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The Potential of Renewable Energy

An Interlaboratory White Paper

Idaho National Engineering Laboratory
Los Alamos National Laboratory
Oak Ridge National Laboratory
Sandia National Laboratories
Solar Energy Research Institute

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March 1990

Prepared for the
Office of Policy, Planning and Analysis
U.S. Department of Energy
Under Contract No. DE-AC02-83CH10093

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Preface

On June 27 and 28, 1989, the U.S. Department of Energy (DOE) national laboratories were convened to discuss plans for the development of a National Energy Strategy (NES) and, in particular, the analytic needs in support of NES that could be addressed by the laboratories. As a result of that meeting, interlaboratory teams were formed to produce analytic white papers on key topics, and a lead laboratory was designated for each core laboratory team. The broad-ranging renewables assignment is summarized by the following issue statement from the Office of Policy, Planning and Analysis:

> To what extent can renewable energy technologies contribute to diversifying sources of energy supply? What are the major barriers to greater renewable energy use and what is the potential timing of widespread commercialization for various categories of applications?

This report presents the results of the intensive activity initiated by the June 1989 meeting to produce a white paper on renewable energy. Scores of scientists, analysts, and engineers in the five core laboratories gave generously of their time over the past eight months to produce this document. Their generous, constructive efforts are hereby gratefully acknowledged.

Idaho National Engineering Laboratory	**Los Alamos National Laboratory**	**Oak Ridge National Laboratory**	**Sandia National Laboratories**
Joel Renner	Richard Benson	William Fulkerson	Eldon Boes
Susan Stiger	Michael Berger	Jack Ranney	Henry Dodd
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Solar Energy Research Institute

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Lynn Coles	David Hudson	Walter Short	Carl Wallace
Bimleshwar Gupta	Robert McConnell	Don Stevens	Federica Zangrando
	Marty Murphy	Tom Surek	Kenneth Zweibel

Contributions to the document were also received from several laboratories that were not part of the consensus-forming core group. The support of Brookhaven National Laboratory, Lawrence Berkeley National Laboratory, and Pacific Northwest Laboratory is appreciated.

More than 30 experts from universities, industry, and policy analysis organizations have contributed to this white paper by reviewing a final draft. They are recognized individually in Appendix K. Their efforts are greatly appreciated.

Finally, special mention should be made of the untiring efforts of Joyce Rush of SERI, without whose diligence this document would never have become a reality.

Thomas D. Bath

Thomas D. Bath, SERI
Task Force Chairman

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The Potential of Renewable Energy

Executive Summary

This document is an evaluation of the present and projected performance status of the renewable energy technologies (RETs) and their potential contributions to the nation's energy requirements over the next four decades. It has been prepared for the National Energy Strategy (NES) Study by the U.S. Department of Energy's national laboratories in response to a request from the Office of Policy, Planning and Analysis. Based on a consensus-forming approach to the assessment of many difficult questions, the paper attempts to convey a sense of what *is* and *is not* known about the range of technical and analytic issues surrounding RET deployment. Although it is apparent that uncertainties are large, we felt that an expert consensus with visible uncertainty was preferable to an *apparently* precise analysis based on unvalidated modeling constructs. As requested, the white paper identifies broadly the research, development, and demonstration (R,D&D) thrusts which, if undertaken, would in our judgment remove the key technological constraints on the utilization of these energy resources and thereby enhance the contribution renewable energy can make. The paper also identifies a number of other constraints, largely institutional, that can be reduced or removed with appropriate action. It does not address the question of what is the appropriate national energy policy, nor does it suggest what policy actions might be undertaken to address the needs discussed here.

In collaborating to produce this report, the Task Force members saw themselves as representatives of a larger community of scientists and engineers who have worked to improve the RETs for more than a decade. Thus, although the report focuses on the impacts of federal policy, it does so in the context of a sustained federal/industry partnership. Ultimate success in this area depends on use of the RETs in the private sector. The best way to ensure that the developed technology is used is to involve users in its development.

Key Results of This Study

1. The availability of the renewable resource is not the limiting factor in the RET contribution; rather, the constraints are technical, institutional, and economic.
2. The fraction of U.S. energy demand currently supplied by renewables (8%) is certain to grow, but only slowly without expanded support for renewable energy.
3. The extent of federal R,D&D support can have a great influence on the rate of increase of renewables' market share and on the success of the domestic RET industry in U.S. and world markets in the coming decades.
4. Expanded federal leadership can lead to a substantial diversification of the U.S. energy mix, while at the same time reducing the environmental impacts of energy supply and reducing the need to import foreign energy resources.

Of the five major primary energy-supply resource categories (oil, gas, coal, nuclear, and renewables), renewable energy is the fourth largest, supplying 8% of the nation's energy in 1988, as shown in Figure 1. The 7 quads of energy supplied by renewable energy in 1988 exceeded the total energy provided by nuclear resources in the same year. The largest portion of the contribution of renewable energy today is from mature technologies that make use of biomass and hydropower resources. The newer technologies developed over the past two decades are beginning to enter the market and will provide an increasing share of renewable energy supplies in coming decades.

The market penetration potential of RETs was assessed by reviewing expected performance against demand and market competition constructs, which are described in the body of the document. This effort, which considered regionalized energy demand and price projections and took into account competition among the renewable options, was designed to produce mid-range penetration estimates. The 40-year time horizon for these estimates introduces very large uncertainties, both with regard to the evolution of the performance and costs associated with technologies that provide energy from renewable resources and with regard to the evolution of the markets in which these technologies compete. However, all energy technologies--and the NES process itself--must deal with substantial uncertainty that increases over time. For simplicity, we have approached our RET performance and penetration projections from a mid-range point of view over three scenarios of RET deployment described below. Ideally, we would have preferred to apply upper and lower bounds and used a range of variables to derive a band of outcomes. We were not able to conduct the study at this level of sophistication because of time and resource limitations.

We find that the contribution of renewable energy to total energy requirements in competition with other energy supply systems should grow over the next four decades, assuming that research and development expenditures continue at present levels, which reflect major reductions from those at the peak of the "oil crisis." In our Business-as-Usual (BAU) Scenario, illustrated in Figure 2, we project that by 2030, renewable energy will provide a domestic contribution of 22 quads, or 15% of projected total energy needs. This assumes that federal funding continues at current levels and energy/environmental policy is unchanged. In this scenario, industry eventually provides much of the development impetus as the technologies become more clearly economic. If federal R,D&D expenditures are expanded by two to three times, or some $3 billion over the next two decades, the projected contribution of renewable energy is nearly double that in the BAU Scenario, or 41 quads by 2030. It is our opinion that such levels of expenditure have been shown by past efforts to be sustainable and effective, and they would pursue well-defined objectives along identified R&D pathways. Much of the

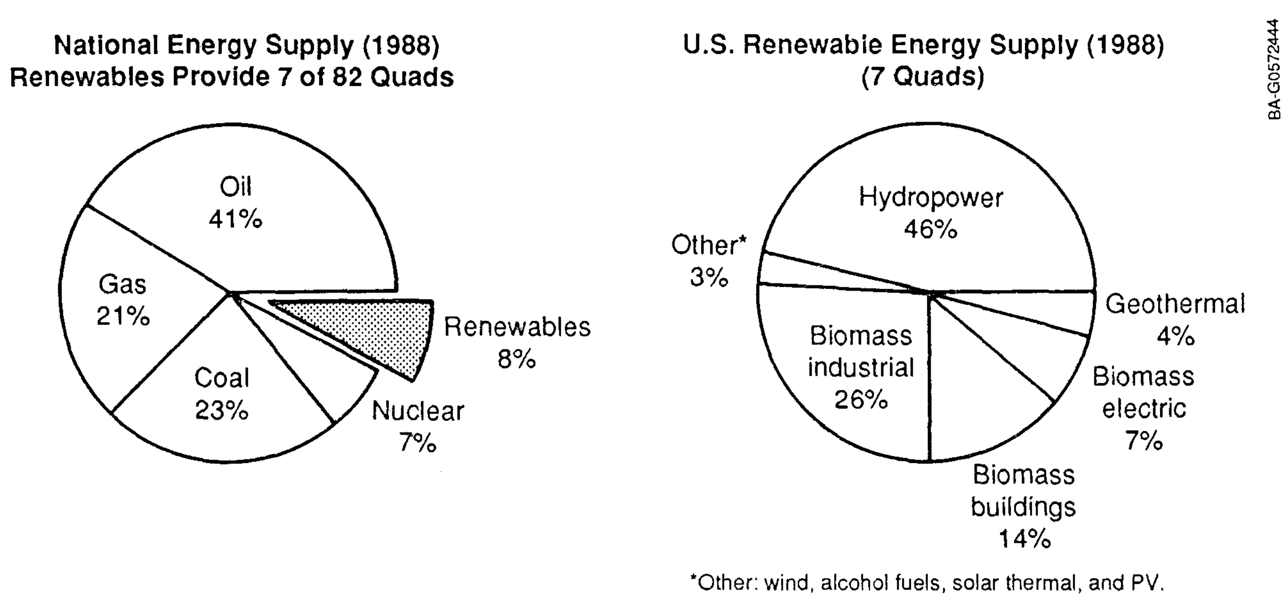

Figure 1. National energy supplies and the renewable contribution

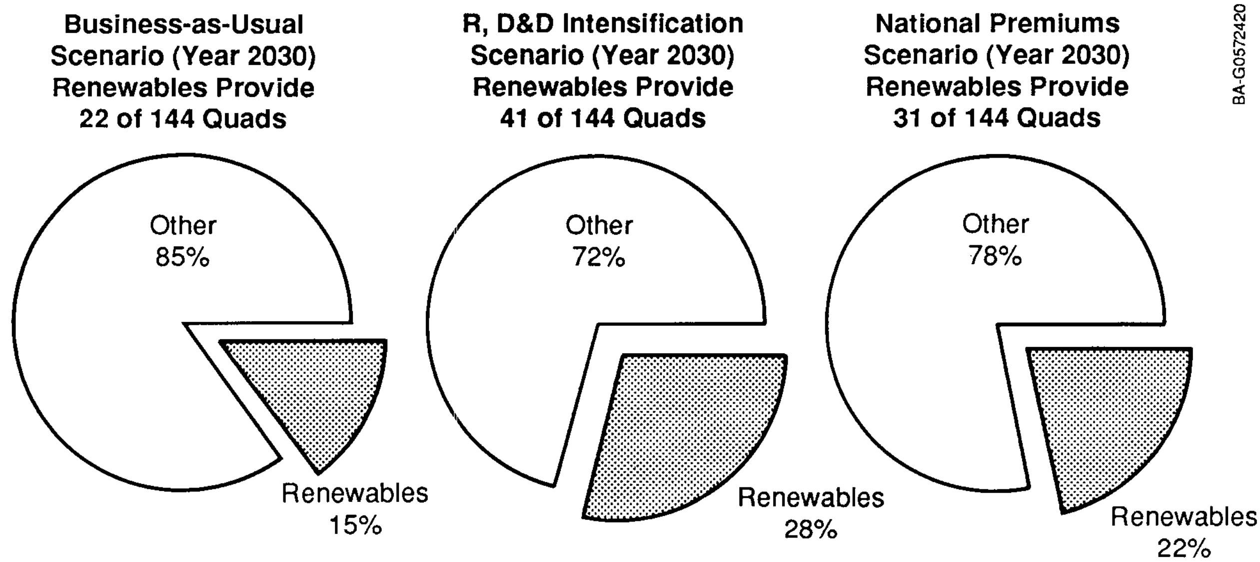

Figure 2. Future contribution of renewables

gain projected in our R,D&D Intensification Scenario is due to the acceleration of the technological improvements that private industry would otherwise pursue independently much later in time as economics become more favorable and risks smaller. This estimate of a substantially greater contribution suggests that large economic and security benefits will derive from this investment because of the existence of a greater range of economic energy alternatives. Additional benefits would accrue as well, because of the generally environmentally attractive character of the RETs.

In addition to the "technology push" implied by the R,D&D Intensification Scenario, the study explored the implications of a "market pull" approach we called the National Premiums Scenario. We assumed that a substantial market incentive (described in Section V) would be applied in order to capture environmental and other national values relevant to renewables. We also assumed that this market incentive would begin to be applied in 1990 to all new RET deployment decisions and continue at that level through 2030. Thus, the market incentive largely affects the deployment of technologies that are at or near market competitiveness. The results of this analysis suggested a 9-quad increase (over BAU) in the renewable energy contribution by 2030. The relatively small size of this increase is largely due to the inability of the premium to substitute for the relatively large increases in RET performance necessary for several of the technologies to enter the competitive range in projected markets.

Both the R,D&D Intensification Scenario and the National Premiums Scenario are artificial constructs, structured for analytic simplicity rather than to detail the realities of the market. Any effort designed to explore technology-push or market-pull mechanisms to increase the deployment of renewable supplies would consider cost-effectiveness in choosing policies, probably applying a mix of policy mechanisms over time to achieve desired goals. Therefore, we do not feel that either scenario represents an upper limit on the potential contribution of renewables.

The contributions from renewable energy presented in this report reflect a mid-range assessment of economic accomplishments, given the inherent uncertainties of the R,D&D process. We are unable to address many other uncertainties, such as those surrounding the demand and price projections used in this study. Neither are we able to assess how conservation and other energy supply systems respond to the impact of the expanded deployment of renewable energy projected in our R,D&D Intensification and National Premiums cases. We have also assumed that no other significant environmental or energy policy changes are implemented that will have impacts on renewable or other energy systems. Most important, we were unable to assess the impact of expanded renewable energy deployment on the projections of market prices of other energy forms. If the markets available for competitive energy are smaller than those reflected in our base case assumptions, market forces are likely to result in lower prices for oil, gas, and coal.

The projected potential contribution of renewable energy rests on a sound base. As shown in Figure 3, the estimated available domestic renewable resources are huge compared with the remaining available U.S. fossil fuel resources projected by the U.S. Geological Survey (USGS). Although today's proven reserves of renewable energy are small relative to proven fossil energy reserves, the relative size of the accessible resource shows the large potential benefit of successful renewable technology development. More detail on this and other relevant comparisons is provided in Section II. This study considers potential limitations of access to renewable resources and competitive uses for land and other resources. In many cases, more than one RET is expected to be competitive in the electric power generation and liquid fuels markets. Hence, the overall projection of the contribution of renewables is neither a maximum potential, nor does it require the success of all technological pathways. Finally, it is our opinion that renewable energy will capture additional energy market share *after* 2030 as technological progress continues and institutional constraints are overcome.

The R,D&D efforts needed to accomplish the projected contribution of RETs are relatively well known. The efforts of the past two decades have permitted key technological constraints and most promising opportunities to be identified, thereby allowing future work to be focused efficiently in the areas that will be most productive in making the renewable technologies competitive with conventional supplies. Expanded efforts would also be targeted to accelerate the deployment of renewable energy, with the government effectively underwriting the risks that the private sector would be unable to justify at this stage of the industry's development. Finally, increased domestic R,D&D should also allow the U.S. manufacturing sector to capture a larger share of renewable energy equipment markets in the United States and overseas.

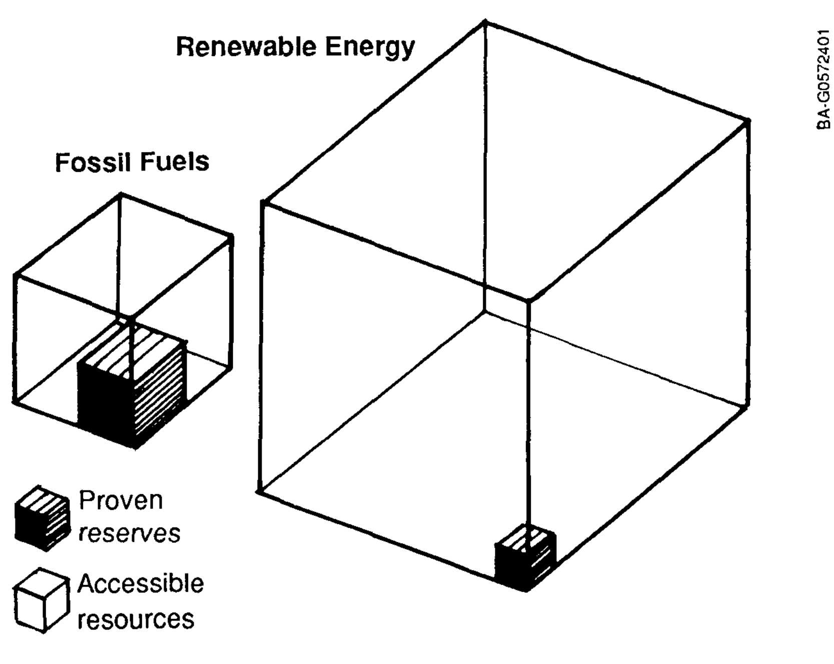

Figure 3. Available U.S. energy resources

Beyond supply diversity, there are other advantages to the United States from expanded use of renewable energy. These are summarized in Section IV and include environmental, security and indirect economic benefits.

In recent years, many industrialized countries have been increasing their R,D&D contributions in support of RETs. They are emphasizing the technologies that appear to have the greatest national potential. For example, Denmark has promoted wind energy, Germany and Japan are investing in photovoltaics, and China is pursuing low-head hydropower. If the United States does not take similar positive actions, foreign manufacturers may gain the advantage in international and even U.S. markets when the technologies reach commercial maturity.

As noted earlier, technological constraints are not the only ones that have impacts on the deployment of RETs. A number of institutional constraints also act to slow the expansion. Some of these are a matter of timing; some of education or technology transfer; some are products of the technological and economic structure of energy-using systems (e.g., autos, buildings); some emanate from financial and tax systems; and others are products of regulatory structure. Many of these institutional constraints can be eliminated, or their impacts reduced, thereby further accelerating the implementation of RETs. The following problem areas, then, present opportunities for appropriate remedies:

- *Integration into existing energy systems.* Renewable technologies face a number of problems connected with integration into electric power and fuel supply systems. Remote electric power sources such as geothermal systems, for example, may not have access to transmission facilities because of location, competitive demands on available facilities, ownership issues, etc., even if there is a market demand for the power. Power may not be provided with the desired degree of dispatchability and storage, or other load-leveling capacities may not be available. Alcohol fuels may require special fleets or vehicles or special distribution facilities; the demand will not exist until the using facilities are in place. The potential fuel supplier may be unable to remove such obstacles without assistance.

- *Access to resources.* The dispersed character of renewable energy resources introduces a number of institutional impacts. Competition, real or perceived, for land use with agricultural, recreational, scenic, or other uses frequently evokes strong reactions from government agencies or other groups. Often, complex trade-offs are involved. In the absence of a comprehensive, detailed assessment of the environmental impacts of renewable energy systems, we have developed our projections based on the generally accepted position that renewable energy is less environmentally intrusive than other options.

- *Perceived risks.* Because most of these new technologies are being developed with heavy government involvement, potential users may understand less about their nature and background than they do about the conventional energy technologies and their recent modifications. Demonstration projects and other evidence of reliability and operability acceptable to industry may be needed to a greater extent for renewables than for evolving conventional technologies.

- *Treatment of risk factors in comparing technologies.* Low initial capital costs can make almost any energy system *appear* attractive in comparison to high-capital-cost technologies. However, over time, price fluctuations in fuel markets, escalations in plant decommissioning costs, or other uncertain future events can put a greater burden on future costs than the one originally estimated. For example, in the electric utility industry, several U.S. utilities installed base-load, oil-fired facilities before the oil supply difficulties of the 1970s. Thus, the decision to use oil for fuel exposed utilities and customers to higher prices and availability problems that were not quantified initially. Renewable electric technologies, having low or no fuel costs, offer protection from such fuel price fluctuations but may be given little economic credit in decision-making for this important risk-reducing quality. There are pressures on the regulated utility market, which involves many state utility commissions, to keep near-term rates as low as possible, thereby implicitly deferring the risk of uncertain future events. The difficulty of evaluating and weighing such risk factors makes technology comparisons complex, and, in our opinion, unduly disadvantages renewable electric technologies.

- *The difficulty of quantifying environmental values*. Many of the environmental costs of fossil fuels are not reflected in today's market prices. Consequently, discussions of the market penetration of renewable energy based on prices alone understate the total potential value of renewables, when nonmarket environmental damages are included. The incentives used in the National Premiums Scenario very likely underestimate these nonmarket values.

As we indicated earlier, we attempt in this document not only to present our Task Force results but also to identify areas where there are gaps in data and analysis. These are presented more fully in Section VI and can be summarized as follows:

- A key area of uncertainty has to do with the evolution of energy markets and their response to renewable-energy-related policies (and other energy policy changes), and most significantly to evolution of the RETs. Although the Task Force members are experts in these technologies, the success of R,D&D depends on creativity and occasionally on good luck as well as good management and technical know-how.

- The R,D&D on renewables conducted in other developed nations has come to exceed current U.S. efforts. The impact that this will have on technology status and competition for markets is not addressed in this paper, but it represents a significant area of uncertainty.

- Current data on RET deployment and energy market trends relevant to future deployment (both in bulk and dispersed applications) are inadequate both for the purposes of this paper and for any assessment of market behavior with respect to these new technologies.

- We conclude that nonmarket externalities, such as environmental benefits, are very important vis-à-vis the RETs. A major need is an acceptable means of assessing these externalities to support formulations of energy policy.

- More accurate means of evaluating resource availability are needed. Examples are questions about sustainable levels of biomass productivity, land use alternatives to provide biomass resources, and site-specific characteristics of wind resources.

The key to realizing the potential contributions of renewable energy in the near term is to intensify R,D&D activities. If market factors--higher prices or special markets--appear earlier than projected, the industry will respond in force only after the prerequisite R,D&D has been carried out. The impacts of U.S. R,D&D must be considered from a global perspective. Where substantial foreign investment is taking place, a lack of U.S. funding would not preclude technological advancements. However, a lack of U.S. R,D&D may mean importing technology for deployment in the United States. If it becomes a goal of U.S. energy policy to see large quantities (>20%) of renewable energy deployed in U.S. markets before 2030, intensified R,D&D is essential. This is not to say that institutional constraints are not important now and will not be more important in the future; however, R,D&D is the key to moving toward that goal. It provides a cost-effective way of providing substantial additional economic energy supplies from domestic sources by 2010 and thereafter, given the base-case projection of conventional energy prices. Thus, we conclude that

- RET deployment increases under all scenarios--the *rate* of increase is the issue;

- Foreign RET technology development is a substantial challenge to domestic industry;

- RET deployment will continue to grow past the planning horizon;

- RET deployment will enhance environmental quality; and

- RET deployment supports other key energy policy goals.

I. Introduction

This white paper evaluates the present and projected performance status of the renewable energy technologies (RETs) and their potential contributions to the nation's energy requirements over the next four decades. It was prepared by the U.S. Department of Energy's (DOE's) national laboratories in response to a request from the Office of Policy, Planning and Analysis for use in the National Energy Strategy (NES) study. This assessment is based on a preliminary set of economic, conventional energy supply and demand, and competitive fuels price assumptions described in the paper. The paper broadly identifies the research, development, and demonstration (R,D&D) actions that would in our consensus judgment remove the key technological constraints on implementing these energy resources and thus enhance the potential renewable energy contribution. The paper also identifies a number of other constraints, largely institutional, that can be reduced or removed with appropriate actions. It does not address the question of what is appropriate national energy policy, nor does it suggest what policy actions should be undertaken to implement any of the potential R,D&D programs discussed. The results of the analyses might suggest that the future of these technologies is certain, but that is not the case. Uncertainties are very large, too great to attempt any statistical characterization of the potential range of uncertainty. Nonetheless, this white paper represents the best estimates that the laboratories can provide to DOE in its important task of developing a renewable energy posture for the NES.

Development Methods and Assumptions

This study was prepared as a consensus project by the contributing staff members from the national laboratories: the Solar Energy Research Institute (the lead laboratory), Idaho National Engineering Laboratory, Los Alamos National Laboratory, Oak Ridge National Laboratory, and Sandia National Laboratories. Each laboratory developed portions of the paper dealing with one or more RETs. These sections were then distributed among the laboratories and the results reviewed and discussed. Agreed-upon assessments were then compiled and summarized. Detailed assessments of each principal technology (or groups of technologies, in some instances) are included in the appendices.

The assessments include an analysis of the technological constraints facing each technology. The R,D&D thrusts needed to overcome these constraints are identified. The experience we have gained in the past two decades in R,D&D supported largely by the federal government was a major factor in formulating these assessments. The assessments also include a survey of the nontechnical constraints--largely institutional--that are impeding progress in deploying renewable energy systems even when they are economically and technically attractive.

The contributions that renewable energy technologies might make to national values are also discussed. These are generally not apparent in market values or prices, but they may be as important as any energy cost savings. Potential contributions include environmental benefits, national energy security gains, domestic economic development benefits both in areas where the technologies are deployed and in the manufacturing and equipment supply sector, and benefits in foreign trade and the economic welfare of developing countries.

The starting point for the paper was a preliminary projection of the nation's energy supply and demand balance prepared by DOE's Office of Policy, Planning and Analysis using the DOE Fossil2 energy model. Independent projections from the Energy Information Administration (EIA) were also used in developing regional assessments of potential RET markets. More detail on the market construct utilized can be found in Appendix J.

Assessments of the Potential Contributions of Renewable Energy Technologies

Estimates of the future contributions of RETs have large uncertainties, particularly for technologies that are not yet commercial. Actual time lines for RET market penetration depend on such factors as the state of development of the technology; the end-use market competition from both conventional fuel sources (tied primarily to competing fuel prices) and among RETs themselves; the ability of RET industries to expand system and component manufacture and, in some cases, resource procurement; and finally, growth in the demand for energy within end-use sectors.

Three scenarios have been formulated to investigate RET performance and market penetration. These scenarios are a reference case and two alternate scenarios--one covering accelerated progress of the technologies and the second, environmental and other noneconomic value considerations. These are described in more detail in Section V.

The first is a Business-as-Usual (BAU) Scenario for market penetration. In this scenario, we describe the RET penetration levels expected given baseline energy prices and competition from conventional fuel sources within each energy-consuming sector. This assumes that federal R,D&D funding for renewable energy technologies remains at current levels.

The second, a Research, Development and Demonstration Intensification (R,D&D) Scenario, maintains the same assumptions regarding projected energy prices and competition. But it incorporates an additional assumption: that federal R,D&D expenditures on renewable energy technologies are increased to accelerate the achievement of longer term RET technology cost and performance potentials. This "technology-push" scenario has the primary impact of accelerating the development time line of the RETs.

Finally, a National Premiums Scenario assumes that heightened national and regional concerns about environmental quality and the adverse impacts of conventional fuel combustion and energy production result in a price premium for clean energy sources. There are many examples of such premiums at state and local levels that address more acute environmental concerns. We assumed in this scenario that environmental concerns will provide a 2¢/kWh price premium to electric power RETs, a $2.00 per million Btu ($2.00/MilBtu) premium to RETs that reduce the use of oil, and a $1.00/MilBtu premium to RET sources of methane, an alternative to natural gas. This scenario is essentially a "market-pull" case, in which the premiums are treated as lower costs (or other market incentives) to induce consumers and energy suppliers to select renewable energy technologies rather than others.

The main elements of the paper are four-fold:

First, the estimated energy contributions under the three scenarios provide a range of forecasts for different snapshots of the future. These changes and response patterns in penetration provide important relational information as well as describe the expected magnitude of renewables market penetration.

Second, we present a review of analytic needs of renewables in a cross-technology format. These represent our suggestions to DOE regarding the next steps to be taken, should increased emphasis in RETs be desired.

Third, the paper reviews and documents (in the appendices) the technological and institutional constraints and opportunities that we have identified as relevant to renewables.

Finally, the paper discusses the contributions that renewables can make to other national values in addition to needs for abundant economic supplies of energy.

II. Renewable Energy Technology Today

Renewable energy technologies are being developed to produce marketable energy by converting natural phenomena into useful energy forms. These technologies use the energy inherent in sunlight, the direct and indirect results of its impact on our planet (photons, wind, falling water, temperature differentials, and plant matter), gravitational forces (the tides), and the Earth's heat as resources for producing energy. These resources represent a massive energy potential (see Table II-1) that dwarfs the potential of fossil fuel resources. However, they are generally diffuse, some are intermittent, and all have different regional availabilities. These aspects give rise to the difficult (but solvable) technical challenges inherent in the development and use of these resources.

Table II-1.
Comparison of U.S. Energy Resources (quads)[1]

Resource Type	Total Resource Base[a]	Accessible Resource[b]	Reserves[c]
Fossil	253,000	52,190	5,654
Renewable[d]	3,560,000	614,700	656
Total	3,813,000	666,890	6,310

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

[b]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 near future.

[c]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.

[d]In the reference, renewable energy annual values are multiplied by 30 years to arrive at a generally comparable figure with fossil fuels.

Given the overall size of the potential resource, we find that resource magnitude is seldom the key constraint on energy production. Rather, energy production is more likely to be constrained by the need to match the resource's location and temporal availability with demand, and the efficiency of resource capture and conversion. The technologies themselves are a mix of mature concepts such as hydropower, geothermal, and biomass; emerging ones entering the market after several years of technology development; and advanced but largely undeveloped concepts with significant potential for future energy supplies. Table II-2 summarizes RETs on these three levels. A key element of this paper is an analysis of the impact of R,D&D in moving technologies from the future category into the more mature category, and in improving the competitiveness of emerging and already mature technologies.

Table II-2.
Renewable Energy Today and Tomorrow

Proven Capability[a]	Transition Phase[b]	Future Supplies[c]
•Hydropower	•Wind	•Advanced Wind
•Geothermal - Hydrothermal (high-temp. electric) (low-temp. heat)	•Solar thermal/gas hybrid •Ethanol from corn	•Advanced Solar Thermal •Transportation fuel from energy crops
•Biomass - Direct combustion - Gasification	•Active solar in buildings	•Bio-derived methane •Ocean thermal
•Passive solar in buildings •Small, remote PV	•Geothermal - Hydrothermal (mod-temp. electric) •Remote PV	•Advanced geothermal - Hot dry rock - Geopressure - Magma
		•Grid-connected PV

[a]Mature technologies.
[b]Has or is entering market as technology develops, often with preferential tax or rate considerations.
[c]Advanced technologies that show potential.

In this section, we review the commercial status and deployment of the RETs in terms of the end-use sectors they serve. Resource and industry assessments are included in these reviews. We also describe a group of technologies that can facilitate the ability of RETs to meet energy service needs. More detailed information on both the production and facilitating technologies is provided in the appendices.

Technical Description and Current Deployment

Electricity

The primary energy consumed by the electric utility industry accounts for roughly 35% of total U.S. energy consumption[2]. As such, this market represents a large potential for renewable energy resources.

Electricity produced from renewable energy resources can be categorized into two groups: (1) dispatchable, or available on demand, and (2) intermittent, or subject to fluctuations over time. This differentiation is important in examining the potential contribution of specific RETs to electricity supplies, as well as the potential need for complementary systems and technologies to facilitate their use at higher penetration levels. Historically, the bulk of utility supply has been dispatchable, but increasing numbers of utilities have incorporated low to modest levels of intermittent technologies such as wind or industrial cogeneration.

Geography also has impacts on the use of RETs. While many renewable resources are widely distributed, the best and most cost-effective sites may be regionally limited. Steam- or hot-water-based geothermal resources in the West, for example, cannot realistically be expected to provide electricity for the Northeast. Likewise, other renewable resources may have regional characteristics that limit initial development. As the technologies develop, the economic region for a given resource can be expected to expand greatly. An example is advanced geothermal systems using hot dry rock, which has a much greater geographic range than current systems.

Dispatchable Sources

Dispatchable renewable energy sources have long contributed to U.S. electricity supplies. Hydropower is a major technology in several regions. Wood-fired technologies have played a key role in certain industries for decades. Geothermal and municipal solid waste (MSW) systems are more recent technologies that represent substantial increments of new capacity growth in recent years.

Hydropower. The largest electricity contribution from renewable energy sources today comes from hydropower. Its development in the United States dates back more than a century. As late as the 1930s, hydropower provided 30% of the nation's total installed capacity and 40% of the electric energy generated. Since that time, the growth in thermal-based capacity has far outstripped its growth, so hydropower (both conventional and pumped storage) represented approximately 10% of U.S. capacity in 1988.

Hydropower facilities are highly flexible. The output from facilities using single-purpose reservoirs can be managed to match electrical energy demands. These systems can also respond quickly to utility short-term load swings. Pumped storage facilities (see Facilitating Options), though generally not considered a renewable resource because the primary fuel is usually coal or nuclear, have much of the operating flexibility of hydropower. This flexibility also provides a mechanism for accommodating intermittent energy production by using reservoir storage to make supplies reliable and to smooth fluctuations in output.

On multipurpose reservoirs, hydropower production represents just one of several competing demands on the water resource. Others include irrigation, flood control, recreation, navigation, and municipal and industrial water supply. Run-of-river developments on rivers, streams, and canal systems use the in-stream water flow instead of impoundments to produce electric energy.

Hydropower competes with conventional fossil capacity in base, intermediate, and peaking roles. Hydropower facilities typically have high front-end capital costs--around $2,000 per kilowatt (kW)--which are offset by low operating costs, long lifetimes, and high plant availabilities. Estimated levelized capital and operating costs for new facilities vary significantly from site to site but are often competitive with conventional fossil generation.

In 1988, there were 71 gigawatts (GW) of conventional hydropower and about 17 GW of pumped storage hydropower generating capacity in the United States[2]. This capacity generated 223 billion kilowatt-hours (kWh) of electricity, the fossil fuel equivalent of 2.32 quads, or 8.3% of total U.S. electric utility industry generation. But 1988 was a drought year in many regions of the United States, and hydropower generation was well below average--only two-thirds of the peak generation that occurred in 1983, when hydropower accounted for 14.4% of total U.S. generation. Additional capacity that could be developed economically in the United States today is estimated at 22 GW. Furthermore, there is some additional energy potential in upgrading and refurbishing existing facilities. For example, the Bureau of Reclamation expects to add 10% to its 13 GW of capacity by the early 1990s through an upgrade program. The greatest impediments to expanding hydropower are the strict environmental and safety licensing requirements.

Because large hydropower developments have decreased in recent years, U.S. manufacturers have left the large turbine business. Foreign suppliers from Japan, Europe, and Canada are very competitive in the world market and have provided most of the new equipment needed for U.S. hydropower facilities.

Biomass electric systems. Biomass sources of energy also contribute to dispatchable electricity supplies. For years, the pulp and paper and forest products industries have used wood and other wastes to cogenerate both steam and power for their production processes. Since the oil price shocks of the

1970s, these industries have increased their use of wood wastes as a percentage of total electricity and process energy needs. The combustion of MSW as a waste disposal alternative is also on the rise. Much of this energy is used to generate electricity. Small amounts of other biomass resources, such as agricultural and food processing wastes, landfill and sewage gas, and feedlot-generated manures are used as energy feedstocks for electricity generation. These tend to be smaller scale operations because the lower density of biomass places constraints on economic collection and transportation of fuel.

Some 8 GW of biomass energy-based generating capacity exists in the United States today[3], primarily owned and operated by industrial or other nonutility entities. Perhaps because of the smaller scale and the remoteness of many biomass operations, utilities have not been major developers of biomass-based plants. To date, utilities have been involved in only a handful of dedicated wood-fired plants in the 40 to 50 megawatts (MW) size range, and in some firing of MSW in conventional fossil plants.

Biomass electric technologies compete with base-load fossil fuel plants, often in a cogeneration configuration. Biomass (wood and MSW) plants are commercially available today. The cost of electricity from wood-fired plants ranges between 4¢ and 5¢/kWh (constant dollars). The costs of MSW electricity generation are competitive with conventional fossil plants in areas with a sufficiently high waste disposal fee. For plants to be competitive with conventional fuels, the biomass feedstocks must be available for about $1.00 to $2.00/MilBtu.

The currently economic but undeployed level of biomass electric technologies is unknown at this time. It probably consists of a portion of some 8 quads of currently available biomass fuels. For energy crops to be a major source of biomass, current costs must be reduced from $3.25/MilBtu to $2.00/MilBtu. Productivities of up to 10 tons/acre/year over wide acreages are needed.

Future growth in the biomass electric technologies is expected to come from expanded deployment of MSW technologies as well as further use of wood and agricultural waste. Additional R,D&D efforts will assist in developing energy crops for use in biomass electric plants.

The existing biofuels industry has multiple interests and is difficult to characterize. It consists of biomass energy users, equipment manufacturers, biomass harvesters and collectors, waste collectors and processors, and sellers of components and systems. By far, the largest segment of the biofuels industry today is related to wood energy, which accounts for almost 95% of all energy from biomass. Energy from MSW represents another growing fuels market; the most established MSW technology is mass burn of collected MSW for process heat and electrical generation.

Geothermal energy. Geothermal systems make use of the natural heat of the earth and contribute to dispatchable electricity supplies. Although most geothermal electric facilities have been dedicated to base-load service, more recently, project developers are considering peaking and intermediate service. Geothermal applications are categorized into four technologies: hydrothermal, hot dry rock, geopressured, and magma geothermal systems.

Hydrothermal energy, in the form of naturally occurring high-temperature water or steam, is providing an economical, trouble-free source of electric energy in a number of locations in the western United States and worldwide. Present installed worldwide capacity is 5.0 GW[4]--2800 megawatts electric (MW_e) in the United States alone; availability factors are commonly above 90%. The largest of these hydrothermal power sources, The Geysers dry steam field in northern California, has been under steady development since 1960. The Geysers is second only to hydropower as the cheapest source of energy in the Pacific Gas and Electric Company generating system and currently supplies 7% of California's power. Development activity has been increasing in the western United States as nonutility projects have begun to tap liquid-dominated, high-grade hydrothermal resources using both flashed-steam and binary (organic working fluid) technology. The flashed-steam geothermal plants typically produce electricity at a levelized cost of 4.5¢ to 6.0¢/kWh. The U.S. Geological Survey (USGS) has estimated that the total hydrothermal geothermal resource usable for electrical power generation in the western

United States, Alaska, and Hawaii is 240 quads, which could provide an additional 95,000 to 150,000 MW_e for 30 years.

Broader application of geothermal systems nationally will, however, probably depend on the success of one or more advanced concepts now being investigated--hot dry rock, geopressured, and magma--which should expand the available U.S. resource base to more than 1 million quads. These technologies are not yet commercial and will require further field testing to reduce uncertainty and to define the base technologies for industry.

Hot dry rock (HDR) geothermal represents the largest portion of this broader available geothermal resource and is also the most advanced in its development. In the HDR concept, a fractured reservoir is created in a deep, hot region of rock by fluid pressure. Current research is directed toward engineering such systems in tight crystalline rock where sufficient natural porosity or permeability does not exist. However, in the future this concept will be expanded to address the significant resource intermediate between hydrothermal and HDR. Many marginal hydrothermal resources could be made commercial by using HDR techniques of reservoir stimulation and pressurized water recharge.

The *geopressured* geothermal resource is located primarily along the Gulf Coast and consists of zones in the Earth of hot brine containing dissolved methane. The ability to produce hot, pressurized brine, to separate the methane, and to control scale deposition has been demonstrated. A system for generating power from this resource, involving thermal and hydraulic energy plus methane, is being developed.

The *magma* geothermal resource is defined as accessible regions of molten rock at temperatures of 850°C and higher. When technological barriers are overcome, this resource will provide a high-quality energy source for efficient conversion to electricity.

Recovering energy from these advanced geothermal resources will generally involve using existing conversion technology adapted from hydrothermal systems. Binary fluid technology, already used in commercial applications, could significantly increase conversion efficiency and resource availability, with no emissions of gaseous effluents. Electric power generation from these geothermal systems can be tailored to fit demand and designed to come on-line quickly (2 to 5-years) in 1- to 100-MW_e modules for base-load electric power production. Direct-use applications can come on-line even more quickly and are now offsetting 0.017 quad of fossil fuels.

Ocean Energy. The ocean contains vast energy potential in its waves, tides, currents, and thermal gradients. U.S. efforts have focused on utilizing thermal gradients, although very large wave and tidal resources have been identified. European efforts in the latter areas have been substantial. Ocean thermal energy conversion (OTEC) technology is based on the principle that temperature differences between warm ocean surface waters and cold water at greater depths can be harnessed to drive base-load electric power generation. Oil-dependent Hawaii and U.S. island territories with a rich OTEC resource are expected to be the initial U.S. market entry points. U.S. industry has the potential to supply equipment for plants at Pacific islands that are interested in independent sources of energy. In addition to base-load electricity generation, OTEC offers such quality-of-life-enhancing benefits as desalinated water production, mariculture, and agriculture.

Intermittent Sources

Power production from intermittent generating technologies is vulnerable to the periodicity of the natural forces upon which it depends. That is, power production from the wind and solar radiation can be achieved only when the wind blows or the sun shines. However, when combined with storage or other integrated system response strategies, these combined resources can reduce the need for other sources of power.

Substantial development of an intermittent resource--wind--has occurred in several utility systems. Photovoltaics (PV) has been successful in reaching the remote power market at thousands of sites worldwide. Thus, intermittent renewable resources are reaching an important stage in acceptance and use. Although it is classified an intermittent, PV provides daytime power that may coincide with utility or customer load profiles. Such a match adds to the value of PV for the user.

Solar thermal systems. Solar thermal systems use concentrated sunlight to generate heat for thermal conversion processes, such as electricity generation. Three types of solar thermal technologies--parabolic-trough systems, central-receiver plants, and parabolic dish systems--are either currently in use or under development. Appropriately configured, any of these can provide dispatchable power and energy.

First, 274 MW of privately funded, grid-connected parabolic-trough generating capacity is operating in southern California[5]. These plants operate in a hybrid mode using auxiliary natural gas to overcome the intermittency of the solar resource as well as to extend generation to better match load. This daytime dispatchability has proven the reliability of the hybrid concept. A project to deliver an additional 80 MW is currently under construction, and there are firm plans for another 300 MW to be built by about 1994. The systems currently provide energy at costs of less than 10¢/kWh. Further expected improvements in the technology could result in 30% cost reductions, making this technology cost-effective in more U.S. and world markets.

The second major technology is the central-receiver plant. A 10-MW central-receiver power plant was deployed by a joint government/industry team and operated successfully for several years in a grid-connected mode by Southern California Edison Company. Thermal storage in the system would move the technology to the dispatchable category for a utility. Six hours of storage is expected to provide daytime dispatching under variable weather conditions. The average levelized capital and operating costs projected for solar thermal central-receiver stations range between 8¢ and 12¢/kWh for early plants, based on current component and system designs.

Finally, prototype parabolic dish electric systems, totaling about 5 MW_e, have been operated in a utility setting in Georgia and in southern California. Prototype dishes with small Stirling heat engines and generators mounted at the focal point of the dish have led to significant increases in system performance and hold the world record for system conversion efficiency from sunlight to electricity (29%). The Stirling engine configurations may be most appropriate for small, stand-alone applications. U.S. industry involvement in this technology is beginning to increase as the technology approaches cost competitiveness in early markets. Germany, Japan and Spain are also working on small dish system concepts for export.

Worldwide interest in solar thermal hybrid systems has increased recently. Plants are planned for India, Jordan, and Israel, and aggressive R,D&D is continuing in Spain, Germany, and Israel to capitalize on these emerging markets, lending the industry a multinational character. The major solar thermal hybrid supplier has both United States and foreign involvements. The U.S. industry hopes to expand to other high-insolation areas of the world.

Wind power. Of the intermittent technologies, wind power is currently the largest contributor, with an installed power-generating base of about 1.5 GW, primarily in California. The many so-called wind farms, or wind power plants, which have been developed by nonutility entities, generated over 2 billion kWh of electricity in 1989[6]. Although early development was closely tied to the availability of federal and state tax incentives, as well as lucrative utility power purchase contracts, cost reductions and performance improvements have been considerable over the last several years. While early systems (arrays of wind turbines) suffered from poor reliability, unit availabilities of the best California wind power plants now approach 95%. The average levelized capital and operating costs for new wind facilities can be as low as 6¢/kWh at excellent sites.

Wind power's primary current market is in California, where wind resources are relatively good and utilities have offered attractive prices for purchased energy. Since the cost of energy from wind turbines depends strongly on wind speed (power output increases with the cube of the wind speed), wind energy can compete with conventional fuels in the near term at the very best sites. These near-term markets are expected to displace high- and moderate-cost fuels. In the long term, our projections suggest that wind energy can compete against low-cost base load fuels using moderate wind resources such as those of the Great Plains. Because of the operating flexibility of hydropower, areas that have hydropower resources or hydropower storage capability may be able to incorporate greater wind penetration than areas without them.

Like other renewable technologies, wind power's early significant advances in this country have led to a worldwide technology development effort that far surpasses current domestic expenditures. In Europe, seven countries and the Commission of European Communities are each spending as much or more on wind energy R,D&D than we are in the United States. A large Japanese manufacturer has also made a major commitment to penetrate the California market with the installation of hundreds of turbines in 1989. Only a handful of U.S. concerns remain participants in the field.

Photovoltaics. Photovoltaic systems have been used for more than 30 years to power spacecraft. The reliable performance of solar cells in space has established PV as a dependable technology. Costs have come down dramatically since the first solar cells were deployed for space applications, opening up a terrestrial market of approximately 42 MW per year (1989). This market has three major segments: consumer products, remote power, and bulk power generation.

The current consumer market is characterized by millions of small, milliwatt-sized systems powering calculators and watches. This market, which has been steady at about 5 MW per year, is now expanding to larger systems such as battery charging and walkway lighting. The largest use of PV today is for remote power. The remote-power market encompasses stand-alone applications to power telecommunications, highway lighting and call boxes, navigation aids, security systems, water supply pumping systems, cathodic protection, vaccine refrigeration, remote monitoring, rural housing, and small villages. Perhaps 20 MW of capacity exists in thousands of remote, stand-alone applications. Bulk power applications of PV are currently limited. Three megawatt-scale plants were installed in the early 1980s that continue to operate reliably. Electric utilities are currently investigating potential uses for PV systems ranging from distribution system applications to bulk power generation. A recent survey[7] conducted by the Electric Power Research Institute (EPRI) identified 219 grid-connected PV systems with a total combined peak power rating of 11.6 MW (including 9.4 MW for the three large plants).

The current levelized cost of energy from PV is 30¢ to 35¢/kWh, too high to be competitive in today's bulk utility power market. But at today's costs there is an untapped remote market of 200 to 300 MW in the United States and abroad.

The most significant energy contribution for PV is nevertheless expected to come in the utility power market. Under baseline assumptions, smaller high-value applications should begin about 1995 followed by major market entry for peak power supply beginning about 2005. Achieving costs of 4¢ to 7¢/kWh in the 2010 to 2030 period should increase penetration significantly.

The private PV industry is a mix of some 40 firms, 90% of which are small- to medium-sized firms involved in manufacturing, distribution, or service. In general, the industry, especially manufacturing, has not been profitable. U.S. companies, which were world leaders in the early 1980s, have encountered serious competition from foreign-owned companies. The U.S. PV market share has severely declined, from 65% in 1981 to 35% in 1989. The world's largest PV company, California-based ARCO Solar, has been purchased by a German-based multinational company. Although the market for PV is growing at a 20% annual rate, and industry margins are improving, this economic turnaround has yet to become fully reflected in a strong investment climate in the United States.

Transportation: Biofuels

Transportation needs consume more than a fourth of the primary energy used in the U.S. economy[2], primarily in the form of petroleum-based liquid fuels. The conversion of biomass resources represents the primary renewable energy-based pathway to transportation fuels production. Although there are several process concepts for producing these so-called biofuels, only ethanol from corn is produced today in commercial quantities. Eight hundred and fifty million gallons of ethanol are produced annually, primarily by fermentation of corn, for blending into gasoline. These ethanol blends are used in approximately 8% of the gasoline in the United States today. At a 10% blend, ethanol thus represents 0.8% of the motor gasoline market.

The U.S. ethanol industry is dominated by 25 plants operating in the Midwest with corn as the feedstock. This industry is principally made up of corn processors that produce a variety of corn products, including sweeteners, corn oil, animal feed, and ethanol. Continuous operation at a profit has been so difficult that smaller plants and those using older technologies have not survived. Nevertheless, the production of ethanol has grown by more than tenfold since 1981, leveling off in 1989. The U.S. cost of ethanol from corn is currently about $1.28 per gallon; however, the viability of corn-to-ethanol conversion is currently based on tax incentives and on present prices for corn in the food and feed markets. If available corn cropland were used, the annual production of ethanol from corn could easily exceed 10 billion gallons or approximately 10% of current gasoline usage in the United States.

The largest potential for ethanol from biomass exists in the use of abundant cellulosic (woody and herbaceous) biomass materials, which can reduce feedstock costs by 50% or more compared with corn. One current focus of R,D&D is to develop techniques to biochemically convert a larger portion of a cellulosic feedstock and material to ethanol. In the last decade, research focused on bioengineering has reduced the cost of wood-derived ethanol to $1.35 per gallon. Current research plans estimate that a goal of $0.60 per gallon could be attained, which would in the future provide ethanol that is economically competitive with the projected price of gasoline without tax incentives.

Biomass resources can also be used to produce methanol, another viable transportation fuel product. Methanol from biomass is made by first gasifying the feedstock and converting it to methanol over commercial catalysts. Improvements are needed primarily in the gasification process to increase conversion efficiencies, provide better cleaning and conditioning of raw gas, and improve the reliability and scalability of the gasifiers. While not yet commercial, current laboratory technology suggests a present-day cost of $0.75 per gallon. A projected research target cost of $0.55 per gallon by 1995 assumes improvements in gas cleanup and a reduction in feedstock costs.

Other pathways being investigated for production of liquid fuels are synthetic hydrocarbon fuels (gasolines) made by pyrolysis of biomass feedstock and diesel oil production from aquatic and terrestrial oil-producing plants. Expanded research will probably be needed to reduce the costs of such renewable fuels to levels competitive with conventional gasoline and fuel oil.

Buildings/Industrial and Other Stationary Uses

Buildings and industrial applications account for the remaining 40% of U.S. primary energy use[2]. In buildings, fuel is used primarily for space conditioning and water heating. In industry, fuel provides process energy and feedstock materials. Renewables currently provide a substantial amount (2.79 quads) in the buildings, industrial, and other stationary use sectors.

Buildings

In buildings, renewable energy sources in the form of wood and solar energy heat space and water. In 1987, an estimated 5 million households used wood as their primary space heating source[2]. Another 17.5 million households used wood as a supplementary heating source, either in wood stoves or fireplaces. The total energy contribution from wood is estimated to be around 0.9 quad, or more than

10% of the total energy used for residential space heating. Wood fuel use in commercial buildings is much smaller, about 2% of the residential use (0.02 quad).

It is estimated that more than a million active solar heating systems installed in the United States today supply approximately 0.04 quad of primary fuel displacement. These systems chiefly use low-temperature collectors for pool and water heating. Most of them were installed in the late 1970s and early 1980s in response to rising energy prices and federal and state tax incentives. When federal tax credits expired at the end of 1985 and fossil fuel prices declined at about the same time, U.S. production of active solar collectors dropped from about 18 million ft^2 per year (between 1980 and 1985) to less than 5 million ft^2 per year in 1987. The number of collector manufacturers also declined from more than 300 in 1979 to less than 80 in 1987. Imports of collectors have remained constant, but these amount to only 600,000 ft^2 per year. Most of the remaining U.S. production is marketed in the southern United States for pool heating.

An estimated 250,000 to 300,000 U.S. homes employ some type of passive solar design features, displacing about 0.01 quad of primary energy. Passive solar includes a variety of building designs and technologies that rely on natural solar-based processes to heat, cool, or light buildings. Passive solar design is particularly attractive because many materials and techniques can be incorporated into new buildings at little additional cost.

The passive solar buildings industry has been affected by expiration of the federal energy tax credits to a lesser extent than its active solar counterpart because many passive measures did not qualify for credits. Reductions in oil and gas prices have no doubt reduced consumers' and builders' interest in conservation and passive solar, but impacts on market penetration are hard to quantify. Many recent advances in windows, daylighting, ventilation, and storage technologies are economic now in new buildings, but not as retrofits to existing buildings. These advances will begin to penetrate the market as the building stock turns over and builders and homeowners become more aware of recent advances in passive solar technologies. This increase in builder awareness is essential to the increased deployment of solar buildings technologies.

Geothermal sources can supply energy to buildings and industrial processes in the form of direct heat. In these applications, which include district heating systems, low-temperature hydrothermal resources are tapped using conventional hot water handling equipment. About one-fourth of installed direct-use geothermal capacity is used in building applications, supplying an estimated 0.005 quad.

