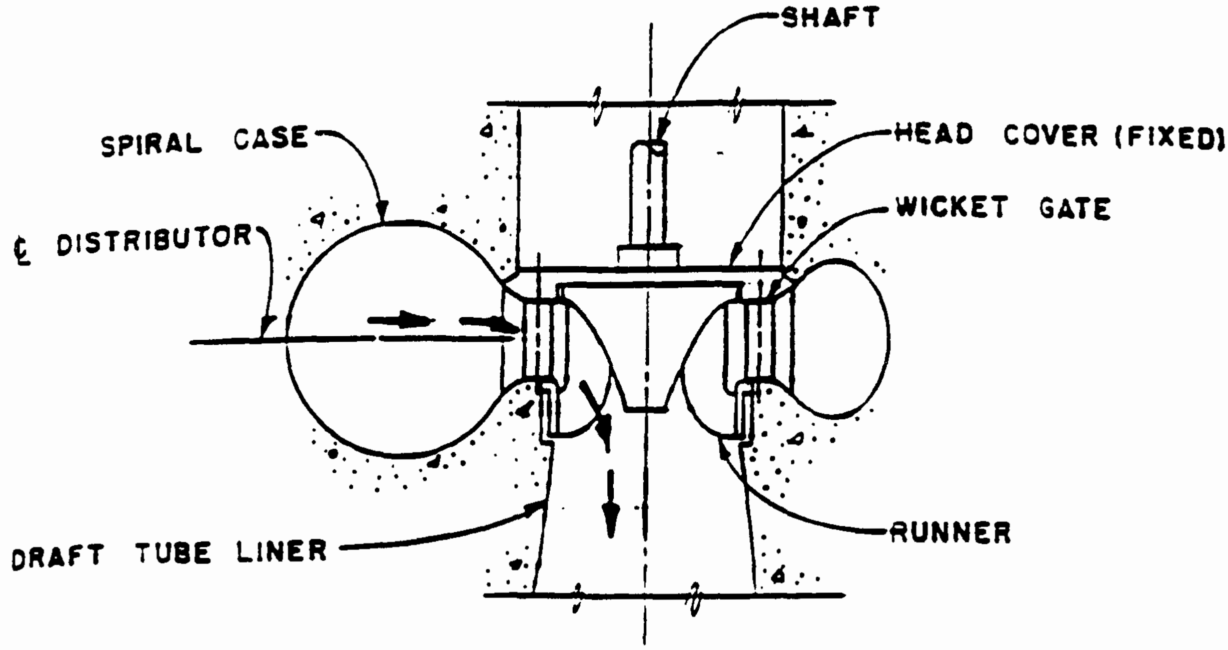


Figure 4. FRANCIS TURBINE

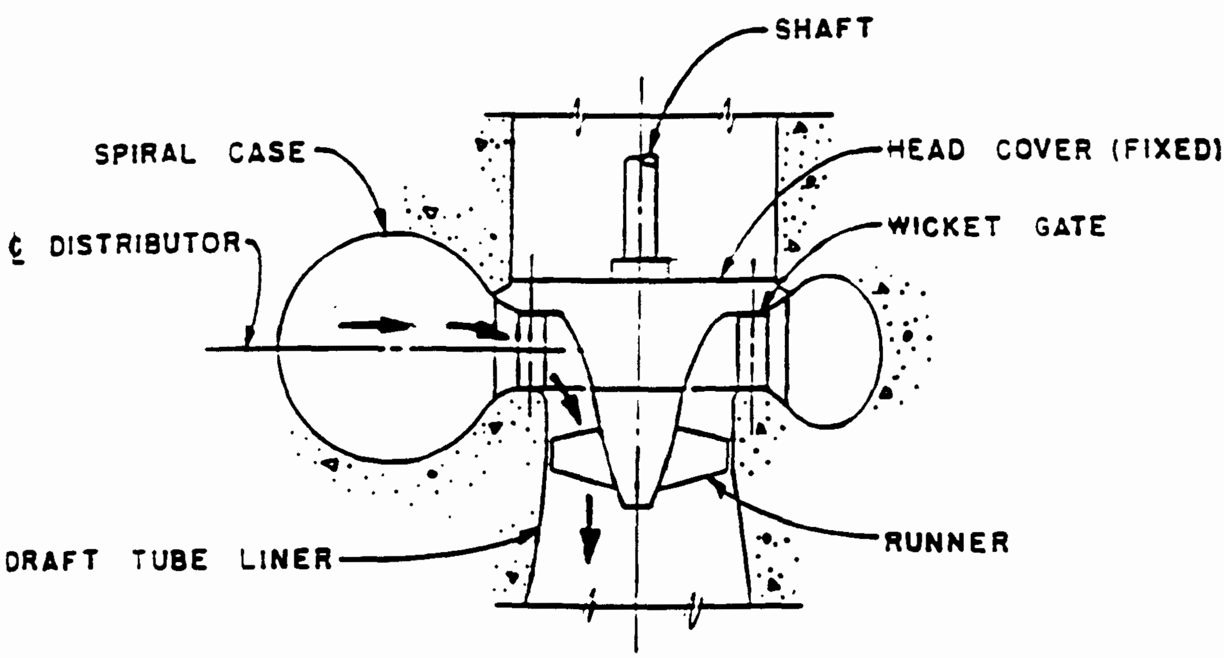


Figure 5. PROPELLER/KAPLAN TURBINE

salmon, are important commercial and recreational species. Fish ladders and other mitigation efforts can alleviate some of these impacts, but are expensive and not completely effective in most cases.

Storage projects have the greatest overall impacts, since the land inundated with water is lost for wildlife and recreation, and peaking operations can seriously disrupt both upstream and downstream river and riparian (shoreline) ecosystems. Upstream impacts are due mostly to fluctuations in reservoir levels. Downstream impacts from peaking operation due to flow variation include changes in water depth, temperature, and dissolved oxygen, as well as the scouring of sediments. These impacts can reduce the abundance, diversity, and productivity of downstream riverine species.[2] Mitigation options include minimum flow requirements and the construction of a re-regulating dam (which can also generate power) to stabilize flows further downstream. Minimum flows are sometimes set below the minimum operational rate of the turbine, and are therefore spilled without producing electricity. Even when minimum flows can be passed through the turbine during the night, the value of energy is typically much lower than daytime generation. Diversions, which can be several miles in length, can reduce or cease stream flows when they divert water from natural streambeds.

Not all impacts are negative. Flood control is an important function of many dams. Some storage projects create lakes large enough for boating and other forms of recreation. Regulated flows on many rivers can in some cases improve the quality of whitewater recreation, although many whitewater enthusiasts remain opposed to controlling or regulating natural flows.

Mitigation technologies must be developed to maximize output given strict environmental constraints. At present, solutions to environmental concerns are applied on a case-by-case basis. While this reflects the uniqueness of hydropower sites to some degree, it also reflects the state of the knowledge regarding mitigation options. At present, only private R&D efforts are being pursued. Additional government research support could help private developers examine a wider range of options and approaches. However, DOE last funded research into small hydro systems in fiscal year 1987.

Resources Recovered and Supply Characteristics

As shown in Table VI-1, approximately 71 thousand MW of hydropower capacity has been installed in the U.S.; storage projects account for over two-thirds of the total capacity. Average generation from all hydropower projects totals just under 300 billion kWh. However, actual

---

[2] See Robert M. Cushman, "Review of Ecological Effects of Rapidly Varying Flows Downstream for Hydroelectric Facilities," *North American Journal of Fisheries Management* 5:330-339, 1985.

hydropower output in the U.S. can vary by as much as 25% in any given year due to rainfall and temperature conditions. The record year for hydroelectric output was 1983, when 371 billion kWh was generated; during the drought year 1988 hydropower provided only 223 billion kWh.

Hydroelectric operation is project specific, governed by capacity, state and federal water allocation rules, climate, utility system characteristics, and other factors. Hydropower, while dispatchable, is not always "firm." Unlike other technologies that are limited by installed capacity, hydroelectric production is often limited by the potential energy stored in the reservoir or watershed. Drought can reduce the availability and power output of a hydropower system, and hydropower output is strongly seasonal in many areas. During 1988, for example, hydropower generation was significantly curtailed during the summer months (as was output from several fossil and nuclear plants that rely on cooling waters.) Moreover, other claims on water resources -- irrigation, flood control, stream flow for navigation, recreation, and wildlife -- can limit the availability of hydropower during certain times of the year.

The output of hydroelectric plants varies with seasonal rainfall and snowmelt, and even extensive reservoir systems cannot store or otherwise smooth out all seasonal loadings. Nationally, hydroelectric power is usually lowest in October or November, but fall rains quickly provide the peak output in January. Another peak occurs around May, due to spring rains and snowmelt. But these patterns vary by region: the peak flow period of the Columbia River in Oregon, for example, occurs between April and October. While the reservoir system has altered these flows, it can store only 40% of the spring and summer runoff, and some energy is lost through spill. Since electric loads in the Pacific Northwest are highest in winter, some of the surplus generation is sold to meet summertime peak load in California.[3]

Utilities operate hydropower to meet base, intermediate, and peak loads, subject to project type (i.e. run of river or storage), water availability, and energy value criteria. Although definitive national data on seasonal plant availability do not exist, hydroelectric plant factors average 48%.[4] Run of river capacity attains an average plant factor of 57% (for average conditions), diversion projects operate at 52% plant factors, while storage projects operate at 45% plant factors.

---

[3] See "Better Use of the Hydropower System" Staff Issue Paper, Northwest Power Planning Council, October, 1989.

[4] Plant factor is defined by FERC as the ratio of the average load on the plant for a given period of time considered to the aggregate rating of all the generating equipment installed in the plant. Thus, plant factor is the same as capacity factor.

Current Economics

In 1989, electricity prices in the U.S. averaged 7 ¢/kWh.[5] Hydroelectricity accounted for 10% of U.S. electricity generation that year. In contrast, in the Northwest region, where over 80% of electricity comes from hydropower, prices averaged 4 ¢/kWh.[6] Electricity produced by currently operating hydroelectric plants costs approximately half that of electricity produced by conventional fossil plants. However, some of the federally-owned dams have been financed on extremely attractive terms, and electricity prices may not reflect the true cost of providing hydropower from existing dams.

Since it is unlikely that a significant amount of new dam development will occur, the future costs of hydropower will be comprised of operating and maintenance costs and the costs of retrofitting and upgrading existing dams that either lack generators or have generators that operate below state-of-the-art efficiencies. These costs are discussed in a latter section.

HYDROELECTRIC EXPANSION OPTIONS

Hydroelectric power generation is considered a mature technology, which is demonstrated by the lack of significant emerging conversion technologies. Thus, while the potential for expanding hydropower is traditionally identified with constructing new dams or augmenting existing power generation facilities, other methods of increasing hydropower output have been the focus of recent attention. Only about 3% of the over 60,000 dams in the U.S. are actually used to generate power, and many of these sites have retired generation facilities. These sites represent power generation potential with less environmental impact than new construction. The Federal Energy Regulatory Commission (FERC) estimates that between 25 and 30 GW of conventional capacity could be developed at existing dams. Areas with the greatest potential for development include the West and the Middle to South Atlantic states. In addition, upgrading existing turbines and generators, and improving operating techniques hold promise for augmenting generation from existing hydroelectric facilities. The various options are discussed below.

---

[5] *Annual Outlook for U.S. Electric Power 1990: Projections Through 2010.* Energy Information Administration, Department of Energy, June 14, 1990

[6] The Bonneville Power Administration currently supplies priority firm wholesale electricity from hydropower at 2.33 ¢/kWh. FERC approved this price and deemed it sufficient to cover costs. Conversation with Roger Seifert, Bonneville Power Administration, April 16, 1991.

New Developments

Dam and powerhouse construction at river sites constitute new development. These projects are typically very capital intensive and contentious. Obtaining a license from FERC represents a substantial hurdle, especially for new projects that would significantly alter the natural streamflow. Most industry observers agree that the era of large hydroelectric project development in this country is over, and many remain pessimistic about the state of new development at smaller sites.

Power Existing Dams

Most of the dams in the U.S. were not originally designed for power generation, but were built for flood control, water supply, navigation, or other water management reasons. Many of these could be retrofitted with turbines. FERC has identified potential projects at non-power dams totalling nearly 19,900 megawatts of capacity which could supply 56,300 gigawatt hours per year assuming average conditions. Owing to the types of structures available, most of this capacity -- over 11,000 MW -- is classified as run of river. Nearly 7,300 MW of reservoir storage projects could be developed, with existing diversions accounting for about 1,600 MW. Table VI-4 shows the breakdown of these projects by region and type.

Although the FERC database is generally considered definitive, it may not be complete for all regions. For example, a 1981 DOE report identified 2,600 MW of potential hydropower development at existing Corps of Engineers navigation and flood control dams located in the Midwest.[7] Many of these potential sites are not listed in the FERC database as either developed, undeveloped, or under construction. While FERC may have evaluated the sites as infeasible by its own criteria, it is possible that some development potential is not reflected in the FERC data. On the other hand, because of water quality impacts, FERC has denied hydropower license applications for retrofitting dams in this region. The feasibility and costs of developing all of the potential sites are not known.

Redevelopment and Expansion

Existing generation sites may enhance power output by raising the dam to create larger impoundments, replacing older turbines built to capture only a portion of the available energy, or by adding new turbines to capture spill in high-head conditions or to extend operation into low-head conditions. A significant portion of existing capacity includes the gains achieved at expanded and redeveloped sites; for example, both Grand Coulee and Hoover dam projects were expanded in the

---

[7] See *Power Marketing in the Great Lakes Area*, U.S. Department of Energy, August 1981.

TABLE VI - 4
POTENTIAL CAPACITY AND GENERATION AT NON-POWER DAMS AND DIVERSIONS

REGION	RUN OF RIVER		DIVERSION		STORAGE		TOTAL	
	MW	GWH	MW	GWH	MW	GWH	MW	GWH
New England	1,588	4,409	85	302	159	377	1,832	5,088
Mid Atlantic	891	3,110	126	394	80	292	1,098	3,796
South Atlantic	1,534	4,296	67	248	889	1,645	2,490	6,188
Florida	18	59	3	14	27	100	48	172
East North Central	907	4,252	13	67	122	275	1,042	4,593
West North Central	681	2,961	4	8	825	3,131	1,510	6,100
East South Central	1,036	4,215	0	0	262	788	1,298	5,003
West South Central	732	2,423	0	0	488	509	1,220	2,932
Mountain	1,144	2,734	575	2,397	886	1,398	2,605	6,529
Arizona/New Mexico	716	3,374	7	27	62	239	784	3,640
California	287	843	460	870	1,961	2,603	2,708	4,316
Washington/Oregon	1,505	4,053	236	918	1,498	2,936	3,239	7,908
TOTAL	11,038	36,727	1,576	5,244	7,259	14,292	19,874	56,264

Source: Federal Energy Regulatory Commission (FERC) database, 1990.

1980s. FERC has identified potential expansion opportunities at existing power generation sites totalling over 6,500 megawatts of capacity that could provide 15,400 gigawatt hours of generation annually. Table VI-5 shows the potential capacity at developed power dams by region and type.

Two studies performed in the early 1980s identified redevelopment potential. The Army Corps of Engineers concluded that expanding existing powerhouses could increase national hydroelectric output by roughly 11%, mostly through additional spill capture, while an Electric Power Research Institute (EPRI) study of large hydroelectric facilities estimated that capacity could be increased by 14% by adding generating units and storage, yielding an increase in generation of 2.6%.[8] FERC has identified 243 existing hydroelectric facilities with potential for expansion, and 20 of the 174 projects under construction as of January 1988 were expansion projects at existing facilities.[9] Thus, some of the potential identified in the late 1970s has probably been realized.

Raising the dam structure to create a larger impoundment and increase head requires a dam safety assessment and could have environmental impacts that would preclude licensing. Adding or replacing turbines, on the other hand, would probably have less adverse environmental impacts. All redevelopment options require significant expense, although substantial gains in capacity and (typically smaller) gains in generation will be economically justified in many cases.

Restore Retired Power Generating Stations

FERC has identified 3,112 retired hydro generating stations, and over two-thirds of those have filed capacity data with FERC.[10] Table VI-6 shows the capacity of these sites by region. If the reported sites are representative of the unreported sites, almost 2,200 MW of potential capacity may exist at retired sites. It is not clear the extent to which these sites are constrained to historic power generating levels if restored with modem equipment. Between 1980 and 1988, 142 retired sites were returned to operation status, amounting to roughly 100 MW of hydroelectric capacity (assuming the sites were representative of the FERC data).[11] However, even the redevelopment of retired

---

[8] See *Potential for Increasing the Output of Existing Hydroelectric Plants, National Hydroelectric Power Resources Study Volume IX* (Washington D.C.: U S Army Corps of Engineers, July, 1981) p. 15, and *Increased Efficiency of Hydroelectric Power*, (Palo Alto: Electric Power Research Institute, June 1982), page S-5.

[9] *Hydroelectric Power Resources of the United States: Developed and Undeveloped*, (Washington D.C.: Federal Energy Regulatory Commission, January 1, 1988), Table IX, p. xxv.

[10] Figures taken from FERC computer printout "Retired Hydropower Plants in the Unites States" dated July 7, 1989.

[11] *Hydroelectric Power Resources of the United States: Developed and Undeveloped*, (Washington D.C.. Federal Energy Regulatory Commission, January 1, 1988), p. xviii.

TABLE VI - 5
ADDITIONAL POTENTIAL CAPACITY AND GENERATION AT DEVELOPED POWER SITES

REGION	RUN OF RIVER		DIVERSION		STORAGE		TOTAL	
	MW	GWH	MW	GWH	MW	GWH	MW	GWH
New England	204	521	0	0	1	2	205	523
Mid Atlantic	470	1,043	0	6	811	1,394	1,281	2,443
South Atlantic	21	94	2	4	161	260	183	358
Florida	0	0	0	0	0	0	0	0
East North Central	33	101	3	91	54	85	90	277
West North Central	24	150	44	100	92	241	160	491
East South Central	59	200	0	0	90	159	149	359
West South Central	1	1	0	0	312	280	313	281
Mountain	183	552	0	1	1,047	790	1,230	1,343
Arizona/New Mexico	0	0	0	0	68	368	68	368
California	1	5	837	2,181	392	1,080	1,231	3,265
Washington/Oregon	69	377	74	258	1,464	5,032	1,607	5,666
TOTAL	1,065	3,043	961	2,640	4,492	9,690	6,517	15,373

Source: Federal Energy Regulatory Commission (FERC) database, 1990.

TABLE VI - 6
RETIRED HYDROELECTRIC FACILITIES

REGION	NUMBER OF SITES	SITES W/ CAPACITY DATA	REPORTED CAPACITY (MW)	# SITES MW > 1	# SITES MW > 5
New England	1,472	716	364	77	7
Mid Atlantic	385	347	248	64	6
South Atlantic	194	170	122	34	1
Florida	3	2	12	2	1
East North Central	435	404	201	54	2
West North Central	240	223	134	30	6
East South Central	34	29	20	2	1
West South Central	20	19	12	5	0
Mountain	149	139	126	23	4
Arizona/New Mexico	11	10	22	1	1
California	53	8	171	13	6
Washington/Oregon	82	81	73	20	2
TOTAL	3,078	2,148	1,505	325	37

Source: Federal Energy Regulatory Commission (FERC) database, printout dated July 7, 1989.

generating stations can provoke dispute. Many of these dam sites were constructed long before environmental impacts were considered and mitigation actions were required. Many retired sites might not be economic to restore when the costs of required studies and mitigation measures are considered. In fact, the attention drawn to retired power generating dams during the license application process has aroused calls for the physical removal of certain dams.

Generator and Turbine Modernization Upgrades

Hydropower operators are investing in efficiency improvements for many generator and turbine sets, with resulting increases in energy and capacity. Both the Army Corps of Engineers study and the EPRI study concluded that equipment uprating and improvement could expand annual hydropower generation by about 3,700 GWh (about 1.4% of 1980 generation), and capacity by about 4,000 MW (about 6% of 1980 capacity according to EPRI). Increased generation can result from mechanical efficiency gains as well as spill capture.

Some of this mechanical potential was realized during the 1980s, and the improvements achieved suggest that the earlier studies may have been conservative. According to a recent industry estimate, about 750 individual turbine units were modernized between 1980 and 1989, split equally among runner replacements, rehabilitation performed by manufacturers, and rehabilitation performed by owners (rehabilitation will typically include a runner replacement). The runner replacements were conducted on units where runners averaged 53 years old, and the average increase in turbine output was an impressive 22 percent.[12]

Index testing and governor calibration is another modernization technique for Kaplan turbines. The index test establishes the optimum wicket gate to turbine blade angle, which can be used to fashion a set of mechanical cams to ensure maximum power output. Output gains of the order of 2% to 3% are possible.

The ultimate potential of hydropower modernization is difficult to gauge. Since the activity during the 1980s was driven by economics, most of the oldest, least efficient facilities may have already been modernized, limiting the energy potential of subsequent projects. On the other hand, continued refinement of techniques and equipment may allow upgrading to supply more power than initial estimates implied, especially as the need for new utility capacity increases. As a rough estimate, perhaps 4,000 to 6,000 MW of additional potential remains.

---

[12] Presentation by Don Froelich, Black & Veatch Inc, at the National Hydropower Association Conference, Washington D.C., July 16, 1990

Improve Operating Practices

Wide-scale adoption of new monitoring and control techniques, as well as changes in reservoir management practices, could maximize energy production from existing developments. For example, opportunities exist at large, multi-turbine, hydroelectric projects to enhance the combined output of the facility by operating individual turbines in an "optimal dispatch," taking into account both the available hydraulic resource and electric load. Many owners are currently investigating these options or implementing improved operating rules.

Changes in reservoir management can increase hydropower output in some cases. Improved coordination of multiproject reservoir systems may enhance the value of generation. Changing reservoir regulation schedules or reallocating flood control space can increase output, although these operational changes require prudent study and face many constraints due to the competition for water resources and the concerns for adequate flood control. The Army Corps of Engineers study suggested that a 1% increase in national hydropower generation may be possible from reallocating flood control storage, and that such actions could increase energy value by enhancing the dependability of the capacity (convert non-firm energy to firm energy).

Modifying the operation of peaking hydropower units to more run-of-river mode would reduce energy value, but in some cases, might also provide aggregate emission reductions in some utility systems dominated by coal baseload plants where gas-fired turbines could provide the lost peak-load generation. Since the peakload variation in waterflow has detrimental effects on downstream water quality, the increased restrictions placed on hydropower operation are moving the industry in this direction already.

Because changes in hydropower operation may be constrained by other claims on river resources, the system implications of transferring hydropower from peak to baseload must be evaluated from an economic and environmental perspective. One recent analysis examined the emissions impact of altering the operation of hydropower capacity in the Los Angeles Department of Water and Power system.[13] The authors estimated that converting peak storage hydroelectric plants to run-of-river operation would increase emissions, due to an increase in fossil-fuel plant output for pumped storage to satisfy peak power demands, as well as technological constraints on reducing the operation of other fossil fuel plants during low demand hours. Thus, the success of altering

[13] See "Assessing the Environmental and Economic Effects of Changes in Hydro Generation on the LADWP System," by Kenneth Henwood and David Branchcomb, paper presented to the National Hydropower Association Conference, Washington D.C., June 17.

hydropower operations as an emission reduction strategy depends on the characteristics of the utility system. For some systems, a change from peaking operation to run-of-river mode may still reduce emissions, and growing concerns over the ecological impacts of peaking operations could stimulate emission reductions in some circumstances.

Hydroelectric Expansion Costs

The costs of hydroelectric investment options vary substantially, from over $3,000 per kW for new developments at some sites to less than $100 per kW for generator or turbine upgrades that yield small gains. Since each hydroelectric project is unique, similar expansion projects display wide variation in costs, as shown in Table VI-7, based on industry surveys. However, institutional and regulatory constraints, rather than costs, dominate most questions of hydropower resource development. In addition, the costs of the environmental impact studies required for licensing or relicensing can be high, and have sometimes led potential developers to abandon a project. Recent data indicate that the cost of studies and other administrative requirements needed to relicense a 1 MW plant averages $300,000, and can exceed $500,000, while a 10 MW plant requires nearly $1,000,000.[14] Thus, relicensing costs between $100 and $500 per kilowatt of capacity. Given construction costs of between $1,500 and $2,500 per kilowatt, the costs of building new capacity can now exceed $3,000/KW. Costs are unlikely to decline to any appreciably in the near future.

TABLE VI - 7
REPRESENTATIVE HYDROELECTRIC EXPANSION COSTS

OPTION	CAPITAL COST ($/KW)	VARIABLE COST (¢/KWh)	LEVELIZED COST (¢/KWh)
New Development	1,500 - 3,500	0.4 - 0.8	4.0 - 9.0
Power Existing Dam	1,250 - 3,000	0.4 - 0.8	3.5 - 8.0
Expand Capacity	1,000 - 2,000	0.3 - 0.6	3.0 - 6.0
Restore Retired Plant	700 - 1,500	0.4 - 0.8	2.0 - 5.0
Turbine Upgrade	50 - 600	N/A	0.1 - 1.5

[14] Figures from "The High Cost of Hydro Licensing" by Richard Hunt, *Independent Energy*, October 1990 based on recent EPRI reports.

According to the FERC database, expansion projects at existing power dams would attain an average plant factors of only 27%, while hydropower developments at existing non-power dams would attain annual plant factors of 32%. In the former case, low plant factors reflect the relatively high proportion of storage projects in the FERC assessment, as well as the limited operation of additional turbines. Most developments at non-power dams would be operated in run of river mode. These relatively low factors also reflect the likelihood that many of the best water resources are already developed.

MARKET CHARACTERISTICS AND CONSTRAINTS

Ownership

The federal government owns and operates 39.5 GW of conventional and pumped storage capacity, or 44 percent of total U.S. hydroelectric capacity (including pumped storage) of 89.1 GW. Three agencies -- The U.S. Army Corps of Engineers (ACE), the Bureau of Reclamation (BOR), and the Tennessee Valley Authority (TVA) -- account for over 99% of this capacity. TVA markets its own power, while other federally generated power is marketed by the five other power marketing agencies (PMAs). The largest of these, the Bonneville Power Administration, markets power from dams in the Northwest. The institutional principles that guide investment and operation in these agencies differ from those that govern utility planning, and reform may lead to more efficient utilization of existing hydropower capacity.

The lack of incentives within certain Federal power authorities is a potential barrier to hydroelectric efficiency improvements. The manner in which power is generated by these authorities and sold by PMAs provides little incentive for implementing efficiency improvements. In order to make the necessary investments, the generating agencies would need to request an appropriation from Congress, and any increased revenues or profits resulting from efficiency improvements would be realized by the PMAs, who would forfeit those to the U.S. Treasury. From the perspective of the ACE and BOR, efficiency improvements involve an increase in their work load with no appreciable benefit in terms of their own financial position. On the other hand, the TVA and public utilities typically have appropriate incentives and are proceeding to implement efficiency improvements.

Municipalities and cooperatives, which are operated for the benefit of the ratepayers, own about 19.2 GW of conventional and pump storage hydropower, or about 22 percent of U.S. capacity. Private utilities and private non-utility ownership accounts for the remainder. Private utilities operate 28.4 GW; non-utility hydropower developers represent a small (1.3 GW), but growing segment of the market. Under the Public Utilities Regulatory Policies Act (PURPA), non-utility developers were guaranteed a market for electric power produced from small hydroelectric plants, and FERC grants a license exemption for any project less than 1,500 KW.

Non-federal owners face the potential for competition for the FERC license. If another entity can prove to FERC that it could operate the project more efficiently than the current owners, then FERC can transfer the license to the contestant, forcing the current owner to sell the plant to the licensee. This institutional arrangement has compelled many owners to examine potential improvements. Before the passage of the Electric Consumers Protection Act of 1986 (ECPA), plants undergoing relicensing often increased capacity and energy, sometimes gaining as much as 40% additional capacity and 65% additional energy production. However, the increased restrictions posed by ECPA (see below) has largely erased large gains, and has lead to reduced capacity and energy in some cases.

Environmental and Regulatory Constraints

Hydropower development faces a barrage of environmental constraints under current law. These range from a complete moratorium on development on federal and state designated scenic rivers to impact studies required for the relicensing of existing hydropower facilities. Some institutional constraints also exist, since many hydroelectric facilities are federally owned and hydropower operation can be limited by rules, contracts, treaties, and other agreements that govern the use of water in a reservoir system.

Electric Consumers Protection Act of 1986 (ECPA). The Electric Consumers Protection Act of 1986 (P.L. 99-495) requires that hydropower licenses be issued only if the benefits of hydroelectric generation exceed the costs, when compared on an "equal consideration" basis. This applies to initial license applications for new projects and to relicensing efforts at existing facilities. ECPA requires that the power benefits be compared with non-power benefits and costs. These non-power concerns do not generally include air emission impacts; however, a broader view of power and non-power impacts, including avoided air emissions, are beginning to be considered in order to better fully measure the benefits of hydropower. Considering the system-wide emission impacts of hydropower operation in licensing or other decisions, while complex, would expand the focus from the local impacts on water quality, fish, plant, and wildlife habitat that currently dominate the process.

The studies and assessments required by ECPA, in addition to other legislation such as the National Environmental Policy Act and the Clean Water Act, have been a source of controversy in the hydropower industry. The cost and time required to perform the studies have derailed some projects, especially smaller ones. A complete assessment of plant and wildlife impacts, water quality, and riparian ecosystems must be made. If a project is approved for licensing, it may be subject to a variety of restrictions, such as minimum stream flow requirements for fish or recreation, dissolved oxygen requirements, and mandatory structures to reduce fish mortality.

The majority of non-federal projects, which account for roughly half of existing conventional capacity, will be subject to relicensing in the next 20 years. About 200 hydroelectric projects have FERC licenses that will expire during the 1990s, with 166 licenses expiring in 1993 alone. As displayed on Table VI-8, the combined capacity of projects subject to relicensing between 1990 and 2010 is 20,900 MW. These plants face the prospect of reduced capacity and energy owing to additional environmental constraints such as minimum flow requirements to protect ecological resources. Minimum flow regimes can reduce the energy for power generation and the value of power output. These impacts are especially pronounced on large storage projects, where industry observers anticipate output reductions up to 10 percent at some projects.

Off-Limit Rivers. According to FERC, roughly 45.8 gigawatts of potential projects, capable of generating 126,370 gigawatt hours annually, are precluded from development, or subject to a moratorium while being studied, under the National Wild and Scenic Rivers Act and other laws.[15] Several states and local jurisdictions have also have designated specific rivers off-limits for hydropower development. For instance, the Northwest Power Planning Council restricted more than 44,000 miles of streams in Oregon, Washington, Idaho, and Montana from hydroelectric development.

Endangered Species Act. Recently, the Shoshone-Bannock Tribes of Idaho, along with fishing associations and environmental groups, filed petitions with the National Marine Fisheries Service to list five species of Northwest Salmon as endangered or threatened under the Endangered Species Act. If these petitions are granted, and similar petitions are brought to protect species in other river basins, river management will be significantly altered. The resulting mitigation measures could substantially reduce hydroelectric generation at existing sites and prohibit development at others.

MARKET ASSESSMENT

The EPA hydroelectric scenarios consider expansion only at existing dam sites, including refurbishment and upgrades, expansion of existing generating facilities, powering existing dams, and restoring retired generation facilities. Both scenarios incorporate the potential impact of post-ECPA relicensing decisions, which could reduce capacity, energy production, or both from existing

[15] *Hydroelectric Power Resources of the United States: Developed and Undeveloped*, Federal Regulatory Commission, January 1, 1988, p. xxvii.

TABLE VI - 8
HYDROELECTRIC LICENSES EXPIRING AT EXISTING PLANTS 1990 - 2010

REGION	RUN OF RIVER		DIVERSION		STORAGE		TOTAL	
	MW	GWH	MW	GWH	MW	GWH	MW	GWH
New England	646	2,975	17	71	428	1,091	1,091	4,137
Mid Atlantic	1,512	9,184	21	39	2,058	13,293	3,591	22,516
South Atlantic	338	1,214	121	601	2,122	5,202	2,581	7,017
Florida	0	0	0	0	0	0	0	0
East North Central	250	1,052	4	25	323	1,326	577	2,403
West North Central	97	532	0	0	263	963	360	1,495
East South Central	146	632	0	0	1,367	4,152	1,513	4,783
West South Central	108	190	0	0	65	117	173	307
Mountain	445	2,719	11	66	1,542	6,960	1,998	9,745
Arizona/New Mexico	7	35	0	0	0	0	7	35
California	35	189	2,516	11,675	509	2,774	3,060	14,639
Washington/Oregon	338	1,984	734	3,753	4,858	25,941	5,931	31,678
TOTAL	3,922	20,706	3,424	16,230	13,536	61,819	20,883	98,755

Source: Federal Energy Regulatory Commission (FERC) database, 1990.

hydropower projects. Run of river projects subject to relicensing are assumed to have capacity reduced by 2% and energy reduced by 1%, but storage projects are assumed to lose 4% of capacity and 2% of energy. These impacts reduce existing capacity by 70 MW between 1990 and 2000, and reduce capacity by 690 MW over the 1990-2010 period, reflecting the concerns of industry analysts that many projects will lose significant capacity and energy in the coming years. Table VI-9 shows capacity and generation estimates for the EPA and DOE/SERI scenarios.

Under the EPA Base Case, conventional hydropower capacity would increase by 3,420 MW between 1990 and 2000 (rising from 71,270 MW to 74,690) and would increase another 2,000 MW between 2000 and 2010 (reaching 76,690 MW), an annual average growth rate of only 0.4% during the period. Because hydropower expansion at existing dams tends to operate at lower plant factors than existing capacity, generation would increase by 6,950 GWh between 1990 and 2000, and increase by 13,640 GWh between 1990 and 2010, an average annual growth rate of about 0.2% over the period.

The EPA Enhanced Market scenario portrays a more robust future for hydroelectric development at existing dams in the U.S., spurred by increased concern over the environmental impacts associated with fossil fuel-fired generating capacity. Additional R&D into mitigation options is assumed to make a greater fraction of the identified potential at existing dams subject to environmentally acceptable development. Although relicensing losses are assumed to be identical to the Base Scenario, the Enhanced Market scenario could increase hydroelectric capacity by 10,500 MW between 1990 and 2000, and by 16,490 between 1990 and 2010, an annual average growth rate in capacity of 1.2%. This additional capacity would provide 45,500 GWh per year under average conditions.

The costs of hydropower expansion options are assumed the same in both EPA scenarios. Because costs are very project specific, they should be regarded as suggestive. On the one hand, some costs are likely to fall as a result of greater market activity in the Enhanced Market scenario, and some streamlining of regulatory process cost is likely. On the other hand, developers will have to undertake more difficult and challenging expansion projects. These two effects are assumed to offset each other, keeping capital costs of each expansion option the same between the two scenarios.

The cost and air pollution prevention figures reported in Tables VI-10 and VI-11 combine the results of separate analyses of run-of-river and storage projects (see Appendix B for separate results). In the Base Case, over 40% of the expansion occurs in the Washington/Oregon region, 13% in California, 10% in the Mountain region, and 9% in the Mid Atlantic region. The expansion of hydropower is more geographically dispersed in the Enhanced Market scenario: the

TABLE VI - 9
HYDROELECTRIC SCENARIOS

Scenario	Capacity 2000 (MW)	Generation 2000 (GWh)	Capacity 2010 (MW)	Generation 2010 (GWh)
DOE/SERI				
Business as Usual	76,800	331,600	77,800	335,500
Intensified RD&D	79,800	333,600	97,500	387,200
National Premiums	81,700	339,400	103,600	404,800
EPA				
Base Case	74,700	305,000	76,700	311,700
Enhanced Market	81,800	324,800	87,800	343,500
1990:	71,300	298,000		

Washington/Oregon region accounts for 23% of the increase, while seven of the remaining eleven regions account for between 7% and 11% of the incremental generation.

Costs

Generation costs vary by region according to the assumed mix of hydroelectric projects, which include refurbishments and upgrades, expansion of existing generating facilities, powering existing dams, and restoring retired generation facilities.[16] Hydroelectric generation costs are very competitive with fossil fuel-fired electricity, especially for storage projects that provide peak load power. However, because hydropower is not always "firm" due to seasonal and yearly variation in precipitation (i.e. hydropower does not receive full capacity credit in the REM), the avoided conventional cost for hydropower generation averages about 4.3 ¢/kWh in 2000 and 5.1 ¢/kWh in 2010. Hydropower generation costs are lowest in the North Central region and highest in California, and overall average about 5 ¢/kWh across the U.S. By 2010, generation from expanded hydropower

[16] Incremental hydropower costs are overstated somewhat because new expansion is offset partially by reduced generation at existing sites subject to relicensing restrictions. The unit costs reported here reflect the expansion costs divided by the net increase in regional generation.

TABLE VI - 10

ELECTRICITY GENERATION COSTS AND AIR POLLUTION PREVENTED

EPA BASE CASE
HYDROPOWER

REGION	AVERAGE UNIT COST IN 2000 (cents/kWh)			AVERAGE UNIT COST IN 2010 (cents/kWh)		
	AVOIDED FOSSIL	HYDROPOWER	COST DIFFERENCE	AVOIDED FOSSIL	HYDROPOWER	COST DIFFERENCE
Northeast	4.4	4.9	0.4	5.9	5.3	-0.6
Southeast	3.7	5.3	1.5	4.3	5.5	1.3
Southwest	4.4	5.2	0.8	5.3	5.2	-0.1
North Central	3.9	4.1	0.2	4.4	4.1	-0.3
Northwest/Mountain	4.5	4.5	0.0	4.6	5.1	0.5
California	4.6	5.7	1.2	7.5	6.1	-1.4
AVERAGE	**4.3**	**4.9**	**0.6**	**5.1**	**5.2**	**0.1**

REGION	INCREMENTAL GENERATION 1990 - 2010 (GWh/yr)	AIR POLLUTION PREVENTED 1990 - 2010 (thousand metric tons/yr)						
		SO_2	NO_x	Particulate Matter	CO	CH_4	CO_2	CO_2 Equivalent
Northeast	2,287	15.5	7.3	0.47	0.34	0.02	1,966	2,258
Southeast	1,826	16.2	7.7	0.47	0.26	0.02	1,831	2,141
Southwest	1,054	2.2	3.9	0.19	0.16	0.01	904	1,062
North Central	1,784	18.1	7.6	0.46	0.26	0.02	1,796	2,102
Northwest/Mountain	4,947	28.1	22.2	1.42	0.69	0.05	5,247	6,140
California	1,740	0.4	4.1	0.06	0.29	0.00	927	1,091
TOTAL	**13,638**	**80.5**	**52.9**	**3.08**	**2.01**	**0.11**	**12,671**	**14,794**

TABLE VI - 11

ELECTRICITY GENERATION COSTS AND AIR POLLUTION PREVENTED

EPA ENHANCED MARKET SCENARIO
HYDROPOWER

REGION	AVERAGE UNIT COST IN 2000 (cents/kWh)			AVERAGE UNIT COST IN 2010 (cents/kWh)		
	AVOIDED FOSSIL	HYDROPOWER	COST DIFFERENCE	AVOIDED FOSSIL	HYDROPOWER	COST DIFFERENCE
Northeast	4 5	5 2	0 8	5 9	5.6	-0.3
Southeast	3 7	5.3	1.5	4.3	5.5	1.3
Southwest	4 4	5 2	0.8	5 3	5.2	-0.1
North Central	3 9	4 1	0 2	4 4	4.1	-0.3
Northwest/Mountain	4 5	4 5	0.0	4.6	5.1	0.5
California	4 6	5 7	1.2	7 5	6.1	-1.4
AVERAGE	**4.3**	**4.9**	**0.6**	**5.1**	**5.2**	**0.1**

REGION	INCREMENTAL GENERATION 1990 - 2010 (GWh/yr)	AIR POLLUTION PREVENTED 1990 - 2010 (thousand metric tons/yr)						
		SO_2	NO_x	Particulate Matter	CO	CH_4	CO_2	CO_2 Equivalent
Northeast	7,894	53.3	25.0	1.63	1.17	0.06	6,766	7,769
Southeast	6,962	62.1	29.6	1.81	1.01	0.06	7,001	8,189
Southwest	4,023	8.5	15.1	0.74	0.62	0.03	3,457	4,063
North Central	6,317	64 2	27.0	1.65	0 91	0.06	6,374	7,459
Northwest/Mountain	15,138	82 5	67.9	4.33	2 13	0 15	16,013	18,738
California	5,175	1 1	12.1	0.17	0.87	0.01	2,757	3,243
TOTAL	**45,508**	**271.7**	**176.6**	**10.32**	**6.70**	**0.36**	**42,368**	**49,461**

generation would be cheaper than fossil fuel generation in the Northeast, Southwest, North Central, and California, and would prevent air pollution at negative cost in those regions.

Air Pollution Prevented

The restricted expansion opportunities at existing sites limits the overall amounts of fossil-fuel emissions displaced by increased hydroelectric output. However, the geographic distribution of potential resources and generating characteristics make hydropower an effective technology for air pollution prevention, as evidenced by relatively high emission reduction rates (per kWh) shown on Table III-6 in Chapter 3. The increase in hydroelectric generation between 1990 and 2010 in the Enhanced Market scenario would reduce annual NO_x emissions by 177,000 metric tons, and CO_2 emissions by 42 million metric tons per year. Hydropower generation in the Enhanced Market scenario could displace up to 270,000 metric tons of SO_2 emissions per year, equivalent to generating about 300,000 allowances.

CHAPTER VII
PHOTOVOLTAICS

Photovoltaic (PV) power uses semiconductor technology to convert sunlight directly into electricity. The first recording of the sunlight-to-energy conversion, the photovoltaic effect, occurred in 1839 when a French physicist observed that illuminating one of two identical electrodes in a weak conducting solution would produce voltage; in the 1870s, the photovoltaic effect was further studied in solids such as selenium. This led to selenium photovoltaic cells with conversion efficiencies of 1% - 2% by the 1880s.[1] The technology lay dormant until 1954 when Bell Laboratories made practical silicon PV cells that reached sunlight-to-electricity conversion efficiencies from 6% to 11%; the cost of these silicon cells was approximately $600 per watt. Not until the late 1950s, with the onset of the space age, did extensive research and development into photovoltaics began. In their earliest applications PV cells made from single-crystal silicon powered America's first space satellites.[2]

Between the late 1950s and the early 1970s, research achievements and refinements in the manufacturing process doubled solar cell efficiencies and brought prices to under $100 per watt; nevertheless, only two companies manufactured solar cells for commercial use in the early 1970s. The 1973 Arab oil embargo greatly stimulated PV development activities by bringing in an infusion of public and private research funding that provided for basic research and the development of new products, expanded the array of PV applications, and induced the growth of the PV industry. Between 1975 and 1976, total sales of PV cells doubled, prices fell to $15 per watt, and some of the cells being tested achieved efficiencies five times greater than that of the Bell team's original prototypes.[3]

Both stand-alone (non grid-connected) and central station utility (grid-connected) PV systems have been researched. These applications hold the possibility for gigawatts worth of installation. However, in order to realize this potential, several obstacles have to be overcome. PV systems must continue to become more efficient, more durable, and less expensive. Photovoltaic costs have declined from $20 per watt in 1977 to $4-$5 per watt in 1988, but costs must decline further and efficiencies increase before PV makes significant contributions to the U.S. electricity supply. Future PV

---

[1] American Solar Energy Society, "Assessment of Solar Energy Technologies," May 1989.

[2] Solar Energy Research Institute, "Photovoltaics -- Entering the 1990s," November 1989.

[3] Susan Williams and Kevin Porter, Investor Responsibility Resource Center, Power Plays: Profiles of America's Independent Renewable Electricity Developers, 1989.

technology development and market penetration will depend on federal support to a greater extent than any other renewable electric technology.

RESOURCE BASE

Base, Accessible, and Reserves

A recent study conducted by Meridian Corporation for DOE estimates the 30 year photovoltaic energy resource at one million quads. This value, which is the same as the biomass and solar thermal energy resource base, is the product of the average incident radiation on the surface of the U.S., about 4.32 kWh/m^2, and the proportion of the radiation which Meridian considers intense enough to be a potentially exploitable resource, which they estimate at 70%.[4] The accessible resource, 600,000 quads, is that portion of the total resource which strikes land not dedicated to forests, cropland, parkland, wilderness area, surface water, roads, national defense and urban areas. Because the levelized cost of PV generated electricity is currently much higher than conventional utility electricity, the PV energy reserve is zero. This does not take into account certain niche markets -- primarily non-grid connected -- where the value of PV generation justifies the high costs.[5] Currently, approximately 13 MW of installed PV capacity produced a fraction (less than one hundredth) of a quad each year.

Geographic Distribution

Scientists have spent more than a decade studying the availability and amount of sunlight throughout the U.S. Actual sunlight totals, adjusted for cloud cover, were measured and broken down by location, time, and type of sunlight.[6] The resulting data bases enable scientists to generate maps of the solar resource. For example, Figure VII-1 displays how much solar radiation is available to a flat plate PV module mounted on a fixed support structure, with the southern tilt (in degrees) equal to the latitude of the site.

---

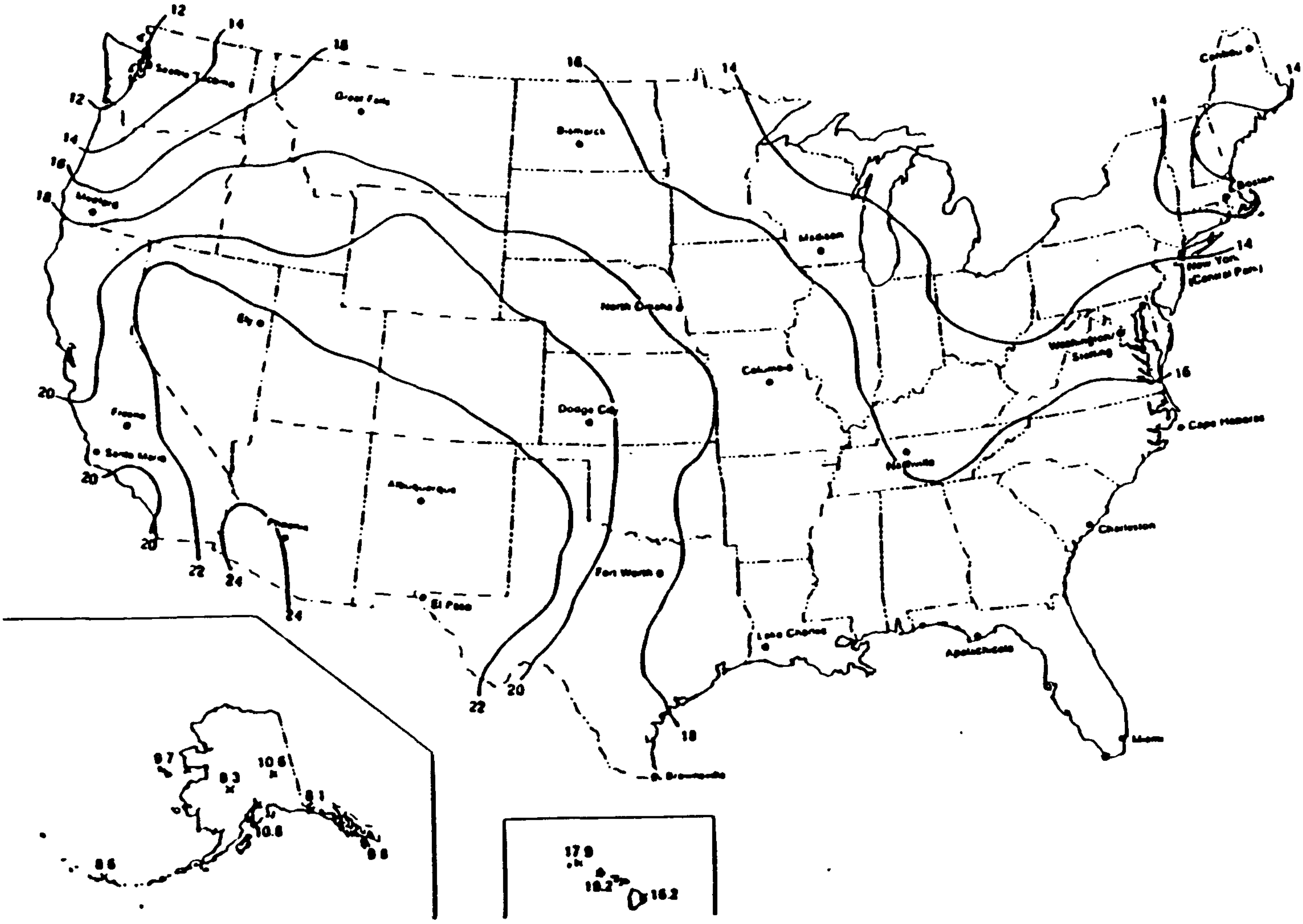
[4] Characterization of U.S Energy Resources and Reserves Prepared for the U.S. Department of Energy by Meridian Corporation, June 1989.

[5] One example is the increasing use of PV by electric utilities as a DSM tool, particularly to reduce high marginal cost peak load demand

[6] See, for example, Probabilities and Extremes of Solar Radiation by Climatic Week, National Weather Service, Fort Worth, Texas Southern Region.

FIGURE VII - 1

Average Annual Global Radiation Available to a Fixed Plate With Tilt Equal to Latitude (100s of kWh/m^2)



Source: Ken Zweibel, *Harnessing Solar Power: The Photovoltaics Challenge*, 1990, p. 231.

As the map indicates, PV resources are available throughout the United States. The annual average solar energy received in the U.S. varies only by a factor of two from northern to southern latitudes, which means that annual solar radiation received anywhere in the continental U.S. is no more than 50% lower than that experienced in a peak location like Phoenix. Unlike solar thermal, PV can utilize indirect (diffuse) as well as direct solar radiation, so that the PV resource is not confined to the arid Southwest. However, the sun shines differently across the U.S., and each geographical region is subject to the vagaries of microclimates and cloud cover.

Seasonal and Daily Variation

Figure VII-2 depicts the regional and seasonal variation of the solar resource in terms of *monthly insolation* figures for Phoenix, Atlanta, Seattle, Madison and Ft. Worth.[7] Based on solar radiation and climatological data, the Southwest region of the U.S. has the most solar radiation, and the Pacific Northwest, North Central and Northeast U.S. have the least.

Solar radiation also varies throughout the day, and the hourly variation depends on time of year, latitude and daily weather patterns. Figure VII-3 compares the hourly insolation values on an average sunny day in June and January for locations at 45 degrees north latitude such as Portland, Oregon or Minneapolis.[8] Because the difference between summer and winter insolation is greater at higher latitude, the case portrayed shows the most extreme seasonal contrast experienced in the continental U.S..

CONVERSION TO ELECTRICITY

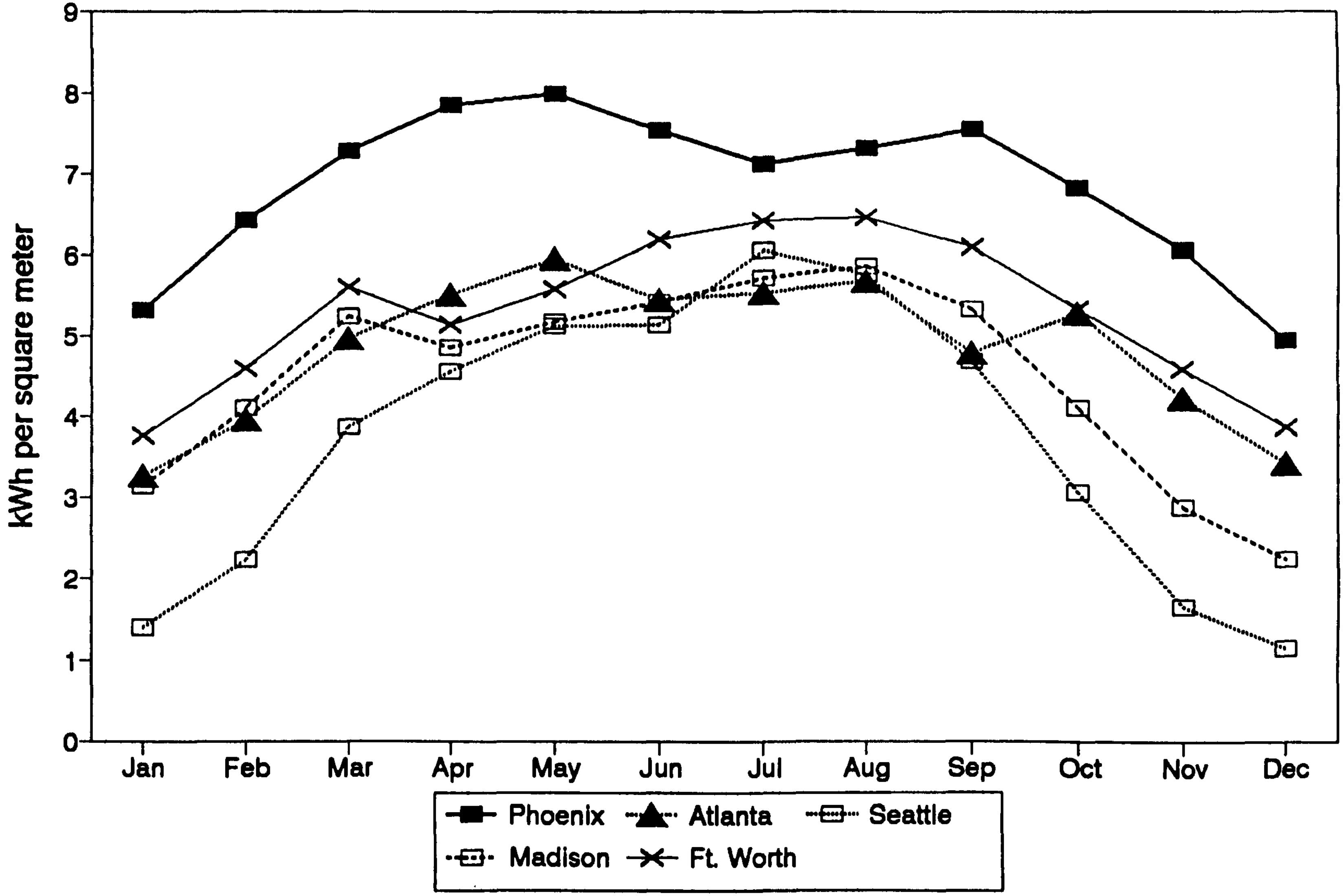
Existing Technologies

The primary element of a photovoltaic system is the solar cell. Each solar cell has two or more layers of dissimilar semiconductor material, between which a junction creates voltage to drive electrons through a circuit. Solar cells are composed of different materials in various states -- single crystal, polycrystalline, and amorphous. PV cells convert light directly into electricity. When sunlight strikes the photovoltaic cell, photons (particles of light energy) enter the cell's semiconductor material

[7] Stand-Alone Photovoltaic Systems A Handbook of Recommended Design Practices, Photovoltaic Design Assistance Center, Sandia National Laboratories, March 1990, pp. A-1 - A-42.