Industrial

The current renewable energy contribution to industrial energy use comes primarily from wood and wood wastes. Both the pulp and paper and forest products industries derive a substantial and growing portion of their energy needs from process by-products. For instance, in 1987 the pulp and paper industry derived a combined 56% of its energy needs, or 1.34 quads, from wood wastes and residues, including spent pulping liquors and solids, hogged fuel, and bark--up from a 40% wood waste energy share in 1972. The lumber and wood products industries consume an additional 0.46 quad of energy in the form of wood waste. Other industries account for a combined 0.049 quad of wood energy use. Even though the undeployed energy is several times that currently used by these industries, the increase is projected to be about 15% every 10 years.

Geothermal energy is used for low-temperature direct-heat applications in industry, such as enhanced oil recovery, crop drying, and aquaculture. These industrial uses combined account for 0.013 quad of geothermal energy use.

Solar thermal processes, too, can provide industrial process heat (IPH). Although several demonstration projects were undertaken in the late 1970s, the cost of energy from solar IPH systems is still too high to compete with current conventional fuel prices. Consequently, the use of concentrating solar technologies to generate heat for industrial processes is limited today to only a handful of installations in the United States. One recently identified industrial application of solar thermal technology currently receiving attention is the detoxification of hazardous wastes. These applications exploit the ability to deliver thermal energy and to make use of the high-energy photons that can more thoroughly decompose and destroy toxic chemicals.

The use of solar energy in the detoxification of hazardous wastes in soil and water is moving out of the laboratory and into field experiments scheduled for the early 1990s. Commercialization of solar detoxification technologies will require the merging of expertise now found in the waste-management industry with that of the concentrating solar systems industry, which is currently directed primarily to electricity generation.

Other Stationary Uses

One source of renewable energy that crosscuts two or more of the categories listed above is gas production from biomass resources. Currently, the primary gas-production pathway is to tap gases generated from anaerobic digestion of MSW in landfills. This source now supplies 0.009 quad. Other potential sources of biogas are digester gases, currently contributing 0.003 quad, and thermal gasification of woody materials and municipal solid waste (0.001 quad). The increased expense of landfilling MSW and other environmental constraints will result in increased production of digester gas from MSW. The undeployed potential is 3 quads per year. Another source, noted earlier, is the energy contained in methane-saturated geothermal brines along the Gulf Coast.

Facilitating Concepts

Facilitating concepts and technologies are the knowledge, tools, or technologies that enable us to use or expand the potential of RETs. A straightforward example of this relationship is battery storage and PV: better, cheaper batteries would enhance the ability of PV to compete with alternative power generation in many remotely located sites. Thus, battery improvements could lead to increases in the market penetration of PV. Several of these enabling or facilitating concepts should be considered in discussing methods of enhancing the levels of market penetration for new RETs.

Resource Assessment

Resource assessment involves developing our knowledge about renewable energy resources and establishing or improving methods for characterizing their magnitude and availability. It is a facilitating concept that can enhance the penetration of renewable technologies by decreasing uncertainties about spatial and temporal distribution of resources.

As Table II-3 shows, a variety of RETs are being developed to make use of renewable energy resources.

Table II-3.
Energy Resources and Associated Renewable Energy Technologies

Energy Resource	RET
Solar Radiation	Photovoltaics
Solar Radiation	Solar Thermal Systems
Wind	Wind Power Systems
Stored Thermal Energy in Oceans	Ocean Thermal Systems
Stored and Moving Water	Hydropower Systems
Biomass/Solar Radiation	Biofuels/Biomass Electric and Thermal Systems
Stored Thermal Energy in the Earth	Geothermal Systems

Some RETs also require ancillary resources, such as nutrients, land, and rainfall for biomass production or land and material resources for PV, wind, and solar thermal applications.

Assumptions about significant potential resources are usually based on preliminary surveys, indicating the general magnitude of the resource. Such surveys include *The Solar Radiation Energy Atlas of the United States*, the *Wind Energy Resource Atlas of the United States, Assessment of Geothermal Resources of the United States (USGS)*, and other publications. These broad resource inventories contain some information on regional variability, but they are usually inadequate for site-selection and design purposes, for analyzing various RET options, or for economic analyses prerequisite to investing in RETs. When an actual RET application is considered, the legal, political, environmental, and financial feasibility factors must be evaluated in site-specific detail. Very specific data on the resource, with defined uncertainty limits, are used with technology efficiency data to predict costs and economic viability. The economic risk is reduced by reducing the uncertainty in the resource data. The investor's confidence in the RET as a viable alternative can thus be increased.

The lack of site-specific information on the resource may constrain the implementation of RETs. Installers of RETs may not be knowledgeable enough to conduct a resource assessment with sufficient accuracy. Thus, overly conservative assumptions regarding output are often reached that reduce the apparent risk but increase the apparent cost of the RET. Even if the project developer has the capability to conduct resource assessments, the time and front-end costs required may be a deterrent to pursuing a project.

Storage

Energy storage allows energy to be available when it is required. RETs using solar and wind have predictable average daily characteristics but unpredictable output at any specific hour. Similarly, many energy loads have a predictable profile on the average but behave randomly in actual practice. A storage system allows energy generated to be saved and used when needed.

Storing electricity in large quantities has proven to be quite difficult. The basic problem is that electricity needs to be converted to some other form of energy, such as the potential energy of a pumped storage facility or the chemical energy in a battery. Another conversion is then necessary to return the stored energy to electricity. Typical forms for storage include chemical storage in the form of batteries, heat stored in oil or rocks, and potential energy in pumped hydropower or compressed-air systems. Details on storage technologies are included in the appendices.

Current deployment of storage covers a wide variety of applications and extends from small residential heat storage to a 2.1-GW, utility-scale pumped hydropower storage plant. Future developments in storage for utilities are expected in batteries and compressed air. There is longer term potential in superconducting magnetic energy storage.

For utilities, storage can permit increased penetration of intermittent renewables by providing energy for periods of reduced renewable output and by smoothing the sometimes highly variable short-term output of these renewables. The current level of utility deployment of pumped storage is 17 GW.

Institutional constraints to the deployment of storage technology are minor, largely bearing on pumped hydropower, which has constraints that are somewhat similar to those on conventional hydropower. Technology constraints related to cost and performance are the most important limitations to expanded use. Perhaps the most important cost factors in expanding application of storage systems are cost-per-unit energy capacity and cycle life. These factors, along with storage efficiency, are key to determining the life-cycle cost of delivered energy. Cost constraints are important because storage raises the total cost of delivered energy.

The relationship between penetration of intermittent electric RETs, like wind and PV, and the availability of storage to maintain system reliability has been investigated to some extent. But significant unknowns still exist regarding utility system needs and the value and benefits of storage with RETs. Key analytic needs include expanding the existing knowledge and data base in these areas.

Hydrogen can be a storage technology, and it has other attributes as a fuel and as an energy carrier that merit further discussion. In contrast to electricity, hydrogen may be transported by pipeline and stored directly. Hydrogen can be used as a fuel in many applications now using fossil fuels. Currently, hydrogen is produced from fossil resources, particularly natural gas. However, this contributes to CO_2 output and may limit the potential of fossil-based hydrogen as a fuel. Producing hydrogen from renewable resources consists primarily of splitting water into its elements by electrolysis or by photoconversion. To deploy hydrogen fuels on a significant scale, progress in productivity, storage, distribution, and utilization systems must be made. Of these elements, production is the least advanced and has the highest potential for reducing costs. Projected costs of producing renewable hydrogen are currently about $28/MilBtu, and this cost could be reduced to $8/MilBtu.

Transmission/Distribution

Electric RETs depend on transmission and distribution systems to deliver electricity to users or purchasers. Thus, the availability of adequate transmission and distribution systems can be a facilitating option. Large RET facilities tie into transmission systems and have many of the same interconnection constraints that conventional power generation has, such as stability, protection, and output control. Small RETs tie to the distribution system and must meet a distinct set of interface issues, such as lineman safety and the generation of harmonics.[8] A key institutional constraint to the deployment of RETs is the lack of transmission paths from the energy source to the transmission and distribution system. These include physical lines from remote resources and contact paths (wheeling) on existing systems. Certain RETs with localized resources, such as hydrothermal, geothermal or wind, may be affected more than others.

III. Constraints and Opportunities Relevant to Renewable Energy

In this section, we review constraints on domestic and international deployment of RETs and opportunities to overcome these constraints. Both technological and institutional constraints can hinder the development and use of these technologies. Technological progress that improves the performance of a technology can open the door to energy markets; however, market success also depends on institutional factors. Thus, both categories can have an important influence on the deployment of RETs. Opportunities for overcoming technological and institutional constraints are as varied as the constraints themselves. In this white paper, the federal role in providing remedies for constraints is a primary focus.

Table III-1 shows five types of technological factors and four types of institutional factors related to RET deployment. Historically, technological factors have been succeeded by institutional factors in each market sector as individual technologies move forward along a development path, although we recognize that technology development does not have to proceed in that order. There may be opportunities to address institutional constraints along with technological constraints. On the other hand, institutional constraints are often addressed in a way that crosscuts the technologies rather than on a case-by-case basis.

Table III-1.
Crosscutting Factors Pertinent to Constraint and Opportunity Factors

Technological	Institutional
• Resource Access	• Regulatory
• Conversion Efficiency	• Financial
• Lifetime/Reliability	• Infrastructural
• Market Compatibility	• Perceptual
• Manufacturability	

The reader should be aware of the qualitative and potentially incomplete nature of our review. In our Business-as-Usual Scenario, we have assumed that current institutional and policy structures continue for the length of the planning period. While this is unrealistic, we have no basis for a specific policy or societal change. Estimates of the impacts of technological constraints are derived from an analysis of the R,D&D Intensification Scenario; estimates of the role of institutional factors are derived from historic parallels and from evaluations of the results of the National Premiums Scenario. Both estimates, particularly the latter, reflect large uncertainties. These factors and their implications on the development and deployment of RETs deserve more detailed analysis. For example, although we have attempted to identify applicable institutional constraints, we cannot foresee all such factors.

Technological Constraints and Opportunities

Technological constraints are limitations to deployment based on cost and performance deficiencies in comparison to alternatives. Such constraints involve limits to scientific knowledge, unsolved engineering problems, unavailability of required materials or production techniques, and others.

The following discussions cover these categories of technological constraints and opportunities: access to resources, conversion efficiency, lifetime and reliability, market compatibility, and manufacturability.

Access to Resources

Technology can improve access to resources, directly or indirectly. Advances in geological and geophysical science can improve the ability to find and understand geothermal resources, for example, as they have for oil, gas, and coal. This has become more relevant as advances in drilling technology have made it economical to reach deeper strata and to exploit shallower resources that were once considered submarginal. Other examples of how technological developments can improve access to resources and thereby lower the ultimate costs of renewable energy include the following:

- Improvements in structures and materials, including lower wind resistance in equipment, will allow taller and larger diameter wind turbines to be developed that can economically reach more available wind energy.

- Lower costs for flat-plate photovoltaic cells will make PV systems economical in areas where available sunlight is diffuse or less intense. This will broaden the geographic area suitable for PV as well as make PV systems more competitive in small installations where tracking and concentrating devices would not be justified.

- Mechanized harvesting equipment can be improved to make it economic to harvest biomass feedstocks that are too costly to collect by using available techniques. This would benefit high-productivity energy crops as well as permit the higher value use of some waste materials and marginal crop and forest lands.

- Means of protecting habitat and water quality after the construction of hydropower projects can be developed (such as retaining the natural fish spawning and development cycle), thus permitting access to the resource.

- The development of crop species (agriculture and trees) that are highly productive in a range of climate and site conditions, resistant to pests, and efficient in using nutrients, can be facilitated by integrating developing biotechnologies with plant breeding. This will increase both the number of acres suitable for energy crops and biomass production per acre.

- Drilling improvements and reservoir characterization for geothermal systems would reduce drilling costs and allow access to more of the resource.

Conversion Efficiency

The economical conversion of resources into usable energy involves efficiency in both the energy conversion--how much of the available resource is converted--and the use of other resources--land, labor, and capital--in the conversion process. Improvements in conversion efficiency can be magnified by additional improvements in the efficiency of the use of other resources. For example, if the conversion efficiency of a photovoltaic cell can be doubled, area requirements will be cut in half. If the cost of structures and power systems can also be cut in half for a given cell area, the combined effect would be to reduce the system cost for a given capacity by 75%.

Examples of potential improvements in conversion efficiency include these:

- The efficiency of PV arrays can be improved from the current 10% to 20% or more. Such improvements would substantially lower the cost of the systems, requiring less supporting structure and simplifying the collection of the electricity produced.

- The further development of the binary cycle will improve efficiency and allow lower temperature geothermal reservoirs to be developed.

- Improved airfoil designs and optimized controls can improve the energy-capture efficiency of wind turbines.

- Improvements in the performance of thermal-to-electric energy conversion in small applications would reduce the costs of smaller solar thermal systems.

- Improvements in the yield of biomass per acre from an average of about 5 tons per acre today to the 10-ton-per-acre target could not only reduce the land requirements for a plant but also reduce the average distance the crops would have to be transported from the field to the conversion plant. Higher yields than the target average are possible in some instances and would increase the economic efficiency of projects using those crops. Similarly, a higher efficiency of conversion of cellulosic biomass to ethanol can increase overall fuel output.

- The efficiency of existing hydropower plants can be improved by several means. The replacement or modernization of turbines and generators can improve output. Water now flowing over spillways, or otherwise not used, can be directed to existing or new turbines. The value of the electricity produced may be increased by increasing generating capacities and controlling the flow of available water to the peak mid-day hours (to the extent downstream flow conditions would permit).

Improvements in the use of other resources, often coming under the heading of "other systems costs" or "engineering improvements," can be made in all technologies. Some will occur as a new technology is identified and applied. Some will involve process changes that lower operating temperatures, pressures, or concentrations of products, thus permitting the use of smaller or lighter equipment or less land, or both. Other improvements will occur as renewable technologies shift from the laboratory to the commercial sector; in some cases, much engineering and design remain to be done before commercial operations are undertaken. Until technology development proceeds to the detailed design engineering phase for commercial projects, potential reductions in costs may be very uncertain.

The following examples suggest needed engineering improvements that can provide a beneficial influence on different RETs:

- Improvements in structural support and tracking for solar thermal systems, particularly those using central receivers, will result in substantial cost reductions.

- Improved materials and aerodynamic designs will reduce the costs (and also provide other efficiencies) of wind turbine support structures.

- Developing enzymes that permit higher concentrations of ethanol to be produced would reduce the size of the vessels needed for the fermentation reaction. This would also reduce the cost of distillation and concentration of the output.

- Reductions in the sizes of process reactors, furnaces, etc., are possible if the speed of reaction can be accelerated, reducing the residence time and thus the volume required in the reactor or furnace. These opportunities are available in all the biofuels technologies.

Lifetime and Reliability

Potential customers for renewable energy systems have to be convinced of the reliability of these systems. Energy costs are a small part of most consumers' costs, but the consequences of power or fuel system failures are not trivial. Renewable energy systems must achieve a reliability equal to that of competing sources to achieve significant penetration of the market.

Examples of suggested improvements and solutions to reliability concerns for renewable energy systems include the following:

- The reliability and expected life of turbine rotors as well as drive trains are the targets of much current research in wind power systems. Several potential improvements have been identified and are being pursued.

- The lifetime and production characteristics of all types of geothermal resources need to be defined to reduce uncertainty.

- Extending the lifetimes of PV cells is a current pursuit, and new materials are being studied to provide a long-lived product to all buyers.

- Municipal solid waste systems, because of the uncertain composition of the refuse feedstock, are particularly susceptible to interruptions. Feedstock pretreatment systems and gasification rather than direct burning may provide reliable systems having attractive economics if the technologies can be advanced sufficiently.

- Biomass supplies can be affected by weather and disease. Developing water-efficient and pest-resistant varieties will reduce the variability of feedstock supplies.

Market Compatibility

Renewable energy systems must be adaptable to consumers' requirements. Fossil fuels, for example, can be transported, stored, and handled fairly easily. Solar radiation, however, must be converted into other forms before it can be used (except for direct heat in buildings). Energy storage, or a supplemental source of energy, may have to be provided to make the solar energy marketable. An energy supply that matches customers' load requirements has the greatest value, providing an alternative to other energy supply capacity. If an energy source is not adaptable, a user saves only the incremental operating costs of the other supply systems. The following are among the many technological challenges and opportunities for renewable energy in this area:

- The development of molten salt receivers in centralized solar thermal power or process heat systems may provide economical storage capacity while also serving as the collection and transport medium.

- Economical battery backup systems for photovoltaic systems may expand the role of PV in supplying reliable electric power to remote housing, agricultural, industrial, and communications installations. The high cost of extending distribution lines even a mile or less creates a substantial market opportunity.

- Pumped storage, where feasible, can greatly enhance the value of a hydropower resource and can also enhance intermittent renewables.

- Most renewable energy systems are advantageous because of their modularity and the short lead times needed for installation. These advantages can save users, such as utilities, money by allowing them to defer investment until capacity needs are clear and by minimizing investment in large units before they can be fully utilized.

- Biofuels can be provided in the most convenient form--liquids--which affords easier transportation and storage and more versatile uses (in autos and other vehicles and in construction, mining, agricultural, and other mobile equipment). In addition, biofuels can be processed into alcohol fuels to meet air pollution constraints or into synthetic petroleum fuels that would be compatible with the present petroleum supply system.

- Mass production of small-scale units on a packaged-system basis offers designers a challenge to create systems that can be sold and installed without expensive custom design and engineering expenses. Remote photovoltaic packages, wind units for irrigation, solar water (or space) heating units, and small-scale MSW gasification packages will be among the products presenting these challenges and opportunities.

Manufacturability

Renewable energy systems must be producible with efficient, proven manufacturing processes. Large-scale processes, standardized modules, prefabricated structures, and simplified installation procedures are needed. There is little incentive now to convert from the laboratory or prototype scale of many technologies to a mass-production format, because markets are uncertain. This transition must occur, however, and it will require significant investments and perhaps several attempts to solve production problems. For some technologies, such as PV, solar thermal, and wind, scale-up to large production volumes is expected to reduce costs significantly and make the technologies more competitive. Any lack in the ability to scale up production is a technological constraint. Other manufacturing factors that affect various RETs are as follows:

- A portfolio of biomass energy crops that includes both annual and perennial crops and both woody and herbaceous species would offer producers the flexibility to adapt production according to the mix of land available near a particular conversion plant site.

- Manufacturers of MSW digesters and packaged biomass boilers need to be able to mass produce prepackaged systems that allow installers to minimize design and construction costs.

- Wind energy equipment suppliers must be able to develop more cost-effective production systems for blades and other unique components to meet market cost and production needs.

- Innovations and processes are needed for manufacturing low-cost PV modules.

Significance of Technological Factors

Figure III-1 illustrates our judgment of the significance of technological factors in the development of the renewable technologies.

The Role of Research, Development, and Demonstration

We explored the likelihood that an increase in R,D&D would reduce constraints and hasten the development of RETs in our R,D&D Intensification Scenario. In this scenario, we focused on the potential for the government to speed processes that would occur at a much slower pace under usual market conditions.

Several RETs are still in the early stages of development. Low-priced fossil fuels such as coal and oil have made the development of new RETs economically unattractive. Historically, the only renewable resources we have used were either easily available or available as by-products of other activities. Even so, many such available renewable resources were not fully used. Today, the uncertainty of fossil fuels prices, the waste-disposal and other environmental costs of fossil fuels, and the limited ultimate availability of fossil resources make investment in renewable energy more attractive. The economics of renewable energy are much more attractive today than they were 10 years ago. Substantial technological advances have been made during the past decade in all sectors of renewable energy development. Opportunities for further advances have been identified and many are being pursued that can alleviate a number of technological constraints on renewable energy deployment.

	Resource Access	Conversion Efficiency	Reliability/Lifetime	Market Compatibility	Manufacturability
Biofuels (transportation)	◒	◒	●	○	○
Biomass	○			○	
Windpower	○	●	●	◒	
Geothermal	◒	○	●		
Hydropower	○				
Photovoltaics		●	◒	◒	●
Solar Thermal Electric		○	◒	○	○
OTEC	●	○	●		●
Solar Buildings/IPH		◒	○	●	
Facilitators		●	●		◒

Legend

● High Significance

◒ Moderate Significance

○ Modest Significance

None: Negligible Impact

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Figure III-1. The significance of technological factors

As we noted, technological constraints on renewable energy include restricted access to resources; limits on efficiency; reliability; adaptability to the requirements of the market; and amenability to mass production. The obvious federal response to most of these constraints is appropriate R,D&D. Table III-2 summarizes many of the technological constraints and opportunities that affect renewable energy technologies.

There is reason for optimism. The prices of fossil fuels have remained low for decades in large part because of continuous advances in exploration technology (particularly geophysics); well drilling and coal mining; refining and processing; and pipeline, tanker, and unit train shipments. The price of electricity has also remained low in part because of technological advances in thermal power station efficiency, scale up and reliability, and reliable power distribution.

The R,D&D Intensification Scenario was designed to allow collaborating technologists to use their best judgment with regard to the scope and direction of federally sponsored R,D&D. The objective was to bring all performance aspects of renewable technologies into competitive ranges as quickly as possible. Thus, the bulk of the R,D&D increments (over the BAU Scenario) is projected to be needed during the first two decades of the planning period. Additional funding (roughly $3 billion) was recommended by the technologists for the 1990-2010 time period. Levelizing over that period would raise the total RET budget from about $105 million per year (the BAU Scenario) to about $270 million per year, or about 2-1/2 times the base quantity. The specific R,D&D increases recommended were variable, depending on opportunity and technological need. Although there is substantial uncertainty about the actual rate of technology performance upgrades that would result from enhanced R&D, the impacts of added investments are projected to be substantial. Incremental inputs from RETs under this scenario, as compared to the BAU case, average 16 quads per year over the last decade of the planning period. Particularly exciting are the projected increases in the contributions of biofuels (5 quads per year),

Table III-2.
Technological Constraints

Sector/Technology	Category	Constraint	Opportunity
—Dispatchable Electric			
Hydropower	Resource Access	Environmental limitations	Develop mitigating technologies—aspirating turbines, cross-flow turbines, and fish compatibility
Geothermal	Resource Access	Uncertain reservoir behavior, discovery of reservoir	R,D&D on reservoir exploration behavior and production
		Demonstration of long term viability of hot dry rocks, geopressurized, and magma resources	Long-term demonstration
		Lack of adequate technology for magma resources	R,D&D for methods and materials for magma
	Conversion Efficiency	Need higher efficiencies to use more of the resource	Develop advanced conversion concepts
	Reliability/Lifetime	Corrosion by high saline liquids in a few hydrothermal conditions	R,D&D in materials
Biomass Electric	Conversion Efficiency	Low efficiency combustion	R,D&D on new designs
	Market Compatibility	Uncertainties in energy crop production	Demonstration
Solar Thermal/ Gas Hybrid	Conversion Efficiency	Better efficiency desired	R,D&D on improving efficiency
	Reliability/Lifetime	Proof needed	Long-term demonstration
	Manufacturability	Scaled up production	Purchase for federal facilities
OTEC	Resource Access	Access via cold water pipe and pump	R,D&D on hardware
	Reliability/Lifetime	Need to prove lifetime	Long-term demonstration
	Manufacturability	Necessary large turbines and heat exchangers	R,D&D on hardware
—Intermittent Electric			
Wind	Resource Access	Need to get more output from each site	R,D&D on large arrays and terrain and wake effects
	Conversion Efficiency	Need more output from machine	R,D&D on airfoils and controls
	Reliability/Lifetime	Need to improve lifetime	R,D&D on structural dynamics, fatigue, and manufacturing
	Market Compatibility	Integration issues with utilities	R,D&D on utility integration issues
Photovoltaics	Conversion Efficiency	Not high enough efficiency	R,D&D in materials science
	Reliability/Lifetime	Proof of lifetime needed	Long-term demonstration
	Market Compatibility	Need mass production of package systems	Standard designs, sizes
		Intermittency	Develop storage or hybrid systems
	Manufacturability	Need to develop low-cost process and to prove scaled-up manufacturing	Federally funded process R,D&D and demonstrations
—Transportation			
Biofuels	Resource Access	Insuffcent variety of high yielding production systems	Genetic, biotechnology R,D&D, productivity demonstrations, harvesting and handling R,D&D
	Conversion Efficiency	Better conversion yields needed	Biotechnical R,D&D
	Reliability/Lifetime	Proof of bulk process	System demonstrations at bulk scale
—Stationary			
Solar Buildings, IPH	Conversion Efficiency	More efficiency, better payback needed	R,D&D on improving efficiency
	Market Compatibility	Need to get technology to marketplace	R,D&D and technical transfer

Table III-2 (Continued).
Technological Constraints

Sector/Technology	Category	Constraint	Opportunity
—Facilitators			
Hydrogen	Conversion Efficiencies	Need to develop cost-effective technologies	R,D&D on improving efficiency
	Reliability/Lifetime	Need to prove long-term viability	R,D&D on lifetime
	Market Compatibility	Need to integrate renewables supply vs. hydrogen use	R,D&D on integration
Storage	Conversion Efficiency	Need for lower cost storage	R,D&D on systems
	Reliability/Lifetime	Proof of life	Long-term demonstration
Transmission & Distribution	Reliability/Lifetime	Maximize use of existing and new transmission	R,D&D to develop tools and control procedures for utilities

biomass (2 quads per year), wind (2 quads per year), solar (2 quads per year), geothermal (3 quads per year), and hydropower (2 quads per year). The projected increase in the biofuels contribution would have major value in improving energy security by reducing oil imports. More details on the technology-specific aspects of this scenario appear in the appendices.

Institutional Constraints and Opportunities

Institutional constraints and opportunities derive from existing structures and processes that govern the application of energy technologies and whose form and content derive from societal concerns and interests. The constraints and opportunities described below are based on team members' knowledge and experience concerning the application of renewable energy technologies. They were not systematized, nor was their significance weighted. A more systematic treatment of RET institutional constraints may be warranted.

The following discussion briefly describes four categories of institutional constraints and opportunities: (1) regulatory, (2) financial, (3) infrastructural, and (4) perceptual. These categories are not mutually exclusive; however, they are delineated to shed light on several facets of RET application that have an impact on RET adoption, either now or in the future.

Regulatory

Through the regulatory process, government directs activities in the broader societal interest. Regulations ordinarily pertain to two broad areas: (1) markets and (2) health and safety, including environmental protection. In implementing these directives, the development of legal precedents often lags behind technology development, causing a delay between the time a technology is ready to be applied and its routinized application under a stable regulatory regime. Potentially, this period of "regulatory lag" could be shortened by performing early impact assessments and by providing mechanisms for earlier public involvement in the decision-making process. Examples of regulatory constraints facing RETs include the following:

- Transmission access rulings that may constrain grid connection of remote RET installations
- Limitations on utility ownership of qualifying facilities (cogeneration and renewable energy generation facilities) under PURPA
- Licensing and relicensing of hydropower facilities under ECPA
- Siting of waste-to-energy facilities in municipalities.

Regulatory opportunities exist when socioeconomic impacts are assessed before deployment of new technologies is attempted. Identifying impacts and concerns at an early stage can aid in the design of regulations and regulatory processes responsive to the concerns of the public and stakeholder groups, as well as to technological and economic constraints. Impact assessment can also influence project designs to assist in societal acceptance.

Financial

Financial constraints pertain to the availability and cost of project capital and to the overall financial attractiveness of RET projects. Examples of significant financial constraints limiting greater deployment of RETs are these:

- Capital markets generally perceive the deployment of emerging technologies as involving more risk than established technologies. The higher the perceived risk, the higher the required rate of return demanded on capital.

- The perceived length and difficulty of the permitting process is an additional determinant of risk.

- The high front-end financing requirements of many RETs often present additional cost-recovery risks for which capital markets demand a premium.

Many opportunities exist to address these financial constraints. First, low interest loans or loan guarantees might serve to reduce perceived investor risk. Tax credits for RET energy production through the early, high-risk years of a project may provide another mechanism. Finally, regulatory cost-recovery mechanisms, which today often favor low-initial-cost, fuel-based technologies, can be modified to recognize life-cycle cost as a more appropriate determinant of cost effectiveness.

Infrastructural

Infrastructure is a general term for the entire energy service production and delivery system. It involves decisions made by a broad range of players. These include consumers; energy service providers, such as utilities, fuel suppliers, and other energy service companies; product manufacturers, distributors, installers, and servicers; the financial community; designers and builders; and others.

With respect to RET deployment, energy projects must be constructed and operated and energy services delivered and integrated into the market. Examples of significant infrastructural constraints facing RETs include the following:

- Fragmentation and lack of standardization in the building construction industry can hinder the adoption of many cost-effective solar buildings technologies.

- The existing automobile production and gasoline marketing and delivery infrastructure may retard development and integration of biomass-derived alternative fuels.

- The longer term biofuels contribution may be limited if sufficient land and resources are not devoted to appropriate biomass production.

Opportunities exist in technology and information transfer to better communicate the virtues of many renewable energy technologies, including economic benefits, to important market players.

Perceptual

Finally, widespread deployment of RETs may depend, in large part, on deeply rooted perceptions held by the general public of such qualities as aesthetics, resource availability, environmental impacts, economic attractiveness, and other factors. Examples of significant perceptual constraints include these:

- Aesthetics, such as the visual impact of a large "farm" or array of wind turbines or residential active solar heating systems
- Environmental, such as the damming of wild rivers and streams for hydropower development or effluents from waste-to-energy plants.

Many opportunities exist to communicate to the public the beneficial qualities of renewable energy sources vis-à-vis many conventional energy technologies, including relative environmental comparisons of the total fuel cycle for the major energy sources currently in use.

Summary

As noted earlier, the taxonomy regarding institutional constraints and opportunities employed here is not rigorous and the factors frequently overlap. Furthermore, these factors have not been quantified and, in some instances, may not be capable of quantification. Nevertheless, their impact on the contribution that RETs can make to the nation's energy supply are and will be as decisive as are the many technological constraints and opportunities.

Figure III-2 illustrates the laboratory team's judgment regarding the relative significance of these factors for each of the RETs described in this report.

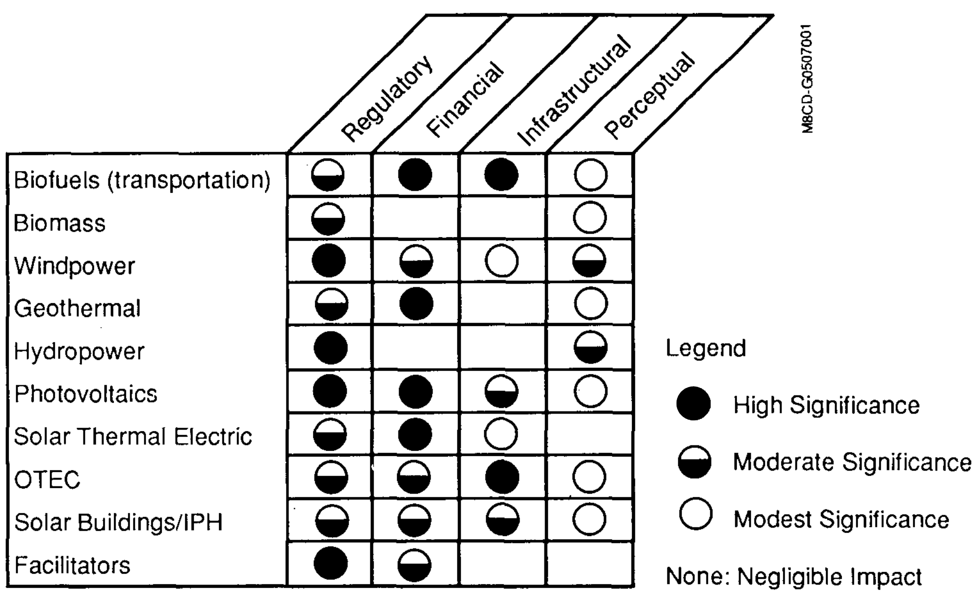


Figure III-2. The significance of institutional factors

The Federal Role

To the extent that institutional factors are regulatory in nature, and that regulation is federal in origin, the federal government can play a significant role in the deployment of RETs. In the more mature renewable systems--hydropower, bioenergy, and hydrothermal geothermal--federal regulatory factors significantly affect the siting and licensing of projects. These regulations can be so complex that they impede the deployment of RETs--particularly hydropower, the direct combustion of wood, biomass wastes, and MSW. If streamlined, the regulations could accelerate the application of these technologies. Several quads of additional renewable energy could be made available within the next decade if siting and permitting procedures were simpler and easier. However, if regulatory processes promote technological adoption at the expense of public "ownership" of siting decisions, public outcry could hamper later efforts to use the technologies. Easing some regulatory strictures could be argued on the basis that fewer environmental impacts result from the use of RETs in comparison with technologies having more deleterious impacts.

The emerging RETs are currently more constrained by technological than by institutional factors. However, as these technologies come closer to commercialization, institutional factors will play a pivotal role. For example, wind, PV, solar thermal electric, and new geothermal systems will have to be licensed before they can compete equitably for capital access and system integration. Similarly, biofuels technologies cannot reach their potential until the agricultural community accepts the idea of growing biofuels feedstocks. These complex issues transcend economics and will inevitably become critical to the adoption of innovative RETs. They require further study, which would ideally be accomplished concomitant with their technological development.

Table III-3 summarizes the institutional constraints and opportunities as they affect renewable energy technologies. A more detailed discussion of institutional factors for each technology can be found in the appendices.

In the absence of a means of assessing the implications of remedies for this set of institutional factors in quantitative terms, we used a surrogate, called a National Premiums Scenario. In this scenario, market incentives for deploying RETs were defined and used to influence RET contribution potentials. The results of this, described more completely in Section V, suggest that a 2¢/kWh-$2/MilBtu market incentive yields an additional 9 quads of RET contribution (over the BAU case) by the end of the planning period. This is substantially less than the 19-quad increase associated with the R,D&D Intensification Scenario. The bulk of this National Premiums Scenario increase is in the more mature technologies because, even with these market incentives, emerging RETs do not become cost-competitive until relatively late in the planning period. A major uncertainty in this case is the presumption that RET performance improvements are controlled by the BAU Scenario posture. Recent accelerations in R,D&D on RETs in many developed nations suggest that the United States would lag behind somewhere over the next two decades, and that the major impact of such market incentives would be to encourage foreign investment in RET production using foreign technology in the U.S. marketplace. More detailed descriptions of the technology-specific implications of the National Premiums Scenario are in the appendices.

Facilitating Options

Resource Assessment

There are opportunities to refine and develop methods for site-specific resource assessments. Our national strategy could anticipate resource needs, establish long-term data collection and resource characterization programs, and reach a consensus on analysis methods for RETs with respect to resource variability and development constraints. This would significantly enhance and facilitate the development and deployment of RETs nationally and internationally.

Table III-3.
Institutional Constraints

Sector/Technology	Category	Constraint	Opportunity
—Dispatchable Electric			
Hydropower	Regulatory	EPCA Regulations	Develop valid methodology for evaluating comparative impacts
			Technical support for relicensing and mitigation
	Perceptual	Perception that federal agencies are pursuing significant R,D&D activities	Education
		Accounting for pumped storage	Develop valid reporting methods
Geothermal	Regulatory/ Perceptual	Utility understanding or acceptance	Tax credits or other incentives
		Scenic and wildlife management issues	Education
		Geothermal perceived as limited to base load	Demonstration projects
	Financial	Uncertain reservoir life	Improve definition of reservoir characteristics
		High front-end costs	Tax credits or other investment incentives
	Infrastructural	Lack of transmission paths for hydrothermal	Facilitate construction/use of transmission
Biomass Electric	Regulatory	Environmental issues on resource procurement, transport, emissions from combustion and waste disposal	Develop control technologies. Internalize environmental costs of landfills
	Perceptual/ Regulatory	Consistent accounting practices to account for use of resources to displace conventional fuels	Develop adequate tools and procedures
		MSW siting difficult near load centers	Continue PURPA preference. Discourage land disposal of MSW
	Infrastructural/ Regulatory	Biomass resources may not be located near electric load centers	Policy changes to encource small generating facilities and to encourage biomass farm to supply larger facilities
Solar Thermal	Regulatory/ Infrastructural	PURPA gas use (25%) restrictions, size restriction (80 MW)	Policy decision to encourage use
	Financial	High front-end costs	Tax credits or other investment incentives
	Infrastructural	Operational constraints related to high levels of penetration	Federal R,D&D to provide analysis
OTEC	Regulatory	Environmental impacts	Federal tests and demonstrations
	Financial	High front-end costs	Tax credits or other investment incentives
	Infrastructural	No industry developed	Aid development of U.S. industry
	Perceptual	Applicable only to tropical band locations	Supporting incentives for these areas
		Utility acceptance or risk and reliability	Long-term demonstrations
—Intermittent Electric			
Wind	Regulatory	Capacity Value	Analyses to develop equitable approaches
		Land use issues	Public Education
	Financial	High front-end costs	Financial incentives on energy supply
	Infrastructural/ Regulatory	Lack of utility participation in developments	Allow utility ownership under PURPA

Table III-3 (Concluded). Institutional Constraints

Sector/Technology	Category	Constraint	Opportunity
—Intermittent Electric (continued)			
Wind	Perceptual/ Regulatory	Utility acceptance, dispatchability costs	Technology transfer, demonstrations, tax or other incentives
	Infrastructural	U.S. industry capability to compete in U.S. market against government financed foreign corporations	Utility involvement, loan guarantees
PV	Perceptual/ Regulatory	Utility acceptance	Assess risks of front-end versus fuel escalation costing
	Regulatory	Environmental issues during manufacture	Define and assess impacts
		Land use issues	Define different systems such as rooftop systems
	Financial/ Infrastructural	Cost of capital to add manufacturing capability	Federal support of R,D&D
		High front-end costs	Loan guarantees to utilities to buy PV
—Transportation			
Biofuels	Regulatory	Alcohol subsidy/farm commodity	Subsidy phase out
		Farm programs that dictate land use	Modify programs to encourage energy crops
		Biotechnology regulation	Facilitate licensing
	Financial	Risk of new technology	Cost shared demonstrations
	Infrastructural	Demand for fuel	Need further analysis leading to policy formulations
		Vehicle market structure	Promote cleaner burning fuels
	Regulatory/ Infrastructural	Land use issues	Policy decisions to encourage use
—Stationary			
Solar Buildings, IPH	Financing	High initial costs	Assess value of front-end versus fuel escalation costing. Federal assistance on loans
	Infrastructural	Integration of bio-derived gas into existing gas delivery systems	Demonstration and tax credits
		Lack of developer/architect interest	Design guides and technical transfer
	Perceptual/ Infrastructural	Lack of awareness (public or developers)	Technical transfer
	Perceptual	Consumer preferences and aethestics	Education, technical transfer
—Facilitators			
Storage	Regulatory	Difficulty in siting or developing hydro storage	Same as for hydropower
	Financial	Long lead time developments mean high risk	Develop improved tools for licensing
Transmission & Distribution	Infrastructural/ Perceptual	Need access to transmission and distribution systems	Policy decisions regarding access
			Development and technical transfer of tools and procedures
			Education

Another opportunity for resource assessment is in evaluating the effect of changing weather patterns that may be caused by global warming. Changes in cloud cover, precipitation, and temperature will directly affect wind, solar, hydropower, and biomass resources. Studies in these areas may also reduce uncertainties about weather that tend to impede RET development.

Storage and Distribution

Cost and performance constraints are the most important limitations to the use of solar and wind resources. The cost constraints associated with storage are important because storage increases the total cost of delivered energy. More knowledge about the interrelationship between storage and RETs is also needed. The ramifications of storage with intermittent renewables for utility systems and the optimum storage needed for a utility system are two of several open issues. The cost limitations and analytic needs associated with energy storage may be addressed in expanded R,D&D efforts.

As noted, another facilitating option is to use hydrogen as a storage medium. To achieve significant deployment of hydrogen fuels, progress must be made on virtually all technical fronts involving production, storage, distribution, and use. In spite of the significant technical barriers, using hydrogen from solar resources may become an important long-run energy strategy for the United States.

Key technical constraints exist to developing transmission and distribution systems that are adequate to transport power and energy from RETs. Transmission-related technical constraints are concerned with getting the most out of existing and expanded transmission systems and providing the data and control needs for utilities to integrate more RETs into their systems. For distribution systems, such constraints are related to power quality, safety, and system protection[8]. Expanded R,D&D would provide the added knowledge needed by utilities and equipment designers to address these issues. R,D&D can provide the design standards, real-time tools, control procedures, and methods of coordinated operation that would allow greater penetration of renewables.

Implications

The examples in this section demonstrate a few of the potential technological hurdles to deployment that we believe can be overcome. They indicate, however, the scope of the activities under way and the additional effort needed to advance renewable energy systems. The cost goals established for various technologies assume that some but not all of the technological challenges are met. On the other hand, there are certain to be unexpected technological gains--some small and some significant--that will enhance the value of some of the systems.

For these and other reasons, research on a wide range of possible renewable energy systems continues to be warranted, particularly for bench-scale and small, pilot research projects. The full benefit of technological advances will remain uncertain, however, until demonstration and commercial-scale units are built. Only then will it be possible to determine the potential savings in well-engineered, production-scale operations. Much of the renewable energy industry is still in early stages of technological development; its full potential cannot yet be predicted accurately. That the potential appears to be great, however, is supported by the progress achieved to date and the specific opportunities already identified for the future.

Technology Transfer

The issue of transferring the results of government-supported energy research and technology to private- and public-sector users is the subject of a paper being prepared by another interlaboratory task force for the National Energy Strategy. However, because the successful transfer of renewable energy technology to the private sector is an important part of the analysis performed by our working group, it deserves some attention here as well.

The renewable energy technologies to be transferred can be defined broadly as "know-how" that includes three elements: product technology; process technology, including standards and practices; and management technology. Therefore, research may result not only in a renewable energy product but also in a new standard or practice that could be used, for example, in the building industry. The classical path that technology takes from the laboratory to the marketplace can be described in the following phases:

- Basic Research
- Exploratory Research
- Applied Research
- Development Research
- Product Improvement.

The transfer of technology occurs between each stage of development and the next, as information is passed from one organization to another. Technology transfer programs attempt to assist the information-transfer process by selecting and combining mechanisms that will help to ensure that appropriate individuals and organizations receive technology information in a timely fashion.

The RETs developed with DOE participation are designed for use by industry and consumers. This presents a significantly more challenging management problem for DOE than that faced by the Department of Defense or the National Aeronautics and Space Administration, for example, who are end users of much of the technology they develop. DOE's most successful technology development programs are those that include market feedback mechanisms and strive to establish government-industry partnerships to pursue development of the RETs.

Significant progress was made in the 1980s toward removing many of the institutional barriers to technology transfer. However, other obstacles hinder the process. Among the most important remaining barriers are issues related to access to information, cultural and perceptual differences between the laboratories and the private sector, and changing market conditions. Timing differences have arisen as markets have changed between the time DOE-supported research began and the time it was completed, or because the research was directed to a long-term national need not addressed in private-sector research.

IV. National Values

Renewable energy systems are associated with several significant values to the nation, and not all of these are reflected in conventional market economics. The values discussed in this section include environmental benefits, national energy security enhancements, and a variety of direct and indirect economic benefits. In spite of their significance, many of these benefits are basically unmeasurable. For example, alternatives to conventional oil work to keep oil prices from reaching the levels they would otherwise attain. Although theoretical economic effects can be estimated, there is no practical way to measure what oil prices would be in the absence of competition from renewables.

Environmental

In evaluating the environmental benefits and costs of using renewable energy rather than other energy sources, we must include the impacts of the complete fuel cycle from beginning to end. This cycle involves the impacts of each stage, from resource extraction or collection to waste and emissions disposal, and from the construction of facilities to their disposition. This evaluation should also include costs and effects that cannot be internalized on the basis of "per unit of energy service delivered." It is difficult to include all costs in such analyses--some costs are external, such as greenhouse-gas emissions; others, while internal, may be so distant and uncertain that we cannot accurately value them, such as the retirement costs associated with generating plants, mines, wells, etc. Some air pollution costs cannot be measured accurately, although the cost of avoiding (or minimizing) pollution can be identified. Governments can impose regulations that require investments and operating expenditures to restrain the level of pollutants, but the cost of avoidance is an imperfect (and heavily debated) measure of the cost of the emissions. The cost of avoiding such emissions as chlorofluorocarbons has been estimated and determined to be worth accepting, but the potential cost of reducing greenhouse-gas emissions, for example, is perceived to be very large. The cost of mitigating CO_2 emissions is uncertain, and the benefit of avoiding such emissions is yet to be defined. Some EPRI analysts project high costs to reduce CO_2 emissions[9].

Renewable energy systems contribute only small amounts of residuals (air emissions and waste products) to the environment. The major environmental impacts tend to be physical, occurring at the site where the resource is captured. The values of some of the impacts can be estimated in terms of the costs of preventing such impacts from other energy forms.

Energy systems that convert solar energy into useful energy--heat or electricity--involve some environmental impacts in the area taken up by the collection system, but little or no others. In some cases, roofs or areas used for other purposes can be allocated to the collectors. The land used by hydropower, geothermal, and wind systems is often valued for scenic, wildlife, or other purposes. Although compromises are often made to preserve environmental values, at times the choice must be made between uses based on a greater public value--which can be difficult to quantify.

Some renewable energy systems provide environmental benefits that are not always fully recognized. The reservoir management that accompanies hydropower projects can also provide flood control, economical water supplies for communities and irrigation, and scenic recreation facilities. Where a large area must be impounded to obtain a satisfactory head for a hydropower project, the impact on land use may be substantial. But such developments should be viewed in comparison to the impacts of other alternatives (e.g., a coal-fired plant).

Biofuels make only minor, if any, contributions to air pollution and solid waste. The growing cycle removes as much or more carbon dioxide from the air as the burning of the fuel returns. Short-rotation woody crops could also fix a significant amount of CO_2, particularly if the land was used previously for an annual crop. Biofuels crops may also reduce wind and water erosion of the soil in comparison to annual food crops.

Biofuels also provide indirect environmental benefits by providing jobs in rural areas, reducing migration to cities, and slowing the pace of urban sprawl. Alcohol transport fuels can also reduce the amount of reactive greenhouse gases and other potentially harmful emissions in comparison to those associated with even the newest gasoline engine technology. By using either alcohol fuels or other clean fuels, we could dramatically improve the mix of clean supply technologies serving today's auto fleets.

The total value of the environmental contributions of renewable energy has not yet been determined. In some cases, such as the reduction of SO_x and NO_x emissions at coal-fired power plants, the average cost of environmental improvement can be estimated--minimizing emissions from high-sulfur coal can cost 2¢/kWh or more. Governments may pass a portion of the environmental costs on to taxpayers or businesses through pollution fees or taxes, maximum emission restrictions, land restoration requirements, capitalized plant decommissioning charges, equipment specifications, wastewater treatment or recycling requirements, etc. In the future, governments may impose additional costs or requirements on energy suppliers and consumers. Because of the relatively benign environmental character of most renewable energy systems, comparing a strict market appraisal of the cost of renewable systems with other systems does not adequately reflect the environmental costs that can be avoided with renewables.

To establish an analytic basis for evaluating the distortions caused by competitive market pricing and costing systems, we estimated the potential market penetration of RETs based on an arbitrary assumption about the environmental costs of using current fossil fuels. The greenhouse-gas and other environmental costs not now reflected in fossil fuel costs are assumed to be 2¢/kWh (or $2/MilBtu for liquid or solid fuels and $1/MilBtu for gaseous fuels). The market penetration of renewable energy systems was projected to the year 2030, assuming renewables were given a market premium of those amounts. The estimate is imperfect, but it allows us to assess effects on market penetration based on one level of assumed premium.

Security

Renewable energy systems enhance energy security. Replacing imported oil with domestic renewable resources obviously contributes to national security. In the developing nations, released demands on foreign exchange accounts would permit more effort to be devoted to economic development needs. Energy systems that reduce the need for natural gas will extend domestic gas resources. The secondary impact of less dependence on imports is that it shifts the supply-demand balance of those fuels, reducing price pressures and costs of other imports and increasing competition in international markets. Greater competition should reduce the likelihood that the Organization of Petroleum Exporting Countries (OPEC) or any other group of producers would be able to restrain supplies and drive prices up.

U.S. energy security would benefit by developing biomass fuels systems in tropical countries that are well suited to economical production of liquid fuels. In addition, producing indigenous energy resources enhances political stability in the developing countries, thus better enabling those countries to cope with an oil crisis. A parallel occurs in the Pacific Rim, Central America, and the African Rift Valley, where geothermal systems could provide substantial indigenous energy. If tropical developing countries should export large quantities of biomass fuels, the broadening of the market would reduce the likelihood of a concerted effort among OPEC and other nations to curtail supplies and raise prices.

Economic and Other

The United States stands to benefit economically from the development and use of renewable energy. As we noted, the foremost advantage is that all energy prices should be lower as renewable (or any other) energy enters the markets. Other benefits include technological and developmental spin-offs and impacts on developing countries and their implications for the United States.

Technology spin-offs of major importance will occur in several segments of domestic industry. Advances in basic materials science and production needed to improve certain renewables technologies will have major impacts on associated industries. For example, the development of high-yield silviculture provides the pulp and paper industry with lower cost feedstock while reducing the acreage needed to support that industry. Advances in PV science have impacts on other users of crystalline materials, such as the semiconductor industry and its customers. Biological processes for ethanol production have application in the chemicals, food, and beverage industries. Composite materials for wind turbine blades may have widespread application in the manufacturing of automobiles, aircraft, and other vehicles, and in construction where lightweight, high-performance materials are needed. Advances in hard-rock drilling for geothermal resources also can benefit the oil and gas industries.

Economic development of domestic rural areas could also occur. A U.S. biofuels program can expand employment and increase incomes in rural areas. Additional employment opportunities and the need for supporting industrial, commercial, and public services in rural areas should reduce migration to urban areas.

The development of renewable technologies that find application abroad will have a number of additional impacts:

- Development of renewable energy resources such as biomass liquids in less developed countries (LDCs) can reduce their need for economic assistance from industrialized countries. Reducing oil imports would improve the balance of payments. Similar benefits would result from using wind, geothermal, hydropower, and other renewables in the developing countries. Low-cost, dispersed power supplies based on PV or other renewable technologies could reduce the need to extend electric power grids, which can be costly. By reducing the drain on scarce capital, these actions could also create more political stability and reduce the sociological and economic pressures to emigrate.

- If LDCs in the tropical regions can produce ethanol (or methanol) from biomass more economically than the United States (or other industrialized countries), exporting such fuels would improve developing countries' balance-of-payments problems. This would further diversify the sources of liquid fuels in world markets, reducing the potential for monopolistic control for economic or political ends.

- U.S. manufacturers of equipment for renewable technologies would probably benefit from being able to export their products. Once local industries develop to supply developing countries' needs, licensing and royalty arrangements could provide some continuing income to U.S. manufacturers.

The United States could also benefit economically from expansion of dispersed power supply. Modular power generation technologies will allow electric utilities to match load growth increments more economically. The reliability of power supply in remote areas might also be improved. If renewable energy reduces the nation's global military vulnerability, or reduces the military resources needed to maintain free trade in energy, the savings could be great.

A Balanced U.S. Energy Portfolio

Much as a balanced or diversified financial portfolio reduces risk, a balanced energy portfolio reduces the risk of interruptions in supply and severe price fluctuations. The risk is reduced because many of the uncertainties in fuel supply availability and cost would then affect only one or a few energy sources. Examples are oil embargoes, coal strikes, or large-scale nuclear shutdowns. With a diversified energy supply, the portion of the system that may be adversely affected becomes potentially smaller. Electric utilities have often relied on a diversified fuel mix to reduce downside risks when strikes, embargoes, or weather limit the availability of fuels. Renewables can assist in diversifying the U.S. energy supply to all end users, including the utility, residential, commercial, industrial, and transportation sectors.

V. Contribution Potential

The Competitive Market Construct

Based on guidance from the Energy Information Administration (EIA) and DOE's Office of Policy, Planning and Analysis on projected energy consumption and price levels, an energy market construct was framed for this study. It employs energy demand levels defined by end-use sector and a set of price tracks for competing fuels. Such a construct is necessary if we are to critically examine the competitive potential of RETs. Our task was not to validate the market framework, but rather to use it to perform our market analyses.

Details of the energy demand and price projections are presented in the appendices. Key energy and economic parameters are presented in Table V-1.

Table V-1.
Energy and Economic Parameters for the Competitive Market Construct

	Prices (1988$)		Annual Compound Growth Rate (%)
	1990	2030	
World Crude Oil Price ($/bbl)	15.00	45.99	2.8
Wellhead Natural Gas Price ($/MCF)	1.73	5.86	3.1
Minemouth Coal Price ($/ton)	24.08	37.48	1.1
Electricity Generation Costs (¢/kWh)			
Baseload	5.0	6.0	0.5
Intermediate	6.0	9.0	1.0
Peaking	9.0	15.0	1.3
Primary Energy Demand (quads)	85.3	144.2	1.3
Primary Energy to Electricity (quads)	30.5	73.2	2.2
Gross National Product (billions)	5,120	12,911	2.3

The Development of RET Contribution Scenarios

As part of this study, potential RET contribution estimates were generated to examine the sensitivity of various pathways of RET evolution. These estimates of potential RET deployment are based on appraisals of both energy market opportunities and RET cost and performance improvements anticipated under three different scenarios. The three scenarios are described in the sections that follow.

The Business-as-Usual Scenario

The Business-as-Usual (BAU) Scenario represents RET penetration levels that can be expected given projected conventional energy prices and demand and projected normal progressions of renewable energy technological development. This case assumes that federal R,D&D funding for renewable energy remains at current levels. As illustrated in Figure V-1, steady RET cost reductions occur over time as a result of technology advancements. Eventually, the levelized RET cost curve crosses over the cost curve(s) for conventional energy supplies (driven up by increasing fuel prices), indicating RET cost competitiveness and market deployment potential.

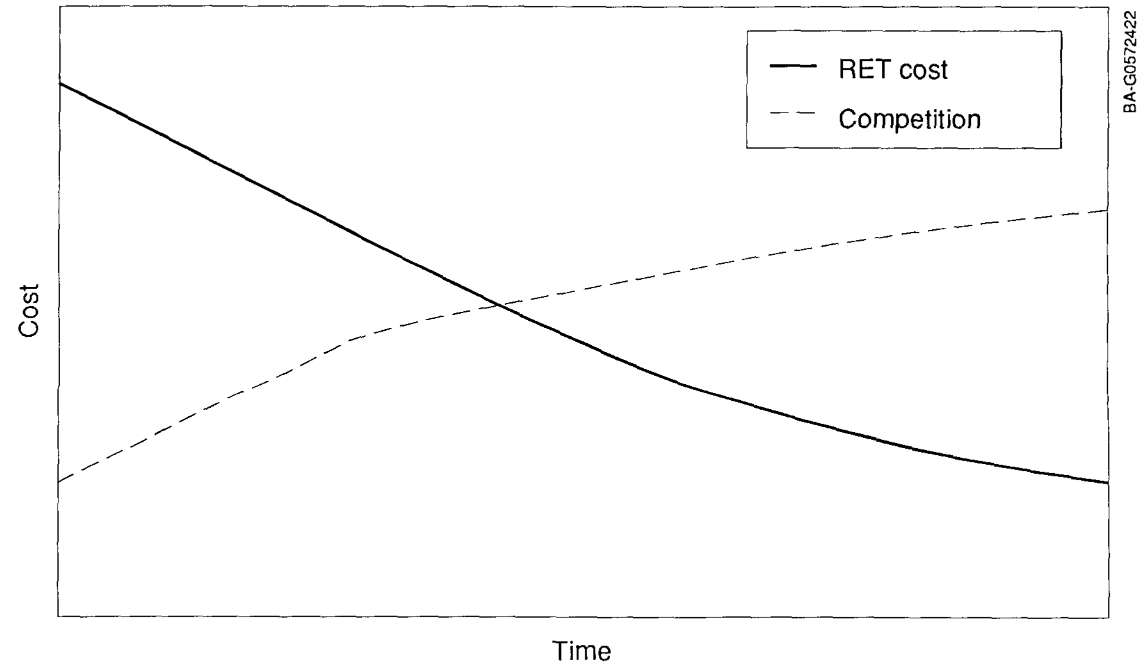


Figure V-1. Competitive construct for RETs: The Business-as-Usual Scenario

The R,D&D Intensification Scenario

This scenario preserves the energy market construct of the BAU case but assumes that federal and other R,D&D funding is accelerated to levels deemed necessary to hasten the development of cost-competitive technologies. As shown in Figure V-2, this scenario projects more rapid near-term RET cost improvements as a result of greater interest in RET development. Cost improvements level off in the longer term as theoretical performance limits are approached and as the need for R,D&D declines. This scenario represents a "technology-push" approach to RET development.

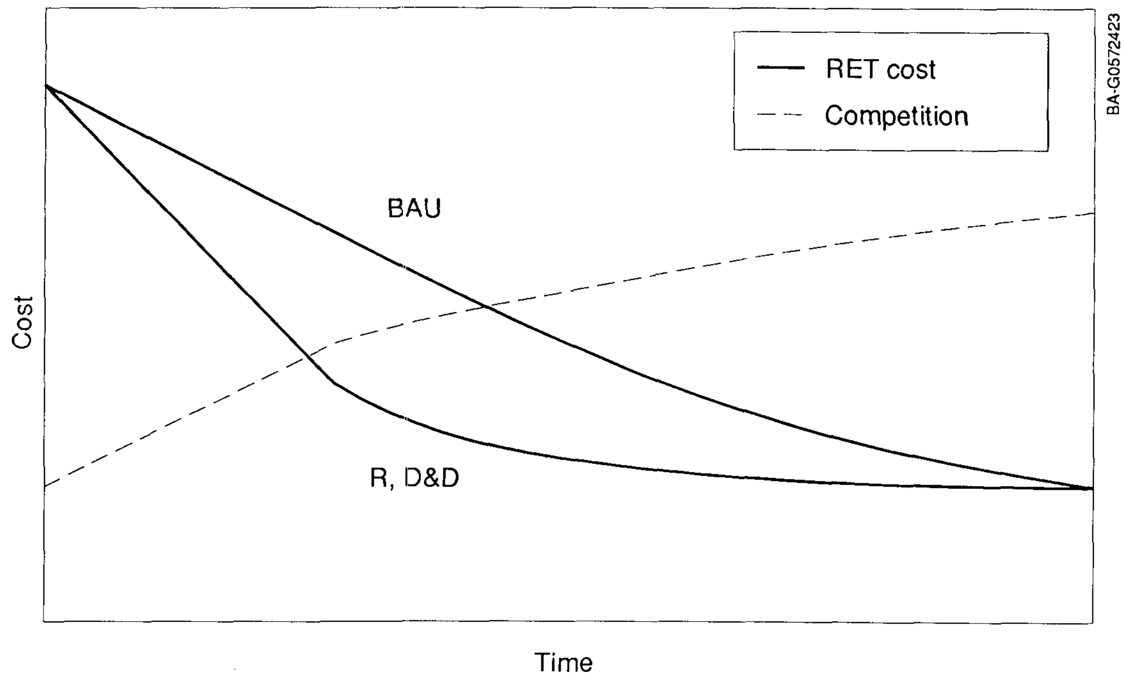


Figure V-2. Competitive construct for RETs: The R,D&D Intensification Scenario

The National Premiums Scenario

The third scenario assumes that heightened national and regional concerns about the externalities of conventional energy production and consumption result in energy market price premiums for clean energy sources. Many examples of specific premiums already exist at state and local levels to address acute environmental concerns. For this scenario, a set of premiums was defined that represent these concerns. The premiums were defined as follows:

- 2¢/kWh on fuel-based electricity generation
- $2.00/MilBtu on direct coal and petroleum consumption
- $1.00/MilBtu on direct natural gas consumption.

The primary effect of the National Premiums Scenario is that it enhances the competitiveness of RETs in the energy marketplace, independent of technology improvements, by providing a market subsidy to RET costs to account for the nonmarket costs of most conventional energy alternatives. This scenario, as illustrated in Figure V-3, essentially represents a "market-pull" approach to RET development. Although the impact of the premium is depicted as a uniform downward shift in the technology cost curve, in actuality such a premium would be likely to elicit additional investment from private industry over time to enhance technology performance. A full accounting of this synergism was beyond the scope of our effort.

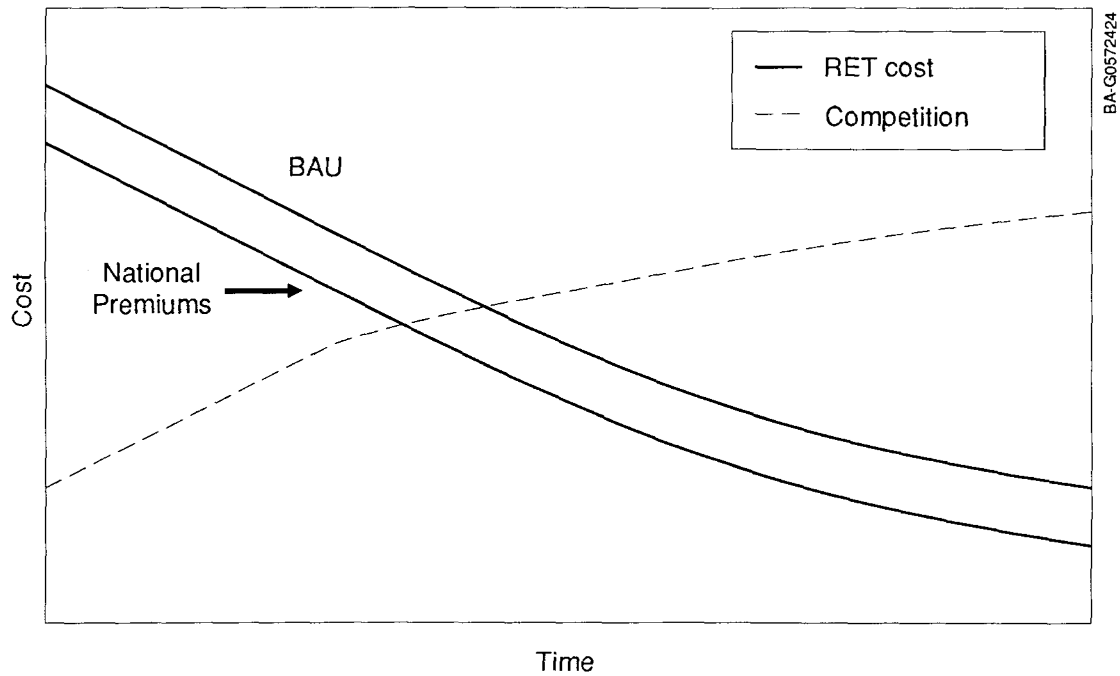


Figure V-3. Competitive construct for RETs: The National Premiums Scenario

The Process for Estimating RET Contribution Potentials

For each renewable energy or technology area, we estimated the energy contribution potential under the three scenarios described above. "Cost curves" were developed for each RET and applied against regional market constructs (see the appendices) to estimate the level of penetration that could be achieved over the study period. The process for projecting RET cost improvements over time is described in the appendices. In this exercise we first estimated the potential for each RET. A subsequent "rollup" took cross-technology competition into account, integrating the individual estimates into an expanded market structure.

The objective in performing the RET deployment projections was to provide a mid-range result, neither too optimistic nor too pessimistic. This approach implicitly recognizes the high degree of uncertainty in making long-term projections. The projected RET contributions were also deliberately limited in several important ways. In most cases, RET penetration was constrained by the need for *additional* energy supply to meet incremental demand. For instance, for the electric generating technologies, displacement of existing capacity was not permitted except for a conservative retirement allotment. Only new capacity needs could be met with RETs.

The RET deployment estimates are also based on preliminary considerations of market penetration dynamics and the ability of the RET industries to scale up manufacturing capabilities as well as time lags in transferring R,D&D advances to industry.

The penetration of particular electric RETs was further constrained by assuming that operating and reliability concerns limited the ability of utilities to incorporate intermittent generation sources. Utility studies have suggested that a 5% to 20% capacity penetration of intermittents is acceptable, depending on existing system response capabilities, without special remedial actions. Therefore, a 10% regional penetration limit for intermittents was adopted for the BAU case through the year 2020, rising to 15% by 2030. The rationale for the increase in the longer term is that as RETs become more cost competitive, both RET manufacturers and utility companies would work to facilitate increased deployment. Similarly, in the National Premiums case, the intermittents penetration is limited to 10% through 2010 but rises to 15% by 2020 and 20% by 2030. The earlier RET competitiveness achieved with the premiums subsidy should foster greater effort on the part of industry and utilities to overcome penetration limits. With R,D&D Intensification, a greater near-term effort would be devoted to developing cost-effective operating and storage modes so that penetration limits would be overcome sooner than in the other two cases. The additional R,D&D boosts the initial 10% limit to 15% by 2010 and to 20% in 2020 and thereafter. Figure V-4 illustrates the assumed penetration limits by scenario.

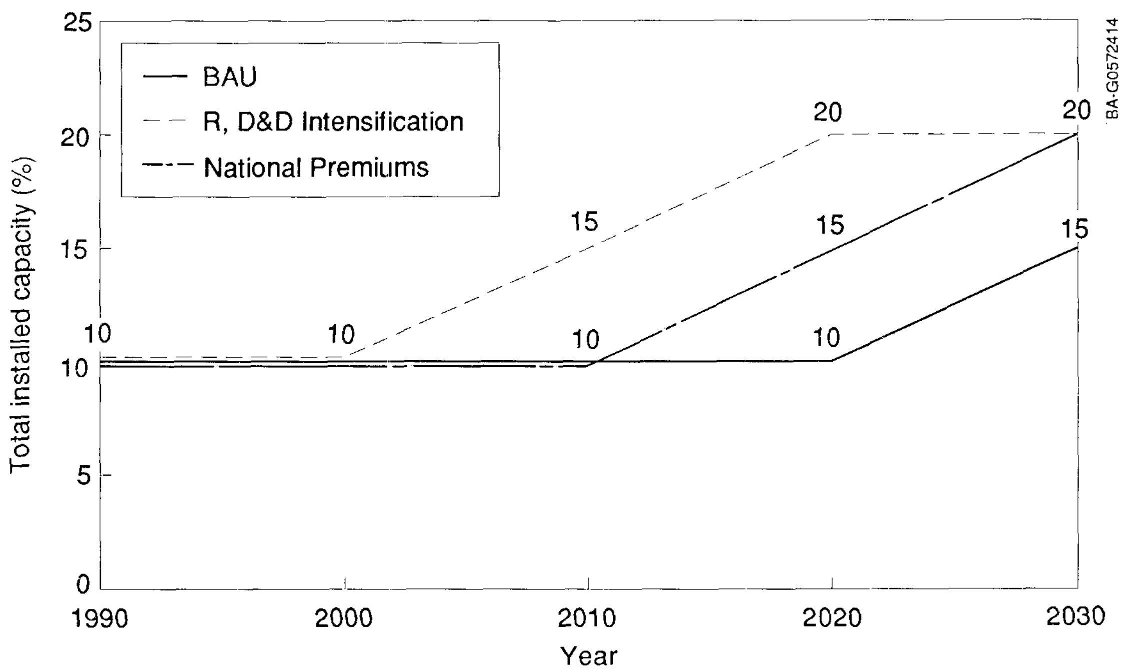


Figure V-4. Regional penetration limit on intermittent generation sources

The intermittent RETs--defined here as wind, photovoltaics, and solar thermal electric technologies--were allowed to collectively penetrate a regional capacity mix up to these predetermined limits. If a limit was reached, progressive intermittent capacity additions were apportioned evenly among the applicable competing RETs.

Estimates of the RET Contribution Potential

Estimates of RET contribution potential depend on several first-order considerations. The first is resource availability. In order to expect any level of contribution from a particular RET, the resource must exist to be exploited. Further, it must be of sufficient *intensity* that the RET can produce energy at or below the price of competing resources. Second, the RET must be able to supply energy in a form that can be effectively used in energy-consuming sectors. For example, to penetrate the transportation sector today and in the near future, energy must be provided in the form of liquid fuels. Other sectors consume end-use energy in the form of electricity and heat. Third, there must be a match between the availability of certain renewable energy resources and demand in a particular region. This is necessary for several renewable resources because their remoteness and diffuseness can make transport between regional energy markets difficult or expensive.

In all regions, we found that renewable energy resources, in one form or another, have the *theoretical* potential to provide for nearly all energy needs in most energy-consuming sectors. Instead, the RET contribution is ultimately constrained by technical factors in terms of resource accessibility and technology performance; economic factors, including the cost of RETs and competition from traditional energy sources and technologies; and institutional factors, as discussed earlier. The differentials between the market and resource potentials of renewable energy are considerable. The energy supply opportunity is so great that it deserves a more structured analysis than we are able to provide at this time.

The BAU Scenario

In the BAU Scenario, the renewable energy contribution is projected to grow from an estimated 6.7 quads in 1988 to 22.3 quads in 2030 (the hydro contribution is projected for a "normal" year) (see Table V-2). The primary driver behind this growth is biomass energy, which provides almost one-half of the energy increment. The contribution from nonbiomass renewable electrics adds 7.7 quads. Implicit in these estimates is the view that, even with level R,D&D funding, specific RETs will still penetrate the market over time as conventional energy costs (prices) increase and the market provides incentives for improvements in RETs. However, this penetration is not anticipated to be substantial until after 2010. Without the 15% utility penetration limitation, it is estimated that the RET intermittents could supply an additional 2.5 quads by 2030.

The R,D&D Intensification Scenario

With R,D&D intensification, the energy contribution from RETs in 2030 could be nearly double that achievable in the BAU Scenario (see Table V-3). Practically all RETs see significantly increased penetration in this scenario. Biomass sources again represent about half of the estimated RET energy supply; the largest biomass portion is an 8.4-quad contribution from alcohol fuels. The combined hydropower and geothermal electric contribution is estimated to increase from 3.4 quads in 1988 to nearly 9 quads in 2030. The RET intermittents provide an estimated 10.4-quad contribution with the 20% penetration constraint but could potentially provide more than double this amount if unconstrained.

R,D&D intensification would have the effect of accelerating the technological and economic readiness of RETs and thus the time period of RET penetration. Technological advances would also be made that might not occur without the expanded effort. Total RET penetration is 1.1 quads greater than that of the BAU Scenario in 2000, 7.1 quads in 2010, 13.5 quads in 2020, and 18.8 quads in 2030. Thus, R,D&D acceleration would have near-term as well as longer-term payouts. Near-term payouts would come from renewable energy sources already in commercial deployment or near commercial application, such as hydropower, geothermal, windpower, and various biomass sources, as expected. In the longer term, all RETs would pay dividends, in the form of a greater energy contribution, from intensified R,D&D.

Table V-2.
Business as Usual

U.S. TOTAL (QUADS)	*(WITH INTERMITTENTS CONSTRAINT)* 1988	2000	2010	2020	2030
HYDROPOWER	3.1	3.4	3.4	3.5	3.5
GEOTHERMAL ELECTRIC	0.2	0.3	0.5	0.7	0.9
SOLAR THERMAL ELECTRIC	<0.1	<0.1	0.3	0.9	2.0
PHOTOVOLTAICS	<0.1	<0.1	0.2	0.7	1.8
WINDPOWER	<0.1	0.2	1.0	1.9	2.9
OTEC	0.0	0.0	<0.1	<0.1	<0.1
BIOMASS - ELECTRIC	0.5	1.0	1.6	1.9	2.2
BIOMASS - BUILDINGS	1.0	1.0	1.5	1.8	2.2
BIOMASS - INDUSTRIAL	1.8	2.2	2.9	3.3	3.8
BIOMASS - LIQUID FUELS	<0.1	0.2	0.4	0.8	2.2
BIOMASS (TOTAL)	3.3	4.4	6.3	7.8	10.3
SOLAR HEAT - BUILDINGS	<0.1	0.2	0.3	0.4	0.5
SOLAR HEAT - INDUSTRIAL	<0.1	<0.1	<0.1	<0.1	0.2
GEOTHERMAL - HEAT	<0.1	<0.1	0.1	0.2	0.2
TOTAL RET	6.7	8.6	12.1	16.1	22.3
% of Total Energy Demand	*8*	*9*	*11*	*13*	*15*

U.S. TOTAL (QUADS)	*(WITHOUT INTERMITTENTS CONSTRAINT)* 1988	2000	2010	2020	2030
HYDROPOWER	3.1	3.4	3.4	3.5	3.5
GEOTHERMAL ELECTRIC	0.2	0.3	0.5	0.7	0.9
SOLAR THERMAL ELECTRIC	<0.1	<0.1	0.3	1.2	3.0
PHOTOVOLTAICS	<0.1	<0.1	0.2	0.7	2.9
WINDPOWER	<0.1	0.2	1.0	2.1	3.3
OTEC	0.0	0.0	<0.1	<0.1	<0.1
BIOMASS - ELECTRIC	0.5	1.0	1.6	1.9	2.2
BIOMASS - BUILDINGS	1.0	1.0	1.5	1.8	2.2
BIOMASS - INDUSTRIAL	1.8	2.2	2.9	3.3	3.8
BIOMASS - LIQUID FUELS	<0.1	0.2	0.4	0.8	2.2
BIOMASS (TOTAL)	3.3	4.4	6.3	7.8	10.3
SOLAR HEAT - BUILDINGS	<0.1	0.2	0.3	0.4	0.5
SOLAR HEAT - INDUSTRIAL	<0.1	<0.1	<0.1	<0.1	0.2
GEOTHERMAL - HEAT	<0.1	<0.1	0.1	0.2	0.2
TOTAL RET	6.7	8.6	12.1	16.7	24.9
% of Total Energy Demand	*8*	*9*	*11*	*13*	*17*

Table V-3.
R,D&D Intensification

U.S. TOTAL (QUADS)	*(WITH INTERMITTENTS CONSTRAINT)* 1988	2000	2010	2020	2030
HYDROPOWER	3.1	3.4	4.0	4.7	5.1
GEOTHERMAL ELECTRIC	0.2	0.4	0.8	2.0	3.7
SOLAR THERMAL ELECTRIC	<0.1	0.2	1.0	2.0	2.6
PHOTOVOLTAICS	<0.1	<0.1	0.7	1.7	2.5
WINDPOWER	<0.1	0.4	2.2	4.2	5.3
OTEC	0.0	0.0	<0.1	<0.1	<0.1
BIOMASS – ELECTRIC	0.5	1.1	1.9	2.4	2.9
BIOMASS – BUILDINGS	1.0	1.2	2.0	2.6	3.2
BIOMASS – INDUSTRIAL	1.8	2.3	3.3	3.9	4.6
BIOMASS – LIQUID FUELS	<0.1	0.3	2.4	4.4	8.4
BIOMASS (TOTAL)	3.3	5.0	9.6	13.3	19.1
SOLAR HEAT – BUILDINGS	<0.1	0.2	0.5	0.7	0.9
SOLAR HEAT – INDUSTRIAL	<0.1	<0.1	0.1	0.2	0.3
GEOTHERMAL – HEAT	<0.1	<0.1	0.3	0.7	1.6
TOTAL RET	6.7	9.7	19.2	29.6	41.1
% of Total Energy Demand	*8*	*10*	*18*	*24*	*28*

U.S. TOTAL (QUADS)	*(WITHOUT INTERMITTENTS CONSTRAINT)* 1988	2000	2010	2020	2030
HYDROPOWER	3.1	3.4	4.0	4.7	5.1
GEOTHERMAL ELECTRIC	0.2	0.4	0.8	2.0	3.7
SOLAR THERMAL ELECTRIC	<0.1	0.2	1.0	3.1	9.0
PHOTOVOLTAICS	<0.1	<0.1	0.7	2.6	6.7
WINDPOWER	<0.1	0.4	2.3	5.7	10.7
OTEC	0.0	0.0	<0.1	<0.1	<0.1
BIOMASS – ELECTRIC	0.5	1.1	1.9	2.4	2.9
BIOMASS – BUILDINGS	1.0	1.2	2.0	2.6	3.2
BIOMASS – INDUSTRIAL	1.8	2.3	3.3	3.9	4.6
BIOMASS – LIQUID FUELS	<0.1	0.3	2.4	4.4	8.4
BIOMASS (TOTAL)	3.3	5.0	9.6	13.3	19.1
SOLAR HEAT – BUILDINGS	<0.1	0.2	0.5	0.7	0.9
SOLAR HEAT – INDUSTRIAL	<0.1	<0.1	0.1	0.2	0.3
GEOTHERMAL – HEAT	<0.1	<0.1	0.3	0.7	1.6
TOTAL RET	6.7	9.7	19.3	33.1	57.1
% of Total Energy Demand	*8*	*10*	*18*	*27*	*40*

The National Premiums Scenario

In the National Premiums Scenario, the improved economic environment for RETs would result in significantly increased near-term penetration above the BAU Scenario: 1.9 quads by 2000 and 4.8 quads by 2010 (Table V-4). As with intensified R,D&D, this near-term differential centers on hydropower, geothermal, wind power, and various biomass sources. However, primarily because of the system penetration constraint on intermittents, the economic premium does not foster much additional penetration above the BAU Scenario in the longer term. Without this constraint, RET intermittents could supply as much as 25 quads of additional energy as a result of the economic premium.

Implications

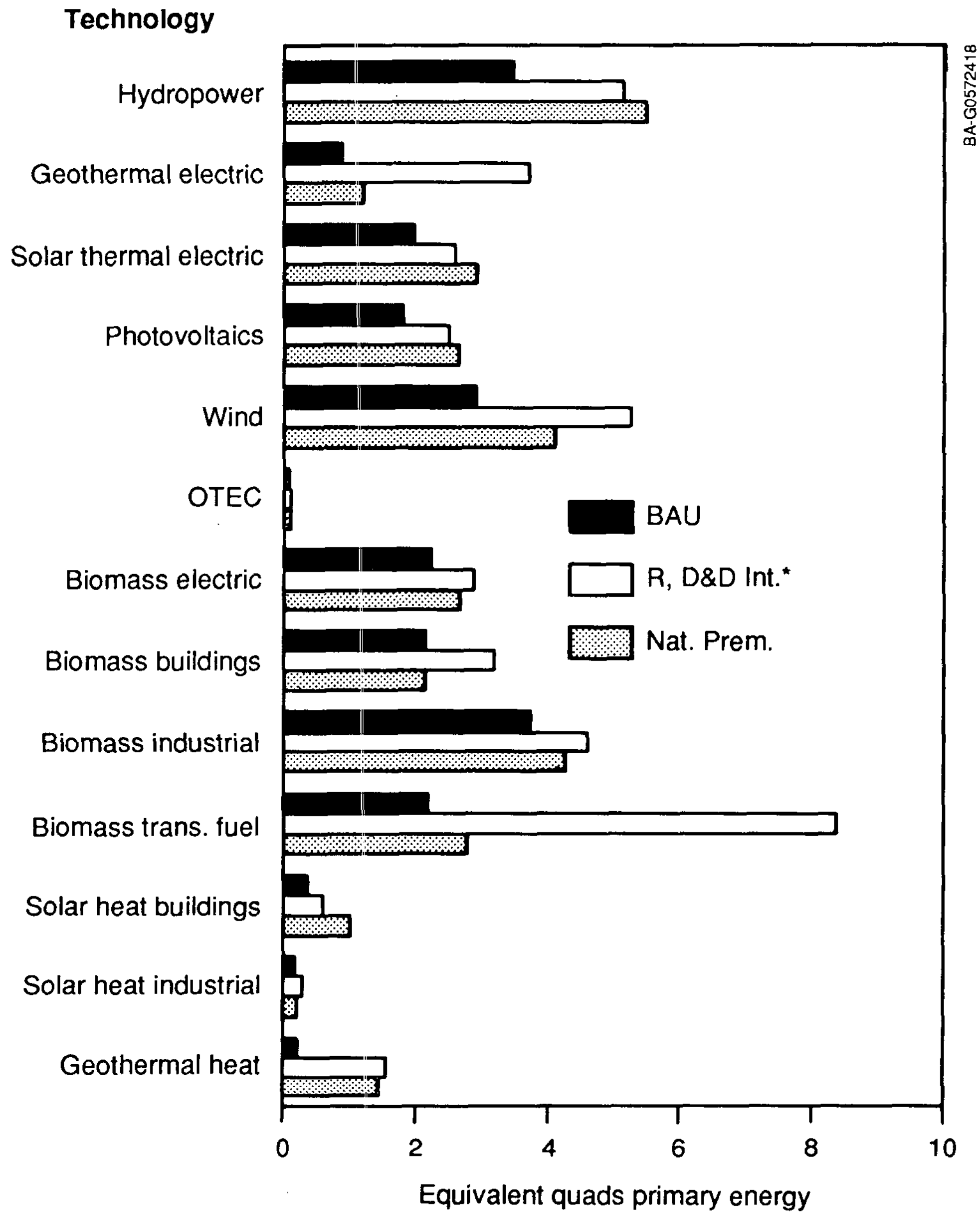
Figure V-5 summarizes the 2030 RET penetration estimates in the three scenarios. The R,D&D Intensification Scenario would have both near-term and long-term payouts in terms of accelerating and expanding the energy contribution from all RETs; it would also allow much of the potential of renewable energy to be realized by 2030. An economic premium would result in a significant near-term increase in the RET contribution above the BAU Scenario, primarily from currently competitive or marginally economic sources. But the magnitude of the longer-term benefits still depends on addressing outstanding technical issues. Maximum penetration is likely to occur with strategies that incorporate the more favorable stimulative elements of both these scenarios.

In the BAU Scenario, renewables are projected to provide more than 15% of U.S. energy needs in 2030, compared with about 8% today. It is clear that with a greater R,D&D commitment or with market recognition of the inherent value of renewable energy technologies as clean, domestic energy sources, renewable energy supply fractions of about 30% or more may be possible by 2030.

Table V-4.
National Premiums

U.S. TOTAL (QUADS)	*(WITH INTERMITTENTS CONSTRAINT)* 1988	2000	2010	2020	2030
HYDROPOWER	3.1	3.5	4.2	4.9	5.5
GEOTHERMAL ELECTRIC	0.2	0.4	0.6	0.8	1.2
SOLAR THERMAL ELECTRIC	<0.1	0.2	0.9	1.7	2.9
PHOTOVOLTAICS	<0.1	<0.1	0.4	1.4	2.7
WINDPOWER	<0.1	0.4	1.7	2.8	4.1
OTEC	0.0	0.0	<0.1	<0.1	<0.1
BIOMASS – ELECTRIC	0.5	1.5	2.1	2.4	2.7
BIOMASS – BUILDINGS	1.0	1.0	1.5	1.8	2.2
BIOMASS – INDUSTRIAL	1.8	2.7	3.4	3.8	4.3
BIOMASS – LIQUID FUELS	<0.1	0.3	1.0	1.5	2.8
BIOMASS (TOTAL)	3.3	5.5	7.9	9.5	11.9
SOLAR HEAT – BUILDINGS	<0.1	0.3	0.9	1.2	1.5
SOLAR HEAT – INDUSTRIAL	<0.1	<0.1	<0.1	0.1	0.2
GEOTHERMAL – HEAT	<0.1	0.2	0.4	0.9	1.5
TOTAL RET	6.7	10.5	16.9	23.4	31.6
% of Total Energy Demand	*8*	*11*	*15*	*19*	*22*

U.S. TOTAL (QUADS)	*(WITHOUT INTERMITTENTS CONSTRAINT)* 1988	2000	2010	2020	2030
HYDROPOWER	3.1	3.5	4.2	4.9	5.5
GEOTHERMAL ELECTRIC	0.2	0.4	0.6	0.8	1.2
SOLAR THERMAL ELECTRIC	<0.1	0.2	0.9	3.5	10.3
PHOTOVOLTAICS	<0.1	<0.1	0.4	3.0	9.4
WINDPOWER	<0.1	0.4	2.5	5.9	10.8
OTEC	0.0	0.0	<0.1	<0.1	<0.1
BIOMASS – ELECTRIC	0.5	1.5	2.1	2.4	2.7
BIOMASS – BUILDINGS	1.0	1.0	1.5	1.8	2.2
BIOMASS – INDUSTRIAL	1.8	2.7	3.4	3.8	4.3
BIOMASS – LIQUID FUELS	<0.1	0.3	1.0	1.5	2.8
BIOMASS (TOTAL)	3.3	5.5	7.9	9.5	11.9
SOLAR HEAT – BUILDINGS	<0.1	0.3	0.9	1.2	1.5
SOLAR HEAT – INDUSTRIAL	<0.1	<0.1	<0.1	0.1	0.2
GEOTHERMAL – HEAT	<0.1	0.2	0.4	0.9	1.5
TOTAL RET	6.7	10.5	17.8	29.8	52.4
% of Total Energy Demand	*8*	*11*	*16*	*24*	*36*



*Added R, D&D funding is variable, depending on opportunities and technology needs.

Figure V-5. Year 2030 renewables contribution: BAU, R,D&D, and National Premiums Scenarios (with constraints)

VI. Conclusions

Our conclusions can be grouped in two areas: general and analytic needs. General conclusions focus on the study results, noted trends, and opportunities for a U.S. energy strategy. Analytic needs are near-term and longer-term studies and investigations that ought to be considered to answer outstanding questions and identify more opportunities for renewables.

General Conclusions

1. Results of Energy Contribution Analyses

   - The Business-as-Usual or BAU Scenario concludes that RETs will make an ever-increasing contribution to the U.S. energy mix over the planning period, from 8% today to 15% of the U.S. energy supply by 2030. This gradual increase is largely driven by technology performance improvements that would reach competitive thresholds in the latter decades of the planning period.

   - The R,D&D Intensification (technology-push) Scenario concludes that RETs can make a much larger contribution, reaching 28% of the U.S. energy supply by 2030 if federal R,D&D is supported at levels roughly 2-1/2 times today's. This increased support, largely in the early part of the planning period, would move many of the technologies into the competitive range during the second decade of the planning period.

   - The National Premiums (market-pull) Scenario concludes that market incentives will increase the RET contribution over the BAU Scenario, but to a lesser degree (22% penetration) than the R,D&D Intensification Scenario. The National Premiums penetration is less than the Intensified R,D&D penetration largely because slower technology development (at the BAU level) delays entry into the competitive range for many technologies.

2. Our analysis of energy contributions presumes that federal support for R,D&D in the United States is the most important factor affecting RET performance status globally. The scope of R,D&D investments in RETs by other developed nations suggests that this may *not* be the case and that a policy based on "market pull" might create a market opportunity in the United States for foreign RETs. This factor requires further study before strategic decisions are made.

3. Our preliminary assessment of market potentials for RETs suggests that, owing to the vast scope of available resources, it is reasonable to expect much larger RET penetration beyond the 2030 planning horizon. This topic deserves additional quantitative assessment.

4. Comparisons of constrained and unconstrained energy contribution analyses make it clear that the influence of electricity storage/load following capability is a very important factor in the deployment of intermittent renewable electric technologies.

5. The R,D&D efforts projected under both the R,D&D Intensification and BAU Scenarios target R&D needs derived from technological understandings developed in the last decade.

6. The study identifies a range of technological and institutional factors pertinent to future RET penetration and suggests their general significance. However, no estimates are made of the importance of specific factors or the efficacy of potential remedies.

7. The energy contribution analysis concludes that RETs can provide energy in all forms to all end-use sectors. This is particularly significant in terms of the large potential to provide liquid fuels to the transportation sector.

8. The position of the Task Force is that RETs generally have much lower environmental impacts than fossil energy systems. However, we believe that a comprehensive, *comparative* analysis of environmental impacts would strengthen a National Energy Strategy.

9. In addition to the environmental benefits already noted, the significant increases in the RET contribution expected in *all* scenarios would support U.S. energy policy goals of domestic security (by reducing imports of liquid fuels), price stability (by diversifying energy supply resources), and competitiveness (by creating opportunities for energy technology exports and technological spin-offs and constraining energy price increases).

Analytic Needs

Our investigations underscore the need for further analytic studies that DOE might pursue as part of future NES efforts. These studies can be expected to produce pertinent, valuable information of an analytic nature to illuminate the unknowns and outstanding questions that we were unable to address to our satisfaction because of time limitations. Key areas needing further analysis are the evolving energy market and responses to policy; the impact of R,D&D in other nations; a more detailed analysis of RET deployment; and an assessment of nonmarket externalities (i.e., environmental benefits) of RETs. Table VI-1 sets forth these analytic needs and, where possible, includes a reference in the report that provides further background on the topic.

Table VI-1.
Analytic Needs

Topic/Need:	Discussion:	Reference:
Combine technology-push and market-pull policies.	A scenario that was not examined is some combination of Intensified R,D&D and National Premiums. This would lead to greater RET penetration than the three cases examined and could provide projections approaching a "maximum" RET scenario.	See Section V on Contribution Potential.
Assess implications of alternative approaches to incorporate externalities such as environmental costs.	The simplistic method of providing a subsidy to RETs for externalities, as in our scenarios, does not deal with implications for markets and end-users. Alternative methods may have different attributes and impacts.	See Section IV on National Goals.
Assess impacts of foreign technology development programs on technology status.	Foreign technology developments may advance technology status faster than we have anticipated in our scenarios. It would be useful to assess these potential effects and our competitive status.	See PV, Wind, OTEC, and others in the appendices.
Evaluate implications of alternate market constructs on renewable contributions.	Our projections made use of a single energy market projection that has great uncertainty and is extended 40 years. It would be very informative to examine the implications of a range of future energy markets to test the sensitivity of penetration results to different futures and to identify specific RETs and policies that allow market penetration over a wide range of futures.	See the Market Construct, Appendix J.
Assess relationship of building efficiency and renewables contribution.	Our buildings RET contribution was based on one level of assumed efficiency, and little is known about the relationship of conservation level and renewables use.	See Solar Heat: Buildings, Appendix H.

Table VI-1 (Continued).
Analytic Needs

Topic/Need:	Discussion:	Reference:
Assess potential of solar buildings technology in commercial sector.	Relatively little data exist on which to estimate the potential energy contribution of these technologies to the commercial sector.	See Solar Heat: Buildings, Appendix H.
Assess implications of expanded use of biomass as an energy resource.	Vastly increased use of biomass, as projected here, implies creation of a major new industry to provide the biomass resource. The impacts of this on the related forest products and agricultural products industries need to be studied.	See Biomass, Resource Availability, Appendix B.
Analyze implications of RET production increases.	The RET production ramp-up rates projected in this paper have not been studied carefully.	See Process of Estimating RET Contribution, Section V.
Explore opportunities for RET-fossil hybrids.	Inadequate study has been made of the potential for fossil-renewable hybrid systems to serve as a means of integrating the use of renewable resources into the economy.	See Biofuels, Wind, Solar Thermal, PV in appendices.
Assess implications of new fossil use technology for biomass use.	New, more efficient technologies for fossil energy conversion have been developed over the past decade. These need to be assessed regarding their implications for biomass use.	See Biofuels, Appendix B.
Evaluate the amount of upgrade capability at existing hydro sites.	Recent studies by federal marketing agencies indicate substantial upgrading and retrofitting capacity at existing sites and low costs. This effort would assess what is available with similar types of upgrades on a national basis.	See Hydropower, Appendix A.
Determine the relationship of storage, transmission and distribution capabilities and intermittent renewables.	The electric systems/reliability issues still need clarification with regard to renewables. How much storage is appropriate and what the relationship is with intermittent renewables need further definition. The benefits and detriments of distributed renewables versus central stations need clarification.	See Storage and Transmission/ Distribution, Appendix I.
Establish national energy accounting standards to allow monitoring of renewables.	As renewables are projected to show continued growth, a consistent track record needs to be developed, even if current energy shares are quite low.	N/A
Explore alternative costing methodologies for high-capital-cost technologies.	Installers of RETs generally face relatively high first costs with generally low operating costs. For utilities, standard costing methods mean unattractive high initial costs but low future costs. There may be alternative costing methods that allow recovery of costs without the initial large increase.	See discussion of risk factors in Summary.

Table VI-1 (Concluded)
Analytic Needs

Topic/Need:	Discussion:	Reference:
Investigate renewables and benefit of diversified energy portfolio.	The actual diversifying benefit of renewables has not been investigated in detail, and additional knowledge would be valuable in determining RET benefits.	See Balanced Energy Portfolio in Section IV.
Study ways to enhance transmission access to renewable resources.	Transmission access at a reasonable price is important for technologies that are just becoming cost effective and may be located away from load centers.	See Transmission & Distribution, Appendix I.
Quantify penetration limits of intermittent RETs on utility systems.	Utility system studies and actual isolated systems in Hawaii have noted operational problems at higher penetration levels of intermittent wind or solar systems. These limits and mitigation techniques need to be quantified to allow evaluation of high levels of supply from RETs.	See Process of Estimating RET Contribution in Section V.
Better quantify non-market values relevant to renewables.	Many of the current values of RETs are not expressed in the marketplace. We have noted that it is difficult to measure these actual benefits, but there is much to be gained by a better quantification than is currently available.	See Section IV on National Goals.
Study ways to expand storage capabilities and assess economic implications.	After storage and its relationship to RETs is studied in a near-term task, it may be beneficial to examine ways to expand storage. Work along these lines would address near-term pumped hydro expansion along with other storage possibilities.	See Storage, Appendix I.
Develop information on magnitude and significance of institutional factors.	Our judgment-based summary of institutional factors provides only a superficial look at constraints. Additional work is needed before defining specific policies aimed at reducing impediments.	See Institutional Constraints in Section III.
Assess options for integration of biofuels.	Options for integration of biofuels have increased opportunity and complexity, with concerns over urban air quality and competing alternative fuels.	See Biofuels, Appendix B.

VII. References

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Appendices: Technology Characterizations and Assessments

Appendix A
Hydropower and Pumped Storage

A.1 Description of the Technology

Hydropower facilities exploit the kinetic energy in flowing or falling water to generate electricity. The majority of these facilities are incorporated into dams or other impoundment structures that capture and store water from streams and rivers. An additional group of facilities operates in a run-of-river mode in which water flow is not altered.

The power generating capacity of a hydropower plant is primarily the function of two variables: water discharge and the hydraulic head. Water discharge is the volume rate of flow with respect to time through the plant defined in cubic feet per second. Hydraulic head is the difference in elevation the water undergoes while passing through the plant.

The principal advantages of utilizing hydropower are the large domestic resource base, low emissions, low operating costs, and the capability of these systems to respond quickly to utility load swings. Hydropower plants also have much higher availabilities (95% on average) than thermal generating plants. Disadvantages may include high initial capital cost, complex environmental issues, and competition with other interests for water resource use.

Hydropower technology can be categorized into two types: conventional and pumped storage. Conventional hydropower development uses the available water from a river, stream, canal system, or reservoir to produce electrical energy. With most conventional development, water is constantly available. A run-of-river development on rivers, streams, and canal systems uses the natural flow to produce electricity. Water releases from single-purpose reservoirs for power production can be adjusted to match electricity demands. Hydropower production is just one of many purposes for which the water in multipurpose reservoirs is used. Other uses can include irrigation, flood control, navigation, and municipal and industrial water supply.

Pumped storage plants operate similarly, but instead of tapping free-flowing water, the plant uses recycled water. (After flowing through the turbine, the water resource is pumped, usually through a reversible turbine, from a lower reservoir back to an upper reservoir.) While pumped storage facilities are net energy consumers, i.e., more energy in total is required for pumping than is generated by the plant (typically 1.25-1.4 kWh required for each kilowatt hour generated), they are valuable to a utility because they can operate in a peak power production mode when electricity is most costly to produce. The pumping to replenish the upper reservoir is performed during off-peak hours utilizing the utility's least costly resources. This process generally provides additional benefits to the utility by increasing the load factor and reducing the cycling of its base load units.

A.2 Current Status of the Technology

Hydropower development in the United States dates back more than a century. In the 1930s, hydropower provided 30% of the nation's total installed capacity and 40% of the electric energy generated. Since then, the growth in thermal-based capacity has surpassed the growth of hydropower to the point that hydropower (both conventional and pumped storage) represented approximately 12% of U.S. capacity in 1989. At the same time, growth of hydropower capacity has been slowing. Hydropower generating capability increased by 28.0 GW during the 1960s, by 17.9 GW during the 1970s, and by 8.2 GW in the 1980s[1,4]. Furthermore, more than 40% of hydropower capacity additions since 1972 have been pumped storage or hybrid conventional/pumped storage facilities, indicating that conventional hydropower additions have declined.

Before the end of this century, 366 existing hydroelectric projects, representing 3.7 GW of capacity and 17,500 GWh of energy production, will be subject to Federal Energy Regulatory Commission (FERC) relicensing. Many of these older projects will require extensive upgrades to comply with the new regulations. Consequently, without further research, development, and demonstration (R,D&D) to address environmental and dam safety issues, some of these projects may cease operation, further reducing U.S. hydroelectric capacity.

Of the nation's total primary energy consumption, 36% is in the form of electricity[1]. Coal generates 56.9% of the annual electric output; petroleum, 4.6%; gas, 10.6%; nuclear power, 17.7%; hydroelectric power, 9.7%; and other, 0.5%[2]. The aggregate capacity of all existing hydroelectric facilities as of November 10, 1988, is approximately 88 GW. This includes 17 GW of pumped hydro capacity, 64 GW of conventional hydro, and 7 GW of small-scale (30 MW or less) hydro. These facilities produced 257 billion kWh in 1987[2].

Hydroelectric power provides approximately 14.5% of the world's electrical energy, and hydropower plants operate in 86 countries with a total producing capacity of approximately 2000 billion kWh in 1986 (conventional and pumped storage).

While the U.S. hydropower industry has declined, foreign interests have successfully filled the void left by declining U.S. industry. A recent Hydro Review Industry Directory listed 54 of 71 suppliers of turbines with American addresses; however, the number of bona fide U.S. companies was a small portion of them. The last major manufacturer of hydraulic turbines (Allis Chalmers) was bought out by Voith (a German company) a few years ago. In August 1989, it was announced that Voith and Escher Wyss (a Swiss company) plan to merge, which will further dilute U.S. participation in turbine manufacture. Many of the companies with a U.S. address are, in reality, sales organizations that deliver foreign-built equipment to projects in the United States.

It is estimated that between 40% and 50% of the $150 million to $250 million hydropower turbine business per year involves new equipment. Approximately 70% to 80% of this business goes to foreign suppliers. The situation is better for upgrading old turbines, probably for logistics reasons. It is estimated that about 80% of the upgrade work is done by U.S. companies.

A.3. Constraints and Opportunities

A.3.1 Institutional Constraints

The Electric Consumer Protection Act (ECPA) of 1986 requires that FERC give equal consideration, thus greater emphasis, to environmental, safety, and efficiency issues for both new development and relicensing of existing hydropower facilities than was previously required. The licensing process now requires the advance examination of dissolved oxygen, instream flow, and other impacts of hydropower development. The methodology for these analyses has been challenged by other federal agencies and environmental organizations. They have identified the primary issue as the development of a valid methodology for determining the cumulative environmental impact of multiple hydropower projects on river basins. Public perceptions of hydropower as environmentally disruptive have driven many regulatory challenges.

Dam safety has been identified by a 1985 Electric Power Research Institute (EPRI)/Federal Emergency Management Agency (FEMA) study as a critical issue affecting hydropower development. New dam safety criteria require upgrading existing dam structures as part of any refurbishment or development. Specific issues identified include reasonable criteria for predicting floods, assuring spillway integrity, allowing for seismic activity, and controlling lift pressures on the base of the dam.

While the regulations may be viewed as constraints, they may also present opportunities for the federal government to exercise leadership in developing both technology and technical information designed to assist the industry in assuring that existing capacity is not unduly diminished and that new capacity can comply with these regulations.

Another constraint is the perception that other federal agencies such as the Tennessee Valley Authority (TVA), the Bonneville Power Administration (BPA), the Bureau of Reclamation, and the U.S. Army Corps of Engineers are pursuing broadly applicable R,D&D activities. Those activities are narrowly focused and directly support the R,D&D needed to resolve specific problems within the agencies such as improving efficiency and reducing operations and maintenance costs.

Non-federal hydroelectric projects are required to be licensed by FERC. Because of new regulations and the extensive licensing process, the non-federal projects will be facing the greatest constraints. In 1987, 54% of the nation's total hydroelectric generation was at non-federal projects. The majority of all non-federal projects are subject to relicensing during the next 20 years.

A.3.2 Performance Constraints and Projections

The performance constraints that apply to the hydropower technology are (1) equipment efficiencies, (2) plant efficiencies (decrease efficiency due to reduced flow and/or head), (3) production/demand loads (matching power production with flows and demand), (4) water spillage (water that is released or diverted but not used for power production), and (5) minimum stream flow requirements.

The *National Hydroelectric Power Resource Study* (NHS), which was completed in 1983 by the U.S. Army Corps of Engineers, conducted a special study of efficiency of existing hydroelectric power projects[3]. This study examined 1288 individual plants with an installed capacity of 63.4 GW. The study found that the energy output from these plants could be increased by 11% with virtually all of the increase due to capturing spill.

Additional potential could be realized at existing generation facilities through the refurbishment and upgrading of older turbines and generators. For instance, by the early 1990s, the Bureau of Reclamation will have added an additional 10% to its 13 GW of hydropower generation capacity through a program of rewinding and upgrading existing units. These upgrades can be performed for well below $1,000/kW. The total upgrade potential of the nation's existing hydropower facilities is currently unknown, but it is probably on the order of 14 GW.

New equipment such as a variable speed, constant frequency generator is being developed to improve plant efficiency. This equipment could allow the turbine to operate at maximum efficiency based on the hydraulic site conditions. As the head changes, the turbine speed could also be changed to maximize efficiency. This equipment could have broad application for both new plants and upgrading existing conventional and pumped storage plants. Additional R,D&D is needed to determine the appropriate hydropower applications and identify the potential increased capacity.

Expanded utilization of pumped storage facilities to offset peak power demands can also improve the overall efficiency. Currently, the U.S. installed-pumped storage capacity is about 17 GW or approximately 3% of the country's total capacity. Foreign studies have shown that 20% of system capacity as storage is a better value to effectively operate the power grid. This level of storage may also be beneficial to U.S. utilities.

A.4 Potential Contributions

A.4.1 Baseline Potential--Conventional and Pumped Storage

According to published FERC data, as of January 1, 1988, the undeveloped hydropower capacity in the United States is 95.2 GW[4]. This undeveloped capacity consists of conventional (76.1 GW) and pumped storage (19.1 GW). An additional resource of 32 GW, excluded from development by the Wild and Scenic Rivers Act, is not included in this total. These data indicate that the United States has developed only 49.5% of the total hydropower capacity. The 1983 NHS[3] screened approximately 60,000 sites in the initial inventory. These sites included approximately 50,000 existing dams or structures, with or without hydroelectric power, and approximately 10,000 undeveloped sites. These sites were evaluated in three stages. Stage 1 analyzed the minimum physical potential for hydroelectric power development. Stage 2 screened the sites for economic feasibility. Stage 3 analyzed the sites for environmental compatibility. The results of this study indicate that the undeveloped capacity identified by FERC[4] is a "real" resource and can be developed. Since the NHS study, other constraints such as the ECPA and dam safety could require additional cost in the development of a hydropower resource. In addition, energy prices have decreased since the 1983 study. Based on ECPA, dam safety, and current energy prices, it is estimated that increasing the current potential conventional capacity by 70% is not economically feasible. The balance of this potential conventional capacity (approximately 22 GW) is currently considered economical but is not being utilized.

This resource is not being developed because of the regulatory complexities and institutional and jurisdictional overlaps. The hydropower licensing process for a major facility requires 3 to 5 years. As a result, hydropower development is discouraged by increased project costs, increased uncertainty, increased lead time, and decreased profits.

A.4.2 Baseline Potential with R,D&D

Additional hydroelectric power sources that were not considered in the NHS or FERC resource data include those projects that require additional R,D&D to further develop the equipment and technology. For example, the use of free-flow turbines in flowing rivers has been estimated to have a potential of 12.5 GW. This concept is unique in that very little civil work is required, and the plant can be installed without creating a water impoundment area or disrupting flow. Equipment has been developed, but the concept should be tested. Irrigation canals, domestic water systems, ultra-low-head (less than 10 ft) sites, and small-scale sites (less than 1 MW) may also provide additional resources. It is estimated that these projects could provide an additional 5 GW. R,D&D to develop new, inexpensive equipment is needed to make these sites feasible. Therefore, it is estimated that the baseline potential can be increased by 17.5 GW with an aggressive R,D&D program.

A.4.3 BAU Penetration--Conventional and Pumped Storage

Based on low energy prices, surplus energy, the effects of ECPA, institutional constraints, and the termination of a DOE Hydropower Program, it is estimated that a net increase of only 13 GW (8 GW conventional and 5 GW pumped storage) will be developed by the year 2030. This reflects a growth of less than 0.5% per year. These extremely modest growth projections are also verified by a review of the industry forecasts for new hydropower construction for the year 2000. The loss of existing capacity under the new, strict licensing procedures contributes to the low net growth.