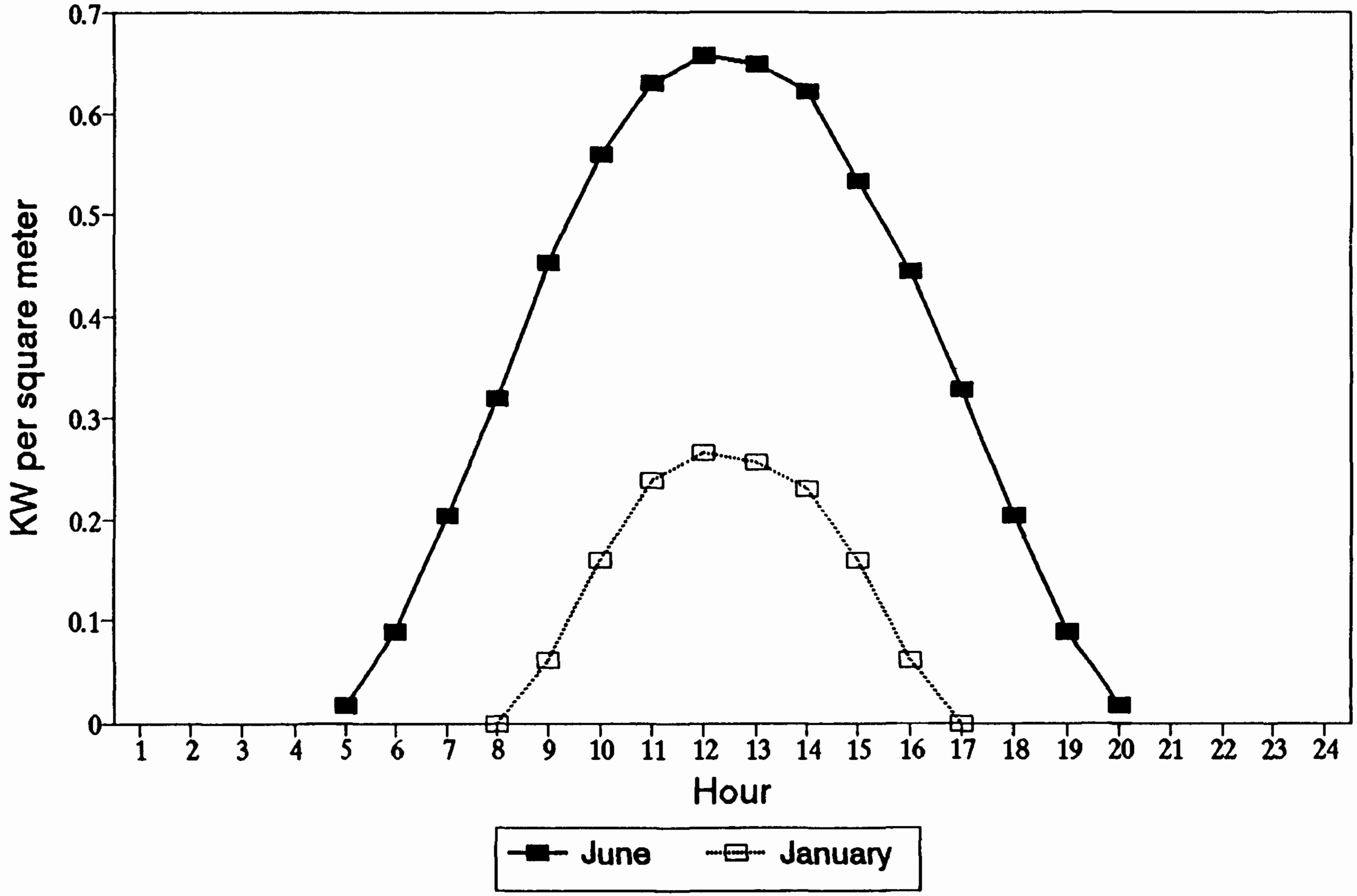
[8] Muhammad Iqbal, An Introduction to Solar Radiation, (New York: Academic Press, 1983), p. 241. The graph shows the power in KW/m^2 incident on a horizontal plane, so the area under the graph gives the daily energy output in kWh/m^2.

FIGURE VII - 2
Average Daily Insolation Availability
Fixed Array (Tilt = Latitude)



Source: Stand-Alone PV Systems: A Handbook of Recommended Design Practices, Sandia National Laboratory, March 1990.

FIGURE VII - 3
Hourly Global Radiation at 45° North



Source: Muhammad Iqbal, "An Introduction to Solar Radiation," 1983.

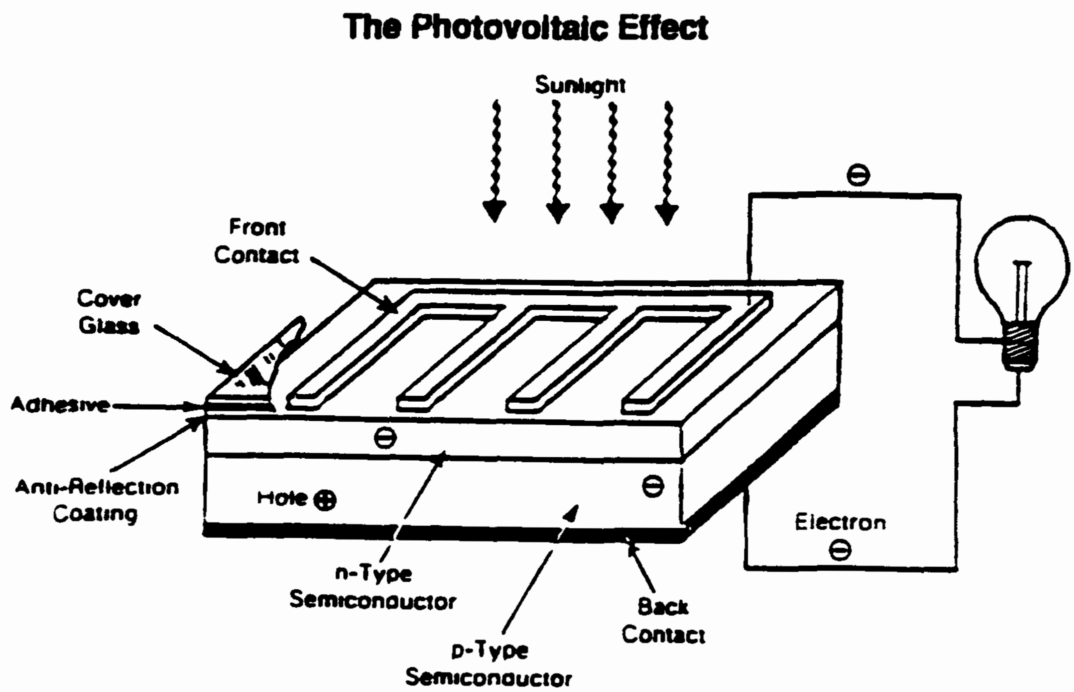
and transfer their momentum to electrons in the cell, knocking them free and forming a "hole" in the cell. The freed electrons travel through the semiconductors and contacts to form direct current (DC). Figure VII-4 shows a schematic of the photovoltaic effect. PV cells require no moving parts or steam cycle and emit no pollutants during operation. Single cells are connected in series to create a PV module or panel, usually less than a square meter in size, which is sealed with a protective layer of plastic or glass. Modules can be combined to create larger flat plate arrays. Larger PV systems consist of multiple arrays that share power conditioning equipment. PV generating systems convert the DC electricity into alternating current (AC) using a power inverter. Some energy losses occur in this conversion, but the process is necessary if the PV power is intended for the AC utility grid. PV systems are rated in peak Watts (Wp), denoting the PV power output when the equivalent of the sun's energy (i.e. 1000 Watts/m^2) is directly shining on the PV surface at noon on a sunny day. PV system efficiency is measured by the percent of available solar energy that is converted into electricity, while actual system output depends on the site's latitude, weather, and time of day.

Materials and Cell Types. PV cells are classified as crystalline thick-film or thin-film cells. The choice between cell type depends on the trade-off between production cost and efficiency: thick-film cells are more costly, more efficient, and have long expected lifetimes, whereas thin-film cells are cheaper, less efficient, and may have problems with long-term stability. The majority of cells applied today are crystalline "thick-film" cells. The cells have achieved efficiencies of 12% to 16% and have demonstrated reliable operation. Thin-film cells offer the most potential for low-cost modules. However, the long-term stability of thin-film cells must first be demonstrated before use of this technology will become widespread. Demonstration projects being conducted by the Solar Energy Research Institute (SERI), in which some thin-film materials (including copper indium diselenide) have shown no signs of degradation after three years while others (including cadmium telluride) have yielded mixed results, may provide the data necessary to resolve questions of long-term stability.

Materials such as silicon, copper indium diselenide, cadmium telluride, and gallium arsenide are being used to manufacture PV cells with single crystal, polycrystalline and amorphous structures. Silicon has been the preferred material because of its abundance, low cost, and attractive chemical properties. Silicon cells now produce 80% of U.S. PV electricity. The amorphous semiconductor structure has received increased commercial research and development focus because it allows application in a few micron-thick film, 50-100 times thinner than wafer application of single and polycrystalline materials. The trade-off between amorphous material and single crystal is one between cost and efficiency: commercial amorphous modules achieve 5% - 8% efficiency but are cheaper to manufacture than single crystal cells that average 10% - 16% efficiency. Increased attention is also being directed to multi-junction or tandem devices using amorphous silicon thin film cells in which multiple, extremely thin, light-activated, electricity-generating junctions are layered on top of each

FIGURE VII - 4

Schematic of the Photovoltaic Effect



Source: *Photovoltaics: Technical Information Guide.* Solar Energy Research Institute. U.S. Department of Energy (SERI/SP-271-2452), February 1985, p. 2.

other. Tandem cells can capture a larger portion of solar radiation than single-junction cells, as the top cell absorbs the high-energy portion of the spectrum and allows the rest through to the cells below. Overall tandem cell efficiencies could reach as high as 20% - 30%.

Tracking Systems. Individual PV modules are combined in configurations that include fixed flat plate arrays, single or double-axis sun tracking flat plate arrays, and double-axis tracking sunlight concentrator arrays. Fixed arrays do not move during the day to capture more sunlight. Single axis trackers follow the sun's course from east to west during the day, while double axis trackers also adjust the array for the sun's change in apparent altitude during the year. This means that the array always points directly at the sun. The power gained from using a single axis tracker over a fixed flat plate is realized mostly during the early morning and late afternoon, and the double axis tracker ensures maximum power during each season. A double-axis tracker picks up as much 40% more energy than a fixed array. The additional cost of tracking devices are often offset by greater energy capture, although fixed plate collectors are the most economic option in many applications.

The tilt of fixed plate and single axis tracking arrays can be adjusted to maximize productivity during a particular season and/or time of day, in order to tailor output to peak electricity demand. Figures VII-5 and VII-6 compare the amount of solar insolation available to fixed and single axis trackers with tilts equal to latitude-15°, latitude, and latitude+15° and to a double axis tracker. In general, a tilt equal to latitude maximizes the yearly output of a fixed or single axis tracker. A tilt of latitude-15° maximizes summer output at a small cost to the yearly output, while a tilt of latitude+15° maximizes winter output. A double axis tracker captures the greatest possible amount of the solar resource during all seasons and times of day. By tilting a fixed array to the east or west, one can receive peak output, respectively, before or after solar noon, at a small cost to total daily output.

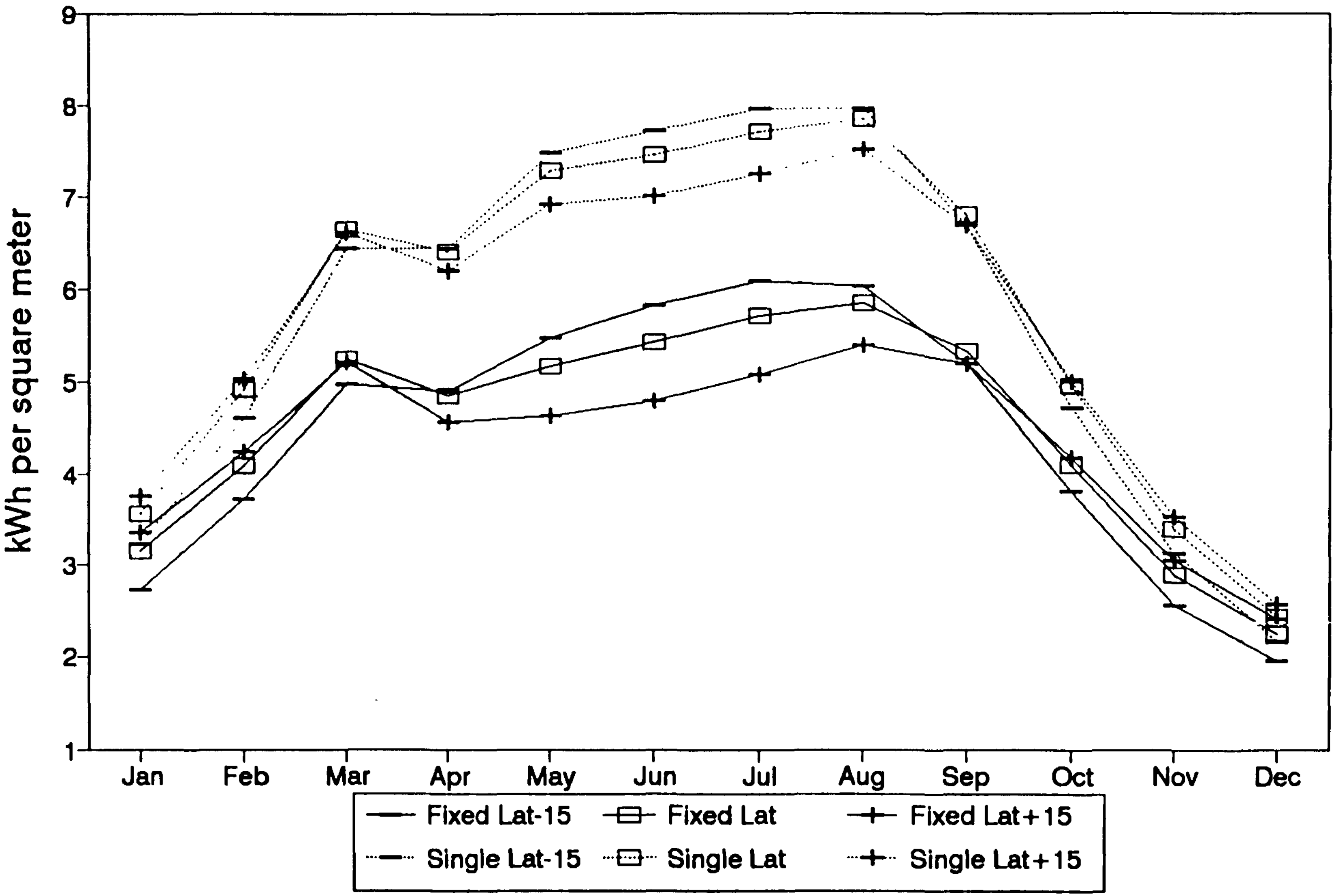
PV concentrator modules use mirrors and lenses to concentrate the sun's light onto a small area, reducing the number of solar cells used in the module. Replacing expensive solar cells with optical elements made of inexpensive glass, plastic, and metal lowers costs. Costs are also reduced because solar cells perform more efficiently in concentrated light than under normal, dispersed sunlight, achieving efficiencies approaching forty percent in laboratory tests.[9] However, since PV concentrator modules must aim directly at the sun, they require more expensive two-axis trackers.

Current Performance of Actual Systems. The Electric Power Research Institute (EPRI) analyzed data from 1987 and 1988 to assess the performance and supply characteristics of operational PV power

---

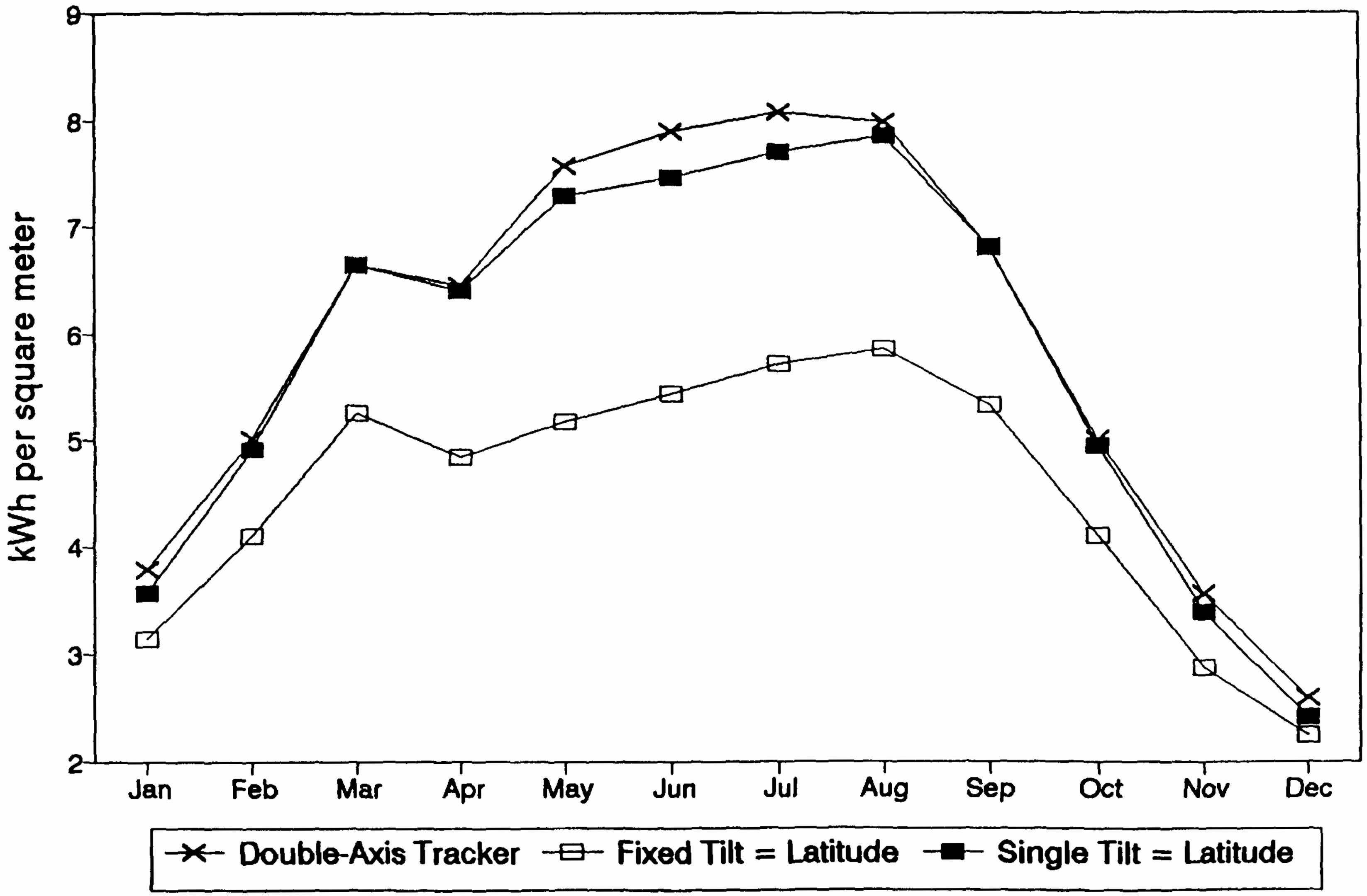
[9] Photovoltaic Energy Program Summary, U.S. Dept. of Energy, Volume I: Overview Fiscal Year 1989, January 1990.

FIGURE VII - 5
Average Daily Insolation Availability
Comparison of Fixed Plate and Single-Axis Trackers



Source: Stand-Alone PV Systems: A Handbook of Recommended Design Practices, Sandia National Laboratories, March 1990.

FIGURE VII - 6
Average Daily Insolation Availability
Comparison of Fixed Plate and Single- and Double-Axis Trackers



Source: Stand-Alone PV Systems: A Handbook of Recommended Design Practices, Sandia National Laboratories, March 1990.

plants[10]. The plant data for 1987 included information from a 204 kW dual axis tracking concentrator plant in Phoenix, Arizona; a 300 kW single axis tracking system in Austin, Texas; a 1000 kW dual axis tracking system at Hesperia, California; and the 2,350 kW single axis tracking Sacramento Municipal Utility District (SMUD) plant in Sacramento County, California. The data from 1988 included information from the above plants as well as a 15 kW amorphous silicon array in Orlando, Florida, and a 4 kW amorphous silicon array at Auburn Hills, Michigan. Daily and seasonal operating characteristics were recorded and analyzed, along with energy output and other variables. The generation data for the four plants surveyed in 1987 is displayed in Table VII-1.

Current Economics

As shown on Figure VII-7, PV costs have fallen significantly over the past two decades, as efficiencies have increased. The costs of a PV system fall under the categories of module costs and balance of system costs (BOS). Currently, module costs are roughly equivalent to BOS costs. Module costs depend on the material used, the amount required and the process used to fabricate the cell. Although crystalline devices are more efficient in energy conversion, they are considerably more expensive than thin-film devices. BOS costs include: design, land, site preparation, installation, trackers and support structure, power conditioning equipment, operation and maintenance and storage and related costs. The costs fall roughly under the categories of area-related and power-related. Trackers and support structure make up the majority, about 75%, of area-related BOS costs. Current tracker costs are $85/m^2 for a single axis tracker, $120/m^2 for a double axis tracker and $140/m^2 for a double axis tracker used for a concentrator module. These figures compare to fixed array support structure costs of roughly $55/m^2.[11] Site preparation and installation currently comprise 15-20% of area-related BOS costs and design and land costs are minimal in comparison, less than $3/m^2. Figure VII-8 shows how these costs break out among the various components.

The power conditioning equipment, which includes all the equipment which controls the DC output of the solar cells and converts it to utility compatible AC current, constitutes the greatest BOS cost after trackers and support structures. This involves complicated control systems that maintain system security during lightning storms or circuit switching problems. The most expensive single element of the power conditioning systems is the inverter that converts the DC power to AC power.

---

[10] Southwest Technology Development Institute for EPRI, "Photovoltaic Field Test Performance Assessment: 1987," March 1989; and Southwest Technology Institute for EPRI, "Photovoltaic Field Test Performance Assessment: 1988," January 1990.

[11] Ken Zweibel, Harnessing Solar Power: The Photovoltaics Challenge, (New York: Plenum Press, 1990), p. 40.

TABLE VII - 1
PERFORMANCE AND SUPPLY CHARACTERISTICS
OF OPERATIONAL PV POWER PLANTS

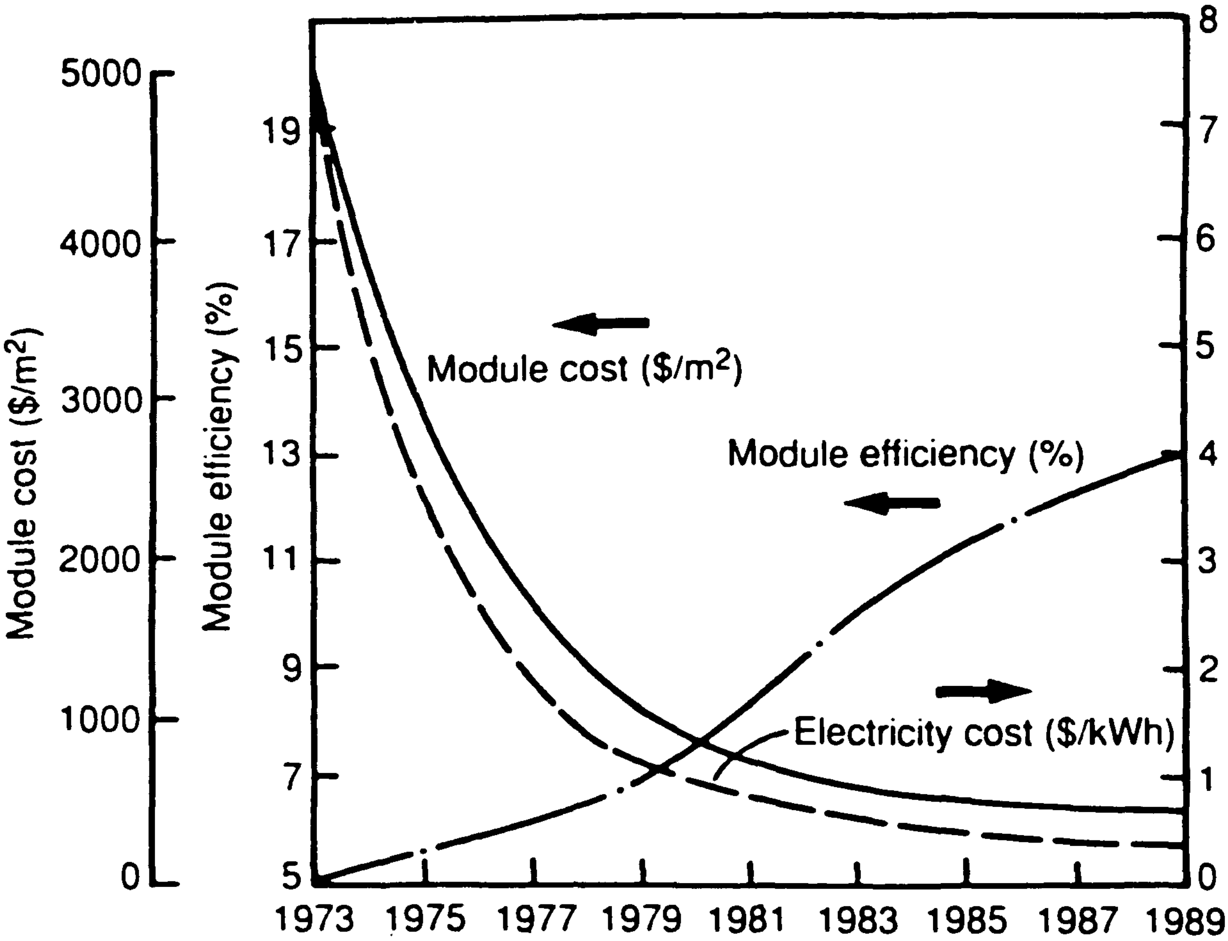
Plant Location, Size	Steady Energy Output (Daily)		Operating Times (a.m. to p.m.)		Capacity Factor
	June	Dec.	June	December	Monthly
Phoenix, AZ 204 kW	120 kW	N/A	6 am to 8 pm	N/A	30% - March -- August; 13% - January; %5 - September
Austin, TX 300 kW	200 kW	175 kW	7 am to 9 pm	8 am to 6 pm	30% - May -- October; 15% - November -- December; 0% - January -- April
Hesperia, CA 1,000 kW	400 kW	800 kW	5 am to 7 pm	7 am to 5 pm	25% - 35%
Sacramento County, CA 2,350 kW	850 kW	450 kW	5 am to 8 pm	8 am to 6 pm	40% - July; 10% - December

Source: *Photovoltaic System Performance Assessment for 1988*, Electric Power Research Institute, January 1990.

Low operation and maintenance costs of PV systems are one of their chief advantages. The greatest contribution to O&M costs comes from repair and maintenance of trackers and support structures. Not surprisingly, O&M costs for two-axis trackers are highest. Actual O&M costs for seven PV systems which began delivering power between 1982 and 1986, including a two-axis concentrator array ranged from 0.4 ¢/kWh to 7.0 ¢/kWh. EPRI estimated the potential O&M costs--the costs after known problems are resolved--to range from 0.2 ¢/kWh to 1.2 ¢/kWh. Thus, reasonable O&M costs

FIGURE VII - 7

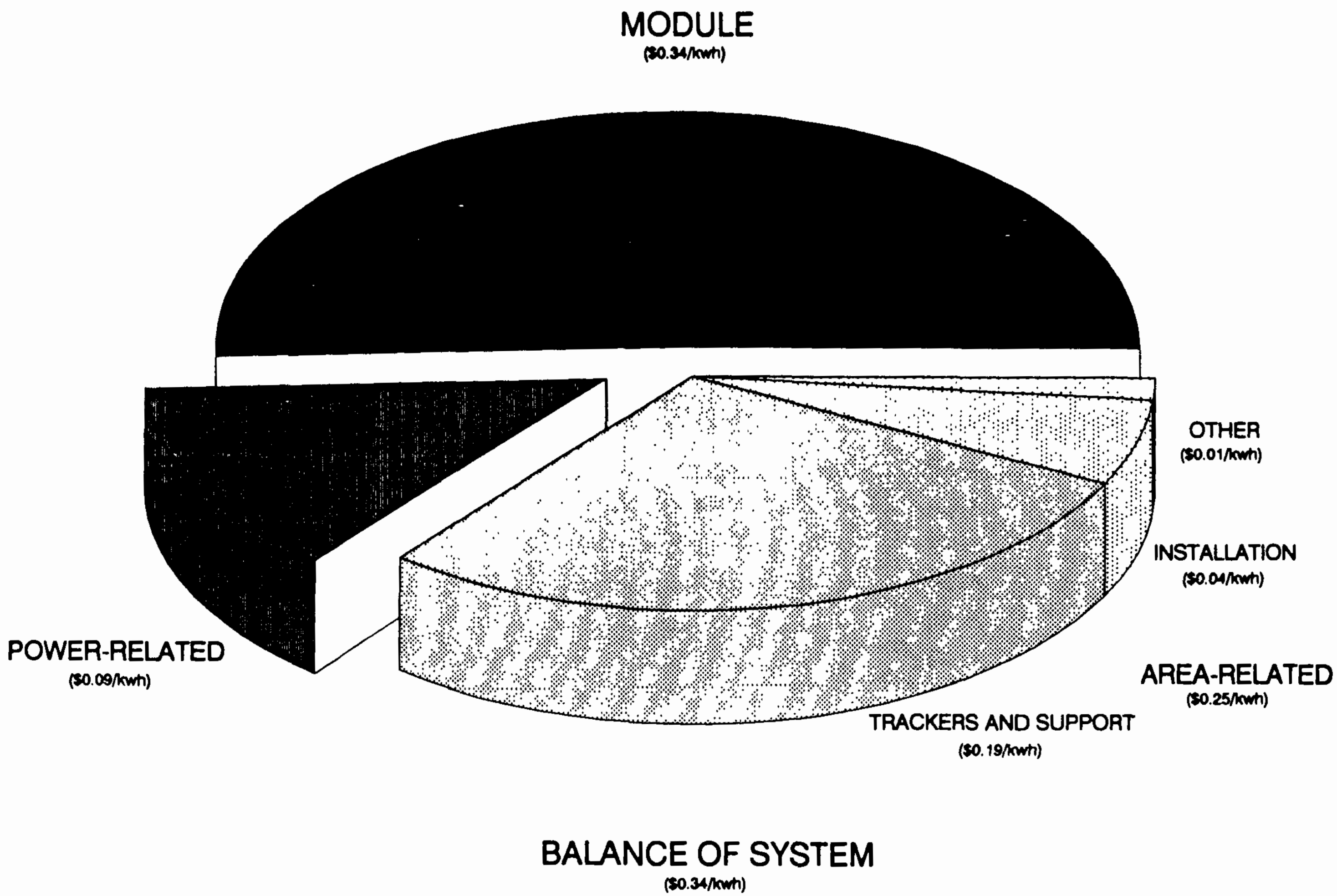
Gains in PV Cost and Module Efficiency



Source: Ken Zweibel, *Harnessing Solar Power: The Photovoltaics Challenge*, 1990, p. 110.

FIGURE VII - 8

COMPONENT COSTS FOR PHOTOVOLTAIC GENERATION



Source: Ken Zweibel, *Harnessing Solar Power: The Photovoltaics Challenge*, (New York: Plenum Press, 1990), p. 51.

for the most expensive configuration, a two-axis tracker for a concentrator, can realistically be estimated around 1 ¢/kWh.[12]

Photovoltaic systems are simple and modular, so the time needed for construction is relatively short. Typical construction time from ground breaking to turn-key operation is about 6 - 8 months for a large (1 to 2 MW) power installation. PV system installation costs range from about $6.00 per peak Watt (Wp) for a 500 Wp system to $3.50/Wp for a 1 MWp system.

Sandia National Laboratories estimates that the total installed cost of an amorphous silicon thin film system is currently between $4.50 to $5.00/Wp. The estimate is based on a 400 kW PVUSA system (5% efficiency) installed for Pacific Gas and Electric. This installed cost estimate includes (1) module cost of $2.00/Wp; (2) rack and mounting cost of $1.25/Wp; (3) an inverter cost of $0.50/Wp; and (4) land and other costs of $0.25/Wp. All of these costs are likely to fall in the near future, as discussed in later sections of this chapter.

Resources Recovered

In 1990, 12 MWp of grid connected PV capacity generated 25 GWh.[13] However, the majority of current solar energy production is not connected to the grid. For example, in 1989 alone, the U.S. PV manufacturers shipped 14 MW of PV cells, 30% of the world market. Because of the high capital cost of current PV systems, photovoltaic electricity is not cost-competitive where utility electric power is readily available. The cost-effective market has been for small, remote, off-grid power applications for meeting such power needs as communications, telemetry, signaling, cathodic protection, lighting, pumping, refrigeration, and battery charging. Specific uses for PV in communications include microwave repeaters, two-way radios and mobile radio systems, remote control systems, radio communications, and telephones. PV walkway and yard lighting systems have been commercial successes, with three million units sold worldwide since their introduction in 1987. Demonstration projects using photovoltaics for central or decentralized utility power generation with sizes of 1 kWp - 6 MWp have been reliably conducted under research and development and tax-credit driven conditions. As PV power becomes cost-competitive, central and residential PV power systems may help meet utility peaking and intermediate power generation needs.

---

[12] Photovoltaic Operation and Maintenance Evaluation, Electric Power Research Institute, December 1989.

[13] Nancy Rader, Power of the States, (Washington, DC: Public Citizen, June 1990.

EMERGING CONVERSION TECHNOLOGIES

Performance/Efficiency

Some R&D efforts are focused on reducing the high energy and process input requirements of single crystal PV cells by substituting polycrystalline and amorphous materials. As techniques for reducing manufacturing costs are developed, trade-offs with reduced efficiencies and efficiency degradation in such materials as amorphous silicon will require further attention. Experiments with different base materials and the use of tandem cells with layered multiple PV junctions are leading to major efficiency improvements from the current 10% - 18% up to 20% - 32%.[14]

SERI has conducted research in advanced thin films development. Because they use less material, solar modules comprised of thin films are anticipated to cost less than conventional modules. Thin films can be produced by a variety of continuous manufacturing processes, and the potential for high-throughput could also lower manufacturing costs. SERI's main objective for advanced thin films research is to reach module efficiencies of 15%, while maintaining the advantages that have lowered costs; achieving 20 to 30 year reliability is also critical. During the next five years, SERI will develop four thin films: amorphous silicon, copper indium diselenide, cadmium telluride, and thin film silicon.

The efficiency of amorphous silicon devices gradually decreases with exposure to light, and this cell instability has been a major focus of research. SERI predicts the degradation losses could be held to 10% by making the amorphous silicon layers thinner. In contrast, copper indium diselenide (CIS) appears to have few instability problems, and SERI hopes to develop CIS modules as stable as crystalline silicon. SERI also plans to investigate other alloys such as gallium to replace indium and sulfur to replace selenium. Cadmium telluride (CdTe) research efforts will focus on increasing the efficiencies of cells toward their practical maximum of 20%. Thin film crystalline silicon research focuses on making larger-area cells and on interconnecting the cells to the utility grid. SERI plans to develop a prototype module capable of competing for remote and peak power applications that is 13% efficient, 4000 square centimeters, and susceptible to less than 5% degradation over a 10-year period.

The SERI research goal for module development is to establish both collector module technology and manufacturing technology for producing cost-effective PV modules. Research areas include: new module design, efficiency improvements, increased yield, scaling to larger areas, more

---

[14] H. M. Hubbard, "Photovoltaics Today and Tomorrow." Science, Volume 244, April 21, 1989.

efficient use of materials or substitution of cheaper materials, and introduction of greater use of automation. The PV Manufacturing Technology Initiative (PVMaT) is a major effort with the goal of reducing production costs by a factor of 2 or 3 from current levels through advances in manufacturing technology.

For utility scale applications, research has been conducted through the DOE in collaboration with industry. The work has been conducted in industrial and university labs as well as DOEs support laboratories. The program has two major strategies in place to deliver economical electric power to utility grids: 1) development of concentrator and flat-plate PV systems based on high-efficiency crystalline cell and module concepts; and 2) the development of flat-plate systems based on thin-film cell and module technology with emphasis on low material and processing costs. As shown in Figure VII-9, the historical trends in these cell efficiencies hold great promise for the future. The strategies will be supplemented by direct research in solid-state materials, the development of advanced characterization techniques, and continued characterization of the solar radiation source.[15]

Several utilities have shown an interest in selling or leasing small systems for remote applications in their districts. Some utilities are also purchasing PV test projects to learn how PV power interacts with their individual systems. PG&E's Photovoltaics for Utility Scale Applications (PVUSA) project, funded jointly with DOE, Electric Power Research Institute (EPRI), the California Energy Commission (CEC), and a number of utilities will result in approximately 1 MW of PV cell sales. PVUSA consists of five parts, with two stressing new and emerging PV technologies and three stressing large, utility scale projects. The emerging technology segments will include five 20 kW systems, and the utility scale projects will include 200-400 kW systems to be installed in Davis, California. This project will use 20 kW arrays to compare and evaluate current and emerging technologies, including crystalline silicon, amorphous silicon, and new thin-film materials; assess O&M costs in an electric utility context; compare the most promising technologies in different locations within a utility service area; and provide U.S. utilities with hands-on experience in installing and operating PV power generation systems.

Experience with test facilities suggests that to be competitive with future electric generation options, PV modules must exhibit efficiencies above 15% at a cost somewhere between 6¢ and 12¢ per kWh, or installation costs between \$1/Wp to \$2/Wp.[16] System efficiencies for PV currently

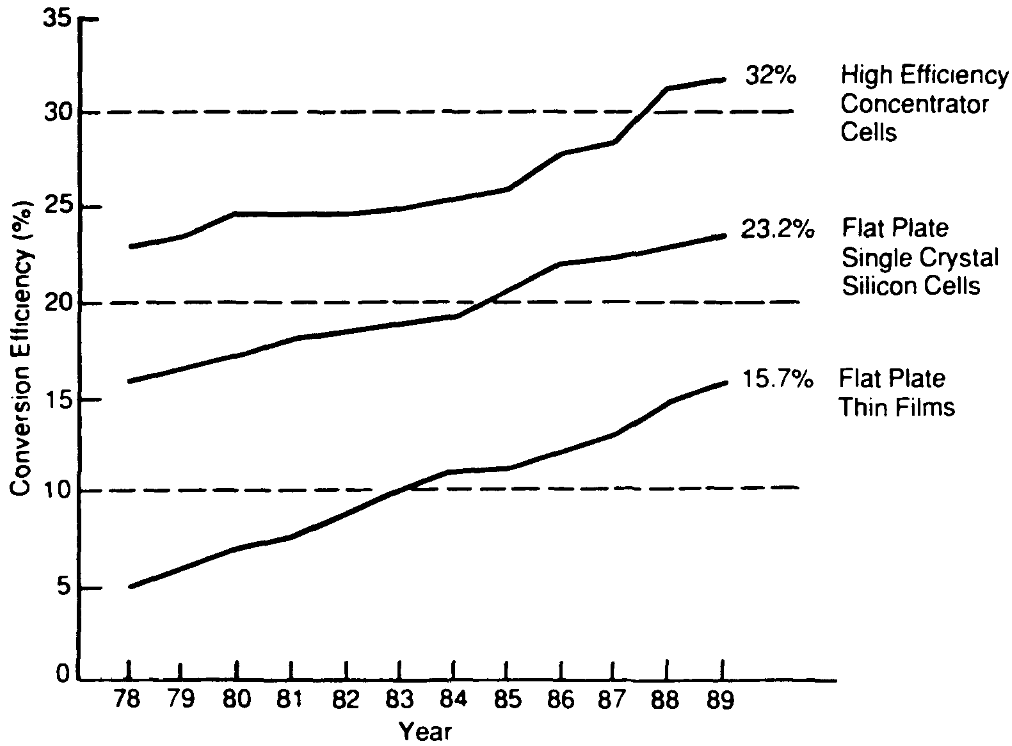
---

[15] H. M Hubbard, "Photovoltaics: Today and Tomorrow," Science, Volume 244, April 21, 1989.

[16] American Solar Energy Society, "Assessment of Solar Energy Technology," May 1989.

FIGURE VII - 9

Progress in Laboratory Cell Efficiency



Source: ***Photovoltaic Energy Program Summary*****, U.S. Department of Energy, Volume I: Overview Fiscal Year 1989, January 1990, p. 2.**

average 12% to 14% at costs of \$8/Wp to \$10/Wp, which includes BOS costs. EPRI predicts that BOS costs will decrease through engineering and scale economies, but improvements must be made in module efficiency and cost in order to reach these targets. The PVUSA project may demonstrate efficiencies at levels in excess of 15% by 1992.

Costs

A recent analysis projected the cost reduction required for a representative PV technology to produce utility-grade PV power competitive with a projected cost of 4-6¢/kWh from new conventional plants.[17] According to the analysis, current PV costs and competitive PV costs are as follows:

TABLE VII - 2
PHOTOVOLTAIC COST REDUCTIONS

COMPONENT	Current	Needed	% Change
Module Cost	\$500/m^2	\$55/m^2	(89%)
Area-Related BOS	\$135/m^2	\$50/m^2	(63%)
Power-conditioning	\$200/kW (\$20/m^2)	\$100/kW (\$14/m^2)	(30%) - (50%)
Module Efficiency	10%-15%	15%	0 - 50%
Cost of DC electricity	37¢/kWh	4¢/kWh	(90%)
AC cost w/storage	68¢/kWh	7¢/kWh	(90%)

The biggest required gain, a ten-fold decrease in module cost, would bring module costs in line with required BOS costs. Although a ten-fold decrease represents an ambitious cost goal, the past 18 years of PV development have witnessed even greater PV cost reductions.

Potential Technology and Multiple Pathways

The costs of emerging technology suggest that simultaneous advances in several components of PV systems will be needed to make large-scale, grid-connected PV electricity competitive with conventional power sources. Current research is pursuing many different pathways for each component.

Manufacturing. Several silicon manufacturing processes are making promising gains in lowering cell cost. These include casting, ribbon growth and melt spinning. In addition to keeping costs low, these

---

[17] Ken Zweibel, Harnessing Solar Power: The Photovoltaics Challenge, (New York: Plenum Press, 1990), p. 40

processes are achieving cell efficiencies up to 17% and module efficiencies as high as 13%.[18] Thin-film silicon cells use less silicon, but at the expense of efficiency; so scientists are investigating methods such as texturing the front surface and making the back surface reflective to increase the likelihood that photons are absorbed by the cell. Theoretical efficiencies are as high as 19%. In April, 1991, Texas Instruments announced a new silicon thin-film manufacturing process that is expected to lower PV electricity costs to 10¢-15¢/kWh around the turn of the century. The process involves forming microscopic balls of silicon, spraying them on a preindented surface and using heat to bond the spheres to the substrate. Although cell efficiencies are not expected to be extremely high, projected costs are low because the manufacturing process is straightforward and does not require high-grade silicon.[19]

Other techniques strive for higher efficiencies rather than minimum manufacturing costs. These include passivation, texturing, point contact cells and microgrooved cells. Passivation is a technique that involves applying a thin layer to the surface of a PV cell to correct for the fact that the concentration of crystal defects is greater on the surface than in the interior of a crystal. A group at the University of New South Wales achieved a cell efficiency of 23% in unfocused light in 1989, the world record for a silicon cell. By chemically texturing the surface of a cell with a substance like hydrazine or sodium hydroxide, fewer photons will be reflected from the cell. A point contact cell is a unique design with the contacts on the back of the cell. Designed primarily for concentrators, it has achieved an efficiency of 28% in focused light. Microgrooving (using a laser to cut grooves roughly 100 microns deep) does not raise efficiencies as much as the sophisticated passivation techniques, but lends itself more readily to low-cost, automated manufacturing processes.

Materials. Materials research is currently focusing on thin-film processes for cadmium telluride (CdTe), gallium arsenide (GaAs), and copper indium selenide (CuInSe), which lead to lower materials, processing and handling costs. In April of 1991, SERI certified three world records. An encapsulated 4 ft^2 CIS module achieved an efficiency of 9.7%, which is twice as high as any other thin-film module. Two records for CdTe cells were set; the current mark stands at 13.4%.[20]

---

[18] Ken Zweibel, Harnessing Solar Power The Photovoltaics Challenge, pp. 114 - 118.

[19] Personal communication with Ken Zweibel, Solar Energy Research Institute, May 30, 1991.

[20] Personal communication with Ken Zweibel, May 30, 1991.

Cell types. Many different multijunction cells are achieving high efficiencies in concentrators. A three-junction amorphous silicon and germanium cell reached 8.4%, a two-junction amorphous silicon and CIS cell attained 10.5% and a two-junction aluminum, gallium and arsenic cell achieved 27.6%.[21]

Concentrators. Because concentrators focus sunlight onto a small area, they require much smaller areas of cells. Furthermore, the conversion efficiencies increase when light is concentrated, so that high-efficiency but expensive cells can prove competitive in concentrators. Several silicon and non-silicon cells, both single and multijunction, have achieved efficiencies of 20% - 32%. These include a module ready silicon cell of 27.2% efficiency and an experimental silicon cell at 28.2% efficiency. Research is also being conducted on less expensive as well as non-imaging optics, which have theoretical concentration yields four times as high as standard imaging optics.[22]

Storage. The development of electricity storage options would allow PV power to provide the reliability needed for utility grid-connected applications. Storage is inherently less than 100% efficient but the value of reliability can offset the costs and inefficiencies of storage. Possible storage media include batteries, pumped hydro, compressed air, flywheels, superconductivity and hydrogen storage. Batteries and pumped hydro represent the current commercial storage options, although batteries have not yet been scaled to central station utility size. Pumped storage reservoirs are typically filled at night and hence do not fit PV output patterns. The other technologies are generally uneconomic and in nascent stages of development, but hold great potential for making significant impacts on the implementation of PV.

Power conditioning, tracking and support structures. Power conditioning systems currently achieve high efficiencies (95%) and acceptable reliability.[23] Manufacturing and operating costs of balance of system components can be lowered, while maintaining or improving performance, through continued applied engineering and research. Progress in improving tracking systems and lowering costs can enhance energy capture and can dramatically improve the economics of photovoltaic systems.

MARKET ASSESSMENT

Projections of future PV sales are extremely sensitive to the presumed timing of cost reductions, especially when future cost and performance attain certain thresholds that make them

---

[21] Photovoltaic Program Summary, 1990

[22] Roland Winston. "Nonimaging Optics," Scientific American, Volume 264, Number 3, March 1991, pp. 76 - 81.

[23] EPRI Photovoltaic Field Test Performance Assessment: 1988.

competitive in utility power generation. A recent report by the Department of Energy and the Solar Energy Research Institute analyzed the impacts of PV technology development on future deployment[24]. The DOE/SERI BAU projection provides the EPA Base Case for PV electric generation. Table VII-3 shows the DOE/SERI and EPA windpower scenarios.

TABLE VII - 3
PHOTOVOLTAIC SCENARIOS

Scenario	Capacity 2000 (MW)	Generation 2000 (GWh)	Capacity 2010 (MW)	Generation 2010 (GWh)
DOE/SERI				
Business as Usual	800	2,000	6,100	14,600
Intensified RD&D	3,600	8,800	27,100	65,300
National Premiums	1,600	3,900	15,800	38,000
EPA				
Base Case	1,000	2,000	7,400	14,600
Enhanced Market	4,400	8,800	98,000	195,100
1990:	12 Mw	25 GWh		

The EPA Enhanced Market PV scenario assumes that an intensified RD&D budget will bring down the costs of materials and production, and that environmental impacts will be incorporated into utility planning. PV is very responsive to intensified R&D, and prices should drop significantly by the year 2000 given sufficient research support. The Enhanced Market scenario for 2000 is based on the alternative PV growth scenario described in the DOE/SERI report (page G-10). Tables VII-4 and VII-5 give the model results for the PV scenarios. The EPA Enhanced Market scenario assumes that average PV generation costs could be reduced to 11.5 ¢/kWh by 2000 and to 6.4 ¢/kWh by 2010 (and lower in regions of good insolation where capacity factors approach 30%). This would require capital costs to fall to roughly $2,100 per kW by 2000 and $1,150 by 2010, compared with the DOE/SERI BAU assumptions of $3,500 in 2000 and $2,100 in 2010. Thus, PV cost reductions are accelerated by at least a decade over the SERI BAU assumptions.

---

[24] The Potential of Renewable Energy: An Interlaboratory White Paper. Prepared for the Office of Policy, Planning and Analysis, U.S. Department of Energy, March 1990, p. G-10.

TABLE VII - 4

ELECTRICITY GENERATION COSTS AND AIR POLLUTION PREVENTED

EPA BASE CASE
PHOTOVOLTAIC

REGION	AVERAGE UNIT COST IN 2000 (cents/kWh)			AVERAGE UNIT COST IN 2010 (cents/kWh)		
	AVOIDED FOSSIL	PHOTOVOLTAIC	COST DIFFERENCE	AVOIDED FOSSIL	PHOTOVOLTAIC	COST DIFFERENCE
Northeast	4.4	26.5	22.1	5.7	16.0	10.3
Southeast	4.2	20.3	16.1	5.1	12.3	7.1
Southwest	4.4	16.2	11.8	5.6	9.8	4.2
North Central	3.9	20.7	16.9	4.4	12.5	8.1
Northwest/Mountain	4.0	17.8	13.9	4.4	10.8	6.3
California	4.4	16.5	12.1	7.1	10.0	2.9
AVERAGE	**4.2**	**19.1**	**14.8**	**5.3**	**11.5**	**6.2**

REGION	INCREMENTAL GENERATION 1990 - 2010 (GWh/yr)	AIR POLLUTION PREVENTED 1990 - 2010 (thousand metric tons/yr)						
		SO_2	NO_x	Particulate Matter	CO	CH_4	CO_2	CO_2 Equivalent
Northeast	1,218	8.4	4.0	0.26	0.18	0.01	1,060	1,220
Southeast	3,657	26.3	12.6	0.81	0.54	0.03	3,278	3,785
Southwest	3,249	6.0	11.6	0.52	0.51	0.02	2,630	3,094
North Central	2,032	19.3	8.5	0.51	0.30	0.02	2,013	2,355
Northwest/Mountain	2,438	6.9	10.4	0.64	0.35	0.02	2,457	2,875
California	2,011	0.4	4.6	0.06	0.34	0.00	1,075	1,263
TOTAL	**14,605**	**67.2**	**51.7**	**2.79**	**2.22**	**0.10**	**12,513**	**14,592**

TABLE VII - 5

ELECTRICITY GENERATION COSTS AND AIR POLLUTION PREVENTED

EPA ENHANCED MARKET SCENARIO
PHOTOVOLTAIC

REGION	AVERAGE UNIT COST IN 2000 (cents/kWh)			AVERAGE UNIT COST IN 2010 (cents/kWh)		
	AVOIDED FOSSIL	PHOTOVOLTAIC	COST DIFFERENCE	AVOIDED FOSSIL	PHOTOVOLTAIC	COST DIFFERENCE
Northeast	4.4	16.0	11.6	5.7	8.8	3.2
Southeast	4.2	12.3	8.1	5.1	6.8	1.7
Southwest	4.4	9.8	5.4	5.6	5.5	-0.1
North Central	3.9	12.5	8.7	4.4	6.9	2.5
Northwest/Mountain	4.0	10.8	6.8	4.4	6.0	1.6
California	4.4	10.0	5.6	7.1	5.6	-1.6
AVERAGE	**4.2**	**11.5**	**7.3**	**5.3**	**6.4**	**1.0**

REGION	INCREMENTAL GENERATION 1990 - 2010 (GWh/yr)	AIR POLLUTION PREVENTED 1990 - 2010 (thousand metric tons/yr)						
		SO_2	NO_x	Particulate Matter	CO	CH_4	CO_2	CO_2 Equivalent
Northeast	16,254	111.1	53.3	3.40	2.41	0.13	14,115	16,256
Southeast	48,766	348.6	168.2	10.69	7.19	0.40	43,622	50,379
Southwest	43,346	79.4	154.1	6.90	6.77	0.25	35,027	41,215
North Central	27,092	256.3	113.2	6.81	3.95	0.23	26,774	31,317
Northwest/Mountain	32,511	91.2	138.3	8.44	4.71	0.29	32,695	38,247
California	27,071	5.1	62.6	0.82	4.60	0.05	14,480	16,998
TOTAL	**195,040**	**891.7**	**689.5**	**37.06**	**29.64**	**1.36**	**166,713**	**194,412**

Basing growth projections on cost reductions, a capacity of 4,400 MW could be installed by 2000. In the Enhanced Market scenario, the market would expand at an average annual growth rate of 26% per year between 2000 and 2010, by which capacity reaches approximately 98,000 MW. This growth would be distributed across the U.S., with over 40% of growth occurring in the South, and approximately 20% in each of the remaining three regions.

Costs

Even with the cost reductions assumed here, PV generation costs remain higher than avoided conventional systems in all but two regions (California and Southwest) in 2010. The conventional generation displaced by PV systems is primarily high cost summer peak electricity, but PV systems do not displace an equivalent amount of conventional capacity because of limited capacity factors and the intermittent resource. Since the costs of PV systems are higher than the avoided cost in most regions, environmental performance is the main driving force in the Enhanced Market scenario. By 2000, PV remains 5 ¢/kWh to 12 ¢/kWh higher than avoided costs. The differential narrows by 2010 in most regions, with the PV in the Northeast remaining 3 ¢/kWh above conventional costs; PV drops below conventional costs in the Southwest and California; while other regions' PV costs fall in between these two extremes.

Air Pollution Prevented

The environmental benefits from PV generation in the Enhanced Market scenario include annual SO_2 reductions of almost 900,000 tons by 2010 (primarily in the Southeast and North Central regions), and annual NO_x reductions of almost 700,000 tons (primarily in the Southeast and Northwest/Mountain regions). Over 190 million metric tons of CO_2 would be displaced annually by PV by 2010, mostly in the Southeast, Southwest, and Northwest/Mountain regions.

CHAPTER VIII
SOLAR THERMAL ELECTRICITY GENERATION

Solar thermal systems concentrate the sun's radiation to attain high temperatures, and then convert this thermal energy into mechanical energy, electricity, or process heat used in the production of fuels and chemicals. The use of solar thermal power is not a new phenomenon: French scientists demonstrated solar thermal engines for pumping and distilling water, and for printing newspaper, at the Paris Exposition in 1878. In the early 20th century, a 4.5 horsepower solar engine pumped water for a farm in California, another solar engine pump operated in the desert in Needles, California, and an American engineer designed and built a solar engine that produced 70 horsepower using a system of trough concentrators.[1]

Currently, 354 MW of solar thermal capacity provides enough electricity in southern California to serve the residential needs of 500,000 people. Continued research and commercial deployment is likely to bring down the cost of solar thermal electricity and expand the region of cost-effective grid-connected solar thermal electricity.

RESOURCE BASE

Total U.S. Resources

A recent study conducted by Meridian Corporation for DOE estimates the 30 year solar thermal energy resource at one million quads.[2] This value, which is the same as the biomass and photovoltaic energy resource base, is the product of the average incident radiation on the surface of the U.S. -- about 4.32 kWh/m^2 -- and the proportion of the radiation which Meridian considers intense enough to be a potentially exploitable resource, which they estimate at 70%. Approximately 45% of the U.S. surface area is committed to uses such as national parks and cropland that do not lend themselves to solar thermal energy, which lowers the accessible solar thermal resource base to approximately 600,000 quads. The portion of the resource considered economically exploitable by solar thermal energy (e.g., energy reserve) is less than 0.1 quads.

---

[1] Solar Technical Information Program, "Solar Thermal Power," February, 1987.

[2] *Characterization of U.S. Energy Resources and Reserves*. Prepared for the U.S. Department of Energy by Meridian Corporation, June 1989.

These estimates of resource base and accessible resources should be regarded as extreme upper bounds for solar thermal conversion. Solar thermal technology relies on direct sunlight and cannot utilize indirect (diffuse) radiation, which makes up a sizeable part of the insolation estimate. On a clear day, direct radiation comprises about 80% to 90% of the total received solar radiation, but on cloudy days the direct portion accounts for only 30% to 50% of the total.