Despite the unique and valuable characteristics hydroelectric projects offer, they are often not developed because of economic policies imposed by state public utility commissions on regulated utilities or by utilities themselves to keep current rates as low as possible. Hydroelectric projects are capital intensive but have very low annual operating costs and exceptionally long service lives. Thus, over their initial years of operation, they are often more expensive than combustion turbines with relatively low capital costs but with high fuel and operating costs. But over their service lives, hydropower projects result in substantial savings to the rate payers. This emphasis on near-term financial factors is also cited as an impediment to hydropower development.

A.4.4 Intensified R,D&D--Conventional and Pumped Storage Penetration

A federal R,D&D program to address the ECPA (environmental and dam safety) issues and develop new equipment and technology would accelerate hydropower development. ECPA requires that careful consideration be given to environmental, safety, and efficiency issues for both new development and relicensing of hydropower facilities. The licensing process now requires the examination of dissolved oxygen, instream flow, and other cumulative impacts of hydropower development. The methodology for these analyses has been challenged by other federal agencies and environmental organizations. The primary issue identified is the development of a valid methodology for determining the cumulative environmental impacts of multiple hydropower projects on river basins. ECPA requirements define 40% of those sites as not economically feasible (54.1 GW). Assuming all plants are relicensed and 50% of those sites affected by ECPA are developed, the increased conventional capacity would be approximately 11.0 GW (54.1 × 0.4 × 0.5). By developing new equipment to expand the resource base, it is estimated that an additional 10 GW of conventional capacity would be realized.

In addition, resolving these issues would reduce the current risks associated with those projects that are defined as currently economically feasible (22 GW). Under an aggressive R,D&D program, it is estimated that at least 75% (16 GW) of these sites would be developed by the year 2030.

In summary, resolving these issues would place an additional conventional capacity of 37 GW (11 + 10 + 16 GW) on line by the year 2030. The 37 GW includes the BAU penetration scenario of 8 GW. Assuming that all the current pump storage potential of 19.1 GW is developed, a total of 56.1 GW of new capacity would be on line by the year 2030. Additional discussion of the R,D&D benefits are included in a separate section.

A.4.5 National Premiums--Conventional Penetration

It is estimated that 60% of those sites that are currently not economically feasible would be developed with a 2¢/kWh price premium. A 2¢/kWh premium represents approximately one-third of the average hydroelectric production costs. It is also estimated that all the sites that are currently economically feasible would be developed because the extra financial incentive would offset the risks due to unknowns. This scenario would place an additional 54.5 GW (0.6 × 54.1 + 22 GW) of capacity on line by the year 2030. Because pumped storage facilities produce no net energy from renewable resources, the premium is not applied to these systems.

Table A-1 describes the resource potential and added capacity for conventional hydropower.

Table A-1.
Conventional Hydropower
Resource Potential and Added Capacity (GW)

Category	Potential	1990-2030 Added Capacity BAU	R,D&D	Nat. Prem.
Economic but Not Used	22.0	8.0	16.0	22.0
Not Economic Due to ECPA	22.0	___	11.0	13.2
Not Economic: Other Constraints	32.1	___		19.3
Run-of-River w/R,D&D	12.5	___	10.0	___
Small Sites w/R,D&D	5.0	___		___
Total	**95.6**	**8.0**	**37.0**	**54.5**

A.4.6 Cost Data

New hydropower facility development costs are highly dependent on site characteristics, which can significantly affect structural design requirements and the need for corrective measures to mitigate environmental impacts. Annual operating costs can fluctuate due to effects of stream flow variation on generation. Retrofits/upgrades at existing sites will be the most cost-effective investment, followed by the installation of energy recovery systems (turbine generators) at existing non-producing or underutilized dams. Finally, new site development is the least cost effective.

The average construction cost for the Technology Development Projects, developed under the DOE program (based on 1985 data), was $2,068/kW. Based on an 1986 Energy Information Administration (EIA) report, the average cost of five conventional hydropower projects that were placed on line between 1983 and 1986 was approximately $1,700/kW[6]. This EIA report also indicated that the average annual operation and maintenance expenses for non-federal conventional hydropower plants in 1986 were $0.2¢/kWh. Capital cost for pumped storage facilities is currently estimated at $800-$1,200/kW.

Figure A-1 illustrates the penetrations of hydropower under the BAU, R,D&D Intensification, and National Premiums Scenarios. Figure A-2 illustrates the combined capacity of hydropower and pumped storage for the BAU and R,D&D Intensification Scenarios. Table A-2 illustrates the estimated regional breakout and chronologic penetration of hydropower in terms of primary equivalent quads.

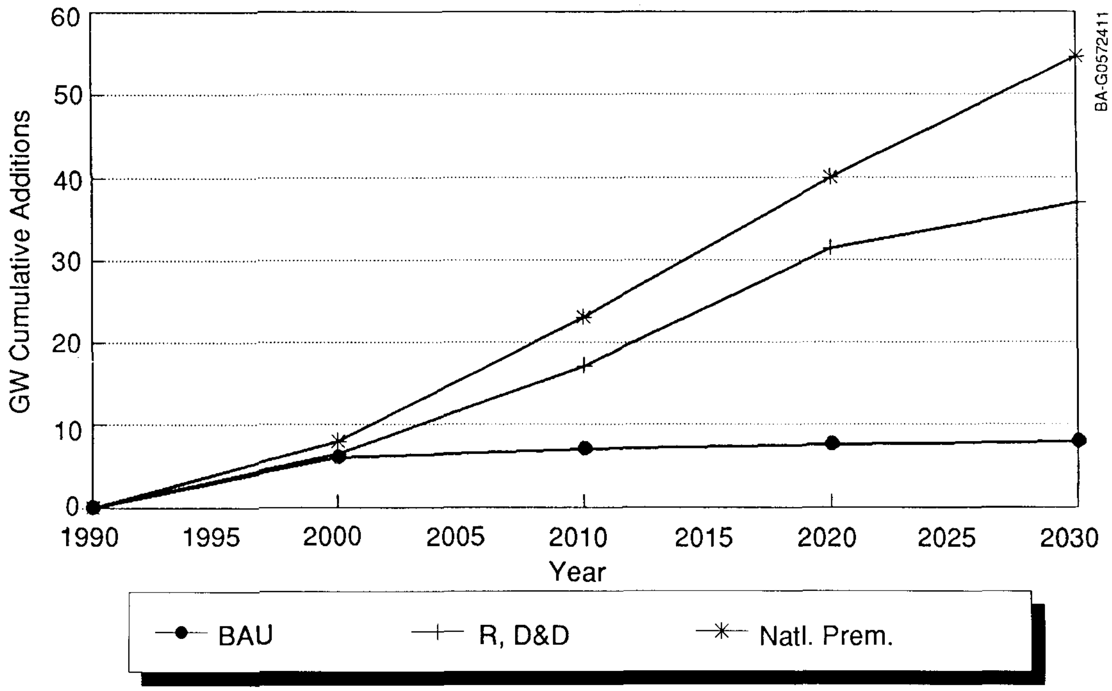

Figure A-1. Conventional hydropower capacity (1990-2030 additions)

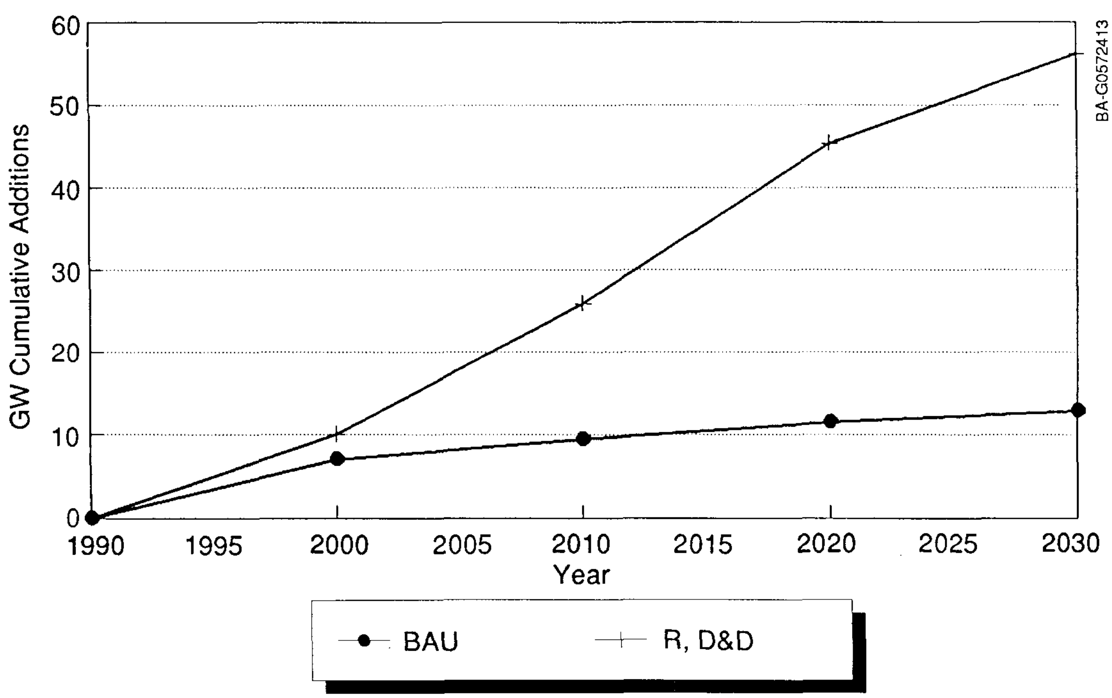

Figure A-2. Conventional hydro and pumped storage (1990-2030 capacity additions)

Table A-2.
Hydropower Penetrations

	Primary Energy (quads)				
	1988[a]	2000	2010	2020	2030
Business-as-Usual Scenario					
Northeast	0.36	0.40	0.41	0.41	0.42
South	0.59	0.63	0.63	0.64	0.64
West	2.09	2.26	2.29	2.30	2.31
North Central	0.10	0.11	0.11	0.11	0.11
Total	**3.14**	**3.40**	**3.44**	**3.46**	**3.48**
R,D&D Intensification Scenario					
Northeast	0.36	0.38	0.53	0.65	0.73
South	0.59	0.65	0.70	0.81	0.87
West	2.09	2.27	2.59	3.07	3.30
North Central	0.10	0.12	0.15	0.18	0.20
Total	**3.14**	**3.42**	**3.97**	**4.71**	**5.10**
National Premiums Scenario					
Northeast	0.36	0.42	0.53	0.66	0.75
South	0.59	0.64	0.74	0.85	0.94
West	2.09	2.31	2.73	3.21	3.58
North Central	0.10	0.11	0.15	0.19	0.22
Total	**3.14**	**3.48**	**4.15**	**4.91**	**5.49**

[a]1988 adjusted to typical water year values.

Construction costs can range from well below $100/kW (minor upgrades to improved efficiency) to an average of $1,700/kW (new site development). The NHS screened 60,000 sites in the initial inventory[3]. These sites included approximately 50,000 existing dams or structure, with or without hydroelectric power, and approximately 10,000 undeveloped sites. This indicates that a large portion of the potential is at existing sites; however, this potential needs to be defined. Even with extensive upgrades to existing dams to meet the current safety requirements, it is estimated that the average development costs at the existing dams will be less than the cost for new development.

Figures A-3 through A-6 illustrate the regional capacity penetration estimated for hydropower.

A.4.7 Research Opportunities

ECPA and requirements for cumulative impact studies will place increased demands on new sites or on old sites that must be relicensed. The requirement for equal consideration of environmental effects and power production will require technology innovations to maintain hydropower as a viable option. New standards and equipment will be developed to improve efficiency and project operation.

The results of research and development projects are unpredictable. However, there are several areas of potential research that appear likely to produce favorable results. In general, the desirable results are as follows:

- Reduced initial equipment capital costs
- Reduced operation and maintenance costs

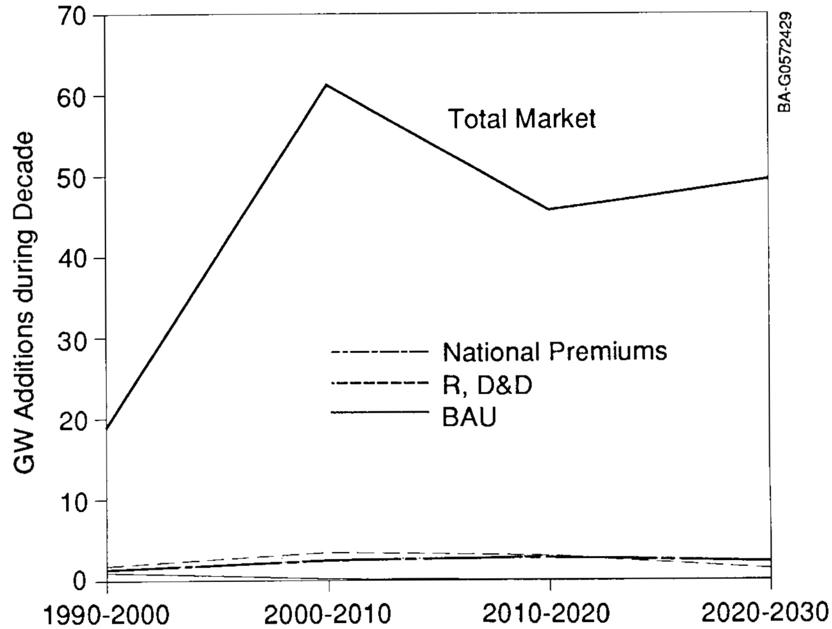

Figure A-3. Hydropower incremental market penetration (Northeast)

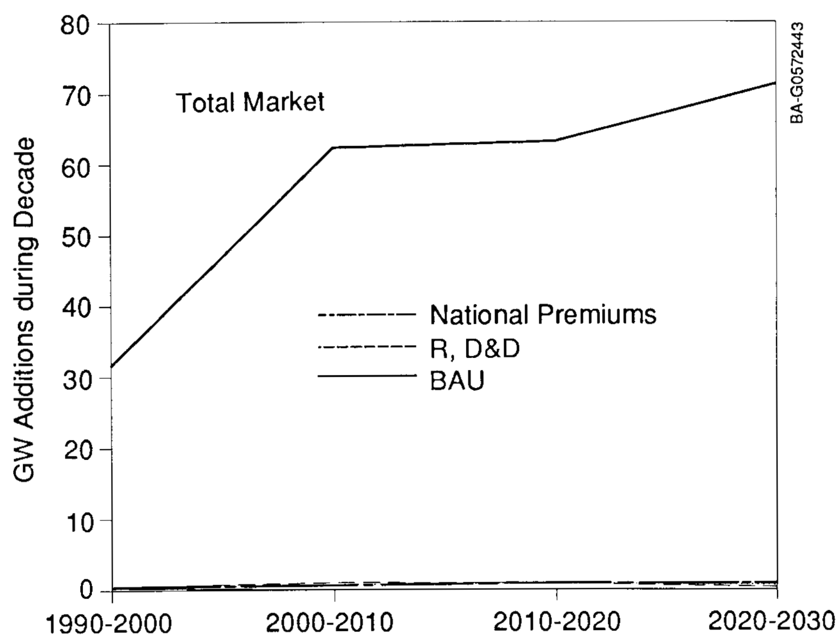

Figure A-4. Hydropower incremental market penetration (North Central)

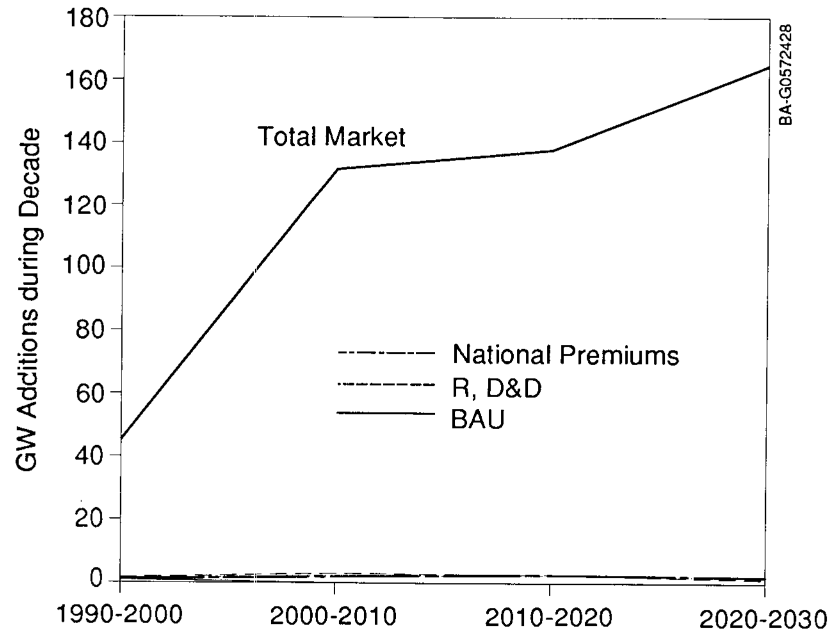

Figure A-5. Hydropower incremental market penetration (South)

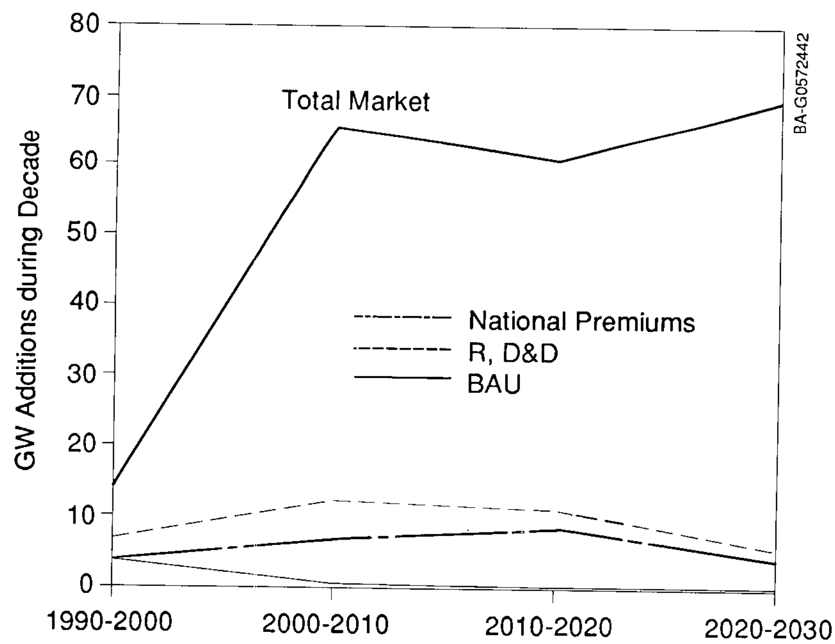

Figure A-6. Hydropower incremental market penetration (West)

- Improved potential for tapping undeveloped resources
- Improved machine efficiency
- Improved designs that favor rehabilitating old plants
- Improved performance favoring environmental aspects of operation (e.g., dissolved oxygen, fish passage)
- Improved facilities for testing equipment to encourage private development of new equipment.

The aspirating turbine is a specific example of promising research. Many turbines have been operating for 30 or 40 years. The efficiency of these units has deteriorated, and new technology may improve their performance from 1% to 15%. Furthermore, the new requirements of ECPA and cumulative environmental impacts will, in many cases, require dramatic water quality improvements before many plants may be relicensed after their current license expires. The development of new design replacement turbine runners with improved efficiency and air ingestion capabilities should be desirable. For example, the gross benefits resulting from replacement of the runner in a 100-MW turbine could be approximately $3.5 million per year assuming the value of energy to be 4.0¢/kWh, 50% plant factor, 5% runner efficiency improvement, 5% (by volume) air ingestion, and the value of oxygen of $40 per ton. The annual gross benefits resulting would be split between the increased energy produced valued at about $900,000 and the oxygen added to the stream worth about $2.6 million. The cost of developing, manufacturing, and testing such a runner has been estimated at $2.9 million. Therefore, allowing for some cost overruns or less than estimated performance improvement, the payback rate for such a venture appears very favorable.

Other potentially beneficial research areas are listed below.

- Kinetic energy turbines that use free-flowing stream potential (potential for new capacity is estimated at 12,500 MW)

- Ultra-low-head turbines that will capture energy at sites with low development potential

- Dam safety technology to develop economical means to survey and repair existing dams for use in hydropower projects

- Cross-flow turbines that will improve efficiency by optimizing air injection and suction head in the draft tube (potential improvement in efficiency--5%)

- Develop economical turbines or other equipment that are more compatible with fish

- Design hydroturbines using new, innovative materials to increase durability (e.g., less susceptible to cavitation, erosion, and corrosion damage) and reduce cost (e.g., inexpensive runners that can be discarded instead of repaired)

- Improve testing methodology for measuring flow rates and other parameters for testing turbines using full or scale models. Develop the models to prototype correlation procedures (e.g., tests involving air ingestion are not now considered to produce reliable results when scaled to prototype)

- Develop a system of standard flow passages designed for each range of plant parameters to provide low-cost, high-efficiency plants

- Improve the automated controls for hydropower plants to provide reliable, efficient operation; on-line diagnostics; environmental data collection; and report generation without requiring full-time operators.

The DOE hydropower program, in connection with industry and other government agencies, has identified the current issues and constraints affecting the development of hydropower. The short-term objective is to initiate research to reduce the impacts of ECPA. A modest budget would allow DOE, with cost sharing from industry, to address the higher priority issues. The combined, cost-sharing effort with industry would further ensure the success of the activities. Table A-3 presents the uniform cost and performance data for hydropower.

Table A-3.
Uniform Cost and Performance Data:
Hydropower Technology

	Capital Cost ($1988/kW)	O&M (¢/kWh)	Capacity Factor	Fuel Cost ($/MilBtu)	Heat Rate Btu/kWh)	Levelized[a] Cost (¢/kWh)	Energy Supply (quads)
1988							
Upgrades	$100	0.5	45%	---	---	0.8	
Existing Sites	b	---	---	---	---	b	3.14
New Sites	$2,000*	0.5	45%	---	---	5.6	
2000 - BAU	d					d	3.40
- R,D&D	d					d	3.42
2010 - BAU	d					d	3.44
- R,D&D	d					d	3.97
2020 - BAU	d					d	3.45
- R,D&D	d					d	4.71
2030 - BAU	d					d	3.48
- R,D&D	d					d	5.10

[a]Over 30 years at 6.1% discount rate (EPRI TAG)
(Levelized annual fixed charge rate of 0.1007)

[b]Costs for developments at existing impoundment sites would range between upgrades and those at new sites.

[c]$1,700/kW plus 15% allowance for interest during construction

[d]1988 cost range would still generally hold for future years and be site-specific. R,D&D Intensification Scenario would offer better performance/cost at a given site.

1988-2030

- Intensified R,D&D produces continued advances to reduce initial equipment cost, reduce maintenance costs, and increase efficiency. Such improvements would improve potential to increase resource base and amount available at lower cost.

- Intensified R,D&D provides improved performance related to environmental aspects and dam safety.

A.5 Contributions to National Goals

A primary environmental benefit of hydropower is a reduction in the amount of carbon dioxide (CO_2) discharged to the atmosphere by power plants. Hydropower is one of the lowest contributors of CO_2. Table A-4 is a comparison of CO_2 emissions between conventional coal and hydropower.

A.6 Other Perspectives

The projected hydropower capacity (71 GW existing plus 76 GW new) reported here is considered reasonable. For example, the Meridian Corporation's report, *Characterization of U.S. Energy Resources and Reserves*, June 1989, states that the total hydropower potential is approximately 500 GW (existing, potential, and at undeveloped sites) (see Table A-4). These estimates are consistent with the total resource identified in the U.S. Army

Corp of Engineers *National Hydroelectric Power Resource Study*, June 1979[3]. Based on this, the projected capacity described here is considered conservative and is believed to represent a resource that can be realistically developed.

Table A-4.
Comparison of CO_2 Emissions between Conventional Coal and Hydropower
(CO_2 in tons/GWh of energy)

	Resource Extraction	Facility Construction	Facility Operations	Total
Conventional Coal Plant w/Scrubber	N.A.	1.048	1057.143	1058.191
Hydro	N.A.	10.95	N.A.	10.95

The comparison of current and potential energy contributions in this white paper and the Meridian report are generally consistent, although expressed in different base terms. This white paper characterizes hydropower based on a fossil-fuel equivalency method whereby the energy is expressed in the amount of fossil fuel needed to produce an equivalent amount of energy. The Meridian report uses a hydraulic energy equivalency whereby the electric energy is adjusted for 17.5% of production losses only. Thus, the Meridian hydropower reserves of 10 billion barrels of oil (BBOE) equivalent (or 1.9 quads per year) would be expressed as 25 BBOE (or 4.8 quads per year).

A.7 References for Appendix A

1. Energy Information Administration. *Annual Outlook for U.S. Electric Power 1988.* U.S. DOE, August 24, 1988.

2. Energy Information Administration. *Electric Power Annual 1987.* U.S. DOE, September, 1988.

3. *National Hydroelectric Power Resources Study; Volume I.* U.S. Army Corps of Engineers, Institute for Water Resources, May 1983.

4. *Hydroelectric Power Resources of the United States.* Federal Energy Regulatory Commission, January 1988.

5. *Kinetic Hydro Energy Methodology Validation and Resource Assessment.* New York University, August 1986.

6. Energy Information Administration. *Historical Plant Cost and Annual Production Expenses for Selected Electrical Plants*, 1986.

Appendix B
Biomass/Biofuels

B.1 Description of the Technology

Biomass is a term that includes all energy materials that emanate from biological sources, whether they are wood or wood wastes, residue of wood-processing industries, food industry waste products, sewage or municipal solid waste (MSW), herbaceous or other biological materials cultivated as energy crops, or other biological materials. (For descriptive purposes of this white paper, biofules are liquid fuels produced from biomass feedstocks.) Biomass is a major current and prospective source of energy. The key feature of the biomass technology is recycling of the carbon in the biological processes. Unlike the burning of fossil fuels, combustion of biomass merely recycles the carbon fixed by photosynthesis in the growth phase.

The use of biomass or biofuels as a source of energy for space heating, process heat, electricity production, transportation fuels, or as an intermediate gaseous fuel is attractive not only for economic reasons (where the fuel is readily available at low cost), but also for economic development and environmental reasons. The systems that convert biomass into usable energy can be modular and efficient on a relatively small scale. Both thermal supply and electric generation systems provide 24-hour, base-load (dispatchable) output. Biomass is a renewable and indigenous resource that requires no foreign exchange. The agricultural and forestry industries that would supply feedstocks would also provide substantial economic development opportunities in rural areas. The pollutant emissions from combustion of biomass are usually lower than those from fossil fuels. Furthermore, commercial use of biomass may avoid or reduce problems of waste disposal in other industries, such as forestry and wood products, food processing, and particularly MSW in urban centers. In addition, recycling of paper, glass, plastics, and metal products, at times performed in conjunction with municipal waste collection and combustion, can conserve energy resources required for the primary manufacture of these energy-intensive materials.

There are four principal ways in which biomass is used as a renewable energy resource. The first, and most common today, is as a fuel used directly for space and process heat, and cooking. The second is as a fuel for electric power generation. The third is by gasification into a fuel used on the site or transported by pipeline to the final consumer for heating or power generation. The fourth is by conversion into a liquid fuel that provides the portability needed for transportation and other mobile applications of energy. Table B-1 shows the estimated consumption of biomass energy in the United States[1].

B.1.1 Thermal Combustion of Biomass

Direct combustion in air is the principal mechanism currently used to convert biomass into useful energy. The heat and/or steam produced is used to generate electricity or thermal requirements for industrial processes, building heating, cooking, or district heating in municipalities. The thermal combustion of biomass for cooking, space heating, or the production of process heat, either directly or in the form of steam, may be attractive where biofuels are available at economic prices or, particularly in rural areas, where the fuel may be available for gathering by the consumer. Small-scale use, such as for home cooking and fireplace use, is usually very inefficient. High-efficiency cooking stoves, home heating stoves, and fireplace systems have been developed and are widely available.

Larger furnaces and boilers have been designed and are available for burning various types of biomass such as wood, wood wastes, chips, black liquor from pulping operations, food industry wastes, and MSW. The larger units can be very efficient, nearly matching the performance of fossil fuel furnaces. The greater moisture content of most biomass, as well as the wide range of particle size and composition, makes it difficult to achieve comparable efficiencies at reasonable costs. The economic advantages of cogeneration, however, make it attractive for most industrial consumers with available biomass feedstock to install cogeneration facilities.

The residential sector uses biomass for direct applications such as cooking and space heating. The industrial sector uses biomass for both process and space heating, as well as power generation, often jointly in cogeneration projects.

Table B-1.
Estimated Consumption of Biomass Energy in the United States[1]

Resource	1987 Quad	1987 BOE/d[a]
Wood and Wood Wastes		
Industrial	1.85	874,000
Residential	0.84	397,000
Commercial	0.022	10,400
Utilities	0.009	4,250
	2.72	
Municipal Solid Wastes	0.11	52,000
Agricultural and Industrial Wastes	0.04	18,900
Methane		
Landfill Gas Recovery	0.009	4,300
Digester Gas Recovery	0.003	1,400
Thermal Gasification	0.001	500
	0.013	
Transportation Fuels		
Ethanol	0.07	33,100
Other Biofuels	0.0	0.0
Total	**2.95**	**1,395,000**
Percent of U.S. Primary Energy Demand	3.7	

[a]Barrels of oil equivalent per day.

B.1.2 Generation of Electric Power Using Biomass

Electric utilities currently make limited use of biomass as a fuel for power generation (although the utilities often buy power from cogenerators who use biomass as fuel). All current power generation from biomass, whether generated by industry or utilities, is via steam turbines. Research is continuing to develop gas clean-up technologies that would permit use of biomass as a fuel for gas turbines, either directly or after gasification, particularly in the cogeneration mode. Wood and wood wastes and byproducts are the principal fuels currently used.

MSW, although a limited resource, has come into prominence because of the advantages provided by energy conversion systems as a means of reducing the problems of MSW disposal. Combustion for use in power generation (or, in some instances, process heat production) or, lacking an attractive market for the energy, incineration has become the principal means of disposing of MSW in new projects as landfills have become more difficult to site and operate. Commercial technologies used for combustion of MSW fall into two general categories: mass burn and refuse-derived fuel (RDF) combustion. Mass burn applications involve direct combustion of the MSW, in some cases with little or no pretreatment or sorting, to produce steam for heating or power generation. For RDF combustion applications, aluminum, glass, and other recyclable materials are removed, along with other noncombustible matter, and the remaining material is pelletized and stored for use as a fuel, possibly at another site.

B.1.3 Gasification of Biomass

The third energy conversion mechanism is the production of gas. Biogas, a mixture of methane and carbon dioxide (CO_2), can be produced from either thermal conversion or the biological anaerobic digestion of biomass materials. The methane can be subsequently separated from the CO_2 using conventional technology to supply gas to a natural gas system or other consumer. The processes have been developed and tested, and some have been applied in commercial operations where biomass feedstock was available at low cost. MSW may be processed by the anaerobic process to produce methane from the digestible components. The volume of gasification residue, which includes materials such as burnable plastics, is greater than the residues from combustion processes. (Combustible plastics and similar materials could be separated if required before feeding the remaining material to the digester.) Landfills are also a source of methane produced from the decomposition of MSW (the economics of recovery of the naturally occurring methane are not universally favorable). A lower-heat-content gas, syngas, consisting primarily of carbon monoxide and hydrogen (CO and H_2), can also be produced for use as a fuel or as an intermediate feedstock. (For example, syngas is produced as the first step in methanol production, as discussed below.)

B.1.4 Biofuels--Conversion of Biomass Into Liquid Fuels

Biofuels are liquid fuels, primarily used in transportation, produced from biomass feedstocks. Identified liquid fuels and blending components include ethanol, methanol, and their ethers, ETBE and MTBE, as well as synthetic gasoline, diesel, and jet fuels.

B.1.4.1 Ethanol

Ethanol can be produced from sugar, starch, or cellulosic feedstocks (wood, energy crops, and municipal and other wastes). Currently in the United States, the primary pathway for conversion of biomass to alcohol fuels is the fermentation of corn to ethanol. The largest potential, however, involves the biochemical conversion of more abundant cellulosic biomass materials to ethanol, which can reduce feedstock costs by 50% or more compared to corn. In the biochemical conversion process, the biomass feedstock is first separated into its three main components--cellulose, hemicellulose, and lignin. The cellulose is hydrolyzed to sugars, primarily glucose, which are then easily fermented to produce ethanol. The hemicellulose portion is more readily converted to sugars, primarily xylose; however, xylose is more difficult to ferment to ethanol. Finally, the lignin, although it cannot be fermented, can be converted to a high-octane liquid fuel or, as is more common today, is burned to provide process energy.

B.1.4.2 Methanol

Methanol is made from biomass by first gasifying the feedstock to form a syngas. Syngas is a mixture of CO, H_2, CO_2, higher hydrocarbons, and tar. A gas shift reaction is employed to adjust the chemical structure of the components of the gas mixture to the requisite H_2-to-CO ratio. The syngas is then cleaned and conditioned before being converted, in the presence of standard commercial catalysts, to form methanol. To date, research, development, and demonstration (R,D&D) has produced several gasifiers that make syngas. Biomass gasifiers are specifically designed to take advantage of the superior characteristics of biomass feedstocks as compared to coal (very little sulfur, high volatility, greater hydrogen content, low ash content) for the production of syngas. Currently, commercial methanol is produced almost entirely by the steam reforming of methane from natural gas to form the intermediate syngas, which is then catalytically converted to methanol. Very little methanol is now produced from coal or biomass.

B.1.4.3 Synthetic Hydrocarbon Fuels (Gasoline, Diesel, Jet Fuel)

The basic approach used in converting biomass to traditional hydrocarbon fuels is first to pyrolyze the biomass feedstock to form an intermediate biocrude liquid product. The second step is to catalytically convert the biocrude to gasoline. The technology uses a fast pyrolysis step that obtains higher yields of desired liquid components than achieved in longer residence-time processes. The fast pyrolysis process has been demonstrated with three different reactor designs. There are two potential routes for the second step: hydrogenation at high pressures and zeolite cracking at low pressures. Attention is currently focusing on the potentially less costly, lower pressure process.

An alternative method of producing hydrocarbon fuels from biomass uses oils that are produced in certain plant seeds, such as rape seed, sunflowers, or oil palms, or from aquatic plants. Certain aquatic plants produce oils that can be extracted and upgraded to produce diesel fuel. The primary processing requirement is to isolate the hydrocarbon portion of the carbon chain that closely matches diesel fuel and modify its combustion characteristics by chemical processing.

B.2 Current Status of the Technology

B.2.1 Resource Availability

Biomass resources potentially available for energy production encompass a wide range of materials, including agricultural and forest crops grown for energy feedstock purposes, agricultural and forest wastes and residues, wastes generated by food processing and forest products industries, MSW and some sewage sludge, and aquatic plants and algae. Biomass tends to occur in a very disperse manner, not in a consolidated manner such as fossil fuel deposits. The cost of collecting large quantities of biomass for a commercial energy application can be significant since the material is by nature dispersed, is often of low energy density, and is moist, if not wet. Consequently, the most attractive applications of biomass energy today generally involve biomass that has been collected for other reasons, such as forest product and food processing industry co-products and wastes, and MSW. Each must be disposed of in some manner; the alternative cost of disposal for MSW, often called the "tipping fee," may be more than $100/ton in congested urban areas if environmentally acceptable landfills or other disposal sites are not available nearby. (A small amount of sewage sludge may also be usable as a supplementary feedstock for MSW gasification plants, but the potential plant capacity to accommodate it is expected to be so small that the available material is not ordinarily included in energy resource estimates.)

One estimate of the aggregate potential biomass resources is shown in Table B-2. This estimate does *not* include the potential resources available from dedicated plantation or farm production of either herbaceous or woody biomass crops for energy feedstocks.

Table B-2.
Potential Energy Available from Biomass in Year 2000[1]
(quads/year)

Resource	Estimated Recoverable	Theoretical Maximum
Wood and Wood Wastes	10.4	25.0
Municipal Solid Wastes		
Combustion	1.8	2.0
Landfill Methane	0.2	1.0
Herbaceous Biomass and Agricultural Residues	1.0	15.0
Aquatic Biomass	0.8	7.7
Industrial Solid Wastes	0.2	2.1
Sewage Methane	0.1	0.2
Manure Methane	0.05	0.9
Miscellaneous Wastes	0.05	1.0
Total	**14.6**	**54.9**

Conventional wood resources consist of wood in excess of the needs of the traditional forest products industry. These resources are available from thinning of commercial stands or from clear-cutting to allow planting of improved stands. This is an enormous resource if managed properly. In the United States, it is estimated that this resource currently amounts to 6.5 quads annually, not including the potential from unutilized lands that might be dedicated to future biofuels production.

Agricultural and forestry wastes represent the portion of plants and trees that remain after the more valuable portions have been separated. Primary residues include stalks, leaves, bark, and limbs left in the field after harvesting. Secondary residues are wastes produced at a processing facility, such as wood bark and scraps, black liquor and other pulping residues, bagasse, rice hulls, corn processing wastes, and feed processing wastes. Utilization of secondary wastes as a fuel at or near the source mill or processing plant has the advantage of incurring little or no additional transport costs because the wastes are a by-product (the wastes usually entail costs for disposal if they are not otherwise used). The primary residues are not only costly to collect, but at least a portion may be more valuable if left in place to decompose and maintain the quality of the soil.

MSW is the solid waste generated from households, commercial and institutional operations, and some industrial production. On the average, about 80% of the dry weight of MSW is organic materials, two-thirds of which is natural lignocellulose. The annual U.S. MSW resource is estimated to be about 2 quads currently and should expand to nearly 3 quads by 2030.

It is somewhat misleading, however, to assert that MSW is an energy resource in the traditional sense, that it is available for fuel use at the discretion of the consumer or power supplier. MSW must be disposed of. If the most economic means of disposal includes the provision of electric power, process heat, or methane as a by-product at current market values of the energy, the by-product energy will be utilized. The market price of the energy will influence the decisions regarding what type of MSW disposal plants will be built. Once plants are built, the energy product will be a permanent part of the local energy supply, irrespective of the value of the energy or the actual price paid to the MSW plant operator.

The largest portion of the biomass resource, however, is the potential available from dedicated production of biomass. Land can be devoted to production of energy crops, such as short-rotation hardwoods, sorghum, napier grass, or "energy" cane. To provide a year-round supply of fuel or feedstock, the biomass feedstock must be available from a continuously harvested source or from storage during the off season. Therefore, feedstock development efforts have been extended to both herbaceous and hardwood species to provide potential energy crops for nearly all regions of the country. Yields of energy crops will vary by region and year. Soil characteristics, insolation, and moisture availability are the primary site-related characteristics affecting yields. Selection of species that grow well on widely distributed sites is the first step in developing high-yielding energy crops. Genetic engineering and breeding to improve characteristics, such as pest and disease resistance, chemical composition, and nutrient- and water-use efficiencies, have been undertaken to increase the yields and lower production costs for the selected species. Tolerance of herbicides is also being promoted to facilitate economical weeding and underbrush control. As a result, these species are nearing a stage in their development that would permit economic energy crop production in most parts of the United States, the low rainfall plains states and other dry areas being the principal exceptions. The most attractive areas are the Gulf Coast and Pacific Northwest regions.

A detailed assessment has not been made of the potential available acreage suitable for energy crops that could be devoted to production without major impact on other forest and crop production. Nearly 10% of the 900 million acres now classified as cropland or commercial forest land is withheld from production under federal government programs; other acreage is only marginally utilized, and additional land may be withdrawn from crop use in the future as food grain productivity continues to improve faster than domestic grain demand provides markets, and competition in international grain markets increases.

Total planted cropland in the United States averaged 328 million acres between 1982 and 1988. In 1988, another 78 million acres of cropland were idled as the result of government programs to reduce crop production or for soil conservation purposes. The New Farm and Forest Products Task Force report to the Secretary of Agriculture indicates that new crops will be needed for 150 million acres of existing cropland that will be surplus as the result of improving productivity of current crops and slowing demand during the next 25 years[2]. Based on the 1982 National Resources Inventory, an additional 150 million acres of land are now in pasture, range, and forest that are capable of supporting crop production[3]. Over the same time period, average energy crop yields are expected to range from 5 to 11 dry tons per acre per year reflecting regional land quality and weather conditions.

If 192 million acres of cropland and potential cropland were dedicated to energy crops and produced an average of 9 dry tons per acre per year, gross biomass energy production from this dedicated acreage would be 26 quads.

B.2.2 Performance of Conversion Technology

B.2.2.1 Thermal Uses of Biomass

Considerable progress has been made in the design of household cooking and heating appliances that use biomass, primarily wood, to improve efficiency and reduce CO and particulate emissions. Energy-efficient cooking appliances as well as heating equipment, such as stoves and fireplaces, have been developed, although costs and appearance of fireplace equipment, for example, have deterred their use, particularly in potential retrofits. Restrictions on allowable emissions from the burning of wood and/or increased conventional energy prices could stimulate additional conversions of existing wood-fired installations and fossil-fueled or electric equipment.

The technology available to larger consumers, however, is equivalent to that used in burning conventional fossil fuels and has been widely implemented. Somewhat lower efficiency is obtained compared to fossil fuels as the result of the high moisture content of biomass; derating of the furnace or boiler used might occur for a plant not designed with flexibility to handle biomass. However, the lower efficiency of the combustion process is often more than offset by the low cost of the fuel, particularly if it is waste or by-product material that otherwise would be disposed of. The small amount of ash produced is usually suitable as a soil supplement.

B.2.2.2 Electric Power Generation Using Biomass

Electric power generation using biomass as a fuel is economic today in situations where the cost of the fuel is competitive with that of fossil fuels. The cost of a commercially available biomass steam-electric power plant is about $1,500/kW for a wood-fired facility. If wood can be obtained at a cost of $2.00/MilBtu, the total cost of power for base-load operation would be about 5¢/kWh. If wood or agricultural wastes are available at lower costs, the cost of electricity would be significantly lower. Similarly, if the low-pressure steam from the turbine exhaust can be used (cogeneration), the overall efficiency would be higher and the costs would be lower.

Greater use of biomass resources (exclusive of MSW) in electricity generation is constrained by delivered resource costs. Wood or other biomass resources must generally be procured within no more than a 50-mile radius of the power plant to be economical, given the high transportation costs of biomass. All current generation capacity (other than MSW plants) has been sited where readily accessible waste resources are available at low cost. If future biomass-fueled plants are to be competitive with coal, oil, and natural gas, the feedstocks, in general, must be available for $2.00/MilBtu or less. (A higher fuel cost may be competitive in isolated locations where low-cost coal is not an alternative fuel source.) At high levels of utilization, competition among energy and nonenergy uses may tend to bid up biomass resource prices. To stabilize price and availability, a potential long-term solution is the development of dedicated high-productivity herbaceous or short-rotation woody crops for feedstock production. In the short term, substantial opportunity exists for greater use of currently underutilized biomass resources.

MSW plants may have higher capital and operating costs than wood-fired plants as a result of the processing costs of the MSW feedstock (they may be separately accounted for if RDF is used as the fuel) and the costs of disposing of the potential emissions and solid wastes. On the other hand, credits are usually applicable for avoidance of a portion of the disposal costs in landfills, which would otherwise be incurred. Thus, power generation via combustion of MSW may have total costs of significantly more or less than 7¢/kWh. Individual studies are required of the specific sites, the actual feedstock available, and the availability and cost of waste disposal facilities to determine the attractiveness of the technology in new applications. The problems of removing dioxins, chlorinated gases, and other toxic emissions from the combustion processes may contraindicate thermal disposal of MSW in many locations.

The costs of a conventional, commercially available, wood-fired, steam-electric power plant are approximately as follows, using the Electric Power Research Institute (EPRI) Technical Assessment Guide basis of evaluation[4]:

Wood-Fired Plant

Utility-owned, base-load (or high-mid-range) service
50 MW capacity, 70% capacity factor
Heat Rate: 12,000 Btu/kWh

Capital Cost:	\$1,500/kW 2.5¢/kWh levelized (constant 1988 dollars)
O&M Cost:	0.5¢/kWh levelized (constant 1988 dollars)
Fuel Cost:	(\$1.00 to \$2.00/MilBtu) 1.2¢ to 2.4¢/kWh levelized (constant 1988 dollars)
Total Generation Cost:	4.2¢ to 5.4¢/kWh levelized (constant 1988 dollars)

B.2.2.3 Gasification of Biomass

Anaerobic gasification of biomass technology has progressed to the point where methane can be produced at a cost of \$4.50/MilBtu, based on a feedstock cost of \$2.00/MilBtu. Currently, this cost is not competitive with conventional natural gas production. However, if MSW is used as the feedstock and the alternative cost of disposing of the MSW exceeds \$40/ton, the net cost of methane from MSW may be as low as \$3.50/MilBtu, or nearly competitive with city-gate costs of natural gas in northeastern locations. Because the process involves digestion in an aqueous mixture, a significant amount of sewage sludge can also be converted simultaneously. No air emissions are produced unless combustion processes are used to dispose of the residue. The water used is cleaned and recycled. The process has been demonstrated and may become an attractive alternative means of MSW disposal for a number of cities, particularly in congested areas where landfill costs are high. (The net cost of MSW disposal using biogas conversion will include the cost of disposal of the concentrated residue from the digesters, which may be a combination of landfill and combustion systems. In some instances, the digester residues may be marketable as a fertilizer or soil conditioner.)

B.2.2.4 Conversion of Biomass to Liquid Fuels

Ethanol. Currently, the cost of ethanol produced from corn in the United States is about \$1.28/gallon, with the corn feedstock representing roughly half of this cost. (Revenues from animal feed co-products include about half the total costs.) At this cost, ethanol production would not be competitive with gasoline in the absence of federal and state tax credits. In the last decade, laboratory research, utilizing biotechnology and genetic engineering, has reduced the estimated cost of cellulose-derived ethanol to about \$1.35/gallon. Current research plans, based on the use of enzymatic hydrolysis technology, suggest that a goal of \$0.60/gallon may be achievable as early as 1998 for ethanol from cellulosic and hemicellulosic feedstocks. This cost would be competitive with the projected prices of gasoline without tax credits.

Methanol. Although biomass-to-methanol technology has yet to be commercialized, current laboratory technology suggests that commercial production would be feasible at a cost of about \$0.75/gallon. Assuming that expected improvements in syngas cleanup and a reduction in feedstock costs are realized, the costs may be reduced to the target of \$0.55/gallon as early as 1995.

Synthetic Hydrocarbon Fuels. Biomass-to-hydrocarbon fuel processes have yet to be commercialized. Based on research results, the current cost estimate for the pyrolysis process is \$1.60/gallon for gasoline. The cost target of \$0.85/gallon by 2005 is based on expected achievement of improvements in the second-stage catalytic conversion process as well as the availability of feedstock at a cost of \$2.00/MilBtu. At the current stage of development of the technology, diesel fuel from algal oil is estimated to cost about \$7.00/gallon. Major process improvements and R,D&D accomplishments are needed to achieve the projected cost goal of \$1.00/gallon by 2010. Substantial improvements in feedstock costs and in extraction technologies would be required in the same period to achieve similar cost reductions in recovering oil from algae or plant seeds.

B.2.3 Current Deployment of the Technology

Approximately 3 quads, or about 4% of the U.S. primary energy supply, are currently provided from biomass sources.

B.2.3.1 Thermal Use of Biomass

Direct combustion of wood and wood waste accounts for most of the biomass energy contribution. The direct combustion market is dominated by two sectors of the economy: the forest products industries and homeowners. The lumber and pulp and paper industries account for approximately 64% of all wood consumed for energy, and the residential sector accounts for most of the rest.

Residential wood use for space heating and cooking currently totals nearly 1 quad of energy. Advances in wood stoves and fireplace designs during the last few years have dramatically increased the potential for energy efficiency in this sector, although many consumers have not invested in the more efficient appliances. Very little wood is used for commercial space heating.

The industrial sector uses twice as much biomass for energy production as the residential sector, or almost 2 quads, nearly all of it wood and wood wastes. The pulp and paper and lumber industries are the primary industrial users of biomass materials for energy. The cogeneration of both heat and electricity is a common conversion mechanism in industry. The food processing and furniture manufacturing industries are also significant users of biomass-derived waste materials for energy.

B.2.3.2 Use of Biomass for Power Generation

The availability of low-cost fuel has been the principal limiting factor in the use of wood or other biomass in power generation. Nearly all current operations are fueled by waste or by-product materials. The cost of collecting biomass materials for power plant use ranges from $1.00 to $3.00/MilBtu, or as much or more than the total delivered cost of coal. Few biomass power plants have been built that rely solely on purchased materials; the economics are very different where waste or by-product material is available on a reliable basis at no cost (or possibly a credit if disposal is otherwise required). Therefore, the use of biomass-based generating plants has been pursued primarily by nonutility, industrial entities. In 1988, almost 8000 MW of nonutility-owned, grid-connected, biomass-based generation capacity was operating. Of this, more than 70% was in cogeneration systems. Wood-fired systems accounted for 77% of the total capacity followed by MSW (11%), agricultural waste (7%), landfill gas (4%), and digesters (1%). A significant amount of remote, nongrid-connected, wood-fired capacity also exists in the wood products industry. About 300 MW of utility-owned wood/agricultural waste-fired capacity and 540 MW of MSW capacity were also in operation[1].

In the future, if assured supplies of low-cost (no more than $2.00/MilBtu) biomass can be provided to utilities or independent producers, additional biomass-fueled generating capacity is likely to be installed in locations near the supplies. Reductions in transmission and distribution investments, achieved by placing power plants closer to the outlying loads of utility systems, are likely to be a significant incentive. Also, utilities having problems securing approval of economic sites in urban areas may look to wood-fired plants as one alternative. New England, in particular, has potential wood supplies available and, as a region, may need base-load or mid-range capacity in the next decade or two.

B.2.3.3 Gasification of Biomass

A few demonstration plants, such as the anaerobic digestion research facility in Florida, comprise the biomass gasification industry today. Extensive commercial development is several years away, requiring improvements in the technology, such as those described below. However, if the costs of disposing of MSW by other means are large (tipping fees in excess of $100/ton) in a locality, the gasification process may be economical today in such locations. (The Finnish paper mill equipment manufacturing company, Ahlstrüm, has developed and sells a wood gasification process that produces a clean gas for use in lime-calcining kilns at paper mills.)

In addition, there are a few landfill operations from which methane is now being produced in sufficient volume to warrant recovery and use as fuel. The total currently is only 0.01 quad. Additional methane is collected from landfills for safety reasons but flared because the volumes do not warrant investment in facilities to use it as a fuel.

B.2.3.4 Production of Biofuels from Biomass

Ethanol is being produced today in commercial quantities. About 850 million gallons (0.07 quad) of ethanol are produced annually from corn and other grains for blending into gasoline. Thus, 8% of the gasoline sold in the United States today is an ethanol blend. A number of plants, primarily smaller, inefficient ones, have been shut down. No demonstration or commercial plants have yet been built to produce methanol or ethanol from cellulosic materials or to produce synthetic petroleum by pyrolysis or algal processes.

B.3 Constraints and Opportunities

B.3.1 Feedstock-Related Factors

Growth of the use of biomass for heat and power production will require an adequate supply of biomass feedstock at economic cost. Currently, conventional wood and wood wastes and other available feedstocks, such as food processing wastes, are used where feasible. Many new applications, such as cogeneration at forest products industry plants, may require the reallocation of waste products from another use, such as low-efficiency process heat generation. Thus, the gains from installing new technology may be partially offset by reduced output of the old disposal processes, effectively increasing the true cost of the fuel. There are no statistics to show the amount of underutilized waste that is available or the "value" of that now inefficiently utilized.

For energy crops to compete as a source of biomass, additional effort is needed to reduce costs from the current level of about $3.25/MilBtu to $2.00/MilBtu. Productivities of from 5 to 11 tons per acre per year throughout a large part of the country are needed, as no single region is likely to be able to produce the volume that may ultimately be needed. Moreover, a variety of crops, woody and herbaceous, and a variety of regions would provide greater stability and assurance of supply. It is estimated that biomass can be produced today for about $42.00/dry ton, or about $2.50/MilBtu, in many parts of the United States and that the $2.00/MilBtu cost goal will be reached by 2010. Costs may be somewhat lower in more tropical areas, particularly if high-yielding herbaceous crops such as energy cane are produced and harvested throughout the year. Woody materials may remain the choice, however, in areas where the growing season does not permit continuous harvesting and the energy feedstock must be stored.

Several objectives must be realized, however. Harvesting technology and the requisite equipment need study. The plant and tree species must not only be productive but must resist pests and diseases and tolerate variable water availability. Growing a single crop (monoculture) over a large area may magnify vulnerability of the species to pests or diseases. Also, the procedures and costs of maintaining (or improving) the productivity of the soil have to be developed in each region for each type of soil used. The latter considerations may offset much or all of the apparent advantage tropical areas might have as the result of low land costs, abundant sunlight and rain, and low-cost labor. Yields of energy crops, like all crops, will vary by region and year. Soil characteristics, nutrients, and moisture availability are the primary site-related characteristics affecting yields. Selection of species that grow well on widely distributed sites is the critical first step to developing high-yielding energy crops. Genetic engineering and breeding to improve characteristics such as pest and disease resistance, chemical composition, and nutrient- and water-use efficiencies can substantially increase the yields and lower production costs for the selected species.

Direct use of biomass for fuel has to compete, however, with other uses of the biomass and the land on which it is grown. Currently, the lumber, furniture, paper, and other forest product industries can afford to pay more for wood than can the fuels industries in most circumstances. A reduction in biomass fuel costs to levels that will allow biomass to compete in the energy markets will also enhance biomass' competitiveness in the building materials, paper, container, rayon, and other markets (and in the ultimate markets for the end products). Thus, growth in the use of wood or other biomass as a fuel for process heat or power production will be strongly influenced by competition with other uses of the same material. Even if biomass can be produced at an attractive cost for energy production, if other uses, such as lumber, pulp, or feedstock for conversion to chemicals or liquid fuel are more valuable, the material will not be available at low prices for power generation until the biomass production capacity is sufficient to meet all the demands.

Ultimately, if the use of biomass for heat and power generation, including indirect use via gasification, is to achieve the potential impact that the resource base can support, energy crops will have to be grown on vast areas of land. Most of the lands will be those not currently used for crops. However, there also will be large land areas released from other agricultural purposes if food crop productivity worldwide continues to rise faster than ultimate demand (population growth).

MSW availability, however, is another matter. Although 2 to 3 quads of MSW are expected to be produced annually in the United States, much of the material may not be available for new applications. Contracts with existing incineration and landfill operations may prevent or delay the use of MSW for other purposes. Similarly, some MSW is committed to existing power plants, which may be of less than optimum design. The larger problem, however, is in obtaining approvals for installation of new facilities in an economic location after the questions of past disposition have been resolved. Not only must the questions of land use, emissions, residue disposal, access by collecting trucks, and proximity to the grid be resolved, but the growing insistence of communities on guarantees of satisfactory performance by the contractors (with huge potential liabilities) has to be reconciled with the costs so imposed. The real issue with MSW is that of the true cost of its disposal; power, process heat, or fuel gas produced in that process is a by-product, a potentially valuable one, but a by-product nonetheless.

B.3.2 Institutional Factors

Environmental and institutional issues may present obstacles to deployment of biomass combustion plants, particularly those using MSW as fuel. The costs of transporting biomass encourages siting plants near the source of the feedstock. Moreover, both power plants and, particularly, process heat plants need to be near demand centers. Consequently, few industries, other than forest products or food processing, use biomass as an energy source, and the wood-fired power plants are limited in number. MSW, being available in urban centers, encounters major problems. Increasing difficulties in obtaining environmentally acceptable sites for landfill disposition of MSW are making combustion or gasification of MSW more attractive. The ability to use some sewage sludge in the gasification process, thereby reducing other disposal site needs, may add to the attractiveness of the gasification option in some communities. Most communities would prefer that MSW be stored and handled at a location remote from the source. Such locations involve a higher cost of transporting the MSW to the plant and transmitting the power back to the grid (or locating an industrial steam consumer at the site).

The Public Utilities Regulatory Policies Act (PURPA) has stimulated commercial use of biomass combustion for electric power production. This power is used on-site with the surplus going to the grid for sale to the utility. A large increase in the number of applications to the Federal Energy Regulatory Commission (FERC) for biomass-fueled power production facilities occurred between 1980 and 1988.

Most institutional factors would benefit the advancement of biofuels. Federal and state governments have developed regulatory, tax, trade, and other options to support the development of the current ethanol market. That market cannot survive without continued support, yet its survival is essential to provide a bridge to the completion of research for the use of nongrain biomass as a source of ethanol that can compete in an unsubsidized marketplace. Driving the initiation of regulatory options to advance the use of oxygenated fuels is the immediate problem of increased greenhouse gases, acid rain, and other environmental pollutants. Loan guarantees, trade barriers, tax incentives, and subsidies would also promote biofuels. However, additional regulation for wood burning, primarily for wood stoves and fireplaces, could inhibit expansion of biomass use for residential purposes.

Currently, it is difficult for energy crops to compete with conventional agricultural crops, in part because of the structure and perceived reliability of government farm programs. A substantial portion of farmers' income is dependent on these programs. Farmers may be unwilling to produce energy crops instead of program crops if some of the "guaranteed" program benefits would be lost.

Until conversion technologies for liquid fuels are developed on a commercial scale, no farmer or forester is likely to plant energy crops, with the possible exception of trees (which could be short rotation) in cases where there is a viable market for use in direct combustion, for electric power fuel, or possibly for pulp. After the conversion technologies are developed, a substantial institutional constraint will remain: producers may not be willing to plant energy crops (especially short-rotation wood crops, with their minimum 5-year lead time before harvest) unless they are assured of markets for their output. Conversely, the conversion industry may not be willing to build conversion facilities unless they are assured that feedstocks will be available. Early facilities are likely, therefore, to rely on feedstocks that are already available, such as waste products collected at industrial plants and existing forest inventories.

B.3.3 Technical and Performance Factors

B.3.3.1 Combustion of Biomass for Heat or Power Generation

The combustion of biomass for process or space heat or for power generation is technologically competitive with fossil fuel technologies today, after allowing for the performance constraint inherent in the high moisture content of biomass. Technologies are available at reasonable cost to remove undesired emissions from most biomass other than MSW. Whole-tree burning systems are being devised to attempt to reduce the costs of handling trees and the penalty otherwise imposed by high moisture content. Biomass gasification systems are being investigated that may produce a clean gaseous fuel for combined cycle or intercooled, steam-injection gas turbine (ISTIG) systems, which might increase thermal efficiency significantly while also reducing particulate emissions.

Newer technologies, which have been under development for the past decade, intended to improve the efficiency and/or environmental impacts of coal and natural gas utilization, also have potential applicability to thermal, electric power, and gasification utilization of biomass. There is a need to assess the applicability to biomass uses of such systems as ISTIG using aeroderivative turbines (particularly the hot gas clean-up systems for gasifiers), coal liquefaction and gasification, and atmospheric and pressurized fluid-bed combustion. The greater reactivity of biomass versus coal feedstocks may provide biomass with an advantage in some of the gasification technologies.

MSW-fueled projects involve several major constraints. However, similar constraints apply to other modes of disposal of MSW. Thus, recovering energy from MSW combustion may be economic in situations where combustion is the most attractive means of disposal. It may also be attractive in cases where landfill or other alternatives for MSW disposal are more economic than incineration alone. Problems remain to be solved, or the costs reduced, in disposing of the toxic gas emissions resulting from MSW combustion, such as dioxins, NO_x, and chlorinated gases, and the solid residue and ash. (Solar thermal technologies for destruction of gaseous emissions offer a possible solution to some problems.) Costs of alternatives may also be high, and all costs are dependent on the specific location and the content of that locality's MSW. Thus, no specific energy cost target can be defined as a meaningful national objective; the key issue is obtaining the lowest net cost of disposal of MSW, valuing any energy supplied at market prices.

B.3.3.2 Biomass Gasification

Improvements are needed in solids loading rates and digestion efficiency for methane production by anaerobic digestion of MSW and other biomass feedstocks. Improvements are also needed in the stability and controllability of digester operation. To reach the goal of $3.50/MilBtu for the process by 1995, an accelerated program is required, including industry involvement with technology and, probably, cost sharing. Performance goals can be exceeded if biomass feedstock costs can be reduced below the goal of $2.00/MilBtu or, for MSW, if tipping fees exceed the $25 to $50/ton range, and if major, unexpected advancements reduce performance constraints in key areas.

B.3.3.3 Conversion of Biomass to Liquid Fuels

Ethanol. Improved conversion efficiency is the major goal of current and projected R,D&D efforts. Development of more effective and stable enzymes and improvements in the processing are needed to increase the yield and concentration of ethanol. Improvements are needed in the pretreatment processes of the cellulose feedstock so that a larger fraction of the sugars can be released more rapidly. Also, the processes for xylose utilization must be improved.

Demonstration is also required of the impacts on costs of scaling up the process to commercial volumes. Further, with respect to manufacturability, the scale of the fermentation processing and the supporting supply industries to produce projected quantities of ethanol will greatly exceed that of any other fermentation process industry. The projected expansion required of the biotechnology industries in relatively few years will strain the industry's technological resources.

The current level of R,D&D projected in the Business-as-Usual (BAU) Scenario would not enable this technology to be feasible until about 2020, as shown in Figure B-1 and Table B-3a. The R,D&D Intensification Scenario would permit completion of the needed research earlier, with the first commercial product being available by about 2000. The credits provided in the National Premiums Scenario would accelerate the marketability of ethanol from cellulose by 5 to 10 years at a constant price of petroleum. The premium alone, without accelerated R,D&D,

would accelerate market entry of ethanol to a lesser degree versus a case in which oil prices were rising over time, as in the market construct for this study.

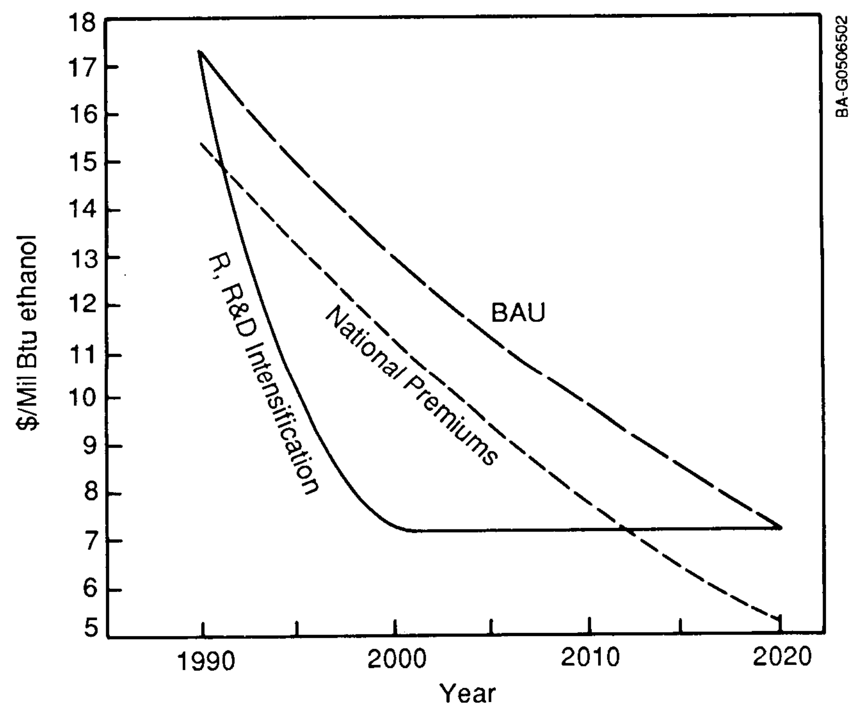

Figure B-1. Ethanol from biomass projected costs

Table B-3a.
Uniform Cost and Performance Data:
Ethanol from Biomass

	Annual Costs (million $)[a]				
	Capital Cost	O&M	Capacity Factor (%)	Feedstock[b] Cost	Levelized[c] Cost ($/MilBtu)
1990	172	47	91	27	17.4
2000 - BAU	129	46	91	22	13.0
- R,D&D	44	27	91	22	7.2
2010 - BAU	99	41	91	22	10.0
- R,D&D	94	27	91	22	7.2
2020	90	27	91	22	7.2

[a] Representative process uses 1920 dry ton/day of energy crops feedstocks; enzymatic hydrolysis and fermentation of cellulose to ethanol; xylose fermentation to ethanol; lignin conversion to MAE.

[b] Pacific Northwest (Region 10) is the first region to reach goal of $2.00/MilBtu for energy crops. Region 10 costs used for 1990 and 2000. Nearly all regions reach target by 2010.

[c] Approach for fuels is consistent with EPRI's required revenues (Fixed Charge Rate) methodology; Science Applications International Corp. model used for economic analysis.

1990 - 2000

- Capital cost reduction as the result of improved conversion efficiency for both xylose and cellulose, increase in ethanol tolerance in the reactor from 4.5% to 8.0%, reduced enzyme requirements, and deletion of the solubles recovery equipment.
- O&M reduction as the result of feedstock cost reduction from $2.50 to $2.00/MilBtu, and reductions in steam and power requirements.

2000 - 2020

- All regions reach feedstock cost of $2.00/MilBtu.

Methanol. Several areas of methanol conversion technology are in particular need of additional research. Improvements are needed in the cleanup of the raw synthesis gas output of the biomass gasifier to increase process efficiency and reduce capital costs. Other processing steps need improvement to achieve the yield of 120 gallons/ton of feedstock that appears necessary for commercial operations. Demonstration of the technology on a commercial scale would permit development of refinements of equipment and processes necessary to achieve process reliability and thereby accelerate industry acceptance.

At the current level of R,D&D activity, the technology will be ready for industrial adoption by about 2000. With intensified R,D&D, the technology would be available to industry by 1995. As in the case of ethanol, the premium provided in the National Premiums Scenario would accelerate market penetration by about 5 years if oil prices were stable, and by less if competing fuel prices rise during 1990 to 2000 (see Figure B-2 and Table B-3b.

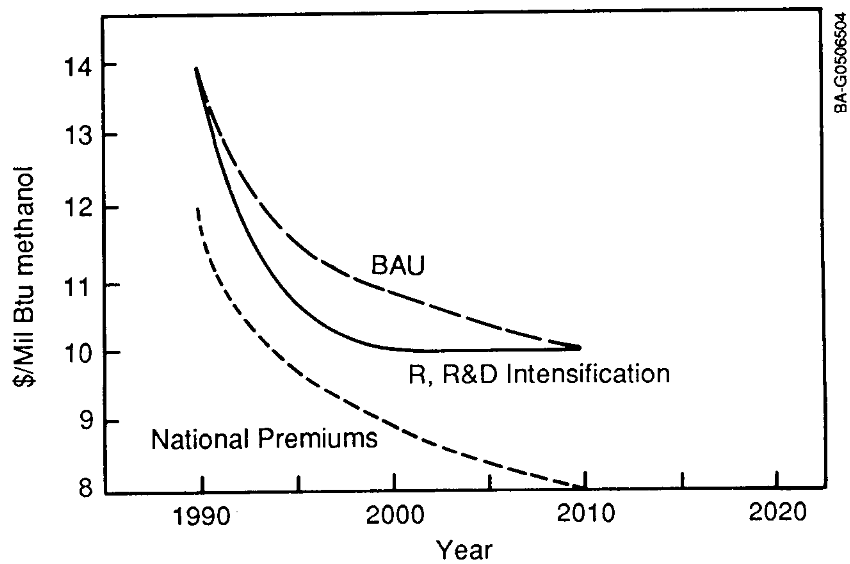

Figure B-2. Methanol from biomass projected costs

Table B-3b.
Uniform Cost and Performance Data:
Methanol from Biomass[a,c]

	Annual Costs (million $)[a]				
	Capital Cost	O&M	Capacity Factor (%)	Feedstock[b] Cost	Levelized[c] Cost ($/MilBtu)
1990	125	41	75	23	13.8
1995 - BAU	120	38	90	19	11.3
- R,D&D	98	40	90	19	10.2
2000 - BAU	115	38	90	19	11.1
- R,D&D	98	40	90	19	10.0
2010 - BAU	98	38	90	19	10.2

[a] Representative process uses 2000 dry tons/day of energy crops; thermal gasification of feedstock plus gas shift yields syngas (mixture of H_2 and CO of suitable ratio); syngas catalytically converted to methanol. Region 10 is the first region to reach goal of $2.00/MilBtu.

[b] Approach for fuels is consistent with EPRI's required revenues (Fixed Charge Rate) methodology; Science Applications International Corp. model used for economic analysis.

[c] Methanol from biomass economic assessment currently being evaluated based on updated process flow sheet (Chem Systems).

1990 - 1995

- Feedstock cost decrease from $2.50 to $2.00/MilBtu, reducing O&M costs.
- Scale-up and demonstration increase reliability and methanol production capacity.
- Improvements in clean-up of raw synthesis gas.

1995 - 2000

- Slight increase in energy conversion efficiency.
- Improvements in compression needs; feed preparation requirements; and removal of particulates, acid gas, oils, tars, and light hydrocarbons from synthesis gas.

2000 - 2010

- Several regions reach energy crops goal of $2.00/MilBtu.
- Improvements in energy conversion efficiency of 5%.

B.3.3.4 Synthetic Hydrocarbon Fuels (Gasoline and Diesel)

Improvements are needed in the efficiency and effectiveness of the fast pyrolysis process. Not only are improved yields of hydrocarbons needed, but improvements in their quality (reduced volatile olefins) are also required. The pyrolysis technology must be demonstrated on a larger scale to be certain that volume and quality yields can be maintained in the much larger volume commercial-sized reactor. The technology for the catalytic conversion step is sufficiently similar to petroleum processing to require relatively little R,D&D, although commercial-scale demonstration units may be costly if processing temperatures and pressures cannot be kept at low levels.

The fast pyrolysis technology is expected to be commercially feasible by 2020 at current levels of effort. R,D&D intensification would accelerate commercialization to about 2005 to 2010. The reference case and the national goals premium case are shown in Figure B-3 to have identical costs since the synthetic gasoline offers advantages arising from its renewable energy source, but no differences in emissions during use. A $2.00/MilBtu premium for its renewable energy source would accelerate the introduction of synthetic petroleum products of fast pyrolysis by 5 to 10 years (see also Table B-3c).

Production of synthetic petroleum liquids from microalgae is not likely to become economic as early as in the case of pyrolysis. Another decade may be required. Among the critical needs of the microalgal process is the development of improved organisms having both high growth rates and high oil contents. Improved performance will then be needed in harvesting, oil extraction, and oil refining technologies. Manufacturing algal oils will present many challenges; algal ponds have never been constructed and operated at the scale envisioned for producing diesel and jet fuel by this process. Demonstration facilities will have to be built once the technology has matured.

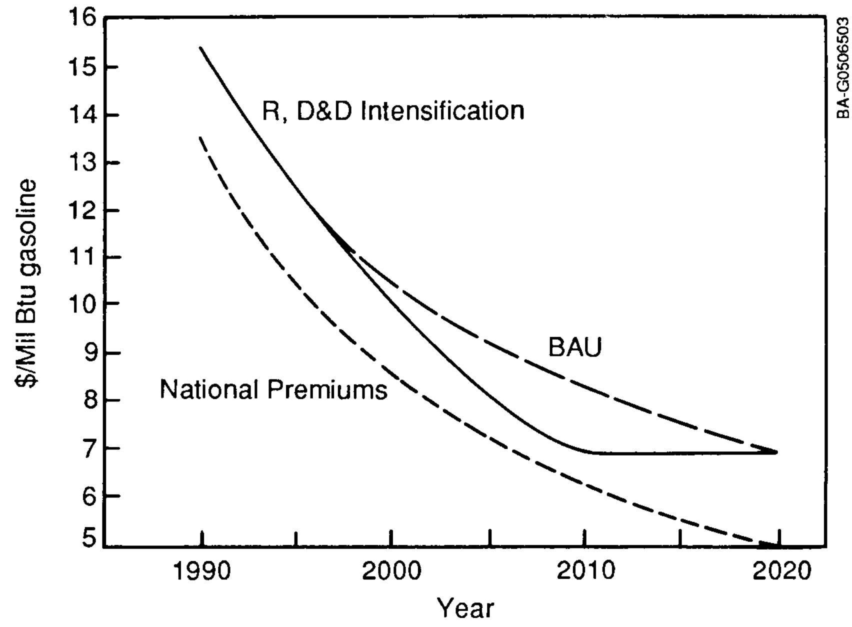

Figure B-3. Gasoline from biomass projected costs

Table B-3c.
Uniform Cost and Performance Data:
Gasoline from Biomass

	Annual Costs (million $)[a]				
	Capital Cost	O&M	Capacity Factor (%)	Feedstock[b] Cost	Levelized[c] Cost ($/MilBtu)
1990	95	57	75	24	15.5
2000 - BAU	85	40	75	19	10.5
- R,D&D	72	30	75	19	10.0
2010 - BAU	80	34	90	19	8.5
- R,D&D	72	30	90	19	7.0
2020	72	30	90	19	7.0

[a]Representative process is 2000 dry tons/day of energy crops; fast pyrolysis of cellulosic feedstock yields biocrude; biocrude is upgraded to yield gasoline.
[b]Pacific Northwest (Region 10) is the first region to reach goal of $2.00/MilBtu for energy crops. Region 10 costs used for 1990 and 2000. Nearly all regions reach target by 2010.
[c]Approach for fuels is consistent with EPRI's required revenues (Fixed Charge Rate) methodology; Science Applications International Corp. model used for economic analysis.

1990-2000

- Energy conversion efficiency increases from 32% to 50% due to improvements in pyrolysis and biocrude upgrading; results in 40% increase in actual gasoline production.
- Feedstock reduction from $2.50 to $2.00/MilBtu in Region 10.

2000-2010

- Energy conversion efficiency increases from 50% to 57.6% due to improvements in biocrude upgrading; results in 54% increase in actual gasoline production.
- Capacity factor increases from 75% to 90%.
- Feedstock costs reach $2.00/MilBtu in all regions.

B.4 Potential Contribution

The potential biomass energy resource base in the United States is very large, particularly if extensive production of biofuels crops is undertaken. As indicated in Table B-2, the total can exceed 55 quads under certain assumptions. In addition, as forestry productivity increases, depending on other demands for wood, existing forest land could provide an additional quantity. The biomass resources available today have been estimated to total about 14 quads, consisting of available wood and wood wastes, agricultural and food processing residues and by-products (including ethanol), and MSW, but *excluding* cultivated energy crops, wood designated for other uses, and grain not now used in ethanol production. The potentially available contributions from each of the technologies, including biofuels, if totaled with others, obviously would exceed the resources available. In addition, there are other, non-energy potential uses for many of the resources. The projections of the contributions of biomass energy shown in Tables B-4 to B-10 consider alternative competitive uses and do not double-count the use of any part of the resources. All the potential resources, however, are not used in any of the cases described since the economic values of each type of resource are highly variable. Thus, even when resources may be economic to use, consumers may not appreciate the values or may decide to use other energy sources.

Table B-4.
Potential Increase in Biomass Availability with Accelerated Energy Crop R&D (2030)[a]

Region	Maximum Acreage[b]	Current R&D Levels Acres[c]	Current R&D Levels Yield[d]	Current R&D Levels Quads[e]	Accelerated R&D Levels Acres[c]	Accelerated R&D Levels Yield[d]	Accelerated R&D Levels Quads[e]
Available from Current Cropland							
Northeast	5	1	7	0.1	3	8	0.3
South/Southeast	26	13	10	2.0	22	11	3.6
Midwest/Plains	106	52	9	7.2	70	10	11.0
West/Northwest	13	3	7	0.3	8	7	0.8
Subtotal	150	69		9.6	103		15.7
Potentially Available Cropland							
Northeast	7	1	5	0.1	4	7	0.4
South/Southeast	57	6	7	0.6	29	9	3.8
Midwest/Plains	75	7	6	0.6	48	8	5.4
West/Northwest	15	2	5	0.1	8	6	0.7
Subtotal	154	16		1.4	89		10.3
Total	**304**	**85**		**11.0**	**192**		**26.0**

[a] Assumes $2.00/MilBtu cost of delivered biomass (including minimum required profit).

[b] Millions; maximum acres of land that are currently managed for agricultural production and will require new crops within 25 years, based on the New Farm and Forest Products Task Force Report.

[c] Millions; available acreage is calculated based on assumptions about development of energy crops and cultural techniques for each region.

[d] Dry tons/acre/year.

[e] Quadrillion Btu per year.

[f] Millions; maximum acres of land not being currently cropped but capable of supporting crop production based on the 1982 National Resource Inventory.

Table B-5.
Potential Contribution of Biomass Energy Supplies by Technology and End Use, 1988-2030
(quads)

	Business-as-Usual Scenario				
Current Technology	1988	2000	2010	2020	2030
Biomass-Electric					
Combustion/Boiler, Incinerators	0.48	0.95	1.62	1.88	2.13
Wood and Wood Wastes	0.33	0.64	1.00	1.00	1.00
MSW	0.11	0.20	0.45	0.66	0.87
Agricultural Wastes	0.03	0.06	0.09	0.12	0.15
Landfill and Digester Gas	0.01	0.05	0.08	0.10	0.11
Biomass-Buildings					
Wood Stove Combustion	0.95	1.00	1.45	1.80	2.16
Biomass-Industrial					
Combustion (Wood and Wood Waste)	1.77	2.20	2.85	3.30	3.75
Biomass-Liquid Fuels					
Ethanol from Grain Crops	0.07	0.20	0.30	0.30	0.30
Advanced Technology					
Biomass-Electric					
MSW Digestion	-	-	0.02	0.05	0.10
Biomass-Liquid Fuels					
Ethanol, Methanol, Gasoline from Energy Crops	-	0.01	0.05	0.50	1.90

Table B-5. (Continued)
Potential Contribution of Biomass Energy Supplies by Technology and End Use, 1988-2030
(quads)

	R,D&D Intensification Scenario				
Current Technology	1988	2000	2010	2020	2030
Biomass-Electric					
Combustion/Boilers, Incinerators	0.48	1.10	1.81	2.19	2.53
Wood and Wood Wastes	0.33	0.72	1.05	1.05	1.05
MSW	0.11	0.26	0.57	0.89	1.20
Agricultural Wastes	0.03	0.06	0.09	0.13	0.16
Landfill and Digester Gas	0.01	0.06	0.10	0.12	0.12
Biomass-Buildings					
Wood Stove Combustion	0.95	1.15	2.00	2.60	3.20
Biomass-Industrial					
Combustion (Wood and Wood Wastes)	1.77	2.32	3.29	3.94	4.59
Biomass-Liquid Fuels					
Ethanol from Grains	0.07	0.30	0.40	0.40	0.40
Advanced Technology					
Biomass-Electric					
MSW Digestion	-	0.02	0.05	0.10	0.15
Combustion/Gasification/ Turbines	-	0.02	0.05	0.10	0.20
Biomass-Liquid Fuels					
Ethanol, Methanol, Gasoline from Energy Crops	-	0.04	2.00	4.00	8.00

Table B-5. (Concluded)
Potential Contribution of Biomass Energy Supplies by Technology and End Use, 1988-2030
(quads)

	National Premiums Scenario				
Current Technology	1988	2000	2010	2020	2030
Biomass-Electric					
Combustion/Boilers, Incinerators	0.48	1.51	2.08	2.30	2.50
Wood and Wood Wastes	0.33	1.05	1.05	1.05	1.05
MSW	0.11	0.34	0.84	1.00	1.17
Agricultural Wastes	0.03	0.06	0.09	0.13	0.16
Landfill and Digester Gas	0.01	0.06	0.10	0.12	0.12
Biomass-Buildings					
Wood Stove Combustion	0.95	1.00	1.45	1.80	2.16
Biomass-Industrial					
Combustion (Wood and Wood Wastes)	1.77	2.70	3.35	3.80	4.25
Biomass-Liquid Fuels					
Ethanol from Grains	0.07	0.30	0.40	0.40	0.40
Advanced Technology					
Biomass-Electric					
MSW Digestion	-	-	0.02	0.05	0.10
Combustion/Gasification/ Turbines	-	-	-	0.05	0.10
Biomass-Liquid Fuels					
Ethanol, Methanol, Gasoline from Energy Crops	-	0.01	0.55	1.10	2.40

Table B-6.
Biomass Electric Penetration

	Primary Energy (quads)				
	1988	2000	2010	2020	2030
Business-as-Usual Scenario					
Northeast	0.14	0.31	0.49	0.58	0.67
South	0.20	0.42	0.65	0.77	0.89
West	0.09	0.11	0.33	0.39	0.45
North Central	0.05	0.10	0.17	0.19	0.22
Total	**0.48**	**0.94**	**1.64**	**1.93**	**2.23**
R,D&D Intensification Scenario					
Northeast	0.14	0.34	0.57	0.72	0.94
South	0.20	0.46	0.76	0.96	1.25
West	0.09	0.23	0.39	0.48	0.63
North Central	0.05	0.11	0.19	0.24	0.31
Total	**0.48**	**1.14**	**1.91**	**2.40**	**2.88**
National Premiums Scenario					
Northeast	0.14	0.45	0.63	0.72	0.81
South	0.20	0.61	0.84	0.96	1.08
West	0.09	0.30	0.42	0.48	0.54
North Central	0.05	0.15	0.22	0.24	0.27
Total	**0.48**	**1.51**	**2.10**	**2.40**	**2.70**

Potential Resource Availability

Buildings, industrial, and biofuels applications also compete for these resources. The resources include energy crops, wood and wood wastes, MSW, and landfill contents.

Table B-7.
Biomass Buildings Penetration

	Primary Energy (quads) 1988	2000	2010	2020	2030
Business-as-Usual Scenario					
Northeast	0.21	0.22	0.29	0.34	0.49
South	0.41	0.42	0.49	0.64	0.69
West	0.11	0.12	0.19	0.24	0.29
North Central	0.22	0.24	0.48	0.58	0.64
Total	**0.95**	**1.00**	**1.45**	**1.80**	**2.16**
R,D&D Intensification Scenario					
Northeast	0.21	0.25	0.40	0.50	0.70
South	0.41	0.45	0.60	0.80	0.90
West	0.11	0.15	0.30	0.40	0.50
North Central	0.22	0.30	0.70	0.90	1.10
Total	**0.95**	**1.15**	**2.00**	**2.60**	**3.20**
National Premiums Scenario					
Northeast	0.21	0.22	0.29	0.34	0.49
South	0.41	0.42	0.49	0.64	0.69
West	0.11	0.12	0.19	0.24	0.29
North Central	0.22	0.24	0.48	0.58	0.69
Total	**0.95**	**1.00**	**1.45**	**1.80**	**2.16**

Potential Resource Availability

Electric power, industrial, and biofuels applications also compete for these resources. The resources include energy crops plus wood and wood wastes.

Table B-8.
Biomass Industrial Penetration

	Primary Energy (quads) 1988	2000	2010	2020	2030
Business-as-Usual Scenario					
Northeast	0.20	0.34	0.45	0.53	0.61
South	0.96	1.13	1.36	1.52	1.67
West	0.41	0.48	0.62	0.71	0.81
North Central	0.20	0.25	0.42	0.54	0.66
Total	**1.77**	**2.20**	**2.85**	**3.30**	**3.75**
R,D&D Intensification Scenario					
Northeast	0.20	0.37	0.56	0.69	0.82
South	0.96	1.16	1.47	1.68	1.88
West	0.41	0.48	0.62	0.71	0.81
North Central	0.20	0.31	0.64	0.86	1.08
Total	**1.77**	**2.32**	**3.29**	**3.94**	**4.59**
National Premiums Scenario					
Northeast	0.20	0.42	0.53	0.61	0.69
South	0.96	1.39	1.62	1.78	1.93
West	0.41	0.59	0.73	0.82	0.92
North Central	0.20	0.30	0.47	0.59	0.71
Total	**1.77**	**2.70**	**3.35**	**3.80**	**4.25**

Potential Resources Available

Electric power, buildings, and biofuels applications also compete for these resources. The resources include energy crops plus wood and wood wastes.

Table B-9.
Market Penetration: R,D&D Intensification Scenario

	Economic Potential[a] (quads)	Penetration (quads)
Northeast		
1988	0.7	0.00
2000	1.4	0.00
2010	2.0	0.04
2020	2.4	0.10
2030	2.7	0.20
South		
1988	1.46	0.01
2000	3.76	0.04
2010	6.06	0.42
2020	8.36	1.04
2030	10.06	2.04
North Central		
1988	0.107	0.06
2000	4.17	0.26
2010	8.27	1.36
2020	14.67	3.06
2030	19.37	5.76
West		
1988	0.7	0.0
2000	1.1	0.04
2010	1.6	0.08
2020	1.95	0.2
2030	2.25	0.4

[a]Includes energy crops, wood plus wood waste, and corn for ethanol.

Table B-10.
Potential Contributions of Biofuels
(quads)

Business-as-Usual Scenario	1988	1990	1995	2000	2010	2020	2030
Biofuels Liquids							
Corn	0.07			0.20	0.30	0.30	0.30
Biocrops	----			0.01	0.05	0.50	1.90
R,D&D Intensification Scenario	**1988**	**1990**	**1995**	**2000**	**2010**	**2020**	**2030**
Biofuels Liquids							
Corn	----			0.30	0.40	0.40	0.40
Biocrops	----			0.04	2.00	4.00	8.00
National Premiums Scenario	**1988**	**1990**	**1995**	**2000**	**2010**	**2020**	**2030**
Biofuels Liquids							
Corn	----			0.30	0.40	0.40	0.40
Biocrops	----			0.01	0.55	1.10	2.40

B.4.1 The BAU Scenario Contribution Potential

B.4.1.1 Thermal Use of Biomass

The use of biomass for thermal purposes, including industrial cogeneration, is the principal use of biomass for energy production today. Industrial consumption of wood wastes for process heat and cogeneration uses totals about 1.8 quads and building heat uses, almost entirely residential consumption, totals about 1 quad. Based on forecasted increases in the prices of fossil fuels and electricity, process heat (including cogeneration) use may increase to 3.8 quads by 2030, and building heat (again primarily residential use) to 2.2 quads. By 2030, the available economic biofuels resources would be largely utilized, requiring the production of energy crops if significant increases in biomass or biofuels usage are desired.

B.4.1.2 Electric Power Production Using Biomass Fuel

The primary constraint on increased biomass-fired power generation is low-cost resource availability near load centers or dispersed loads. Fossil fuels and, initially, nuclear power have been more readily available and more economic near most major cities and load centers. Thus, a very low-cost biomass fuel would be required for biomass power to become a major supply source, an unlikely occurrence. The potential for biomass-sourced power is defined almost entirely by the availability of low-cost waste material that has no higher valued use, such as forestry industry wastes, food processing wastes, and MSW. (Some apparent "waste," such as wood chips, may be a valuable raw material for chemicals or building products, such as chip board, and not be economical for use as a fuel.) Once the waste resource is fully utilized, new sources of biomass dedicated to the energy market must be provided at attractive costs if additional biomass energy supplies are desired. MSW deployment is further constrained by institutional and environmental issues.

Current biomass energy uses consume only a small fraction of the estimated annual wood and agricultural waste resource. Thus, there are adequate resources physically available to support a greater level of utilization in base-load service or cogeneration. Currently, only about 0.5 quad of biomass energy are exploited for electricity generation, using more than 8000 MW of installed capacity. Biomass-based generation, including MSW, could provide 1.6 quads by 2010, with capacity reaching 20,000 MW if recent trends continue. By 2030, the contribution may reach 2.1 quads.

B.4.1.3 Gasification of Biomass

Methane production from waste sources (landfills, sewage treatment, and farm wastes) will continue to increase commensurate with growth in the waste stream and may be important in specific locales. However, these sources of biogas are not expected to contribute substantially to the overall national energy supply. The small amount of current production, less than 0.1 quad, is included in the statistics cited above.

Large-scale market penetration of biomass-derived methane production, aside from the small-scale localized sources, will depend not only on production at costs competitive with natural gas at projected well-head prices, but the ability to economically integrate biomass-derived production into the existing gas delivery system. With achievement of the research and development (R&D) cost goals, biomass-derived methane could supply 10% or more of gas use in favorable resource areas by 2010. The projected cost of methane produced from biomass--$3.50/MilBtu--at a feedstock cost of $2.00/MilBtu--would make biomass-derived methane attractive versus conventional natural gas supplies after 2000. Conversion of MSW into methane for delivery to local gas systems would be attractive and is assumed to occur in some markets, particularly the coastal areas distant from the gas fields. However, large-scale production of biomass for gasification would compete with the use of that same biomass for liquid fuel projects. While 2 quads or more of biologically derived methane could be delivered to the nation's gas systems by 2030, this white paper assumes that the economic and environmental pressures to produce clean liquid fuels result in the biofuels farming/plantation effort being directed at providing feedstock for conversion to liquid fuels between now and 2030. Should an alternative choice be made, a substantial portion of the biomass feedstock could be converted instead into methane at a competitive cost to natural gas, supplying possibly more than 2 quads by 2030, at locations accessible at reasonable cost by the nation's gas pipeline systems.

B.4.1.4 Biofuels

In the BAU Scenario, biofuels can make a significant contribution to the nation's energy requirements. The main contribution would come from ethanol produced from corn, if current tax incentives remain in place, for the next two decades. It has been estimated that 4 billion gallons/year of ethanol can be produced from corn without serious impact on the grain and animal feed markets. Considerably more ethanol could be produced if additional acreage were returned to corn production, and the currently uncertain market impacts of the co-products were acceptable. Production of methanol and ethanol from dedicated biomass crops would begin around 2000, with methanol being the first product. By 2030, the contribution of the two fuels could reach nearly 2 quads. Since feedstock may not be available from dedicated crop or plantation production until after 2010, the earlier plants will probably use by-product and waste materials from forest products and food processing industry plants. Similar limitations would apply to the alternative use of the biomass as a feedstock for pyrolysis processes. Substantial quantities of cellulose-derived methanol, ethanol, or synfuels are likely to be available only after 2020. Although ethanol appears today to be the ultimate alcohol fuel of choice, based on current estimates of achievable costs, the difference is too small between the fuels and their related processes to assert that either alcohol or synthetic gasoline or diesel fuel would be clearly superior. Consequently R,D&D needs to be continued in each of the areas until a clear choice is indicated by the technologies and the markets.

B.4.2 The R,D&D Intensification Scenario Contribution Potential

B.4.2.1 Focus of Accelerated R,D&D

The focus of accelerated R,D&D should be on a few key areas. Principal among these are studies to accelerate the kinetics and efficiency of technologies to convert woody feedstocks to alcohols. Although the major beneficiary of feedstock research is likely to be biofuels conversion technologies, accelerated economic production of herbaceous and woody crops would expand markets for biomass in power generation and process heat. The costs must be brought to the $2.00/MilBtu level as early as possible. At the same time, reliability of the feedstock production must be demonstrated if farmers and land owners are to commit large land areas to long-term production of energy crops. Monoculture herbaceous and woody energy crops must be produced on a large scale over an extended time to demonstrate the viability of several species under a variety of seasonal and annual climatic conditions, such as abundant or minimal rainfall and temperature extremes; exposure to insects, fungi, and other pests and diseases; and tolerance of pesticides and herbicides.

Needs for additional R,D&D on biomass-derived methane relate to the production of methane from MSW as well as more uniform biomass with more predictable processing behavior. Improvements in reactor stability, gas enrichment, and conversion rates are needed to reduce costs from $4.50/MilBtu to $3.50/MilBtu.

The production of electricity and heat from biomass resources is currently commercial. Little additional research is needed in the existing technology. Any achievements in advanced fossil fuel generation technologies should be studied to evaluate their potential adaptation for biomass fuels. Improvements in the performance (particularly the lifetimes) of emission clean-up catalysts would reduce the cost of efficient wood-burning equipment and improve its market acceptance. In addition, the development of a biomass gasifier and gas clean-up system might make combined cycle technology feasible using wood or other biomass and reduce costs by virtue of greatly improved efficiency. Research on MSW feedstock preparation, particularly improvements in separating and recovering recyclable materials, and removing materials that produce toxic or other unwanted emissions in the combustion process, is also needed.

B.4.2.2 Potential Contributions by Sector

Thermal Use of Biomass. Improvements in emission control catalysts and their costs, as well as other aspects of biomass combustion technology, will make wood burning more attractive than in the BAU Scenario. However, the advances in biofuels technologies will result in competition for biomass supplies, particularly the larger sources of wood and other biomass wastes. Given the forecasted prices of oil and gas, the economic incentives will be strong to use biomass wastes as feedstocks rather than as fuel, particularly where coal may be the competitor. In the BAU Scenario, virtually all forest products and food processing industries are assumed to have met their own energy needs with the available waste and by-product materials. By 2030, only 1.9 additional quads of energy are likely to be supplied to residential and industrial consumers of biomass fuel.

Electric Power Generation with Biomass. Advances in combustion technology and feedstock availability are projected to result in a small increase in the use of biomass for power generation in the accelerated R,D&D case. By 2030, an additional 0.7 quad of power is projected to be produced from biomass power plants. Some of the gain comes from lower cost biomass feedstocks but most is related to lower costs of MSW power generation and emission controls, increasing the use of MSW power generation as an alternative to land fills and incineration.

Gasification of MSW and Other Biomass. Acceleration of R,D&D of gasification technology would increase the application of the process in MSW disposal and in the production of alternative supplies of methane to the nation's gas pipelines. The MSW output is included in the totals for buildings, industrial, and electric power use of biomass. The production of pipeline-quality methane as a supplement to natural gas supplies could be as great as 2 quads if biofuels plantations were devoted to supplying gas conversion plants rather than liquid fuels facilities. For purposes of this white paper, it is assumed that air quality concerns and related local and regional automotive fuel use regulations in conjunction with process economics will make it more attractive to produce liquid fuels rather than methane. The likely feasible rate of expansion of the biofuels plantations is likely to be the overriding constraint in biofuels supply. The attractive economics of biogas versus either domestic or imported natural gas from 2010 and beyond may result in development of some biogas plants and associated biofuels plantations, providing as much as 2 quads of methane to the pipelines. The Pacific Northwest region could supply existing pipelines to California, and the southern region could supply pipelines going to the Northeast, Mid-Atlantic, and Florida markets.

Biofuels. With accelerated R,D&D, the production of dedicated feedstocks and the conversion technologies for methanol and ethanol would be advanced significantly, and alcohol fuels could provide more than 8 quads of liquid fuels by 2030. Some improvements would impact the production of ethanol from corn, increasing that potential slightly by 2000. The major contribution would come from establishment of a significant dedicated biomass production industry--farms, plantations, dedicated forests, etc.--by 2010. Both ethanol and methanol technologies would be fully developed by that time and synthetic fuels from pyrolysis or plant oils would be near commercial status by 2010. By 2030, the output could be any of the fuels, depending on the economic success of each technology and on developments regarding emission controls and automotive technology. The biomass producers would also have a potential market of biomass gasification, as noted above, which might compete for use of the feedstocks. The biomass production industry would probably find it difficult to prepare to supply more than 8 quads by 2030--that alone would be a major challenge. Therefore, if gasification of cellulosic biomass crops is undertaken, the potential contribution of liquid biofuels probably would be correspondingly smaller, without a development program featuring significant government intervention or much higher energy prices than have been projected.

B.4.3 The National Premiums Scenario Contribution Potential

Adding a $2.00/MilBtu incentive to biomass utilization would appear to have the effect of providing nearly free fuel to potential users and thus greatly expand markets. This would be true in areas having unused biomass, particularly higher cost material, available for use in furnaces, power plants, and gasifiers. However, most of the potential material is expected to be used in the BAU Scenario, and some higher cost material would become economic and be used in the National Premiums Scenario. In the energy crop market, the $2.00 premium for the liquid fuels (or possibly for pipeline gas) would make those markets more attractive than combustion uses for process heat or electric power, particularly since much greater incremental transportation costs would have to be incurred to move either the biomass or the electric power to more distant power markets than would be required to transport liquid fuels or methane. However, unless R,D&D is accelerated, the development of the dedicated biomass crop industry will limit the potential contribution of liquid and gaseous fuels. Higher prices might attract sufficient private R,D&D funding, but delays will probably result in little impact before 2030. This could prove to be a conservative assumption.

Tables B-6, B-7, and B-8 show the estimates of biomass market penetration, by region, during the 1988 to 2030 time period for electric, buildings, and industrial sectors, respectively, for the BAU, R,D&D Intensification, and National Premiums cases. Table B-9 shows the market penetration for accelerated R,D&D for transportation uses of biomass by region. Table B-10 shows the potential contributions of biofuels for the BAU, R,D&D Intensification, and National Premiums Scenarios.

B.5 Contributions to National Goals

The use of liquid biofuels could provide several benefits to the United States. Foremost would be an added measure of energy security by increasing energy self-sufficiency and substantially lessening dependence on foreign oil. The reduction of imports could result in an annual balance-of-payments savings of up to $100 billion while creating a domestic biofuels industry that would provide jobs, economic growth, additional tax revenue, and a potential export market. Additionally, liquid fuels from biomass can benefit the environment by recycling rather than adding CO_2 to the atmosphere, making biofuels a desirable option for reducing the impact of potential global warming. Expanded use of biomass in other applications would have similar effects in improving the environment and, to the extent imported petroleum is effectively replaced, in improving energy security and the balance of payments.

B.6 Perspectives from Other Forecasts and Analyses

B.6.1 Resources

The aggregate biomass resources have been estimated by a number of sources and vary significantly. We note the absence of a definitive survey of land use and potential use, accepted measures of potential land productivity, and measures of current production and availability of wastes. A Meridian Corporation report, for example, defines *reserves* as "that resource which is identified and which can be economically and legally extracted with existing technology and under present economic conditions to yield useful energy or an energy commodity."[5] Using this definition, Meridian estimates a biomass reserve of 57.7 billion barrels of oil (335 quads) for a 30-year period of the resource, which translates into about 11 quads/year on a sustainable basis. This is the present *reserve* and does not consider utilization of new lands or current set-aside lands for energy crops or expanded corn production.

The only significant difference between this white paper and the Meridian report is in the area of land for energy crops and ethanol from corn. Oak Ridge National Laboratory (ORNL) estimates that 192 million acres may be available for energy crops by 2030 with yields of 9 tons per acre per year or about 26 quads/year of sustainable biomass energy supplies[6]. Ethanol from corn has potential for much greater production than the current 850 million gallons (0.07 quad). The Meridian report shows a *reserve* of about 0.116 quad. Scientists at the Solar Energy Research Institute (SERI) estimate that 5 billion gallons of ethanol per year (0.4 quad), or more, could be produced from corn[7]. The National Advisory Panel on Cost Effectiveness for Fuel Ethanol Production estimates that up to 3.4 billion gallons/year could be produced by 1992 under a rapid growth scenario[8]. Additional amounts of corn could be processed into ethanol (and animal feed co-products) if the significant impact on the grain and animal feed markets were acceptable.

Most other perspectives that exist about the resource base for production of biomass crops were prepared in the late 1970s or early 1980s when views on agricultural needs were much different than they are now. Among six land-use scenarios evaluated by the MITRE Corporation[9], the "current" quad production estimates ranged from, 0.2 to 6.8 and "future" quad production estimates ranged from 0.4 to 13.7. The MITRE report assumptions differ from current assumptions in two major ways: (1) the yields assumed are much higher (8 and 15 dry tons/acre for "current" and "future" scenarios respectively), and (2) the land base assumed is quite low (the largest land base scenario included only 49 million acres). The most optimistic projection of the Office of Technology Assessment (OTA), was that 65 million acres might be available for dedicated energy crop production and that about 16.2 quads of energy could be obtained from a mixture of forestry (5 to 10 quads), agriculture crops (6 quads), and agriculture residues (1.2 quads)[10]. The Energy Research Advisory Board (ERAB) estimated that the quad contribution from all biomass sources including all sources of wood and wood wastes, animal wastes, agricultural residues, MSW, bagasse, etc., would equal about 10.7 to 11.3 quads by 2000[11]. Only 1.57 quads were estimated to come from wood plantations and forage by 2000. Those views were heavily influenced by the belief that agricultural needs would require additional land in the future.

In contrast, a report prepared by the New Farm and Forest Products Task Force recently proposed that a national goal be established for developing and commercializing new farm and forest products within 25 years to utilize at least 150 million acres of productive land in the United States[2]. This report reflects the trend toward reduction in harvestable cropland observed between 1985 and 1988 and incorporates the prospect of further increases in crop productivity brought about by biotechnology[12]. The most recent available publication of estimates of biomass resources was prepared by Klass[1]. Recoverable yields from all biomass resources by 2000 were estimated by Klass to be 14.6 quads and maximum theoretical yields were estimated to be 54.9 quads. The 26 quads proposed as possible with accelerated R,D&D is thus within the range of other current published estimates.

B.6.2 Use of Biomass for Electric Power Generation

B.6.2.1 Use of Agricultural Wastes for Power Generation

Projections of production of energy from agricultural wastes indicate that output will be limited. OTA estimates 0.8 to 1.2 quads of gross energy potential by 2000[10]. This compares to an estimate of 2.2 quads of gross energy by ORNL for 2010 if 20% of available residues are recoverable[13]. ERAB estimates 1.4 quads of potential gross energy from this resource by 2000[11]. Meridian Corporation estimates about 0.8 quad for agricultural waste potential[5]. Although the *potential* energy contribution of agricultural waste is on the order of 0.8 to 2.2 quads around the turn of the century, actual market utilization is projected to be small (0.06 for 2000 and 0.09 for 2010 for the R,D&D Intensification Scenario). This is due to many reservations, primarily associated with the need and value of residues for maintaining the quality of land, harvesting problems, environmental issues, and the marginal economics of the entire process under the best of circumstances. Forestry wastes may be a different matter but have not been analyzed adequately.

B.6.2.2 Power Generation Using MSW for Fuel

It is generally agreed that the United States generates about 3.5 lb/day of MSW per capita. This translates into 2.36 quads/year of gross energy for a population of 285 million in 2010. Klass estimates that 90% of MSW is *recoverable*. For the year 2000, ERAB estimated that less than 60% of MSW would be available for energy, or a gross energy content of 0.9 quad. The National Energy Policy Plan (NEPP) Projections to 2010 projects MSW utilization of 0.31 quad for 2010 (BAU Scenario). These estimates compare to 0.47 quad utilization in the BAU Scenario and 0.62 quad in the R,D&D Intensification Scenario projections presented here for 2010.

B.6.3 Gasification of Biomass

Landfill methane is estimated by Klass at 0.2 quad recoverable in 2000. For the year 2010, the NEPP projections show landfill plus sewage gas contributing 0.05 quad. This compares to 0.08 quad in the BAU Scenario and 0.10 quad in the R,D&D Intensification Scenario discussed earlier.

A recently completed DOE-sponsored research experiment (REFCOM) successfully showed that anaerobically digested MSW and sewage sludge can be converted to biogas at a cost of $5.00/MilBtu after credits for a tipping fee of $25/ton. This experiment was co-funded with industry and designed to operate at a scale of 50 to 100 tons/day.

During the paper's peer review process, two reviewers suggested that thermal gasification of biomass, coupled with steam injected aeroderivative gas turbines, could provide lower costs than conventional combustion of biomass and could make a significant contribution to both industrial thermal energy and electricity generation. The lower costs are a result of potentially lower capital costs as well as higher efficiency use of the feedstock. The potential impacts of these technologies and others that can be adapted to biomass were judged to be important analytic needs for energy decision makers.

B.6.4 Biomass-Liquid Fuels

The potential for liquid fuels production from biomass is based to a large extent on the resource availability and economic competitiveness of the overall fuel cycle. To produce liquid fuels, which include ethanol, methanol, and gasoline from energy crops, economic assessments are based on conceptual designs since no commercial plants are operating. Market penetration projections for these technologies are subjective in nature. Ethanol from grain crops, primarily corn, is a commercial technology and currently contributes 0.07 quad of energy. However, this industry is heavily subsidized to be competitive.

B.6.4.1 Ethanol from Corn

Approximately 850 million gallons/year of ethanol are currently produced from corn, with a selling price of about $1.28/gallon. Newer facilities incorporate technology improvements that result in somewhat lower costs.

Using data for available farm land, SERI estimates that more than 5 billion gallons of ethanol/year could be produced from corn. These calculations assume that conventional uses for corn, such as animal feed, would continue at current levels. The National Advisory Panel on Cost Effectiveness for Fuel Ethanol Production estimates that up to 3.4 billion gallon/year could be produced by 1992 under a rapid growth scenario. This white paper does not estimate potential past 1992.

B.6.4.2 Ethanol from Woody Biomass

The potential for producing ethanol from woody or herbaceous biomass is based on significantly different assumptions than for producing ethanol from corn. First, the potential biomass resource is much larger than corn. Estimates for the availability range from 17 to 55 quads. At approximately 50% conversion efficiency, the maximum potential for ethanol ranges from 8.5 to 22.5 quads/year. The actual potential will be less than this maximum, due to competition for the resource by other fuel technologies such as gasification or combustion and possibly from the pulp and paper industry for feedstock.