Geographic Distribution

Because solar thermal electric generation relies on direct solar radiation, the geographic distribution of solar thermal resources is more constrained by prevailing cloud conditions than are photovoltaic resources. The best solar thermal resources in the U.S. are found in the arid Southwest. Figure VIII-1 shows the geographic distribution of annual average daily direct solar radiation, which ranges from approximately 8 kWh/m^2 in the Southwest to less than 3 kWh/m^2 in the Northwest and Northeast. Florida, an area traditionally thought of as sunny, does receive high *global* solar radiation -- 70% of the national maximum. However, Florida is not a likely site for solar thermal plants because its annual cloud cover and precipitation patterns result in low levels of direct solar radiation.

The geographic range of economical solar thermal electric generation is confined to the desert southwest under current costs and regulation. Lower costs and regulatory reform could expand the viable range of this technology to a region that would span the entire Western U.S. beginning in central California, ranging north to the Canadian border and extending as far east as Iowa, Missouri, and Arkansas.[3]

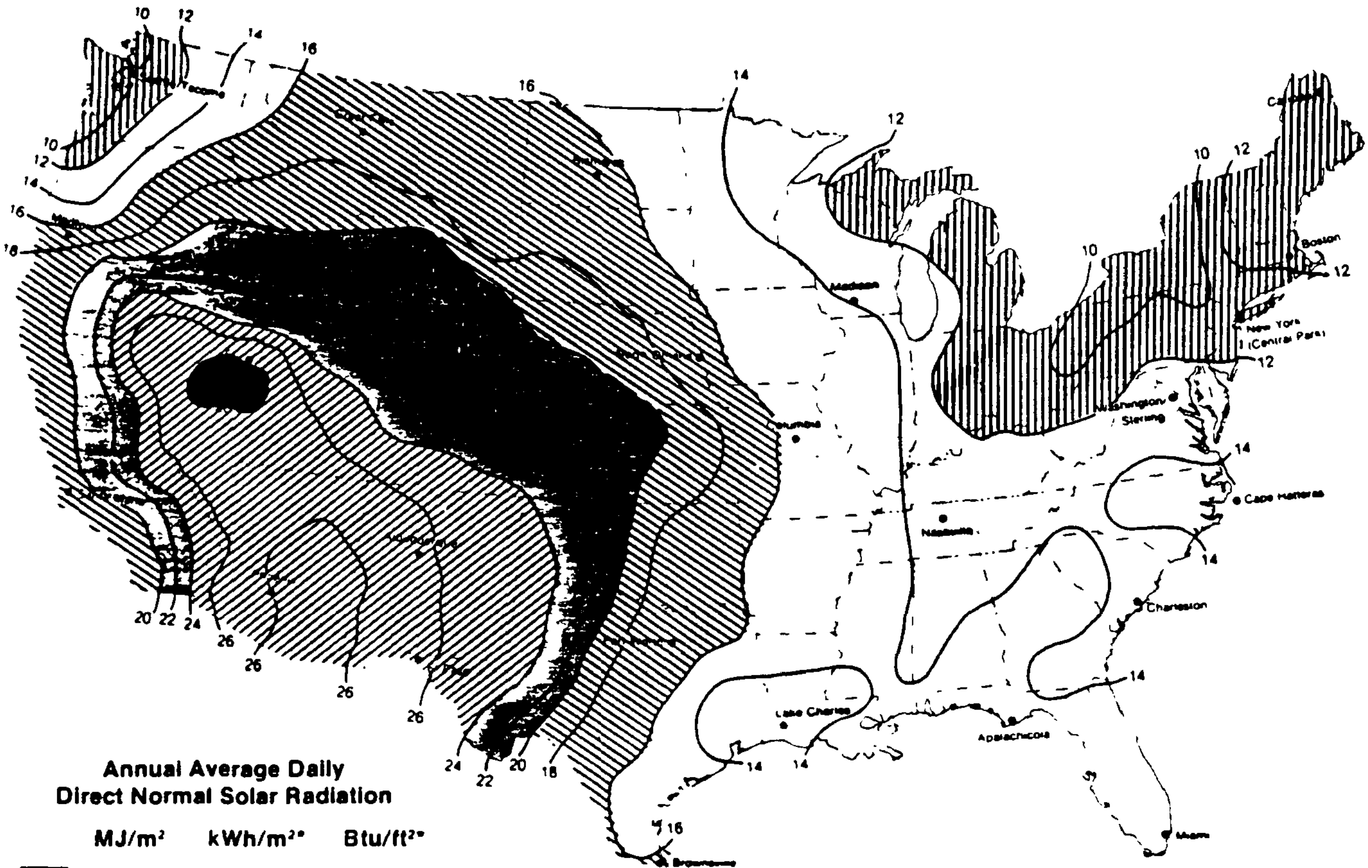
CONVERSION TO ELECTRICITY

A solar thermal plant converts solar energy to useable energy with four basic subsystems: concentrator, receiver, transport/storage, and conversion/delivery. Solar concentrators focus large amounts of solar energy onto the receiver, which heats a fluid used to generate electric power or to provide heat for industrial applications. To provide power, the fluid must be transported through a piping system, or stored for later use. At point of use, the heat is converted to electric power and delivered to the grid, or used to produce steam, hot water, or hot gases for industrial applications.

[3] James Bazor, Testimony before the U.S. Department of Energy National Energy Strategy Hearing, Tulsa, Oklahoma, August 8, 1989.

FIGURE VIII - 1

Annual Average Daily Direct Solar Radiation



	MJ/m²	kWh/m²*	Btu/ft²*
(vertical lines)	8-12	2 2-3.3	700-1050
(blank)	12-16	3 3-4 4	1050-1400
(diagonal hatching)	16-20	4 4-5.5	1400-1750
(dark stipple)	20-24	5 5-6 6	1750-2100
(light hatching)	24-28	6 6-7 7	2100-2450
(solid black)	28+	7 7+	2450+

*Approximate Values

NOTE Numbered contours represent MJ/m²

Direct (beam) radiation can be converted into high temperature steam or directly into electricity by concentrating collectors which track the sun.

Source: Solar Energy Research Institute (September 1983). *Solar Energy: A Brief Assessment.*

Existing Technologies

Four basic solar thermal energy technologies are used to concentrate or absorb sunlight: parabolic troughs, parabolic dishes, central receivers, and solar ponds. With the exception of solar ponds, these are all considered concentrating collector systems. Figure VIII-2 displays the collector system technologies.

Parabolic Troughs. Parabolic troughs are reflective troughs, curved in one dimension, that track the sun on a single axis and focus the sun's light onto the receiver, a tube located at the trough's focal point. The receiver is a specially coated pipe inside a glass vacuum tube. The heat transfer fluid in the pipes is typically a synthetic oil heated to over 700 °F and piped to a heat exchanger to create superheated steam for the turbine generator.

Trough technology is currently the technology most in use, and a key advantage of the parabolic trough system is modularity. A basic module is a row of reflectors activated by a drive motor to track the sun. A control system operates as many modules as necessary to heat the fluid in the pipes to the temperature required for process heat. The process heat created can be increased in temperature using fossil energy for applications such as driving a generator for electric power production. Hybrid natural gas-solar thermal electric systems expand power generation beyond sunlight periods and provide reliable power during cloudy times. Several natural gas-solar hybrid plants have been commercially deployed in California. Figure VIII-3 shows the parabolic trough system of Luz International Ltd., a major solar thermal electricity producer.

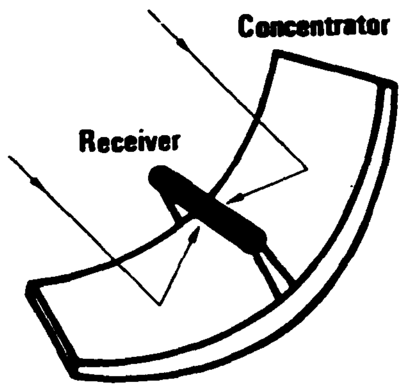
Parabolic Dish Systems. Dish systems use parabolic reflectors in the shape of a dish to accurately focus the sun's rays onto a receiver mounted above the dish at its focal point. The solar energy heats fluid circulating through the receiver and this hot fluid can either be piped to a central heat exchanger and turbine generator to be used for a variety of uses, or electric power can be generated by a small engine mounted at the focal point of the dish. A single parabolic dish, 15 meters in diameter, can achieve temperatures in excess of 2700 °F and produce up to 50 kW of electricity.[4] Solar dishes require very accurate tracking devices but they achieve the highest performance of all concentrator types in terms of annual collected energy and peak solar concentration.

A dish-Stirling system is named for its two major components: the dish-shaped solar concentrator and a Stirling heat engine. Stirling engines can operate efficiently at the high temperatures attained by dish reflectors. The engine is a sealed system filled with gas, and as the gas

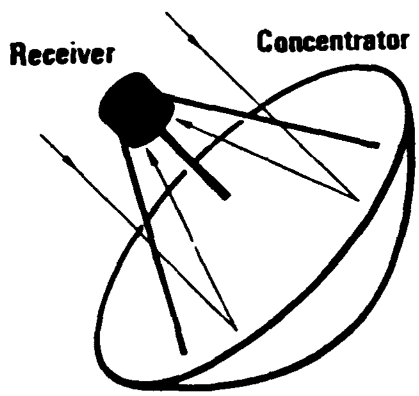
---

[4] Solar Technical Information Program, "Solar Thermal Power," February, 1987.

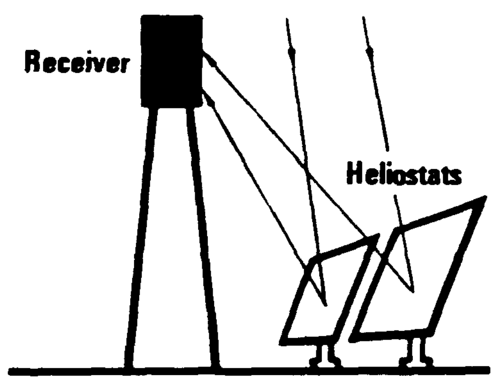
FIGURE VIII - 2
Solar Thermal Collector System Technologies



Parabolic Trough Systems

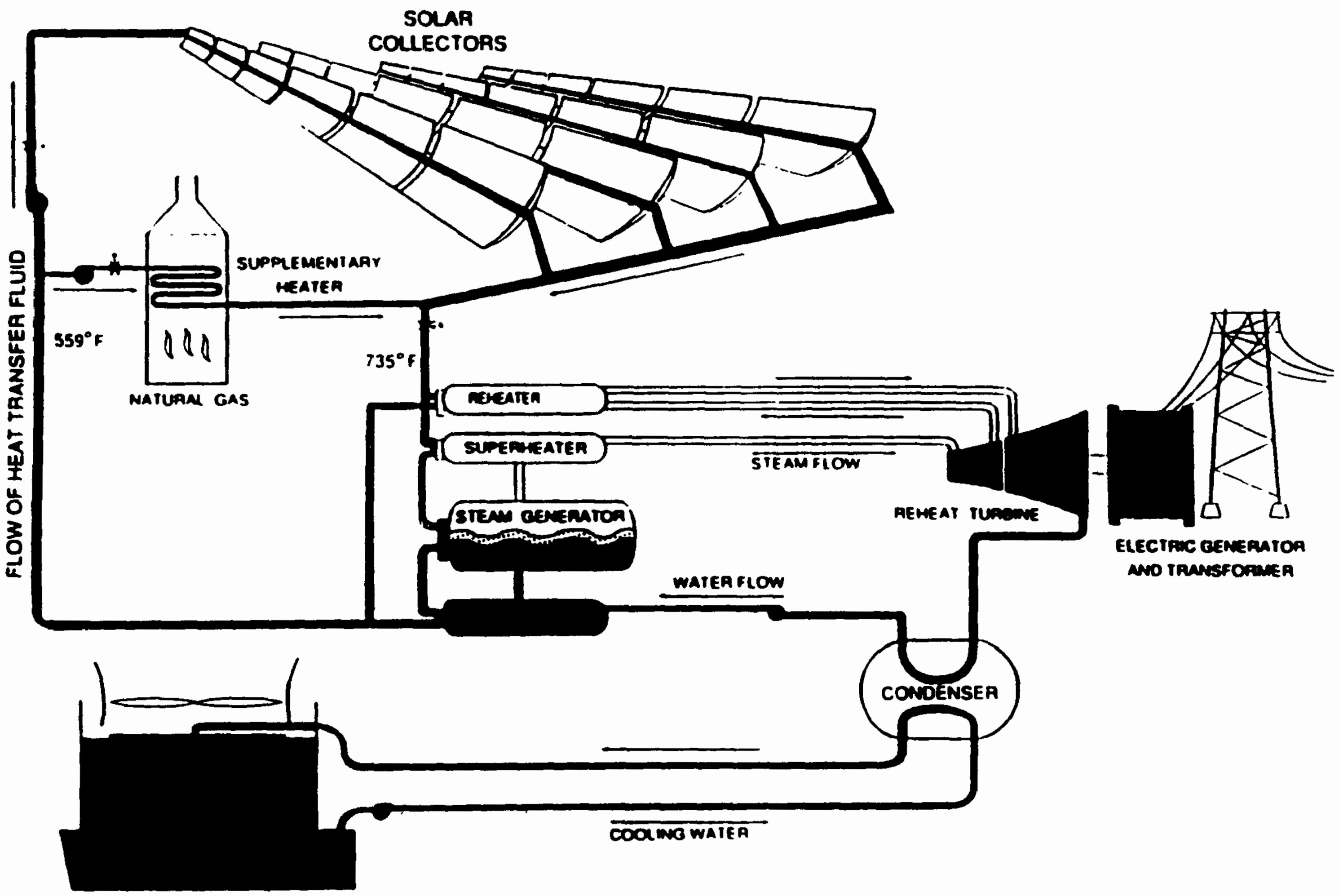


Parabolic Dish Systems



Central Receiver Systems

FIGURE VIII - 3
The Luz System



heats and cools, its pressure rises and falls. The change in pressure is controlled to drive the pistons inside the engine, producing mechanical power. The Stirling engines are either kinematic or free-piston. In the kinematic model, the pistons are physically linked to coordinate their movement. In the free-piston model, there is no mechanical link between the pistons, and motion is dependent upon gas springs.

The Department of Energy has supported several parabolic dish projects. These include the Vanguard solar dish in Rancho Mirage, California, and the Solar Total Energy Project (STEP) in Shenandoah, Georgia. The Vanguard, which was jointly funded by Advanco Corporation, is a 36 foot diameter parabolic dish concentrator combined with a Stirling engine generating 25 kW of electric power. In 1988 the system converted 29.4% of available solar energy to electricity, a record for any solar experiment. The STEP system, a joint venture between DOE and Georgia Power, incorporated 114 parabolic dish collectors and a steam powered generator to produce up to 400 kW of electric power, 1400 pounds of steam at 350 °F, and 257 tons of air-conditioning per day for use in an adjacent textile mill. Funding for STEP was terminated and the project was mothballed in November, 1988. Demonstrating a much larger application of parabolic dish technology, the 4.4 MW LaJet Solarplant 1 near San Diego makes steam for two turbine generators, using an array of 700 dish concentrators.

Central Receivers. Central receiver solar thermal systems feature a central receiver point on a tower that collects focused sunlight from a large surrounding array of heliostats that track the sun. In 1965, the first true central receiver system, by today's standards a small one, was built near Genoa, Italy. Subsequent plants were built that produced steam in the range of 900 °F to 1100 °F. Around the same time, solar furnaces were being built in France using large, computer guided flat mirrors (heliostats) to redirect the solar beam (direct sunlight) into a fixed parabola. Tilting the heliostats and aiming them toward the receiver on top of the fixed parabolic structure resulted in a configuration much like the central receiver plants that are being built today. A heat transfer fluid, which could be steam, molten salt, or sodium at temperatures of 1000 °F to 2700 °F, can be used to drive a turbine to produce electric power. Given a good solar resource and enough heliostats, temperatures on the receiver can exceed 1800 °F for gas-cooled receivers, while steam Rankine cycle turbines can generate electricity with working temperatures under 1100 °F.[5] The principal advantage of central receiver systems is their ability to efficiently deliver energy at very high temperatures. Figure VIII-4 shows a central receiver system.

---

[5] A rankine cycle engine is a type of heat engine, a thermodynamic device which converts thermal energy to work. The working fluid used in the conversion process is usually steam, but other fluids can be used.

The only commercial demonstration built in the U.S. was the Solar One plant in Barstow, California. Solar One was a 10 MW generating plant using a water/steam receiver that contributed to the Southern California Edison (SCE) grid between 1982 and 1987, while operating on a five year research and development contract with USDOE. The project consisted of 1,818 individual tracking heliostats with 766,000 square feet of reflective area that focused enough sunlight on the receiver to achieve a temperature of 1150 °F. Through August 1986, the maximum annual output was 8,816 MWh, demonstrating about a 10% capacity factor. In addition to direct steam use in the turbine generator, the plant used a thermal storage unit with capacity of about 34,000 cubic feet of thermal oil, which was used to produce steam for the turbine during cloudy periods and after sundown.[6] The project provided data on the operation, reliability, and maintenance of central receiver power plants. As a result of experience with Solar One, improved heliostats, receivers, and computerized controls are being designed, which will yield more cost-effective operation. The Solar One plant has been dormant since 1987, the last year of the R&D contract with DOE, but is being maintained by SCE for future use. The National Renewable Energy Laboratory (formerly SERI) is currently attempting to raise the necessary funds to use the facility to test molten salt as a receiver medium.

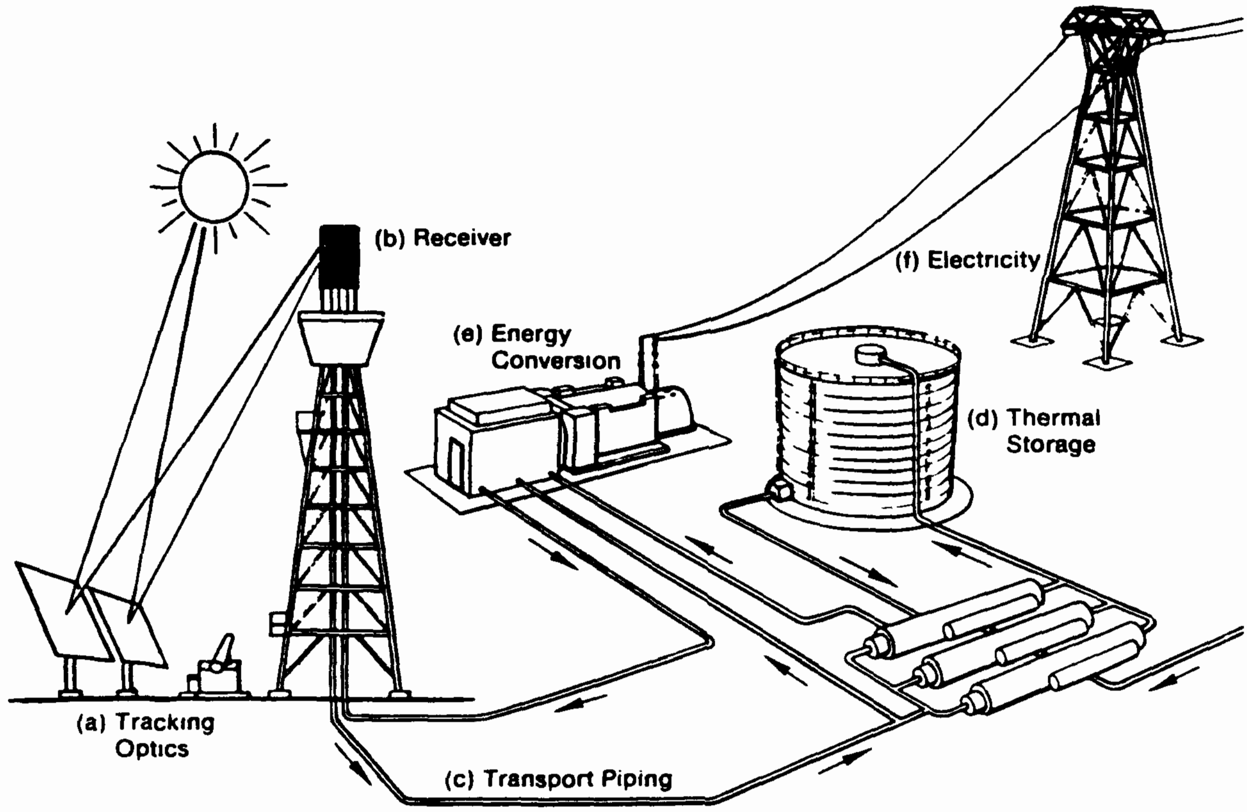
Solar Ponds. Solar ponds control the fluid composition, density, and convective flows of different temperature fluids in a pond exposed to the sun to maximize the temperature difference between the bottom and top layers of a pond warmed by the sun. This temperature difference can be harnessed to drive a turbine generator or produce process heat. In 1984, Ormat Systems constructed a 62 acre solar pond near the Dead Sea in Israel, which supplies 5 MW at peak operation and about 1,500 MWh per year at about 10¢/kWh. In the U.S., the Bureau of Reclamation has funded a 36,000 ft^2 solar pond project that uses a 100 kW power system. After the oil shortages of the 1970s, the U.S. DOE funded several pond research projects aimed at producing space heating and cooling and industrial process heat. DOE funding for solar ponds was terminated in 1983.

Stand-Alone Systems. Some of the earlier system experiments used trough technology and heat engines to produce power for irrigation systems. The largest, the 150 kW Coolidge Solar Irrigation Project, was funded through a cooperative agreement between DOE and the state of Arizona. The operation of the plant demonstrated a "hands-off" automated control system and established an outstanding reliability record, operating during 97% of the adequate insolation.

[6] Solar Technical Information Program, "Solar Thermal Power," February 1987.

FIGURE VIII - 4

Solar Thermal Central Receiver System



Solar Thermal System. Solar thermal systems convert the sun s radiation to useful products (such as electricity, fuels, or direct heat) via a thermal process. The basic elements of any solar thermal design are (a) the tracking optics used to concentrate the sun's energy, (b) the receiver, which transfers the sun s energy to a fluid, (c) piping to transfer the hot fluid to (d) storage for later use or directly to (e) the conversion device, which converts the heat in the fluid to a usable form such as (f) electricity or process heat.

Resources Recovered

In 1990, 279 MW of installed solar thermal capacity produced 765 GWh of electricity, yielding a natural gas-assisted capacity factor of 31%. LaJet's parabolic dish system accounted for 5 MW of the installed capacity; Luz's parabolic trough systems comprised the rest. Luz currently has 354 MW of capacity on-line in southern California.

Current Economics

Costs for central receiver systems have declined from the $15,000/kW for the Barstow Solar One project to about $3,000 to $4,000/kW in 1986. Cost trends for parabolic dishes have also witnessed a rapid decline over the last decade. Area-related costs of collectors have dropped from $1000/m^2 in 1978 to less than $180/m^2 for the LaJet dish and $160/m^2 for the Acurex dish in 1987. System costs have dropped from $13,500/kW to about $2,500/kW in that time.[7]

The capital cost of parabolic troughs with gas enhancement is currently $3000 - $3500/kW. Levelized real (1988 dollars) costs of energy have dropped from 25¢/kWh in 1984 to about 8¢/kWh today. The solar portion of the costs has decreased by a factor of five since the first commercial installation built in 1984. The Solar Electric Generating System (SEGS I) produced 13.8 MW using parabolic trough collectors and oil thermal energy storage. SEGS I and subsequent SEGS plants led to the negotiation of contracts with Southern California Edison (SCE) for nearly 600 MW to be built in 30 MW increments in the Mojave Desert. By late 1988, Luz had built six additional 30 MW facilities and was delivering a total of 194 MW to the SCE grid. The next operational plants, SEGS VI and VII at 30 MW, produced power at about 11¢/kWh. Responding to the 1987 legislation that increased limits on power from Qualifying Facilities (QFs) from 30 MW to 80 MW, Luz completed SEGS VIII in December of 1989 and SEGS IX in late 1990, bringing their total installed capacity to 354 MW; the latest plants produce power at 8¢/kWh. The California Public Utilities Commission directed San Diego Gas and Electric (SDG&E) to enter into an 80 MW power purchase agreement with Luz.[8] Table VIII-1 details characteristics of current and future SEGS. Recent events, however, have clouded the future viability of solar thermal electricity generation. Citing the recent recession and depressed oil and natural gas prices, as well as the failure of California to extend property tax relief and the expiration of

---

[7] William B. Stine, *Progress in Parabolic Dish Technology*. Solar Energy Research Institute: June 1989.

[8] Conversation with Michael Lotker, April 3, 1991.

TABLE VIII - 1 LUZ SOLAR ELECTRIC GENERATING SYSTEMS						
Plant	Capacity (MW)	Capital Costs ($/kW)	Collector Area (M_2)	Annual Energy (MWh)	Capacity Factor	In-Service Date
SEGS I	13.8	4,500	82,960	30,100	.25	1984
SEGS II	30	3,200	165,000	80,500	.31	1985
SEGS III	30	3,620	230,300	91,311	.35	1986
SEGS IV	30	3,760	230,300	91,311	.35	1987
SEGS V	30	4,020	233,120	92,553	.35	1988
SEGS VI	30	N/A	188,000	91,356	.35	1989
SEGS VII	30	3,870	194,280	92,646	.35	1989
SEGS VIII	80	3,788	464,000	252,700	.36	1989
SEGS IX	80	3000 - 3500	464,000	252,700	.36	1990
SEGS X through SEGS XII	220	3000 - 3500	464,000 per SEG	252,700 per SEG	.36	??
SEGS XIII	80	2000	N/A	N/A	N/A	??

Sources: Northwest Power Planning Council, "Solar Electric Resources", Staff Issue Paper, November 1, 1989.
"Solar Electric Generating Systems Information Overview for the Public Utilities Commission of the State of Colorado," Luz International Limited, February 14, 1990.

federal tax credits, Luz recently declared bankruptcy. It is unclear whether Luz will be able to continue to operate in the future without government support or increased prices for fossil fuels.[9]

Although Luz would not break down the installed cost into component costs for proprietary reasons, they did report that at least 50 percent of the cost is due to the solar field (the troughs, mirrors, etc.). The balance of plant (turbine, generator, and other conventional equipment used to produce power) results in the next largest component cost. Other component costs include four oil heaters necessary for use with a natural gas system, the control center, land improvement, and transmission lines.

[9] See "Top Solar Power Firm Cuts Work Force in Half," in The Los Angeles Times, Business Section, p. 2, July 6, 1991. and "Luz Rescue Plan Collapses as ABB Backs Out of Deal," in The Energy Daily, November 20, 1991.

Typical construction time from ground breaking to turn-key operation for a major solar thermal energy system is 8 to 18 months; Luz's latest plant was financed, constructed and brought on-line in 7 1/2 months.[10] In order to provide continuous power generation during cloudy and night-time periods, the Luz power plants use up to 25% natural gas during non-solar periods. Gas use is restricted to 25% under current PURPA regulation, a restriction that would not apply to utility-built solar thermal hybrid plants. By extending the period of operation through increased natural gas use, the cost per kilowatt can decrease, because the fuel cost is offset by greater capital utilization. In addition, solar thermal electric plants are likely to have scale economies that were unrealized under the 80 MW PURPA restriction in effect until 1990.

Storage presents another option to extend the period of operation. Storage systems, such as batteries and thermal storage, sacrifice instantaneous power supply during the peak periods because they divert some of the energy to maintain several hours of stored electricity. For example, a 1 MW plant with storage may be capable of providing 2 MW of power, but instead uses the extra for storage. The economic tradeoff is one between greater (but intermittent) peak power and lower (but firmer) capacity. Storage capacity may enable a solar thermal plant to obtain some capacity credit. However, pumped storage hydro is probably not a viable storage option since pumped storage plants typically fill reservoirs at night, and water may not be available in arid regions for dedicated pumped storage plants.

Even without storage, solar thermal plants can operate when very brief cloud cover occurs, since the working fluid has some thermal storage capacity. However, extended cloud cover will reduce power output to zero. This is different than the type of intermittent output expected from a photovoltaic (PV) plant. If a single cloud shades a PV plant, output would immediately drop by 30% to 50% but would quickly recover full power as the cloud passes. Because PV technology utilizes indirect as well as direct light, however, PV systems can continue to operate at 30-50% of peak sunlight capacity under extended cloudy conditions.

EMERGING TECHNOLOGIES

During the past decade, solar thermal systems have improved with the development of more efficient concentrators, longer-lasting and cheaper reflective materials, and a variety of receivers and systems. These advances have positioned solar thermal systems for utility-scale applications. In addition to generating electricity, solar thermal systems can be used for destroying hazardous wastes, liquefying coal, and processing metals and chemicals due to the high temperatures they achieve and

---

[10] *Solar Industry Journal*, Fourth Quarter 1990, Volume 1, Issue 4, p. 6.

the energetic properties of the solar spectrum. Spin-offs from these areas may have applications in solar thermal electricity generation. The progress made by Solar One and early commercial thermal plants along with the prospect for producing vital fuels and chemicals through solar thermal technology are encouraging, but further development of system components is necessary.

Potential Technology and Multiple Pathways

Each of the four solar thermal electric technologies -- parabolic troughs, parabolic dishes, central receivers, solar ponds -- employs the same basic subsystems: concentrator, receiver, transport/storage, and conversion/delivery. Advances in a given technology will result from research gains not just in that technology but also from advances in any of its subsystems, which are themselves occurring along a variety of pathways. For example, research on concentrators in 1989 involved heliostats, parabolic dishes, optical materials and structural analysis.[11]

Reflectors. When the Solar One plant was built, the cost of its heliostats was approximately 60% of the total cost of the power plant. Advanced heliostats are now 3 to 4 times larger (150 square meters instead of 40 square meters) than the originals, reducing the (per area) cost of the heliostat. In addition, the heavy silvered glass of the original heliostats is being replaced with lightweight silvered plastic, allowing for lighter and simpler supporting structures. An example is the stretched membrane, where the reflective material is stretched over a metal rim. Small stretched membranes were used in the LaJet Solarplant 1 parabolic dishes. Further development of the membrane reflectors should lead to larger, more efficient designs at a lower cost.[12]

Receivers. The future potential for central receiver technology remains uncertain. Industry/utility teams have identified the need for a commercial 10-30 MW commercial project to validate current technology at a scale larger than component tests. Next generation plants will likely use stretched membrane heliostats and advanced direct-absorption receivers.[13] Further improvements for central receivers will decrease the size and weight of solar receivers by using materials and fluids that absorb more energy. For example, advanced receivers using molten salt or sodium as heat transfer fluids

[11] *Solar Thermal Program Summary*, Volume I: Overview, U.S. Department of Energy, January, 1990.

[12] Solar Technical Information Program, "Solar Thermal Power," February, 1987.

[13] The U.S. Department of Energy, "Bringing Solar Technology to the Marketplace -- A Report to the U.S. Congress," August 1988.

could be 80% smaller than the Solar One steam receivers. The new fluids can also be stored at high temperature and low pressure for plant operation during long hours of reduced sunlight.[14]

Solar Ponds. Many questions remain unanswered about the technological and commercial feasibility of solar ponds. Research needs are different for natural and constructed ponds, but common to both is the need to develop pond and power system maintenance procedures and to investigate alternate salts, salt management, and load matching and optimization. For natural ponds, further research needs include soil impermeability treatment studies, plastic liner development, and control of ground heat losses.[15]

Costs

Costs of central receivers, parabolic dishes and parabolic troughs have been falling steadily. Although commercial experience with central receivers is limited, costs are projected to decrease to \$1,500/kW by 1995-2000. For parabolic dishes, SERI forecasts system costs of \$1000/kW, energy costs of 5¢/kWh and concentrator costs of \$140/m^2 by 1995.[16] Luz estimates that the levelized cost of electricity from their third generation parabolic trough plants, of which 160 MW have already been brought on line, will remain at 8¢/kWh. Their next generation of plants is projected to cost \$2000/kW installed, and produce electricity at a levelized real cost of 6¢/kWh. These cost reductions will be due to technological and engineering advances, Luz's growing experience with the commercial application of solar thermal systems, improved manufacturing techniques, and economies of scale, which were not available before Congress rescinded the 80 MW PURPA limit in 1990.

In the recent DOE/SERI analysis of the development of solar thermal electric generation with storage, costs and energy supply are projected forward from 1988.[17] Capital costs for systems with storage drop from \$3000/kW in 1988 to \$2400/kW (BAU scenario) or \$1750/kW (Intensified RD&D) in 2000. Costs were projected to decline further by 2010, ranging from \$1530/kW (BAU) to \$1450/kW (RD&D) in 2010. O&M costs are projected to remain constant at 2.0 ¢/kWh under both scenarios. Given these assumptions, levelized energy costs fall from 15.8 ¢/kWh in 1988 to 7.5 ¢/kWh (BAU) to 6.0 ¢/kWh (RD&D) in 2000, and decline to 5.5 ¢/kWh (BAU) to 5.0 ¢/kWh (RD&D) in 2010.

---

[14] Solar Technical Information Program, "Solar Thermal Power," February 1987.

[15] The U.S. Department of Energy, "Bringing Solar Technology to the Marketplace -- A Report to the U S. Congress," August 1988.

[16] William B. Stine, *Progress in Parabolic Dish Technology*, Solar Energy Research Institute: June 1989.

[17] *The Potential of Renewable Energy: An Interlaboratory White Paper*. Prepared for the Office of Policy, Planning and Analysis, U.S. Department of Energy, March 1990.

MARKET ASSESSMENT

The EPA Base Case and Enhanced Market scenarios are derived primarily from the DOE/SERI scenarios and are shown in Table VIII-2. The DOE/SERI BAU scenario yields an increase of solar thermal electric from 0.004 quads of primary energy to 0.29 quads in 2010, an average annual growth rate of almost 21%.[18] The National Premiums policy scenario would triple solar thermal electric generation compared to the BAU projection, while the RD&D policy would lead to 1.01 quads by 2010. In all scenarios, solar thermal systems are located only in the West and South.
The DOE/SERI analysis considers hybrid systems, along with stand-alone systems with and without storage (peaking systems), but does not indicate which technologies would be chosen. The economics of storage and fuel backup are probably more favorable from the utility perspective than intermittent peak power, unless the solar resource is extremely dependable or located in an area where weather forecasting is reliable. However, the DOE/SERI report suggests that storage systems will be improved to the point where they are more economical than natural gas backup systems.

The EPA Base case is identical to the DOE/SERI BAU scenario (as noted on Table VIII-2, the generation figures in the EPA scenarios include the portion of natural gas hybrid systems attributed to gas-fired operation). Capacity installed between 1990 and 2000 is assumed to be natural gas hybrid operating at 25% gas backup in all regions. Between 2000 and 2010, capacity is assumed to be a mixture of peaking (stand-alone) stations and systems with storage.

The Enhanced market scenario assumes that additional R&D brings about cost reductions indicated in the DOE/SERI Intensified RD&D scenario, but that additional growth in market deployment in both hybrid and stand-alone systems is spurred by environmental concerns. Chapter X gives detailed information about the input assumptions for the solar thermal market analysis for hybrid and non-hybrid systems.

Tables VIII-3 and VIII-4 show the model results for costs and air pollution prevented. Because solar thermal systems rely on direct solar radiation, they are not economic in areas that experience clouds and haze during much of the year. Therefore, solar thermal electric generation is assumed to grow only in the Southwest, Northwest/Mountain, and California regions. While natural gas backup beyond the 25% assumed in this analysis could extend the range somewhat, solar thermal systems would still be most economic in these three regions. In the Base Case, annual solar thermal electric generation grows by 30,400 GWh between 1990 and 2010. Over 75% of the growth occurs in the

---

[18] DOE/SERI projections only account for the solar energy input to hybrid systems. Thus, actual generation from solar hybrid systems may be higher than these figures indicate.

TABLE VIII - 2 SOLAR THERMAL SCENARIOS				
Scenario	**Capacity 2000 (MW)**	**Generation 2000 (GWh)**	**Capacity 2010 (MW)**	**Generation 2010 (GWh)**
DOE/SERI				
Business as Usual	3,200	8,800	10,300	28,300
Intensified RD&D	6,000	16,600	35,900	98,500
National Premiums	5,300	14,600	32,000	87,800
EPA				
Base Case	3,800	11,700	9,600	31,200
Enhanced Market	7,200	22,100	35,200	115,100
1990:	300	800		

Note: DOE/SERI generation figures are solar contribution only. EPA figures include some fossil fuel (natural gas) input for hybrid systems.

Southwest region, which includes Texas, Arizona and New Mexico. In the Enhanced Market scenario, solar thermal electric generation grows by over 114,300 GWh between 1990 and 2010, again mostly in the Southwest.

Costs

Because solar thermal electric systems with natural gas backup can provide reliable peak power, avoided utility costs are fairly high. By 2010 in the Base Case, average solar thermal generation costs are 0.1 ¢/kWh lower than conventional costs in the Southwest regions, and 1.3 ¢/kWh lower than conventional costs in California. In the Enhanced Market scenario, costs by 2010 are significantly lower than conventional costs; solar thermal generation costs 0.5 ¢/kWh less than conventional generation in the Southwest and costs 1.8 ¢/kWh less in California.

TABLE VIII - 3

ELECTRICITY GENERATION COSTS AND AIR POLLUTION PREVENTED

EPA BASE CASE
SOLAR THERMAL

REGION	AVERAGE UNIT COST IN 2000 (cents/kWh)			AVERAGE UNIT COST IN 2010 (cents/kWh)		
	AVOIDED FOSSIL	**SOLAR THERMAL**	**COST DIFFERENCE**	**AVOIDED FOSSIL**	**SOLAR THERMAL**	**COST DIFFERENCE**
Northeast	NA	NA	NA	NA	NA	NA
Southeast	NA	NA	NA	NA	NA	NA
Southwest	7 5	11 5	4 0	6 6	6.5	-0.1
North Central	NA	NA	NA	NA	NA	NA
Northwest/Mountain	6 9	11 4	4 4	5 0	6.4	1 3
California	5 7	11 4	5 7	7.7	6.4	-1 3
AVERAGE	**7.1**	**11.4**	**4.3**	**6.5**	**6.5**	**-0.1**

REGION	INCREMENTAL GENERATION 1990 - 2010 (GWh/yr)	AIR POLLUTION PREVENTED 1990 - 2010 (thousand metric tons/yr)						
		SO_2	NO_x	Particulate Matter	CO	CH_4	CO_2	CO_2 Equivalent
Northeast	0	0.0	0.0	0.00	0.00	0.00	0	0
Southeast	0	0.0	0.0	0.00	0.00	0.00	0	0
Southwest	22,974	29.7	71.7	2 33	3 67	0 09	15,765	18,645
North Central	0	0 0	0.0	0 00	0.00	0 00	0	0
Northwest/Mountain	4,118	8 2	17 1	1.06	0 58	0 04	4,069	4,756
California	3,353	0.6	7.6	0.10	0.56	0 01	1,755	2,059
TOTAL	**30,445**	**38.5**	**96.4**	**3.50**	**4.80**	**0.13**	**21,588**	**25,460**

TABLE VIII - 4

ELECTRICITY GENERATION COSTS AND AIR POLLUTION PREVENTED

EPA ENHANCED MARKET SCENARIO
SOLAR THERMAL

REGION	AVERAGE UNIT COST IN 2000 (cents/kWh)			AVERAGE UNIT COST IN 2010 (cents/kWh)		
	AVOIDED FOSSIL	SOLAR THERMAL	COST DIFFERENCE	AVOIDED FOSSIL	SOLAR THERMAL	COST DIFFERENCE
Northeast	NA	NA	NA	NA	NA	NA
Southeast	NA	NA	NA	NA	NA	NA
Southwest	7.5	10.3	2.8	6.8	6.3	-0.5
North Central	NA	NA	NA	NA	NA	NA
Northwest/Mountain	6.9	10.3	3.4	5.5	6.5	1.0
California	5.7	10.4	4.6	8.3	6.5	-1.8
AVERAGE	**7.0**	**10.3**	**3.3**	**6.8**	**6.3**	**-0.5**

REGION	INCREMENTAL GENERATION 1990 - 2010 (GWh/yr)	AIR POLLUTION PREVENTED 1990 - 2010 (thousand metric tons/yr)						
		SO_2	NO_x	Particulate Matter	CO	CH_4	CO_2	CO_2 Equivalent
Northeast	0	0.0	0.0	0.00	0.00	0.00	0	0
Southeast	0	0.0	0.0	0.00	0.00	0.00	0	0
Southwest	83,878	108.8	263.2	8.57	13.48	0.34	57,890	68,465
North Central	0	0.0	0.0	0.00	0.00	0.00	0	0
Northwest/Mountain	15,605	30.8	64.7	3.98	2.20	0.14	15,345	17,940
California	14,840	2.8	33.4	0.45	2.46	0.03	7,760	9,106
TOTAL	**114,323**	**142.4**	**361.3**	**13.00**	**18.14**	**0.50**	**80,995**	**95,511**

Air Pollution Prevented

Because solar thermal electric generation occurs only in the West, where natural gas and oil-fired generation are the marginal fuels and where coal-fired sources are fairly well controlled, SO_2, PM, and CO_2 emission reductions per kWh generated are generally lower than other renewable technologies. However, solar thermal generation reduces a significant amount of air pollution. In the Enhanced Market scenario for 2010, annual SO_2 emissions are reduced by 142,000 metric tons; NO_x emissions by 361,000 metric tons; and CO_2 emissions by 81 million metric tons.

CHAPTER IX
WINDPOWER

Wind energy has powered sailing vessels for thousands of years, and has been used for centuries to power windmills for pumping water and grinding grain. In 1941, energy from wind was first used to generate grid connected electricity. Wind energy generation has increased dramatically during the past decade, particularly when oil prices were high and major federal and state tax incentives and R&D expenditures were in place. Throughout the period, wind energy costs steadily declined.

Wind energy development initially focused on the individual wind turbine, but by the late 1970s the focus shifted to minimizing the cost by maximizing the total generation from groups of wind turbines. Since 1981, thousands of turbines large enough to supply power to utility systems have been installed and the numbers continue to grow. With a maturing of technology and a shakeout and consolidation among manufacturers and developers in recent years, the wind industry is poised to make significant commercial power contributions in the 1990s.[1]

RESOURCE BASE

The total wind energy resource in the U.S. is defined as the amount of energy contained in all air of wind power classes 2 through 7 (see below), which means the energy in all air moving faster than 6.1 meters/second at a height of 50 meters. This resource totals approximately one million quads. The accessible wind resource equals the energy contained in all air of wind power classes 3-7 which would strike the rotors of an adequately spaced array of commercially available wind turbines covering the available land in the U.S.[2] The available land does not include forested areas, parkland and wilderness areas, national security areas and the surfaces of lakes, streams and rivers. The accessible wind resource is about five thousand quads. Meridian equates the subset of the accessible resource which can be economically converted to electricity with the installed wind capacity of wind turbines.

---

[1] Taylor Moore, John Schaefer, and Edgar DeMeo, "Excellent Forecast for Wind," *EPRI Journal*, June 1990.

[2] This is defined as MOD 5-B wind turbines, spaced 10 rotor diameters apart in each row with a 5 diameter spacing between rows. See *Characterization of U.S. Energy Resources and Reserves*, prepared for the U.S. Department of Energy by Meridian Corporation, June 1989, from which this information is taken.

Another recent resource assessment performed by Pacific Northwest Laboratories (PNL) evaluated the windpower potential for the U.S. under various assumptions regarding conversion technologies and land-use restrictions.[3] Although land-use factors eliminated roughly 70% of the energy potential from the resource base in the most restricted scenario, the estimated remaining potential was larger than the wind energy reserves identified in the Meridian report and would exceed total U.S. electricity consumption in 1990.

Geographic Distribution

The Wind Atlas prepared by Pacific Northwest Laboratory for the U.S. Department of Energy (DOE), categorizes wind resources according to wind power classes.[4] Measured at 50 meters above the ground, wind resources are categorized into the following classes: Class 2 is between 12.5 and 14.3 mph; Class 3 is between 14.3 and 15.7 mph; Class 4 is between 15.7 and 16.8 mph; Class 5 is between 16.8 and 17.9 mph; and Class 6 is between 17.9 and 19.7 mph. The Atlas further defines wind resources potentially suitable for wind energy applications as those rated in Class 3 or above. The Atlas also depicts windpower data on a series of maps, which can be used for initial resource assessments. However, the data necessary to successfully site wind turbines requires a far more detailed evaluation of site-specific patterns.

Many areas within the United States have suitable wind energy resources. These areas include much of the Great Plains from northwest Texas and eastern New Mexico north to Montana; North Dakota and West Minnesota; the Atlantic Coast from North Carolina to Maine; the Pacific Coast from California to Washington; and the Texas Gulf Coast. Further, many ridge crests and mountain summits throughout the Appalachians and the Western U.S., as well as specific wind corridors throughout the mountainous western states have good wind resources. Figure IX-1 displays regional wind resources.

According to the maps found in The Atlas, the most powerful wind resources, rated in the 5 to 6 power class, are concentrated in the Pacific, Mountain and Northeastern regions. These regions correspond to the Washington/Oregon, West Mountain, New England, and Mid-Atlantic regions defined in this analysis. Good wind resources, those in Class 3 or 4 rating, can be found in northern

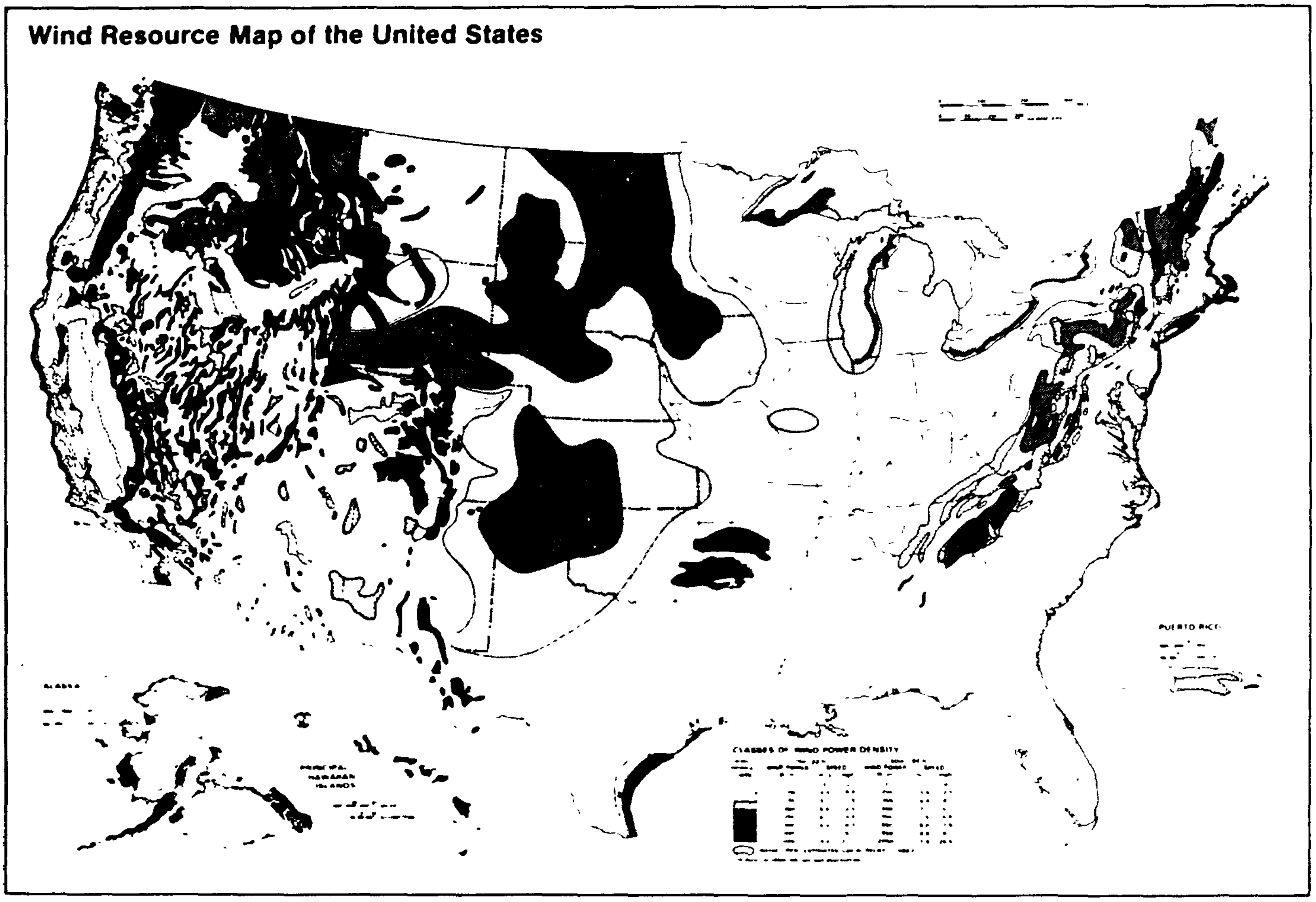
---

[3] D. L. Elliot, L.L. Wendell, and G.L. Gower, "U.S. Areal Wind Resource Estimates Considering Environmental and Land-Use Exclusions" presented at the American Wind Energy Association (AWEA) Windpower '90 Conference, September 28, 1990.

[4] D.L. Elliot, C.G. Holladay, W.R. Barchet, H.P. Foote, and W.F. Sandusky, *Wind Energy Resource Atlas of the United States*, (Golden, Colorado: Solar Energy Research Institute, DOE/CH 10093-34, 1986).

FIGURE IX - 1

Regional Wind Resources



Source: *Wind Energy Resource Atlas of the U.S.*, U.S. Department of Energy, March 1987 and southern Great Plains regions, which correspond to the West North Central and West South Central regions defined by this analysis. Coastal areas in the Northeast from Maine south to New Jersey and in the Northwest south to northern California have class 4 or higher resources.

The PNL study cited above provides estimates of state-level windpower potential. The report presents the average wind electric potential for the 48 contiguous states (in GW) based on current turbine technology (30 meter hub height) sited in Class 5 or above wind resources, and turbines sited in class 3 or above resources (at 50 meter hub height). Figure IX-2 and Table IX-1 show PNL estimates for the 12 EPA regions. After excluding land for environmental and economic reasons, 78% of the class 5 and above resource is located in just 3 states (Montana, North Dakota, and Wyoming); consequently, the EPA West North Central and Mountain regions contain 88% of these class 5 resources. These same regions contain 70% of the class 3 and above wind resource, while another 17% of class 3 potential resides in the West South Central region.

Seasonal Variation

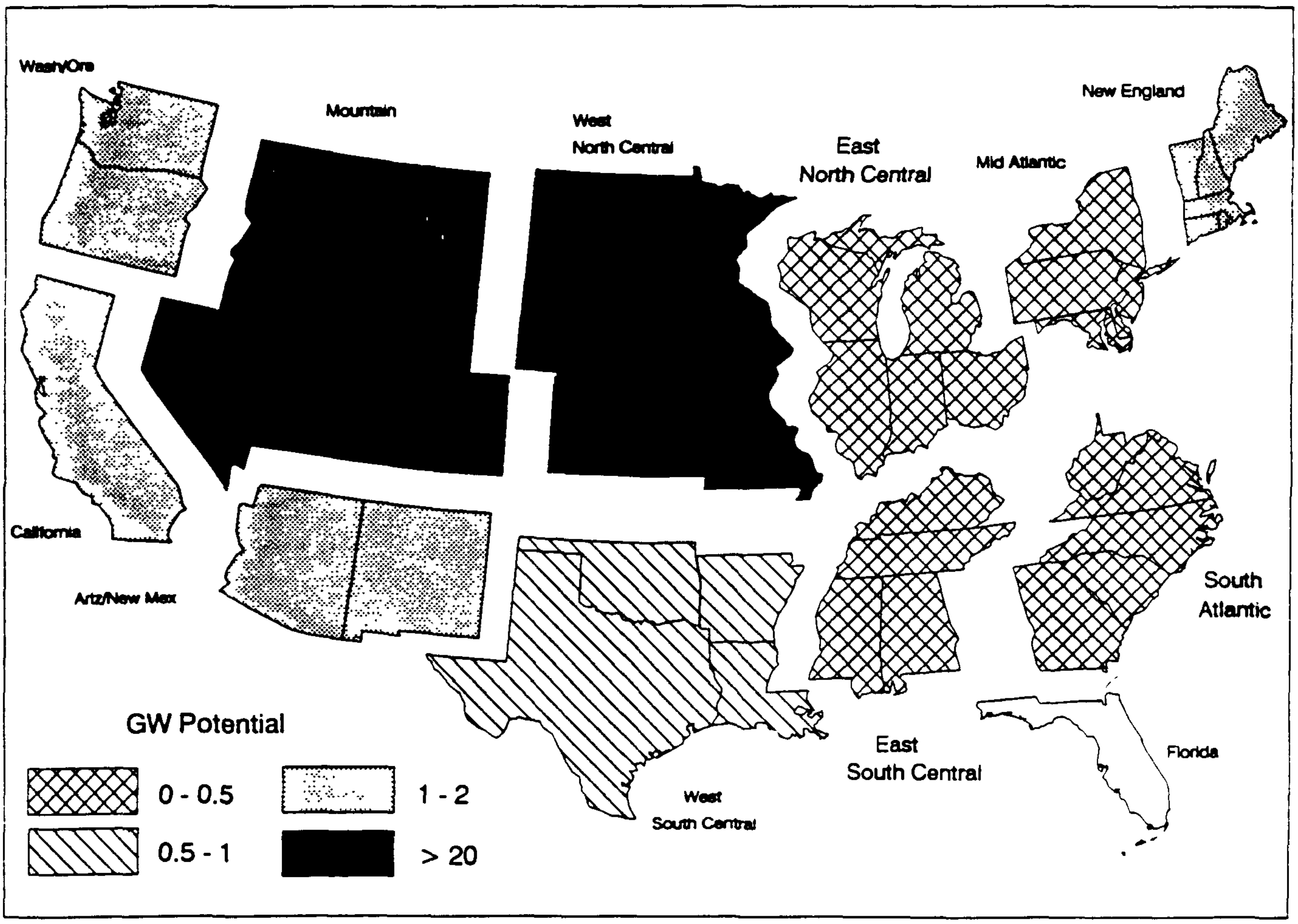
In addition to regional variation in wind resources, seasonal variation in resources occurs. For the most part, the maximum wind speeds occur in the winter and spring seasons with the minimum speeds during the fall and summer seasons throughout most of the U.S. Many of the higher exposed ridge crests and mountain summits in the eastern and western U.S. experience high wind resources throughout the year. However, extreme wind, icing, and inaccessibility caused by poor weather in regions such as the Southern Rocky Mountains, the Pacific Northwest, and the Great Lakes region restrict the suitability of many of these areas for wind energy development. Another barrier to ridge and mountaintop wind development is aesthetic impact. Local terrain features can also cause wind speed to vary considerably over short distances, especially in areas of coastal, hilly, and mountainous terrain.

CONVERSION TO ELECTRICITY

Producing electricity from wind energy requires that conversion technology be matched with a viable wind resource. Improvements in wind turbines and in wind resource assessment were instrumental in the development of windpower during the 1980s, and further refinements are expected to reduce the costs of capturing wind energy to provide electric power.

FIGURE IX - 2

Regional Wind Potential



1/ The electric potential is based on current technology (30 meter hub height) sited in Class 5 wind or above wind resources.

2/ Source: Elliot, D.L., L.L. Wendell, and G.L. Gower. "U.S. Areal Wind Resource Estimates Considering Environmental and Land-Use Exclusions."