The extent to which ethanol will achieve its potential will depend on cost. For instance, the Tennessee Valley Authority reports that ethanol costs would be about $1.25/gallon if an acid hydrolysis process is used to convert cellulose to fermentable sugars[14]. SERI estimates that, with additional research, ethanol can be produced, using enzymatic hydrolysis, for about $0.60/gallon by 2000[15]. A significant amount of technoeconomic analysis has been performed internationally on wood-to-ethanol processes. A recent report to the Canadian government indicates ethanol can be produced for $0.20-0.35/L in Canadian funds[16]. This is equivalent to approximately $0.59-$1.05/U.S. gallon in U.S. funds. Neither the SERI nor Canadian processes rely upon credits from by-product production to achieve these costs. Similar product costs have also been discussed by Austria and Sweden at workshops sponsored by the International Energy Agency (IEA)[17].

B.6.4.3 Synthetic Petroleum (Gasoline) from Biomass

Gasoline is currently produced almost entirely from petroleum. However, synthetic gasoline is currently produced in New Zealand and South Africa. The New Zealand process converts methane to methanol to gasoline using zeolite catalysts. The catalysts and product slate are similar to that in the wood-to-gasoline process. Zeolite catalysts are also used in the petroleum industry in catalytic cracking, visbreaking, and hydrocrackers to convert heavy crude oil fractions and processing bottoms into gasoline and diesel fuel components.

For the DOE program, technoeconomic assessments have been made that show gasoline can potentially be produced for about $0.85/gallon. Similar analyses have been produced by an IEA activity on biomass liquefaction[18]. This work incorporates recent results from Canada, Sweden, Finland, Italy, and other European countries. The international study uses costs representative of those obtained in the participating countries. Several of these costs, including feedstock costs, are higher in Europe than in North America. When adjustments are made in the IEA analysis to reflect reasonable costs, the gasoline product is projected to be about $1.00/gal, about 15% to 20% higher than the DOE program analysis.

B.6.4.4 Methanol from Biomass

The overall potential of methanol from biomass in terms of energy contribution is directly related to feedstock availability and the economic competitiveness of the conversion process. Over the years, biomass resource assessments have ranged from conservative annual estimates of about 10 quads of embodied energy to more optimistic estimates of more than 50 quads. The wide variations among estimates are attributable to assumptions involving land availability and biomass productivity.

Several technical and economic assessments have been prepared by the private sector for methanol production from selected biomass feedstocks. Since there are no biomass-to-fuel-methanol plants operating in the world, these analyses are based on conceptual processes. Considerable variation is noted in process flowsheets, plant sizes, feedstock costs, methods of financing, etc; hence, a wide variability in the ultimate product economics is observed. Estimates of costs of methanol from biomass, using today's technology, range from $0.60 to $1.70/gallon, depending on assumptions. For comparative purposes, methanol from natural gas is in the $0.45 to $0.60/gallon cost range, depending on the assumption made regarding natural gas prices. Estimates of the cost of methanol from coal range from $0.65 to more than $1.00/gallon. The goal of DOE's methanol from biomass program is $0.55/gallon ($8.30/MilBtu) based on a feedstock cost of $2.00/MilBtu and expected achievements in improving gas clean-up and yields and in methanol synthesis, as noted above.

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Appendix C
Geothermal Resources

C.1 Description of the Technology

C.1.1 Overview

Geothermal resources merit careful review because they represent a regionally significant, currently economical renewable energy technology. With the addition of advanced geothermal technologies, this resource offers a very large resource base, given only modest technology advances. Geothermal resources offer a replacement for fossil fuel energy generation with little environmental impact.

The U.S. geothermal industry is currently producing 2800 MW_e in base-load mode at 4¢ to 6¢/kWh. Geothermal resources are currently providing 7% of California's power, and are displacing 1700 MW_t of fossil fuels in heating and industrial applications at a cost savings of 25% to 35%.

The U.S. Geological Survey (USGS)[8] estimates sufficient resources are available to supply 23,000 MW of electricity capacity over 30 years using currently available technology. Full utilization of these resources can soon be achieved with modest technology improvements. If the technology for advanced geothermal systems such as hot dry rock, magma, and geopressure can be proven, a much larger, long-term resource will be available. Geothermal energy is an enormous resource base (estimated to be 100 million quads worldwide and as much as 10 million quads in the United States).

Using geothermal energy can improve national energy security, dependability, and flexibility for utilities, industrial, and residential users while reducing the U.S. balance of payments deficit through displacing imported energy resources and providing a significant opportunity for U.S. industry to export technology and equipment.

Geothermal power plants and direct-use applications have minimal environmental impact. Geothermal emissions do not contribute to smog or acid rain. CO_2 emissions are generally less than 5% of a typical coal plant, thereby reducing greenhouse effects. Binary technology can eliminate all emissions from geothermal power plants.

Geothermal energy can be tailored to fit demand and designed to come on-line quickly (2 to 5 years) in 1- to 100-MW_e modules for base-load electric power production. Direct-use applications can come on-line more quickly, offsetting fossil fuel use.

Technology issues include reducing risk in resource discovery, field confirmation, and reservoir management, as well as decreasing well completion costs, and improving binary processes for effective use of all geothermal resources. The size of the current geothermal industry and the magnitude of these technological uncertainties suggest that private enterprise alone cannot undertake such a program. The required aggressive research and development (R&D) program can only be done with government support.

C.1.2 Geothermal Technology

Geothermal energy has its source in the natural heat of the earth. This energy can be used directly for heat or converted to electricity. The accessible temperatures of resources in general use are from 75°C for direct uses to 250°C for electrical generation. Heat pump technology uses geothermal resources with temperatures as low as 10°C.

The basic elements of a geothermal energy conversion system are (1) the production well, through which the geothermal resource is brought to the surface; (2) the conversion system, which converts the geothermal energy to useful energy; and (3) the injection well, through which the spent geothermal fluids are recycled back into the reservoir.

Three primary conversion technologies--dry steam, flash steam, and binary--may be employed to generate electricity, depending on the temperature and makeup of the geothermal resource. Conventional turbine generators of standard materials convert dry natural steam to power. Using natural steam eliminates the boiler used in conventional steam generator systems.

Flash steam technology is employed when the resource occurs as a high-temperature liquid (>200°C). The hot liquid is allowed to boil in a separator as pressure is reduced as the fluid reaches the ground surface. The steam is separated from the residual liquid and used to drive a turbine generator.

Binary cycles are used to generate electricity from hydrothermal resources not hot enough for efficient flash steam production (<200°C). This technology, which is still undergoing improvement, incorporates a "closed" system in which the heat of the geothermal liquid vaporizes a secondary working fluid for use in the turbine. Commercial binary power plants are operating in California, Nevada, New Mexico, and Utah.

Heat from geothermal resources can also be used directly for space heating, greenhouses, food and industrial processing, enhanced oil recovery, aquaculture, refrigeration, and recreation. Cogeneration (combined electricity generation and process heat supply) and the use of geothermal heat for feedwater heating in power plants are also possible using geothermal resources.

C.2 Current Status of the Technology

C.2.1 The Resource Base

The geothermal resource base is the usable heat contained beneath the earth's crust to a depth of approximately 10 km (30,000 ft). Assuming a temperature base of 85°C, this resource base is about 10 million quads for the United States and 100 million quads worldwide[1,12,13].

Thermal energy recoverable at the surface from identified hydrothermal systems greater than or equal to 90°C is estimated to be 380 quads[8]. Electrical supply capability producible from identified high-temperature (>150°C) systems is estimated, in the same publication, to be 23,000 MW for 30 years. The total of identified and undiscovered thermal energy in reservoirs of hydrothermal systems (systems greater than or equal to 90°C) to a depth of 3 km (excluding energy in national parks) is estimated to be 9000 quads. Recoverable thermal energy--2300 quads--could contribute 95,000-150,000 MW of electricity for 30 years and 240-330 quads of direct heat[8].

The geopressured-geothermal resource, the energy contained in overpressured reservoirs of hot water containing dissolved methane, is estimated by the USGS[8] to be 160,000 quads of thermal and methane energy in place. Of this, 0.25% to 2.6% is estimated to be recoverable.

Geothermal reservoirs, created by man-made fracturing in regions of deep crystalline rock (hot dry rock) or bodies of partially molten rock (magma), represent the largest part of the geothermal resource. Tester and others[12,13] estimate that 650,000 quads would be available from the high-grade hot dry rock resource (temperature gradients in excess of 45°C/km). The USGS[8] estimates the U.S. igneous-related accessible resource base to be 96,000 quads evaluated and more than 800,000 quads unevaluated.

Geothermal resources can also supply energy suitable for lower grade heating and processing. Assessment of the hydrothermal resource potential at lower temperatures (less than 90°C) indicates an identified accessible resource base of 25,000 quads and recoverable energy of 80 quads throughout the United States[11]. This resource estimate does not include an enormous amount of shallow groundwater that can be accessed using heat pumps. This estimate also excludes the lower temperature geopressured and hot dry rock resources.

C.2.2 State of Development

C.2.2.1 Hydrothermal Electric

Geothermal plants offer a viable base-load alternative to conventional fossil fuel and nuclear plants. For existing geothermal power plants, availability is 95%. This is in contrast to an average fossil fuel plant factor of less than 80% and 70% or less for nuclear plants. Designs for geothermal power plants are being evaluated to extend their use to intermittent and peaking power.

Conversion of high-grade hydrothermal resources to electricity has been commercialized since the early 1900s in Italy and since 1960 in the United States. These applications use natural steam or steam flashed from naturally occurring hot water. The plants are small (1-5 MW) to medium-sized (25-60 MW), with a few as large as 110 MW.

C.2.2.2 Advanced Technologies - Electric

The conversion of energy from geopressured, hot dry rock, and magma geothermal systems can be accomplished using the same conversion systems currently being used for hydrothermal resources. The 95% reliability and availability factors that have been demonstrated by hydrothermal systems are also expected to apply to the advanced systems.

Geopressured-Geothermal. The ability to produce geopressured-geothermal resources, to separate methane from the brine, and to control scale deposition has been demonstrated. Thermal, natural gas, and hydraulic energy in the resource can be converted to electricity using existing technology. The natural gas can also be introduced into a pipeline or used to produce methanol. Projected power costs using current technology range from 7.5¢/kWh to 16¢/kWh, depending on the resource temperature and resource life[10].

Hot Dry Rock. Much of the U.S. geothermal resource base of about 10 million quads can be commercially developed with advanced geothermal technologies such as hot dry rock (HDR). HDR is a man-made heat extraction system designed to create fractured reservoirs in hot regions of the earth's surface. Water is then pumped through these reservoirs, naturally heated, and brought back to the surface where the heat is converted to electricity or used in direct applications.

Current HDR research is focused on testing and evaluating a deep fractured rock system for at least a year to provide industry with key operational and economic parameters for future commercial plant development. Cost estimates indicate that 5¢/kWh is approachable with the necessary technology development.

Magma. Magma resources are at temperatures of 600° to 1000°C and can provide high-quality energy for efficient conversion to electricity. As in HDR, water would be injected into the subsurface to extract the heat. Surface conversion equipment would be similar to that now used in the hydrothermal power industry with its demonstrated reliability. Laboratory and analytical studies suggest that heat extraction from the magma body itself should be efficient. Field experiments are needed to confirm reservoir dynamics, drilling techniques, and energy extraction efficiencies. Estimates suggest magma energy costs may approach the 4.5¢ to 8¢/kWh costs of conventional coal-fired and current nuclear energy.

C.2.2.3 Direct Use

Geothermal could displace fossil fuels for heating and industrial applications. The geothermal production field, which includes wells, pumps, and collection pipes, replaces the boiler in a conventional heating system. A recent evaluation of geothermal district heating systems prepared by the Oregon Institute of Technology[7] indicates that geothermal fluids are being economically delivered at costs from 66% to 75% of current natural gas or fuel oil prices.

C.2.3 Current Deployment

As of 1987, 5000 MW of electrical generating capacity was on-line in 17 countries, with an additional 1700 MW_e under construction or in advanced planning[2]. The United States had the largest installed capacity, with 92 units in four states totaling 2200 MW_e. The expected 1989 installed capacity in the United States is 2900 MW_e[1].

Direct-heat use of geothermal resources worldwide totals 0.5 quad/year[4]. Direct-use projects in the United States have principally used hydrothermal resources in the western states, but applications are documented in 44 states. In 1988, the annual direct-use capacity in the United States reached 1700 MW_t[5]. About 54% of this capacity was used for industrial applications, 28% for space heating, 10% for agriculture and aquaculture, and the remainder for commercial resorts[7]. In the near term, greatest growth is expected in geothermal heat pumps (10% to 18% average annual growth during the next 20 years), resulting in as much as 0.15 quad/year of energy being supplied[6].

Engineering feasibility has been demonstrated for geopressured-geothermal and hot dry rock energy extraction. Since 1985, 700 million standard cubic feet of natural gas have been produced from two geopressured wells in the Gulf Coast region. A 1-MW_e demonstration power plant that converts thermal energy and methane to electricity came on-line in late 1989. Two hot dry rock field programs, one in New Mexico and one in Britain, are currently being conducted. Research programs in Japan, France, West Germany, and the Soviet Union are under way. Drilling of a magma test well in California began in mid-1989 as a first step to confirming magma and recovery technology. These advanced systems are at a stage where further field testing and demonstration are essential to transfer the technology to U.S. industry for commercial implementation.

C.2.4 Relation of Technology to Today's Competitive Markets

Geothermal power costs are highly dependent on resource characteristics such as temperature, depth, fluid chemistry, and ease of drilling. Electric power from The Geysers in northern California, using dry steam, is competitive today. According to the president of Pacific Gas & Electric (PG&E), "geothermal is second only to hydro as the cheapest source of energy in the PG&E system." The less expensive flash-steam hydrothermal plants produce electricity at about 4.5¢ to 6¢/kWh; a fraction of these resources are near that economic threshold.

Hydrothermal resources are used today at a limited number of sites in the western United States. Where steam is the fluid produced from the ground, the resource is competitive relative to other energy sources with no tax or contract incentives. The systems that produce hot water are being brought into production under outstanding contracts signed with utilities to purchase electricity at attractive rates. It is uncertain how rapidly geothermal power will come on-line after these outstanding contracts have been fulfilled.

Penetration of cost-competitive geothermal power into the marketplace has been slowed by the lack of acceptance by utilities, land use restrictions, and performance uncertainties, as well as the general lack of new power needs in the geographic region in which hydrothermal resources exist. It is difficult, however, to differentiate clearly between the cost and institutional factors that adversely affect market potential.

C.2.5 Supporting Industry

The geothermal industry draws heavily on the existing oil and natural gas service infrastructure for field development and engineering. Much of the research needed to develop technology specifically for geothermal is not conducted because of the small size of the industry and restricted market for geothermal-specific technology. On the other hand, much of the technology developed by the geothermal industry has been rapidly accepted by the oil and natural gas industries. Significant savings ($300 million to $500 million per year) in drilling costs have been realized by the oil and natural gas industries as a result of geothermal sponsorship of improved drilling technology.

Turbine generator sets are the major hardware items needed to develop a geothermal project. Equipment currently supplied in the United States for vapor-dominated or flash steam plants is primarily of Japanese manufacture. U.S. manufacturers are active in the binary plant market, although Israel supplies most small-scale turbines.

C.2.6 Attitude and Practice of Regulatory Commissions and Utilities

Regulatory commissions are chartered to provide reliable, low-cost power to consumers (through the utility grids). Given the current energy climate, particularly of excess electrical capacity in the western United States, there is little incentive for utilities to support new resources if the resources are uncertain or do not fit the existing power network.

Utility commissions such as those in California have had the foresight to provide a balanced energy supply through special contract offers that spurred development of many renewable resources. However, the combination of a perceived capacity surplus and public concern about new development is curtailing the provision of additional special offers and will probably slow further development of renewable resources.

C.3 Constraints and Opportunities

C.3.1 Institutional Constraints

Geothermal systems have the advantages of low operating and maintenance costs, high plant capacity, rapid cash flow, low environmental impact, and a flexible load capability. The "not-in-my-backyard" syndrome is as true for geothermal as it is for other energy resources. Geothermal has an advantage over other energy technology options because land usage is confined to a single site, no fuel or wastes are transported off-site, and environmental impacts of a well-managed system are minimal. However, development of some geothermal sites has been restricted because of perceived scenic values, wildlife management issues, or other environmental concerns.

The inability to assure production for 30-year periods leads to high investor risk and, therefore, high finance rates to developers. In addition, uncertainty in tax structures, regulations, and pricing policies leads to investment uncertainty and cost. Research on reservoir characterization could reduce this risk.

The small, independent geothermal power producers do not fit into the current mold of large, utility-controlled systems. In addition, a significant portion of power to the grid from independents can lead to significant perceived reliability problems, which are the responsibility of the utilities. Consequently, some utilities are reluctant to accommodate the geothermal power producers and may present obstacles to their wheeling of geothermal electricity across the power networks. The utilities have, of course, developed a significant amount of geothermal power under their ownership and control.

C.3.2 Technological Constraints

The principal technological constraints that restrict development of the resource include the risk associated with discovery of the resource, verification of reservoir size, projection of long-term reservoir performance, maintaining well integrity, long-term operational uncertainties, and conversion of the resource to a usable energy form. The geothermal industry is limited in its ability to solve these technological problems because it is composed of small firms (with a few exceptions) whose principal and, generally, only business is the development of geothermal resources.

The industry uses oil and gas technology for exploration, well drilling and completion, and reservoir characterization. However, because of the limited geothermal market, the oil and gas industry is not willing to develop specific geothermal technology. The high-temperature geothermal environment has provided many modifications to existing oil and gas technology. These modifications have been utilized immediately in oil and gas operations, thereby improving the competitiveness of the oil companies and their service industry in the world market. Significant technology transfer to the petroleum industry has already occurred in the areas of diamond drill bits, high-temperature instrumentation, and reservoir fracture diagnostics.

Current expectations for improved geothermal operations resulting from DOE-sponsored research are a 30% to 40% reduction in the cost of producing power from hydrothermal resources[3]. However, these goals will not soon be reached unless a more aggressive program of research is funded. The projected technology improvements and concomitant cost reductions are expected to enable a near-term increase in electrical power generation of about 4000 MW_e from conventional hydrothermal resources. These expectations can be substantially exceeded if technology improvements were to increase confidence in the advanced concepts such as geopressured, hot dry rock, and magma resources.

An aggressive federal program could be encouraged by combining both public and private funding sources related to the much larger petroleum industry. The geothermal industry and DOE have agreed to conduct joint research and are currently pursuing several cost-shared projects. The lack of accurate techniques to find and predict performance of hydrothermal reservoirs adds to the cost of developing resources, because of the increased expenses of financing and the drilling of unneeded wells. The lack of reliable predictive techniques also inhibits the development of geopressured, hot dry rock, and magma technologies. Improved resource exploration and reservoir confirmation technology could result in possible cost reductions of 15% to 22% for reservoir characterization.

Drilling, completing, and operating geothermal wells are other areas in which substantial cost reductions could be achieved. Accelerated research on high-temperature equipment, corrosive resistant materials, and improved lost circulation control would enhance the ability to develop this resource. Improved technology could yield possible cost reductions of 15% to 20% in well-related costs for hydrothermal systems and as much as 25% to 40% for the advanced concepts.

Although large-scale binary cycle technology has been tested, the technology is now only marginally economic. Further efficiency improvements are needed to fully exploit moderate-temperature resources and to bring the advantages of zero-emissions and conservation of reservoir fluids. Improved operating efficiency of binary conversion systems can gain possible cost reductions of 17% to 28%.

The research needed is divided into research generic to all geothermal resources (exploration, drilling technology, reservoir engineering, energy conversion, etc.) and research and demonstration projects specific to the advanced technologies of geopressured, hot dry rock, and magma.

If successful, this aggressive program could reduce the cost of producing electricity from hydrothermal resources by 30% to 40% and, when coupled with demonstration of the productivity of advanced resource concepts such as geopressured, hot dry rock, and magma, where greater cost reductions are possible, would enable the development of these very large resources. An aggressive program of research, if carried to its completion, will result in costs to produce of about 3¢ to 7¢/kWh by the turn of the century as compared to costs of 4¢ to 15¢ for newly developed sites.

C.4 Potential Contribution of Geothermal Resources

Geothermal's potential contribution to U.S. energy supply, using the advanced resource concepts, is summarized for the United States in Tables C-1 and C-2 (dispatched electric in Table C-1 and stationary thermal, both industrial and buildings in Table C-2). Each table develops the quads of displaced energy, input energy, for three end use market applications. The first scenario, the Business as Usual (BAU) Scenario, represents market penetration levels that can be expected given projected energy prices and demand, with R,D&D continuing at current levels. The R,D&D Intensification Scenario assumes that RD&D funding is accelerated. The National Premiums Scenario assumes the equivalent of a price reduction for energy from renewable technologies, reflecting the value of heightened environmental and national energy concerns.

Basic cost data and resultant cost of energy (COE) employed in developing geothermal's contribution are summarized in Table C-3. The cost of energy, levelized costs stated in ¢/kWh, represents a plausible value given exploitation of the better quality resources. Of course, reservoir temperatures and flow rates, as well as depths of the resource, vary greatly among geographic locations. Each will influence regional costs, and hence the COE reported in Table C-3 represents our judgment as to representative values for the best resources.

Projections of the growth of geothermal power plant capacity in the United States can be made using historical trends and information about plants that are currently under construction or in the advanced planning stage. A base case average annual growth rate of about 4% is indicated during the next 20 years, assuming there are no changes in the price of oil or federal tax policies, and the current level of federal research continues. Continuation of current policies and funding levels for the advanced geothermal technologies would have little impact on generation capacity within this time frame, although some impact would be likely in later years.

An accelerated program of research as described in Section C.3.2 will impact the utilization of geothermal resources. Penetration of the resource into the market will be determined by reductions achieved in costs of development and increased acceptance of the resource, particularly the advanced resources, as a result of verification of these technologies through demonstration projects. The improvements in technology are based on a consensus of researchers and industry familiar with the DOE research program. (See for example *Geothermal Energy Technology: Issues, R&D Needs, and Cooperative Arrangements*,[9].) Potential decreases in costs associated with these improvements were based on calculations using economic models described by Entingh and others[3] and Testor and Herzog[12] and the authors' judgment.

If a national premium of 2¢/kWh is applied to energy technologies with minimal environmental impact, the effect would be to increase the geothermal resource base that could be economically developed. Hydrothermal resource development would be hastened, but the premium would not significantly shorten the development time for the advanced technologies. However, once a technology has been commercially demonstrated, further development would be accelerated.

In the BAU Scenario, (Table C-1), growth in electric geothermal production is projected to be fairly modest, increasing from 0.23 quad in primary energy to slightly more than 1 quad by 2030. With intensified R,D&D, geothermal electricity production increases to more than 4 quads (primary energy) by 2030. In the early years, under the National Premiums Scenario, electric production increases mirror those from an intensified R,D&D program. However, by 2020 that growth is much smaller than is projected in the Intensification Scenario.

Table C-1.
Electric Power Supply from Geothermal Resources

	Equivalent Primary Energy (quads)				
	1988	2000	2010	2020	2030
Business as Usual Scenario					
Hydrothermal	0.23	0.29	0.47	0.59	0.56
Geopressured		0.01	0.03	0.05	0.07
Hot Dry Rock		<0.01	0.02	0.10	0.27
Magma			<0.01	0.02	0.05
Total	**0.23**	**0.41**	**0.61**	**0.76**	**1.03**
R,D&D Intensification Scenario					
Hydrothermal	0.23	0.41	0.61	0.76	1.03
Geopressured			0.03	0.05	0.07
Hot Dry Rock		0.01	0.23	0.94	1.82
Magma			0.05	0.49	1.24
Total	**0.23**	**0.42**	**0.92**	**2.24**	**4.16**
National Premiums Scenario					
Hydrothermal	0.23	0.39	0.61	0.69	0.81
Geopressured			0.05	0.07	0.10
Hot Dry Rock		<0.01	0.03	0.14	0.37
Magma			<0.01	0.03	0.06
Total	**0.23**	**0.40**	**0.70**	**0.93**	**1.34**

Table C-2.
Stationary Thermal Industrial and Buildings Energy
Supplied from Geothermal Resources

	Primary Energy (quads)				
	1988	2000	2010	2020	2030
Business as Usual Scenario					
Hydrothermal	.02	.03	.05	.07	.12
Geopressured					
Hot Dry Rock		.04	.05	.08	.11
Magma					
Total	**.02**	**.07**	**.10**	**.15**	**.23**
R,D&D Intensification Scenario					
Hydrothermal	.02	.06	.06	.12	.23
Geopressured		<0.01	.02	.06	.11
Hot Dry Rock		.05	.13	.32	.24
Magma		<0.01	.05	.20	.51
Total	**.02**	**.12**	**.26**	**.70**	**1.59**
National Premiums Scenario					
Hydrothermal	.02	.10	.14	.20	.29
Geopressured		.01	.03	.07	.12
Hot Dry Rock		.08	.23	.64	1.04
Magma			<0.01	.01	.03
Total	**.02**	**.19**	**.41**	**.92**	**1.48**

Table C-3.
Uniform Cost and Performance Data: Geothermal Electric Technologies

	Capital Cost ($1988/kW)	O&M (¢/kWh)	Capacity Factor	Fuel Cost ($/MilBtu)	Heat Rate Btu/kWh)	Levelized[a] Cost (¢/kWh)	Energy Supply (quads)
1989							
Hydrothermal							
- BAU	1800	1.8	80%	--	--	4.4	0.23
- R,D&D	1800	1.8	80%	--	--	4.4	0.23
Geopressured							
- BAU	3200	2.9	80%	--	--	7.5	
- R,D&D	3200	2.9	80%	--	--	7.5	
Hot Dry Rock							
- BAU	2800	2.5	80%	--	--	6.5	
- R,D&D	2800	2.5	80%	--	--	6.5	
Magma							
- BAU	8300	10.0	80%	--	--	21.9	
- R,D&D	8300	10.0	80%	--	--	21.9	
2000							
Hydrothermal							
- BAU	1700	1.8	80%	--	--	4.2	0.29
- R,D&D	1600	1.8	80%	--	--	4.1	0.41
Geopressured							
- BAU	2700	2.6	80%	--	--	6.5	
- R,D&D	2600	2.4	80%	--	--	6.1	0.41
Hot Dry Rock							
- BAU	2500	2.3	80%	--	--	5.9	>0.01
- R,D&D	2200	2.0	80%	--	--	5.2	0.01
Magma							
- BAU	6100	8.0	80%	--	--	16.8	>0.01
- R,D&D	5100	5.0	80%	--	--	12.3	
2010							
Hydrothermal							
- BAU	1700	1.7	80%	--	--	4.1	0.47
- R,D&D	1500	1.5	80%	--	--	3.7	0.61
Geopressured							
- BAU	2200	2.4	80%	--	--	5.6	0.03
- R,D&D	2100	2.1	80%	--	--	5.1	0.03
Hot Dry Rock							
- BAU	2300	2.1	80%	--	--	5.4	0.02
- R,D&D	1800	1.6	80%	--	--	4.2	0.23
Magma							
- BAU	4600	6.0	80%	--	--	12.6	<0.01
- R,D&D	2600	4.0	80%	--	--	7.7	0.05

[a]Over 30 years at 6.1% discount rate (EPRI TAG)
(Levelized annual fixed charge rate of 0.1007).

Table C-3 (Continued). Uniform Cost and Performance Data: Geothermal Electric Technologies

	Capital Cost ($1988/kW)	O&M (¢/kWh)	Capacity Factor	Fuel Cost ($/MilBtu)	Heat Rate Btu/kWh)	Levelized[a] Cost (¢/kWh)	Energy Supply (quads)
2020							
Hydrothermal							
- BAU	1600	2.0	80%	--	--	4.3	0.59
- R,D&D	1300	1.4	80%	--	--	3.3	0.76
Geopressured							
- BAU	2000	2.2	80%	--	--	5.1	0.05
- R,D&D	1900	1.9	80%	--	--	4.6	0.05
Hot Dry Rock							
- BAU	2100	1.9	80%	--	--	4.9	0.10
- R,D&D	1600	1.4	80%	--	--	3.7	0.94
Magma							
- BAU	3400	4.5	80%	--	--	9.4	0.02
- R,D&D	1500	3.0	80%	--	--	5.2	0.49
2030							
Hydrothermal							
- BAU	1600	2.2	80%	--	--	4.5	0.56
- R,D&D	1200	1.3	80%	--	--	3.0	1.03
Geopressured							
- BAU	2000	2.0	80%	--	--	4.9	0.07
- R,D&D	1900	1.7	80%	--	--	4.4	0.07
Hot Dry Rock							
- BAU	2000	1.7	80%	--	--	4.6	0.27
- R,D&D	1400	1.3	80%	--	--	3.3	1.82
Magma							
- BAU	2100	3.0	80%	--	--	6.0	0.05
- R,D&D	1400	2.1	80%	--	--	4.1	1.24

Notes

[a] Over 30 years at 6.1% discount rate (EPRI TAG)
(Levelized annual fixed charge rate of 0.1007)

[b] Cost ranges can and do range quite widely for any new technology. Cost data used and presented here are representative of the lower end of possible values, with the geographic region, quality of the reservoir (e.g., temperature and flow rate), and power plant selection playing crucial roles in final dollar values.

[c] Major capital cost components include exploration, wells, reservoir stimulation, fluid distribution and power plant. Capital costs are rounded to nearest hundred dollar increment.

[d] Includes the traditional O&M expenses (e.g., labor and supplies), as well as redrilling and additional well requirements throughout project life, and make-up water costs where appropriate.

[e] Fuel cost component is not relevant for geothermal. Heat rate will vary depending upon reservoir temperature. Higher temperature reservoirs will generally be developed first. For example, for HDR we have assumed a reservoir gradient of 70°-80°C/km to a depth of 3 km.

Table C-3 (Concluded).
Uniform Cost and Performance Data:
Geothermal Electric Technologies

1990-2000

- Only marginal cost reductions expected in the base case for all geothermal technologies, with geopressure benefiting somewhat more than others.

- Enhanced R,D&D activities, such as completion of long-term flow tests at Fenton Hill for HDR and successful completion of drilling tests at Long Valley for magma, result in measurable decreases of drilling costs. Improvements in other cost components are also noted.

- Costs continue to fall as some research programs are brought to fruition in the base case. Magma and, to a lesser extent, geopressure gain most.

- Drilling costs are reduced 25% to 50%, reservoir stimulation costs fall 15% to 30%, and power plant costs are reduced 10% to 20%. In addition, O&M expenses are lowered because of improvements in operations. Most demonstration programs for HDR are completed, with hydrothermal efforts being refocused on extending the economic life of existing reservoirs. Magma research continues to emphasize drilling at depth and commercial systems development.

2010-2020

- Operating experience for geopressure and HDR result in small cost reduction gains for the base case. Successful magma demonstration results in lower drilling and power plant costs. Hydrothermal costs for drilling continue to fall, but lower quality reservoirs (aging lower flow and temperature) will likely result in higher total costs. Except for magma, most R,D&D activities are coming to a close. All demonstration programs were completed. Further reductions in drilling costs continue because of exploitation of past R,D&D and increased experience in working differing geologic media. Reservoir stimulation costs continue to fall as past research is put into practice. Improvements to power plant costs continue as better understanding of optimized systems occurs from increased production and focused research.

2020-2030

- Operating experience and some base level of research continue to result in cost reductions for all technologies but hydrothermal in the base case. (Utilization of lower quality reservoirs for hydrothermal increases its total cost.)

Displacement of fossil fuels with lower temperature hydrothermal resources is expected to continue at a low growth rate, with the current displacement of nearly 0.019 quad increasing to about 0.05 quad by 2010. Accelerated R,D&D will have little impact until the advanced technologies have been proven. With cost-shared demonstration programs, coupled with effective technology transfer, tax credits, low-cost loans, and federal/industry resource confirmation programs, an additional 0.16 quad could be on-line by 2010.

As noted in Figures C-1 through C-4, estimated penetration of geothermal technologies in the electric utility markets, even when taken as a whole, is generally quite low. The economic potential, based upon estimates of the regional costs of energy, both fossil and geothermal, for all but the western United States remains significantly below requirements. Hydrothermal, magma, and HDR technologies are all available in the western United States and under an intensified R,D&D scenario, the economic potential of geothermal is significant. The southern United States benefits from geopressured resources, while the North Central and Northeast regions enjoy only HDR technology opportunities. Estimated penetration forecasts for each region, under all three scenario constructs, have been conservative. In all cases, except the intensified R,D&D scenario for the western United States where three of the four geothermal technologies are utilized, geothermal's contribution to both requirements and economic potential is generally less than 10%. While this is a relatively low number, it represents a significant improvement over geothermal's current contribution. Moreover, a conservative estimate of penetration leaves capacity for greater exploitation of geothermal resources if other energy supply options do not prove viable or are judged unacceptable for environmental or other reasons.

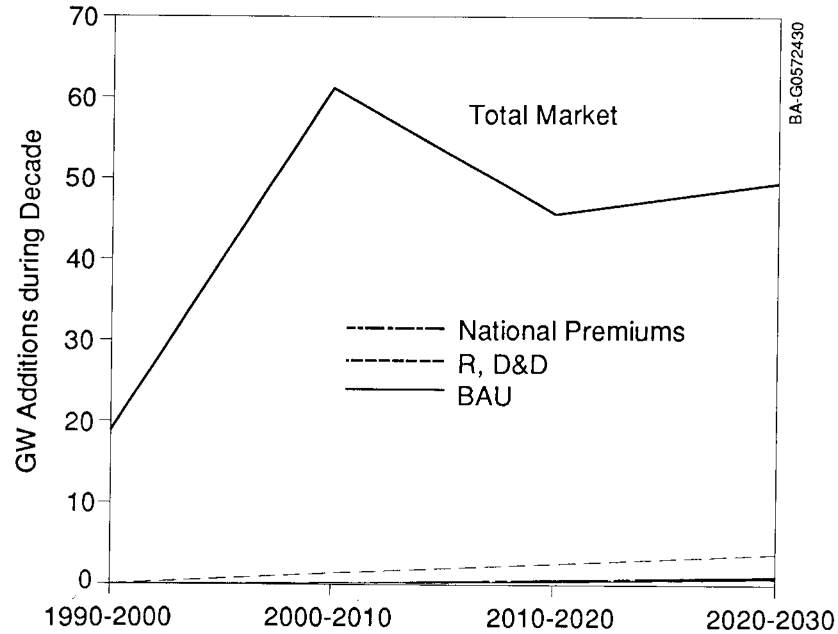

Figure C-1. Geothermal electric incremental market penetration (Northeast)

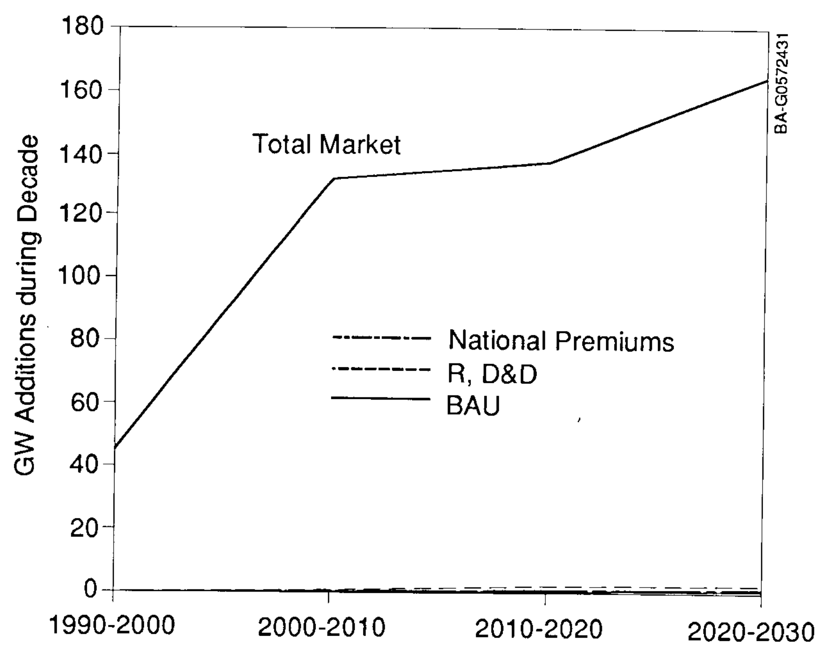

Figure C-2. Geothermal electric incremental market penetration (South)

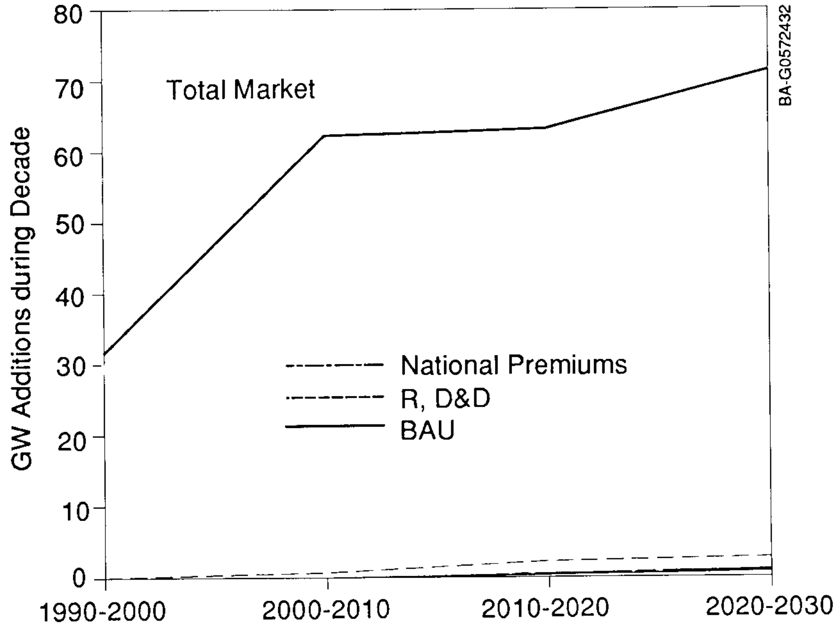

Figure C-3. Geothermal electric incremental market penetration (North Central)

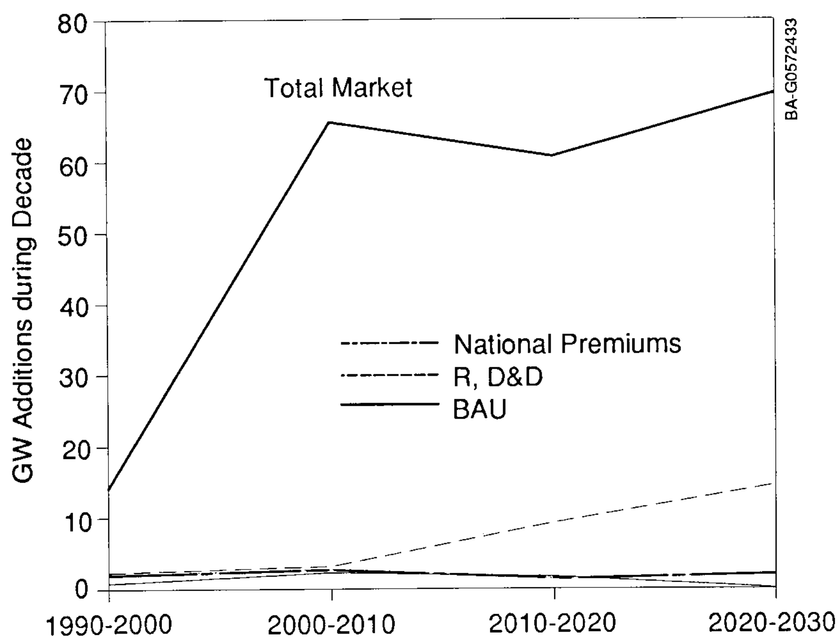

Figure C-4. Geothermal electric incremental market penetration (West)

The values shown in Table C-4 suggest the best resources will be exploited. The wide range of values is due to geographic resource and technology-specific differences.

Table C-4.
Cost of Energy, Geothermal Direct Use ($/MilBtu)

	1990	2000	2010	2020	2030
Business as Usual Scenario	6-10	5.25-9	4.80-8.50	4.50-8.25	4.25-8.00
National Premiums Scenario	4-8	3.50-7	3.10-6.75	2.75-6.50	2.50-6.50
Intensified R,D&D Scenario	6-10	4.90-8.75	3.80-8.00	3.30-7.50	3.70

The lower end of the ranges in Table C-4, especially in the later years, is much lower than competitive process or commercial heat provided by fossil fuels, but applications are limited because of the mismatch of demand center locations and resource sites.

C.4.1 Hydrothermal

For the electric utility market category, hydrothermal resources are developed only in the western United States, although some potential does exist for development of resources in other regions of the United States. Because the known higher temperature resource base is predominantly in the western United States, costs of electricity from hydrothermal production are competitive for further base-load electrical development.

Stationary industrial potential for geothermal rests on its use as a thermal resource, both directly as in current enhanced oil recovery operations, and indirectly as an economical source for process heat applications.

Energy costs and demand center locations are as important as the resource base itself. Moreover, increased geothermal cogeneration activity beginning around 2010 will contribute to stationary industrial thermal markets. Thermal production begins in the western United States, followed by the Northeast and the South, then the North Central region. During 2010 to 2020, energy from geothermal industrial thermal applications in the Northeast exceeds those of the West. For every time period, combined production from the West and Northeast regions greatly exceeds that from the South and North Central regions.

Stationary thermal use of geothermal by the buildings sector, although relatively small, sees greater development in the Northeast early on, followed by the West, with the South and North Central regions providing only minimal contributions by 2030. A significant portion of this development is expected to be geothermal heat pumps. Lund[6] suggests a yearly increase of 10% to 18% in their use during the next 20 years, resulting in 740,000 to 2,900,000 units installed by 2010.

C.4.2 Geopressure

Geopressured-geothermal development for all three market segments is focused in the Louisiana and Texas Gulf Coast, where the majority of resources are located.

C.4.3 Magma

Magma energy development for the electric sector, process heat, and cogeneration occurs only in the West.

C.4.4 Hot Dry Rock

HDR geothermal development centers first in the West, where the most is known about the resource base, first for the electric power sector. Extensive production in the Northeast will follow due principally to energy process and electric demand growth. HDR electric production also occurs in the South, then North Central region, as 2020 and 2030 are approached under the R,R&D Intensification Scenario. Thermal production from HDR is centered more in the Northeast in the early years due to demand centers' colocation with the resource.

C.5 Contribution to National Goals

C.5.1 Environmental Integrity

Hydrothermal resources using binary conversion technology produce no emissions. Emissions from steam and flash plants contain no smog- or acid-rain-causing pollutants. Sulfurous gases, as contained in the reservoir fluids produced at The Geysers, are effectively removed by existing scrubbing technology. The release of CO_2 from these plants is less than one-tenth that released from fossil fuel plants.

In some geothermal systems sludges bearing hazardous metals are formed during flash steam operations. Research is currently under way using biotechnology and other methods to remove these metals from the sludge and, perhaps, recover the metals for beneficial use. Although this sludge is of concern in the Imperial Valley, California, geothermal systems elsewhere in the United States do not have similar solid waste disposal problems. Utilization of binary technology would alleviate this concern as well as the potential release of CO_2 and sulfurous gases.

C.5.2 Security

Development of geothermal resources in the United States means development of an indigenous resource that is not subject to supply interruption or the actions of foreign governments. Development of geothermal resources internationally would contribute to lower demand for fossil fuels, which will have a beneficial effect on the generation of greenhouse gases and reduce the demand for increasingly scarce liquid fossil fuels.

C.6 References for Appendix C

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Appendix D
Ocean Energy Technologies

The ocean contains vast energy potential in its waves, in its tides, in the temperature difference between cold, deep waters and warm surface waters, and in the salinity differences at river mouths. Waves are a power source for which numerous systems have been conceived. The gravitational pulls of the sun and moon and the earth's rotation work together to cause the ocean's tides, another potential source of energy. The ocean also acts as a gigantic solar collector, capturing the energy of the sun in its surface waters as heat. The temperature difference between warm surface waters and cold water from the ocean's depths provides a potential source of energy. The following sections describe the status of the various ocean energy technologies; ocean thermal energy conversion (OTEC), which has greater near-term potential and broad applicability, is emphasized.

D.1 Ocean Thermal Energy Conversion

D.1.1 Description of the Technology

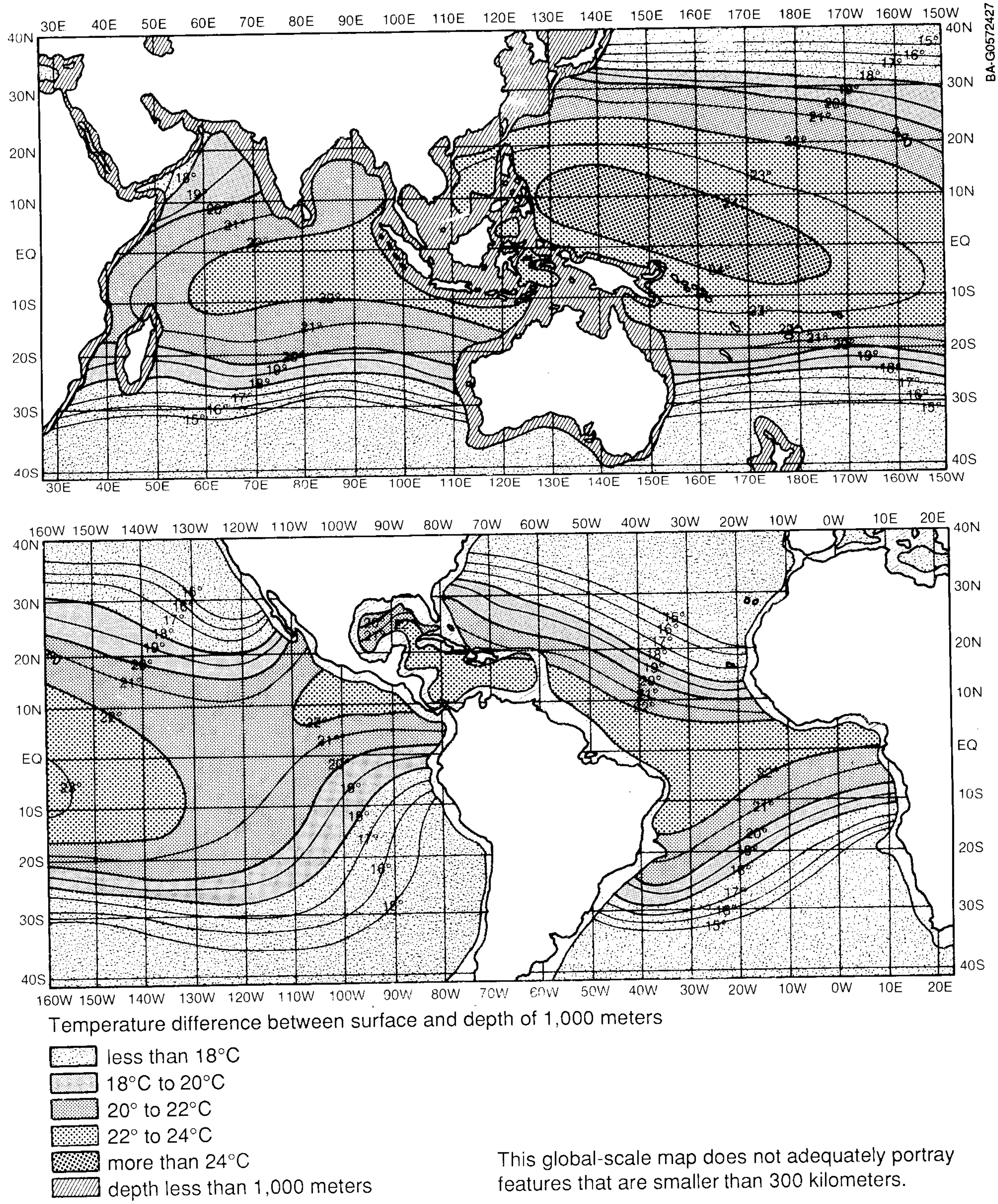
Ocean thermal energy conversion (OTEC) technology is based on the principle that energy can be extracted from two reservoirs at different temperatures. A temperature differential as small as 20°C can be exploited effectively to produce usable energy. Temperature differences of this magnitude prevail between ocean waters at the surface and at depths up to 1000 m in many areas of the world, particularly in tropical latitudes between 24 degrees north and south of the equator (see Figure D-1). Here, surface water temperatures typically range from 22° to 29°C, while temperatures at a depth of 1000 m range from 4° to 6°C. This constitutes a vast, renewable resource, estimated at 10^{13} W, for baseload power generation.

Research efforts have concentrated on two OTEC power cycles for converting this thermal energy to electrical energy, namely, closed-cycle and open-cycle[1]. In a closed-cycle system, warm seawater is used to vaporize a working fluid, such as ammonia, flowing through a heat exchanger (evaporator). The vapor expands at moderate pressures, and turns a turbine. The vapor is then condensed in another heat exchanger (condenser) using cold seawater pumped from the ocean's depths through a cold water pipe. The condensed working fluid is pumped back to the evaporator to repeat the cycle. The working fluid remains in a closed system and is continuously circulated. In an open-cycle system, warm seawater is the working fluid. The warm seawater is "flash" evaporated in a vacuum chamber to make steam at an absolute pressure of about 2.4 kilopascals (kPa). The steam expands through a low-pressure turbine coupled to a generator to produce electricity. The steam exiting the turbine is condensed by using cold seawater pumped from the ocean's depths through a cold water pipe. If a surface condenser is used, the condensed steam remains separated from the cold seawater and provides a supply of desalinated water.

Effluents from either a closed-cycle or open-cycle system can be further processed to enhance production of desalinated water through a flash evaporator/condenser system in a second stage. Other proposed OTEC cycles, such as hybrid, mist lift, and thermoelectric have not been investigated extensively.

D.1.2 Current Status of the Technology

For electric power generation, utilization of the OTEC resource is focused on domestic coastal areas of the Gulf of Mexico and Florida, and islands such as Hawaii, Puerto Rico, and the Virgin Islands. International regions of interest include a larger number of island nations and tropical coastal areas. Although no commercial OTEC plants are operational today, significant progress has been made in research. Concepts for land-based, near-shore, and floating plants have been studied. Land-based and near-shore facilities in the size range of 1 MW_e to 15 MW_e are considered the most probable for early OTEC market penetration[2]. Near-shore and floating plants are projected to be economically viable in the mid-term. Long-term use of OTEC is envisioned as floating self-propelled plantships that would manufacture energy-intensive products such as hydrogen, ammonia and methanol (see, for example,[3].



This global-scale map does not adequately portray features that are smaller than 300 kilometers.

Figure D-1. Worldwide distribution of the ocean thermal resource

The following major accomplishments of OTEC R&D deserve to be noted.

- The United States first demonstrated the production of net power using a 50 kW_e closed-cycle OTEC plant operating off a floating platform; the Japanese followed with a shore-based 100 kW_e closed-cycle OTEC plant.

- The design methodology for suspended cold water pipes was validated.

- Materials research has demonstrated that aluminum alloy can be used in place of more expensive titanium in making large heat exchangers for the OTEC systems.

- At-sea tests demonstrated that heat exchanger biofouling and corrosion can be controlled. Biofouling appears not to be a problem in cold seawater systems and can be controlled with minimal intermittent chlorination in warm seawater systems.

- Scientists are developing cost-effective, state-of-the-art turbines for open-cycle OTEC systems.

- A test program of state-of-the-art industrial heat exchangers of 1 MW_t rating was concluded at Argonne National Laboratory (ANL). Linde, Trane, Carnegie Mellon University, and Johns Hopkins University participated in the program. Information was obtained on the thermohydraulic performance of various enhancements. Increases in the overall heat transfer rates by factors of three over plain tubes were achieved.

- Researchers at the Solar Energy Research Institute (SERI) developed a flash evaporator to convert warm seawater into low-pressure steam for open-cycle OTEC. Efficiencies as high as 97% were achieved. Direct-contact condensers using advanced packings have been demonstrated that provide an efficient method for the disposal of steam.

- Desalinated water was produced by using the open-cycle process at the Seacoast Test Facility, Hawaii, as a result of joint SERI/ANL efforts. This was the first time in the DOE Ocean Energy Program that, operating under prototypical conditions, desalinated water was produced.

- The deployment of a 1-m-diameter cold-seawater and a 0.7-m-diameter warm-seawater supply system at the Seacoast Test Facility was completed, demonstrating the feasibility of large polyethylene cold-water pipes for OTEC use.

- British researchers have designed and are testing aluminum heat exchangers that could reduce heat-exchanger costs to $1,500 per installed kilowatt capacity.

- A concept for a low-cost soft seawater pipe has been developed and patented, that could remove the size limitations and improve the economics of OTEC systems.

These accomplishments led the technical community to conclude that both cycles are feasible. However, there remain several issues to be addressed: (1) the development and demonstration of larger turbines, which can remove the size constraints on open-cycle OTEC plants; (2) the development and demonstration of cost-effective cold water supply technology for larger OTEC plants; and (3) the demonstration of OTEC (both open-cycle and closed-cycle) at pre-commercial sizes, which address scaling, operation, maintenance, reliability, and performance uncertainties.

U.S. industry has not implemented OTEC because of the aforementioned issues and the capability of competing technologies to produce electricity at lower costs. The limited interest in OTEC also stems from the power industry's preference for investing in power plants of proven designs. Potentially, as crude oil prices reach $35 to $40 per barrel, large OTEC plants may become attractive for generation of electricity. However, the cost of transporting oil to some island nations in the Pacific makes OTEC potentially competitive today. If value is attached to by-products such as the desalinated water, OTEC appears to be economically attractive today for specific island markets[4].

Economic analysis indicates that, over the next five to ten years, OTEC may become competitive in four markets. The first market is the small island nations in the South Pacific or the island of Molokai in Hawaii, where the cost of diesel-generated electricity and desalinated water is such that a small (1 MW_e) land-based, open-cycle OTEC plant coupled with a second-stage desalinated water production system could be cost effective today based on engineering estimates of system capital and operating costs and process efficiencies. A second market is U.S. territories such as Guam and American Samoa, where land-based, open-cycle OTEC plants rated at 10 MW_e with second-stage water production systems might be cost effective with credit for desalinated water. A third market may be viable for a larger land-based, closed-cycle OTEC plant on some Hawaiian islands to produce electricity with a second stage desalinated water production system. OTEC becomes cost effective in this market with a doubling of the cost of diesel fuel and for plants rated at 50 MW_e or larger. A fourth market may some day consist of floating, closed-cycle plants, rated at 40 MW_e or larger, that house a factory or transmit electricity to shore via a submarine power cable. Such plants could be used in Puerto Rico and the Gulf of Mexico, and the Pacific and Atlantic Oceans. The military and security implications of large floating plantships having major life-support systems (power, desalinated water, cooling, and aquatic food) supplied by OTEC systems should also be considered in this category.

D.1.3 Constraints and Opportunities

D.1.3.1 Institutional

No major institutional constraints to the utilization of OTEC have been identified since the technology is still in its early stages. In the long run, unresolved technological issues, such as the distribution of coproducts, may pose significant institutional constraints. Some uncertainties relative to environmental impact and regulatory issues remain because the required quantitative measurements cannot been made before construction of a pre-commercial plant (i.e., 500 kW_e). The primary environmental issues are on the trajectories, dispersion, and dilution of the seawater effluents and the character and quantity of dissolved gases in the seawater. While these potential environmental impacts must be investigated, it is believed that engineering will provide cost-effective solutions. There is a need for quantitative data to assess what control measures may be appropriate.

A financial constraint is the development of a U.S.-OTEC industry capable of meeting the substantial OTEC market potential. The Japanese have formed an OTEC group called the Ocean Thermal Energy Conversion Association (OTECA) precisely to capture this market. Efforts from the United States could be in the form of: accelerated funding for the current federal program to ensure an operating open-cycle OTEC plant by the mid-1990s; construction of a pre-commercial-sized OTEC plant of 1 MW_e net; and continued research required to remove the critical technical impediments to the development of larger-sized plants.

Since OTEC is an emerging technology in its early stages, potential infrastructural constraints are yet to be identified. They may include (1) problems of integrating OTEC plants into island electrical systems, particularly if large OTEC plants are required to achieve economic performance; (2) integrating OTEC fresh-water systems into existing systems, while providing maintenance or emergency storage or backup; (3) integrating cooling systems with hotels, etc., while providing backup capacity; and (4) coastal right-of-way access for large water systems, that will distribute water to users, including return flows to the OTEC plants. Environmental issues may also be involved.

Perceptual constraints for the OTEC technology lie in the perceived risks associated with the reliability and long-term operation of the system. To encourage investments on the early development and market penetration of a capital-intensive technology, demonstration of the reliability of OTEC systems over periods comparable to payback periods--10 years or more--may be required. Significant R,R&D expenditures are required over the next decade to address issues related to scaling, operation, reliability, and performance uncertainties in demonstrations of closed-cycle and open-cycle OTEC systems at pre-commercial sizes.

The discussed constraints limit the development of OTEC technology even in regions where it appears to be economically viable today. The dependency of island nations and regions on imported oil may be prolonged with an increased drain on their economies. Alternately, these regions might become more energy self-sufficient within the next two decades using indigenous resources through accelerated development of OTEC. The Japanese program noted above is developing technology to address these markets.

Institutional decisions on meeting demands for other OTEC co-products, such as desalinated water described elsewhere, will enhance the opportunity for OTEC to penetrate baseload power generation applications.

D.1.3.2 Performance

The major constraint that remains on the performance of OTEC systems is the lack of operational data for energy production. All other constraints or issues can be resolved through the normal engineering design process--no major breakthroughs are required for the first generation of OTEC plants.

An OTEC system may be divided into three major subsystems: power, seawater, and support facilities. The apparent technical uncertainties in scaling the power and seawater subsystems represent major constraints to elevating OTEC to a viable energy production alternative. These two subsystems also offer the greatest opportunity for performance improvement and cost reduction. Advances in these two areas will yield the needed cost reduction in the third major subsystem, plant and structures. Therefore, in parallel with the construction of a demonstration plant for first-generation plants, to improve the competitive position of OTEC, a research and development (R&D) program must be carried out on innovative turbines for open-cycle OTEC to increase the size limit at least tenfold (from 2.5 MW to 25 MW), on cold water pipe materials and construction, on deeply submerged bottom pumps, and on the viability of innovative power cycles.

The design, construction, and operation of demonstration plants targeted to the identified markets should yield the needed operational data and experience toward commercialization. By the year 2015, a cumulative global market of $13 billion (1989$) could result from intensified R,D&D, including the building of demonstration plants.

D.1.3.3 Additional Values of Cold Water

The described markets do not consider other potential uses of the OTEC cold water. *Co-products of OTEC offer unique advantages not provided by any other renewable resource.* They not only provide an additional revenue stream, but also provide quality-of-life-enhancing aspects.

To improve the overall economics of the total OTEC system, recent development plans include utilizing the nutrient-rich, pathogen-free, cold water from the deep ocean. Products (in addition to electricity and desalinated water) include mariculture, greenhouses with temperatures controlled by cold water, and use of chilled water for air-conditioning. The entire system of co-products from OTEC has been developing at a faster pace than electricity, primarily because the private sector has been able to attract funding to carry out the pre-commercial work. There is great need, however, to package the total system for specific locations, since the quality and value of many of the co-products are site-specific.

Mariculture. The ability to provide flexible, accurate, and consistent temperature control; high-volume flow rates; and nutrient-rich seawater relatively free of biological and chemical contaminants leads to a natural synergism that can be translated into a marketable product. The cold seawater contains 200 times more nitrates and 20 times more phosphates than surface seawater. Marine life already grown in this environment at the Natural Energy Laboratory of Hawaii (NELH) include salmon, trout, nori (seaweed popular in the Japanese diet), opihi, lobsters, abalone, and both macro and micro algae. The values of these products are high enough that the costs of production can be recovered and profitability ensured--even considering the high cost of the deep-ocean pipeline.

Desalinated Water. The condensate from spent steam in OTEC systems is desalinated water suitable for human consumption and agricultural purposes. The market value of this water in the Pacific islands ranges from $0.40 to $1.60/m^3. The revenue from desalinated water is projected to offset the cost of OTEC electricity by as much as 12¢/kWh in South Pacific islands and 3¢/kWh in Hawaii.

Air-Conditioning/Refrigeration. The deep-ocean cold water can be used as a chiller and in air-conditioning systems. The facilities at the NELH are air-conditioned by passing the cold water through a heat exchanger[5]. The cold seawater delivered to an OTEC plant is suitable for use in chilled water coils to provide building space air-conditioning. For example, cold water from an OTEC electric power plant, when used to provide cooling, displaces more than 10 times its electric capacity for the air-conditioning load.

Agriculture. Another use of cold seawater is to place an array of cold water pipes on the ground to maintain a cool soil temperature. Atmospheric condensate external to the pipes provide continuous drip irrigation for crop growth. This method has been successful in the growth of cool-weather plants such as strawberries and lettuce at the NELH site.

Figure D-2 illustrates the additional values of cold water. The effective cost of electricity is reduced by the revenues from coproducts--desalinated water, mariculture products, and refrigeration. Depending on the extent to which products other than electricity are included, the electricity cost ranges in 1990 from 22¢ down to 8¢/kWh. Thus, OTEC combined with coproducts may be cost effective today for certain markets.

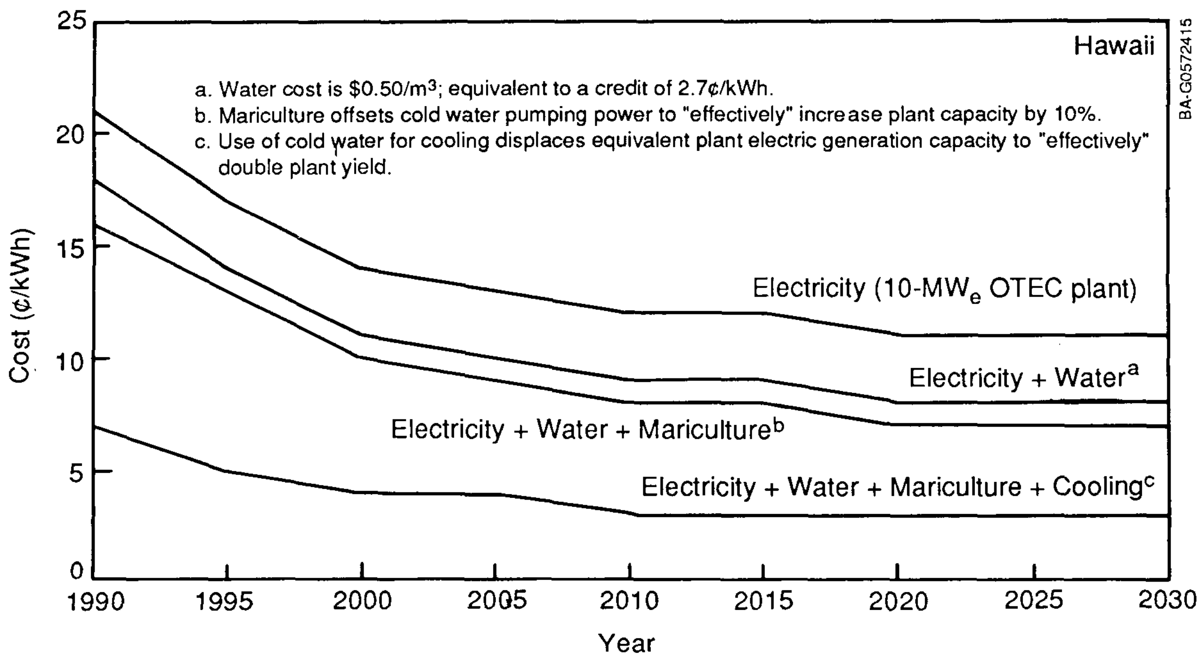


Figure D-2. Effective costs of electricity offset by the added value of coproducts

For developing tropical countries where OTEC is feasible, the social benefits from OTEC might far outweigh economic factors. Some of these benefits include energy self-sufficiency, minimal environmental impact, and improved sanitation and nutrition for inhabitants from desalinated water and mariculture products.

In the longer term, the market potential for energy-intensive products other than electricity from OTEC has also been examined. These products include methanol, ammonia, hydrogen, aluminum, chlorine, and other chemicals. Floating OTEC processing plants to produce such products would have economic advantages over anchored plants because they do not require a power cable, and station-keeping costs are reduced. Hydrogen electrolyzed from water could be used for synthesis of methanol or ammonia fuels, which would be transported to shore to displace nonrenewable fuels.

To accelerate OTEC development, the focus of research should be directed in the following areas: (1) obtaining data on the operation of OTEC with appropriately sized demonstration plants; (2) developing and characterizing cold water pipe (CWP) technology and providing a data base with respect to materials, design, deployment, and installation; (3) performing further research on heat exchanger systems to improve heat transfer performance and to decrease costs; (4) conducting research in the areas of innovative turbine concepts for large-size machines required for the open-cycle systems; (5) identifying and evaluating advanced concepts for ocean thermal energy extraction; and (6) increasing the involvement of the private sector to assess OTEC development and progress and guide future government-sponsored investigations in high-risk areas. These activities are projected to result in a 50% reduction in the costs from the current estimates for near-shore/land-based OTEC plants.

D.1.4 Contribution Potentials

D.1.4.1 Global

The greatest potential for OTEC is to supply a significant fraction of the world's fuel needs using large plantships to produce hydrogen, ammonia, or methanol. The development of such plants is impeded, however, by the large capital investment required and market uncertainties. Implementation awaits smaller scale demonstrations to reduce perceived risks.

Of the three worldwide markets studied for small OTEC installations--U.S. Gulf Coast and Caribbean regions, Africa-Asia, and the Pacific islands--the Pacific islands are expected to be the initial market for an entry point for open-cycle OTEC based on the cost of oil-fired power, on the demand for desalinated water, and on the social benefits from this clean energy technology. Continued research and development could open markets to OTEC in the Asia-Pacific region in the 1990s.

In 1981, a survey identified OTEC markets in 67 developing nations and U.S. territories[6]. The study also assessed the OTEC resource, technology, market, barriers and incentives to implementation of OTEC in developing nations. The United Nations Department of International Economic and Social Affairs also has recognized the potential for OTEC in the developing countries[7]. The World Bank indicated that dependence of developing countries on imported oil affects adversely the balance of payments for these nations and takes away valuable resources that could be otherwise used for developmental purposes. Recently, 26 Southeast Asia and Pacific island sites were surveyed to determine their potential for this renewable energy resource[8]. Total additional demand for power (over the base year 1987) projected for these islands for the year 2015 was 5000 MW_e. Potential OTEC sites were identified in these nations such that at least 800 MW_e of the additional power could be provided by land-based OTEC plants.

The potential for desalinated water and mariculture of open-cycle OTEC has prompted several Pacific island governments to conduct studies of the feasibility of this technology for their islands (see, for example,[9]). While the Pacific islands are currently dependent on imported fuel for electricity generation, fluctuations in the price of oil do not seem a major determinant in their decision to request these studies. Even the availability of an inexhaustible, renewable, clean source of energy does not seem to be as attractive as the potential benefits of desalinated water and mariculture for their economic development. The Asian and Pacific island nations seem to be more influenced by the potential hazardous impact of conventional energy resources on their environment. OTEC promises a source of clean energy and little adverse impact on the environment.

In summary, the Pacific and Asian islands offer a market for 1 MW_e to 100 MW_e OTEC plants. It is estimated that, globally, without major breakthroughs but with intensified R&D as described, at least 350 MW_e could be provided by OTEC by the year 2005, and 2100 MW_e by 2010. In the longer term, the production of methanol and hydrogen for transportation fuel uses may prove to be economically feasible and could raise this potential by a factor of five to the 10 GWe range.

The combination of unstable oil prices, growing environmental concern, need for water, and drive for economic self-sufficiency will interest various equatorial islands in considering OTEC as a development option in the 1990s. In the 21st century, higher energy prices and expanded applications for OTEC could result in large systems for processing seabed ores, producing fertilizer and transportation fuel, developing fisheries, and generating baseload electricity.

D.1.4.2 Domestic

The most likely U.S. market for OTEC systems consists of three segments: utilities in Hawaii and the U.S. island territories; utilities in the U.S. Gulf coast region; and producers of energy-intensive products. Of these three markets, the oil-dependent Hawaii and U.S. island territories with a rich OTEC resource are expected to be the initial market entry point for OTEC systems. Although this market is limited, it represents a significant base that would provide the necessary experience for U.S. industry to become competitive.

Military installations in the Caribbean and Pacific islands offer another market for both electrical energy production as well as utilization of the desalinated water production potential of open-cycle OTEC. One other market area in the islands that may have significant interest in open-cycle OTEC is hotel/resort development.

Under the intensified R&D scenario, the following program has been assumed:

- Research support during the immediate five-year period (1990-1995) for the development of

  (i) a system-level open-cycle OTEC experiment to validate the feasibility to produce net power,
  (ii) innovative turbines for the open-cycle OTEC to increase power level from 2.5 MW to 25 MW,
  (iii) cold water pipes, materials, and deeply submerged pump, and
  (iv) innovative power cycles such as mist lift and thermoelectric.

- Following successful completion of items i and iii, design, construction, and operation of a land-based 1-MW_e open-cycle OTEC facility with a second stage desalination plant.

- In the latter part of the 1990s, undertake

  (i) the design, construction, and operation of a land-based 5-MW_e closed-cycle OTEC facility with second stage desalination and, if successful, subsequently

  (ii) the design, construction, and operation of a 5-MW_e closed-cycle OTEC plantship.

The above-described research effort would require a sixfold increase from the current level of R&D expenditures over the next decade. Figure D-3 illustrates projected OTEC performance and the domestic market penetration potentials over the next 40 years. Intensified R&D provides accelerated opportunities for U.S. industries in the potentially large international markets. Credit for the potential added value of the cold water offsets part of the projected cost of electricity. Such values, however, are site-specific; the estimated offsets shown are for Hawaii.

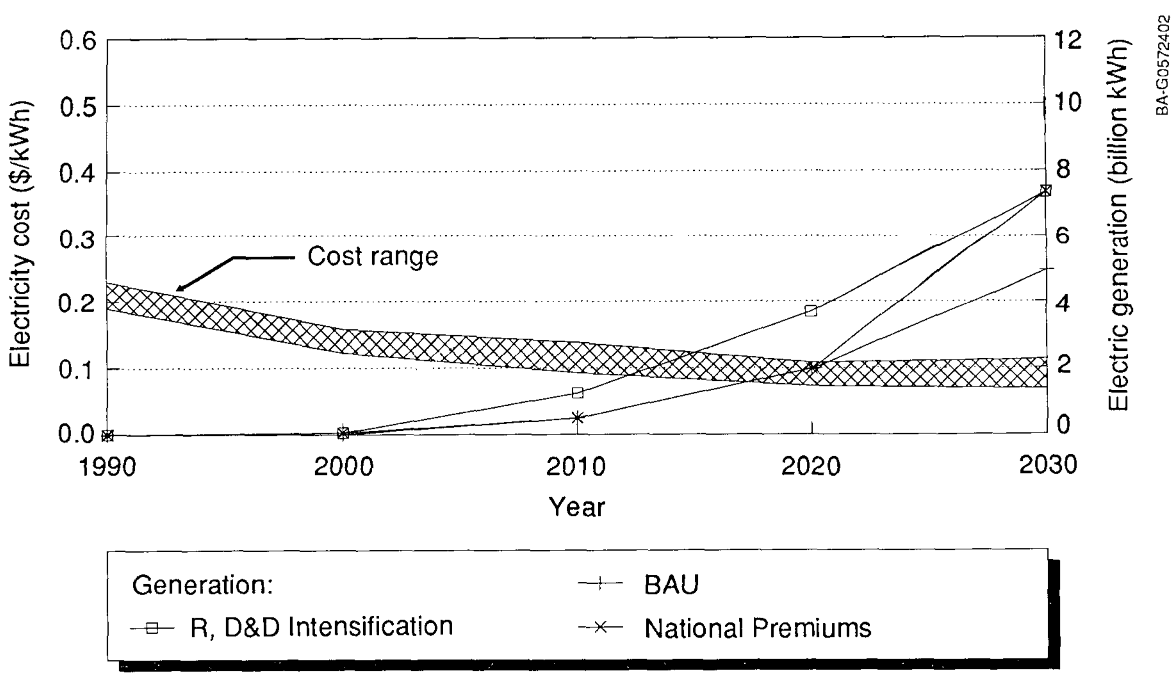


Figure D-3. Projected performance and cost and domestic electricity generation for OTEC

D.1.5 Contributions to National Goals

The value of an OTEC plant and continued OTEC development must be measured both by the economic and noneconomic benefits. These benefits can be categorized as follows and can be used as value indices in the evaluation of the technology.

D.1.5.1 Economic Benefits

The potential economic benefits from OTEC include production of fuels (hydrogen, ammonia, and methanol); production of base-load electrical energy; desalinated water for industrial, agricultural, and residential use; resource for on-shore and near-shore mariculture operations; building space air-conditioning; moderate temperature refrigeration; and significant export potential.

D.1.5.2 Noneconomic Benefits

The noneconomic benefits of OTEC, which facilitates achievement of environmental goals, are promotion of U.S. competitiveness and international trade, enhancement of energy independence and energy security, promotion of international socio-political stability, promotion of a significant presence of U.S. industry in Pacific and Asian-rim countries, and a potential for mitigation of greenhouse emissions.

D.1.6 Other Perspectives

Development of low-cost heat exchangers by British engineers, together with soft seawater pipe implementation have the potential to reduce OTEC capital costs to $2,000 to $2,500 per installed kilowatt capacity, substantially less than the cost estimated in this paper. Under such circumstances, OTEC could become the preferred renewable energy option for all markets where OTEC is feasible.

Other technologists have projected that large floating plantships up to 500 MW_e can be realized and may yield electricity at costs as low as 2¢/kWh[20].

D.2 Wave Energy

The greatest wave energy potential is found on the coasts of Washington, Oregon, and California. Mean incident energy is estimated to be 40 to 50 kW/m. During the summer the intensity decreases to less than 10 kW/m. Winter storms cause larger increases reaching intensities of over 200 kW/m. These large waves cause safety problems, and also large design penalties for extraction systems.

Various methods for harnessing wave energy have been proposed. Evaluation of the economics indicate that the energy cost from waves is roughly 20¢/kWh at an intensity level of 20 kW/m[10]. The cost decreases to 10¢/kWh at an intensity of 50 kW/m. These costs have an estimated uncertainty of ±100% at this point. The cost of power delivery by submarine cable is not included.

No major wave energy research and development efforts are pursued today within the federal Ocean Energy Technology Program. Major research and development efforts have been carried out in Britain, Norway, and Japan. The Norwegians installed a 500-kW wave energy conversion device off their west coast in the North Sea in October 1985[11]. This device, called the KVAERNER multi-resonant oscillating water column (MOWC), is designed to produce 1 MW peak power and 500 kW_e on the average, at an average wave energy flux of 15 kW/m. The electricity cost from this demonstration was estimated to range between 4¢ and 5¢/kWh.

The British concluded that a flexible bag device called the "Sea Clam" had the best potential for cost effectiveness. Prototype models have been built and tested off the coast of Scotland[12].

The potential for wave power extraction for the Pacific Northwest has been investigated[13]. Using a contouring raft conversion system 180-m long, located 520 km west of Cape Disappointment, Washington, the authors predict a yearly average power level of 1.64 MW, yielding a peak power of more than 3.3 MW during winter months.

Major technical issues that require engineering evaluations and development are problems with off-shore siting (since the wave energy dissipates rapidly closer to shore), mooring, power transmission cable, and structural difficulties.

D.3 Tidal Power

The technology for generating electricity from tides is, in principle, similar to hydroelectric power generation, making use of a hydrostatic head created by the rising and falling tides. A minimum tidal range (the difference between high and low tide levels) is needed if tidal power is to be practical. A range of 5 m is often cited as the minimum. On this basis, about 40 sites exist globally, according to one assessment[14]. In the United States only three coastal areas are promising. One is the Bay of Fundy area in Maine, where the highest tides in the world occur. The other two are in Cook Inlet and Bristol Bay, Alaska. Total U.S. tidal potential has been estimated at 18,300 GW[15].

At this time, the expanded interest in microhydro systems in this country and around the world may yield technology to make tidal systems economically feasible at lesser tidal levels. Such progress should be monitored to assess its relevance to the tidal resources.

D.4 Ocean Currents

Although a great deal of energy resides in ocean currents in various parts of the world, most of those currents flow too slowly for power generation. In the United States, the Florida Current flowing between the mainland and the Bahamas, called the Gulf Stream or the North Atlantic Drift, has been assessed for energy production.

In the stretch between Florida and the Bahamas, this current is about 75 miles wide and flows at speeds up to 2.9 knots (3.3 mph), with a potential total power of 25,000 MW. The world's second most powerful current, the Kuroshio southeast of Tokyo, is rated at 8000 MW.

Only a small portion of that power can ever be harnessed, but the possibilities are very appealing. The Florida Current is adjacent to a densely populated coastal area with great demand for electricity.

Although no electrical power has yet been generated from ocean currents, the technology seems simple and attainable. One method is to suspend a turbine in the current flow, using special turbines developed for this purpose[16]. Another, less expensive, method is the drogue chute system. Studies on both approaches indicate their technical feasibility but raise engineering questions related to the size of the turbine and the durability of the drogue chutes.

D.5 Salinity Gradient Conversion System

Because of the osmotic pressure difference between fresh and salt water, a 240-m waterfall theoretically exists at the mouth of every river. At present, river water mixes irreversibly with the ocean water. However, if half the flow of the Columbia River could be converted to electricity at 30% efficiency, 2300 MW would be produced. The potential power available in the world's salt gradients is estimated at 10^{13} W, comparable to the energy level of ocean thermal gradients[17].

It takes energy to separate salt from water. Therefore, the reverse process, i.e., mixing the salt and water, would release energy. Proposed methods to generate electricity from such a process include reverse electrodialysis, pressure-retarded osmosis, and utilizing vapor-pressure differences.

Engineering design studies were completed by DOE on systems based on pressure-retarded osmosis to create a hydraulic turbine system at the ocean floor[18]. Fresh water from the river flows through a penstock to a hydraulic turbine on the ocean floor. It then flows into a submerged tank and diffuses into the sea by osmosis through a semipermeable membrane. These membranes are similar to those commonly used in reverse-osmosis desalination systems. The cost and maintenance of these membranes are the major technical and cost issues. Preliminary economic assessment of these methods indicate that a significant cost reduction in the process equipment is necessary to make salinity-gradient conversion systems competitive.

D.6 Marine Biomass

Growing biomass crops for energy production on land could use valuable agricultural land. Oceans offer potential areas to grow biomass for fuel production. The oceans are uncultivated and underutilized for plant growth. Cultivation of seaweeds for energy would not compete for production of food or fiber crops in terms of space, effort, or economics.

Oceans can yield certain species three to five times the typical land-based yield of crops (at 5 dry ton/ acre/year). These seaweeds yield cultures worth $500 to $1,000 per dry ton on the present somewhat limited food market[19].

Seaweed culture as a large-scale commercial operation is in its infancy. As with other biomass fuel crops, open-ocean energy farming of seaweeds must be regarded as a long-term commercial prospect.

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Appendix E
Solar Thermal Electric

E.1 Description of the Technology

The concept for using concentrated sunlight to generate electricity by thermodynamic processes is well documented. Reflective surfaces, which may take the form of parabolic troughs, parabolic dishes, or heliostats, concentrate incident sunlight onto a receiver where it is absorbed into a working fluid that powers a thermal conversion-generator device. Solar thermal systems, operating either with storage or in a hybrid mode with an auxiliary fuel, offer significant potential as capacity to meet utility peaking or intermediate electric power generation needs.

Three main types of concentrating collectors have evolved for use in solar thermal systems--low concentration parabolic troughs, high concentration parabolic dishes, and central receivers. Higher concentration allows higher temperatures to be generated in a working fluid and makes electrical generation more efficient.

Parabolic trough systems use surface reflectors to concentrate sunlight onto a fluid-filled receiver tube that is positioned along the line of focus. Concentration ratios of more than 100 times are typically used to generate temperatures of 400° to 500°C. Troughs are modular and many can be grouped together to produce large amounts of heated fluid, which is then transported to a nearby facility to generate electricity. As a result of a concentrated R,D&D effort in the early years of the DOE Solar Thermal Program, troughs are the most mature solar thermal technology.

The modular parabolic troughs and dishes are classified as distributed systems, whereas central receiver systems, in which heliostats are deployed in a central receiver configuration by placing large numbers of them around a tower-mounted receiver, are more centralized. All concentrating systems have their best annual output in regions where direct insolation is highest (e.g., the southwestern United States and other semiarid regions of the world), but they also can be utilized, at slightly higher cost, in other regions with somewhat lower levels of direct insolation. Solar thermal systems take advantage of an enormous energy resource; a recent report estimates that solar insolation accounts for more than 87% of the total accessible U.S. energy resource base[1].

E.2 Current Status of the Technology

All solar thermal electric types have been demonstrated in industrial-like settings. A 10-MW_e experimental central receiver power plant was deployed by a joint government-industry team and operated successfully by Southern California Edison (SCE) on its grid for 6 years, thus achieving the objectives of the experiment. While system efficiency for this plant (7.4%) was somewhat below initial predictions, extensive operational experience was gained and the plant delivered more than 37,000 MWh net energy to the grid. Based on recent utility central receiver studies, which assumed advanced heliostat and receiver technologies and improved operational procedures learned from the pilot plant experiences, annual system efficiencies of 14% to 15% with costs of 8¢ to 12¢/kWh have been projected for a next generation plant[2].

Prototype parabolic dish electric systems, totaling about 5 MW_e, have also been operated in a utility setting in Georgia and in southern California. More recent development of a dish mounted engine-generator concept has led to significant increases in system performance compared with the earlier designs, which collect the heat as thermal energy and transport it to a central location for electric generation. Indeed, a dish/Stirling engine-generator module set a record of 29% overall system conversion of sunlight to electricity.

Currently, 274 MW_e of privately funded, parabolic-trough electric generating capacity is operating on the SCE utility grid. In addition, 80 MW_e is currently in construction, and current plans are to add an additional 300 MW_e by 1994. These trough systems operate in a hybrid mode using natural gas and collectively account for more than 90% of the world's solar electric capacity. The cost of these systems has fallen steadily from 24¢/kWh for the first 14-MW system (1984) to an estimated 8¢/kWh for the 80-MW plant installed in 1989[3]. Company officials estimate that further system cost reductions of 30% or more can be achieved, making this technology cost effective in an even wider range of U.S. and worldwide electricity markets[4].

E.3 Constraints and Opportunities

Research and development (R&D) conducted by the government and industry over the past 12 years has developed impressive new technologies and has reduced technical and financial risks. As previously described, first generation solar thermal systems have been successful and are proving the viability of the technology. However, deployment of these systems could be greater. Low fuel costs, changes in the availability of federal and state tax incentives, and other market factors have constrained solar thermal technology's potential to significantly penetrate the domestic electric generating market. And in some cases, the availability of power (primarily fossil fuel derived) from many third-party suppliers, combined with conservation (which has reduced demand), has left many utilities with excess generating capacity.

International markets also provide opportunity for solar thermal technology. Small systems, like the Stirling, have potential to be competitive in either grid-connected or stand-alone applications in many third-world countries. However, other developed countries are threatening to challenge the United States in tapping these markets. European countries are significantly increasing their investments in solar thermal research. At the same time, the U.S. budget has steadily declined over the past decade. This situation may make it difficult for U.S. industry to exploit its current leadership in marketing solar thermal technology in foreign markets.

Two related factors currently limit increased implementation of solar thermal electric systems: cost and the lack of pilot-plant demonstrations of technological improvements in a utility setting. Significant cost improvements have been achieved by reducing component and system costs while improving system performance; the cost of energy from solar thermal electric systems, which was 60¢/kWh in 1980, has been reduced to 8¢ to 12¢/kWh today. Components that provide further improvement have been developed and are currently being evaluated. Dish electric systems utilizing a stretched-membrane dish integrated with a reflux receiver and a reliable Stirling engine, when developed and mass produced, are projected to cost $1,200/kW_e$. Cost estimates for energy from such a dish electric system are projected to reach 5¢/kWh, low enough to be competitive in a substantial market[5]. For central receiver technology, there is a need for a 30 to 100 MW_e pilot-plant demonstration incorporating improved receiver concepts (molten salt, direct absorption, or air) and stretched-membrane heliostats; both offer significant improvement in performance and energy costs. These advanced technologies are a direct result of the government-sponsored research, development, and demonstration (R,D&D) work, and continued improvements will depend directly on the continued vitality of the R,D&D program.

To take advantage of continuing component improvements and attain further cost reductions, system demonstrations are necessary. The utility market environment requires demonstration of any new technology on a scale that is readily expanded to full-size plants. Reliable system performance is being demonstrated and cost improvements realized with each successive parabolic trough system. Similar operation and experiences are necessary for both central receiver and dish electric concepts where the advanced technologies that are proven on a component scale can be integrated into a system in an industrial setting. Utility participation in such projects on a cost-shared basis is considered critical to success.

Research efforts in the DOE Solar Thermal Program are developing the foundations necessary to further enable a viable solar thermal technology. These efforts are focused on concepts, processes, and materials for a broad range of applications and on the identification and proof of concept of advanced applications for highly concentrated solar energy. Some of these include research on (1) optical materials and advanced optical techniques to improve conversion efficiencies and reduce costs, and (2) high-temperature materials to enable receivers to more effectively absorb concentrated sunlight. R&D of prototype hardware applies these new materials and reduces system costs. Testing of the hardware provides field experiences that lead to improvements in reliability. R&D in this area has led to the development and testing of the following systems: (1) low-cost, lightweight membrane heliostats and parabolic dish collectors; (2) advanced molten-salt receivers for central receiver systems; (3) high-flux sodium reflux receivers for dish systems; (4) high-performance, low-maintenance Stirling engines for modular dishes; and (5) direct absorption receivers for central receiver systems.

Future solar thermal systems are expected to be used in either a peaking mode without the use of storage or with an integral thermal storage system for intermediate and base-load plants. The lowest levelized energy costs are expected to be achieved by use of a thermal energy storage system. However, to realize these lower energy costs, additional R,D&D of storage systems will be necessary. Research in higher density phase-change storage concepts should lead to low-cost storage systems in the future. Furthermore, storage systems at commercial scale capacities have not yet been demonstrated. In today's trough systems, a hybrid mode of operation, with natural gas, is used to provide dispatchability and achieve a higher capacity factor and lower cost of delivered energy.

To bring additional solar thermal technology to the market, a strong interaction between government and industry is required. Specific efforts to facilitate this process include providing technical assistance to suppliers and users of solar thermal technology, and implementing joint-venture projects in which industry and government share the risk of developing a solar thermal technology for a specific market. As part of this effort, the federal program and some utilities are studying the benefits of demonstrating new solar thermal technologies on a scale that is readily expanded to full-size plants. One benefit of these system demonstrations is that these field experiences help improve reliability and reduce operation and maintenance costs.

E.4 Potential Contributions

An assessment of the status of solar thermal technology, along with an examination of the business plans and projections of industry and users, leads to the conclusion that significant marketplace opportunities exist in both the near and long term. The domestic utility market holds major long-term opportunities for large-scale application of solar thermal systems. In this market, one of the largest potential applications for solar energy is for generating electricity during daytime summer peak load periods. Currently, most utilities use and are planning to add fossil-fuel-fired generators to meet these demands. Solar electric plants, which produce energy during daylight hours, represent an environmentally benign competitor to meet peak electrical demands.

Efforts to bring solar thermal technology to the domestic market are proving increasingly fruitful. Building on the experiences of a decade of DOE-sponsored research, the parabolic trough systems in California are a prime example of applying past research to today's needs. Planned additions to these solar thermal power plants will bring the total electric generation to the equivalent of about 0.01 quad/year in 1990. Further improvements and additions to the trough systems, coupled with the implementation of the higher efficiency dish electric system, are projected to bring the total solar thermal contributions to about 0.04 quad/year in the West region by 2000. Continuing growth of these technologies and implementation of advanced central receiver designs could increase the solar thermal contribution substantially over time. The projected increase in capacity versus time for this base case is shown in Figures E-1 and E-2 and Table E-1. These projections pertain to the southern United States (called the South region in this study) where the primary area of collection and conversion is in west Texas with its high direct solar radiation resource, and to the western United States (West region). The electricity generated is assumed to be available to the entire South region without any transmission or distribution limitations.

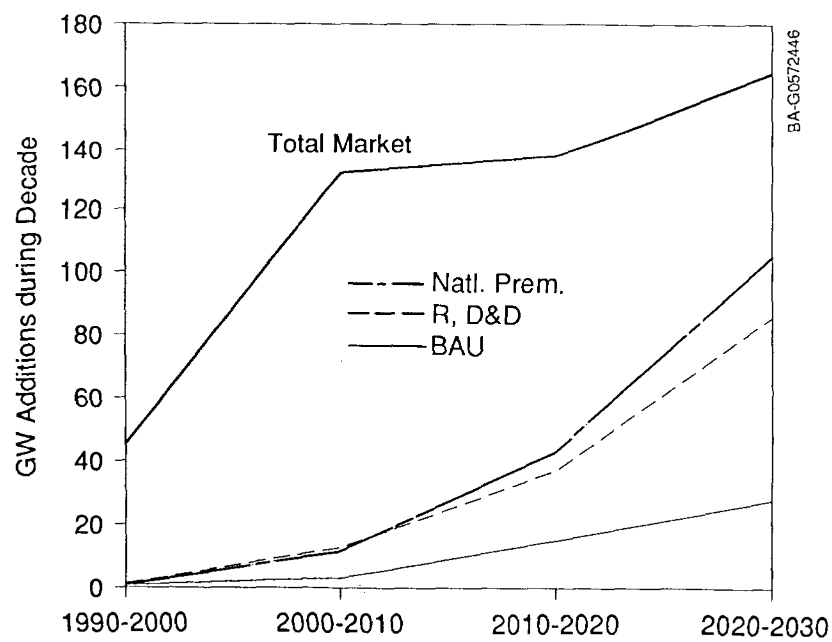

Figure E-1. Solar thermal electric incremental market penetration (South; unconstrained)

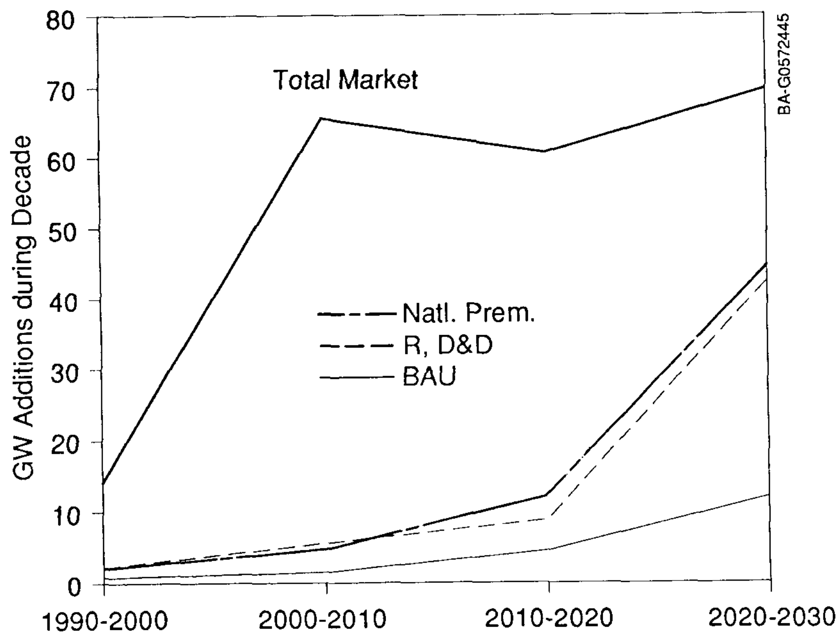

Figure E-2. Solar thermal electric incremental market penetration (West; unconstrained)

Table E-1.
Solar Thermal Electric Penetration[a]

	Primary Energy (quads)				
	1988	2000	2010	2020	2030
Business-as-Usual Scenario					
South	0.00	0.04	0.18	0.87	2.16
West	0.00	0.05	0.11	0.32	0.87
Total	**0.00**	**0.09**	**0.29**	**1.19**	**3.03**
R,D&D Intensification Scenario					
South	0.00	0.06	0.64	2.35	6.31
West	0.00	0.11	0.37	0.77	2.72
Total	**0.00**	**0.17**	**1.01**	**3.12**	**9.03**
National Premiums Scenario					
South	0.00	0.05	0.58	2.58	7.40
West	0.00	0.10	0.32	0.88	2.93
Total	**0.00**	**0.15**	**0.90**	**3.46**	**10.33**

[a]Not reduced for regional market penetration limits or intertechnology competition.

If accelerated R&D plans were to be implemented, a substantial increase in installed capacity could be expected by 2030. This increased activity would focus on commercial-scale field pilot-plant projects, demonstrating the technologies developed under the federal R,D&D program, and increased core technology development levels, to build upon the pilot plant experiences in an efficient and timely manner. It is expected that the federal program would contribute primarily to increases in conversion efficiencies, and the private sector would direct its efforts in the manufacturing/construction and operations areas. Advances in durability and reliability would likely come from both the federal and private sides working closely together. Additional effort in the proposed R,D&D

Intensification Scenario would be concentrated in the early years to take advantage of the recent central and distributed receiver systems technical advances made in the federal Solar Thermal Program. These advances include stretched membrane heliostats and concentrators, advanced molten salt and air central receivers, refluxing distributed receivers, and high reliability converter technologies, all of which need to be exercised in systems contexts at reasonable scales by committed industrial participants to demonstrate viability and provide feedback for further development. In later years, new storage options would be implemented in the systems' field tests.

In the National Premiums Case, the cost premium allows the trough hybrid technology, now only marginally competitive, to more fully penetrate existing markets as well as to extend its cost-effective geographical range. In the longer term, this cost premium spurs increased private activity in the development of the dish and central receiver technologies, although this is assumed to occur at a somewhat slower pace than with intensified federal R,D&D. Advances in storage technologies, also aided by a greater private role, are assumed to occur under this scenario.

In all these scenarios, resource access and demand compatibility were not considered to be limiting factors. Use of the vast semiarid areas of the western United States, New Mexico, and west Texas for electricity generation does not appear to have any competitors, natural or man-made, for the needed insolation. Plant experience in southern California has proven high correlations between utility demand peaks and available insolation. It is expected that this correlation could be extrapolated for much of the western United States plus New Mexico and Texas.

In addition to the domestic utility market, there are near-term opportunities in foreign markets, particularly third-world countries. In these areas, small, modular solar electric systems could be used to supply electricity and hot water for clinics, communication, and village power. Although not completely quantified, it is thought that these electrical generation requirements may exceed those in the United States.

Table E-2 summarizes the capital cost and other factors used to derive the levelized energy cost, with and without thermal storage, for the penetration scenarios.

E.2 Contribution to National Goals

Solar thermal technology can contribute to national goals in a variety of ways. First, the need for improving the environment is increasingly clear. "Global warming" and "acid rain," both of which have been linked to burning of fossil fuels, have the potential to adversely affect natural systems. Other fossil fuel burning emissions, such as nitrogen oxides, and related products, like ozone, are known to imperil human health. As a result, new regulatory laws are being considered to constrain the use of fossil fuel generators.

Solar energy is a clean and environmentally benign energy source. Electricity generated from solar produces few emissions. Further, the combination of solar and fossil fuel generators (hybrid plant) helps minimize fossil fuel emissions.

Finally, the development of solar thermal technology has the potential for creating multibillion dollar markets, both domestically and overseas. Promoting and selling the technology in these markets can improve U.S. international competitiveness and help reduce the trade deficit.

E.6 Other Perspectives

Industry perspectives suggest that in the near term the solar trough/gas hybrid approach is the most marketable. However, utility studies suggest that the central receiver and dish technologies have the greatest potential for achieving cost-competitive generation in the longer term[6]. Cost-effective storage will also need to be developed to achieve substantial deployment of the technology.

Many of the current policy perspectives on solar thermal electric technology were developed almost a decade ago. The technological progress and change in market conditions that have occurred since then argue for a revised analysis of the cost and market potential for solar thermal electric technology.

Table E-2.
Uniform Cost and Performance Data:
Solar Thermal Technology Characteristics

	Capital Cost ($1988/kW)	O&M (¢/kWh)	Capacity Factor	Fuel Cost ($/MilBtu)	Heat Rate (Btu/kWh)	Levelized[a] Cost (¢/kWh)	Energy[b] Supply (quads)
Systems With Storage (Intermediate and Base-load),							
1988	3000	2.0	0.25	--	--	15.8	0.00
2000 - BAU	2400	2.0	0.50	--	--	7.5	0.09
- R,D&D	1750	2.0	0.50	--	--	6.0	0.17
2010 - BAU	1530	2.0	0.50	--	--	5.5	0.29
- R,D&D	1400	2.0	0.50	--	--	5.0	1.01
2020 - BAU	1400	1.5	0.50	--	--	4.7	1.19
- R,D&D	1350	1.2	0.50	--	--	4.3	3.12
2030 - BAU	1200	1.2	0.50	--	--	4.0	3.03
- R,D&D	1200	1.2	0.50	--	--	4.0	9.03

[a]Over 30 years at 6.1% discount rate (EPRI TAG) (Levelized annual fixed charge rate of 0.1007).

[b]Includes all systems, both with and without storage

Notes: Combined gas and some thermal storage included in 2000-2010. Thermal storage costs included in the capital cost.

	Capital Cost ($1988/kW)	O&M (¢/kWh)	Capacity Factor	Fuel Cost ($/MilBtu)	Heat Rate (Btu/kWh)	Levelized Cost (¢/kWh)	Energy Supply (quads)
Systems Without Storage (Peaking)							
1988	3000	2.0	0.25	--	--	15.8	--
2000 - BAU	1800	2.0	0.25	--	--	10.3	--
- R,D&D	1250	2.0	0.25	--	--	7.7	--
2010 - BAU	1200	2.0	0.25	--	--	7.5	--
- R,D&D	1050	2.0	0.25	--	--	6.8	--
2020 - BAU	850	1.5	0.25	--	--	5.9	--
- R,D&D	900	1.2	0.25	--	--	5.3	--
2030 - BAU	800	1.2	0.25	--	--	4.9	--
- R,D&D	800	1.2	0.25	--	--	4.9	--

Notes: Cost reductions are achieved in the solar system in early years. Additional cost reduction occurs in later years because of larger systems. About 40% solar system and 60% balance of plant costs assumed.

1988-2000

- Capital cost reductions are largely related to the increased overall system efficiency and the reduction in the collector cost per unit area. Further reductions in the R,D&D Scenario are related to large-scale manufacturing approaches and installation techniques.
- Capacity factor is increased by introduction of some thermal energy storage, while keeping the allowable auxiliary fuel (gas) burning capability in the system.

2000-2010

- Capital cost is further reduced because of manufacturing techniques, improved installation approaches, and more efficient material usage in lightweight concentrators.
- Cost includes storage system costs.

2010-2020

- Improved materials and operating techniques reduce the O&M costs.

2020-2030

- Costs are further reduced in both the solar system and thermal storage system. Larger system sizes allow for economies of scale imbalance of plant equipment, further contributing to capital cost reductions.

E.7 References for Appendix E

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Appendix F
Wind Energy Technology

F.1 Description of the Technology

The use of wind as a renewable energy source involves the conversion of power contained in moving air masses to rotating shaft power. These air masses represent the complex circulation (winds) in the earth's boundary layer that are caused by the earth's rotation and by convective heating from the sun. The actual conversion process utilizes basic aerodynamic forces--lift and/or drag--to produce a net positive torque on a rotating shaft, resulting in the production of mechanical power, which can then be converted to electrical power.

The scope of the wind resource, both domestically and globally, is widespread and is less dependent upon latitude than other solar technologies. The accessible resource in the United States has been conservatively estimated to be capable of providing more than 10 times the electricity currently consumed in this country (however, considerations discussed in this section would preclude total penetration of generating capacity)[1]. Wind is a very complex resource. It exists in three dimensions, rather than the "two" associated with other solar resources. It is intermittent and is strongly influenced by geography (terrain effects). Finally, there is a nonlinear (cubic) relationship between wind speed and power/energy available. This last factor is best illustrated by comparing good, excellent, and outstanding wind sites having average wind speeds of 13, 16, and 19 mph, respectively. This 3-mph difference results in the excellent site having 86% more available energy per unit area than the good site for conversion to electricity, while the outstanding site has 212% more available energy than the good site.

F.2 Current Status of the Technology

Wind energy has proven to be the most cost-competitive and utilized solar energy technology for the bulk power market. Of the 1700 MW of wind turbines installed worldwide, 1500 MW are located in California. Approximately one-half the current inventory of turbines in California is the direct result of federal and state tax incentives that expired in 1985. These early installations were plagued with problems, ranging from low availability and poor overall performance to major equipment failures. As a result of this past experience, the industry has improved turbine technology and operating strategies such that today's installations reliably produce energy at costs that now rival those of some nonrenewable sources[2]. Since 1985, 622 MW of wind capacity have been installed in California without the benefit of tax incentives, representing almost a billion dollars of capital investment[3].

Wind technology also provides economical energy to remote areas and for specialized applications, both in this country and worldwide. The modularity of wind turbines and the wide range of sizes available enable wind energy to serve many applications, such as small radio transmitters, offshore oil rigs, navigational aids, and remote communities. By combining the intermittent wind energy with backup power sources, such as diesel generators or storage devices, most loads can be reliably and competitively served. The focus of this white paper is on the bulk electricity power market; therefore, these applications for wind energy will not be addressed in detail. However, wind is continuing to make a significant impact in this market.

F.3 Constraints and Opportunities

F.3.1 Institutional Constraints and Opportunities

Several institutional constraints to the increased deployment of cost-effective wind energy currently exist. First, electric utilities have been forced to purchase generated power from individual wind farm operators without being actively involved in wind farm development or operation. This lack of control over an energy source that is intermittent has caused utilities to be less than enthusiastic about seeing the role of wind expand. On the other hand, several progressive utilities, as well as the Electric Power Research Institute (EPRI), have continued to follow the wind industry very closely. Some are even now participating in industry activities, such as advanced wind turbine design, in order to gain a better understanding of wind power as a possible future contributor to their generation mix. The wind industry would probably benefit greatly from expanded utility involvement.

Another issue centers on how wind (and other intermittent solar technologies) should be considered relative to capacity credits. Historical approaches would give little, if any, capacity credit because wind cannot be considered dispatchable nor can the output be relied upon to coincide with utility loads. Improved weather forecasting techniques as well as greater geographic dispersal of wind farms should help to mitigate this concern, but consistent methodologies should be developed to establish the level of capacity credit that can be attributed to wind in any particular utility setting. For example, recent studies by the Pacific Gas & Electric Company (PG&E) do indicate the existence of a capacity credit for wind farms connected to its system ranging between 20% and 80%[4]. Projections presented later in this section avoid this issue altogether by making the very conservative assumption of zero capacity credit for wind energy.

Wind energy possesses the same basic environmental impacts associated with many other renewable technologies: little or no impact on flora, fauna, climate, materials, and human health hazards, but a potential negative impact on land use. On the negative side, three siting considerations require mention: the visual impact of large, rotating structures; the nearby acoustic disturbance associated primarily with the generation of aerodynamic forces on the rotating airfoils; and some concerns about the possibility of bird kills from the rotating blades. In general, the California experience has shown these factors to be minimal, as long as the turbines are not located in proximity to populated areas.

On the positive side, the three-dimensional nature of the resource provides a distinct advantage relative to other solar technologies. Specifically, because the general rule for turbine siting is "the higher the better," and turbines typically are spaced about 2 to 3 diameters apart crosswind and 10 diameters apart downwind, only a small fraction of a wind farm land area is actually occupied. The rest of the land remains available for other useful applications, such as crop production or livestock grazing.

F.3.2 Technological Constraints and Opportunities

Performance of wind turbines, as with other sources of energy, must be judged by the cost of energy (COE)--in this case the levelized cost per kilowatt hour of electricity produced. For wind turbines, this cost can be determined from only a few parameters[5]: the capital cost (in $\$/m^2$, including all balance of system costs), the annual energy capture (in kWh/m^2), and the O&M/replacement costs (annualized to ¢/kWh). The current costs in California of 7¢ to 10¢/kWh derive from capital costs of about $\$450/m^2$, annual energy capture of 600 to 800 kWh/m^2, and O&M and replacement costs of 1.2¢ to 1.4¢/kWh. These numbers represent a significant improvement over the values for machines installed in the early 1980s, particularly with respect to their capital costs. But to tap a significant portion of the accessible resource mentioned, performance must be improved. In fact, future turbines will have to perform better at "good" sites than current machines do at "excellent" sites. Fortunately, the improvements to achieve this are near.