TABLE IX - 1 REGIONAL WIND ELECTRIC POTENTIAL BASED ON CURRENT TECHNOLOGY ESTIMATES		
EPA Model Region	**30 Meter Hub Height, Class 5 or Above Wind Resource (GW)**	**50 Meter Hub Height, Class 3 or Above Wind Resource (GW)**
New England	1.3	10.7
Mid Atlantic	0.3	12.5
South Atlantic	0.5	2.7
Florida	N/A	N/A
East North Central	0.4	20.5
West North Central	22.1	619.0
East South Central	N/A	N/A
West South Central	0.7	221.0
Mountain	36.6	273.0
Arizona/New Mexico	1.1	51.0
California	1.7	7.0
Washington/Oregon	1.7	9.0
Total United States	67	1,267

Source: Elliot, D.L., L.L. Wendell, and G.L. Gower. "U.S. Areal Wind Resource Estimates Considering Environmental and Land-Use Exclusions." Pacific Northwest Laboratory, September 1990. Table 6, based on "reasonable exclusion scenario." Note: Wind electric potential is estimated in this report in GW equivalents; these capacity figures are not, however, equal to nameplate capacity.

Conversion Technology

Wind power systems convert kinetic energy into electricity through the use of a wind turbine which in turn drives an electric generator. An individual wind turbine can be used to provide on-site power for a specific load or multiple wind turbines can be combined together into a wind farm for larger scale power generation. Two basic wind turbine designs are currently in use: (1) the more common horizontal-axis wind turbines (HAWTS) using either an upwind or downwind design with typically 2 or 3 blades where the axis of rotation is parallel to the wind stream and the ground, and (2) vertical-axis wind turbines (VAWTS) where the axis of rotation is perpendicular to the wind and the ground. VAWTS are the hoop-shaped, or "egg-beater" turbines.

Many variations in design are possible for the HAWTS; over 50 different HAWT machines are commercially available that vary both in size and design. For example, a yawing device, which controls side to side motion, keeps the rotor oriented properly in the wind stream. Some HAWT designs have a tail vane or rudder to control the yawing motion; others, typically the larger machines, have active yaw systems controlled by microprocessors. VAWTS are similar in design and size, ranging from 100 to 300 kW. In California, HAWTS represent more than 93% of current wind generating capacity, while VAWTS account for the remainder. Nearly three-fourths of all blades have been built from fiberglass, the remainder are built from either laminated wood or made from aluminum. Almost all new turbines being installed in California use fiberglass blades.[5]

Turbine system measurements are comprised of two critical dimensions: rotor diameter and tower height.[6] Recommended tower height varies according to rotor diameter; towers can be constructed from modular sections containing 10 to 20 foot modules. Wind system dimensions range from less than one kW for electric water pumping systems to utility scale turbines of greater than one MW. Examples of turbine configurations and dimensions are found in Figures IX-3 and IX-4.

Turbines produced for wind farms typically range in size from 18 to 600 kW, with the majority being in the 100 kW range. Turbine manufacturers rate output (in kW) at an arbitrary wind speed for comparative purposes. The actual capacity of a wind turbine, however, depends on site characteristics and can be higher or lower than standardized ratings assigned by turbine manufacturers. Therefore, kilowatt ratings for wind turbines are imperfect measures to compare directly with conventional power plant capacity ratings. Rotor diameter and rotor swept area, which is

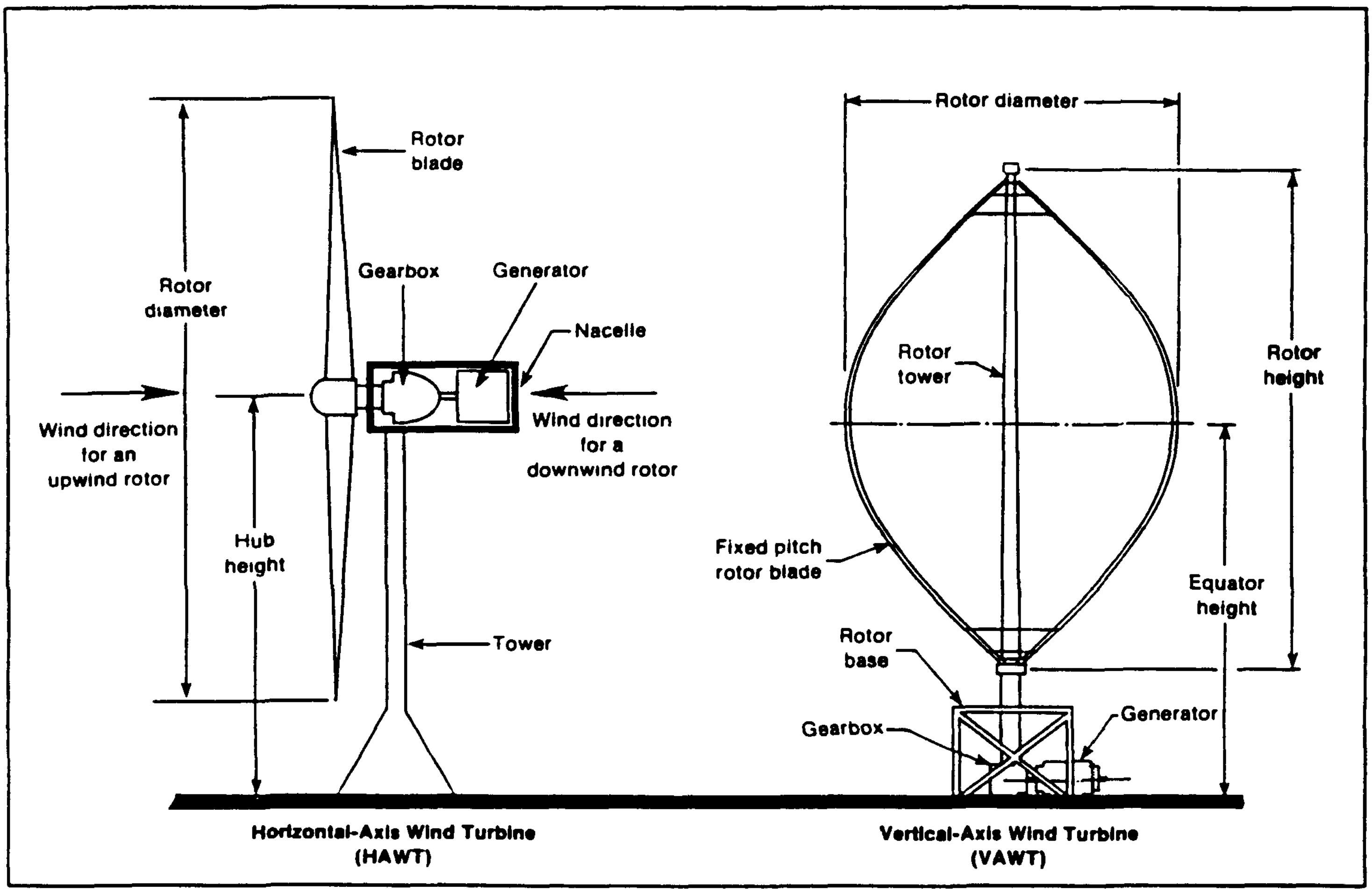
---

[5] Paul Gipe, "Wind Energy Comes of Age in California," May 1990.

[6] A two- or three-bladed HAWT has a rotor diameter equal to the diameter of the circle swept out by the blades. For VAWTS, rotor diameter is measured from the outside edge of one blade to the outside edge of the other.

FIGURE IX - 3

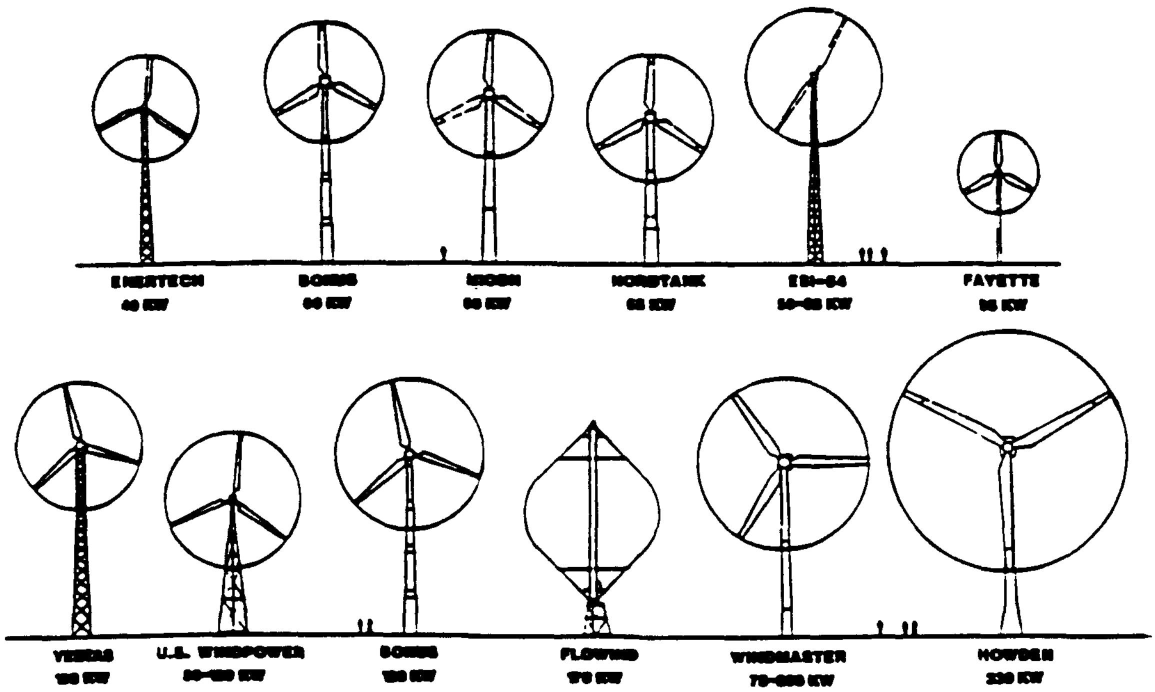
Wind Turbine Configurations



Source: *Five Year Research Plan, 1985 - 1990, Wind Energy Technology: Gaining Power from Wind, p. 2.*

FIGURE IX - 4

Altamont Pass Wind Turbines



Source: D. R. Smith, "The Wind Farms of the Altamont Pass Area," *American Review of Energy*, 1987, 12:145-83, p. 153.

proportional to the square of the rotor diameter, are much more reliable indicators of wind turbine generation potential.

Capital costs (expressed in $/kW) and capacity factors also depend on the rated wind speed, complicating comparisons among different wind turbines as well as comparisons against conventional fossil fuel alternatives. For example, Fayette reports a 5% capacity factor in Altamont Pass compared to an average of 20% for other makes of turbines in the Pass. However, the actual output per square meter of rotor area (a measure of conversion efficiency) is only 19% below the average output of the remaining turbines in the Pass. The discrepancy exists because Fayette rates its wind machines at unusually high wind speeds.[7]

Siting and Resource Assessment

Because the energy contained in the wind increases with the cube of wind speed, areas with the highest average wind speed offer the most potential for power generation. For example, a site with average wind speeds of 16 miles per hour has almost 90% more available wind energy per unit of area than a site with average speeds of 13 miles per hour, while a site with average speeds of 19 miles per hour has over 210% more available energy than a 13 miles per hour site. However, since wind turbines can capture only a portion of this energy, the electricity generated by a turbine rises approximately with the square of the annual average wind speed.[8] Thus, turbine output is about 50% higher at a 16 miles per hour site and about 110% higher at a 19 miles per hour site compared to a 13 miles per hour site.

In addition to average wind speed, the geography of an area is very important. Certain geographical characteristics found in coastal, mountainous, and great plains regions can work together to create conditions suitable for wind power. For instance, in California the combination of cool ocean air and hot interior air generate pronounced differences in atmospheric pressure which result in a diurnal flow of cool ocean air inland at certain times of the day. Natural breaks in the Sierra-Nevada mountain range funnel this wind, creating ideal sites for wind power generation. Data on expected daily and seasonal wind speed variation can help project developers evaluate the value of the wind generation to the utility system as a whole. Recent research has also confirmed the importance of micrositing or making more extensive wind measurements prior to siting a wind turbine;

---

[7] D.R. Smith, "The Wind Farms of the Altamont Pass Area," *Annual Energy Review*, 1987.

[8] Don Bain, "Issue Paper 89-40 Wind Resources," Northwest Power Planning Council, October 17, 1989.

small changes in the position and height of a turbine can make a large difference in the wind resource captured.

Wind resource assessment, or wind prospecting, is done in two stages. The initial stage of assessment, macro-prospecting, has largely been done. Macro-prospecting entails the broad, regional assessment of wind resources as defined by The Wind Atlas.[9] The second stage of resource assessment begins with preliminary wind prospecting and is followed by site specific evaluations. To determine long term variations in the wind resource, preliminary prospecting involves measuring wind speeds at a prospective site for a few years and evaluating the data against a nearby location for which longer term wind data exist, such as an airport. The site specific evaluations entail determining average wind speeds and direction by minute, hour and day and how these figures vary across the site and at different heights. Since wind speed and direction is not uniform over all heights at a specific site, and since the area swept by the rotor can span over 100 feet, this data is necessary to accurately evaluate the wind regime and select an appropriate turbine, location and height. This data can then be used to analyze the coincidence of the wind resource and utility peaking.[10]

Even when grouped in wind farms, turbines must be dispersed enough to capture wind energy effectively. If the turbines are placed too closely together, the wind is not fully replenished before it encounters the next turbine. The extraction of energy by upwind turbines causes "array losses," which can reduce energy production by as much as 15 to 20 percent. In the past, some developers installed their turbines too closely together because of their poor understanding of interaction effects, complex terrain, and inadequate micrositing practices, and experienced array losses as a result. In addition, improper turbine siting induced turbulence that made downwind turbines less reliable. In response, developers have tried to minimize array losses and turbulence effects by increasing the scope of micrositing studies.

Resources Recovered

In 1990, 1360 MW of installed capacity produced 2100 GWh of electricity. At rated capacity, therefore, the capacity factor for wind turbines currently averages about 18%, a figure that has been steadily rising as older machines are replaced by newer models and as resource assessment continues to improve. Pacific Gas and Electric (PG&E) recently reported that the capacity factor of the 734 MW of turbines in its service territory at Altamont Pass increased from 9% in 1983 to 16% in 1988

---

[9] *The Wind Energy Resource Atlas of the United States*, Prepared by Pacific Northwest Laboratory for the U.S. Department of Energy, October, 1986

[10] Information obtained from conversation with Robert Lynette, August 22, 1990.

due to (in order of importance) increased reliability, more efficient turbine designs, and improved siting evaluation and implementation. Over 97% of wind energy output in the U.S. is captured in California, where HAWTs dominate the market.[11] California windpower generation is concentrated in five areas: Altamont Pass, Pacheco Pass, San Gorgonio Pass, Solano County, and Tehachapi Pass. The most productive wind power stations are located in San Gorgonio pass, where wind turbines have consistently exceeded 30% capacity factors.

Current Economics

Total costs of wind energy system deployment are comprised of the following costs: project lead time, land acquisition, system components and installation (capital costs), operation, and replacement. California's wind farms consist of first and second generation technology. First generation machines of the early 1980s, mainly of U.S. design, tended to be small-scale, lightweight designs based on aerospace technology. The representative turbine was rated at 50 kW and cost $2,220/kW installed. Second generation machines, installed from the mid-1980s through the present, are largely of European design. These turbines are medium-scale, averaging 300 kW, heavyweight machines whose conservative engineering largely overcame the lack of understanding regarding structural and aerodynamic stress. Their cost is currently about $1,000/kW - $1,200/kW installed.[12]

The project lead time costs include the cost of a wind resource assessment, which could involve up to 3 years of site data collection and developing additional micrositing data after a resource has been identified. The measurements are necessary to determine the potential energy production and cost-effectiveness of a potential site. Also, a 12 to 18 month micrositing, engineering, and permitting period is needed after resource assessment and before construction. Typical construction time from ground breaking to turn-key operation for a representative stand-alone turbine system is 1-2 weeks. Construction of most wind farms would be expected to take fewer than 6 months.

The total cost of a well researched resource assessment is, as a rule of thumb, $10/kW, or 1% of current total installed costs. The detailed evaluation includes setting up about seven towers, seven data loggers and fourteen anemometers. The cost of the equipment is approximately $21,000. The cost of maintaining the equipment, downloading and analyzing the data is approximately $50,000. An upper bound estimate for maintenance and data analysis would be no more than $100,000, bringing

[11] Nancy Rader, *Power of the States*, Appendix 1, Table 2.

[12] Don Bain, "Issue Paper 89-40. Wind Resources," Northwest Power Planning Council, October 17, 1989. See also Electric Power Research Institute, *Technical Assessment Guide: Electricity Supply - 1989*, Volume 1, Revision 6, September 1989.

the high cost estimate for resource assessment to $15/kW. The equipment used in the first detailed site assessment can be used for further assessments.[13]

Land acquisition costs vary according to potential alternative uses of a site and zoning requirements. The exact amount of land required for a multi-megawatt turbine system is determined by many factors, which include on-site wind characteristics, the geologic and natural features of a specific site, and the individual turbine capacity. Wind sites must include sufficient land for construction of facilities, routing transmission lines, proper spacing of turbines, as well as a buffer of extra land to ensure the accessibility of the wind resource, since nearby buildings, billboards, trees, etc. could shield turbines from available wind. Since wind systems require only about 5% to 10% of the actual land area, agricultural and grazing uses are typically compatible with wind installations.

Wind system component and installation costs include rotor, drive-train, tower to support rotor and drive-train, turbine and support controls, and balance-of-system (BOS) costs. The nacelle enclosure, which contains the turbine's generator, transmission, and control system, accounts for about 35% of the total capital cost. The turbine tower, the rotor blades, and the down tower box account for about 10% each. The remaining 33% are non-machine costs, of which 18% are for permits, land use, warranty and insurance, and 15% are for roads, power lines, and other infrastructure. Average construction costs have dropped from $3,100/kW of capacity in 1980 to between $850 and $1,400/kW, with annual O&M costs between 1 ¢/kWh and 2 ¢/kWh in 1989.[14] PG&E reports current installed costs of $1,100/kW, O&M costs of 1 ¢/kWh and a capacity factor of 25%.[15]

The BOS charges include costs of system infrastructure: interconnection facility, roads and service buildings, and contingency fees. BOS costs vary according to site, turbine, and project size. Where transmission lines are required to connect remote wind resources to the grid, the costs of building transmission capacity would also be included in the capital costs of wind development. A 115 kilovolt transmission line that could transport electricity from a 150 MW power plant would cost about

---

[13] Information obtained from conversation with Robert Lynette, August 22, 1990.

[14] *The Potential of Renewable Energy*, Interlaboratory White Paper prepared for the Office of Policy, Planning, and Analysis, U.S. Department of Energy, (Golden, Colorado: Solar Energy Research Institute, March 1990), p. F-10

[15] D.R Smith, M.A. Ilyin, and W J Steeley, "PG&E's Evaluation of Wind Energy," 1989.

$110,000 per mile.[16] For wind systems, the cost of transmission line additions would be spread over the wind farm and not an individual turbine.

Operation and maintenance (O&M) costs include regular turbine inspection, blade cleaning and lubrication. Some blade designs lose up to 15% efficiency due to dirt and bug accumulation. Periodic overhauls of rotor, gearbox, and generator and periodic component replacement are also included in the operating costs. Replacement costs in the 8th and 20th year of turbine operation are estimated to be $27,000 to $40,000. The cost includes $17,000 to $23,000 for blade replacement with the remainder for replacement and overhaul of other system components. A levelized replacement cost for a 13 mph site is approximately 0.5 ¢/kWh to 0.9 ¢/kWh.[17] Table IX-2 displays a summary of windpower technology cost estimates.

The costs do not include energy storage or backup options. The availability of cost-effective storage options, as well as system options to help firm or shift windpower output could promote widespread deployment of wind energy systems. At present, few cost-effective storage options are available for extensive use. Chapter X discusses these options in some detail, and examines the economics of hybrid wind-fossil energy systems.

In addition to quantifiable costs, wind electric generation incurs some social costs such as increases in area noise levels, interference with television and radio reception, occasional bird deaths, and negative aesthetic impacts in some areas. The noise from wind turbines includes the sound of the blades hitting the air, as well as the sound of gears turning and the hum of the generator. The noisiest turbines have been described as creating a high-pitched aerodynamic whizzing sound, but most turbines make very little noise more than ambient wind noise.

Intermittent Generation and System Operations

Unless smoothed or otherwise mediated by a storage technology, the intermittent generation from wind turbines can pose some technical problems for the utility system. The intermittent nature of wind generation makes it difficult for utility system planners to calculate a constant flow of power from the source to be included in balancing instantaneous power supply and demand. Windpower's intermittent contribution to the electricity grid may be limited by technical constraints governing

[16] This figure is used in "Geothermal Resources" Northwest Power Planning Council Staff Issue Paper, October 1989, p.27

[17] J.M. Cohen, T.C. Schweizer, S.M. Hock, and J.B Cadogan, "A Methodology for Computing Wind Turbine Cost of Electricity Using Utility Economic Assumptions," 1989.

TABLE IX - 2 WINDPOWER TECHNOLOGY COST MATRIX	
<u>PROJECT LEAD TIME</u> 1/	
-- Resource Assessment	\$10/kW, or \$71,000
<u>SYSTEM COMPONENTS</u> 2/	
-- Total System Costs	**\$1,013/kW**
-- Rotor, Drive-Train, Tower, Turbine, and Support Controls	\$750/kW
-- Balance of System Costs (BOS)	\$263/kW
-- Interconnection Facility, Roads and Service Buildings, Contingency Fees	
<u>OPERATING AND MAINTENANCE COSTS</u> 1/	
-- Turbine Inspection, Blade Changing, Periodic Overhauls, Component Replacement	0.5¢ - 2¢/kWh
Component Replacement Costs 3/	
-- Blade Replacement	\$23,000
-- Replacement of Other Components	\$17,000

1/ Cost estimates for resource assessment and operations and maintenance were obtained from Robert Lynette dunng a conversation on August 22, 1990.

2/ Source: Electric Power Research Institute. *Technical Assessment Guide: Electricity Supply - 1989*. Volume 1, Revision 6. September 1989.

3/ Source: "A Methodology for Computing Wind Turbine Cost of Electricity Using Utility Economic Assumptions" by J.M. Cohen, T.C. Schweizer, S.M. Hock, and J.B. Cadogan, 1989.

operating and reliability concerns that limit a utility's ability to incorporate intermittent generating sources. Wind plants produce alternating current (AC) power, but require frequency regulation electronics because windpower turbines produce variable frequency current. These frequency regulation systems are subject to stress, reduced reliability, and limit the maximum power available from wind. Recently developed solid state power conversion technology can allow a wind turbine to generate as much power as possible, convert the variable frequency power to AC, and supply reactive power to compensate for the natural induction of wind turbine generators.

Aspects of interconnecting wind plants to utility transmission systems in California have been less problematic than anticipated, primarily because almost all windpower in California is supplied to the state's two largest utilities. The utilities' large, diverse power systems are better able to accommodate substantial increments of power rising and falling with the wind. In contrast, less extensive utility systems with constrained generating and transmission capacity would be less able to accommodate the power fluctuations that would accompany using windpower to supply a significant portion generation.

Beyond the technical problems encountered when accommodating wind energy into electricity supply systems, the value of intermittent windpower is not as high as "firm" energy from fossil fuel sources. Because of the emphasis on system reliability, utilities do not typically count windpower as a resource that can replace conventional capacity. Chapter X explores the economics of intermittent renewable resources and examines hybrid options that can enhance the value of windpower generation.

Land-Use Conflicts

The potential impact of land-use and zoning laws on wind system siting will largely depend on the ownership of the land being sought for development. Land-use conflicts not only involve potential competition from higher-valued uses, but they also confront restrictions based on nuisance factors, building-scale requirements, and on-site environmental impacts. Nuisance factors that could restrict the use of suitable land include turbine noise, dust and other negative impacts on flora and fauna in surrounding areas. The size of a wind turbine project can also be limited by building and zoning regulations that protect aesthetic values. Many potential wind resource areas are in national forests and wilderness areas that are precluded from development.

The federal government controls large tracts of undeveloped land that hold some of the most favorable sites for wind turbine system development. For example, the U.S. government holds title to more than 40% of the land in the 11 contiguous western states, states which also contain over 60% of the best wind sites.[18] Both the Bureau of Land Management (BLM) and the United States Forest Service (USFS) are given broad authority to manage these lands according to Federal policy, which dictates that all uses of such land must serve the national interest and comply with multiple use and environmental regulations. However, Congress can designate some BLM lands as permanent wilderness areas, which would preclude all development activities. Land-use and zoning policies on the federal, state, and local level can also impede wind system deployment. A developer's ability to gain access to land regulated by state and local authorities will be affected by long-term comprehensive land-use plans and the mechanisms available to developers to lease or acquire that land. State land-use regulations can restrict or encourage particular land-use options.

Remote Transmission Access

Transmission costs pose a potentially large obstacle to windpower development. When good wind sites are far from existing transmission lines, lines must be extended to access the power from these sites. Building transmission lines from the wind site to the existing grid involves additional expenditures, increasing the capital costs of windpower. Depending on terrain and design capacity, high power transmission lines cost between $100,000 and $500,000 per mile.[19] These costs add roughly $80/kW for a 100 mile line. In light of the high cost and various obstacles to siting and building transmission lines in the U.S., transmission could potentially impede windpower development. Small power producers, such as qualifying facilities (QFs) under PURPA, face the same regulatory maze that a utility faces when building additional transmission facilities. Given the choice between building on a remote site or close to existing transmission, a utility will likely choose the site close to existing transmission capacity. If QF developers only have access to the remote site, adding the cost of additional transmission lines increases their capital costs. The additional expense makes remote siting primarily an economic issue, although institutional issues such as permitting, financing, and eminent domain can also hinder transmission capacity development.

A slightly different transmission limitation has arisen in the wind regions of California, where windpower development has strained the capacity of existing transmission lines. Upgrading a transmission line is less expensive than building new lines, but conflicts can emerge over the

[18] According to the recent PNL analysis, the 11 western states have 41 GW of class 5 potential wind resources that could be developed, out of a national total of 67 GW (see Table IX-1). About 340 GW of class 3 wind resource could be developed in these western states, out of a nationwide total of 1,267.

[19] See "Geothermal Resources" Northwest Power Planning Council Staff Issue Paper, October, 1989, p. 27 ($110,000 per mile for a 115 kilovolt line that could serve a 150 MW power plant); and *Power Plays*, by Susan Williams and Kevin Porter, Investor Responsibility Resource Center, 1989, p. 170, ($520,000 per mile for a 230 kilovolt line that serves 600 MW of capacity)

allocation of upgrading costs between utilities and windpower developers. At issue is the level of "system-wide" benefits that would occur as a consequence up transmission upgrade, which utilities (and eventually ratepayers) must pay to the QF for its upgrade project.

EMERGING CONVERSION TECHNOLOGIES

Wind machines have progressed through two generations of development, and are now entering a third. A public/private research, development and demonstration program is continuing to improve all aspects of wind electric generation technology.

Costs and Performance

A third generation -- so called next generation or advanced generation turbines -- is currently being developed using improved understanding of aerodynamics to develop lighter weight and more efficient designs. These machines are larger in size, at 150 to 600 kW, and are projected to cost roughly $650/kW. The third generation wind turbines are still in their R&D phase. However, U.S. Windpower (USW), Electric Power Research Institute (EPRI), and several utilities have developed and are testing an advanced wind turbine program, scheduled to run through 1993. The program includes two USW model 33M-VS (variable speed) turbines and an advanced power electronic converter. The turbines each have rotor diameters of 33 meters (108 ft), and generate 400 kW. One of these turbines was erected in Altamont Pass, California in June 1989. The design is expected to produce 800 MWh/year at a life cycle electricity cost of about 5 ¢/kWh.

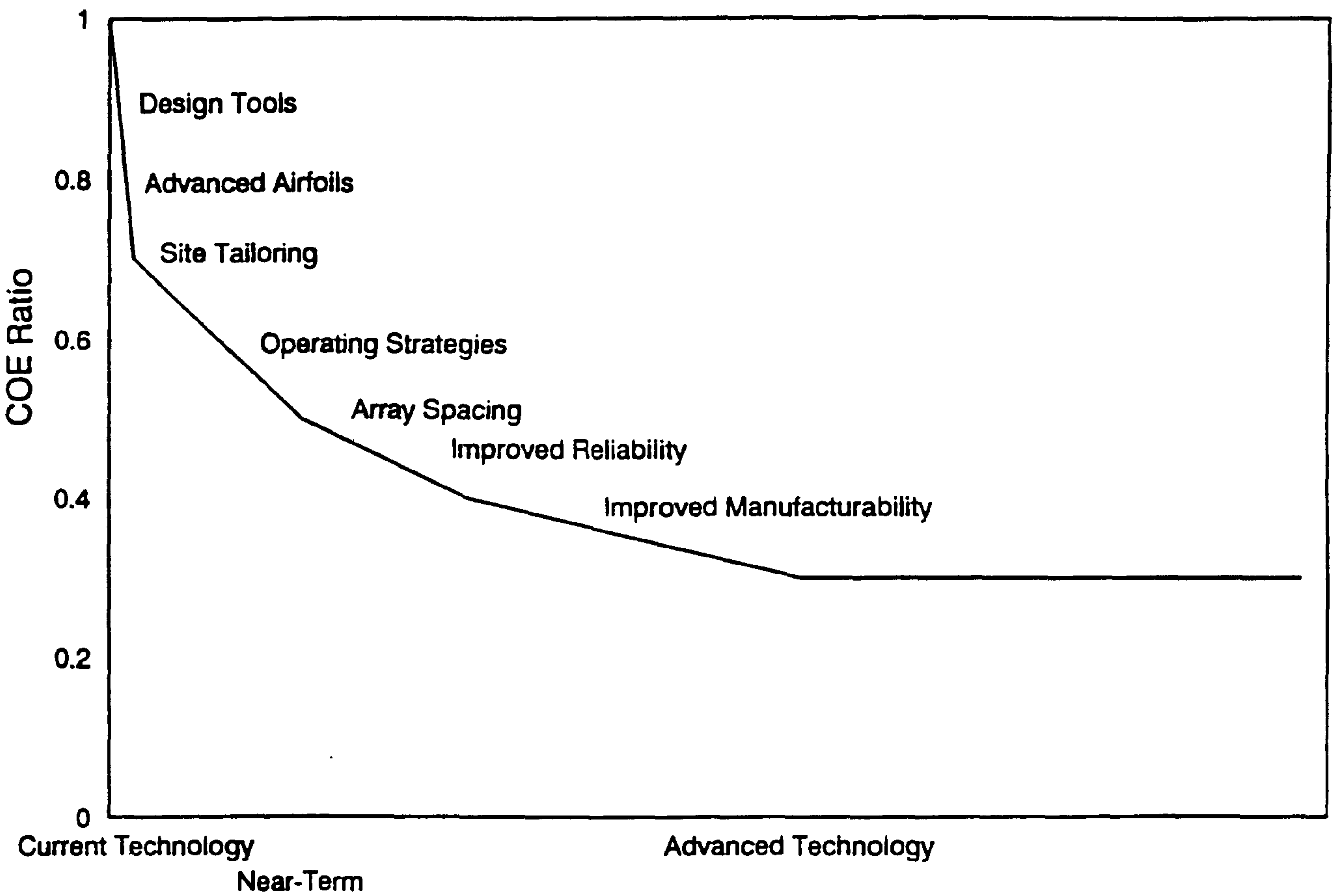
Figure IX-5 shows a SERI estimate of the impact of future technology improvements on cost of electricity (COE) expressed as a fraction of current costs. Various technological innovations discussed below have the potential to reduce O&M costs, boosting energy output and decreasing overall system costs. According to SERI, these technological developments could reduce levelized costs to between 3 ¢/kWh and 4 ¢/kWh by 2010.

Potential Technology and Multiple Pathways

The primary focus of the DOE/EPRI/USW R&D program is to increase the efficiency and reduce the capital costs of wind turbines. The advanced wind turbine system would combine a series of technical improvements developed in the laboratory and field over the past several years to lower costs of wind systems, improve system durability, and increase power output. This turbine design

FIGURE IX - 5

Future Technology Improvements



Source: The Potential of Renewable Energy, Interlaboratory White Paper prepared for Office of Policy, Planning, and Analysis, U.S. Department of Energy (Golden, Colorado: Solar Energy Research Institute, March 1990).

R&D is expected to lead to major efficiency improvements from the current 15% - 20% up to 30% - 35%.

The major objectives of the R&D program are: to develop advanced hub designs and materials which reduce stress and fatigue; to improve blades which will boost energy capture and suffer less degradation from dust and insect buildup; to refine power electronics to ensure that power quality meets utility standards; to incorporate adaptive controls for higher energy capture; to introduce variable speed turbines and generators; to optimized drive-trains (The drive-train includes the gearbox and generator); and to improve micrositing. These enhancements will be incorporated into a new generation of 200 kW to 600 kW wind turbines that should operate more reliably and efficiently at variable wind speeds with a generation cost (assuming annual average wind speeds of 13 mph) of about 5 ¢/kWh. This target would represent about a 40% improvement over current designs. The gains in efficiency in variable wind speed operating conditions would make much more land suitable for windpower development.

The variable speed turbine employs a power electronic converter between the generator and the utility line. This allows the rotor and the generator to speed up with stronger winds. The increased energy is then converted into more electricity without increasing strain on the drive-train. Variable speed generators can maintain peak efficiency over a wider range of wind speeds by controlling generator speed. They further help to reduce transient and dynamic loads that are transmitted from the rotor through the drive-train to the turbine tower. Transient loads are stresses that occur during start-up, shutdown, and during turbulent wind conditions; dynamic loads are transmitted from the rotor through the drive-train during normal operation. These advantages may help designers to alleviate the serious component fatigue problems encountered by existing wind systems, increasing component lifetime by up to 25 percent. Variable speed generators are generally more complicated and expensive than constant speed generators. However, increased energy capture, estimated at 15 to 20 percent for large turbines, should reduce the cost of energy by 10 to 15 percent.[20] Researchers at Sandia National Laboratories (SNL) are working to better understand how the constantly changing aerodynamic forces and the subsequent structural responses affect variable speed operations.

Structural fatigue problems may be alleviated through the use of advanced materials such as fiberglass composites. Research is being conducted to understand the response of both conventional

---

[20] Solar Energy Research Institute, "Variable Speed Operation of Wind Turbines: Impact on Energy Capture and Economics," by S. Hock and P Tu, presented at the ASES 1986 Annual Meeting and Passive Conference, June 8-14, 1986

blade materials, such as aluminum for VAWTS and wood epoxy for HAWTS, as well as newer materials. Field tests are being conducted by SNL to study fatigue damage of sample materials on commercial machines. SNL's research also includes fracture analysis to predict the growth of blade cracks.

In 1988, SERI began collecting the world's first simultaneous measurements of wind inflow, pressure, strain, power output, and other characteristics of a rotating HAWT. The research focuses on a fully instrumented HAWT measuring 10 meters in diameter and rated at 8 kW. Measurements are fed to a data acquisition device mounted on the rotating hub, while a video camera allows researchers to observe the interplay of airflow and the forces that create stress. Small tufts attached to the blade surface indicate the presence of smooth or turbulent flow, while color changes in liquid crystals applied to the blades show the effects of varying airflow forces.[21]

This "combined experiment" will lead to greater understanding of the aerodynamic forces at work during wind turbine operation. Preliminary results are still being analyzed, but this unique experiment is expected to reshape the basic assumptions of wind turbine aerodynamics. Actual measurements of aerodynamic forces and structural response will soon be available for improved computer models and design codes. The experiment is also expected to validate the performance of advanced components such as SERI's specialized airfoils.

Decreases in windpower costs may be achieved through the development of a variable speed rotor that uses power electronics and a stall controlled rotor with aerodynamic controls. Development of the stall control rotor depends on research into overspeed control, smaller drive-train components, and lowering thrust loads as a result of better stall control. Research into stall behavior may resolve technical problems related to the application of variable speed generators to wind turbines. Preliminary estimates indicate that the variable speed rotor will not alter the installed cost of the overall system, but could increase annual energy output by 56% while reducing operations and maintenance (O&M) costs by about 0.5 ¢/kWh. The stall control rotor will reduce overall system costs by approximately 12%, and increase annual energy output by 49%, with a 0.6 ¢/kWh reduction in annual O&M costs.[22]

SERI has also identified "advanced" technology improvements, targeted to appear around the year 2010, that can reduce costs and increase windpower penetration. These technologies will

---

[21] Solar Energy Research Institute, "Windpower... Today's Energy Option," April 1989.

[22] Susan M. Hock, Robert W. Thresher, and Joseph M. Cohen, "Performance and Cost Projections for Advanced Wind Turbines," 1989.

incorporate currently unexplored subsystem concepts to increase energy capture from individual wind sites, potentially reducing the costs of windpower to about 3 ¢/kWh. Possible features of the advanced technology include: advanced airfoils, innovative aerodynamic controls, fatigue tolerant rotor designs, advanced articulated blade/hub configurations, adaptive controls, advanced generation concepts, new materials for all components, optimized wind plant layout, and parts designed for easy manufacture, installation, and maintenance.[23]

MARKET ASSESSMENT

Table IX-3 shows the DOE/SERI and EPA scenarios for windpower. In the DOE/SERI report, the costs of windpower generated at excellent and outstanding sites are assumed to become competitive with the variable costs of natural gas-fired generation between 1995 and 2000 in the BAU scenario, and generation from good sites becomes competitive with gas by 2005. These favorable economics are accelerated under the policy scenarios: by 2010 generation from outstanding sites becomes competitive with the variable costs of coal-fired generation.

If windpower indeed becomes competitive with coal-fired baseload generation, then the economic comparison between fossil generation and wind will be less sensitive to the seasonal and daily variation of windpower. In the interim, however, some of the expected wind generation would occur during seasons and periods of the day when the marginal fuel is not exclusively gas. The assumption that windpower would always displace gas overstates the true avoided energy cost from wind generation.

Given this observation, the DOE/SERI BAU projection of 22% annual average growth in wind power generation between 1988 and 2000, and 20% annual average growth between 1988 and 2010, appears optimistic.[24] The EPA Base Case and Enhanced Market scenario were constructed using a model of regional windpower cost, which is described in Appendix B. The Enhanced Market scenario assumes that the barriers identified above are addressed (leading to greater land areas available for windpower), and that intensified RD&D would lower wind turbine costs.

---

[23] Susan Hock and Robert Thresher.,"Performance and Cost Estimates for Advanced Wind Turbines," January 1990

[24] The impact of fuel prices on the SERI projections is explored in "The Sensitivity of Wind Technology Utilization to Cost and Market Parameters," by Henry M. Dodd, Susan M. Hock, and Robert W. Thresher in the AWEA *Windpower '90 Proceedings*, September 1990. Variations of 50% in fuel costs were found to have order-of-magnitude impacts on near-term windpower penetration rates

TABLE IX - 3 WINDPOWER SCENARIOS				
Scenario	**Capacity 2000 (MW)**	**Generation 2000 (GWh)**	**Capacity 2010 (MW)**	**Generation 2010 (GWh)**
DOE/SERI				
Business as Usual	8,800	20,500	39,500	99,500
Intensified RD&D	15,000	38,000	78,400	223,400
National Premiums	17,200	41,000	95,000	240,900
EPA				
Base Case	4,900	10,100	20,900	48,600
Enhanced Market	10,600	26,500	57,400	141,800
1990:	1,400	2,100		

The recent PNL study provided the potential wind resource data used in the EPA market assessment. The EPA Base Case and Enhanced Market scenario assume that regional windpower resource development is proportional to the cost differential between windpower and fossil energy sources. The EPA Base Case for 2000 assumes the DOE/SERI BAU capital costs of $1,000/kW and operating costs of 1.2 ¢/kWh, which fall to $965/kW and 0.9 ¢/kWh in 2010. The Enhanced Market scenario for 2000 assumes the DOE/SERI RD&D scenario capital costs of $950/kW and operating costs of 1.0 ¢/kWh, falling to $850/kW and 0.8 ¢/kWh (based on turbines operating in 13 mph average wind speed regimes).[25] A capital charge rate of 10% was used to compute levelized costs for windpower, which assumes that developers would be able to secure longer term financing in the future compared with current practice. Regional capacity factors were assumed to increase over time, as a result of increased reliability and improved siting practices. Capacity credits were set at 50% of the regional capacity factor in 2000, and 67% of the regional capacity factor in 2010, reflecting the increased attention to utility peaking needs when siting wind turbines.

[25] Please note that because windpower costs have declined rapidly in recent years, it is likely that estimates of capital and operating costs in future years reported here are already dated.

Tables IX-4 and IX-5 give the air pollution prevention and cost results of the EPA scenarios. In the Base Case, annual windpower generation increases at an annual average growth rate of 17% between 1990 and 2010, adding 46,000 GWh per year from current levels. Because of vast wind resource potential, the West North Central and Mountain regions account for the majority of the generation increase. In the Enhanced Market scenario, generation from wind increases by 140,000 GWh between 2000 and 2010, approximately 3 times the Base Case growth in generation between 1990 and 2010, again concentrated in the North Central and Mountain regions.

Costs

Despite partial capacity credits, the seasonal pattern of windpower generation in most regions made avoided costs for windpower lower than for other renewables: about 3.0 ¢/kWh (2000) and 3.7 ¢/kWh (2010) in the Base Case and 2.9 ¢/kWh (2000) and 3.5 ¢/kWh (2010) in the Enhanced Market scenario. The low avoided cost continued to place windpower at a small cost disadvantage in many regions; however, in the Northeast, Southwest, and California, windpower was less expensive than the fossil fuel electricity it displaces in 2010 in both scenarios. Chapter X describes how fossil-fuel hybrid options can increase the value of windpower generation as measured by utility avoided costs.

Air Pollution Prevented

Substantial amounts of air pollution are prevented from increased windpower generation between 1990 and 2010 in the Enhanced Market scenario. Over 600,000 metric tons of SO_2 could be freed for the allowance market, and almost 570,000 metric tons of NO_x would be avoided. Windpower in the Enhanced Market scenario could displace 135 million tons of CO_2 emissions annually by 2010.

Because of the geographic distribution of windpower and the assumed seasonal and daily operating patterns, windpower tends to displace more coal-fired generation at the margin than other renewable electric technologies examined in this report. As seen on Table III-3 (Chapter III), windpower could displace between 940 and 965 kilograms of CO_2 per MWh generated, and could displace about 4 Kg/MWh of NO_x from fossil fuel plants. However, these estimates do not take into account many of the more sophisticated utility system operating constraints. For example, utilities accepting large quantities of intermittent windpower may have to increase "spinning reserves," which are operating plants that provide little or no power to the grid to accommodate fluctuations in load. More sophisticated production simulation models would help verify the emission reduction potential of windpower generation in specific utility systems.

TABLE IX - 4

ELECTRICITY GENERATION COSTS AND AIR POLLUTION PREVENTED

EPA BASE CASE
WINDPOWER

REGION	AVERAGE UNIT COST IN 2000 (cents/kWh)			AVERAGE UNIT COST IN 2010 (cents/kWh)		
	AVOIDED FOSSIL	WINDPOWER	COST DIFFERENCE	AVOIDED FOSSIL	WINDPOWER	COST DIFFERENCE
Northeast	5 0	6.0	1 0	6 9	4 6	-2.3
Southeast	2 5	6 0	3 4	3 2	4.6	1.4
Southwest	3 1	5 3	2.2	4.4	4 2	-0.2
North Central	2 8	4 7	1 9	3.4	4.0	0.7
Northwest/Mountain	2 6	4 7	2.1	3.1	4 0	0.9
California	4 0	4 4	0.4	6.3	4 0	-2 3
AVERAGE	**3.0**	**4.8**	**1.8**	**3.7**	**4.1**	**0.4**

REGION	INCREMENTAL GENERATION 1990 - 2010 (GWh/yr)	AIR POLLUTION PREVENTED 1990 - 2010 (thousand metric tons/yr)						
		SO_2	NO_x	Particulate Matter	CO	CH_4	CO_2	CO_2 Equivalent
Northeast	2,782	13.1	5.9	0.41	0.42	0.02	1,962	2,200
Southeast	102	0.8	0.4	0.03	0.01	0.00	103	121
Southwest	1,504	2.9	5.4	0.25	0.23	0.01	1,233	1,452
North Central	14,289	118.9	60.6	3.64	2.08	0.12	14,257	16,688
Northwest/Mountain	24,192	52.9	102 8	6.21	3.51	0.21	24,212	28,339
California	3,554	0 8	8.3	0.11	0 59	0.01	1,891	2,226
TOTAL	**46,423**	**189.5**	**183.5**	**10.66**	**6.85**	**0.37**	**43,659**	**51,026**

TABLE IX - 5

ELECTRICITY GENERATION COSTS AND AIR POLLUTION PREVENTED

EPA ENHANCED MARKET SCENARIO
WINDPOWER

REGION	AVERAGE UNIT COST IN 2000 (cents/kWh)			AVERAGE UNIT COST IN 2010 (cents/kWh)		
	AVOIDED FOSSIL	WINDPOWER	COST DIFFERENCE	AVOIDED FOSSIL	WINDPOWER	COST DIFFERENCE
Northeast	4.9	5.5	0.6	6.7	4.0	-2.6
Southeast	2.5	5.5	3.0	3.2	4.0	0.9
Southwest	3.1	4.9	1.8	4.1	3.7	-0.4
North Central	2.8	4.3	1.5	3.4	3.6	0.2
Northwest/Mountain	2.6	4.3	1.7	3.1	3.6	0.4
California	4.0	4.0	0.0	6.3	3.5	-2.8
AVERAGE	**2.9**	**4.3**	**1.5**	**3.5**	**3.6**	**0.1**

REGION	INCREMENTAL GENERATION 1990 - 2010 (GWh/yr)	AIR POLLUTION PREVENTED 1990 - 2010 (thousand metric tons/yr)						
		SO_2	NO_x	Particulate Matter	CO	CH_4	CO_2	CO_2 Equivalent
Northeast	7,283	36.0	16.3	1.13	1.11	0.05	5,257	5,914
Southeast	1,004	8.2	4.3	0.26	0.15	0.01	1,002	1,173
Southwest	3,616	7.8	13.7	0.69	0.55	0.02	3,144	3,694
North Central	45,198	377.7	191.5	11.52	6.57	0.39	45,086	52,774
Northwest/Mountain	77,492	172.1	329.6	19.92	11.24	0.68	77,616	90,847
California	5,081	1.2	11.9	0.16	0.85	0.01	2,704	3,183
TOTAL	**139,675**	**602.9**	**567.2**	**33.68**	**20.46**	**1.17**	**134,810**	**157,585**

CHAPTER X

INTERMITTENT TECHNOLOGY AND HYBRID/STORAGE OPTIONS

This chapter describes how intermittent renewable resources can be integrated into the "grid," or electric supply systems. Intermittent resources include hydroelectric, solar, and wind. Discussions of intermittent resources tend to focus on the "capacity credit" of renewable generation options. Capacity credit (sometimes called contribution to reserve margin) is the fraction of rated (nameplate) capacity that utilities can count on as "firm" resources during peak demand periods. In this context, firm refers to a level of reliability (or availability) equivalent to conventional fossil units. A related concept is dispatchable capacity, which refers to the level of control a utility has over the power output of a generating unit. Intermittent renewable generating facilities are neither dispatchable nor firm by conventional utility definitions.[1]

Because of the emphasis on reliability, utilities do not usually grant intermittent renewable resources capacity payments when negotiating power purchase agreements with Qualifying Facilities under PURPA. Likewise, intermittent renewable generation may be at a disadvantage in competitive procurements because the methods used to evaluate bids are structured so that only firm capacity bids will be chosen. Current utility practice may inhibit the emergence of hybrid renewable or storage options that have at least some capacity value when considered in the context of the entire system.

Many options exist to make intermittent resources firm from a utility standpoint. The solar thermal/natural gas hybrid is an example of such a system, but it is only one of the possible configurations. The multitude of other configurations can be divided into supply options, demand options, and storage options.

SUPPLY OPTIONS

Supply options use other generating units on the grid to compensate for the variable output of an intermittent resource. These can be further divided into renewable/renewable options, renewable/fossil options, and renewable/system options.

[1] Hydropower is somewhat different. Hydropower is dispatchable (controllable in the short run) but not firm because it can be limited by the amount of water stored in the watershed. Because historical river flow records exist, hydroelectric projects are often rated in under "adverse flow" conditions.

Renewable/Renewable Options

One way to boost renewable capacity credit is to geographically disperse the renewable generating stations in order to minimize the potential that all stations would not be operating at the same time. The probability that several dispersed PV collectors would be under cloud cover at the same time in a large area is lower than the likelihood that one centralized plant would be covered with clouds. Another option would be to combine several types of renewable resources, such as wind and solar, in order to take advantage of inverse probabilities and complementary output patterns. A recent analysis conducted by Pacific Gas and Electric suggested that a combination of wind energy and solar energy would provide a good fit to daily patterns of utility demand in California. These "portfolio approaches" would imply some capacity credit for the total renewable generation, whereas each individual station might have little or none.[2] Such options would be especially valuable when utilizing resources that tend to inversely vary. For example, if windy periods coincide with cloudy days, then windpower could help to firm the availability of solar thermal or PV. Another option would be to use biomass derived liquid or gas fuels to run backup thermal systems.

Wind and hydroelectric capacity are especially complementary, since the hydrosystem can provide storage as well as firming capacity, and hydroelectric generation is especially responsive to variable loads. One such system was proposed by the Bureau of Reclamation in the Department of Interior in Medicine Bow, Wyoming. The daily and seasonal pattern of the wind resource fit well with the utility load and the seasonal output of the hydroelectric system.[3] Although the analysis indicated that such systems would be economically viable, technical problems were encountered with the two multi-megawatt turbines installed in 1982, and the project was abandoned during the mid 1980s.

Renewable/Fossil Options

Fossil fuel capacity can be used to compensate for intermittent renewable resources. Grid-connected options can be either bundled or non-bundled.[4]

---

[2] See "Wind Energy Resource Potential and the Hourly Fit of Wind Energy to Utility Loads in Northern California" by D.R. Smith, in *Windpower '90 Proceedings*, (Washington, DC: American Wind Energy Association, 1990)

[3] See *Wind-Hydroelectric Energy Project - Wyoming*, by the U.S. Department of Interior Bureau of Reclamation, August 1982.

[4] Non-grid connected (stand-alone) renewable electric systems are sometimes combined with fossil fuel backup generation or storage technologies to provide steady power output.

Bundled Systems. Bundled systems are either physically connected or else use a dedicated fossil fuel unit to provide backup for a renewable energy source. For systems that involve thermal conversion, fossil fuel backup can be integrated into the conversion system to provide heat. For example, solar thermal hybrid plants use natural gas to heat the transfer fluid during cloudy periods.[5] Another configuration for solar thermal is combined cycle. The 4.9 MW Solarplant One parabolic dish plant in California has been modified with exhaust heat recovery exchangers from two 1 MW diesel generating sets. The turbine generators can be powered by solar-generated steam or steam generated from the heat remaining in diesel engine exhaust.[6]

Other bundled systems include dedicated fossil backup capacity that provides generation when intermittent resources are not available. For example, fuel cells or diesel or gas turbine generators can be built alongside of solar or wind generating stations. The expense of building redundant capacity at the same scale as the intermittent renewable capacity often does not justify such an approach. However, capacity payments given by utilities to renewable energy developers may be based on the rating of the fossil-fuel backup generator. Such a payment would understate the value to the utility of the intermittent capacity in some cases.

Non-Bundled System Options. Non-bundled options use other generating units in the utility system to compensate for intermittent resources. This is how utilities normally accept intermittent generation without planning specific capacity additions, but the amount of available backup is limited by the current generation mix. In this context, however, a non-bundled option refers to building fossil capacity to compensate for intermittent renewables, but choosing specific capacity types and sizes based on system reliability concerns rather than arbitrarily scaling the unit to firm the renewable capacity to 100% of its nameplate rating. Decoupling the backup capacity requirements from the needs of a specific renewable energy system may have economic and operational advantages.

A recent analysis conducted for U.S. Windpower illuminates this point. Taking into account the Sacramento Municipal Utility District (SMUD) power system and the statistical pattern of windpower output, the analysis showed that a 100 MW windfarm combined with a 60 MW combustion turbine (operating at 4% capacity factor) would have the same system reliability (as measured by loss-of-load probability) as a 100 MW combustion turbine. Thus, U.S. Windpower could build a dedicated 60 MW turbine in order to qualify for a full capacity payment for the 100 MW windfarm. In fact, U.S.

---

[5] An example of a non-intermittent bundled system is a configuration that uses low-temperature geothermal resource to provide heat for boiler feedwater as a way to reduce fossil fuel requirements.

[6] See William Stine, *Progress in Parabolic Dish Technology* published by the Solar Energy Research Institute (SERI/SP-220-3237) June 1989, p. 8.

Windpower submitted bids with and without the backup capacity, and SMUD determined that they could supply the backup power more cheaply through other units and bulk purchases: the non-backup configuration was preferred. U.S. Windpower and SMUD are now negotiating the non-backup power contract.

The Northwest Power Planning Council (NPPC) has been considering proposals to "firm" the hydropower output in the region by adding natural gas capacity as an alternative to building new baseload coal plants. Again, the overall reliability of the system, not the specific attributes of individual hydropower sites, determines the value of such options.[7]

DEMAND OPTIONS

Two demand-side management (DSM) techniques could be used to help integrate intermittent renewable electric generation. They are peak shaving, which attempts to limit the maximum demand level (e.g. through offering interruptible service) or load shifting, which attempts to shift part of the maximum load before or after the system peak period (e.g. through thermal storage). These strategies are already valuable for utilities trying to defer capacity construction, but may have added value if they could help control demand as a way to compensate for intermittent renewable supplies.

Commercial buildings can use thermal storage in order to avoid paying high peak demand rates for air conditioning load. In areas where maximum windpower output predictably lags or leads system peak hours, thermal storage at the point of end use would allow windpower to reliably serve these loads. For example, the maximum daily output of windpower at the Altamont Pass in California lags the utility peak load by several hours. Load shifting strategies could increase the value of wind generation in such a circumstance.

Some utilities offer interruptible service to customers (at lower rates) in order to reduce loads when unpredictable demand spikes and/or forced outages strain existing capacity. The value of interruptible service may be higher when intermittent generation is part of the generation mix (although the frequency of interruption may be higher).

These strategies offer utilities the opportunity to influence demand as a way to compensate for predictable or unanticipated limits on supply; such DSM options can also provide utilities with another instrument to help accommodate intermittent renewable generation. While utility planners have

---

[7] See "Better Use of the Hydropower System" Staff Issue Paper 89-37 by the Northwest Power Planning Council, October 16, 1989.

traditionally viewed intermittent generation as an additional risk to providing reliable supply, consideration of emerging demand-side options could encourage a more economic balance between intermittent generating resources and fluctuations in electric demand. The evolution toward integrated resource planning recognizes that the distinction between electricity demand and supply is not well defined, and that the risks of supplying reliable electricity services may be shared by controlling both the demand and supply of electric power.

STORAGE OPTIONS

Storage options can increase energy value, but they reduce net energy production because no perfect electric storage medium exists. Thus, the economics of storage require that the increased energy value (from increased reliability or from shifting power output to system peak load hours) compensate for the storage cost and energy losses. Current storage options include conventional and pumped storage hydro, batteries, compressed air, flywheels, and thermal storage. The availability of cost-effective storage options compatible with utility systems and renewable resource profiles could promote widespread deployment of intermittent generation. At present, few cost-effective storage options are available for extensive use.

Conventional and Pumped Storage Hydro

As discussed earlier, conventional storage hydroelectric facilities can store intermittent renewable generation. This occurs because the hydroelectric output can be reduced by the amount of renewable generation provided, storing potential energy in the water that would otherwise turn the hydraulic turbines. This form of storage can be used with solar energy or windpower. Pumped storage hydro plants capitalize on the difference between base load and peak load generating costs by using cheap base load electricity to pump water up behind the dam, which in turn is released to generate power during higher demand periods. However, about 30% of the energy is lost in the process. Because the pump cycle typically occurs during the night, pumped storage facilities are most compatible with windpower.

An example of pumped storage potential exists in California, where the Altamont wind farms produce their daily maximum output about eight hours after the daily utility peak need. A small pumped storage hydro system could be constructed in the Pass, where there is suitable topography and water available. This would enable the wind energy captured during the night to be used during the following peak afternoon hours. Other hydroelectric storage strategies might also come into play when the utility has discretionary hydroelectric capacity. For example, very hot afternoons in California, which increase peak electric loads from air-conditioning, are almost always followed by windy evenings. It may be possible to increase hydroelectric plant output during the day while relying on increased wind farm output later that night to meet demand, thus reducing the need to deplete the reservoir further.[8]

However, the storage option feasible for Altamont Pass is site specific and may not be a viable option for other areas. Total pumped storage resources, which consist of developed, under construction, and projected pumped storage systems, are located in 11 of the 12 regions defined by this analysis. Table X-1 displays regional pumped storage capacities. The South Atlantic, Mid-Atlantic, West Mountain, and California regions combined contain approximately 60% of total pumped storage resources, and projections for new pumped storage plants in West North Central and Mountain regions could facilitate the development the immense windpower potential in these regions.

Emerging Storage Options

Other storage technologies are in earlier stages of development or commercial use or are not available for utility-scale applications. These include batteries, compressed air, and thermal storage.[9]

Batteries. Batteries use reversible chemical reactions to store electricity, and are frequently used in "stand-alone" (not grid connected) solar or windpower systems. These options are still being investigated for utility-scale applications and questions remain as to their performance and costs in the near term. The two leading contenders for utility-scale application are advanced lead-acid batteries and zinc-chloride batteries, but zinc-bromide and sodium-sulfur have promise as well. The chief advantage of batteries are modularity: battery installations can be scaled to utility needs and expanded as needs increase. Currently, batteries supply storage for many small stand-alone PV and windpower systems, and continued research and demonstration of battery technologies may make battery storage more cost-effective for larger scale grid-connected applications.

Compressed Air Energy Storage (CAES). CAES systems use electric power to pressurize an underground cavern, releasing the air through a turbine when electricity is needed. Like pumped storage, CAES systems would primarily pump air during offpeak night hours, and would be most suitable for wind energy generation. These plants can also be used to provide compressor power for conventional gas turbines used in peaking operation, which reduces the energy neededo to drive the turbine by about two-thirds (only one-third of the energy used in turbines provides net power, the

[8] Smith, D.R. "The Wind Farms of the Altamont Pass Area." *Annual Energy Review.* 1987.

[9] A discussion of batteries and compressed air storage is found in *New Electric Power Technologies: Problems and Prospects for the 1990s*, U.S. Office of Technology Assessment, 1985.

TABLE X - 1
PUMPED STORAGE HYDROELECTRIC PLANTS OR ADDITIONS

Developed, Under Construction, or Projected
as of January 1988
(Kilowatts)

REGION	Developed	Under Construction	Other Projected	Total
New England	1,453,000	0	75,000	1,528,000
Mid-Atlantic	2,902,887	0	1,727,000	4,629,887
South Atlantic	3,994,094	1,975,000	2,250,000	8,219,094
East North Central	1,978,800	0	1,530,000	3,508,800
West North Central	600,802	0	2,376,800	2,977,602
East South Central	1,530,000	0	0	1,530,000
West South Central	299,050	0	1,660,000	1,959,050
Mountain	510,000	0	3,998,200	4,508,200
Arizona/New Mexico	148,500	0	1,950,000	2,098,500
California	3,360,150	0	735,750	4,095,900
Washington/Oregon	314,000	0	820,000	1,134,000
Total U.S.	17,091,283	1,975,000	17,122,750	36,189,033

Source: Federal Energy Regulatory Commission, *Hydroelectric Power Resources of the United States - Developed and Undeveloped*, January 1, 1988.

Note: Florida does not have any pumped storage capacity.

other two-thirds drives the compressor). A 290 MW CAES that uses an underground salt dome for the pressure chamber has operated in Huntorf, Germany since 1978; and a pilot plant (also using a salt dome) is being built in McIntosh, Alabama, for load leveling. Suitable geological features exist throughout the U.S. for CAES development.

Thermal Storage. Instead of fossil fuel backup, solar thermal electric plants can employ thermal storage to compensate for short cloudy periods or to shift power output to late afternoon or early evening peak periods. The Solar One plant at Barstow California used a thermal oil/rock storage tank, which provided several hours of storage under cloudy conditions. Other thermal storage options are oil and molten salts. Molten salt offers the potential for longer storage periods, up to a few days, further "firming" this resource. Thermal storage is most suited for solar thermal applications, since the thermal cycle is already part of the plant's operation.

Future Storage Options

Superconducting magnetic energy storage systems offer long-term promise for electrical storage, but have been demonstrated only in small applications and are unlikely to provide economic storage in the near term unless breakthroughs are make in high-temperature superconductive materials. Hydrogen created by PV electrolysis of water represents a storage potential capable of providing utility and transportation fuel. Hydrogen combustion does not produce CO_2, and hydrogen can be stored and transported through pipelines similar to natural gas pipelines (which can be converted to hydrogen transport). A recent study by World Resources Institute examines the prospects of PV derived hydrogen to provide transportation fuels, and suggests that if technology or manufacturing breakthroughs occur and PV costs drop, a transition to renewable hydrogen fuels could begin by the turn of the century.[10]

SENSITIVITY ANALYSIS OF AVOIDED COST

The renewable electric model (REM) was modified in order to make additional cost comparisons of hybrid options for photovoltaic and windpower (the model already accounts for solar thermal hybrid systems). The cost estimates should be viewed as illustrative, since the simple assumptions employed do not take into account more complex technical and operational characteristics of electric utility system operation. However, they do reveal some of the economic tradeoffs encountered in using hybrid systems to firm intermittent renewable generation.

---

[10] Joan M. Ogden and Robert H. Williams, *Solar Hydrogen: Moving Beyond Fossil Fuels*, World Resources Institute, 1989.

Hybrid Assumptions

The sensitivity analysis assumes that a natural gas combustion turbine (CT) is used to firm the intermittent resource. The turbine costs $400 per kilowatt installed, operates at a heat rate of 13,500 Btu/kWh, and costs 1.0 ¢/kWh to operate and maintain. These assumptions are representative of CT systems evaluated in the 1989 EPRI Technical Assessment Guide. The heat rate assumes that the CT operates at 75% load on average; intermittent resources could effect CT operation in various ways, but 75% load is reasonable. Regional natural gas fuel prices are already imbedded in the model, and vary by season. The spring/fall prices were used as annual averages, since they tend to be between summer and winter prices.

The CT is only operated to "firm" the intermittent resource, and therefore operates at low capacity factors typical of a peaking unit. (An alternative strategy could be to enhance capacity utilization by supplying more generation than what is required to compensate for resource variability during peak load periods.) No attempt was made to selectively alter seasonal/daily generation patterns from PV, since PV generation occurs during the peak periods as defined in the model (except for winter peaking regions). For PV, therefore, the contribution of the CT is assumed simply to increase annual capacity factor. For windpower, two cases were examined. The first simply increases capacity factor as in the PV case, without altering seasonal or daily generation profiles. Another case shifts some of the annual generation to the summer daytime period in regions where utilities experience peak demand during the summer and windpower is typically low during the summer months. This "shift" case illustrates the value of CT output to augment the more random seasonal and daily patterns of windpower.

CT capital costs are attributed to the renewable technology, and operating and fuel costs are apportioned to renewable generation, taking into account the assumed hours of operation. Two CT operation scenarios were examined. In the conservative "Full Backup" scenario, the CT is assumed to be of the same scale as the renewable capacity, and operates at a 10% annual capacity factor. In the "Partial Backup" scenario B, the CT is assumed to be built at 60% of the rated renewable technology capacity, and only operates at an annual capacity factor of 5%. These CT operation scenarios were applied to the EPA Base Case and the EPA Enhanced Market renewable cost assumptions. In all cases, the "capacity credit" for wind and PV generation was boosted to 100%. This implies that utilities would value the generation from hybrid technologies as much as firm, dispatchable, conventional capacity.

Sensitivity Analysis Results

The analysis suggests that CT-based hybrid options would increase the competitiveness of windpower in 2000 in several regions, and substantially increase the competitiveness of both windpower and PV in 2010 in most regions. Tables X-2 through X-4 display the results of the hybrid cost analysis of windpower in 2000 and 2010, and PV in 2010 (the PV hybrid results for 2000 indicated that PV was still not broadly competitive).

Windpower. The conventional cost comparisons for windpower assumed a capacity credit equal to 1/3 the regional capacity factor in 2000 and 1/2 the regional capacity factor in 2010. Under these assumptions, windpower generation in 2000 would be equal to avoided cost in California in the Enhanced Market scenario, and would be within 0.5 ¢/kWh of avoided costs in New England (Enhanced Market scenario) and California (Base Case).

The range of avoided costs in the windpower tables for the hybrid cost comparisons reflect the impact of the shifting strategy. The lower figure is the avoided cost of the wind-CT hybrid generation assuming no change in the seasonal generation pattern, while the higher figure gives the avoided costs of windpower generation when the wind-CT hybrid generation is shifted to utility peak seasons. The shift can increase the value of windpower-CT hybrid generation (as measured by avoided fossil fuel and capacity costs) by as much as 2 ¢/kWh in some regions.

Despite higher generation costs attributed to building and operating the CT hybrid windplants, the hybrid strategy would make windpower more competitive. If partial backup can give windpower full capacity credit (as suggested in the U.S. Windpower study discussed above) then Table X-2 shows that windpower would stay competitive (within 0.5 ¢/kWh) under Base Case costs in New England and California, and also become competitive in the West North Central and Mountain regions. In Washington/Oregon, windpower-CT hybrids would become less expensive than fossil fuel generation. Under the costs assumed in the Enhanced Market scenario, windpower-CT hybrids would be within 0.5 ¢/kWh in New England, West North Central, and West South Central regions, while windpower-CT hybrid generation costs would be equal to or lower than conventional costs in the Mountain, California, and Washington/Oregon regions.

As Table X-3 shows, windpower-CT hybrids would be competitive in nearly every region under a variety of assumptions. In the Partial Backup/Enhanced Market scenario assumptions, windpower is extremely competitive in every region except for Florida and East South Central (where the wind resource is so poor that the REM does not consider windpower feasible). Besides those two regions, and in the South Atlantic region (where windpower hybrid generation is within 0.3 ¢/kWh of

TABLE X - 2 HYBRID SENSITIVITY CASE - WINDPOWER 2000 Costs in 1990 ¢/kWh									
REGION	**Conventional Costs**			**Hybrid Cost Comparisons**					
	Avoided	**Windpower**		**Avoided**	**Windpower-CT Hybrid**				
		Base Case	**Enhanced Market**		**Base Case Full**	**Base Case Partial**	**En. Mkt Full**	**En. Mkt. Partial**
New England	5.1	6.0	***5.5***	6.6 - 6.8	7.8	***7.2***	8.1	***7.0***
Mid Atlantic	2.7	6.0	5.5	3.2 - 4.4	7.7	7.1	8.0	6.9
South Atlantic	2.5	6.0	5.5	3.0 - 4.6	7.6	7.1	7.9	6.9
Florida	NA	NA	NA	NA	NA	NA	NA	NA
East North Central	2.5	6.6	6.2	4.9 - 5.4	8.3	7.8	8.6	7.6
West North Central	2.8	4.7	4.3	4.3 - 5.4	6.3	***5.7***	6.4	***5.5***
East South Central	NA	NA	NA	NA	NA	NA	NA	NA
West South Central	3.4	5.3	4.9	4.6 - 6.0	6.9	6.3	6.9	***6.1***
Mountain	2.5	4.7	4.3	4.4 - 5.4	6.2	***5.6***	6.2	**5.4**
Arizona/New Mexico	2.9	5.3	4.9	4.2 - 5.1	6.9	6.3	6.9	6.1
California	4.0	***4.4***	**4.0**	5.0 - 5.3	5.9	***5.4***	5.9	**5.1**
Washington/Oregon	3.5	4.8	4.8	6.2 - 7.0	6.4	**5.8**	6.4	**5.6**

Notes: (1) Shaded cells indicate windpower costs are at or below avoided costs.

(2) ***Italic bold*** windpower costs are within 0.5 ¢/kWh of avoided costs.

(3) Range of avoided costs in the hybrid comparison shows the "shifting strategy." Lower figure assumes that seasonal patterns of generation are unchanged, while the higher figure assumes that the CT operates more during the utility peak season.

(4) Base Case and Enhanced Market "Full" cases assume that each MW of wind capacity is backed up with 1 MW of CT capacity (i.e. full backup) which operates at a 10% annual capacity factor; "Partial" cases assume that the CT is built at 60% of the wind plant and operates at 5% annual capacity factor.

TABLE X - 3 HYBRID SENSITIVITY CASE - WINDPOWER 2010 Costs in 1990 ¢/kWh								
	Conventional Costs			**Hybrid Cost Comparisons**				
REGION	**Avoided**	**Windpower**		**Avoided**	**Windpower-CT Hybrid**			
		Base Case	**Enhanced Market**		**Base Case Full**	**Base Case Partial**	**En. Mkt Full**	**En. Mkt. Partial**
New England	6.9	4.6	4.0	9.2 - 9.6	7.2	6.2	7.4	5.9
Mid Atlantic	3.5	4.6	***4.0***	4.1 - 5.9	7.1	***6.1***	7.3	5.9
South Atlantic	3.2	4.6	4.0	3.8 - 5.5	7.0	6.1	7.3	***5.8***
Florida	NA	NA	NA	NA	NA	NA	NA	NA
East North Central	3.1	4.6	4.0	5.4 - 5.9	7.0	***6.1***	7.3	5.8
West North Central	3.4	4.0	***3.6***	4.9 - 5.9	***6.4***	5.5	6.5	5.2
East South Central	NA	NA	NA	NA	NA	NA	NA	NA
West South Central	5.1	4.2	3.7	6.3 - 7.9	6.5	5.6	6.6	5.4
Mountain	3.1	4.0	***3.6***	4.8 - 5.8	***6.2***	5.4	***6.3***	5.1
Arizona/New Mexico	3.5	4.2	***3.7***	4.8 - 5.7	6.5	5.6	6.6	5.4
California	6.3	4.0	3.5	8.7 - 9.4	6.2	5.3	6.3	5.0
Washington/Oregon	3.7	4.0	3.6	6.2 - 6.9	6.3	5.4	6.4	5.2

Notes: (1) Shaded cells indicate windpower costs are at or below avoided costs.

(2) ***Italic bold*** windpower costs are within 0.5 ¢/kWh of avoided costs.

(3) Range of avoided costs in the hybrid comparison shows the "shifting strategy." Lower figure assumes that seasonal patterns of generation are unchanged, while the higher figure assumes that the CT operates more during the utility peak season.

(4) Base Case and Enhanced Market "Full" cases assume that each MW of wind capacity is backed up with 1 MW of CT capacity (i.e. full backup) which operates at a 10% annual capacity factor; "Partial" cases assume that the CT is built at 60% of the wind plant and operates at 5% annual capacity factor.

TABLE X - 4
HYBRID SENSITIVITY CASE - PHOTOVOLTAIC 2010
Costs in 1990 ¢/kWh

REGION	Conventional Costs			Hybrid Cost Comparisons				
	Avoided	Photovoltaic		Avoided	Photovoltaic-CT Hybrid			
		Base Case	Enhanced Market		Base Case Full	Base Case Partial	En. Mkt Full	En. Mkt. Partial
New England	7.0	16.0	8.8	10.1	15.3	15.8	11.3	10.9
Mid Atlantic	5.0	16.0	8.8	9.3	15.2	15.7	11.1	10.8
South Atlantic	4.7	12.3	6.8	8.1	12.7	12.7	8.9	8.7
Florida	6.0	12.3	6.8	8.3	12.7	12.7	8.9	***8.7***
East North Central	4.3	13.9	7.7	7.3	13.8	14.0	9.8	9.6
West North Central	4.5	11.6	6.4	7.3	12.3	12.2	8.6	8.3
East South Central	4.7	12.3	6.8	8.1	12.7	12.7	8.8	***8.6***
West South Central	6.2	10.5	5.8	9.5	11.3	11.1	7.7	7.5
Mountain	4.6	10.0	5.6	7.2	10.9	10.6	***7.3***	7.2
Arizona/New Mexico	5.0	9.1	***5.1***	8.1	10.2	9.9	6.8	6.6
California	7.1	10.0	5.6	10.3	11.0	***10.7***	7.4	7.2
Washington/Oregon	3.9	14.9	8.2	5.1	14.4	14.8	10.3	10.1

Notes: (1) Shaded cells indicate PV costs are at or below avoided costs.
(2) ***Italic bold*** PV costs are within 0.5 ¢/kWh of avoided costs.
(3) Base Case and Enhanced Market "Full" cases assume that each MW of PV capacity is backed up with 1 MW of CT capacity (i.e. full backup) which operates at a 10% annual capacity factor; "Partial" cases assume that the CT is built at 60% of the PV plant and operates at 5% annual capacity factor.

conventional costs, windpower-CT hybrid generation would be less expensive than conventional generation.

Photovoltaics. Under conventional cost comparisons, PV generation becomes less expensive than fossil fuel generation in the Enhanced Market scenario in the West South Central and California regions; and is within 0.1 ¢/kWh of fossil generation costs in Arizona/New Mexico. In other regions shown on Table X-4, levelized PV costs in the Enhanced Market Scenario are between 1.0 ¢/kWh (e.g., Mountain) and 4.3 ¢/kWh (e.g., Washington/Oregon) more expensive than fossil fuel generation.

CT-hybrid PV generation is more competitive than PV alone. In the Enhanced Market scenario, PV-CT hybrid generation is within 0.5 ¢/kWh in Florida and the East South Central region (Partial Backup case) and less expensive in the West South Central, Mountain, Arizona/New Mexico, and California regions. Even if full backup were required, PV-CT hybrid generating costs in the Enhanced Market Scenario remain below fossil fuel generating costs in the West South Central, Arizona/New Mexico, and California regions, and would be only 0.1 ¢/kWh higher in the Mountain region.

Conclusions

Most storage and backup technologies are best evaluated on a system perspective, where the opportunity set for optimization is broader. This requires sophisticated modelling and control strategies, but enlarging the focus from individual plant evaluation to a full range of supply and demand-side options may enhance the economic prospects of intermittent renewable generation.

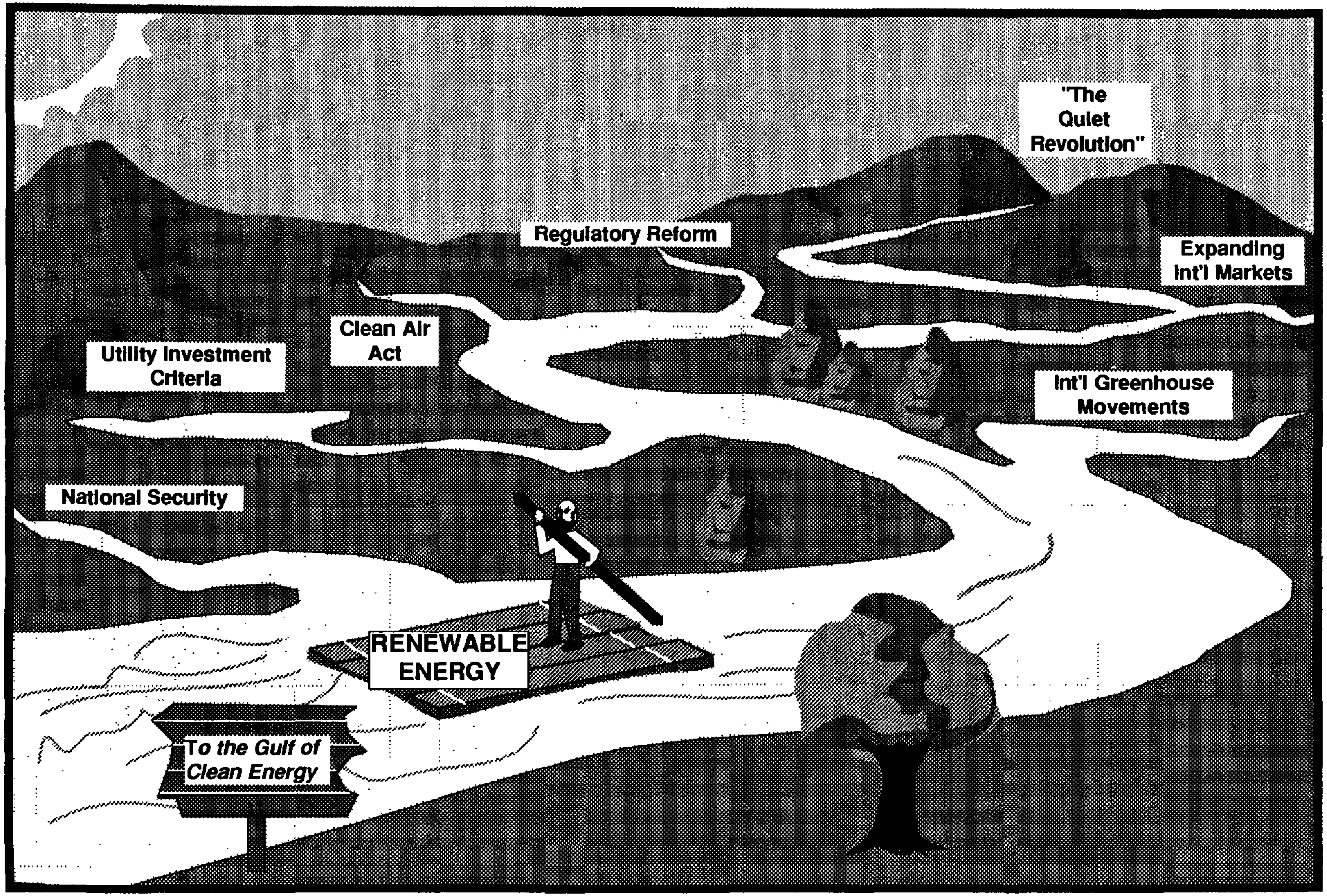
As stated before, these results are based on a simplified methodology, and must be regarded as suggestive. Additional utility and technology-specific studies are needed to calculate the value of hybrid options in a more definitive way. The emissions from CT generation (primarily NO_x) should be taken into account when evaluating the overall environmental impact of hybrid options; however, the emissions expected from infrequent CT operation would be less than the emissions from using fossil fuels to generate the electricity produced from the renewable hybrid system. Therefore, hybrid options can enhance the value of intermittent renewable generation with less environmental impact than pure fossil fuel-fired electric generation.

EPILOGUE

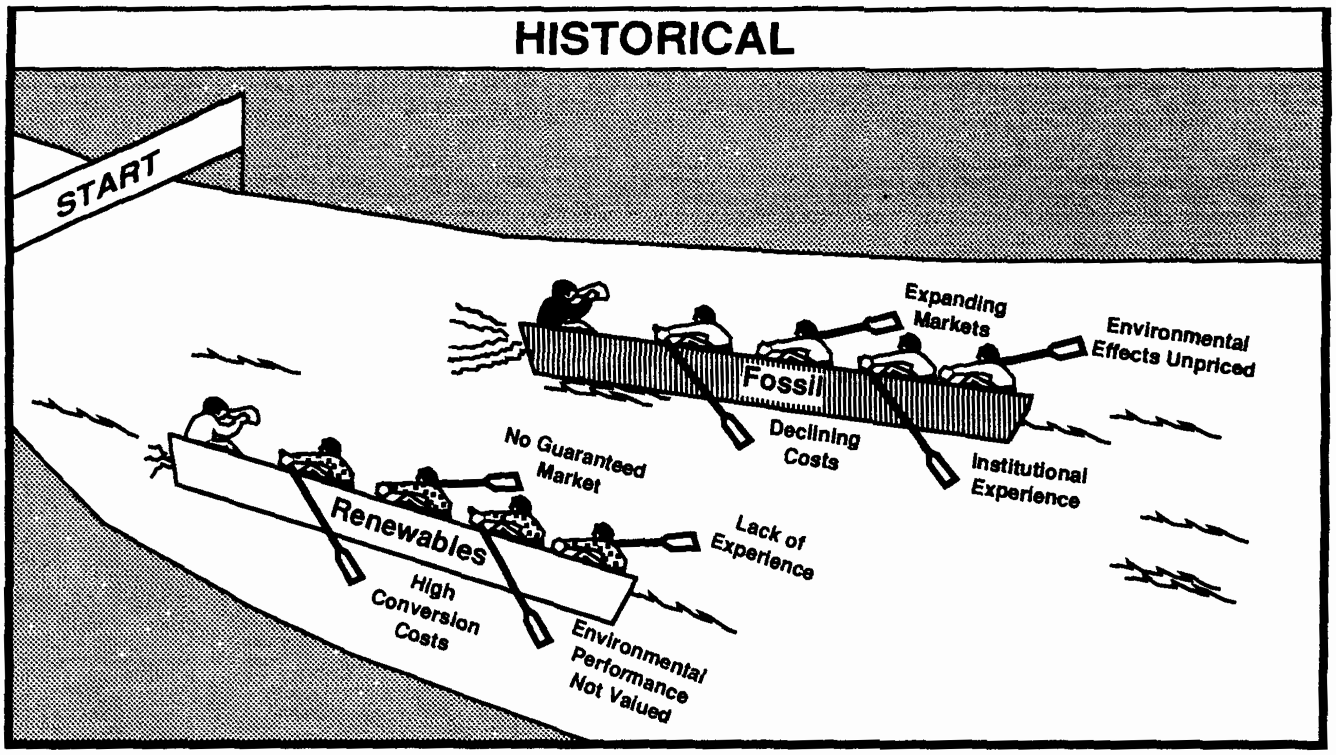
The market for renewable electric generation has evolved dramatically since the 1970s. Renewable resources have emerged as commercial alternatives to fossil fuel-fired generation, and their environmental advantages are becoming more recognized. Among these advantages, this report emphasizes the potential for renewable electric technologies to reduce emissions of air pollutants and greenhouse gases. In the 1990s, renewables face a market characterized by two related, but different views. These two views are represented in the pictures that follow.

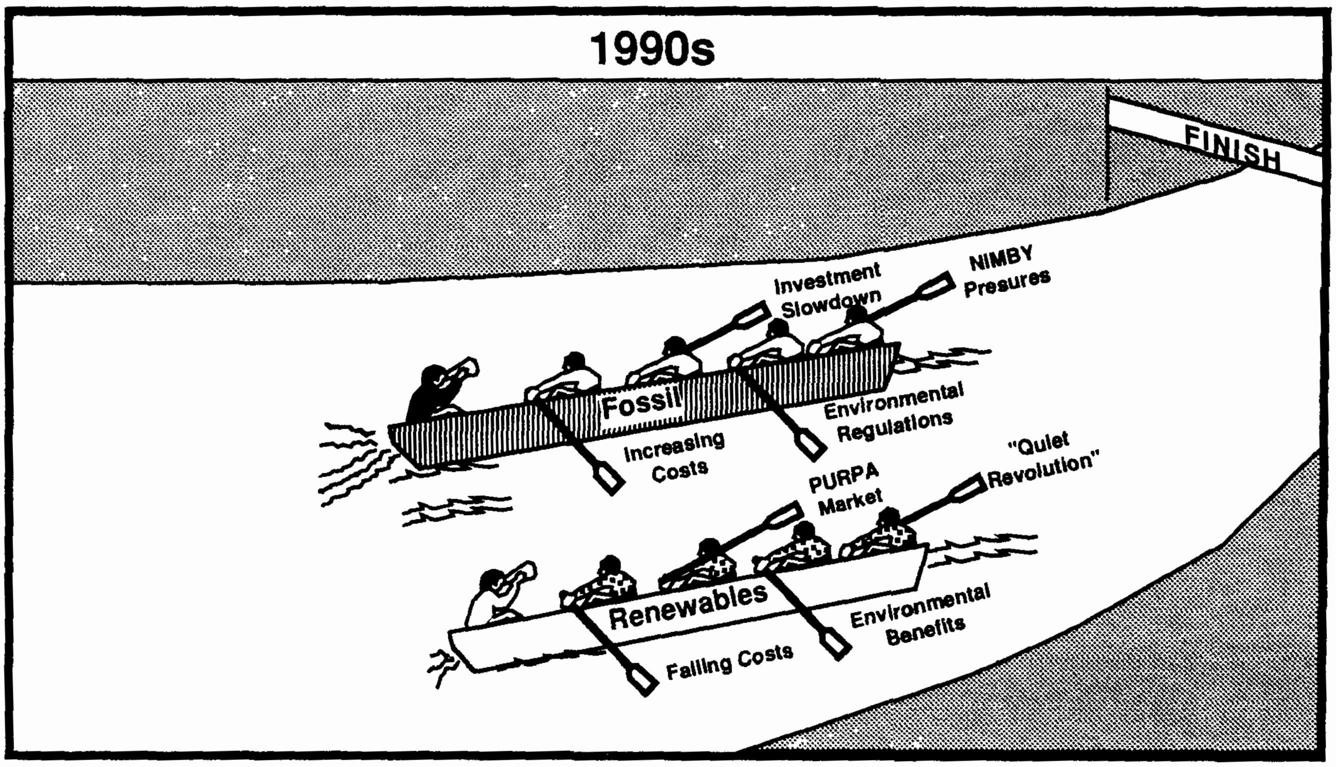
The first of these emphasizes the growing momentum of commercial renewable development, where expansion is propelled by recent economic, regulatory, and political trends. These include the Clean Air Act Amendments of 1990; regulatory reform in electricity markets that influences utility investment; the "Quiet Revolution" of public opinion and local activism; increased concern over the national security implications of fossil fuel dependence; expanding international awareness of, and markets for, renewable technology; and international concern over the implications of increased greenhouse gas concentrations in the atmosphere. This confluence of trends has helped position renewables for rapid growth.

The second view recognizes that renewables must compete aggressively with fossil fuels in the domestic energy market, and that fossil fuels have historically held the lead in such a competition. The rapid expansion of fossil fuel-fired electric generation in the past was characterized by declining costs and more limited concern over environmental impacts than exists today. The early market prospects for renewables were limited by relatively high costs, lack of market access and utility awareness, and a low value attached to the environmental advantages of renewable



The Raft Gains Momentum...





The Race Is Not Over...

energy. Entering the 1990s, however, fossil fuels may encounter more resistance in the market as all of the costs to society of fossil fuel use are recognized. At the same time, the competitive stature of renewables has been enhanced by falling costs, regulatory trends, increased public support, and growing awareness of the environmental advantages of renewable energy sources. The extent to which these factors will boost renewables' competitive position is still unclear.

These two views of renewable energy prospects -- growing momentum and intense competition -- are not mutually exclusive. Renewable energy developers regard the current momentum as cause for optimism, but not complacency; and renewables will continue to face stiff challenges in competitive markets. Growing recognition of the environmental benefits of renewable energy development, supportive policies in the regulated electricity market, and continued commercial success offer the prospect for a sustained expansion of renewable electric generation in the 1990s and beyond. This report highlights the vast potential for development of renewable electric generation and its ability to prevent air pollution. The report demonstrates the potential for renewable electric generation to [help mitigate] the dual problems of air pollution and fossil fuel dependence. However, this potential can only be realized through the combined efforts of policymakers, researchers, utility planners, and utility commmissions. Continued investment--by industry and government--is crucial.

Cathy Zoi
Project Officer, Global Change Division
Office of Air and Radiation
U.S. Environmental Protection Agency

APPENDIX A

RENEWABLE ELECTRIC TECHNOLOGY PENETRATION SCENARIOS

The Renewable Electric Model (REM) described in Chapter III estimates pollution prevention and costs based on assumed renewable electric technology penetration scenarios. In order to estimate pollution reduction potential and costs, the EPA constructed a Base Case and an Enhanced Market scenario. Many of the technical and cost assumptions were taken from the recent analysis conducted by the Department of Energy (DOE) and the Solar Energy Research Institute (SERI).[1] For some technologies, the DOE/SERI market projections formed the basis for EPA scenarios, while for other technologies, EPA constructed scenarios based on other sources and data. This appendix describes how the scenarios were constructed for each technology considered in the report.

BIOMASS ELECTRIC SCENARIOS

EPA made separate technology penetration scenarios for the three biomass fuel sources: solid combustion (primarily wood and wood waste), municipal solid waste, and landfill gas. The EPA Base Case generally follows the DOE/SERI Business as Usual assumptions, except for MSW and landfill methane, where the Base Case was derived from EPA analysis of potential fuel supply. The EPA Enhanced Market scenario is based on analyses of individual biomass technologies and respective fuel supplies. Because biomass technologies operate as reliably as fossil fuel systems when adequate fuel is available, all technologies are given full capacity credit in the REM.

Wood, Wood Waste, and Agricultural Waste

Table A-1 shows the assumptions used in constructing the EPA scenarios. The EPA Base Case for wood and wood waste essentially equals the DOE/SERI BAU scenario. Under this scenario, electricity generation equals about 70 million mWh in 2000 and over 100 million mWh in 2010. Costs and emissions for the Base case scenario are calculated based on the following mix of conversion technologies: for 2000, 75% of the capacity built would be conventional boilers, with Whole Tree Burner systems (WTB) accounting for the remaining 25% of capacity; wood-fired capacity built

---

[1] *The Potential of Renewable Energy*, Interlaboratory White Paper prepared for the Office of Policy, Planning, and Analysis, U.S. DOE (Golden, Colorado: Solar Energy Research Institute, March, 1990).

TABLE A - 1

MODEL ASSUMPTIONS FOR WOOD, WOOD WASTE, AND AGRICULTURAL WASTE

Assumption	Units	Value	Comments/Source
SRWC FUEL SUPPLY			
Available Acres:			Land identified as eroding or environmentally sensitive that would benefit from tree planting by Moulton (USFS) and Richards (ERS/USDA).
Dry Cropland	10^6 acres	117	
Wet Cropland	10^6 acres	107	
Dry Pasture	10^6 acres	16	
Wet Pasture	10^6 acres	24	
Enrolled Acres:			
Dry Cropland	%	25	In all regions except for Arizona/New Mexico and Mountain, where SRWC is not thought to be viable on a large scale.
Wet Cropland	%	25	
Dry Pasture	%	25	
Wet Pasture	%	25	
Enrolled Acre Total	10^6 acres	63	
Average Annual Growth	dry tons/acre/yr	4.7	Varies by region and land type, estimated by L Wright (ORNL). Tons of oven dried wood equivalent.
Average Rotation	years	8	Varies by region. Estimated by L Wright.
Wood Heat Content	mmBtu/dry ton	17	Equal to 8500 Btu/lb.
FUEL COSTS			
SRWC			
Establishment Costs			
Cropland	$/acre	250	Estimated by L Wright.
Pasture	$/acre	280	
Average Rental Rate	$/acre/yr	53	Marginal rental rate estimated by Moulton and Richards. Varies by region and land type.
Treatment Costs	$/acre/year	26	Estimated by L Wright.
Harvesting and Delivery Costs	$/dry ton	16	Estimated by L Wright. At low end of range of estimates given since no chipping necessary for WTB.
Conventional Wood			
Low Cost Regions	$/mmBtu	2.50	Representative regional costs.
High Cost Regions	$/mmBtu	3.50	

Assumption	Units	Value		Comments/Source
Wood, Wood Waste, and Agricultural Waste (continued)				
CONVERSION TECHNOLOGIES				
Share of New Capacity		2000	2010	
Base Case				
Conventional Boiler	%	75	50	Based on assessment of available and developing technologies. *Fluidized bed* combustion use would lower emissions, but increase costs.
WTB	%	25	50	
Enhanced Market				
Conventional Boiler	%	75	40	
WTB	%	25	40	
Gas Turbine	%	–	20	
Capital Costs		2000	2010	
Conventional Boiler	$/kW	2,220	2,220	EPRI TAG 1986
WTB	$/kW	900	900	D. Ostlie (100 MW unit)
Gas Turbine	$/kW	–	1,220	Larson et. al. (1989)
Scenario Average				
Base Case	$/kW	1,890	1,560	
Enhanced Market	$/kW	1,890	1,490	
O&M Costs		2000	2010	
Conventional Boiler	¢/kWh	0.6	0.6	Mich. Elec. Option Study
WTB	¢/kWh	0.3	0.3	D. Ostlie (100 MW unit)
Gas Turbine	¢/kWh	–	0.6	Larson et. al. (1989)
Scenario Average				
Base Case	¢/kWh	0.5	0.5	
Enhanced Market	¢/kWh	0.5	0.5	
Heat Rates		2000	2000	
Conventional Boiler	Btu/kWh	16,250	16,250	Mich. Elec. Option Study
WTB	Btu/kWh	9,960	9,960	D. Ostlie (100 MW unit)
Gas Turbine	Btu/kWh	–	10,500	Larson et. al. (1989)
Scenario Average				
Base Case	Btu/kWh	14,760	13,210	
Enhanced Market	Btu/kWh	14,760	12,690	
Emissions Factors		2000	2010	
CO_2	lb/mmBtu	0.0	0.0	
CH_4	lb/mmBtu	0.0	0.0	
NO_x	lb/mmBtu	0.25	0.25	Mich. Elec. Option Study
SO_2	lb/mmBtu	0.04	0.04	EPA estimate
PM	lb/mmBtu	0.05	0.05	Mich. Elec. Option Study

between 2000 and 2010 are assumed to be equally divided into conventional and WTB systems. Because of its low heat rate (about 10,000 Btu/kWh, compared to 12,000-16,000 Btu/kWh for conventional plants), and low fuel handling costs (especially with SRWC), WTB should quickly become the "state of the art" in wood-fired electricity generation, assuming that initial plants demonstrate these advantages.

The EPA Enhanced Market scenario for wood and agricultural fuelstocks builds on the DOE/SERI "National Premiums" projection. Additional market enhancement in the form of promoting extensive SRWC planting on marginal crop and pasture land to provide wood fuel for electricity generation could result in a significant increase in generation over the DOE/SERI National Premiums scenario.

SRWC can be chipped and used in conventional wood-fired boilers or utilized in whole tree burners (WTB). Given the marked cost advantage of WTB over conventional boilers, especially when using SRWC, the Enhanced Market scenario also assumes 25% of the new capacity built between 1990 and 2000 will be WTB, with conventional systems account for the remaining 75% of capacity. Between 2000 and 2010, the Enhanced Market scenario assumes that WTB accounts for 40% of capacity built, conventional systems account for 40%, and biomass combustion turbines account for the remaining 20% of new capacity.

An estimate of the potential supply of wood fuel from SRWC on marginal cropland has been made for the twelve EPA model regions using a SRWC supply model constructed by ICF. This model calculates the total amount of wood available for harvest in a given year based on the amount of land planted and the expected growth rates and rotation lengths for SRWC plantations. Additionally, fuel prices have been determined based on marginal land rents, establishment and annual treatment costs, and harvest and delivery costs.

Land considered in this analysis consists of marginal or environmentally sensitive crop and pasture land. Most of this land is being eroded rapidly by either wind or water, and requires the planting of a cover crop. When managed property, short rotation trees can provide adequate protection from erosion. Costs to establish SRWC plantations will vary depending on the amount of site preparation that is required, with crop land requiring less preparation than pasture. Productivities vary depending on the amount of water available: dry lands typically yield less than lands with adequate moisture. Thus, land inputs for each region are classified as crop or pasture and as being either wet or dry. The estimated amount of available land in each of these classifications is presented in Table A-2. Productivity and cost inputs for each of these land classifications are provided in Table A-3.

TABLE A - 2
PROJECTED SRWC PLANTING ON MARGINAL LANDS BY REGION THROUGH 2010
(thousand acres)

REGION	Dry Cropland	Wet Cropland	Dry Pasture	Wet Pasture	Total
New England	100	100	*	100	400
Mid Atlantic	1,300	1,200	200	400	3,000
South Atlantic	2,000	1,300	600	500	4,500
Florida	100	100	*	200	500
East North Central	6,000	7,200	500	700	14,500
West North Central	10,100	8,400	1,100	1,400	21,000
East South Central	2,900	2,800	900	900	7,500
West South Central	3,200	4,100	500	1,200	9,000
Mountain	0	0	0	0	0
Arizona/New Mexico	0	0	0	0	0
California	200	100	*	70	400
Washington/Oregon	1,100	800	100	170	2,200
Total	27,200	26,100	3,900	5,600	62,900

* Indicates land less than 50 thousand acres.

Note: Totals may not equal sum of columns due to independent rounding.

TABLE A - 3
PRODUCTIVITY AND COST INPUTS FOR WOOFS MODEL
Weighted Averages by Region

REGION	Annual Growth (tons/acre/yr)	Rotation (yrs)	Establishment Costs ($/acre)	Rental Rate ($/acre/yr)	Treatment Costs ($/acre/yr)	Harvest and Delivery Costs ($/ton)
New England	3.5	9	$261	$61	$26	$16
Mid Atlantic	4.5	7	$257	$65	$26	$16
South Atlantic	5.8	5	$260	$59	$26	$16
Florida	7.3	5	$269	$52	$26	$16
East North Central	4.3	9	$253	$55	$26	$16
West North Central	4.2	9	$255	$52	$26	$16
East South Central	5.0	7	$259	$54	$26	$16
West South Central	5.2	7	$257	$43	$26	$16
Mountain	NA	NA	NA	NA	$26	$16
Arizona/New Mexico	NA	NA	NA	NA	$26	$16
California	6.4	7	$258	$48	$26	$16
Washington/Oregon	7.3	7	$254	$53	$26	$16
Total	4.7	8	$256	$53	$26	$16

Sources: Rental rates were taken from "Costs of Sequestering Carbon through Tree Planting and Forest Management in the United States" by R.J. Moulton and K.R. Richards, USFS, August 27, 1990 final draft. All other inputs were estimated by L. Wright, ORNL.

TABLE A - 4
PROJECTED SRWC FUEL SUPPLY AND COSTS BY REGION

REGION	Land Harvested (thousand acres)		Fuel Supply (trillion Btu)		Total Cost (million $)		Fuel Price ($/mmBtu)
	2000	2010	2000	2010	2000	2010	
New England	10	30	10	20	20	50	3.46
Mid Atlantic	90	290	50	150	140	450	2.98
South Atlantic	160	650	80	320	200	810	2.55
Florida	20	70	10	40	20	90	2.40
East North Central	360	1,150	240	750	680	2,140	2.87
West North Central	520	1,660	340	1,070	960	3,040	2.84
East South Central	230	710	140	420	350	1,100	2.66
West South Central	270	860	170	530	400	1,260	2.46
Mountain	0	0	0	0	0	0	NA
Arizona/New Mexico	0	0	0	0	0	0	NA
California	10	40	10	30	20	60	2.39
Washington/Oregon	70	210	60	180	120	370	2.12
Total	1,740	5,650	1,090	3,510	2,910	9,370	2.73

Note: Totals may not equal sum of columns due to independent rounding.

Over 260 million acres of crop and pasture land are presently eroding or are environmentally sensitive and would benefit from being enrolled in a program that takes them out of agricultural production, such as the Conservation Reserve Program (CRP). This land base represents the total acreage potentially available for SRWC planting on marginal lands, but not all of this land could be planted with SRWC. The primary goal of programs like the CRP is to protect the land from further damage. SRWC is one of a number of practices that can halt erosion and begin rebuilding the soils (through root development and leaf litter). Therefore, EPA assumes that 25 percent of the available land base will be planted with SRWC over the next twenty years in all regions except for the Arizona/New Mexico and Mountain regions, where SRWC is not expected to be viable on a large scale. A little over 60 million acres would be planted under these assumptions, averaging 3 million acres planted per year over the next twenty years of enrollment. Given that SRWC technology is still developing, less land could be planted in earlier years; EPA assumes that in the first year about 1.5 million acres will be planted, an amount that would increasing steadily until the final year of analysis when about 4.5 million acres will be planted. The rotation lengths used in this model average eight years and annual growth is expected to average a little under 5 dry tons per acre per year.

The results of this analysis, including expected fuel supply, total costs, and resulting fuel prices for the twelve model regions are presented in Table A-4. We expect that a total of roughly one quad of wood fuel will be available for electricity generation in 2000 rising to 3.5 quads in 2010 at an average price of roughly \$2.70/mmBtu.[2] Fuel prices for SRWC range from about \$2.10/mmBtu in Washington/Oregon to almost \$3.50/mmBtu in the Northeast.

Municipal Solid Waste

Both EPA scenarios for municipal solid waste-to-energy are based (WTE) on EPA projections of MSW generation. Table A-5 shows the assumptions regarding mass-burn and refuse-derived fuel plants in the EPA scenarios. In the Enhanced Market scenario, capital costs are reduced because of increased commercial experience, which can lower construction costs and reduce the contingency factor applied to capital cost estimates. These cost parameters are only illustrative, since the REM analysis assumed that generation costs would equal avoided costs by construction. (This assumption was made in order to account for common practice, and to avoid the need to forecast regional tipping fees.) The heat rates and technology mix determine how much electricity could be generated for assumed fuel supplies. Emission rates were taken from the Michigan Electric Option Study (1986).

---

[2] Alternatively, liquid fuels can be produced with these SRWC fuelstocks. Assuming a conversion rate of about 75 to 100 gallons of biocrude-derived gasoline per dry ton of wood, approximately 15 to 20 trillion gallons of gasoline could be produced in 2010. This is enough fuel to power 50 to 70 million automobiles travelling 10,000 miles per year at 35 mpg.

TABLE A - 5

MUNICIPAL SOLID WASTE MODEL ASSUMPTIONS

Assumption	**Units**	**Value**		**Comments/Source**
Capital Costs		**2000**	**2010**	
Base Case				
Mass Burn	\$/KW	6,220	6,220	EPRI TAG \$1990
RDF Plant	\$/KW	7,570	7,570	EPRI TAG \$1990
Enhanced Market				
Mass Burn	\$/KW	5,960	5,710	EPRI TAG - 25%, 50% contingency
RDF Plant	\$/KW	7,450	7,340	EPRI TAG - 15%, 30% contingency
Operating Cost				
Base Case				
Mass Burn	¢/KWh	1.8	1.8	EPRI TAG \$1990
RDF Plant	¢/KWh	2.5	2.5	EPRI TAG \$1990
Enhanced Market				
Mass Burn	¢/KWh	1.8	1.8	EPRI TAG \$1990
RDF Plant	¢/KWh	2.5	2.5	EPRI TAG \$1990
Heat Rates				
Mass Burn	Btu/KWh	17,040	17,040	EPRI TAG \$1990
RDF Plant	Btu/KWh	15,450	15,450	EPRI TAG \$1990
Capacity Factor	%	85	85	EPRI TAG
Emission Rates				
SO_2	lb./mmBtu	0.07	0.07	MEOS
NO_x	lb..mmBtu	0.30	0.30	MEOS
CO	lb./mmBtu	0.07	0.07	MEOS
PM	lb..mmBtu	1.39	1.39	MEOS
Assumed Technology Mix		**Mass Burn**	**RDF Plant**	
(all years)	%	75	25	EPRI TAG projection

In Characterization of Municipal Solid Waste prepared by Franklin Associates, the EPA projects MSW generation to rise from the current 180 million tons per year to 216 million tons in 2000 and 250 million tons in 2010. The EPA Office of Solid Waste expects that 25% of the waste stream will go to waste-to-energy (WTE) facilities in the year 2000. In the Base Case, EPA assumed that NIMBY (not in my back yard) sentiments will keep the percent of MSW that goes to WTE facilities from growing much beyond the current percentage through the year 2000 (although the total incinerated will increase due to projected growth in total MSW generation). The Base Case share of MSW generation accounted for by waste-to-energy in 2000 and 2010 is expected to equal 15 and 25 percent, respectively.

For the Enhanced Market, the percent of MSW generation consumed by WTE facilities in each region was scaled upwards such that (1) the national average equalled 25% in 2000 and 33% in 2010 and (2) regions with low percentages increased more rapidly than those with high waste-to-energy percentages. Electric generation by WTE facilities is projected to equal roughly 33 million mWh in 2000 and grow to 50 million mWh in 2010.

Landfill and Digester Gas

EPA scenarios for landfill and digester gas are based on estimates of national totals since regional data were not available at the time of this analysis. Since landfill gas currently accounts for about 98 percent of electricity generation from landfill and digester gas, EPA projections are focused on potential growth in this energy source. Current landfill methane generation was estimated using the capacity data contained in *The Power of the States*, but the generation figures were calculated using a 72% capacity factor, since the 90% capacity factor used in that study appeared unrealistically high. Table A-6 shows the landfill conversion model assumptions, which were taken primarily from a recent study of landfill generation economics.[3]

EPA regulations currently being considered for control of VOCs from large landfills would mandate that gas collection devices be installed at all landfills meeting certain size criteria. It is estimated that the 850 largest landfills are responsible for about 60 percent of landfill methane emissions in the U.S.. These landfills will likely be affected by this regulation, assumed to take affect by the year 2000. Assuming that 65 percent of landfill gas from these landfills is captured, approximately 0.1 quads of energy will be available for electricity generation. For comparison, it is

---

[3] Bill Wolf and Greg Maxwell, "Commercial Landfill Gas Recovery Operations - Technology and Economics," in *Energy from Biomass and Wastes XIII*, (Chicago: The Institute of Gas Technology), 1990.

TABLE A - 6

LANDFILL METHANE CONVERSION MODEL ASSUMPTIONS

Assumption	Units	Value		Comments/Source
Capital Costs		**2000**	**2010**	
Base Case				
Reciprocating-Low	$/KW	1,150	1,150	EBW - XIII, p. 1260 ($1990)
Reciprocating-High	$/KW	2,560	2,560	EBW - XIII, p. 1260 ($1900)
Gas Turbine	$/KW	1,770	1,770	EBW - XIII, p. 1260 ($1990)
Enhanced Market				
Reciprocating-Low	$/KW	1,030	920	EBW x 0.9 (2000) x 0.8 (2010)
Reciprocating-High	$/KW	2,310	2,050	EBW x 0.9 (2000) x 0.8 (2010)
Gas Turbine	$/KW	1,590	1,420	EBW x 0.9 (2000) x 0.8 (2010)
Operating Cost				
Base Case				
Reciprocating-Low	¢/KWh	1.6	1.6	EBW - XIII, p. 1260 ($1990)
Reciprocating-High	¢/KWh	1.8	1.8	EBW - XIII, p. 1260 ($1900)
Gas Turbine	¢/KWh	1.1	1.1	EBW - XIII, p. 1260 ($1990)
Enhanced Market				
Reciprocating-Low	¢/KWh	1.6	1.6	EBW - XIII, p. 1260 ($1990)
Reciprocating-High	¢/KWh	1.8	1.8	EBW - XIII, p. 1260 ($1900)
Gas Turbine	¢/KWh	1.1	1.1	EBW - XIII, p. 1260 ($1990)
Heat Rates				
Reciprocating-Low	Btu/KWh	11,690	11,690	EBW - XIII, p. 1259 ($1990)
Reciprocating-High	Btu/KWh	12,330	12,330	EBW - XIII, p. 1259 ($1900)
Gas Turbine	Btu/KWh	15,560	15,560	EBW - XIII, p. 1259 ($1990)
Capacity Factors				
Reciprocating-Low	%	65	65	EBW - XIII, p. 1259 ($1990)
Reciprocating-High	%	65	65	EBW - XIII, p. 1259 ($1900)
Gas Turbine	%	80	80	EBW - XIII, p. 1259 ($1990)
NOx Emission Rates				
Reciprocating-Low	lb./mmBtu	3.33	3.33	EBW - XIII, p. 1259 ($1990)
Reciprocating-High	lb./mmBtu	1.39	1.39	EBW - XIII, p. 1259 ($1900)
Gas Turbine	lb./mmBtu	0.16	0.16	EBW - XIII, p. 1259 ($1990)
CO Emission Rates				
Reciprocating-Low	lb./mmBtu	1.20	1.20	EBW - XIII, p. 1259 ($1990)
Reciprocating-High	lb./mmBtu	0.50	0.50	EBW - XIII, p. 1259 ($1900)
Gas Turbine	lb./mmBtu	0.13	0.13	EBW - XIII, p. 1259 ($1990)
Methane Emission Rate	lb./mmBtu	-42.3	-42.3	CH_4 input=emission reduced
Assumed Technology Mix				
Reciprocating-Low	%	25	25	
Reciprocating-High	%	25	25	Proportional to capacity size
Gas Turbine	%	50	50	

estimated that if all landfill gas emitted annually in the U.S. were captured, approximately 0.25 quads of energy would be available for use. As projected by DOE/SERI, increased research and development should result increase the use of digester gas, especially from MSW digestion. This growth should push the national total to 0.15 quads of primary energy equivalents in 2010. We use this estimate for the EPA Enhanced Market scenario for 2000.

Incremental generation totals were allocated to regions according to the distribution of MSW generation 10 years prior, due to the lag between landfilling and methane generation. For example, the incremental electricity generation from this source between the years 2000 and 2010 (about 5 million mWh) was allocated to regions according to the distribution of year 2000 MSW generation.

The EPA Base case scenario was assumed to be identical to the DOE/SERI Business as Usual Scenario. It should be noted, however, that the initial (1988) DOE/SERI estimate of 0.01 quads of primary energy equivalent is substantially below the EPA 1990 generation estimate. The emission reductions computed from incremental generation between 1990 and 2000, therefore, are quite a bit higher in the DOE/SERI BAU Scenario than in the EPA Base case scenario, even though the same amount of generation was assumed in 2000. This is due to the discrepancy in initial generation estimates.

GEOTHERMAL SCENARIOS

Table A-7 shows the capital and operating cost assumptions used in the analysis, which are based on DOE/SERI data. Geothermal conversion systems all operate as baseload capacity and are given full capacity credit in the REM. The EPA Base Case is identical to the DOE/SERI Business as Usual scenario. EPA constructed the Enhanced Market scenario based on the historical growth of the geothermal industry (primarily hydrothermal) over the last 12 years, and DOE's analysis of the impact of particular policy options on geothermal technologies. The EPA Enhanced Market Scenario assumes that policies are put into place to encourage geothermal development.

Hydrothermal resource development has continued in the U.S. during times of decreased federal funding for geothermal programs, and decreased costs of fossil fuels. Assuming an accelerated federal and state support of hydrothermal, the EPA Enhanced Market scenario is based on an annual growth rate of 8 percent through the year 2000, primarily in the West. This would result in an energy contribution of 0.56 quads in the year 2000 and 1.25 quads in 2010.

Based on DOE and other analyses, geopressured brines are likely to develop most significantly under a "national premiums" scenario, since RD&D is well underway and does not appear

TABLE A - 7

GEOTHERMAL MODEL ASSUMPTIONS

Assumption	Units	Value		Comments/Source
		2000	2010	
Capital Cost				
Basecase				
Hydrothermal	\$/KW	1700	1700	
Geopressurized	\$/KW	2700	2200	DOE/SERI BAU
Hot Dry Rock	\$/KW	2500	2300	
Enhanced Market				
Hydrothermal	\$/KW	1600	1500	
Geopressurized	\$/KW	2600	2100	DOE/SERI RD&D
Hot Dry Rock	\$/KW	2200	1800	
Operating Cost				
Basecase				
Hydrothermal	¢/KWh	1.8	1.7	
Geopressurized	¢/KWh	2.6	2.4	DOE/SERI BAU
Hot Dry Rock	¢/KWh	2.3	2.1	
Enhanced Market				
Hydrothermal	¢/KWh	1.8	1.5	
Geopressurized	¢/KWh	2.4	2.1	DOE/SERI RD&D
Hot Dry Rock	¢/KWh	2.0	1.6	
Capacity Factor	%	80	80	DOE/SERI
Capacity Credit	%	100	100	Firm capacity

to be the limiting factor in development. Assuming aggressive policies in the Enhanced Market scenario, geopressured brines contribute approximately .02 quads in the year 2000, and .08 quads in 2010. Expansion of hot dry rock resources hinges on technological advances in the field in the coming years. The DOE/SERI report projects that HDR could provide 0.05 quads in 2000 and 0.23 quads by 2010 under and intensified R,D&D program. These projections are adopted in the Enhanced Market scenario. Magma does not contribute to the Enhanced Market scenario.

HYDROELECTRIC SCENARIOS

The operation of hydroelectric plants depends on streamflow availability, storage, and (to the extent that a plant can be operated in peaking or load following mode) energy value criteria. Since energy value is utility-specific, storage availability is site-specific, and streamflow availability varies from year to year, any representation of hydroelectric operation in an aggregate model is an approximation.

Seasonal variability was estimated by analyzing state-level monthly hydroelectric output data for the years 1983-1989, as well as historical streamflow data.[4] Generation by state was aggregated into the 12 EPA regions and monthly figures were aggregated into seasonal totals, so that the portion of yearly generation that occurs during each season could be calculated in each region. In order to estimate a "representative" seasonal output, a simple, unweighted average of the yearly figures was used.

The four seasonal generation fractions were split further into daily profiles. Different rules were applied to peak plants and run-of-river plants, although few plants run purely in one mode or another during the entire year. Peak plants, for example, will operate continuously during high flow periods in order to capture potential spill as power output. Conversely, run-of-river plants will operate in peaking mode (and sometimes not at all) during low-flow seasons when insufficient flow exists for continuous operation.[5]

For run of river operation in the three highest flow seasons, the seasonal portions were multiplied proportionally by the times represented in the daily load segments, i.e. by 13/24 for peak operation, and 11/24 for off-peak operation. During the lowest flow season in each region, run-of-river plants are assumed to run in a modified peak mode, where the peak operation is 18/24 times the

---

[4] Streamflow data was taken from *The Water Atlas* (Port Washington, New York: Water Information Center, 1975). Monthly generation was derived from issues of *Electric Power Monthly*, published by the Energy Information Administration.

[5] See EPRI *Increased Efficiency of Hydroelectric Power*, June, 1982, p. 3-3.

seasonal portion, and the off-peak generation is 6/24 times the seasonal portion. Fall is the lowest flow season in all regions except New England and East North Central, when it occurs in summer. In the South Atlantic region, both summer and fall were assumed to operate in modified peak mode.

The seasonal profiles were split differently for peaking plant operation. In regions that had one or two distinct low seasons, plants only operated during the peak hours during those seasons, i.e. the entire seasonal allocation was placed in peak time, and off-peak times were zero. For other seasons, modified peak operation (18/24 to peak, 6/24 to off-peak) was assumed, which reflects continuous operation during the very highest portions of the peak season, with peak operation during the remainder. Since storage capacity is usually less than inflow during the highest flow periods, operators run as much through the turbine as possible and spill the rest. Regional stream flow data was also consulted in order to select seasons that operate in modified peak mode. The seasons for modified peak operation are as follows:

	PEAKING PLANTS	RUN-OF-RIVER
REGION	Modified Peak Season	Modified Peak Season
New England	Spring	Summer
Mid Atlantic	Spring	Fall
South Atlantic	Winter/Spring	Summer/Fall
Florida	Spring	Fall
E. N. Central	Spring	Summer
W. N. Central	Spring/Summer	Fall
E. S. Central	Winter/Spring	Fall
W. S. Central	Spring	Fall
Mountain	Spring	Fall
Ariz/N. Mexico	Spring/Summer	Fall
California	Spring	Fall
Wash./Oregon	Winter/Spring	Fall

Other factors can affect daily generation patterns. For example, evaporative transfer in summer can reduce afternoon flows, causing peak flows to occur in very early morning (e.g. 6:00 am). Pondage options that store a few hours of water can help shift these peaks to afternoon. In regions dominated by winter or spring snowmelt, generation peaks can occur between 2 and 6 PM as a result of higher daytime temperatures that increase melting. These factors were not taken into account.

Regional capacity credit for hydroelectric generation reflects two considerations--the coincidence of peak flows with peak electricity demand and the seasonal variability of available power. The fraction of seasonal peak generation that occurs in the utility demand peak season represents the first concern. Thus, if peak generation occurs in the summer in a summer peaking utility, the fraction

TABLE A - 8

HYDROELECTRIC MODEL ASSUMPTIONS

Assumption	Units	Value	Comments/Source
<u>Capital Costs</u>			
Refurbishment/upgrade	$/KW	350	
Expand existing facility	$/KW	1400	Representative costs based
Power non-power dams	$/KW	1800	on industry surveys.
Restore retired site	$/Kw	800	
<u>Operation & Maintenance</u>	¢/KWh	0.5	DOE/SERI
<u>Capacity Credit</u>			
Storage Plants			
New England	%	44	
Mid Atlantic	%	59	
South Atlantic	%	43	Calculated as the ratio of
Florida	%	68	hydroelectric output in peak
East North Central	%	50	flow season over the
West North Central	%	67	hydroelectric output during
East South Central	%	48	peak electric demand
West South Central	%	45	season in each region. The
Mountain	%	68	ratio is scaled by 0.7 to
Arizona/New Mexico	%	70	account for adverse flow
California	%	70	conditions (drought).
Washington/Oregon	%	67	
Run of River Plants			
New England	%	32	Calculated as the ratio of
Mid Atlantic	%	42	hydroelectric output in peak
South Atlantic	%	31	flow season over the
Florida	%	49	hydroelectric output during
East North Central	%	35	peak electric demand
West North Central	%	48	season in each region. The
East South Central	%	34	ratio is scaled by 0.5 to
West South Central	%	32	account for adverse flow
Mountain	%	49	conditions (drought).
Arizona/New Mexico	%	50	
California	%	50	
Washington/Oregon	%	48	
<u>Plant Factors</u>			
Storage Plants	%	12-44	Depends on regional project
Run-of-River Plants	%	27-54	mix (based on FERC data).

TABLE A - 9: EPA BASE HYDROELECTRIC SCENARIO

EXPANSION OPTION	Cost ($/KW)		Capacity Gain (% of Potential)		Energy Gain (% of Potential)		Capacity Change (from 1990 MW)		Generation Change (from 1990 GWH)	
Year:	2000	2010	2000	2010	2000	2010	2000	2010	2000	2010
Refurbishment/Upgrades										
Run of River & Diversion	350	350	3	4	1	2	630	840	1,010	2,010
Storage	350	350	3	4	1	2	1,510	2,020	1,980	3,950
Expand Existing Facilities										
Run of River & Diversion	1,400	1,400	10	25	10	25	200	510	570	1,420
Storage	1,400	1,400	5	15	5	15	230	670	480	1,450
Power Non-Power Dams										
Run of River & Diversion	1,800	1,800	5	10	5	10	630	1,260	2,100	4,200
Storage	NA	1,800	0	5	0	5	0	360	0	720
Restore Retired Sites										
Run of River & Diversion	800	800	20	30	20	30	300	450	1,000	1,500
Storage	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Relicensing Impacts										
Run of River & Diversion	NA	NA	-2	-2	-1	-1	-40	-150	-110	-370
Storage	NA	NA	-4	-4	-2	-2	-30	-540	-70	-1,240
Subtotals										
Run of River & Diversion							1,720	2,910	4,560	8,760
Storage							1,700	2,510	2,390	4,880
TOTALS							3,420	5,420	6,950	13,640

TABLE A - 10: EPA ENHANCED MARKET HYDROELECTRIC SCENARIO

EXPANSION OPTION	Cost ($/KW)		Capacity Gain (% of Potential)		Energy Gain (% of Potential)		Capacity Change (from 1990 MW)		Generation Change (from 1990 GWH)	
Year:	2000	2010	2000	2010	2000	2010	2000	2010	2000	2010
Refurbishiment/Upgrades										
Run of River & Diversion	350	350	6	7	3	4	1,250	1,460	3,020	4,020
Storage	350	350	6	7	3	4	3,020	3,530	5,930	7,900
Expand Existing Facilities										
Run of River & Diversion	1,400	1,400	35	75	35	75	710	1,520	1,990	4,260
Storage	1,400	1,400	20	40	20	40	900	1,800	1,940	3,880
Power Non-Power Dams										
Run of River & Diversion	1,800	1,800	25	50	25	50	3,150	6,310	10,490	20,990
Storage	1,800	1,800	15	25	15	25	1,090	1,820	2,140	3,570
Restore Retired Sites										
Run of River & Diversion	800	800	30	50	30	50	450	750	1,500	2,500
Storage	800	800	NA	NA	NA	NA	NA	NA	NA	NA
Relicensing Impacts										
Run of River & Diversion	NA	NA	-2	-2	-1	-1	-40	-150	-110	-370
Storage			-4	-4	-2	-2	-30	-540	-70	-1,240
Subtotals										
Run of River & Diversion							5,520	9,890	16,880	31,400
Storage							4,980	6,600	9,940	14,110
TOTALS							10,500	16,490	26,820	45,500

is 1 (as in California and Arizona/New Mexico). At the other extreme, only 62 percent of the peak seasonal output occurs during the summer utility demand peak in the South Atlantic region. This variable is further scaled by the factor 0.7 for peaking plants and 0.5 for run-of-river plants to account for adverse flow conditions.

Because the EPA Scenarios were based on FERC data that identified existing and potential projects by type (except for retired facilities), incremental storage capacity assumed in the EPA scenarios was assumed to operate in peaking mode, while additional run-of-river and diversion capacity was assumed to operate in run-of-river mode (as were all restored retired facilities). Costs were assigned to each project type, although it should be noted that the costs of hydropower expansion options are very site specific. Table A-8 shows the project costs assumed in the analysis, and the capacity credits calculated. In the Base Case, very limited expansion is assumed to occur at existing hydropower sites. Table A-9 shows the hydroelectric expansion assumptions used in the Base Case analysis, and Table A-10 shows the assumptions used in the Enhanced Market scenario.

PHOTOVOLTAIC SCENARIOS

Projections of future PV sales are extremely sensitive to the presumed timing of cost reductions, especially when future costs attain certain thresholds that make them competitive in utility power generation. Table A-11 shows the costs and regional capacity factors used to construct the EPA technology penetration scenarios.

Generation in the Base Case is identical to the DOE/SERI Business as Usual scenario, which was allocated to the 12 REM regions according to received insolation. (Because the REM has regional capacity factors, the capacity from the EPA Base Case generation differs somewhat from the capacity imputed from the DOE/SERI generation figures.)

The EPA Enhanced Market PV scenario assumes an intensified RD&D budget will bring down the costs of materials and production, and that environmental impacts are incorporated into least cost utility planning. The Enhanced Market scenario is based on the alternative PV growth scenario described in the DOE/SERI report. PV is very responsive to intensified R&D, and prices drop significantly by the year 2000. At a threshold price of between 6¢/kWh and 10¢/kWh, explosive growth would be expected to occur in the industry. A number of new players will then enter the market, further increasing competition and reducing costs of PV energy. The EPA Enhanced Market scenario assumes that PV generation costs could be reduced to 8 ¢/kWh by 2000 and to 5¢/kWh by 2010 (in regions of good insolation where capacity factors approach 30%). This would require capital costs to fall to roughly $2,100/KW by 2000 and $1,150 by 2010, compared with the DOE/SERI BAU

TABLE A - 11

PHOTOVOLTAIC MODEL ASSUMPTIONS

Assumption	Units	Value		Comments/Source
		2000	2010	
Capital Cost				
Basecase	$/KW	3750	2750	DOE/SERI BAU (in $1990)
Enhanced Market	$/KW	2750	1230	DOE/SERI Alternative Scenario
Operating Cost				
Basecase	¢/KWh	0.2	0.2	DOE/SERI BAU
Enhanced Market	¢/KWh	0.2	0.2	DOE/SERI RD&D
Capacity Factor				
New England	%	16		
Mid Atlantic	%	16		
South Atlantic	%	21		
Florida	%	21		Based on solar insolation data and operating records for plants in specific regions.
East North Central	%	19		
West North Central	%	23		
East South Central	%	21		
West South Central	%	25		
Mountain	%	26		
Arizona/New Mexico	%	29		
California	%	26		
Washington/Oregon	%	18		
Capacity Credit	%	Equal to capacity factor		Typically coincident with utility peaking needs.

assumptions of $3,500 in 2000 and $2,100 in 2010. In other words, PV cost reductions are accelerated by at least a decade.

The capacity credit for PV systems is assumed to equal the capacity factor. This reflects the fact that the expected generation from PV systems will not displace fully the need to build the conventional capacity, but that the correlation between maximum PV output and utility peaking needs would be sufficient to earn partial capacity credit.

SOLAR THERMAL ELECTRIC SCENARIOS

The EPA Base case and Enhanced Market scenarios are derived primarily from the DOE/SERI scenarios. Tables A-12 and A-13 show the assumptions used in constructing the EPA scenarios.

The EPA Base case is identical to the DOE/SERI Business as Usual scenario. The DOE/SERI analysis considers hybrid systems, along with stand-alone systems with and without storage (peaking systems), but does not indicate which technologies would be chosen. The economics of storage and fuel backup are probably more favorable from the utility perspective than intermittent peak power, unless the solar resource is extremely dependable or located in an area where weather forecasting is reliable. In constructing the EPA Base Case, it was assumed that all capacity built between now and 2000 would be operated in natural gas hybrid mode. The capacity built between 2000 and 2010 was assumed to be stand-alone (non-hybrid) systems with storage. This assumption reflects the DOE/SERI belief that storage systems will be improved to the point where they are more economical than natural gas backup systems.

The Enhanced Market scenario assumes that additional R&D brings about the level of market deployment indicated in the DOE/SERI Intensified RD&D scenario, and features the additional development of hybrid natural gas solar thermal systems. These grow at an annual average rate of 4% between 2000 and 2010, in addition to the growth in stand alone systems assumed to be the same as in the DOE/SERI RD&D scenario.

WINDPOWER SCENARIOS

EPA scenarios for windpower are based on a model of regional windpower and fossil fuel generation costs. The model calculates the difference between conventional costs (from the REM) and projected windpower costs, which vary as a function of regional capacity factors. Wind energy scenarios are based on regional cost differences, resource potential, and projected demand growth.

TABLE A - 12

SOLAR THERMAL (NON-HYBRID) MODEL ASSUMPTIONS

Assumption	Units	Value		Comments/Source
Capital Cost		2000	2010	
Basecase				
Systems w/ storage	$/KW	NA	2570	DOE/SERI BAU
Peaking	$/KW	NA	1930	DOE/SERI BAU
Assumed 50/50 mix	$/KW	NA	2250	(in $1990)
Enhanced Market				
Systems w/ storage	$/KW	NA	1500	DOE/SERI RD&D
Peaking	$/KW	NA	1120	DOE/SERI RD&D
Assumed 50/50 mix	$/KW	NA	1300	(in $1990)
Operating Cost				
Basecase	¢/KWh	NA	2.1	DOE/SERI BAU
Enhanced Market	¢/KWh	NA	2.1	DOE/SERI RD&D
Assumed 50/50 mix	¢/KWh	NA	2.1	(in $1990)
Capacity Factor				
New England	%	NA	NA	(Direct solar resource
Mid Atlantic	%	NA	NA	not sufficient for
South Atlantic	%	NA	NA	economic energy
Florida	%	NA	NA	production in these
East North Central	%	NA	NA	regions.)
West North Central	%	NA	NA	
East South Central	%	NA	NA	
West South Central	%	38	38	Based on solar
Mountain	%	39	39	insolation data and
Arizona/New Mexico	%	43	43	projected storage
California	%	39	39	capability.
Washington/Oregon	%	NA	NA	
Capacity Credit	% of capacity factor	100	100	Typically coincident with utility peaking needs.

TABLE A - 13

SOLAR THERMAL HYBRID MODEL ASSUMPTIONS

Assumption	Units	Value		Comments/Source
		2000	2010	
Capital Cost				
Basecase	$/KW	2570	1640	DOE/SERI BAU ($1990)
Enhanced Market	$/KW	2250	1500	Luz analysis of 80MW plant (2000); DOE/SERI RD&D (2010) ($1990)
Operating Cost				
Basecase	¢/KWh	2.1	2.1	DOE/SERI BAU ($1990)
Enhanced Market	¢/KWh	2.1	2.1	DOE/SERI RDD ($1990)
Gas Price	$/mmBtu	3.2-3.8	5.3-6.3	Depends on region and season.
Capacity Factor				
New England	%	NA		Direct solar resoruce not sufficient for economic energy production.
Mid Atlantic	%	NA		
South Atlantic	%	NA		
Florida	%	NA		
East North Central	%	NA		
West North Central	%	NA		
East South Central	%	NA		
West South Central	%	33		Based on solar insolation data and 25% natural gas use.
Mountain	%	35		
Arizona/New Mexico	%	38		
California	%	35		
Washington/Oregon	%	NA		
Capacity Credit	%	100		Gas use provides firm capacity
Heat Rate	Btu/KWh	10,500		Radian (gas boiler)
Emissions (gas input basis)				
CO_2	lb./mmBtu	23.3		Radian (gas boiler)
CO	lb./mmBtu	0.01		Radian (gas boiler)
CH_4	lb./mmBtu	0.00005		Radian (gas boiler)
NO_x	lb./mmBtu	0.11		Radian (gas boiler)
SO_2	lb./mmBtu	0.0		Radian (gas boiler)
PM	lb./mmBtu	0.00005		Radian (gas boiler)

A series of regional cost differentials was calculated as the difference between the levelized cost of windpower and the avoided utility costs, which depend on the assumed seasonal and daily pattern of wind generation in each region. Four ranges of cost differentials are used as thresholds to categorize wind energy penetration. The ranges defined for the cost differential (D) are: Range (1): D greater than 1;' Range (2): D is greater than 0 and less than or equal to 1; Range (3): D is greater than -1 and less than or equal to 0; and Range (4): D is less than or equal to -1. Each region was assigned a resource development factor for wind based on the value of the cost differential. These are shown on Table A-14.

The potential wind resource data used in the analysis were calculated by Pacific Northwest Laboratory (PNL), taking into account the exclusion of land owing to environmental or land-use considerations.[6] The data reflects wind electric potential for the 48 contiguous states based on current turbine technology (30 meter hub height) sited in Class 5 or above wind resources. The regional resource potential was multiplied by the resource development factors defined in each scenario, which yields the windpower potential that could be developed. These resource development percentages were then scaled by EIA regional electric demand growth figures.[7] In the Base Case, growth factors in 2000 are: 1% growth for New England, South Atlantic, East North Central, Mountain, Arizona/New Mexico, California, and Washington/Oregon; 2% growth for Mid-Atlantic and West North Central; and no growth for West South Central. Growth factors for 2010 are 1% growth for West South Central and Mountain and 2% for the remaining regions, except for Florida and East South Central, which do not have wind resources. The capacity growth factors for the Enhanced Market scenario reflect greater than anticipated demand for electric services; the growth factor in 2000 is 2% and in 2010 is 2.5% for all regions.

Capital and O&M costs in the Base Case are identical to the DOE/SERI BAU scenario, and the Enhanced Market scenario uses DOE/SERI RD&D costs, based on turbines operating in 13 mph average wind speed regimes. Table A-15 lists specific scenario cost and capacity factor assumptions. Modest capacity credits were assumed in the EPA scenarios. The capacity credit in 2000 was set at 1/2 the regional capacity factor; capacity credit in 2010 was assumed to be 2/3 the regional capacity factor. This reflects growing attention paid to developing wind resources which coincide with utility peak demand periods.

---

[6] Elliot, D.L., L.L. Wendell, and G.L. Gower. "U.S. Areal Wind Resource Estimates Considering Environmental and Land-Use Exclusions" presented at the American Wind Energy Association (AWEA) Windpower '90 Conference, September 28, 1990.

[7] Energy Information Administration, *Annual Energy Outlook for U.S. Electric Power 1990, Projections through 2010*, Reference Table B1: Electric Power Data and Projections.

TABLE A - 15: ASSUMPTIONS FOR BASE CASE AND ENHANCED MARKET SCENARIOS						
Scenario	Resource Development Factors Based on Ranges of Cost Differentials (D): (¢/kWh)				Capital Costs	O&M Costs
	D > 1	1 ≤ D < 0	-1 < D ≤ 0	D ≤ - 1	($/KW)	(¢/kWh)
Base Case 2000: % Development 1/	1	5	10	15	1,000	1.2
Base Case 2010: % Development	1	5	10	15	965	1.0
Enhanced Market 2000: % Development	3	6	12	20	950	0.9
Enhanced Market 2010: % Development	10	15	25	40	850	0.8

1/ Percent of regional wind resource developed based on regional cost differential (D). The cost differential is calculated as the wind generation cost less the avoided utility cost.

TABLE A - 16

WIND ENERGY MODEL ASSUMPTIONS

Assumption	Units	Value		Comments/Source
		2000	2010	
Capital Cost				
Basecase	$/KW	1000	950	DOE/SERI BAU
Enhanced Market	$/KW	965	850	DOE/SERI RD&D
Operating Cost				
Basecase	¢/KWh	1.2	1.0	DOE/SERI BAU
Enhanced Market	¢/KWh	0.9	0.8	DOE/SERI RD&D
Capacity Factor				
New England	%	24	30	
Mid Atlantic	%	24	30	
South Atlantic	%	24	30	
Florida	%	NA	NA	Based on projected wind turbine efficiencies and regional wind resources.
East North Central	%	21	30	
West North Central	%	33	35	
East South Central	%	NA	NA	
West South Central	%	28	33	
Mountain	%	33	35	
Arizona/New Mexico	%	28	33	
California	%	36	36	
Washington/Oregon	%	32	35	
Capacity Credit	% of capacity factor	50	67	Based on improved siting for utility peaking.

APPENDIX B: 12 REGION MODEL RESULTS

TABLE B – 1a

RENEWABLE EMISSIONS MODEL RESULTS
EPA BASE CASE
ALL RENEWABLES – BY TECHNOLOGY

TECHNOLOGY	INCREMENTAL GENERATION (GWh/yr)	UNIT COST (cents/kWh)			TOTAL ANNUAL COST ($ millions)		UNIT COST OF EMISSIONS AVOIDED ($/MT)		POLLUTION PREVENTED (million kg/yr)							
		AVOIDED	RENEWABLE	DIFFERENCE	AVOIDED	RENEWABLE	CO2 EQ	CO2	CO2 EQ	CARBON	CO2	CO	CH4	NOX	SO2	PM
INCREMENTAL 1990 – 2000																
Hydropower – Storage	2,389	4.9	4.0	-0.9	118	98	-8	-9	2,813	656	2,405	0.34	0.02	10.2	15.1	0.62
Hydropower – RoR & Div.	4,559	4.0	4.6	0.7	181	211	6	7	4,822	1,128	4,136	0.67	0.04	17.1	27.5	0.99
Biomass Electric – Wood	36,742	5.0	8.0	3.0	1,851	2,952	32	34	34,715	8,774	32,171	-56.06	0.28	67.7	223.2	-4.76
Biomass Electric – MSW	7,245	4.9	4.9	0.0	355	355	0	0	6,717	1,733	6,353	-2.97	0.05	9.3	45.1	-74.59
Biomass Electric – Gas	3,901	4.7	4.2	-0.4	183	166	-1	-6	23,937	782	2,869	-11.18	1,036.92	-17.9	16.0	0.52
Geothermal Electric	7,143	4.7	4.5	-0.2	334	323	-2	-3	4,804	1,112	4,078	1.18	0.02	18.1	3.2	0.36
Windpower	7,906	3.0	4.8	1.8	238	377	16	19	8,706	2,034	7,457	1.16	0.06	31.1	34.2	1.84
Solar Thermal – Hybrid	10,939	7.1	11.4	4.3	781	1,252	49	58	9,548	2,215	8,120	1.62	0.06	35.6	15.9	1.54
Solar Thermal	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Photovoltaic	1,925	4.2	19.1	14.8	81	367	145	170	1,966	460	1,686	0.29	0.01	7.0	9.3	0.39
ALL RENEWABLES	82,749	5.0	7.4	2.4	4,121	6,099	20	29	96,027	18,893	69,275	-64.94	1,039.47	177.9	369.6	-73.10
INCREMENTAL 2000 – 2010																
Hydropower – Storage	2,493	5.8	5.1	-0.7	144	127	-6	-7	2,803	653	2,395	0.37	0.02	10.2	14.2	0.59
Hydropower – RoR & Div.	4,197	5.0	4.6	-0.4	211	193	-4	-5	4,357	1,019	3,735	0.63	0.03	15.5	23.6	0.87
Biomass Electric – Wood	39,988	6.4	7.0	0.6	2,549	2,809	7	8	37,422	9,392	34,437	-53.98	0.30	78.5	234.1	-4.07
Biomass Electric – MSW	17,841	6.3	6.3	0.0	1,118	1,118	0	0	16,180	4,169	15,286	-7.28	0.13	22.8	102.9	-183.92
Biomass Electric – Gas	4,877	6.9	4.2	-2.7	337	207	-4	-37	29,859	963	3,532	-13.97	1,296.65	-22.6	18.9	0.62
Geothermal Electric	21,759	7.2	4.4	-2.8	1,559	955	-36	-42	16,847	3,916	14,359	3.48	0.09	61.9	30.7	2.06
Windpower	38,517	3.7	4.1	0.4	1,423	1,571	3	4	42,321	9,873	36,202	5.69	0.31	152.4	155.3	8.82
Solar Thermal – Hybrid	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Solar Thermal	19,506	6.5	6.5	-0.1	1,278	1,265	-1	-1	15,911	3,673	13,468	3.18	0.08	60.8	22.6	1.96
Photovoltaic	12,679	5.3	11.5	6.2	677	1,458	62	72	12,626	2,953	10,827	1.93	0.09	44.8	57.8	2.40
ALL RENEWABLES	161,858	5.7	6.0	0.3	9,292	9,700	2	3	178,327	36,611	134,241	-60.96	1,299.69	424.3	680.3	-170.66
INCREMENTAL 1990 – 2010																
Hydropower – Storage	4,882	5.4	4.6	-0.8	262	223	-7	-8	5,616	1,309	4,800	0.71	0.04	20.3	29.4	1.22
Hydropower – RoR & Div.	8,757	4.5	4.6	0.1	391	404	1	2	9,178	2,147	7,871	1.30	0.07	32.6	51.1	1.86
Biomass Electric – Wood	76,731	5.7	7.5	1.8	4,400	5,761	19	20	72,136	18,166	66,608	-110.04	0.58	146.2	457.4	-8.82
Biomass Electric – MSW	25,086	5.9	5.9	0.0	1,471	1,471	0	0	22,897	5,902	21,639	-10.25	0.18	32.1	148.1	-258.51
Biomass Electric – Gas	8,778	5.9	4.2	-1.7	520	373	-3	-23	53,796	1,746	6,401	-25.15	2,337.57	-40.5	34.9	1.14
Geothermal Electric	28,902	6.5	4.4	-2.1	1,893	1,279	-28	-33	21,662	5,028	18,437	4.66	0.10	80.0	33.9	2.42
Windpower	46,423	3.6	4.2	0.6	1,661	1,948	6	7	51,026	11,907	43,659	6.85	0.37	183.5	189.5	10.66
Solar Thermal – Hybrid	10,939	7.1	11.4	4.3	781	1,252	49	58	9,548	2,215	8,120	1.62	0.06	35.6	15.9	1.54
Solar Thermal	19,506	6.5	6.5	-0.1	1,278	1,265	-1	-1	15,911	3,673	13,468	3.18	0.08	60.8	22.6	1.96
Photovoltaic	14,605	5.2	12.5	7.3	758	1,824	73	85	14,592	3,413	12,513	2.22	0.10	51.7	67.2	2.79
ALL RENEWABLES	244,607	5.5	6.5	1.0	13,413	15,800	9	12	276,354	55,504	203,516	-124.90	2,339.15	602.3	1,049.9	-243.75

TABLE B - 1b

RENEWABLE EMISSIONS MODEL RESULTS
EPA ENHANCED MARKET SCENARIO
ALL RENEWABLES - BY TECHNOLOGY

TECHNOLOGY	INCREMENTAL GENERATION (GWh/yr)	UNIT COST (cents/kWh)			TOTAL ANNUAL COST ($ millions)		UNIT COST OF EMISSIONS AVOIDED ($/MT)		POLLUTION PREVENTED (million kg/yr)							
		AVOIDED	RENEWABLE	DIFFERENCE	AVOIDED	RENEWABLE	CO2 EQ	CO2	CO2 EQ	CARBON	CO2	CO	CH4	NOX	SO2	PM
INCREMENTAL 1990 - 2000																
Hydropower - Storage	9,936	4.9	4.8	-0.1	489	477	-1	-1	11,461	2,673	9,801	1.44	0.09	41.3	61.6	2.50
Hydropower - RoR & Div.	16,884	3.9	4.9	1.0	666	831	9	11	18,034	4,217	15,463	2.49	0.13	64.0	101.5	3.73
Biomass Electric - Wood	150,529	4.9	7.8	2.8	7,448	11,714	28	31	160,393	37,704	138,247	-229.82	1.19	320.3	1,052.8	-17.07
Biomass Electric - MSW	19,871	4.8	4.8	0.0	960	960	0	0	18,430	4,740	17,381	-6.13	0.15	26.5	121.1	-204.57
Biomass Electric - Gas	6,671	4.7	4.0	-0.7	313	264	-1	-9	41,447	1,459	5,351	-19.14	1,776.37	-26.7	30.9	1.10
Geothermal Electric	31,877	4.6	4.1	-0.5	1,483	1,321	-7	-9	22,215	5,150	18,885	5.20	0.09	82.8	23.3	1.96
Windpower	24,344	2.9	4.3	1.5	704	1,058	13	15	27,480	6,411	23,505	3.56	0.20	99.0	104.9	5.88
Solar Thermal - Hybrid	21,342	7.0	10.3	3.3	1,503	2,206	37	44	18,958	4,403	16,145	3.15	0.12	70.0	31.7	3.18
Solar Thermal	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Photovoltaic	8,753	4.2	11.5	7.3	368	1,007	72	84	8,906	2,084	7,640	1.32	0.06	31.5	42.0	1.74
ALL RENEWABLES	290,206	4.8	6.8	2.0	13,934	19,839	19	23	317,325	68,841	252,417	-238.92	1,778.41	707.1	1,569.7	-201.66
INCREMENTAL 2000 - 2010																
Hydropower - Storage	4,177	5.8	5.5	-0.3	244	231	-3	-3	4,663	1,067	3,985	0.61	0.03	16.9	23.8	0.96
Hydropower - RoR & Div.	14,512	4.9	5.1	0.2	715	744	2	2	15,304	3,578	13,119	2.15	0.11	54.4	84.8	3.12
Biomass Electric - Wood	193,936	5.7	6.4	0.7	10,993	12,444	7	8	201,481	49,713	182,280	-250.44	1.53	498.0	1,462.6	-11.82
Biomass Electric - MSW	17,200	6.3	6.3	0.0	1,076	1,076	0	0	15,599	4,019	14,738	-7.02	0.12	22.0	99.3	-177.31
Biomass Electric - Gas	4,877	6.6	3.7	-2.9	320	179	-5	-37	30,223	1,048	3,844	-13.99	1,298.66	-21.3	21.5	0.77
Geothermal Electric	102,057	6.9	4.0	-2.9	7,089	4,121	-35	-42	83,659	19,453	71,329	16.16	0.48	306.8	202.0	11.56
Windpower	115,331	3.5	3.6	0.1	4,066	4,159	1	1	130,105	30,356	111,305	16.90	0.97	468.2	498.0	27.80
Solar Thermal - Hybrid	11,054	8.9	8.5	-0.4	982	941	-4	-5	9,544	2,216	8,124	1.64	0.06	36.3	15.3	1.53
Solar Thermal	81,927	6.5	6.0	-0.5	5,356	4,946	-6	-7	67,009	15,471	56,726	13.34	0.33	255.9	95.5	8.30
Photovoltaic	186,287	5.3	6.4	1.0	9,951	11,896	10	12	185,506	43,384	159,073	28.31	1.30	658.0	849.7	35.32
ALL RENEWABLES	731,367	5.6	5.6	0.0	40,791	40,738	0	0	743,092	170,325	624,524	-192.31	1,303.57	2294.3	3,352.4	-99.77
INCREMENTAL 1990 - 2010																
Hydropower - Storage	14,113	5.2	5.0	-0.2	733	708	-2	-2	16,124	3,760	13,786	2.05	0.12	58.2	85.4	3.46
Hydropower - RoR & Div.	31,395	4.4	5.0	0.6	1,381	1,576	6	7	33,338	7,795	28,582	4.65	0.25	118.4	186.3	6.84
Biomass Electric - Wood	344,464	5.4	7.0	1.7	18,441	24,157	16	18	361,874	87,416	320,527	-480.26	2.73	818.2	2,515.4	-28.90
Biomass Electric - MSW	37,071	5.5	5.5	0.0	2,036	2,036	0	0	34,029	8,760	32,119	-15.15	0.27	48.7	220.4	-381.96
Biomass Electric - Gas	11,547	5.5	3.8	-1.6	633	444	-3	-21	71,671	2,508	9,195	-33.12	3,075.03	-50.0	52.4	1.87
Geothermal Electric	133,935	6.4	4.1	-2.3	8,571	5,443	-30	-36	105,874	24,604	90,213	21.36	0.56	389.6	225.2	13.52
Windpower	139,675	3.4	3.7	0.3	4,770	5,217	3	3	157,585	36,766	134,810	20.46	1.17	567.2	602.9	33.68
Solar Thermal - Hybrid	32,396	7.7	9.7	2.0	2,485	3,147	23	27	28,501	6,619	24,269	4.79	0.17	105.4	46.9	4.71
Solar Thermal	81,927	6.5	6.0	-0.5	5,356	4,946	-6	-7	67,009	15,471	56,726	13.34	0.33	255.9	95.5	8.30
Photovoltaic	195,040	5.3	6.6	1.3	10,319	12,903	13	15	194,412	45,467	166,713	29.64	1.36	689.5	891.7	37.06
ALL RENEWABLES	1,021,563	5.4	5.9	0.6	54,726	60,577	6	7	1,060,417	239,165	876,940	-432.23	3,081.97	3001.3	4,922.1	-301.42

TABLE B - 2a

RENEWABLE EMISSIONS MODEL RESULTS

EPA BASE CASE

ALL RENEWABLES - BY REGION

REGION	INCREMENTAL GENERATION (GWh/yr)	UNIT COST (cents/kWh)			TOTAL ANNUAL COST ($ millions)		UNIT COST OF EMISSIONS AVOIDED ($/MT)		POLLUTION PREVENTED (million kg/yr)							
		AVOIDED	RENEWABLE	DIFFERENCE	AVOIDED	RENEWABLE	CO2 EQ	CO2	CO2 EQ	CARBON	CO2	CO	CH4	NOX	SO2	PM
INCREMENTAL 1990 - 2000																
New England	6,908	5.9	6.8	1.0	407	473	11	14	5,962	1,314	4,817	-7.88	49.67	3.6	29.4	-8.41
Mid Atlantic	3,793	4.3	5.7	1.4	183	217	6	14	8,892	1,043	3,824	-3.90	233.05	4.6	32.8	-14.00
South Atlantic	7,503	4.5	7.1	2.6	341	536	23	25	8,502	2,095	7,683	-9.68	0.92	20.7	62.1	-6.72
Florida	4,847	5.2	8.6	3.3	254	416	45	46	3,606	962	3,491	-6.45	3.23	1.6	20.1	-6.77
East North Central	4,814	4.6	7.1	2.5	223	342	15	24	7,786	1,344	4,930	-5.61	116.74	10.5	57.7	-12.17
West North Central	4,329	3.6	6.0	2.4	155	258	20	23	5,181	1,207	4,427	-1.19	5.42	16.1	37.2	-3.78
East South Central	7,599	4.9	8.4	3.5	376	639	30	34	8,733	2,122	7,781	-10.20	6.87	21.0	72.9	-3.88
West South Central	9,525	6.3	10.0	3.7	600	953	47	59	7,459	1,641	6,015	-2.79	27.03	22.1	9.5	-6.83
Mountain	7,739	4.3	7.3	3.0	332	565	25	30	9,449	2,136	7,839	-0.10	17.00	31.3	15.6	0.18
Arizona/New Mexico	3,262	6.6	9.8	3.1	217	318	26	31	3,917	890	3,262	-0.30	7.04	12.7	9.1	-0.09
California	16,310	4.7	6.2	1.5	760	1,012	12	29	20,696	2,357	8,641	-11.02	550.55	13.1	1.8	-10.22
Washington/Oregon	6,122	4.8	6.1	1.3	294	371	10	12	7,826	1,790	6,565	-6.81	21.96	20.5	41.4	-1.41
TOTAL	82,740	5.0	7.4	2.4	4,121	6,099	20	29	98,027	18,893	69,275	-64.94	1038.47	177.9	389.6	-73.10
INCREMENTAL 2000 - 2010																
New England	10,229	8.0	6.3	-1.7	818	640	-20	-22	8,813	1,945	7,130	-7.41	82.10	10.0	44.5	-9.80
Mid Atlantic	6,154	5.6	6.8	1.2	344	420	6	13	12,439	1,641	6,017	-5.17	291.32	8.0	49.6	-31.96
South Atlantic	10,006	5.4	6.7	1.4	539	675	12	14	11,067	2,711	9,941	-9.64	1.15	28.3	78.1	-17.41
Florida	6,612	7.2	8.3	1.1	476	547	14	16	4,985	1,298	4,751	-6.30	4.04	4.2	27.6	-11.77
East North Central	7,714	5.1	6.7	1.6	396	519	11	16	11,387	2,091	7,666	-6.53	148.93	16.9	86.9	-32.70
West North Central	15,407	3.8	4.9	1.1	582	750	9	11	17,875	4,170	15,291	0.13	6.86	61.0	125.7	-7.16
East South Central	9,667	5.4	7.7	2.3	520	744	21	23	10,862	2,619	9,604	-9.97	8.59	27.7	87.5	-9.89
West South Central	22,228	6.7	6.8	0.1	1,481	1,506	1	2	17,288	3,891	14,267	-1.24	33.81	57.9	22.2	-16.82
Mountain	25,868	3.6	4.8	1.2	922	1,238	10	12	30,376	6,997	25,657	2.42	21.39	106.6	49.9	2.16
Arizona/New Mexico	6,915	5.3	5.9	0.6	366	409	5	6	8,139	1,868	6,650	0.15	6.83	27.6	18.3	-1.16
California	31,406	7.6	5.5	-2.1	2,382	1,731	-20	-39	32,752	4,559	16,716	-10.96	668.21	40.4	4.2	-30.49
Washington/Oregon	9,654	4.8	5.4	0.6	464	521	5	6	12,344	2,823	10,351	-5.40	27.46	35.8	65.9	-3.62
TOTAL	161,858	5.7	6.0	0.3	9,292	9,700	2	3	178,327	36,611	134,241	-59.96	1299.69	424.3	660.3	-170.66
INCREMENTAL 1990 - 2010																
New England	17,137	7.1	6.5	-0.7	1,225	1,113	-8	-9	14,795	3,258	11,947	-15.29	111.77	13.7	73.9	-18.21
Mid Atlantic	9,947	5.1	6.4	1.3	507	637	6	13	21,330	2,684	9,840	-9.07	524.38	12.6	82.4	-45.96
South Atlantic	17,508	5.0	6.9	1.9	880	1,211	17	19	19,568	4,807	17,624	-19.32	2.07	49.0	140.1	-24.13
Florida	11,459	6.4	8.4	2.0	731	963	27	28	8,590	2,248	8,242	-12.75	7.26	5.8	47.7	-18.54
East North Central	12,528	4.9	6.9	1.9	619	861	13	19	19,172	3,435	12,595	-12.13	262.67	27.4	144.6	-44.88
West North Central	19,735	3.7	5.1	1.4	737	1,007	12	14	23,056	5,378	19,718	-1.06	12.27	77.1	162.9	-10.92
East South Central	17,265	5.2	8.0	2.8	896	1,383	25	28	19,595	4,741	17,385	-20.17	15.46	48.6	160.4	-13.78
West South Central	31,753	6.6	7.7	1.2	2,080	2,459	15	19	24,748	5,532	20,282	-4.03	60.84	80.0	31.7	-22.66
Mountain	33,606	3.7	5.4	1.6	1,255	1,803	14	16	39,824	9,135	33,496	2.31	38.39	137.9	66.5	2.33
Arizona/New Mexico	10,177	5.7	7.1	1.4	583	728	12	14	12,056	2,758	10,112	-0.16	15.87	40.3	27.4	-1.28
California	47,716	6.6	5.7	-0.8	3,142	2,743	-7	-16	53,448	6,916	25,357	-22.01	1236.77	53.6	6.1	-40.72
Washington/Oregon	15,776	4.8	5.7	0.9	758	892	7	8	20,172	4,613	16,916	-11.21	49.42	56.3	107.2	-5.03
TOTAL	244,607	5.5	6.5	1.0	13,413	15,800	9	12	276,354	55,504	203,516	-124.90	2338.15	602.3	1049.9	-243.75

TABLE B – 2b

RENEWABLE EMISSIONS MODEL RESULTS
EPA ENHANCED MARKET SCENARIO
ALL RENEWABLES – BY REGION

REGION	INCREMENTAL GENERATION (GWh/yr)	UNIT COST (cents/kWh)			TOTAL ANNUAL COST ($ millions)		UNIT COST OF EMISSIONS AVOIDED ($/MT)		POLLUTION PREVENTED (million kg/yr)							
		AVOIDED	RENEWABLE	DIFFERENCE	AVOIDED	RENEWABLE	CO2 EQ	CO2	CO2 EQ	CARBON	CO2	CO	CH4	NOX	SO2	PM
INCREMENTAL 1990 – 2000																
New England	14,485	5.9	6.9	1.1	850	1,004	13	15	11,587	2,754	10,098	-16.14	54.67	9.8	61.8	-11.99
Mid Atlantic	12,888	4.3	6.2	1.9	554	798	11	19	22,950	3,542	12,988	-12.66	428.81	24.9	111.1	-35.12
South Atlantic	23,133	4.5	7.0	2.5	1,042	1,627	22	25	26,634	6,459	23,685	-28.58	20.95	64.9	191.8	-19.90
Florida	11,248	5.2	8.4	.3.2	588	943	42	44	8,448	2,208	8,097	-14.53	10.29	4.5	48.7	-14.01
East North Central	27,889	4.7	7.3	2.6	1,314	2,045	21	26	34,745	7,789	28,561	-36.74	191.75	72.4	334.1	-37.43
West North Central	36,001	4.3	6.8	2.5	1,557	2,459	21	24	42,159	10,051	36,852	-37.67	47.55	110.5	306.1	-10.66
East South Central	26,720	4.9	7.9	3.0	1,315	2,104	26	29	30,502	7,462	27,359	-35.23	12.16	74.8	256.4	-11.88
West South Central	28,906	5.6	8.3	2.6	1,630	2,390	36	40	21,407	5,130	18,811	-23.41	21.92	56.2	28.1	-22.81
Mountain	24,367	4.0	6.2	2.1	981	1,501	17	21	30,613	6,750	24,751	0.28	90.48	99.0	49.5	1.45
Arizona/New Mexico	8,680	6.3	8.2	1.9	546	710	14	19	11,465	2,376	8,712	-1.07	70.03	32.7	24.3	-1.09
California	53,258	4.7	5.6	.0.9	2,480	2,975	11	18	46,947	7,700	28,233	-17.02	741.28	79.9	7.3	-35.13
Washington/Oregon	22,848	4.8	5.7	0.9	1,078	1,282	7	8	30,119	6,682	24,502	-18.15	118.50	79.8	155.2	-3.03
TOTAL	290,206	4.8	6.8	2.0	13,934	19,839	19	23	317,326	66,841	282,417	-239.92	1778.41	707.1	1569.7	-201.66
INCREMENTAL 2000 – 2010																
New England	17,885	7.4	8.0	-1.4	1,324	1,071	-17	-20	14,537	3,383	12,402	0.04	40.02	32.4	80.1	-7.37
Mid Atlantic	27,983	5.4	6.9	1.8	1,509	1,924	11	15	37,082	7,422	27,214	-13.11	313.66	83.0	227.4	-27.57
South Atlantic	39,244	5.1	6.3	1.2	2,005	2,478	11	12	44,468	10,611	38,906	-23.70	15.61	132.7	309.4	-13.01
Florida	19,565	6.3	6.9	0.8	1,237	1,342	7	8	15,337	3,788	13,889	-1.91	7.61	32.3	83.3	-8.96
East North Central	59,489	5.1	6.5	1.4	3,019	3,855	12	14	68,707	16,113	59,080	-52.81	116.58	182.4	676.0	-29.19
West North Central	115,997	4.6	5.5	0.9	5,316	6,322	8	9	131,837	31,410	115,170	-67.31	35.53	403.1	936.2	2.26
East South Central	41,085	5.2	6.6	1.4	2,121	2,706	13	14	46,334	11,110	40,739	-28.02	9.07	137.2	373.8	-6.12
West South Central	118,090	6.7	6.1	-0.6	7,952	7,218	-8	-10	88,195	20,634	75,658	-22.39	18.33	306.5	117.3	-16.46
Mountain	109,823	3.9	4.4	0.5	4,290	4,848	4	5	128,540	29,658	108,748	14.96	66.94	458.5	213.0	23.60
Arizona/New Mexico	44,666	5.4	5.0	-0.4	2,398	2,240	-3	-4	52,597	12,030	44,110	5.72	51.53	164.7	119.8	8.53
California	109,153	7.6	4.8	-2.8	8,307	5,206	-39	-53	78,704	15,846	58,099	7.61	542.07	229.9	21.7	-25.99
Washington/Oregon	28,163	4.6	5.4	0.8	1,303	1,528	6	7	36,464	8,257	30,276	-11.61	96.74	110.5	193.9	0.44
TOTAL	731,357	5.6	5.6	0.0	40,791	40,736	0	0	743,092	170,326	624,524	-192.31	1303.57	2294.3	3362.4	-99.77
INCREMENTAL 1990 – 2010																
New England	32,370	6.7	6.4	-0.3	2,174	2,053	-4	-4	26,124	6,136	22,498	-16.10	94.69	42.1	141.8	-19.36
Mid Atlantic	40,871	5.0	6.7	1.6	2,062	2,722	11	16	60,031	10,964	40,202	-25.76	742.46	107.9	338.5	-62.69
South Atlantic	62,378	4.9	6.6	1.7	3,047	4,105	15	17	71,102	17,070	62,591	-52.28	36.46	197.6	501.1	-32.91
Florida	30,814	5.9	7.4	1.5	1,825	2,284	19	21	23,786	5,996	21,987	-16.44	17.90	36.8	130.0	-22.96
East North Central	87,378	5.0	6.8	1.8	4,333	5,900	15	18	103,452	23,902	87,641	-88.55	280.33	254.7	1009.1	-66.62
West North Central	151,998	4.5	5.8	1.3	6,874	8,781	11	13	173,996	41,460	152,022	-104.98	83.08	513.6	1241.3	-8.40
East South Central	67,805	5.1	7.1	2.0	3,436	4,810	18	20	76,836	18,572	68,098	-63.25	21.23	212.0	630.3	-18.00
West South Central	146,996	6.5	6.5	0.0	9,582	9,606	0	0	109,602	25,765	94,469	-45.80	38.24	361.7	145.4	-39.27
Mountain	134,190	3.9	4.7	0.8	5,271	6,349	7	8	159,153	36,409	133,499	15.23	157.42	557.6	262.5	25.05
Arizona/New Mexico	53,346	5.5	5.5	0.0	2,943	2,950	0	0	64,062	14,406	52,821	4.65	121.56	217.4	144.1	7.44
California	162,411	6.6	5.0	-1.6	10,787	8,181	-21	-30	125,650	23,546	86,332	-9.21	1283.35	309.9	29.0	-61.12
Washington/Oregon	51,006	4.7	5.5	0.8	2,393	2,810	6	8	66,603	14,939	54,778	-29.76	205.24	190.1	349.1	-2.59
TOTAL	1,021,563	5.4	5.9	0.6	54,728	60,577	6	7	1,060,417	239,165	878,940	-432.23	3081.87	3001.3	4922.1	-301.42

TABLE B – 3a

RENEWABLE EMISSIONS MODEL RESULTS

EPA BASE CASE

BIOMASS ELECTRIC – WOOD, WOOD WASTE, & AGRICULTURAL WASTE

REGION	INCREMENTAL GENERATION (GWh/yr)	UNIT COST (cents/kWh)			TOTAL ANNUAL COST ($ millions)		UNIT COST OF EMISSIONS AVOIDED ($/MT)		POLLUTION PREVENTED (million kg/yr)							
		AVOIDED	RENEWABLE	DIFFERENCE	AVOIDED	RENEWABLE	CO2 EQ	CO2	CO2 EQ	CARBON	CO2	CO	CH4	NOX	SO2	PM
INCREMENTAL 1990 – 2000																
New England	4,751	6.1	7.1	1.1	288	340	15	16	3,360	904	3,314	-7.23	0.03	2.2	20.0	-0.91
Mid Atlantic	603	4.4	8.6	4.2	27	52	38	41	665	166	609	-0.92	0.01	1.5	5.2	-0.04
South Atlantic	8,209	4.6	7.1	2.5	288	444	22	25	6,995	1,734	6,360	-9.60	0.06	16.6	61.3	-0.42
Florida	4,069	5.3	8.6	3.4	214	361	48	47	2,974	800	2,933	-6.20	0.03	1.5	16.9	-0.70
East North Central	2,570	4.8	8.6	3.8	124	222	34	37	2,896	718	2,633	-3.93	0.02	6.9	30.6	-0.17
West North Central	896	4.8	8.6	3.9	43	77	34	38	1,012	251	920	-1.38	0.01	2.4	7.5	-0.06
East South Central	6,581	5.0	8.6	3.6	331	568	32	35	7,414	1,838	6,741	-10.07	0.06	17.6	63.1	-0.44
West South Central	2,212	5.1	8.6	3.5	113	191	49	53	1,602	406	1,466	-3.34	0.01	3.1	2.1	-0.54
Mountain	545	4.8	8.6	3.8	26	47	34	37	614	152	558	-0.83	0.00	1.5	0.9	-0.04
Arizona/New Mexico	375	5.0	8.6	3.6	19	32	32	35	423	105	384	-0.57	0.00	1.0	0.9	-0.03
California	4,167	4.6	8.6	4.0	192	359	73	76	2,309	604	2,216	-6.29	0.01	2.8	-0.4	-1.26
Washington/Oregon	3,763	5.0	7.1	2.2	187	269	19	20	4,431	1,096	4,018	-5.79	0.04	10.7	24.9	-0.15
TOTAL	36,742	5.0	8.0	3.0	1,851	2,962	32	34	34,715	8,774	32,171	-68.06	0.28	67.7	223.2	-4.76
INCREMENTAL 2000 – 2010																
New England	5,171	8.4	6.2	-2.2	434	322	-30	-31	3,718	984	3,606	-6.96	0.04	3.3	21.9	-0.81
Mid Atlantic	656	5.8	7.6	1.8	38	50	16	18	707	175	643	-0.89	0.01	1.6	5.3	-0.03
South Atlantic	6,757	5.5	6.2	0.7	375	421	6	7	7,433	1,833	6,720	-9.15	0.06	18.5	52.8	-0.32
Florida	4,428	7.4	7.6	0.1	329	334	2	2	3,270	870	3,192	-5.97	0.03	2.4	18.6	-0.61
East North Central	2,797	5.3	7.6	2.3	148	211	20	23	3,077	759	2,782	-3.79	0.02	7.6	31.6	-0.13
West North Central	978	5.3	7.6	2.2	52	74	20	22	1,076	265	972	-1.32	0.01	2.7	7.8	-0.05
East South Central	7,163	5.5	7.6	2.0	396	541	18	20	7,879	1,943	7,123	-9.70	0.06	19.6	64.8	-0.34
West South Central	2,407	6.9	7.6	0.7	165	182	10	10	1,761	441	1,617	-3.21	0.01	3.8	2.4	-0.51
Mountain	593	5.3	7.6	2.3	31	45	21	23	652	161	590	-0.80	0.01	1.6	1.0	-0.03
Arizona/New Mexico	408	5.6	7.6	2.0	23	31	18	20	449	111	406	-0.55	0.00	1.1	1.0	-0.02
California	4,535	7.8	7.6	-0.2	352	343	-4	-4	2,648	658	2,412	-6.05	0.01	3.8	-0.3	-1.21
Washington/Oregon	4,095	5.0	6.2	1.2	206	255	10	11	4,853	1,193	4,373	-5.58	0.04	12.4	27.2	-0.02
TOTAL	39,988	6.4	7.0	0.6	2,549	2,809	7	8	37,422	9,392	34,437	-63.96	0.30	78.5	234.1	-4.07
INCREMENTAL 1990 – 2010																
New England	9,922	7.3	6.7	-0.6	722	662	-9	-9	7,098	1,887	6,920	-14.19	0.07	5.5	41.9	-1.71
Mid Atlantic	1,259	5.1	8.1	2.9	65	102	27	29	1,372	342	1,252	-1.81	0.01	3.1	10.5	-0.07
South Atlantic	12,966	5.1	6.7	1.6	663	865	14	15	14,428	3,567	13,080	-18.65	0.12	36.0	104.1	-0.73
Florida	8,497	6.4	8.1	1.7	543	685	23	23	6,245	1,670	6,124	-12.18	0.07	3.9	35.5	-1.31
East North Central	5,367	5.1	8.1	3.0	272	433	27	30	5,972	1,477	5,414	-7.72	0.05	14.5	62.4	-0.30
West North Central	1,876	5.0	8.1	3.0	95	151	27	30	2,088	516	1,893	-2.70	0.02	5.1	15.3	-0.11
East South Central	13,744	5.3	8.1	2.8	727	1,109	25	28	15,293	3,781	13,864	-19.77	0.12	37.1	127.9	-0.78
West South Central	4,618	6.0	8.1	2.1	278	373	28	31	3,363	846	3,103	-6.56	0.02	7.0	4.5	-1.05
Mountain	1,138	5.0	8.1	3.0	57	92	27	30	1,266	313	1,148	-1.64	0.01	3.1	1.9	-0.06
Arizona/New Mexico	784	5.3	8.1	2.8	42	63	25	27	872	216	790	-1.13	0.01	2.1	1.9	-0.04
California	8,702	6.2	8.1	1.8	544	702	33	34	4,857	1,262	4,628	-12.33	0.02	6.6	-0.7	-2.47
Washington/Oregon	7,858	5.0	6.7	1.7	393	524	14	16	9,284	2,288	8,391	-11.36	0.08	23.1	52.1	-0.18
TOTAL	76,731	5.7	7.5	1.8	4,400	5,761	19	20	72,136	18,166	66,608	-116.04	0.58	146.2	457.4	-8.82

TABLE B - 3b

RENEWABLE EMISSIONS MODEL RESULTS

EPA ENHANCED MARKET SCENARIO

BIOMASS ELECTRIC - WOOD, WOOD WASTE, & AGRICULTURAL WASTE

REGION	INCREMENTAL GENERATION (GWh/yr)	UNIT COST (cents/kWh)			TOTAL ANNUAL COST ($ millions)		UNIT COST OF EMISSIONS AVOIDED ($/MT)		POLLUTION PREVENTED (million kg/yr)							
		AVOIDED	RENEWABLE	DIFFERENCE	AVOIDED	RENEWABLE	CO2 EQ	CO2	CO2 EQ	CARBON	CO2	CO	CH4	NOX	SO2	PM
INCREMENTAL 1990 - 2000																
New England	10,252	6.1	7.2	1.1	620	737	16	16	7,294	1,960	7,161	-15.60	0.07	4.7	43.1	-1.96
Mid Atlantic	4,575	4.4	8.1	3.7	203	371	33	36	5,047	1,260	4,620	-7.01	0.04	11.2	39.3	-0.31
South Atlantic	18,266	4.8	7.2	2.5	847	1,309	22	25	20,579	5,103	18,710	-27.96	0.17	48.7	151.0	-1.22
Florida	9,211	5.3	8.5	3.3	485	785	44	45	6,734	1,811	6,639	-14.04	0.07	3.4	38.4	-1.59
East North Central	21,447	4.8	8.0	3.1	1,034	1,709	28	31	24,163	5,991	21,969	-32.83	0.20	57.2	256.9	-1.44
West North Central	24,889	4.8	7.7	3.0	1,184	1,926	26	29	28,040	6,953	25,494	-38.10	0.23	66.4	209.0	-1.67
East South Central	22,891	5.0	8.2	3.2	1,152	1,877	28	31	25,790	6,395	23,447	-35.04	0.21	61.1	219.3	-1.53
West South Central	16,007	5.1	7.6	2.5	815	1,218	35	37	11,592	2,933	10,756	-24.18	0.06	22.7	15.3	-3.93
Mountain	1,138	4.8	8.6	3.8	55	98	34	37	1,282	318	1,166	-1.74	0.01	3.0	2.0	-0.08
Arizona/New Mexico	784	5.0	8.6	3.6	39	68	32	35	883	219	803	-1.20	0.01	2.1	2.0	-0.05
California	9,338	4.6	8.5	3.9	430	797	71	74	5,175	1,364	4,966	-14.09	0.02	6.3	-1.0	-2.82
Washington/Oregon	11,731	5.0	7.0	2.0	582	820	17	19	13,814	3,416	12,527	-18.04	0.11	33.5	77.6	-0.46
TOTAL	150,529	4.9	7.8	2.8	7,446	11,714	28	31	150,393	37,704	136,247	-229.82	1.19	320.3	1052.8	-17.07
INCREMENTAL 2000 - 2010																
New England	1,206	8.4	6.2	-2.2	101	74	-31	-32	872	230	843	-1.56	0.01	0.8	5.1	-0.17
Mid Atlantic	8,264	5.8	6.7	0.9	478	556	9	10	8,920	2,210	8,103	-10.70	0.07	21.2	67.1	-0.29
South Atlantic	19,677	5.5	6.1	0.5	1,092	1,197	5	5	21,695	5,337	19,569	-25.46	0.17	56.0	154.0	-0.69
Florida	2,910	7.4	7.0	-0.5	216	202	-6	-7	2,156	572	2,097	-3.75	0.02	1.6	12.3	-0.37
East North Central	40,568	5.3	6.8	1.3	2,151	2,673	12	13	44,729	11,003	40,345	-62.49	0.35	113.4	459.4	-1.41
West North Central	57,837	5.3	6.5	1.2	3,075	3,754	11	12	63,769	15,687	57,519	-74.84	0.50	161.6	459.9	-2.02
East South Central	23,193	5.5	6.6	1.1	1,282	1,532	10	11	25,572	6,291	23,065	-30.01	0.20	64.8	210.2	-0.81
West South Central	28,400	6.9	6.1	-0.7	1,947	1,746	-10	-11	20,854	5,205	19,083	-36.21	0.10	46.9	28.6	-5.64
Mountain	43	5.3	7.3	2.1	2	3	19	21	48	12	43	-0.06	0.00	0.1	0.1	-0.00
Arizona/New Mexico	30	5.8	7.3	1.8	2	2	16	18	33	8	30	-0.04	0.00	0.1	0.1	-0.00
California	1,907	7.8	7.1	-0.7	148	135	-12	-13	1,076	277	1,014	-2.43	0.00	1.7	-0.0	-0.49
Washington/Oregon	9,898	5.0	5.8	0.7	499	569	6	7	11,755	2,883	10,570	-12.89	0.10	30.6	65.9	0.06
TOTAL	193,936	5.7	6.4	0.7	10,993	12,444	7	8	201,481	49,718	182,280	-260.44	1.53	498.0	1462.8	-11.82
INCREMENTAL 1990 - 2010																
New England	11,460	6.3	7.1	0.8	722	811	11	11	8,166	2,180	7,993	-17.16	0.08	5.6	48.2	-2.13
Mid Atlantic	12,839	5.3	7.2	1.9	681	926	18	19	13,967	3,470	12,723	-17.71	0.12	32.4	106.4	-0.59
South Atlantic	37,943	5.1	6.6	1.5	1,939	2,506	13	15	42,274	10,440	38,279	-53.42	0.34	103.7	305.0	-1.91
Florida	12,121	5.8	8.1	2.4	702	988	32	33	8,890	2,383	8,736	-17.79	0.09	5.1	50.6	-1.96
East North Central	62,015	5.1	7.1	1.9	3,185	4,382	17	19	68,892	16,994	62,313	-95.32	0.55	170.6	716.3	-2.85
West North Central	82,726	5.1	6.9	1.7	4,260	5,680	15	17	91,810	22,640	83,013	-112.94	0.73	228.0	668.9	-3.68
East South Central	46,084	5.3	7.4	2.1	2,434	3,409	19	21	51,361	12,686	46,513	-65.05	0.41	125.9	429.5	-2.34
West South Central	44,407	6.2	6.7	0.5	2,763	2,963	6	7	32,447	8,138	29,839	-60.39	0.16	69.6	43.9	-9.57
Mountain	1,181	4.8	8.6	3.7	57	101	33	36	1,330	330	1,208	-1.80	0.01	3.2	2.0	-0.08
Arizona/New Mexico	813	5.0	8.6	3.5	41	70	31	34	916	227	832	-1.24	0.01	2.2	2.0	-0.05
California	11,245	5.1	8.3	3.1	578	932	57	59	6,252	1,631	5,980	-16.52	0.02	8.0	-1.1	-3.31
Washington/Oregon	21,629	5.0	6.4	1.4	1,081	1,389	12	13	25,569	6,299	23,097	-30.93	0.21	64.0	143.5	-0.42
TOTAL	344,464	5.4	7.0	1.7	18,441	24,157	16	18	351,874	87,418	320,527	-490.26	2.73	818.2	2515.4	-28.90

TABLE B - 4a

RENEWABLE EMISSIONS MODEL RESULTS

EPA BASE CASE

BIOMASS ELECTRIC - MUNICIPAL SOLID WASTE

REGION	INCREMENTAL GENERATION (GWh/yr)	UNIT COST (cents/kWh)			TOTAL ANNUAL COST ($ millions)		UNIT COST OF EMISSIONS AVOIDED ($/MT)		POLLUTION PREVENTED (million kg/yr)							
		AVOIDED	RENEWABLE	DIFFERENCE	AVOIDED	RENEWABLE	CO2 EQ	CO2	CO2 EQ	CARBON	CO2	CO	CH4	NOX	SO2	PM
INCREMENTAL 1990 - 2000																
New England	744	6.1	6.1	0.0	45	45	0	0	514	141	519	-0.30	0.01	-0.1	3.0	-7.70
Mid Atlantic	1,410	4.4	4.4	0.0	63	63	0	0	1,527	366	1,424	-0.59	0.01	2.6	11.8	-14.43
South Atlantic	634	4.6	4.6	0.0	29	29	0	0	701	177	649	-0.26	0.01	1.3	5.1	-6.49
Florida	589	5.3	5.3	0.0	31	31	0	0	419	116	425	-0.24	0.00	-0.1	2.3	-6.09
East North Central	1,200	4.8	4.8	0.0	58	58	0	0	1,326	336	1,229	-0.50	0.01	2.5	14.1	-12.28
West North Central	440	4.8	4.8	0.0	21	21	0	0	487	123	451	-0.18	0.00	0.9	3.6	-4.50
East South Central	354	5.0	5.0	0.0	18	18	0	0	391	99	362	-0.15	0.00	0.7	3.3	-3.62
West South Central	554	5.1	5.1	0.0	28	28	0	0	390	102	372	-0.22	0.00	0.6	0.4	-6.77
Mountain	162	4.8	4.8	0.0	8	8	0	0	180	45	166	-0.07	0.00	0.3	0.2	-1.66
Arizona/New Mexico	80	5.0	5.0	0.0	4	4	0	0	86	22	82	-0.03	0.00	0.2	0.2	-0.82
California	891	4.6	4.6	0.0	41	41	0	0	476	129	474	-0.35	0.00	0.1	-0.3	-9.33
Washington/Oregon	187	5.0	5.0	0.0	9	9	0	0	216	54	199	-0.08	0.00	0.4	1.2	-1.90
TOTAL	7,246	4.9	4.9	0.0	365	365	0	0	6,717	1,738	6,363	-2.97	0.05	9.3	45.1	-74.59
INCREMENTAL 2000 - 2010																
New England	926	8.4	8.4	0.0	78	78	0	0	640	176	646	-0.38	0.01	-0.1	3.7	-9.59
Mid Atlantic	3,172	5.8	5.8	0.0	184	184	0	0	3,327	848	3,110	-1.31	0.03	5.5	26.0	-32.50
South Atlantic	1,705	5.6	5.6	0.0	95	95	0	0	1,828	463	1,696	-0.71	0.01	3.4	12.9	-17.48
Florida	1,096	7.4	7.4	0.0	81	81	0	0	779	216	790	-0.45	0.01	-0.2	4.4	-11.33
East North Central	3,220	5.3	5.3	0.0	171	171	0	0	3,452	873	3,202	-1.33	0.03	6.3	36.7	-33.00
West North Central	1,024	5.3	5.3	0.0	54	54	0	0	1,096	276	1,018	-0.42	0.01	2.0	7.9	-10.49
East South Central	970	5.6	5.6	0.0	54	54	0	0	1,040	263	965	-0.40	0.01	1.9	8.6	-9.94
West South Central	1,690	6.9	6.9	0.0	116	116	0	0	1,169	310	1,135	-0.67	0.01	1.4	1.3	-17.59
Mountain	400	5.3	5.3	0.0	21	21	0	0	426	108	397	-0.17	0.00	0.8	0.6	-4.09
Arizona/New Mexico	267	5.6	5.6	0.0	15	15	0	0	286	72	265	-0.11	0.00	0.5	0.6	-2.73
California	2,871	7.8	7.8	0.0	223	223	0	0	1,533	416	1,527	-1.13	0.01	0.2	-0.9	-30.06
Washington/Oregon	499	5.0	5.0	0.0	25	25	0	0	576	145	533	-0.21	0.00	1.1	3.2	-6.10
TOTAL	17,841	6.3	6.3	0.0	1,116	1,116	0	0	16,180	4,169	15,298	-7.28	0.13	22.8	102.9	-183.82
INCREMENTAL 1990 - 2010																
New England	1,670	7.4	7.4	0.0	123	123	0	0	1,154	318	1,165	-0.66	0.01	-0.2	6.7	-17.30
Mid Atlantic	4,582	5.4	5.4	0.0	248	248	0	0	4,854	1,237	4,534	-1.90	0.04	8.1	38.8	-46.93
South Atlantic	2,339	5.3	5.3	0.0	124	124	0	0	2,530	640	2,345	-0.97	0.02	4.7	18.1	-23.96
Florida	1,686	6.7	6.7	0.0	113	113	0	0	1,198	331	1,215	-0.69	0.01	-0.4	6.7	-17.43
East North Central	4,420	5.2	5.2	0.0	229	229	0	0	4,780	1,209	4,432	-1.83	0.04	8.8	49.8	-45.28
West North Central	1,464	5.1	5.1	0.0	75	75	0	0	1,585	401	1,469	-0.61	0.01	2.9	11.5	-15.00
East South Central	1,324	5.4	5.4	0.0	71	71	0	0	1,431	362	1,327	-0.55	0.01	2.6	11.9	-13.56
West South Central	2,244	6.4	6.4	0.0	144	144	0	0	1,560	411	1,508	-0.89	0.01	1.9	1.7	-23.36
Mountain	562	5.1	5.1	0.0	29	29	0	0	606	154	564	-0.23	0.00	1.1	0.8	-5.76
Arizona/New Mexico	347	5.4	5.4	0.0	19	19	0	0	374	95	347	-0.14	0.00	0.7	0.8	-3.55
California	3,762	7.0	7.0	0.0	264	264	0	0	2,009	546	2,001	-1.48	0.01	0.3	-1.1	-39.38
Washington/Oregon	686	5.0	5.0	0.0	34	34	0	0	794	200	732	-0.29	0.01	1.6	4.4	-7.00
TOTAL	25,086	5.9	5.9	0.0	1,471	1,471	0	0	22,897	5,902	21,659	-10.25	0.18	32.1	148.1	-258.51

TABLE B - 4b

RENEWABLE EMISSIONS MODEL RESULTS
EPA ENHANCED MARKET SCENARIO
BIOMASS ELECTRIC - MUNICIPAL SOLID WASTE

REGION	INCREMENTAL GENERATION (GWh/yr)	UNIT COST (cents/kWh)			TOTAL ANNUAL COST ($ millions)		UNIT COST OF EMISSIONS AVOIDED ($/MT)		POLLUTION PREVENTED (million kg/yr)							
		AVOIDED	RENEWABLE	DIFFERENCE	AVOIDED	RENEWABLE	CO2 EQ	CO2	CO2 EQ	CARBON	CO2	CO	CH4	NOX	SO2	PM
INCREMENTAL 1990 - 2000																
New England	1,013	6.1	6.1	0.0	61	61	0	0	700	193	707	-0.41	0.01	-0.1	4.1	-10.49
Mid Atlantic	3,527	4.4	4.4	0.0	156	156	0	0	3,819	971	3,562	-1.47	0.03	6.5	29.6	-36.09
South Atlantic	1,902	4.6	4.6	0.0	88	88	0	0	2,105	531	1,949	-0.79	0.02	4.0	15.4	-19.47
Florida	1,214	5.3	5.3	0.0	64	64	0	0	863	239	875	-0.50	0.01	-0.3	4.8	-12.56
East North Central	3,592	4.8	4.8	0.0	173	173	0	0	3,974	1,003	3,679	-1.49	0.03	7.5	42.3	-38.75
West North Central	1,139	4.8	4.8	0.0	54	54	0	0	1,260	318	1,167	-0.47	0.01	2.4	9.3	-11.66
East South Central	1,083	5.0	5.0	0.0	54	54	0	0	1,196	302	1,109	-0.45	0.01	2.2	10.2	-11.08
West South Central	1,889	5.1	5.1	0.0	96	96	0	0	1,329	346	1,269	-0.75	0.01	1.6	1.4	-19.66
Mountain	445	4.8	4.8	0.0	21	21	0	0	492	124	456	-0.18	0.00	0.9	0.7	-4.55
Arizona/New Mexico	299	5.0	5.0	0.0	15	15	0	0	330	83	306	-0.12	0.00	0.6	0.7	-3.06
California	3,212	4.6	4.6	0.0	148	148	0	0	1,715	466	1,708	-1.26	0.01	0.3	-1.0	-33.62
Washington/Oregon	567	5.0	5.0	0.0	28	28	0	0	644	162	596	-0.23	0.01	1.3	3.6	-5.66
TOTAL	19,871	4.8	4.8	0.0	960	960	0	0	18,430	4,740	17,381	-8.13	0.15	26.8	121.1	-204.67
INCREMENTAL 2000 - 2010																
New England	913	8.4	8.4	0.0	77	77	0	0	631	174	637	-0.37	0.01	-0.1	3.7	-9.45
Mid Atlantic	3,064	5.8	5.8	0.0	177	177	0	0	3,214	819	3,004	-1.27	0.03	6.3	24.2	-31.40
South Atlantic	1,641	5.5	5.5	0.0	91	91	0	0	1,759	445	1,632	-0.68	0.01	3.2	12.4	-16.82
Florida	1,066	7.4	7.4	0.0	79	79	0	0	757	209	767	-0.44	0.01	-0.2	4.2	-11.01
East North Central	3,099	5.3	5.3	0.0	164	164	0	0	3,322	840	3,082	-1.28	0.03	6.1	34.3	-31.75
West North Central	989	5.3	5.3	0.0	53	53	0	0	1,060	268	983	-0.41	0.01	1.9	7.6	-10.13
East South Central	933	5.5	5.5	-0.0	52	52	-0	-0	1,001	253	928	-0.39	0.01	1.8	8.2	-9.56
West South Central	1,622	6.9	6.9	0.0	111	111	0	0	1,142	297	1,090	-0.64	0.01	1.3	1.2	-16.89
Mountain	385	5.3	5.3	0.0	20	20	0	0	413	104	383	-0.16	0.00	0.8	0.5	-3.95
Arizona/New Mexico	256	5.6	5.6	0.0	14	14	0	0	274	69	254	-0.11	0.00	0.5	0.6	-2.62
California	2,753	7.8	7.8	0.0	214	214	0	0	1,470	399	1,464	-1.08	0.01	0.2	-0.8	-28.82
Washington/Oregon	481	5.0	5.0	0.0	24	24	0	0	556	140	513	-0.20	0.00	1.1	3.1	-4.90
TOTAL	17,200	6.3	6.3	0.0	1,076	1,076	0	0	15,599	4,019	14,738	-7.02	0.12	22.0	99.3	-177.31
INCREMENTAL 1990 - 2010																
New England	1,926	7.2	7.2	0.0	138	138	0	0	1,331	366	1,343	-0.78	0.01	-0.3	7.7	-19.95
Mid Atlantic	6,591	5.1	5.1	0.0	334	334	0	0	7,033	1,791	6,566	-2.74	0.06	11.9	53.8	-67.49
South Atlantic	3,544	5.1	5.1	0.0	179	179	0	0	3,864	977	3,581	-1.47	0.03	7.2	27.8	-36.28
Florida	2,278	6.3	6.3	0.0	143	143	0	0	1,619	448	1,642	-0.93	0.02	-0.5	9.0	-23.56
East North Central	6,690	5.0	5.0	0.0	337	337	0	0	7,296	1,844	6,761	-2.77	0.06	13.6	76.7	-69.51
West North Central	2,128	5.0	5.0	0.0	107	107	0	0	2,320	586	2,150	-0.88	0.02	4.3	17.0	-21.79
East South Central	2,016	5.3	5.3	0.0	106	106	0	0	2,196	556	2,037	-0.84	0.02	4.1	18.4	-20.64
West South Central	3,511	5.9	5.9	0.0	207	207	0	0	2,471	643	2,359	-1.39	0.01	2.9	2.7	-36.55
Mountain	830	5.0	5.0	0.0	42	42	0	0	905	229	839	-0.34	0.01	1.7	1.2	-8.50
Arizona/New Mexico	554	5.3	5.3	0.0	29	29	0	0	605	153	560	-0.23	0.00	1.1	1.2	-5.68
California	5,965	6.1	6.1	0.0	361	361	0	0	3,185	865	3,172	-2.34	0.01	0.5	-1.8	-62.44
Washington/Oregon	1,037	5.0	5.0	0.0	52	52	0	0	1,201	302	1,108	-0.44	0.01	2.3	6.7	-10.59
TOTAL	37,071	5.5	5.5	0.0	2,036	2,036	0	0	34,029	8,760	32,119	-15.15	0.27	48.7	220.4	-381.98

TABLE B - 5a

RENEWABLE EMISSIONS MODEL RESULTS

EPA BASE CASE

BIOMASS ELECTRIC - LANDFILL & DIGESTER GAS

REGION	INCREMENTAL GENERATION (GWh/yr)	UNIT COST (cents/kWh)			TOTAL ANNUAL COST ($ millions)		UNIT COST OF EMISSIONS AVOIDED ($/MT)		POLLUTION PREVENTED (million kg/yr)							
		AVOIDED	RENEWABLE	DIFFERENCE	AVOIDED	RENEWABLE	CO2 EQ	CO2	CO2 EQ	CARBON	CO2	CO	CH4	NOX	SO2	PM
INCREMENTAL 1990 - 2000																
New England	186	6.1	4.2	-1.8	11	8	-3	-26	1,129	36	130	-0.53	49.62	-1.0	0.8	0.03
Mid Atlantic	875	4.4	4.2	-0.2	39	37	-0	-2	5,646	241	884	-2.52	233.02	-3.1	7.8	0.23
South Atlantic	3	4.6	4.2	-0.4	0	0	-1	-4	21	1	3	-0.01	0.85	-0.0	0.0	0.00
Florida	12	5.3	4.2	-1.0	1	1	-2	-14	73	2	9	-0.03	3.19	-0.1	0.1	0.00
East North Central	438	4.8	4.2	-0.6	21	19	-1	-6	2,837	122	449	-1.28	116.70	-1.5	5.4	0.12
West North Central	20	4.8	4.2	-0.5	1	1	-1	-5	131	6	21	-0.06	5.38	-0.1	0.2	0.01
East South Central	26	5.0	4.2	-0.8	1	1	-1	-8	165	7	26	-0.07	6.80	-0.1	0.3	0.01
West South Central	101	5.1	4.2	-0.8	5	4	-1	-13	616	19	68	-0.29	27.00	-0.5	0.1	0.01
Mountain	64	4.8	4.2	-0.6	3	3	-1	-6	412	18	66	-0.18	16.93	-0.2	0.1	0.02
Arizona/New Mexico	26	5.0	4.2	-0.8	1	1	-1	-8	171	7	27	-0.08	7.01	-0.1	0.1	0.01
California	2,067	4.6	4.2	-0.4	96	88	-1	-7	12,202	300	1,099	-5.90	550.53	-11.0	0.5	0.07
Washington/Oregon	82	5.0	4.2	-0.7	4	3	-1	-7	536	24	88	-0.24	21.89	-0.3	0.6	0.02
TOTAL	3,901	4.7	4.2	-0.4	183	168	-1	-6	23,937	782	[illegible]	-11.18	1038.82	-17.9	16.0	0.62
INCREMENTAL 2000 - 2010																
New England	233	8.4	4.2	-4.2	20	10	-7	-60	1,411	44	162	-0.67	62.03	-1.3	1.1	0.03
Mid Atlantic	1,094	5.8	4.2	-1.6	63	46	-2	-16	7,019	292	1,072	-3.15	291.28	-4.0	9.2	0.28
South Atlantic	4	5.5	4.2	-1.3	0	0	-2	-13	26	1	4	-0.01	1.06	-0.0	0.0	0.00
Florida	16	7.4	4.2	-3.2	1	1	-5	-44	91	3	11	-0.04	3.99	-0.1	0.1	0.00
East North Central	548	5.3	4.2	-1.1	29	23	-2	-11	3,528	149	545	-1.58	145.87	-1.9	6.4	0.14
West North Central	25	5.3	4.2	-1.1	1	1	-2	-11	163	7	25	-0.07	6.72	-0.1	0.2	0.01
East South Central	32	5.5	4.2	-1.3	2	1	-2	-13	206	9	32	-0.09	8.50	-0.1	0.3	0.01
West South Central	127	6.9	4.2	-2.6	9	5	-4	-39	769	23	85	-0.36	33.74	-0.6	0.2	0.01
Mountain	79	5.3	4.2	-1.0	4	3	-2	-10	512	22	79	-0.23	21.16	-0.3	0.2	0.02
Arizona/New Mexico	33	5.6	4.2	-1.3	2	1	-2	-13	212	9	33	-0.09	8.77	-0.1	0.1	0.01
California	2,584	7.8	4.2	-3.5	200	110	-6	-66	15,252	375	1,374	-7.38	688.16	-13.8	0.6	0.08
Washington/Oregon	103	6.0	4.2	-0.8	5	4	-1	-7	671	30	110	-0.30	27.37	-0.3	0.7	0.03
TOTAL	4,877	6.9	4.2	-2.7	337	207	-4	-37	29,859	963	3,532	-13.87	1298.65	-22.6	18.9	0.62
INCREMENTAL 1990 - 2010																
New England	419	7.4	4.2	-3.1	31	18	-5	-45	2,540	80	292	-1.20	111.66	-2.3	1.9	0.06
Mid Atlantic	1,969	5.2	4.2	-0.9	102	84	-1	-9	12,664	533	1,956	-5.67	524.30	-7.1	17.0	0.51
South Atlantic	7	5.1	4.2	-0.9	0	0	-1	-9	46	2	7	-0.02	1.91	-0.0	0.1	0.00
Florida	27	6.5	4.2	-2.2	2	1	-4	-31	164	5	19	-0.08	7.17	-0.2	0.1	0.00
East North Central	986	5.1	4.2	-0.8	50	42	-1	-8	6,365	271	994	-2.84	262.57	-3.4	11.8	0.26
West North Central	45	5.1	4.2	-0.8	2	2	-1	-8	293	12	46	-0.13	12.10	-0.2	0.4	0.01
East South Central	57	5.3	4.2	-1.1	3	2	-2	-10	371	16	58	-0.17	15.30	-0.2	0.6	0.01
West South Central	228	6.1	4.2	-1.8	14	10	-3	-27	1,385	42	153	-0.65	60.74	-1.0	0.3	0.02
Mountain	143	5.1	4.2	-0.8	7	6	-1	-8	923	39	144	-0.41	38.09	-0.5	0.3	0.04
Arizona/New Mexico	59	5.3	4.2	-1.1	3	3	-2	-11	383	16	60	-0.17	15.78	-0.2	0.2	0.02
California	4,651	6.4	4.2	-2.1	296	198	-4	-40	27,454	675	2,474	-13.28	1238.68	-24.8	1.1	0.15
Washington/Oregon	185	5.0	4.2	-0.8	9	8	-1	-7	1,207	54	198	-0.53	49.26	-0.6	1.3	0.05
TOTAL	8,778	5.9	4.2	-1.7	520	373	-3	-23	53,796	1,746	6,401	-25.15	2337.57	-40.5	34.9	1.14

TABLE B - 5b

RENEWABLE EMISSIONS MODEL RESULTS
EPA ENHANCED MARKET SCENARIO
BIOMASS ELECTRIC – LANDFILL & DIGESTER GAS

REGION	INCREMENTAL GENERATION (GWh/yr)	UNIT COST (cents/kWh)			TOTAL ANNUAL COST ($ millions)		UNIT COST OF EMISSIONS AVOIDED ($/MT)		POLLUTION PREVENTED (million kg/yr)							
		AVOIDED	RENEWABLE	DIFFERENCE	AVOIDED	RENEWABLE	CO2 EQ	CO2	CO2 EQ	CARBON	CO2	CO	CH4	NOX	SO2	PM
INCREMENTAL 1990 – 2000																
New England	205	6.1	4.0	-2.1	12	8	-3	-30	1,242	39	143	-0.59	54.57	-1.1	0.9	0.03
Mid Atlantic	1,610	4.4	4.0	-0.5	71	64	-1	-5	10,385	443	1,626	-4.63	428.70	-5.7	14.4	0.43
South Atlantic	78	4.6	4.0	-0.7	4	3	-1	-7	504	22	80	-0.22	20.74	-0.3	0.7	0.02
Florida	38	5.3	4.0	-1.3	2	2	-2	-18	233	8	28	-0.11	10.21	-0.2	0.2	0.01
East North Central	606	4.8	4.0	-0.9	29	24	-1	-8	3,927	169	621	-1.75	161.60	-2.0	7.5	0.16
West North Central	177	4.8	4.0	-0.8	8	7	-1	-8	1,148	50	182	-0.51	47.22	-0.6	1.5	0.05
East South Central	45	5.0	4.0	-1.1	2	2	-2	-10	290	13	46	-0.13	11.92	-0.1	0.4	0.01
West South Central	82	5.1	4.0	-1.1	4	3	-2	-17	496	15	55	-0.23	21.82	-0.4	0.1	0.01
Mountain	339	4.8	4.0	-0.9	16	13	-1	-8	2,195	95	347	-0.98	90.27	-1.1	0.7	0.09
Arizona/New Mexico	263	5.0	4.0	-1.1	13	10	-2	-10	1,701	73	269	-0.76	69.95	-0.9	0.7	0.07
California	2,763	4.6	4.0	-0.6	128	110	-1	-12	18,426	404	1,480	-7.95	741.19	-14.8	0.6	0.09
Washington/Oregon	444	5.0	4.0	-1.0	22	18	-2	-9	2,896	129	474	-1.28	118.28	-1.4	3.1	0.13
TOTAL	6,671	4.7	4.0	-0.7	313	264	-1	-9	41,447	1,459	5,351	-19.14	1778.37	-28.7	30.9	1.10
INCREMENTAL 2000 – 2010																
New England	150	8.4	3.7	-4.7	13	6	-8	-68	908	26	104	-0.43	39.89	-0.6	0.7	0.02
Mid Atlantic	1,177	5.8	3.7	-2.1	68	43	-3	-22	7,552	315	1,164	-3.39	313.41	-4.3	9.9	0.30
South Atlantic	57	5.5	3.7	-1.9	3	2	-3	-19	367	15	57	-0.16	15.17	-0.2	0.5	0.01
Florida	28	7.4	3.7	-3.8	2	1	-6	-52	170	6	20	-0.08	7.46	-0.2	0.1	0.00
East North Central	443	5.3	3.7	-1.6	24	16	-3	-16	2,855	120	441	-1.28	118.07	-1.5	5.1	0.11
West North Central	130	5.3	3.7	-1.6	7	5	-3	-16	835	35	129	-0.37	34.52	-0.4	1.1	0.03
East South Central	33	5.5	3.7	-1.8	2	1	-3	-19	211	9	33	-0.09	8.71	-0.1	0.3	0.01
West South Central	60	6.9	3.7	-3.2	4	2	-5	-47	364	11	40	-0.17	15.96	-0.3	0.1	0.01
Mountain	248	5.3	3.7	-1.6	13	9	-2	-16	1,596	67	246	-0.71	65.99	-0.9	0.5	0.06
Arizona/New Mexico	192	5.6	3.7	-1.9	11	7	-3	-19	1,237	52	191	-0.55	51.14	-0.7	0.5	0.05
California	2,035	7.8	3.7	-4.1	158	75	-7	-77	12,010	295	1,082	-5.81	541.86	-10.9	0.5	0.07
Washington/Oregon	325	5.0	3.7	-1.4	16	12	-2	-13	2,119	95	347	-0.94	86.47	-1.0	2.3	0.10
TOTAL	4,877	6.6	3.7	-2.9	320	179	-6	-37	30,223	1,049	3,844	-13.99	1298.66	-21.3	21.5	0.77
INCREMENTAL 1990 – 2010																
New England	355	7.0	3.8	-3.2	25	14	-5	-46	2,149	67	247	-1.02	94.46	-2.0	1.6	0.05
Mid Atlantic	2,787	5.0	3.8	-1.2	139	107	-2	-12	17,938	758	2,790	-8.02	742.12	-10.1	24.3	0.73
South Atlantic	135	5.0	3.8	-1.2	7	5	-2	-12	871	37	136	-0.39	35.91	-0.5	1.1	0.04
Florida	66	6.2	3.8	-2.3	4	3	-4	-32	403	13	48	-0.19	17.67	-0.4	0.3	0.01
East North Central	1,050	5.0	3.8	-1.2	53	40	-2	-12	6,782	290	1,062	-3.02	279.57	-3.6	12.6	0.27
West North Central	307	5.0	3.8	-1.2	15	12	-2	-11	1,983	85	311	-0.88	81.75	-1.0	2.6	0.08
East South Central	77	5.2	3.8	-1.4	4	3	-2	-14	501	21	78	-0.22	20.64	-0.3	0.7	0.02
West South Central	142	5.8	3.8	-2.0	8	5	-3	-30	861	26	95	-0.41	37.77	-0.7	0.2	0.01
Mountain	587	5.0	3.8	-1.2	29	23	-2	-12	3,791	162	594	-1.69	156.26	-2.0	1.2	0.15
Arizona/New Mexico	455	5.3	3.8	-1.4	24	17	-2	-14	2,938	125	460	-1.31	121.10	-1.5	1.3	0.12
California	4,818	5.9	3.8	-2.1	286	185	-4	-39	28,437	699	2,562	-13.76	1283.05	-25.7	1.1	0.16
Washington/Oregon	769	5.0	3.8	-1.2	38	30	-2	-11	5,017	224	821	-2.22	204.74	-2.4	5.3	0.23
TOTAL	11,547	5.5	3.8	-1.6	633	444	-3	-21	71,671	2,508	9,195	-33.12	3075.03	-50.0	52.4	1.87

TABLE B - 6a

RENEWABLE EMISSIONS MODEL RESULTS

EPA BASE CASE

GEOTHERMAL ELECTRIC

REGION	INCREMENTAL GENERATION (GWh/yr)	UNIT COST (cents/kWh)			TOTAL ANNUAL COST ($ millions)		UNIT COST OF EMISSIONS AVOIDED ($/MT)		POLLUTION PREVENTED (million kg/yr)							
		AVOIDED	RENEWABLE	DIFFERENCE	AVOIDED	RENEWABLE	CO2 EQ	CO2	CO2 EQ	CARBON	CO2	CO	CH4	NOX	SO2	PM
INCREMENTAL 1990 - 2000																
New England	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Mid Atlantic	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
South Atlantic	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Florida	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East North Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West North Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East South Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West South Central	967	5.1	6.5	1.4	49	62	17	20	770	177	650	0.16	0.00	3.0	1.3	0.09
Mountain	291	4.8	4.2	-0.6	14	12	-5	-6	349	81	298	0.04	0.00	1.3	0.6	0.08
Arizona/New Mexico	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
California	5,884	4.6	4.2	-0.4	271	249	-6	-7	3,685	854	3,129	0.98	0.01	13.8	1.4	0.19
Washington/Oregon	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
TOTAL	7,143	4.7	4.5	-0.2	334	323	-2	-3	4,804	1,112	4,078	1.18	0.02	18.1	3.2	0.36
INCREMENTAL 2000 - 2010																
New England	975	8.4	5.4	-3.0	82	52	-39	-43	764	186	680	0.15	0.01	2.1	4.4	0.14
Mid Atlantic	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
South Atlantic	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Florida	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East North Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West North Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East South Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West South Central	1,951	6.9	5.5	-1.3	134	108	-17	-20	1,553	357	1,311	0.32	0.01	6.0	2.5	0.17
Mountain	873	5.3	4.1	-1.1	46	36	-10	-11	1,017	237	869	0.13	0.01	3.7	1.7	0.22
Arizona/New Mexico	1,951	5.6	4.1	-1.4	108	80	-12	-14	2,271	529	1,940	0.28	0.02	8.3	5.2	0.49
California	14,058	7.8	4.3	-3.5	1,090	598	-56	-66	8,804	2,039	7,477	2.33	0.03	33.0	3.3	0.46
Washington/Oregon	1,951	5.0	4.1	-0.9	98	80	-7	-9	2,437	568	2,083	0.27	0.02	8.8	13.6	0.57
TOTAL	21,759	7.2	4.4	-2.8	1,559	955	-36	-42	16,847	3,916	14,360	3.46	0.08	61.9	30.7	2.06
INCREMENTAL 1990 - 2010																
New England	975	8.4	5.4	-3.0	82	52	-39	-43	764	186	680	0.15	0.01	2.1	4.4	0.14
Mid Atlantic	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
South Atlantic	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Florida	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East North Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West North Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East South Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West South Central	2,918	6.3	5.8	-0.4	183	170	-5	-6	2,323	536	1,961	0.48	0.01	9.0	3.8	0.26
Mountain	1,164	5.1	4.2	-1.0	60	48	-8	-10	1,366	318	1,167	0.17	0.01	5.0	2.3	0.30
Arizona/New Mexico	1,951	5.6	4.1	-1.4	108	80	-12	-14	2,271	529	1,940	0.28	0.02	8.3	5.2	0.49
California	19,943	6.8	4.2	-2.6	1,361	846	-41	-49	12,489	2,893	10,606	3.31	0.04	46.8	4.6	0.65
Washington/Oregon	1,951	5.0	4.1	-0.9	98	80	-7	-9	2,437	568	2,083	0.27	0.02	8.8	13.6	0.57
TOTAL	28,902	6.5	4.4	-2.1	1,893	1,279	-28	-33	21,652	5,028	18,437	4.64	0.10	80.0	33.9	2.42

TABLE B - 6b

RENEWABLE EMISSIONS MODEL RESULTS
EPA ENHANCED MARKET SCENARIO
GEOTHERMAL ELECTRIC

REGION	INCREMENTAL GENERATION (GWh/yr)	UNIT COST (cents/kWh)			TOTAL ANNUAL COST ($ millions)		UNIT COST OF EMISSIONS AVOIDED ($/MT)		POLLUTION PREVENTED (million kg/yr)							
		AVOIDED	RENEWABLE	DIFFERENCE	AVOIDED	RENEWABLE	CO2 EQ	CO2	CO2 EQ	CARBON	CO2	CO	CH4	NOX	SO2	PM
INCREMENTAL 1990 – 2000																
New England	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Mid Atlantic	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
South Atlantic	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Florida	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East North Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West North Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East South Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West South Central	967	5.1	6.1	1.0	49	59	13	15	770	177	650	0.16	0.00	3.0	1.3	0.09
Mountain	1,762	4.8	4.1	-0.7	85	72	-6	-7	2,112	492	1,806	0.25	0.02	7.7	3.6	0.47
Arizona/New Mexico	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
California	27,417	4.6	4.1	-0.5	1,263	1,119	-8	-10	17,170	3,977	14,581	4.56	0.06	64.4	6.4	0.90
Washington/Oregon	1,731	5.0	4.1	-0.9	86	71	-7	-8	2,433	567	2,079	0.27	0.02	8.8	13.5	0.57
TOTAL	31,877	4.6	4.1	-0.5	1,483	1,321	-7	-9	22,216	5,150	18,886	5.20	0.09	82.8	23.3	1.98
INCREMENTAL 2000 – 2010																
New England	2,926	8.4	4.2	-4.2	246	122	-54	-61	2,292	557	2,041	0.45	0.02	6.2	13.3	0.42
Mid Atlantic	2,926	5.8	4.2	-1.6	169	122	-14	-16	3,339	782	2,869	0.42	0.03	11.7	24.6	0.74
South Atlantic	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Florida	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East North Central	2,926	5.3	4.2	-1.1	155	122	-10	-11	3,407	794	2,910	0.43	0.03	12.4	34.0	0.74
West North Central	2,926	5.3	4.2	-1.1	156	122	-10	-12	3,407	794	2,910	0.43	0.03	12.4	24.1	0.74
East South Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West South Central	4,877	6.9	5.1	-1.8	334	249	-22	-26	3,883	894	3,277	0.80	0.02	15.1	6.3	0.44
Mountain	8,864	5.3	3.9	-1.3	465	348	-11	-13	10,310	2,401	8,606	1.29	0.06	37.5	17.2	2.24
Arizona/New Mexico	9,753	5.6	4.0	-1.6	542	385	-14	-16	11,357	2,645	9,700	1.42	0.06	41.3	26.2	2.47
California	60,798	7.8	4.0	-3.8	4,716	2,414	-60	-71	38,075	8,819	32,334	10.09	0.01	142.7	14.1	1.98
Washington/Oregon	5,855	5.0	3.9	-1.1	295	238	-9	-10	7,316	1,705	6,252	0.80	0.06	26.5	40.7	1.72
TOTAL	102,057	6.9	4.0	-2.9	7,069	4,121	-35	-42	83,659	19,453	71,329	16.16	0.46	306.8	202.0	11.58
INCREMENTAL 1990 – 2010																
New England	2,926	8.4	4.2	-4.2	246	122	-54	-61	2,292	557	2,041	0.45	0.02	6.2	13.3	0.42
Mid Atlantic	2,926	5.8	4.2	-1.6	169	122	-14	-16	3,339	782	2,869	0.42	0.03	11.7	24.6	0.74
South Atlantic	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Florida	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East North Central	2,926	5.3	4.2	-1.1	155	122	-10	-11	3,407	794	2,910	0.43	0.03	12.4	34.0	0.74
West North Central	2,926	5.3	4.2	-1.1	156	122	-10	-12	3,407	794	2,910	0.43	0.03	12.4	24.1	0.74
East South Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West South Central	5,844	6.6	5.3	-1.3	384	308	-16	-19	4,653	1,071	3,927	0.96	0.02	18.1	7.6	0.52
Mountain	10,616	5.2	4.0	-1.2	550	420	-11	-12	12,422	2,894	10,610	1.54	0.09	45.1	20.8	2.71
Arizona/New Mexico	9,753	5.6	4.0	-1.6	542	385	-14	-16	11,357	2,645	9,700	1.42	0.06	41.3	26.2	2.47
California	88,215	6.8	4.0	-2.8	5,978	3,533	-44	-52	55,246	12,795	46,915	14.64	0.16	207.1	20.5	2.88
Washington/Oregon	7,603	5.0	4.0	-1.1	392	309	-9	-10	9,750	2,272	8,332	1.07	0.06	36.3	54.2	2.29
TOTAL	133,936	6.4	4.1	-2.3	8,571	5,443	-30	-36	105,874	24,604	90,213	21.36	0.55	389.6	225.2	13.82

TABLE B – 7a

RENEWABLE EMISSIONS MODEL RESULTS
EPA BASE CASE
HYDROPOWER – STORAGE

REGION	INCREMENTAL GENERATION (GWh/yr)	UNIT COST (cents/kWh)			TOTAL ANNUAL COST ($ millions)		UNIT COST OF EMISSIONS AVOIDED ($/MT)		POLLUTION PREVENTED (million kg/yr)							
		AVOIDED	RENEWABLE	DIFFERENCE	AVOIDED	RENEWABLE	CO2 EQ	CO2	CO2 EQ	CARBON	CO2	CO	CH4	NOX	SO2	PM
INCREMENTAL 1990 – 2000																
New England	2	5.8	18.1	12.3	0	0	180	179	2	0	1	0.00	0.00	0.0	0.0	0.00
Mid Atlantic	228	4.5	4.2	-0.3	10	10	-2	-3	263	62	226	0.03	0.00	0.9	2.0	0.06
South Atlantic	104	3.9	6.4	2.5	4	7	21	25	123	29	106	0.01	0.00	0.4	0.9	0.03
Florida	3	5.6	1.8	-3.8	0	0	-48	-54	2	0	2	0.00	0.00	0.0	0.0	0.00
East North Central	10	4.3	9.3	5.0	0	1	42	49	12	3	11	0.00	0.00	0.0	0.1	0.00
West North Central	100	5.1	3.9	-1.1	5	4	-10	-11	119	28	102	0.01	0.00	0.4	0.9	0.03
East South Central	188	4.6	3.6	-1.0	9	7	-8	-9	224	52	191	0.03	0.00	0.8	1.8	0.05
West South Central	56	4.6	7.6	3.0	3	4	39	46	42	10	36	0.01	0.00	0.2	0.1	0.00
Mountain	217	5.5	6.4	0.9	12	14	7	8	256	60	220	0.03	0.00	0.9	0.4	0.06
Arizona/New Mexico	98	5.5	3.6	-1.8	8	4	-15	-18	117	27	100	0.01	0.00	0.4	0.3	0.03
California	167	5.2	3.8	-1.4	9	6	-22	-26	105	24	89	0.03	0.00	0.4	0.0	0.01
Washington/Oregon	1,217	5.0	3.3	-1.7	60	40	-13	-16	1,546	360	1,321	0.17	0.01	5.6	8.6	0.36
TOTAL	2,389	4.9	4.0	-0.9	118	98	-8	-9	2,613	656	2,405	0.34	0.02	10.2	15.1	0.62
INCREMENTAL 2000 – 2010																
New England	17	8.0	7.5	-0.5	1	1	-8	-7	13	3	12	0.00	0.00	0.0	0.1	0.00
Mid Atlantic	49	5.9	8.2	2.3	3	4	21	24	55	13	47	0.01	0.00	0.2	0.4	0.01
South Atlantic	124	4.7	7.9	3.2	6	10	28	33	144	33	123	0.02	0.00	0.5	1.0	0.03
Florida	8	8.1	3.3	-4.7	1	0	-60	-67	6	1	5	0.00	0.00	0.0	0.0	0.00
East North Central	37	4.9	5.0	0.1	2	2	1	1	43	10	37	0.01	0.00	0.2	0.4	0.01
West North Central	270	5.6	3.9	-1.7	15	11	-15	-17	313	73	267	0.04	0.00	1.1	2.2	0.07
East South Central	157	5.1	3.7	-1.4	8	6	-12	-14	182	42	155	0.02	0.00	0.7	1.4	0.04
West South Central	93	6.5	9.5	3.0	6	9	40	47	70	16	59	0.02	0.00	0.3	0.1	0.01
Mountain	215	5.9	8.8	2.9	13	19	25	29	249	58	213	0.03	0.00	0.9	0.4	0.05
Arizona/New Mexico	129	6.0	2.9	-3.1	8	4	-27	-31	149	35	127	0.02	0.00	0.5	0.3	0.03
California	297	9.0	6.9	-2.2	27	20	-35	-41	187	43	159	0.05	0.00	0.7	0.1	0.01
Washington/Oregon	1,097	5.0	3.8	-1.3	55	41	-10	-12	1,393	325	1,190	0.15	0.01	5.0	7.7	0.33
TOTAL	2,493	5.8	5.1	-0.7	144	127	-6	-7	2,803	653	2,396	0.37	0.02	10.2	14.2	0.59
INCREMENTAL 1990 – 2010																
New England	19	7.7	8.7	0.9	1	2	12	14	15	4	13	0.00	0.00	0.0	0.1	0.00
Mid Atlantic	277	4.7	4.9	0.2	13	14	2	2	318	75	274	0.04	0.00	1.1	2.4	0.07
South Atlantic	228	4.3	7.2	2.9	10	16	25	29	267	62	228	0.03	0.00	1.0	1.9	0.06
Florida	10	7.4	2.9	-4.5	1	0	-57	-64	8	2	7	0.00	0.00	0.0	0.0	0.00
East North Central	48	4.7	5.9	1.2	2	3	10	12	56	13	48	0.01	0.00	0.2	0.6	0.01
West North Central	370	5.5	3.9	-1.5	20	14	-13	-16	431	101	369	0.05	0.00	1.6	3.1	0.09
East South Central	345	4.8	3.7	-1.1	17	13	-10	-11	406	95	347	0.05	0.00	1.5	3.3	0.09
West South Central	148	5.8	8.8	3.0	9	13	39	47	113	26	96	0.02	0.00	0.4	0.2	0.01
Mountain	432	5.7	7.6	1.9	26	33	16	19	507	118	433	0.06	0.00	1.8	0.9	0.11
Arizona/New Mexico	227	5.8	3.2	-2.5	13	7	-22	-25	266	62	226	0.03	0.00	1.0	0.6	0.06
California	464	7.6	5.8	-1.9	35	27	-30	-35	291	68	248	0.08	0.00	1.1	0.1	0.01
Washington/Oregon	2,314	5.0	3.5	-1.5	116	81	-12	-14	2,939	685	2,511	0.32	0.02	10.6	16.3	0.69
TOTAL	4,882	5.4	4.6	-0.8	282	223	-7	-8	5,616	1,309	4,800	0.71	0.04	20.3	29.4	1.22

TABLE B – 7b

RENEWABLE EMISSIONS MODEL RESULTS
EPA ENHANCED MARKET SCENARIO
HYDROPOWER – STORAGE

REGION	INCREMENTAL GENERATION (GWh/yr)	UNIT COST (cents/kWh)			TOTAL ANNUAL COST ($ millions)		UNIT COST OF EMISSIONS AVOIDED ($/MT)		POLLUTION PREVENTED (million kg/yr)							
		AVOIDED	RENEWABLE	DIFFERENCE	AVOIDED	RENEWABLE	CO2 EQ	CO2	CO2 EQ	CARBON	CO2	CO	CH4	NOX	SO2	PM
INCREMENTAL 1990 – 2000																
New England	81	5.8	6.8	1.0	5	5	13	15	62	15	55	0.01	0.00	0.2	0.4	0.01
Mid Atlantic	800	4.5	4.3	-0.2	36	35	-1	-2	924	217	795	0.11	0.01	3.2	6.9	0.21
South Atlantic	600	3.9	6.9	3.0	23	41	26	30	715	167	611	0.09	0.01	2.6	5.1	0.16
Florida	23	5.6	4.0	-1.6	1	1	-20	-22	18	4	16	0.00	0.00	0.0	0.1	0.00
East North Central	112	4.3	5.7	1.4	5	6	12	14	133	31	114	0.02	0.00	0.5	1.4	0.03
West North Central	802	5.1	4.3	-0.8	40	34	-8	-8	955	223	817	0.12	0.01	3.4	6.9	0.21
East South Central	695	4.6	3.4	-1.2	32	23	-10	-12	828	193	708	0.10	0.01	3.0	6.8	0.18
West South Central	257	4.6	10.4	5.8	12	27	76	90	195	45	164	0.04	0.00	0.8	0.3	0.02
Mountain	926	5.5	7.4	1.9	51	69	16	18	1,104	257	944	0.13	0.01	4.0	1.9	0.25
Arizona/New Mexico	349	5.5	3.0	-2.4	19	11	-20	-24	416	97	356	0.05	0.00	1.5	1.0	0.09
California	947	5.2	7.8	2.7	49	74	42	50	594	138	506	0.16	0.00	2.2	0.2	0.03
Washington/Oregon	4,344	5.0	3.5	-1.5	216	150	-12	-14	5,516	1,286	4,714	0.61	0.04	20.0	30.7	1.30
TOTAL	9,936	4.9	4.8	-0.1	489	477	-1	-1	11,461	2,673	9,801	1.44	0.09	41.3	61.6	2.50
INCREMENTAL 2000 – 2010																
New England	36	8.0	6.9	-1.0	3	2	-13	-15	28	7	25	0.01	0.00	0.1	0.2	0.01
Mid Atlantic	203	5.9	6.0	0.1	12	12	1	1	226	54	196	0.03	0.00	0.6	1.7	0.05
South Atlantic	232	4.7	7.7	3.0	11	18	26	30	269	63	230	0.03	0.00	1.0	1.9	0.06
Florida	13	8.1	4.1	-3.9	1	1	-50	-55	10	2	9	0.00	0.00	0.0	0.1	0.00
East North Central	60	4.9	5.7	0.8	3	3	7	8	69	16	59	0.01	0.00	0.2	0.7	0.01
West North Central	451	5.6	4.4	-1.3	25	20	-11	-13	522	122	446	0.07	0.00	1.9	3.7	0.11
East South Central	212	5.1	3.7	-1.4	11	8	-12	-14	246	57	210	0.03	0.00	0.9	2.0	0.05
West South Central	146	6.5	11.3	4.8	9	17	64	76	111	26	94	0.02	0.00	0.4	0.2	0.01
Mountain	364	5.9	9.0	3.1	22	33	27	31	421	98	360	0.05	0.00	1.5	0.7	0.09
Arizona/New Mexico	177	6.0	2.9	-3.1	11	5	-27	-31	205	48	175	0.03	0.00	0.7	0.5	0.04
California	536	9.0	8.4	-0.7	48	45	-11	-12	336	78	266	0.09	0.00	1.2	0.1	0.02
Washington/Oregon	1,747	5.0	3.9	-1.2	88	67	-9	-11	2,216	517	1,896	0.24	0.02	8.0	12.3	0.52
TOTAL	4,177	5.8	5.5	-0.3	244	231	-3	-3	4,663	1,087	3,986	0.61	0.03	16.9	23.8	0.96
INCREMENTAL 1990 – 2010																
New England	116	6.4	6.8	0.4	8	8	5	5	90	22	80	0.02	0.00	0.2	0.5	0.02
Mid Atlantic	1,003	4.8	4.7	-0.1	48	47	-1	-1	1,152	270	991	0.14	0.01	4.0	8.6	0.26
South Atlantic	832	4.1	7.1	3.0	34	59	26	30	984	229	841	0.12	0.01	3.6	7.0	0.22
Florida	35	6.5	4.0	-2.4	2	1	-31	-34	28	7	25	0.01	0.00	0.1	0.2	0.01
East North Central	172	4.5	5.7	1.2	8	10	10	12	202	47	173	0.02	0.00	0.7	2.0	0.04
West North Central	1,253	5.3	4.3	-0.9	66	54	-8	-9	1,477	344	1,263	0.18	0.01	5.3	10.6	0.33
East South Central	907	4.7	3.4	-1.2	42	31	-10	-12	1,074	250	918	0.13	0.01	3.9	8.7	0.24
West South Central	403	5.3	10.7	5.4	21	43	72	85	306	70	258	0.07	0.00	1.2	0.4	0.03
Mountain	1,292	5.7	7.9	2.2	73	102	19	22	1,525	356	1,304	0.19	0.01	5.5	2.6	0.34
Arizona/New Mexico	527	5.6	3.0	-2.7	30	16	-22	-26	622	145	531	0.08	0.00	2.2	1.5	0.14
California	1,482	6.6	8.0	1.5	97	119	23	27	930	216	792	0.25	0.00	3.4	0.3	0.05
Washington/Oregon	6,091	5.0	3.6	-1.4	304	218	-11	-13	7,734	1,803	6,610	0.85	0.06	28.0	43.0	1.82
TOTAL	14,113	5.2	5.0	-0.2	733	706	-2	-2	16,124	3,760	13,796	2.06	0.12	58.2	85.4	3.46

TABLE B – 8a

RENEWABLE EMISSIONS MODEL RESULTS

EPA BASE CASE

HYDROPOWER – RUN OF RIVER & DIVERSION

REGION	INCREMENTAL GENERATION (GWh/yr)	UNIT COST (cents/kWh)			TOTAL ANNUAL COST ($ millions)		UNIT COST OF EMISSIONS AVOIDED ($/MT)		POLLUTION PREVENTED (million kg/yr)							
		AVOIDED	RENEWABLE	DIFFERENCE	AVOIDED	RENEWABLE	CO2 EQ	CO2	CO2 EQ	CARBON	CO2	CO	CH4	NOX	SO2	PM
INCREMENTAL 1990 – 2000																
New England	536	5.2	5.2	0.0	26	26	0	0	419	102	373	0.06	0.00	1.1	2.4	0.06
Mid Atlantic	537	3.6	4.7	1.1	19	25	9	11	629	146	541	0.06	0.01	2.2	4.8	0.14
South Atlantic	342	3.4	5.7	2.4	12	20	20	23	410	96	350	0.05	0.00	1.5	2.9	0.09
Florida	12	4.8	3.8	−1.0	1	0	−13	−15	10	2	9	0.00	0.00	0.0	0.1	0.00
East North Central	446	3.3	3.3	−0.0	15	15	−0	−0	536	125	458	0.06	0.00	1.9	5.5	0.12
West North Central	301	3.8	3.7	−0.1	11	11	−1	−1	360	84	308	0.04	0.00	1.3	2.6	0.06
East South Central	286	3.5	4.5	0.9	10	13	8	9	345	80	295	0.04	0.00	1.2	2.9	0.06
West South Central	156	3.8	5.4	1.6	6	8	20	24	124	29	105	0.03	0.00	0.5	0.2	0.01
Mountain	446	3.8	5.3	1.5	17	24	12	14	533	124	456	0.06	0.00	1.9	0.9	0.12
Arizona/New Mexico	191	4.3	4.1	−0.2	8	8	−2	−2	229	53	196	0.03	0.00	0.8	0.5	0.05
California	651	4.3	4.7	0.5	28	31	7	9	408	94	346	0.11	0.00	1.5	0.1	0.02
Washington/Oregon	653	3.9	4.3	0.4	25	28	3	3	819	191	700	0.09	0.01	3.0	4.6	0.19
TOTAL	4,569	4.0	4.6	0.7	181	211	6	7	4,822	1,126	4,136	0.67	0.04	17.1	27.5	0.99
INCREMENTAL 2000 – 2010																
New England	472	7.1	5.2	−1.9	33	24	−26	−28	369	90	326	0.07	0.00	1.0	2.1	0.07
Mid Atlantic	446	4.6	4.9	0.4	20	22	3	4	506	119	437	0.06	0.00	1.6	3.7	0.11
South Atlantic	305	4.1	5.8	1.7	12	18	14	17	354	83	303	0.04	0.00	1.3	2.5	0.08
Florida	8	6.5	3.9	−2.8	1	0	−32	−36	6	2	6	0.00	0.00	0.0	0.0	0.00
East North Central	365	3.9	3.4	−0.5	14	12	−4	−5	424	99	362	0.05	0.00	1.5	4.2	0.09
West North Central	253	4.4	3.8	−0.6	11	10	−5	−6	295	69	252	0.04	0.00	1.1	2.1	0.06
East South Central	288	4.1	4.4	0.3	12	13	2	3	335	78	286	0.04	0.00	1.2	2.7	0.07
West South Central	150	5.4	5.3	−0.2	8	8	−2	−3	120	28	101	0.02	0.00	0.5	0.2	0.01
Mountain	454	4.3	5.1	0.8	20	23	6	8	526	123	451	0.07	0.00	1.9	0.9	0.11
Arizona/New Mexico	181	4.9	4.1	−0.7	9	7	−6	−7	211	49	180	0.03	0.00	0.8	0.5	0.05
California	626	7.0	4.8	−2.2	44	30	−35	−41	392	91	333	0.10	0.00	1.5	0.1	0.02
Washington/Oregon	649	4.1	4.0	−0.1	26	26	−1	−1	815	190	697	0.09	0.01	3.0	4.5	0.19
TOTAL	4,197	5.0	4.6	−0.4	211	193	−4	−5	4,357	1,019	3,736	0.63	0.03	15.5	23.6	0.87
INCREMENTAL 1990 – 2010																
New England	1,008	6.1	5.2	−0.9	61	52	−11	−13	787	191	701	0.15	0.01	2.1	4.6	0.14
Mid Atlantic	983	4.1	4.8	0.8	40	47	7	8	1,138	267	978	0.14	0.01	4.0	8.5	0.26
South Atlantic	647	3.7	5.7	2.0	24	37	17	20	764	178	653	0.09	0.01	2.8	5.4	0.17
Florida	20	5.5	3.8	−1.8	1	1	−21	−23	16	4	14	0.00	0.00	0.0	0.1	0.00
East North Central	812	3.6	3.4	−0.2	29	27	−2	−2	960	224	821	0.12	0.01	3.5	9.7	0.21
West North Central	554	4.1	3.7	−0.3	22	21	−3	−3	655	153	559	0.08	0.00	2.4	4.7	0.14
East South Central	576	3.8	4.4	0.6	22	26	5	6	681	159	581	0.08	0.01	2.5	5.5	0.15
West South Central	306	4.6	5.3	0.7	14	16	9	11	244	56	206	0.05	0.00	0.9	0.4	0.03
Mountain	899	4.1	5.2	1.1	37	47	9	11	1,061	247	906	0.13	0.01	3.6	1.8	0.23
Arizona/New Mexico	372	4.6	4.1	−0.5	17	15	−4	−5	440	102	376	0.06	0.00	1.6	1.0	0.10
California	1,276	5.6	4.8	−0.8	72	61	−13	−16	799	186	679	0.21	0.00	3.0	0.3	0.04
Washington/Oregon	1,302	4.0	4.1	0.1	52	54	1	1	1,634	381	1,397	0.18	0.01	5.9	9.1	0.38
TOTAL	8,757	4.5	4.6	0.1	391	404	1	2	9,179	2,147	7,871	1.30	0.07	32.6	51.1	1.86

TABLE B – 8b

RENEWABLE EMISSIONS MODEL RESULTS

EPA ENHANCED MARKET SCENARIO

HYDROPOWER – RUN OF RIVER & DIVERSION

REGION	INCREMENTAL GENERATION (GWh/yr)	UNIT COST (cents/kWh)			TOTAL ANNUAL COST ($ millions)		UNIT COST OF EMISSIONS AVOIDED ($/MT)		POLLUTION PREVENTED (million kg/yr)							
		AVOIDED	RENEWABLE	DIFFERENCE	AVOIDED	RENEWABLE	CO2 EQ	CO2	CO2 EQ	CARBON	CO2	CO	CH4	NOX	SO2	PM
INCREMENTAL 1990 – 2000																
New England	1,841	6.2	5.8	0.6	96	106	6	8	1,438	349	1,281	0.28	0.01	3.9	8.3	0.28
Mid Atlantic	1,792	3.6	5.0	1.4	65	69	12	14	2,101	493	1,806	0.26	0.02	7.4	15.9	0.48
South Atlantic	1,392	3.4	6.1	2.6	47	86	23	27	1,666	368	1,424	0.20	0.01	6.0	11.9	0.37
Florida	31	4.8	4.6	–0.3	2	1	–3	–4	25	6	22	0.00	0.00	0.1	0.1	0.01
East North Central	1,513	3.3	3.8	0.4	51	57	4	4	1,813	422	1,549	0.22	0.01	6.6	18.6	0.41
West North Central	1,041	3.6	4.1	0.3	40	43	3	3	1,246	291	1,065	0.15	0.01	4.5	9.1	0.28
East South Central	1,276	3.5	4.6	1.0	45	58	9	10	1,526	356	1,306	0.18	0.01	5.5	12.6	0.34
West South Central	699	3.8	5.5	1.7	26	38	22	26	556	128	469	0.11	0.00	2.2	0.9	0.06
Mountain	1,809	3.8	5.6	1.8	69	101	16	17	2,167	505	1,852	0.26	0.02	7.8	3.7	0.48
Arizona/New Mexico	883	4.3	4.2	–0.1	38	38	–1	–1	1,058	247	904	0.13	0.01	3.8	2.5	0.24
California	2,139	4.3	4.8	0.5	92	102	8	9	1,340	310	1,136	0.36	0.00	5.0	0.5	0.07
Washington/Oregon	2,467	3.9	4.5	0.6	96	111	5	6	3,097	722	2,647	0.34	0.02	11.2	17.2	0.73
TOTAL	16,884	3.9	4.9	1.0	666	831	9	11	18,034	4,217	15,463	2.49	0.13	64.0	101.5	3.73
INCREMENTAL 2000 – 2010																
New England	1,647	7.1	5.9	–1.2	117	98	–15	–17	1,286	312	1,146	0.25	0.01	3.5	7.5	0.24
Mid Atlantic	1,496	4.6	5.3	0.7	68	79	6	7	1,702	399	1,462	0.22	0.01	6.0	12.5	0.38
South Atlantic	1,272	4.1	6.3	2.2	52	80	19	22	1,479	345	1,264	0.19	0.01	5.4	10.3	0.32
Florida	27	6.5	4.7	–1.8	2	1	–22	–26	21	5	19	0.00	0.00	0.1	0.1	0.00
East North Central	1,371	3.9	3.8	–0.1	53	52	–1	–1	1,595	372	1,363	0.20	0.01	5.8	15.9	0.35
West North Central	968	4.4	4.2	–0.2	42	41	–1	–2	1,126	262	961	0.14	0.01	4.1	8.0	0.24
East South Central	1,189	4.1	4.7	0.5	49	55	5	6	1,384	322	1,182	0.17	0.01	5.0	11.1	0.30
West South Central	639	5.4	5.6	0.2	35	36	2	2	508	117	429	0.11	0.00	2.0	0.8	0.06
Mountain	1,656	4.3	5.7	1.4	71	95	12	14	1,926	449	1,645	0.24	0.01	7.0	3.2	0.42
Arizona/New Mexico	872	4.9	4.3	–0.6	42	37	–5	–6	1,014	236	866	0.13	0.01	3.7	2.3	0.22
California	1,554	7.0	5.3	–1.7	109	82	–27	–32	973	225	827	0.26	0.00	3.6	0.4	0.05
Washington/Oregon	1,823	4.1	4.9	0.8	74	89	6	8	2,289	533	1,956	0.25	0.02	8.3	12.7	0.54
TOTAL	14,512	4.9	5.1	0.2	715	744	2	2	15,304	3,576	13,119	2.15	0.11	54.4	84.8	3.12
INCREMENTAL 1990 – 2010																
New England	3,488	6.1	5.8	–0.2	212	204	–3	–3	2,724	662	2,426	0.53	0.02	7.4	15.8	0.50
Mid Atlantic	3,287	4.1	5.1	1.1	133	168	9	11	3,803	891	3,268	0.47	0.03	13.3	28.4	0.86
South Atlantic	2,665	3.7	6.2	2.5	99	165	21	25	3,146	733	2,688	0.39	0.02	11.4	22.2	0.69
Florida	58	5.6	4.6	–1.0	3	3	–12	–13	46	11	42	0.01	0.00	0.1	0.3	0.01
East North Central	2,884	3.6	3.8	0.2	104	109	2	2	3,408	794	2,912	0.42	0.03	12.4	34.5	0.76
West North Central	2,008	4.1	4.2	0.1	82	84	1	1	2,372	553	2,027	0.29	0.02	8.6	17.0	0.52
East South Central	2,465	3.8	4.6	0.8	94	114	7	8	2,912	679	2,488	0.36	0.02	10.6	23.7	0.64
West South Central	1,338	4.6	5.5	1.0	61	74	12	15	1,063	245	897	0.22	0.00	4.1	1.7	0.12
Mountain	3,465	4.1	5.6	1.6	141	196	13	16	4,093	954	3,497	0.50	0.03	14.8	6.9	0.90
Arizona/New Mexico	1,755	4.6	4.3	–0.3	81	75	–3	–3	2,072	483	1,770	0.25	0.02	7.5	4.8	0.46
California	3,692	5.4	5.0	–0.4	200	184	–7	–8	2,313	536	1,965	0.61	0.01	8.7	0.8	0.12
Washington/Oregon	4,290	4.0	4.7	0.7	170	200	5	6	5,386	1,255	4,603	0.59	0.04	19.5	29.9	1.27
TOTAL	31,396	4.4	5.6	0.6	1,381	1,576	6	7	33,338	7,796	28,582	4.65	0.25	118.4	186.3	6.84

TABLE B - 9a

RENEWABLE EMISSIONS MODEL RESULTS

EPA BASE CASE

PHOTOVOLTAIC

REGION	INCREMENTAL GENERATION (GWh/yr)	UNIT COST (cents/kWh)			TOTAL ANNUAL COST ($ millions)		UNIT COST OF EMISSIONS AVOIDED ($/MT)		POLLUTION PREVENTED (million kg/yr)							
		AVOIDED	RENEWABLE	DIFFERENCE	AVOIDED	RENEWABLE	CO2 EQ	CO2	CO2 EQ	CARBON	CO2	CO	CH4	NOX	SO2	PM
INCREMENTAL 1990 - 2000																
New England	54	5.1	26.5	21.4	3	14	279	313	41	10	37	0.01	0.00	0.1	0.2	0.01
Mid Atlantic	108	4.0	26.5	22.5	4	29	198	228	124	29	106	0.02	0.00	0.4	0.9	0.03
South Atlantic	163	3.9	20.3	16.4	6	33	138	161	193	45	165	0.02	0.00	0.7	1.4	0.04
Florida	162	4.6	20.3	15.7	7	33	200	222	128	31	115	0.02	0.00	0.3	0.7	0.03
East North Central	108	3.8	23.0	19.2	4	25	162	189	129	30	110	0.02	0.00	0.5	1.3	0.03
West North Central	163	3.9	19.2	15.3	6	31	129	150	193	45	165	0.02	0.00	0.7	1.4	0.04
East South Central	162	4.1	20.3	16.2	7	33	136	159	193	45	165	0.02	0.00	0.7	1.6	0.04
West South Central	216	4.3	17.3	13.0	9	37	174	208	161	37	135	0.04	0.00	0.6	0.2	0.01
Mountain	271	4.1	16.5	12.4	11	45	105	122	322	75	275	0.04	0.00	1.2	0.6	0.07
Arizona/New Mexico	216	4.5	15.1	10.6	10	33	89	104	257	60	219	0.03	0.00	0.9	0.6	0.06
California	250	4.4	16.5	12.1	11	41	193	226	157	36	134	0.04	0.00	0.6	0.0	0.01
Washington/Oregon	54	3.7	24.6	21.0	2	13	164	192	69	16	59	0.01	0.00	0.3	0.4	0.02
TOTAL	1,926	4.2	19.1	14.8	81	367	145	170	1,966	460	1,686	0.29	0.01	7.0	9.3	0.39
INCREMENTAL 2000 - 2010																
New England	352	7.0	16.0	9.0	26	56	117	131	270	66	241	0.06	0.00	0.7	1.5	0.05
Mid Atlantic	704	5.0	16.0	11.0	35	113	98	114	786	184	676	0.10	0.01	2.7	5.7	0.17
South Atlantic	1,057	4.7	12.3	7.6	50	130	66	77	1,220	284	1,043	0.15	0.01	4.4	8.4	0.26
Florida	1,057	6.0	12.3	6.2	64	130	79	88	832	204	747	0.16	0.01	2.1	4.5	0.16
East North Central	704	4.3	13.9	9.6	30	98	83	97	813	190	695	0.10	0.01	2.9	8.0	0.18
West North Central	1,057	4.5	11.6	7.1	47	123	62	72	1,220	284	1,043	0.15	0.01	4.4	8.6	0.26
East South Central	1,057	4.7	12.3	7.6	49	130	66	77	1,220	284	1,043	0.15	0.01	4.4	9.7	0.26
West South Central	1,409	6.2	10.5	4.3	87	147	57	68	1,051	241	885	0.24	0.00	4.1	1.4	0.09
Mountain	1,761	4.6	10.0	5.4	80	176	47	55	2,033	474	1,738	0.26	0.02	7.3	3.4	0.44
Arizona/New Mexico	1,409	5.0	9.1	4.1	71	129	36	42	1,626	379	1,390	0.21	0.01	5.9	3.8	0.36
California	1,761	7.1	10.0	2.9	125	176	46	54	1,106	257	942	0.30	0.00	4.1	0.3	0.05
Washington/Oregon	352	3.9	14.9	11.0	14	52	66	101	450	105	385	0.06	0.00	1.6	2.5	0.11
TOTAL	12,679	5.3	11.5	6.2	677	1,456	62	72	12,626	2,953	10,827	1.96	0.09	44.6	57.8	2.40
INCREMENTAL 1990 - 2010																
New England	406	6.6	17.4	10.8	27	71	139	155	311	76	277	0.06	0.00	0.8	1.8	0.06
Mid Atlantic	812	4.9	17.4	12.5	40	141	112	130	910	213	782	0.12	0.01	3.2	6.6	0.20
South Atlantic	1,219	4.6	13.3	8.7	56	163	75	88	1,413	329	1,208	0.18	0.01	5.1	9.8	0.31
Florida	1,219	5.8	13.3	7.5	71	163	95	106	960	236	862	0.18	0.01	2.4	5.2	0.19
East North Central	813	4.3	15.1	10.8	35	123	94	109	942	220	806	0.12	0.01	3.4	9.3	0.21
West North Central	1,219	4.4	12.6	8.2	54	154	71	83	1,413	329	1,208	0.18	0.01	5.1	10.0	0.31
East South Central	1,219	4.6	13.3	8.7	56	163	75	88	1,413	329	1,208	0.18	0.01	5.1	11.2	0.31
West South Central	1,624	5.9	11.4	5.4	96	185	73	87	1,211	278	1,020	0.27	0.00	4.8	1.6	0.11
Mountain	2,032	4.5	10.8	6.4	91	220	55	64	2,355	549	2,013	0.30	0.02	8.5	4.0	0.51
Arizona/New Mexico	1,625	4.9	9.9	5.0	80	161	43	50	1,883	439	1,610	0.24	0.01	6.8	4.4	0.41
California	2,011	6.8	10.8	4.0	136	217	64	75	1,263	293	1,075	0.34	0.00	4.6	0.4	0.06
Washington/Oregon	406	3.8	16.2	12.3	16	66	98	113	520	121	444	0.06	0.00	1.9	2.9	0.12
TOTAL	14,606	5.2	12.5	7.3	758	1,824	73	86	14,592	3,413	12,513	2.22	0.10	51.7	67.2	2.79

TABLE B - 9b

RENEWABLE EMISSIONS MODEL RESULTS
EPA ENHANCED MARKET SCENARIO
PHOTOVOLTAIC

REGION	INCREMENTAL GENERATION (GWh/yr)	UNIT COST (cents/kWh)			TOTAL ANNUAL COST ($ millions)		UNIT COST OF EMISSIONS AVOIDED ($/MT)		POLLUTION PREVENTED (million kg/yr)							
		AVOIDED	RENEWABLE	DIFFERENCE	AVOIDED	RENEWABLE	CO2 EQ	CO2	CO2 EQ	CARBON	CO2	CO	CH4	NOX	SO2	PM
INCREMENTAL 1990 - 2000																
New England	243	5.1	16.0	10.9	12	39	142	159	186	45	166	0.04	0.00	0.5	1.1	0.03
Mid Atlantic	487	4.0	16.0	12.0	19	78	104	121	559	131	481	0.07	0.00	2.0	4.2	0.13
South Atlantic	731	3.9	12.3	8.3	29	90	70	82	869	203	744	0.11	0.01	3.1	6.2	0.19
Florida	731	4.6	12.3	7.7	34	90	97	109	576	141	517	0.11	0.01	1.5	3.1	0.11
East North Central	488	3.8	13.9	10.1	18	68	85	99	580	135	496	0.07	0.00	2.1	5.9	0.13
West North Central	731	3.9	11.6	7.7	29	85	65	76	869	203	744	0.11	0.01	3.1	6.3	0.19
East South Central	731	4.1	12.3	8.2	30	90	69	80	869	203	743	0.11	0.01	3.1	7.1	0.19
West South Central	974	4.3	10.5	6.1	42	102	82	97	726	167	612	0.16	0.00	2.9	0.9	0.07
Mountain	1,219	4.1	10.0	5.9	49	122	50	58	1,449	338	1,239	0.18	0.01	5.2	2.5	0.32
Arizona/New Mexico	974	4.5	9.1	4.7	43	89	39	46	1,158	270	991	0.14	0.01	4.2	2.8	0.28
California	1,198	4.4	10.0	5.6	52	119	89	105	752	175	641	0.20	0.00	2.8	0.2	0.04
Washington/Oregon	244	3.7	14.9	11.2	9	36	88	102	312	73	266	0.03	0.00	1.1	1.7	0.07
TOTAL	8,753	4.2	11.6	7.3	366	1,007	72	84	8,906	2,084	7,640	1.32	0.06	31.5	42.0	1.74
INCREMENTAL 2000 - 2010																
New England	5,175	7.0	8.8	1.8	362	458	24	27	3,960	964	3,536	0.80	0.03	10.5	22.7	0.71
Mid Atlantic	10,349	5.0	8.8	3.8	518	915	34	40	11,551	2,709	9,933	1.51	0.09	40.3	83.2	2.53
South Atlantic	15,524	4.7	6.8	2.1	729	1,057	18	21	17,921	4,178	15,321	2.26	0.13	64.8	123.6	3.89
Florida	15,524	6.0	6.8	0.8	937	1,057	10	11	12,223	2,994	10,977	2.35	0.12	30.9	66.5	2.41
East North Central	10,349	4.3	7.7	3.4	448	796	29	34	11,947	2,786	10,214	1.51	0.09	43.2	117.7	2.59
West North Central	15,524	4.5	6.4	2.0	696	1,000	17	20	17,921	4,178	15,321	2.26	0.13	64.8	126.4	3.89
East South Central	15,524	4.7	6.8	2.1	726	1,057	18	22	17,921	4,178	15,321	2.26	0.13	64.8	142.0	3.89
West South Central	20,699	6.2	5.8	-0.4	1,278	1,204	-5	-6	15,436	3,545	12,997	3.46	0.06	60.7	20.0	1.39
Mountain	25,873	4.6	5.6	1.0	1,178	1,436	9	10	29,868	6,964	25,534	3.77	0.22	108.0	60.1	6.48
Arizona/New Mexico	20,699	5.0	5.1	0.1	1,039	1,053	1	1	23,895	5,571	20,427	3.02	0.18	86.4	55.6	5.19
California	25,873	7.1	5.6	-1.6	1,839	1,436	-25	-29	16,246	3,774	13,839	4.40	0.05	59.6	4.9	0.78
Washington/Oregon	5,175	3.9	8.2	4.4	200	426	34	40	6,618	1,542	5,655	0.73	0.05	24.0	36.8	1.56
TOTAL	186,287	5.3	6.4	1.0	9,951	11,896	10	12	185,506	43,384	159,073	26.31	1.30	658.0	849.7	35.32
INCREMENTAL 1990 - 2010																
New England	5,418	6.9	9.2	2.2	375	497	29	33	4,146	1,010	3,702	0.83	0.04	11.0	23.7	0.75
Mid Atlantic	10,836	5.0	9.2	4.2	537	993	38	44	12,110	2,840	10,414	1.58	0.10	42.2	87.4	2.66
South Atlantic	16,255	4.7	7.1	2.4	758	1,147	21	24	18,790	4,381	16,064	2.37	0.14	67.9	129.8	4.08
Florida	16,255	6.0	7.1	1.1	971	1,147	14	15	12,798	3,136	11,494	2.46	0.12	32.4	69.7	2.52
East North Central	10,837	4.3	8.0	3.7	466	864	32	37	12,527	2,921	10,709	1.58	0.09	45.3	123.6	2.72
West North Central	16,255	4.5	6.7	2.2	724	1,085	19	22	18,790	4,381	16,064	2.37	0.14	67.9	132.7	4.08
East South Central	16,255	4.7	7.1	2.4	756	1,147	21	24	18,790	4,381	16,064	2.37	0.14	67.9	149.1	4.08
West South Central	21,673	6.1	6.0	-0.1	1,321	1,306	-1	-1	16,162	3,712	13,609	3.62	0.06	63.5	21.0	1.46
Mountain	27,092	4.5	5.8	1.2	1,227	1,558	11	12	31,317	7,302	26,774	3.95	0.23	113.2	52.6	6.81
Arizona/New Mexico	21,673	5.0	5.3	0.3	1,083	1,142	2	3	25,053	5,841	21,418	3.16	0.19	90.5	58.4	5.45
California	27,071	7.0	5.7	-1.2	1,892	1,556	-20	-23	16,998	3,949	14,480	4.60	0.06	62.6	5.1	0.82
Washington/Oregon	5,418	3.9	8.5	4.7	209	462	36	43	6,929	1,615	5,922	0.76	0.05	25.1	38.5	1.63
TOTAL	195,040	5.3	6.6	1.3	10,319	12,903	13	15	194,412	45,467	166,713	28.64	1.36	689.5	891.7	37.06

TABLE B – 10a

RENEWABLE EMISSIONS MODEL RESULTS
EPA BASE CASE
SOLAR THERMAL ELECTRIC – HYBRID SYSTEMS

INCREMENTAL 1990 – 2000

REGION	INCREMENTAL GENERATION (GWh/yr)	UNIT COST (cents/kWh)			TOTAL ANNUAL COST ($ millions)		UNIT COST OF EMISSIONS AVOIDED ($/MT)		POLLUTION PREVENTED (million kg/yr)							
		AVOIDED	RENEWABLE	DIFFERENCE	AVOIDED	RENEWABLE	CO2 EQ	CO2	CO2 EQ	CARBON	CO2	CO	CH4	NOX	SO2	PM
New England	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Mid Atlantic	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
South Atlantic	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Florida	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East North Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West North Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East South Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West South Central	5,202	7.4	11.8	4.4	384	614	62	74	3,706	851	3,122	0.82	0.02	14.5	5.0	0.36
Mountain	2,167	6.9	11.4	4.4	150	247	38	45	2,504	585	2,143	0.29	0.02	9.0	4.4	0.58
Arizona/New Mexico	2,167	7.7	10.7	3.0	166	231	26	30	2,504	585	2,143	0.29	0.02	9.0	6.2	0.58
California	1,402	5.7	11.4	5.7	80	160	96	112	834	194	711	0.22	0.00	3.1	0.3	0.04
Washington/Oregon	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
TOTAL	10,938	7.1	11.4	4.3	781	1,252	49	58	9,548	2,215	8,120	1.62	0.06	35.6	15.9	1.54

INCREMENTAL 2000 – 2010

REGION	INCREMENTAL GENERATION (GWh/yr)	UNIT COST (cents/kWh)			TOTAL ANNUAL COST ($ millions)		UNIT COST OF EMISSIONS AVOIDED ($/MT)		POLLUTION PREVENTED (million kg/yr)							
		AVOIDED	RENEWABLE	DIFFERENCE	AVOIDED	RENEWABLE	CO2 EQ	CO2	CO2 EQ	CARBON	CO2	CO	CH4	NOX	SO2	PM
New England	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Mid Atlantic	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
South Atlantic	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Florida	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East North Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West North Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East South Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West South Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Mountain	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Arizona/New Mexico	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
California	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Washington/Oregon	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
TOTAL	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00

INCREMENTAL 1990 – 2010

REGION	INCREMENTAL GENERATION (GWh/yr)	UNIT COST (cents/kWh)			TOTAL ANNUAL COST ($ millions)		UNIT COST OF EMISSIONS AVOIDED ($/MT)		POLLUTION PREVENTED (million kg/yr)							
		AVOIDED	RENEWABLE	DIFFERENCE	AVOIDED	RENEWABLE	CO2 EQ	CO2	CO2 EQ	CARBON	CO2	CO	CH4	NOX	SO2	PM
New England	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Mid Atlantic	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
South Atlantic	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Florida	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East North Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West North Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East South Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West South Central	5,202	7.4	11.8	4.4	384	614	62	74	3,706	851	3,122	0.82	0.02	14.5	5.0	0.36
Mountain	2,167	6.9	11.4	4.4	150	247	38	45	2,504	585	2,143	0.29	0.02	9.0	4.4	0.58
Arizona/New Mexico	2,167	7.7	10.7	3.0	166	231	26	30	2,504	585	2,143	0.29	0.02	9.0	6.2	0.58
California	1,402	5.7	11.4	5.7	80	160	96	112	834	194	711	0.22	0.00	3.1	0.3	0.04
Washington/Oregon	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
TOTAL	10,938	7.1	11.4	4.3	781	1,252	49	58	9,548	2,215	8,120	1.62	0.06	35.6	15.9	1.54

TABLE B - 10b

RENEWABLE EMISSIONS MODEL RESULTS
EPA ENHANCED MARKET SCENARIO
SOLAR THERMAL ELECTRIC - HYBRID SYSTEMS

REGION	INCREMENTAL GENERATION (GWh/yr)	UNIT COST (cents/kWh)			TOTAL ANNUAL COST ($ millions)		UNIT COST OF EMISSIONS AVOIDED ($/MT)		POLLUTION PREVENTED (million kg/yr)							
		AVOIDED	RENEWABLE	DIFFERENCE	AVOIDED	RENEWABLE	CO2 EQ	CO2	CO2 EQ	CARBON	CO2	CO	CH4	NOX	SO2	PM
INCREMENTAL 1990 - 2000																
New England	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Mid Atlantic	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
South Atlantic	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Florida	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East North Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West North Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East South Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West South Central	7,603	7.4	10.7	3.3	576	836	47	55	5,559	1,277	4,683	1.23	0.02	21.8	7.8	0.52
Mountain	4,768	6.9	10.3	3.4	331	492	29	34	5,509	1,286	4,716	0.64	0.04	19.8	9.6	1.27
Arizona/New Mexico	4,768	7.7	9.7	2.0	366	463	18	21	5,509	1,286	4,716	0.64	0.04	19.8	13.6	1.27
California	4,003	5.7	10.4	4.6	230	416	78	92	2,381	554	2,030	0.64	0.01	8.7	0.8	0.12
Washington/Oregon	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
TOTAL	21,342	7.0	10.3	3.3	1,503	2,206	37	44	18,958	4,403	16,145	3.15	0.12	70.0	31.7	3.18
INCREMENTAL 2000 - 2010																
New England	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Mid Atlantic	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
South Atlantic	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Florida	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East North Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West North Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East South Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West South Central	3,901	9.5	8.8	-0.7	369	342	-10	-12	2,780	639	2,342	0.61	0.01	10.9	3.8	0.26
Mountain	2,384	7.2	8.5	1.3	173	203	11	13	2,673	624	2,287	0.32	0.02	9.6	4.6	0.60
Arizona/New Mexico	2,384	8.1	8.1	-0.1	194	193	-0	-1	2,673	624	2,287	0.32	0.02	9.6	6.4	0.60
California	2,384	10.3	8.6	-1.8	247	204	-30	-35	1,418	330	1,209	0.38	0.00	5.2	0.5	0.07
Washington/Oregon	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
TOTAL	11,054	8.9	8.5	-0.4	982	941	-4	-5	9,544	2,216	8,124	1.64	0.05	35.3	15.3	1.53
INCREMENTAL 1990 - 2010																
New England	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Mid Atlantic	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
South Atlantic	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Florida	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East North Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West North Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East South Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West South Central	11,704	8.1	10.1	2.0	946	1,177	26	33	8,339	1,916	7,026	1.84	0.03	32.7	11.3	0.79
Mountain	7,152	7.0	9.7	2.7	504	695	23	27	8,182	1,910	7,002	0.96	0.06	29.4	14.4	1.86
Arizona/New Mexico	7,152	7.8	9.2	1.3	560	656	12	14	8,182	1,910	7,002	0.96	0.06	29.4	20.0	1.86
California	6,387	7.5	9.7	2.2	476	620	38	44	3,798	883	3,239	1.02	0.01	13.9	1.2	0.19
Washington/Oregon	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
TOTAL	32,396	7.7	9.7	2.0	2,485	3,147	23	27	28,501	6,619	24,269	4.79	0.17	105.4	46.9	4.71

TABLE B - 11a

RENEWABLE EMISSIONS MODEL RESULTS
EPA BASE CASE
SOLAR THERMAL ELECTRIC

REGION	INCREMENTAL GENERATION (GWh/yr)	UNIT COST (cents/kWh)			TOTAL ANNUAL COST ($ millions)		UNIT COST OF EMISSIONS AVOIDED ($/MT)		POLLUTION PREVENTED (million kg/yr)							
		AVOIDED	RENEWABLE	DIFFERENCE	AVOIDED	RENEWABLE	CO2 EQ	CO2	CO2 EQ	CARBON	CO2	CO	CH4	NOX	SO2	PM
INCREMENTAL 1990 - 2000																
New England	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Mid Atlantic	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
South Atlantic	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Florida	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East North Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West North Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East South Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West South Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Mountain	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Arizona/New Mexico	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
California	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Washington/Oregon	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
TOTAL	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
INCREMENTAL 2000 - 2010																
New England	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Mid Atlantic	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
South Atlantic	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Florida	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East North Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West North Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East South Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West South Central	13,655	6.7	6.6	-0.1	918	899	-2	-2	10,183	2,338	6,574	2.28	0.04	40.0	13.2	0.92
Mountain	1,951	5.0	6.4	1.3	96	124	12	14	2,252	525	1,925	0.28	0.02	8.1	3.8	0.49
Arizona/New Mexico	1,951	5.7	6.0	0.4	110	117	3	4	2,252	525	1,925	0.28	0.02	8.1	5.2	0.49
California	1,951	7.7	6.4	-1.3	150	124	-21	-24	1,225	285	1,043	0.33	0.00	4.5	0.4	0.06
Washington/Oregon	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
TOTAL	19,506	6.5	6.5	-0.1	1,276	1,265	-1	-1	15,911	3,673	13,468	3.18	0.06	60.8	22.6	1.96
INCREMENTAL 1990 - 2010																
New England	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Mid Atlantic	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
South Atlantic	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Florida	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East North Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West North Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East South Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West South Central	13,655	6.7	6.6	-0.1	918	899	-2	-2	10,183	2,338	6,574	2.28	0.04	40.0	13.2	0.92
Mountain	1,951	5.0	6.4	1.3	96	124	12	14	2,252	525	1,925	0.28	0.02	8.1	3.8	0.49
Arizona/New Mexico	1,951	5.7	6.0	0.4	110	117	3	4	2,252	525	1,925	0.28	0.02	8.1	5.2	0.49
California	1,951	7.7	6.4	-1.3	150	124	-21	-24	1,225	285	1,043	0.33	0.00	4.5	0.4	0.06
Washington/Oregon	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
TOTAL	19,506	6.5	6.5	-0.1	1,276	1,265	-1	-1	15,911	3,673	13,468	3.18	0.06	60.8	22.6	1.96

TABLE B - 11b

RENEWABLE EMISSIONS MODEL RESULTS
EPA ENHANCED MARKET SCENARIO
SOLAR THERMAL ELECTRIC

REGION	INCREMENTAL GENERATION (GWh/yr)	UNIT COST (cents/kWh)			TOTAL ANNUAL COST ($ millions)		UNIT COST OF EMISSIONS AVOIDED ($/MT)		POLLUTION PREVENTED (million kg/yr)							
		AVOIDED	RENEWABLE	DIFFERENCE	AVOIDED	RENEWABLE	CO2 EQ	CO2	CO2 EQ	CARBON	CO2	CO	CH4	NOX	SO2	PM
INCREMENTAL 1990 - 2000																
New England	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Mid Atlantic	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
South Atlantic	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Florida	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East North Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West North Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East South Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West South Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Mountain	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Arizona/New Mexico	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
California	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Washington/Oregon	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
TOTAL	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
INCREMENTAL 2000 - 2010																
New England	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Mid Atlantic	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
South Atlantic	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Florida	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East North Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West North Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East South Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West South Central	56,569	6.7	6.1	-0.6	3,804	3,468	-8	-9	42,186	9,688	35,521	9.44	0.17	165.8	54.8	3.80
Mountain	8,453	5.0	5.9	0.9	425	502	8	9	9,758	2,275	8,342	1.23	0.07	35.3	16.4	2.12
Arizona/New Mexico	8,453	5.7	5.6	-0.0	478	474	-0	-0	9,758	2,275	8,342	1.23	0.07	35.3	22.7	2.12
California	8,453	7.7	5.9	-1.7	650	502	-28	-33	5,306	1,233	4,521	1.44	0.02	19.5	1.6	0.26
Washington/Oregon	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
TOTAL	81,927	6.5	6.0	-0.5	5,356	4,946	-6	-7	67,009	15,471	56,728	13.34	0.33	255.9	95.5	8.30
INCREMENTAL 1990 - 2010																
New England	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Mid Atlantic	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
South Atlantic	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
Florida	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East North Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West North Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East South Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West South Central	56,569	6.7	6.1	-0.6	3,804	3,468	-8	-9	42,186	9,688	35,521	9.44	0.17	165.8	54.8	3.80
Mountain	8,453	5.0	5.9	0.9	425	502	8	9	9,758	2,275	8,342	1.23	0.07	35.3	16.4	2.12
Arizona/New Mexico	8,453	5.7	5.8	-0.0	478	474	-0	-0	9,758	2,275	8,342	1.23	0.07	36.3	22.7	2.12
California	8,453	7.7	5.9	-1.7	650	502	-28	-33	5,306	1,233	4,521	1.44	0.02	19.5	1.6	0.26
Washington/Oregon	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
TOTAL	81,927	6.5	6.0	-0.5	5,356	4,946	-6	-7	67,009	15,471	56,728	13.34	0.33	255.9	95.5	8.30

TABLE B - 12a

RENEWABLE EMISSIONS MODEL RESULTS

EPA BASE CASE

WINDPOWER

REGION	INCREMENTAL GENERATION (GWh/yr)	UNIT COST (cents/kWh)			TOTAL ANNUAL COST ($ millions)		UNIT COST OF EMISSIONS AVOIDED ($/MT)		POLLUTION PREVENTED (million kg/yr)							
		AVOIDED	RENEWABLE	DIFFERENCE	AVOIDED	RENEWABLE	CO2 EQ	CO2	CO2 EQ	CARBON	CO2	CO	CH4	NOX	SO2	PM
INCREMENTAL 1990 - 2000																
New England	635	5.1	6.0	0.8	33	38	11	12	497	121	444	0.10	0.00	1.3	2.9	0.09
Mid Atlantic	33	2.7	6.0	3.2	1	2	28	32	38	9	33	0.00	0.00	0.1	0.3	0.01
South Atlantic	49	2.5	6.0	3.4	1	3	29	34	58	14	50	0.01	0.00	0.2	0.4	0.01
Florida	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East North Central	39	2.5	6.6	4.1	1	3	35	41	47	11	40	0.01	0.00	0.2	0.5	0.01
West North Central	2,407	2.8	4.7	1.9	67	112	16	18	2,880	671	2,461	0.35	0.02	10.4	21.0	0.64
East South Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West South Central	61	3.4	5.3	1.9	2	3	24	28	49	11	41	0.01	0.00	0.2	0.1	0.01
Mountain	3,577	2.5	4.7	2.1	90	167	18	21	4,278	997	3,667	0.51	0.03	15.5	7.4	0.96
Arizona/New Mexico	108	2.9	5.3	2.3	3	6	20	23	129	30	110	0.02	0.00	0.5	0.3	0.03
California	831	4.0	4.4	0.4	33	36	6	7	520	121	442	0.14	0.00	1.9	0.2	0.03
Washington/Oregon	166	3.5	4.8	1.2	6	8	10	11	210	49	179	0.02	0.00	0.8	1.2	0.05
TOTAL	7,906	3.0	4.8	1.8	236	377	16	19	8,706	2,034	7,457	1.16	0.06	31.1	34.2	1.84
INCREMENTAL 2000 - 2010																
New England	2,082	6.9	4.6	-2.4	145	95	-30	-34	1,629	397	1,454	0.32	0.01	4.3	9.6	0.30
Mid Atlantic	32	3.5	4.6	1.1	1	1	9	11	38	9	31	0.00	0.00	0.1	0.3	0.01
South Atlantic	53	3.2	4.6	1.4	2	2	12	14	62	14	53	0.01	0.00	0.2	0.4	0.01
Florida	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East North Central	43	3.1	4.6	1.5	1	2	13	16	50	12	42	0.01	0.00	0.2	0.5	0.01
West North Central	11,800	3.4	4.0	0.6	401	478	6	7	13,712	3,195	11,713	1.72	0.10	49.8	97.0	2.96
East South Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West South Central	747	5.1	4.2	-0.8	38	32	-11	-12	592	136	499	0.12	0.00	2.3	0.9	0.07
Mountain	19,541	3.1	4.0	0.9	610	791	8	9	22,704	5,290	19,395	2.85	0.17	82.4	36.0	4.93
Arizona/New Mexico	587	3.5	4.2	0.7	21	25	6	7	683	159	583	0.09	0.01	2.5	1.6	0.15
California	2,723	6.3	4.0	-2.3	171	108	-37	-44	1,706	395	1,449	0.45	0.01	6.4	0.6	0.09
Washington/Oregon	908	3.7	4.0	0.3	34	37	3	3	1,147	267	960	0.13	0.01	4.2	6.4	0.27
TOTAL	38,517	3.7	4.1	0.4	1,423	1,571	3	4	42,321	9,873	36,202	5.69	0.31	152.4	155.3	8.82
INCREMENTAL 1990 - 2010																
New England	2,718	6.5	4.9	-1.6	177	133	-21	-23	2,126	518	1,898	0.41	0.02	5.7	12.6	0.40
Mid Atlantic	65	3.1	5.3	2.2	2	3	19	22	75	18	64	0.01	0.00	0.3	0.6	0.02
South Atlantic	102	2.9	5.2	2.4	3	5	20	24	121	28	103	0.01	0.00	0.4	0.8	0.03
Florida	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East North Central	82	2.8	5.6	2.7	2	5	23	27	96	22	82	0.01	0.00	0.3	1.0	0.02
West North Central	14,207	3.3	4.2	0.9	468	590	7	9	16,592	3,866	14,175	2.07	0.12	60.2	117.9	3.62
East South Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West South Central	809	4.9	4.3	-0.6	40	35	-8	-9	640	147	540	0.13	0.00	2.5	1.0	0.07
Mountain	23,118	3.0	4.1	1.1	700	958	10	11	26,983	6,287	23,062	3.36	0.20	97.9	45.3	5.89
Arizona/New Mexico	695	3.5	4.4	0.9	24	31	8	10	811	189	693	0.10	0.01	2.9	1.9	0.18
California	3,554	5.7	4.1	-1.7	204	144	-27	-32	2,226	516	1,891	0.59	0.01	8.3	0.8	0.11
Washington/Oregon	1,074	3.7	4.2	0.5	40	45	4	4	1,357	316	1,159	0.15	0.01	4.9	7.5	0.32
TOTAL	46,423	3.6	4.2	0.6	1,661	1,948	6	7	51,026	11,907	43,659	6.86	0.37	183.5	189.5	10.66

TABLE B - 12b

RENEWABLE EMISSIONS MODEL RESULTS
EPA ENHANCED MARKET SCENARIO
WINDPOWER

REGION	INCREMENTAL GENERATION (GWh/yr)	UNIT COST (cents/kWh)			TOTAL ANNUAL COST ($ millions)		UNIT COST OF EMISSIONS AVOIDED ($/MT)		POLLUTION PREVENTED (million kg/yr)							
		AVOIDED	RENEWABLE	DIFFERENCE	AVOIDED	RENEWABLE	CO2 EQ	CO2	CO2 EQ	CARBON	CO2	CO	CH4	NOX	SO2	PM
INCREMENTAL 1990 - 2000																
New England	850	5.1	5.5	0.4	43	47	5	6	665	162	593	0.13	0.01	1.8	3.9	0.12
Mid Atlantic	98	2.7	5.5	2.8	3	5	24	26	115	27	99	0.01	0.00	0.4	0.9	0.03
South Atlantic	163	2.5	5.5	3.0	4	9	25	29	195	46	167	0.02	0.00	0.7	1.4	0.04
Florida	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East North Central	131	2.5	8.2	3.7	3	8	31	36	156	36	134	0.02	0.00	0.8	1.6	0.03
West North Central	7,221	2.8	4.3	1.5	202	310	12	15	8,639	2,014	7,384	1.04	0.07	31.3	62.9	1.93
East South Central	0	NA	NA	NA	0	0	NA	NA	0	0	.0	0.00	0.00	0.0	0.0	0.00
West South Central	229	3.4	4.9	1.5	8	11	19	22	181	42	153	0.04	0.00	0.7	0.3	0.02
Mountain	11,959	2.5	4.3	1.8	303	513	15	17	14,304	3,334	12,226	1.72	0.11	51.7	24.6	3.20
Arizona/New Mexico	359	2.9	4.9	1.9	11	18	16	19	430	100	368	0.05	0.00	1.6	1.0	0.10
California	2,222	4.0	4.0	0.0	89	89	0	0	1,392	323	1,183	0.37	0.00	5.2	0.5	0.07
Washington/Oregon	1,111	3.5	4.4	0.9	39	49	7	8	1,404	327	1,200	0.15	0.01	5.1	7.6	0.33
TOTAL	24,344	2.9	4.3	1.5	704	1,058	13	15	27,480	6,411	23,505	3.56	0.20	99.0	104.9	5.88
INCREMENTAL 2000 - 2010																
New England	5,831	6.9	4.0	-2.9	405	236	-37	-42	4,561	1,111	4,072	0.89	0.04	12.1	27.0	0.85
Mid Atlantic	505	3.5	4.0	0.5	18	20	5	5	574	135	493	0.07	0.00	2.0	4.2	0.13
South Atlantic	841	3.2	4.0	0.9	27	34	7	9	977	228	835	0.12	0.01	3.5	6.8	0.21
Florida	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East North Central	673	3.1	4.0	0.9	21	27	8	9	781	182	668	0.10	0.01	2.8	7.8	0.17
West North Central	37,173	3.4	3.6	0.2	1,263	1,328	1	2	43,198	10,064	36,901	5.41	0.32	156.8	305.4	9.38
East South Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West South Central	1,177	5.1	3.7	-1.3	60	44	-17	-20	932	215	787	0.19	0.00	3.6	1.5	0.10
Mountain	81,562	3.1	3.6	0.5	1,920	2,199	4	5	71,527	16,664	61,102	8.97	0.53	259.7	119.6	15.64
Arizona/New Mexico	1,850	3.5	3.7	0.2	66	69	2	2	2,150	501	1,837	0.27	0.02	7.8	5.0	0.47
California	2,859	6.3	3.5	-2.8	180	100	-44	-52	1,791	415	1,522	0.48	0.01	6.7	0.6	0.09
Washington/Oregon	2,559	3.7	3.6	-0.2	107	102	-1	-1	3,613	842	3,088	0.40	0.03	13.1	20.1	0.85
TOTAL	115,331	3.5	3.6	0.1	4,066	4,159	1	1	130,105	30,358	111,306	16.90	0.97	468.2	498.0	27.89
INCREMENTAL 1990 - 2010																
New England	6,681	6.7	4.2	-2.5	449	282	-32	-36	5,226	1,272	4,665	1.02	0.05	13.9	31.0	0.98
Mid Atlantic	603	3.4	4.3	0.9	20	26	8	9	688	161	592	0.09	0.01	2.4	5.1	0.15
South Atlantic	1,004	3.1	4.3	1.2	31	43	10	12	1,173	273	1,002	0.15	0.01	4.3	8.2	0.26
Florida	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
East North Central	804	3.0	4.4	1.4	24	36	12	14	936	218	801	0.12	0.01	3.4	9.4	0.20
West North Central	44,394	3.3	3.7	0.4	1,465	1,637	3	4	51,836	12,078	44,285	6.45	0.39	188.1	368.3	11.32
East South Central	0	NA	NA	NA	0	0	NA	NA	0	0	0	0.00	0.00	0.0	0.0	0.00
West South Central	1,406	4.8	3.9	-0.9	68	55	-11	-13	1,113	256	940	0.23	0.01	4.3	1.8	0.12
Mountain	73,522	3.0	3.7	0.7	2,223	2,712	6	7	85,831	19,999	73,329	10.69	0.64	311.4	144.2	18.74
Arizona/New Mexico	2,210	3.4	3.9	0.5	76	87	4	5	2,580	601	2,204	0.32	0.02	9.4	6.0	0.56
California	5,081	5.3	3.7	-1.6	268	189	-25	-29	3,183	738	2,704	0.85	0.01	11.9	1.2	0.16
Washington/Oregon	3,970	3.7	3.8	0.1	146	151	1	1	5,017	1,169	4,287	0.56	0.04	18.2	27.9	1.18
TOTAL	139,675	3.4	3.7	0.3	4,770	5,217	3	3	157,585	36,768	134,810	20.46	1.17	567.2	602.9	33.68

APPENDIX C

RENEWABLE ELECTRIC MODEL DESCRIPTION

The Renewable Electric Model (REM) used in the cost and emission analysis is a set of linear equations and coefficient matrices that estimate the avoided costs the displaced emissions from regional projections of renewable electric generation.

Geographical Regions

A fundamental premise of the analysis is that regional variation in renewable energy resource bases and in utility systems is an important determinant of the avoided costs and emissions from fossil fuel generation. Twelve geographical regions are used to depict variation in renewable resource bases and electricity supply systems.

Renewable Electric Levelized Costs

The REM converts cost and performance data for renewable electric technologies into levelized (cents/kilowatthour) costs. These technical data are reported in Appendix A. The levelized cost methodology (1) annualizes capital cost ($/KW) with a capital charge rate of 0.10; (2) allocates the annual capital cost across yearly generation using a capacity factor (which can vary by region); and (3) adds to this levelized capital cost the operating and maintenance (O&M) and fuel costs on a cent/kWh basis. This is a conventional real levelization costing approach.

Renewable Electric Generation Profiles

Renewable resources can vary by region, season, and time of day. Solar technologies, for example, only provide power during the daylight hours, while hydroelectric resources are usually available more during the spring runoff and fall rainy seasons. Biomass generation, on the other hand, depends only on fuel supplies that typically are available year round when adequate storage exists. Thus, each renewable electric technology has an annual operating pattern or "generation profile" that describes the likely hours of power supply during the year.

Regional generation profiles were constructed for each technology for three seasons (winter, summer, and spring/fall) and for peak (daytime) and off-peak (nighttime) periods. For each technology, and each region, there were six coefficients (three seasons times two daily periods) which represented the fraction of annual generation likely to occur in each seasonal/daily load segment. For baseload technologies, constant annual operation was assumed. The annual output of intermittent technologies were assigned to load segments based on available average resource data, although subjective assessments were unavoidable for some resource/region combinations. These coefficients only distributed the annual generation across time segments; they sum to one by construction. Thus, they are distinct from a capacity factor, which expresses the fraction of hours during the year that a plant will operate; nor are they related to the peak load reliability factors (capacity credits) used in the avoided capital cost calculations.

Regional Electric Utility Description

Electric utilities vary their generation mix depending on the level of electricity demand. In periods of low demand, such as nighttime, electric utilities operate only their lowest cost generation plants, which are usually coal, nuclear, and in some regions hydroelectric plants. As demand levels increase, they bring on line their more expensive oil and gas generation units. Since greenhouse gas emission rates are significantly different for these different types of generation units, emissions can vary significantly due to seasonal and time of day variations in renewable electric output levels. Avoided costs depend on those factors plus a reliability component that determines whether renewable electric generation can displace capacity builds in the long run.

The utility side of the REM depicts the generation units most likely to be displaced by increased renewable electric contribution. The renewable electric generation -- distributed by region, season, and time of day through the generation profiles -- is mapped onto identically dimensioned matrices of coefficients that give avoided utility costs and emissions. These coefficients are based on the plants that would otherwise be dispatched to meet seasonal and daily loads in each region. The model incorporates judgments concerning the *marginal* (highest cost) fossil fuel-fired plants in the utility dispatch decision for each load segment, as these would be the most likely plants "backed down" to accommodate additional renewable generation.

The marginal utility resource coefficients were based on extensive modeling experience with the Integrated Planning Model (IPM) developed by ICF Resources. This detailed utility simulation model has been used to model most of the major utility systems in the country. Those simulation results informed the construction of the marginal resource coefficients, which are interpreted as the dispatch mix used to generate the most expensive 25 percent of the electricity generated in the peak and off-peak periods during each season. This assumed mix of fossil fuel generation resources -- coal-, oil-, and gas-fired units -- provides the basis for evaluating the avoided utility costs and emissions.

Avoided Emissions

Avoided emissions from renewable generation are a function of the marginal utility resource coefficients described above. The assumed blend of fossil fuel units yield a marginal emission coefficient for each load segment, based on the emission characteristics.

Emission estimates for carbon dioxide, carbon monoxide, nitrogen oxides, and methane were based on national average rates for all fossil fuel generation types. Sulfur dioxide emission rates for oil- and coal-fired power plants were based on regional SO_2 emission rates.

National average fossil fuel emission rates were based on an analysis by Radian Corporation:

EMISSION FACTORS FOR ELECTRIC GENERATION

(KG/MMBTU OUTPUT)

UNIT TYPE	CO2	CO	CH4	NOX
Residual Fuel Boiler	243.980	0.047	0.003	0.627
Distillate Fuel Boiler	233.370	0.047	0.000	0.211
Natural Gas Boiler	159.117	0.056	0.003	0.785
Coal - PC Wall Fired	350.054	0.045	0.003	1.484

Source: Radian Corporation, *Emissions and Cost Estimates from Globally Significant Anthropogenic Combustion Sources of NOX, N2O, CH4, and CO2*, December 28, 1987.

Regional SO_2 emission factors for oil- and coal-fired powerplants were developed from DOE/EIA data from 1988. Several renewable electric technologies -- such as biomass and solar thermal/natural gas hybrid systems -- emit some atmospheric pollutants. These emissions were netted out from avoided emission estimates for these technologies.

Avoided Costs

Electricity avoided cost estimates were calculated from three components:

- avoided cost of oil, natural gas, and coal purchases;
- variable operation and maintenance costs; and
- capital cost of new capacity.

The fuel and O&M costs avoided were based on generation displaced by the marginal resource coefficients for each region, season, and period. Avoided capital costs were more complicated, and are determined by new capacity costs and renewable generation reliability in peak demand seasons.

Avoided Fuel and O&M Costs

The avoided costs for electric utility purchases of oil and coal were derived from the EIA's price projections.[1] The natural gas fuel avoided costs were based on EIA projections and were adjusted to reflect seasonal variations.

The electric utility variable operation and maintenance cost estimates used for this analysis were 2.2 mills per kwh delivered for oil and gas plants and 3.3 mills per kwh for coal plants. These cost estimates were based on data used in the Integrated Planning Model.

Avoided Capital Costs

The avoided capital cost estimates represent the costs savings associated with reduced need for electric utility capacity additions. Electric utilities must have sufficient generating capacity to meet the peak electricity demand for their system. When peak demand increases, the electric utility will incur costs associated with the construction of additional generating capacity to meet that increase in consumption and maintain their target capacity reserve margin. A reduction in demand growth or an increase in renewable generation will lead to a cost savings due to avoided fossil capacity expansion.

For this analysis, the projections of the North American Electric Reliability Council were used to construct regional capacity addition mixes for the year 2000. Between 2000 and 2010, new capacity additions in each region are assumed identical to the nationwide average EIA projections. The Electric Power Research Institute Technical Assessment Guide (EPRI TAG) provided the capital cost data for new fossil-fuel generating units. The assumptions about future capacity additions and capital cost data were blended to create a marginal capital cost for each region in the year 2000 and 2010.

Instead of spreading these capital costs over the entire load curve (i.e. the generation profile), the capital costs were allocated to one peak period or split among two periods depending on the

---

[1] Department of Energy, Energy Information Administration, Regional Projections of End-Use Energy Consumption and Prices Through 2000, April 1989. Annual Energy Outlook 1990, January 12, 1990.

region. The following table lists the assumed peak season(s) for each of the twelve regions. These peak season assumptions were made based on seasonal peak generation data reported by the North American Electric Reliability Council.[2] In general, most regions are summer peaking or summer and winter peaking. Only Florida and Washington/Oregon are winter peaking regions. Florida is a winter peaking region apparently due to the influx of tourists during winter months.

SEASONAL PEAK GENERATION ASSUMPTIONS

Region	Peak Seasons
New England	Summer and Winter
Mid-Atlantic	Summer
South Atlantic	Summer
Florida	Winter
East North Central	Summer and Winter
East South Central	Summer
West North Central	Summer
West South Central	Summer
North Mountains	Summer and Winter
Arizona/New Mexico	Summer and Winter
Washington/Oregon	Winter
California	Summer

The electricity capacity cost estimates were allocated to either a single season (winter <u>or</u> summer) region, or split among the two peaks in two season (winter <u>and</u> summer) peaking regions. The number of hours in a peak season was calculated based on a 13 hour peak time of day period and

[2] North American Electric Reliability Council, <u>1989 Electricity Supply and Demand</u>, October, 1989.

three months to a season. Thus, the number of hours in a peak period for regions with a single peak season was estimated to be 1,186.[3]

This capital cost allocation was necessary to account for reliability when estimating potential capacity avoided by expanding intermittent renewable generation. Each renewable technology was assigned a "capacity credit" factor valued between zero (no capital displacement) and one (peak reliability equivalent to fossil units). Baseload renewables such as biomass electric were given a capacity credit of one; biomass generation is "firm" capacity that can be counted on during daily and seasonal peak demand periods. Other renewables received partial capacity credit, such as wind and solar technologies. The combination of the generation profile coefficient and the capacity credit will determine the capital cost displaced by an intermittent renewable generation technology in a given region. This costing methodology can reflect "coincidence factors," or the correlation between an intermittent renewable resource and a regional utility system peak demand. High coincidence factors make renewables nearly as valuable as dispatchable fossil fuel units, while low coincidence factors will limit the avoided capital cost from expanded renewable electric generation. Capacity credits for intermittent technologies are given in Appendix A.

---

[3] The number of peak hours for a region with a single peak season was calculated as follows:

1,186 = 8,760 hours per year * (13 hours in daily peak / 24 hours per day) * (3 months per season / 12 months per year).