Figure F-1 identifies potential incremental technological advancements that in aggregate would represent a dramatic improvement in turbine performance. The potential reduction in COE relative to current levels is shown as a function of time, or technology improvements. The improvement areas identified in Figure F-1 are necessarily broadly defined, because of the inherent uncertainty associated with long-term research. However, the near-term improvement possibilities are fairly well defined. Initial improvements to existing designs will be derived through the use of advanced design tools, including turbulence codes, aerodynamic and structural codes, and fatigue life models. Also included is the use of advanced airfoils designed specifically for wind turbines to increase both energy output and rotor fatigue life. Site tailoring refers to the optimization of system designs for site-specific characteristics. Examples of this might include tall towers for locations with a strong vertical wind shear and control strategies optimized for different turbulence levels that would maximize power output while minimizing operation in damaging wind conditions. Operating strategies include the possible use of power electronics that allow the speed of the rotor to vary with wind speed while still maintaining constant frequency power output. This would allow the turbine to operate at optimum efficiency over a wide range of wind speeds, increasing performance and reducing damaging structural loads at the same time. Possible array spacing strategies are being investigated that maximize the energy capture over large arrays of wind turbines. The optimum spacing of turbines, both within and between rows, is dependent on the terrain as well as predominant atmospheric conditions. Other strategies include varying the heights of adjacent turbines to promote mixing in the boundary layer, which would reduce wake energy deficits and turbulence effects for downstream rows of turbines.

Research areas for the longer term include new configurations for advanced designs that achieve dramatically improved reliability and manufacturability. New rotors designed to withstand the fatigue loads, which are now only beginning to be understood, would provide the reliability that the market demands. These advanced designs might include new, highly flexible, lightweight rotors that are relatively insensitive to high wind turbulence levels. The use of new materials would be included in all design components to provide greater strength or flexibility at reduced weights and costs. Finally, advanced turbines would be designed for optimum manufacturability. Unique components of the advanced designs, such as rotors or blades and hub attachments, must be efficiently manufactured so that costs will be minimized. The estimated net effect of all of these improvement areas, if successfully implemented, would be to reduce the COE from wind energy to 30% to 40% of current levels.

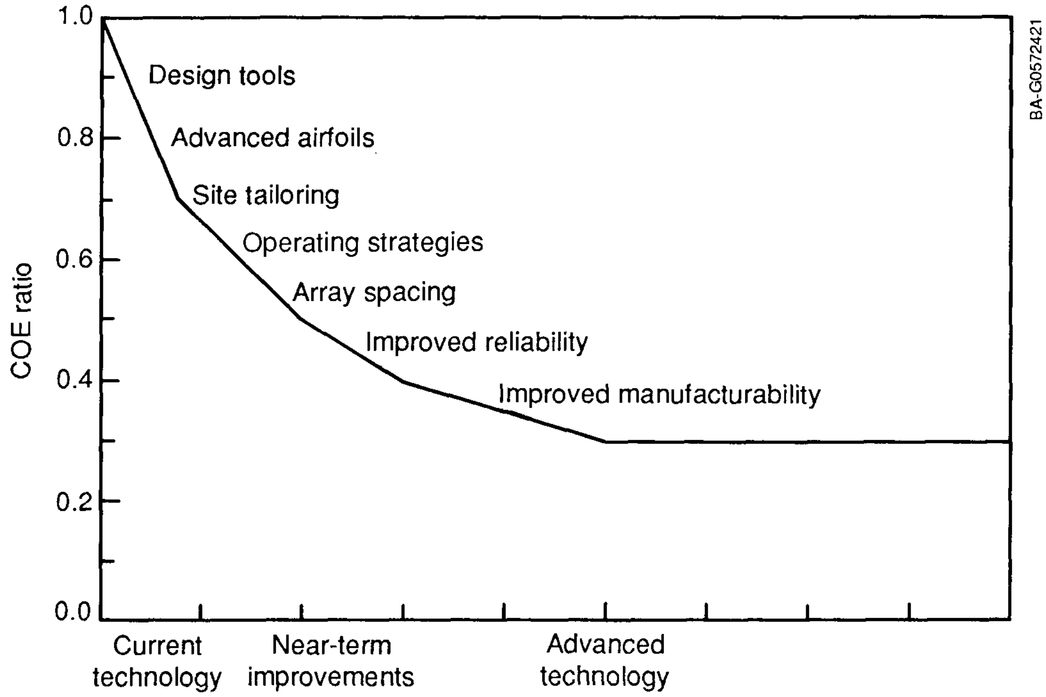

Figure F-1. Impact of wind technology improvements

The achievement of these research goals would lead to cost reductions that can be viewed from two perspectives. On the one hand, the available land areas for cost-effective machines (i.e., ~5¢/kWh) would be substantially increased. On the other hand, if a wind farm can produce electricity for 5¢/kWh at a good site, then it can produce electricity for 3¢ to 4¢/kWh at better sites. Excellent wind sites, while less common than the good sites, can provide an economic wedge to begin penetration of the generation market in all areas of the country.

In the longer term, the issue of facilitating options, such as storage and transmission, might be very important to the success of wind. The availability of cost-effective storage coupled to wind systems would yield capacity credit benefits. In addition, because of its often isolated locations, the value of wind would benefit from transmission/distribution access. For example, in the Pacific Northwest, the Bonneville Power Administration (BPA) has identified 20,000 to 40,000 MW of potential wind capacity in eastern Idaho and Montana. If such a resource could be coupled with existing hydropower capacities (which could be viewed as system storage devices) and an economic transmission route to the Pacific Coast, wind might then play an important role in the generation mix.

F.4 Contribution Potentials

It is clear that wind energy's greatest potential contribution is in bulk electricity generation, and the most significant marketplace today is the United States. In this market, the wind farm or wind plant will continue to be the configuration of choice. The individual turbine's relatively small size (100 kW to 1 MW) allows rapid development (less than one year) in a modular fashion, eliminating the capital risks associated with longer lead time technologies. Other advantages include not having to shut down an entire plant for maintenance activities and not having to commit a significant fraction of the plant's value to spares inventories.

Wind energy is already making significant contributions to electricity generation in this country, as evidenced by the more than 2 billion kWh of electricity generated in 1989, providing more than 1% of California generation[3]. In the near term (10 years), wind's projected drop in cost of energy to below 5¢/kWh (in 1989 dollars) at "good" sites could open vast areas of the country for development. However, efforts to significantly impact the bulk generation market with wind could begin almost immediately. Of course, the amount of increased generating capacity required and the method by which the mix is chosen will be key issues to this development. In the long term (30 years), wind could see costs reduced to as low as 3¢/kWh, and this would certainly lead to significant growth in installed capacity.

Estimates for the delivered cost of energy for wind can be made with some certainty because a large amount of wind generating capacity has already been installed in California and current costs are well documented. In addition, incremental improvements to existing designs are continuing to be implemented and tested by the industry with DOE program support. Projections to the year 2030 for the delivered COE from wind energy, assuming annual average wind speeds representing good to outstanding wind resources (13 to 19 mph), are shown in Figure F-2 and Table F-1. Note that these COE values represent technology that is available for mass market implementation. There is an implicit lag, assumed to be 5 years, between the time that technology improvements are demonstrated and the time they are widely incorporated into commercial machines. In Figure F-2, two different levels of R&D effort are assumed. The top set of curves (solid lines) represents the range of COE projections, assuming current federal R&D funding levels (Business As Usual [BAU]). The lower set of curves (dotted lines) shows projections of the impact of the R,D&D Intensification Scenario on COE levels. The estimated impact of the R,D&D Intensification Scenario is to reduce the COE sooner than could probably be achieved given the current level of R&D involvement. Also shown in Figure F-2 are projected displaced energy cost trends for natural gas- and coal-fired electrical generation. These conventional generation costs represent the competing market for wind energy for electric utility applications.

The COE information presented in Figure F-2 was used to estimate the economic impact of wind energy on the national energy supply. As previously noted, wind energy is intermittent and thus was assumed to compete as a fuel saver only; in other words, no credit was given for potential capacity displacement. Wind energy is assumed to be economically competitive when its COE crosses below that for competing generation sources. However, if a significant capacity credit was assigned to wind energy, the competitive crossover points would occur much sooner. Given the degree of uncertainty and the site- and utility-specific nature of wind capacity credits, it was not possible to incorporate these credits into the current analysis.

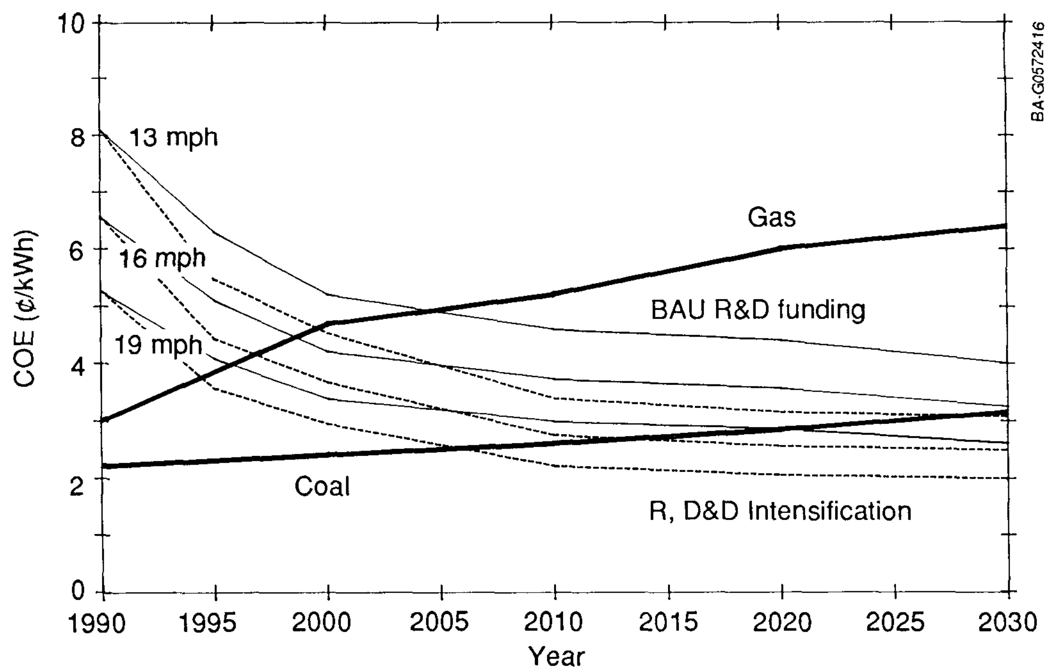

Figure F-2. Comparison of COE projections for wind energy versus fuel and variable O&M costs for natural gas and coal

Table F-1.
Uniform Cost and Performance Data:[a]
Wind Energy Technology Characteristics

	Capital Cost ($1988/kW)	O&M (¢/kWh)	Capacity Factor	Fuel Cost ($/MilBtu)	Heat Rate Btu/kWh)	Levelized[b] Cost (¢/kWh)	Energy Supply (Quads)
1988	1125	1.8[c]	20%	–	–	8.30	.02
2000 - BAU	1000	1.2	28%	–	–	5.3	0.22
- R,D&D	950	1.0	30%	–	–	4.6	0.39
2010 - BAU	965	0.9	29%	–	–	4.7	1.02
- R,D&D	850	0.8	33%	–	–	3.8	2.29
2020 - BAU	915	0.8	30%	–	–	4.3	2.09
- R,D&D	800	0.6	34%	–	–	3.3	5.68
2030 - BAU	850	0.8	31%	–	–	4.0	3.30
- R,D&D	750	0.6	35%	–	–	3.1	10.65

[a] Projected turbine performance and costs are based on wind sites with a 13 mph average annual wind speed. Improved performance, and thus lower costs, will be realized at better wind sites.

[b] Over 30 years at 6.1% discount rate (EPRI TAG)
(Levelized annual fixed charge rate of 0.1007).

[c] Includes replacement costs of 1.0¢/kWh.

1988–2000

- Capital cost reduced by 10%.
- 25% and 50% improvements in output in BAU Scenario and with R,D&D Intensification Scenario, respectively, because of improved airfoils, larger turbines, and more efficient operating strategies.
- Improved designs and components lead to virtual elimination of replacement costs (above normal O&M costs) in the intensified greater turbine output. O&M costs, including a replacement allotment, remain high in the base case.

2000–2010

- Capital cost is reduced an additional 10% with R,D&D Intensification Scenario because of innovative concepts resulting in lower loads and the use of lighter weight materials and designs conducive to lower cost manufacture.
- Both cases incorporate additional improvements in output because of continuing operational advances.
- O&M reduced slightly (on a ¢/kWh basis) because of the greater turbine output.

2010–2020

- Improvements in capital cost and performance are related to enhanced manufacturability--manufacturing process and tolerances are optimized as industry scales up to meet increased turbine demand.

2020–2030

- Stable, mature market in place.

As can be seen in Figure F-2, assuming current R&D funding levels, the economic crossover occurs in 1995 for gas displacement at outstanding wind sites (19 mph) and in 2005 at good wind sites (13 mph). Lower COEs from wind energy are required to displace coal generation. It is estimated that this crossover will not occur until 2020, and then only at the outstanding wind sites. The economic crossover timelines, assuming R,D&D intensified funding, are shortened for all wind speed classes against both fuels. In addition, the largest estimated payoff for the increased research effort occurs when the wind COE dips below coal costs for the good and excellent wind sites. This competitive position with coal is important for achieving greater levels of wind energy penetration because coal is predicted to provide a major share of the bulk generating capacity for electric utilities.

The dispersed nature of the U.S. wind resource is depicted in Figure F-3. The wind energy resource for each of four regions was sorted by annual average wind speed class[6]. The total deliverable energy for each region was calculated based on the available land area for each wind speed class. These energy values were based on the following assumptions: wind turbine capacity factor of 25% and wind turbine arrays arranged with minimum spacings of 10 diameters between machines and between rows.

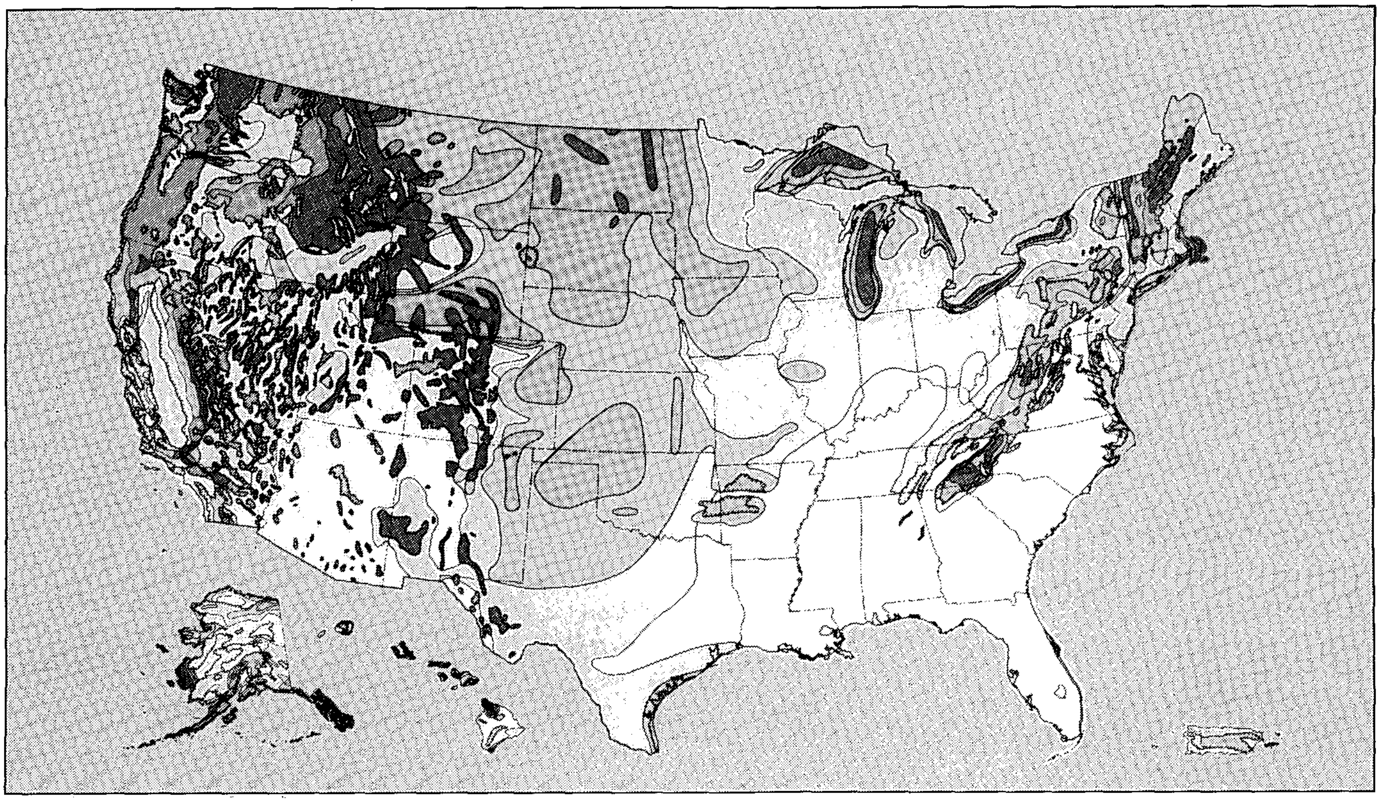

Figure F-3. Average annual wind resource estimates in the contiguous United States

A base market potential, or the amount of energy that could be delivered economically, was estimated for each region and each year. This involved comparing the wind energy available in each wind speed class (and thus different delivered COEs) with the incremental capacity additions projected by fuel type for each region. In most cases, the limiting factor in this step was the need for new capacity *not* the wind resource. After determining the amount of wind energy that could be economically supplied for each scenario, a factor was applied to represent limiting constraints, such as manufacturing capabilities and utility acceptance levels. This multiplicative fraction varies from 2% in 1995 to 20% in 2030.

This process was applied to the BAU Scenario, using the higher estimates for wind energy COEs. It was then repeated for the second and third cases, which represent the R,D&D Intensification Scenario (and thus lower COE estimates), and the National Premiums Scenario, where the wind COE is reduced by 2¢/kWh. Figures F-4 through F-7 show the four regional estimates of the total market for capacity, and the market penetration projections for the BAU, R,D&D Intensification, and National Premiums Scenarios. The penetration curves simply represent that fraction of the potential market that could reasonably be supplied by the wind industry. The penetration fractions for the BAU Scenario are 5%, 10%, 15%, and 20% of the theoretical cost-effective market for the years 2000, 2010, 2020, and 2030, respectively. For the other two scenarios, the penetration fraction was assumed to increase faster because of the increased market pull created by the greater cost competitiveness of wind energy; therefore, the corresponding market penetration fractions for these scenarios are 10%, 20%, 30%, and 40% of the theoretical cost-effective market. For consistency with other technologies, the penetration is expressed in gigawatts of capacity. However, because of the 25% to 35% capacity factor for wind turbines, an energy penetration chart would appear about 50% lower. Table F-2 summarizes the projected contribution of electricity production from wind energy in terms of quads of primary fuels displaced.

It may be somewhat surprising that the results indicate higher penetration values for wind energy in the South, because this region generally does not have outstanding wind resources (see Figure F-3). However, the projected growth in electricity demand for this region is very high, and the wind resource, mostly located in northwestern Texas, is able to economically displace oil and gas in the BAU Scenario, and coal in the R,D&D Intensification and National Premiums Scenarios. In conducting the penetration analysis, it was assumed that adequate transmission capability would exist within each region to accommodate capacity growth. This assumption may be overly optimistic in this case because the wind resource is concentrated in one specific area, while load growth probably occurs more uniformly across the entire region. Conversely, for the West region where the wind resource is outstanding, the penetration estimates are more modest because of the slower capacity growth projections for this region. Projected penetration in the Northeast region does not show the same dramatic increase in later years as the other regions, reflecting the saturation of the available resource.

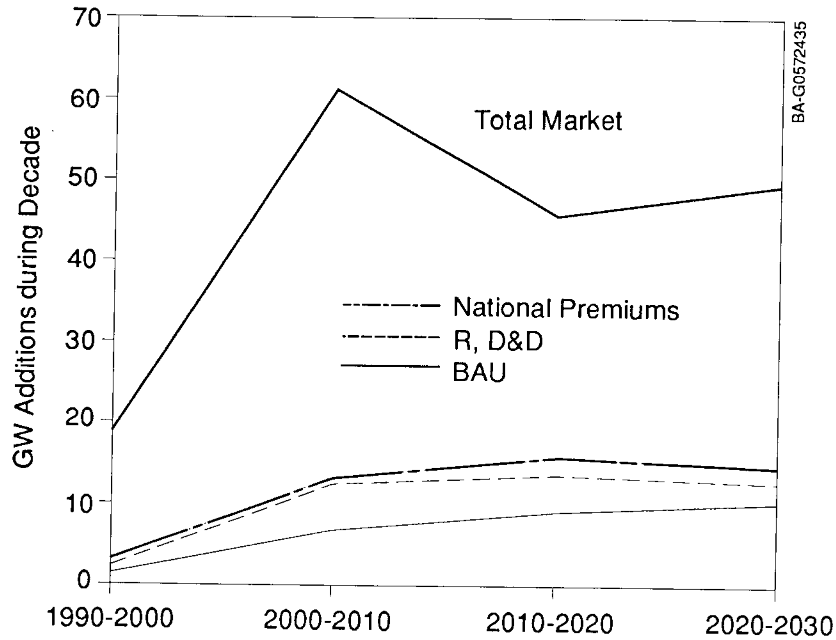

Figure F-4. Wind power incremental market penetration (Northeast; unconstrained)

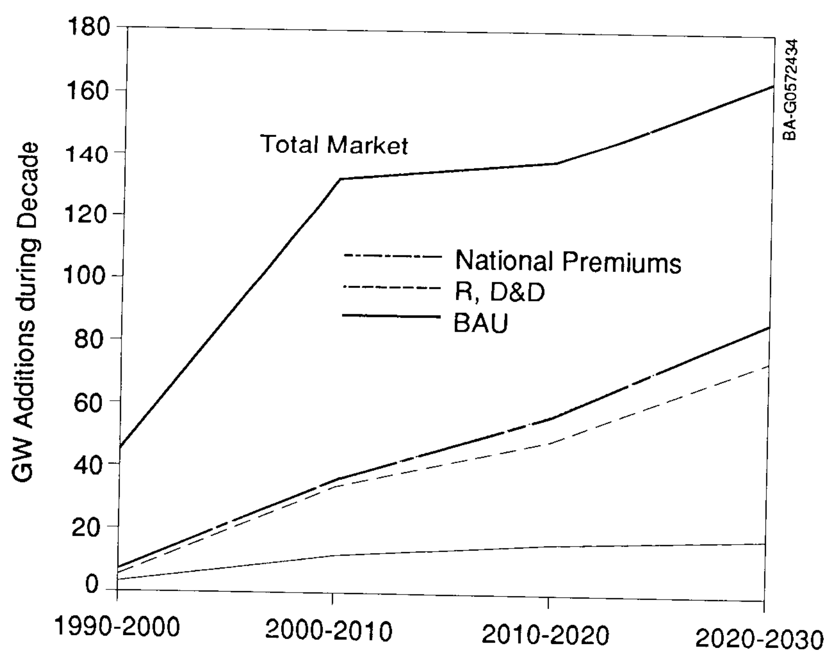

Figure F-5. Wind power incremental market penetration (South; unconstrained)

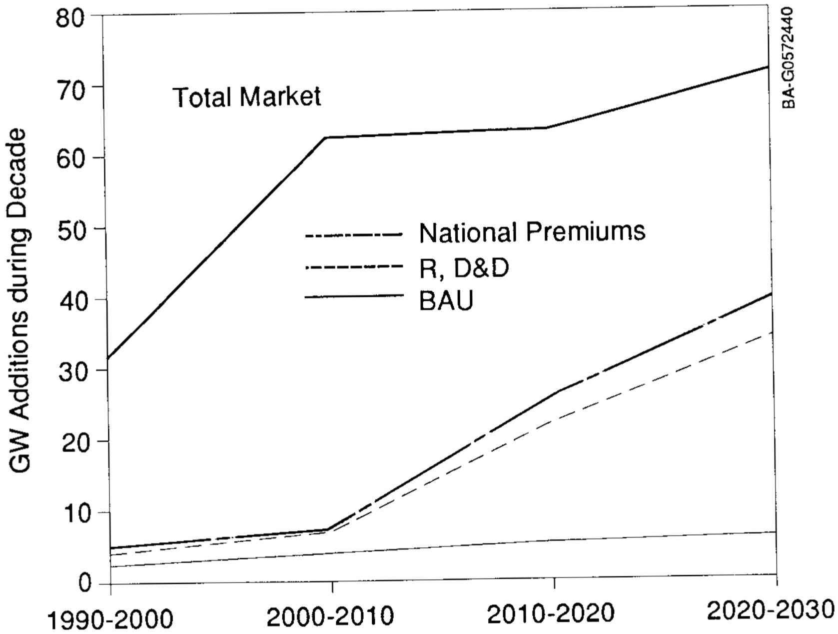

Figure F-6. Wind power incremental market penetration (North Central; unconstrained)

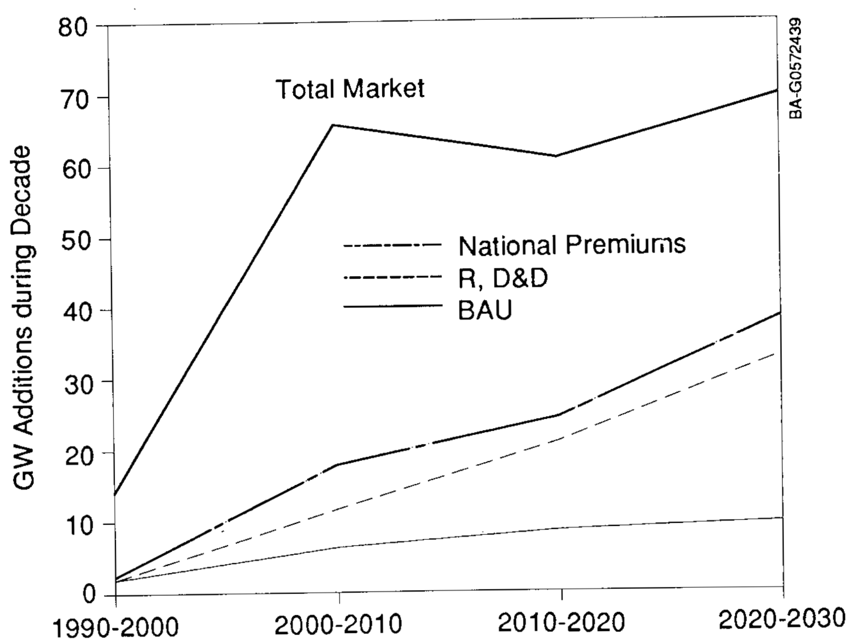

Figure F-7. Wind power incremental market penetration (West; unconstrained)

Table F-2.
Wind Energy Penetration

	Primary Energy (quads)				
	1988	2000	2010	2020	2030
BAU Scenario					
N.E.	0.00	0.03	0.22	0.47	0.75
South	0.00	0.07	0.40	0.84	1.34
N. Central	0.00	0.05	0.16	0.31	0.47
West	0.02	0.06	0.24	0.47	0.74
Total	**0.02**	**0.22**	**1.02**	**2.09**	**3.30**
R,D&D Intensification Scenario					
N.E.	0.00	0.06	0.43	0.87	1.28
South	0.00	0.15	1.14	2.71	5.12
N. Central	0.00	0.11	0.31	1.02	2.11
West	0.02	0.07	0.41	1.09	2.15
Total	**0.02**	**0.39**	**2.29**	**5.68**	**10.65**
National Premiums Scenario					
N.E.	0.00	0.07	0.43	0.87	1.28
South	0.00	0.17	1.16	2.73	5.13
N. Central	0.00	0.11	0.32	1.02	2.11
West	0.02	0.07	0.56	1.24	2.30
Total	**0.02**	**0.42**	**2.47**	**5.86**	**10.82**

It is clear that wind has the potential to make meaningful contributions in virtually all areas of the country. It is also clear that both intensified R,D&D and the national premium are estimated to greatly affect the penetration values. This is mainly due to the reduction of the COE for wind below that of coal. This opens up vast markets for base load fuel displacement in all regions.

F.4.1 Competitiveness/Trade

The nondomestic market appears to be on the verge of a major expansion. In industrialized countries, particularly Europe, significant activities to commercialize wind for electric utility applications are under way. In developing countries, the interest for wind use in traditional roles (e.g., water pumping) as well as for newer uses (e.g., part of a hybrid system for village electrification) appears to be on the increase. These potential markets should not be ignored.

Similar to other renewable technologies, wind energy experienced significant early R,D&D advances in this country but is now undergoing a worldwide technology development effort that far surpasses current domestic expenditures. In Europe alone, seven countries (Denmark, Germany, Italy, The Netherlands, Spain, Sweden, and the United Kingdom) as well as the Commission of European Communities (CEC) are spending as much or more on wind energy R,D&D than we are in this country. In addition, a major Japanese manufacturer (Mitsubishi) has made a major commitment to penetrate the California market with the installation of 340 intermediate-sized (250 kW) turbines in 1989. Given these activities, a sustained domestic commitment to wind energy, including close cooperation between the federal wind program and U.S. industry (both manufacturers and end users), will be required, lest both domestic and international market opportunities be lost to foreign industry.

F.4.2 Opportunities

The unresolved technical issues constraining a major expansion of wind energy are significant but are believed to be solvable with modest additional federal support. A sustained, significant R&D commitment will be required to address the outstanding issues in turbulence, aerodynamics, structural response, materials and fatigue, and improved operating strategies. In addition, a continued effort to transfer these incremental improvements to U.S. industry is essential to the success of this technology.

There now exists an infrastructure in California to effectively operate wind farms; the real challenge is to provide that infrastructure (and utilities) with a more competitive U.S. product--competitive both with other generating technologies and with foreign wind turbines. The provision of this competitive technology should be achievable with very modest increases in the federal R,D&D program to accelerate development of near- and far-term advanced wind turbine designs. This increased budget would also be used to maintain the basic engineering science research foundation, which is necessary to lead the technology, and to support joint ventures with industry to design, develop, and test both a mature design targeted for 1995 and an advanced design targeted for 2010. This effort has already begun with conceptual designs of advanced concepts, which should be followed up with engineering development and detailed design and testing.

If the current funding for federally sponsored research is not increased, the advanced turbine development effort will proceed at a slower pace with increased uncertainties associated with its success because fewer designs can be developed and field tested. Without additional support for basic engineering science research, the ability of U.S. industry to compete for long-term markets will be reduced greatly and might be preempted entirely by advanced European and Japanese hardware.

F.5 Contribution to National Goals

The most significant environmental impact of wind is that there is virtually no impact. The manufacture of a turbine involves only conventional materials (steel, aluminum, and/or fiberglass), and its installation requires only conventional civil engineering and electrical power components (i.e., relatively small concrete foundations and simple interconnecting roads and transmission/transformer subsystems). Its mechanical and electrical components (bearings, gearboxes, generators, etc.) are typically "off-the-shelf" components extensively used in other industries. Thus, wind brings to the environmental integrity index exactly what is desirable: a bulk electric power source that can displace fossil sources without any pollutants associated with power production and with very minimal impacts associated with manufacturing, installation, and operation. In the short run, energy from primarily natural gas- and oil-fired generation will be displaced by wind; in the longer term, coal energy displacement may be possible, depending upon cost levels achieved and facilitating options, such as storage and transmission.

Arguments have been made that the external (social) costs of all energy sources should be included in future decision making processes. A recent West German (FRG) study estimated that excluding environmental and external economic considerations has delayed significant penetration of wind energy in the FRG bulk power market by 7 to 10 years (to 1994 instead of 1984-87)[7]. Although the U.S. situation is certainly different from that in the FRG, consideration of these external costs would improve the relative cost-effectiveness of virtually all renewable energy technologies.

F.6 Other Perspectives

The assumptions for the cost of energy from wind turbines used for the market penetration analysis are supported by independent studies by R. Lynette and Associates[8]. A report on the current status of the industry lists installed costs of new wind turbines in 1989 to be between $850 and $1,400/kW, with annual O&M costs between 1¢ and 2¢/kWh. Lynette predicts that efficiencies will increase by 10% to 20% and that costs will decline to $600/kW by 1995 and $400 to $500/kW by 2000. These improvements will result in a 40% COE reduction during this time period. Lynette also reports current capacity factors for the best wind stations as reaching 35%.

Cost and performance numbers presented in a recent report by PG&E also support our assumptions[4]. The report describes current installed costs of $1,100/kW, O&M costs of 1¢/kWh, and a capacity factor of 25%. The COE calculation is 5¢/kWh, assuming wind speeds typical of those in the Altamont Pass of California. They also reference a PG&E study, *Scenario Evaluation and Research Choice*, which indicates that wind energy will become the most economic new energy source (at the most favorable wind sites) by the year 2002 under the expected fuel cost scenario.

The trend for COE reduction in the near term is further supported by estimates published by *U.S. Windpower*, the largest U.S. wind turbine manufacturer[9]. The company estimates a COE of 4.73¢/kWh for its soon-to-be-commercial model 33-300 wind turbine sited in the Altamont Pass.

F.7 References for Appendix F

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Appendix G
Photovoltaics

G.1 Description of the Technology

Photovoltaics is the direct conversion of sunlight into electricity using devices made of thin semiconductor layers. As long as it is exposed to sunlight, a photovoltaic (PV) device produces an electric current that is proportional to the amount of light it receives. The phenomenon upon which PV is based--the roots of the word allude to it; the conversion of solar photons into electrical voltage--is a rather complex one involving the separation of oppositely charged, light-generated charge carriers (electrons and holes) by a built-in electric field at the interface of the semiconductor layers. Although complex, it relies on a concept quite familiar to modern electronics because the key element--a built-in electric field--is also at the heart of most high-technology semiconductor devices, e.g., the diode, the transistor, and the laser.

The smallest unit of a PV system is called the PV cell. (*Cell* is an appropriate term since PV devices produce dc electricity as does a battery cell.) One of the characteristics of PV is that there are many semiconductor materials for cells (silicon, copper indium diselenide, cadmium telluride, and gallium arsenide are the principal ones) and even two different approaches for putting cells together into modules--flat plates and concentrators. Concentrators are based on using lenses to focus sunlight on small, highly efficient cells; cost is potentially less because the lenses and other module parts are less costly than the cell area that is being displaced. This variety of approaches reflects the strength and potential of PV, in the sense that most alternatives are progressing neck-and-neck toward reduced cost. Having several approaches raises the probability of attaining ambitious cost goals. It also shows that the possibility of attaining those goals is based on a generic capability of PV, not on some unique property of one exotic approach.

Modules are aggregates of PV cells and they are large enough to provide reasonable power. Modules are the building blocks of large PV systems. They can be 1 ft^2 to more than 20 ft^2 and can be expected to produce from 5 to 20 W/ft^2 of power during a clear midday, depending on their effectiveness in turning sunlight into electricity. This effectiveness is measured as efficiency (the percentage ratio of electricity produced to the amount of sunlight incident on the PV device) and is a critical figure-of-merit characterizing all PV cells, modules, and systems. Another important value is called a device's peak-watt power. The output power of a module at noon on a clear day is called its peak-watt power because it represents a maximum typical output. A module characterized as 100 W_p produces 100 W of power during a clear midday.

Photovoltaics is one of the most benign forms of electricity generation likely to be available in the next 50 years. It requires low operation and maintenance (O&M) expenditures, no fuel, no fumes, no noise, and no cooling water, greatly increasing its value in the United States and the world.

G.2 Current Status of the Technology

As previously mentioned, a very useful parameter for measuring PV status is efficiency. The efficiency of today's flat-plate modules (concentrator modules have correspondingly higher efficiencies and costs) ranges from about 5% to almost 15%. Two other important parameters are lifetime and module cost. Present lifetimes range from a few years, for some of the newer technologies, to 20 years or more for crystalline silicon modules. Module costs are in the range of $200 to $500/$m^2$ and have shown a continual decline that is expected to be ongoing[1,2,3].

The present terrestrial PV market has three major segments---consumer products, remote power, and utility generation. The consumer product market was one of the first economic applications of the technology and is characterized by millions of small, milliwatt-sized cells powering calculators and watches. This market has been more than 5 MW per year. The consumer product market is now expanding to larger systems--for battery charging and walkway lighting--reaching power levels near those used for the remote power application market.

The largest use of PV today is the remote power market[4]. The self-contained and modular nature of PV systems has led to their adoption to meet power loads remote from the electric utility. These applications have come to be referred to as "stand-alone" because all of the energy needed by the load must come from on-site sources. Typical stand-alone uses are power for telecommunications, lighting, security systems, water supply, battery charging, cathodic protection, vaccine refrigeration, remote monitoring, rural housing, and small villages. The systems are economical because there is no reasonable alternative, such as for a microwave repeater on an inaccessible mountain top, or because the alternative (often diesel generators) is too costly to install, operate, and refuel. This market accounts for the vast majority of the sales by U.S. industry and is split about equally between international and domestic applications. The domestic customers are remote homeowners, companies purchasing for telecommunications, cathodic protection, and literally hundreds of other uses, as well as governmental agencies like the Coast Guard (navigation aids), the Department of Defense (battery chargers), and state highway departments (emergency call boxes). The international customers are governments or donor agencies involved in rural electrification and development. The current rapid growth rate in PV sales (more than 30% annually) is almost exclusively because of the increase in sales for remote power. There is a growing acceptance and recognition of photovoltaics as a reliable and economical remote power source.

The current utility purchases for PV are relatively small, but very important[4]. Utilities are buying PV for testing purposes. Pacific Gas & Electric's PVUSA (Photovoltaics for Utility Scale Applications) project, funded jointly with DOE, the Electric Power Research Institute (EPRI), and the California Energy Commission, will result in over a megawatt of installations in the next year; however, most other utility purchases are small, less than 100 kW. Utilities are investigating the technology both for their own use and to learn how it interacts with their systems; for example, if homeowners chose to interconnect their own PV system with the utility grid. Several utilities have shown an interest in selling or leasing small systems for remote cabins and homes in their service districts in the near future.

The present market penetration does not fully reflect PV's competitive potential for many reasons, including high initial cost, a lack of awareness in the marketplace, and the need for systems packaging and design assistance. Further, there is an expectation for continued technological progress leading to higher efficiency, longer lifetime, and lower cost. Continued progress is expected because estimates of maximum efficiencies and minimum costs are still far from today's values and because researchers and developers have made consistent progress over the past decade.

The private PV industry is a mix of some 40 firms (90% are small or medium sized) providing manufacturing, distribution, or service[5]. Several large oil firms are (or have been) key players. In general, the industry, especially the manufacturers, has not made money. U.S. companies have encountered serious competition from foreign-owned companies to the extent that the U.S. market share has severely decreased. The world's largest photovoltaic company, California-based ARCO Solar, is being purchased by a German-owned firm.

G.3 Constraints and Opportunities

The potential of PV to displace very significant amounts of conventional energy is based in large part on the fact that the main resource of PV--sunlight--is almost ubiquitous. About 700 times the total annual energy used by the United States falls on this country as sunlight.

Clearly, the resource is immense. Just as significantly, PV systems are not geographically limited by sunlight variations in the United States. All PV systems, except those based on concentrators, can be used everywhere in the United States, including the upper Midwest and the Northeast. This is because PV systems produce a fixed proportion of the annual sunlight as electricity, and annual sunlight only varies by 25% from an average U.S. value of about 1800 kWh/m^2 (the amount available in Kansas City for a module not tracking the sun).

A major technological opportunity is the possibility to significantly improve the conversion efficiency of PV cells and modules. The importance of higher efficiencies is universally recognized because of its impact on both cost (less material and land area is needed) and energy production (more energy per unit area). For this reason, more efficient cells and modules have been a high priority for the baseline funding of the DOE PV research effort. Both materials research (to control the composition of the materials, to enhance "electronic properties" within the cell layers, and to analyze and optimize surface and interface chemistry between layers) and improved devices (innovative designs and multijunction cells, which have several electric fields tuned to different portions of the solar spectrum) offer many approaches to achieving higher efficiencies[6]. Previous improvements in laboratory cell efficiencies have been followed, with a time lag of approximately 5 to 10 years, by equivalent module efficiencies for systems purchased from PV manufacturers[1]. This trend is expected to continue. Today's record PV efficiencies for laboratory cells can be expected to appear as commercial module efficiencies before the turn of the century. In fact, today's laboratory cell efficiencies are already high enough (10% to 30%) to permit significant market penetration if they were module efficiencies. Progress in this area can be accelerated by intensified federal R&D.

Of course, progress depends on ongoing funding both by industry and DOE. The PV industry is still young and hence very fragile. But PV costs are dropping rapidly and some markets are taking off; the outlook today is much better than it was even 2 years ago. However, this change has yet to turn the industry around. It remains burdened with losses, debt, and high start-up costs for new manufacturing, resulting from the prior decade of environmental and energy complacency.

For example, a major opportunity to reduce costs is to develop the manufacturing and processing capabilities needed to produce PV on a large scale[7]. There are two aspects associated with future cost reductions; one is the reduction arising from economies of scale and the second will come from new processing R&D knowledge as production facilities are built. PV module cost reductions will result from both aspects, as well as from continued improvements in cell materials and designs. Nonmodule costs, so-called balance-of-system costs, are expected to drop primarily from economies of scale. These lower balance-of-system costs are expected to result from increased market development of PV systems and from improvements in module efficiency.

To achieve PV module cost reductions requires production facilities and the capital with which to build them. Venture capital for such projects is constrained because of today's low energy costs and the perception that there is insufficient near-term return on investments in PV firms. The creation of a market, especially the utility market, would permit PV manufacturers to develop facilities to reduce PV's costs in large-scale production. Loans to electric utilities to purchase PV systems offer an opportunity if there is an offset on the interest paid by the utilities. Such an offset dramatically changes the economics of technologies, such as PV, having high initial costs. The Solar Energy Industries Association has proposed such a program in which the offset, paid by the U.S. government, would be a small fraction of the total loan value.

Next, the durability of the PV module is another critical opportunity for cost reduction through research and development. Most studies assume 30-year lifetimes for PV systems. These have been nearly achieved in some PV technologies (e.g., crystalline silicon) but are as yet unproven in the newer ones. Work on stabilizing various components of PV modules (the semiconductors, the metal interconnects that carry current) is ongoing, as is development of techniques to better encapsulate the modules from the environment. Lifetime of the array is critical in every cost evaluation, because falling short of expected use increases cost proportionally. The probability for improved durability and longer lifetimes would be greatly enhanced by an R,D&D Intensification Scenario.

Probably the most significant institutional barrier to utility market penetration is the high initial cost (per kilowatt) of the technology compared with the very low initial cost of some conventional alternatives. In this respect, PV resembles hydroelectric generation, which also has a high initial cost but is impervious to future, increasingly uncertain fuel prices. On an annual basis, the first year's cost of energy from a PV system is high, but the energy cost reduces to near zero after 20 and 30 years because there are no fuel costs and the initial capital costs are almost paid. Generation technologies using various fuels have energy cost trends opposite to those of PV, i.e., energy costs in the first year are low because of low initial capital cost and high after 20 and 30 years because of rising fuel costs and high maintenance costs. Regulatory commissions are just beginning to consider the implications of these cost trends for customers, who would normally incur the risks associated with the possibility of fuel prices rising at speculative rates.

One serious constraint for the U.S. industry could be the commitment of foreign-owned industry to succeed in the international competition to develop PV technology. This commitment is supported by foreign governments. Germany's PV budget alone is 65% larger than the U.S. budget; Japan's is 40% greater. If foreign efforts are successful, many of the manufacturers, distributors, or service organizations could be foreign owned. Indeed, if large segments of the industrial structure are foreign owned, there could be effects on the ownership and operation of other elements in that structure. Already, the U.S. market share has seriously declined from 65% in 1981 to 31% in 1988. Such inroads on the part of foreign-owned companies, besides negatively affecting our balance of trade, could hamper the development of a strong U.S. PV industry.

Photovoltaics is one of the cleanest, most environmentally benign energy technologies. The informed public has expressed nothing but unanimous approval and support for the deployment of PV technology because of its clean, silent, and trouble-free production of electricity from sunlight.

Except in the U.S. West, land is perceived as a constraint for the deployment of PV by utilities, but forward-thinking utilities are already testing PV either on customers' rooftops or on their own land contiguous to substations or their conventional power plants. The space needs are equivalent for dispersed or central station generation systems. A recent study by DOE[8] shows that PV land requirements (on a per kilowatt-hour basis) are very similar to those for coal production and combustion. At present land costs (e.g., $2,000/acre in Illinois for prime farmland), the land portion of cost is less than 1% of PV system costs. It is unlikely that land constraints (siting or cost) will become a limiting factor in the United States for the foreseeable future. PV systems can be put on rooftops or can use land without competing uses (i.e., deserts and land with no water access), as well as submarginal croplands or rangeland. Materials availability is also not a constraint because the amounts of semiconductor material used in the PV cell are small or because the materials are as common in nature as sand. PV's small requirements for semiconductor material can be best understood via a comparison with nuclear power[9]. For a breeder reactor with 50% fuel recycling, 1 g of uranium produces about 4 MWh of electricity. For a thin-film module (layers of 0.3 to 1 μm thickness), there are about 2 g of semiconductor for each square meter of module area. Over a 30-year life, a 10% efficient module (1 m^2 in size) would produce about 6 MWh of electricity in a typical U.S. location (e.g., Kansas City). Thus, the PV output (about 3 MWh/g) and the output of a breeder reactor (with fuel recycling) would be about the same.

In summary, PV appears to be a long-term and desirable solution to U.S. and global concerns for energy and environment. Other countries clearly recognize the opportunity.

G.4 Contribution Potentials

We have assumed that PV's end-use sector is electric power. But in the future, PV electricity could also be used in electric vehicles or to make fuels, such as hydrogen for vehicular use. We have *not* assumed *any* contribution from these more speculative applications. However, they could be of great significance--even outweighing the impact of grid-connected PV electricity during the next 40 years. PV is not resource limited relative to these markets in any region. The required land area for all capacity needs in 2030 is about 60,000 km^2, approximately 1% of U.S. land area. Therefore, PV could meet 100% of the market needs as an ultimate theoretical potential. Referring to peaking needs only, they are estimated to be 15% of these capacity needs for the Northeast and North Central areas, and 8% in the South and West. Electricity for peak power is expected to be the major market for PV during the next 5 to 15 years.

We have projected PV technology performance under three scenarios: Business-as-Usual (BAU) Scenario; research, development, and demonstration (R,D&D) Intensification Scenario; and a National Premiums Scenario of 2¢/kWh. Our cost projections are levelized electricity costs for intermittent ac in ¢/kWh ($1989). The BAU Scenario assumes a DOE budget of $35.7 million per year for R&D and factors international competition into the cost projections. The R,D&D Intensification Scenario assumes greatly increased funding through the 1990s, with some reductions thereafter. The National Premiums Scenario is based on a subsidy to the price of PV electricity of 2¢/kWh. A summary of costs and performance data is presented in Table G-1.

Table G-1
Projected PV Technology Performance (¢/kWh)

	1990	1995	2000	2010	2020	2030
BAU Scenario	30	20	15	9	6	5
R,D&D Intensification Scenario	30	15	10	7	5	4
National Premiums Scenario	28	18	12	6	4	3

We have compared our projections with the assumed costs of peak and intermediate electricity from conventional sources of energy in the market construct. With our projections of technology performance and market potential, market entry points (chosen where PV energy costs equal projected peaking costs) are 2005 for the BAU Scenario, 1998 for the R,D&D Intensification Scenario, and 2000 for the National Premiums Scenario. There is an uncertainty of plus or minus 2 years in these estimates. After these initial market penetrations, further technical improvements will lower PV costs well below average peaking costs, which will be 12¢ to 15¢/kWh during the 2000-2030 period. This will allow a much enhanced market penetration in subsequent years. In fact, in the later years, PV costs (4¢ to 6¢/kWh without storage) will be significantly lower than intermediate (9¢/kWh) and baseload (6¢/kWh) projections for conventional energy sources. This implies that PV could absorb a significant cost increment for avoiding intermittency (with storage) and still be competitive in most electricity markets after 2020. It is clear that the most important parameter affecting the future role of PV is cost per kilowatt hour.

In the four regions, Northeast (NE, U.S. federal regions 1, 2, and 3); North Central (NC, federal regions 5 and 7); South (S, federal regions 4 and 6); and West (W, federal regions 8, 9, and 10), the projected incremental new electric capacity need by region (in GW) is shown in Figures G-1 to G-4. Along with the estimated PV market penetration, equivalent quads of energy are presented in Table G-2. For comparison with conventional capacity, it is necessary to note that 2 GW_{peak} of PV is approximately the energy equivalent to 1 GW of conventional supply because PV capacity factors are lower. Another equivalence is that 40 GW_{peak} of PV equals 1 quad of primary energy equivalent, assuming a 0.275 capacity factor. In our projections of regional market penetration, we have assumed that PV would be equally capable of meeting demand in any U.S. region. The regions of less insolation (e.g., NE) tend to have higher electricity costs, which allows PV to be competitive with less solar resource. Thus, regional effects are estimated simply by a weighted average. Not considered are facilitating technologies, electric transportation markets, or PV's potential as fuel supply (PV-hydrogen production). Uncertainties appear most significantly in the time scale (5 to 20 years). A small capacity credit, resulting from coincidence with utility peaks, is taken as equivalent to 1¢/kWh for the PV technology performance projections. Table G-3 shows cost and performance data for PV technology.

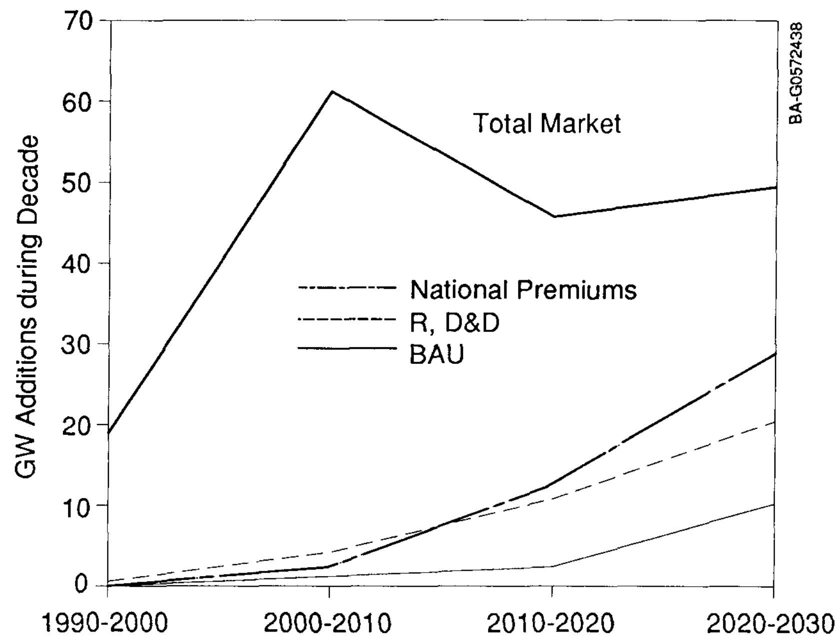

Figure G-1. Photovoltaics incremental market penetration
(Northeast; unconstrained)

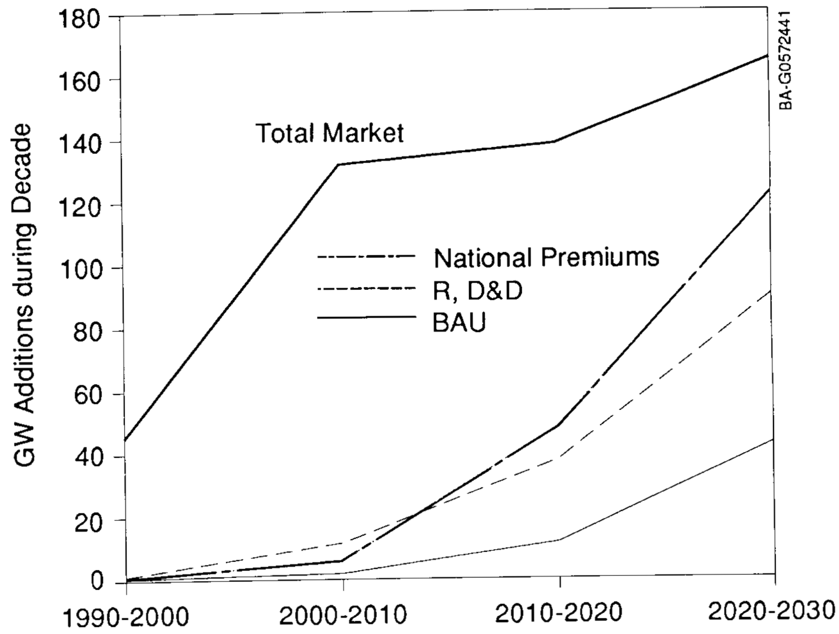

Figure G-2. Photovoltaics incremental market penetration
(South; unconstrained)

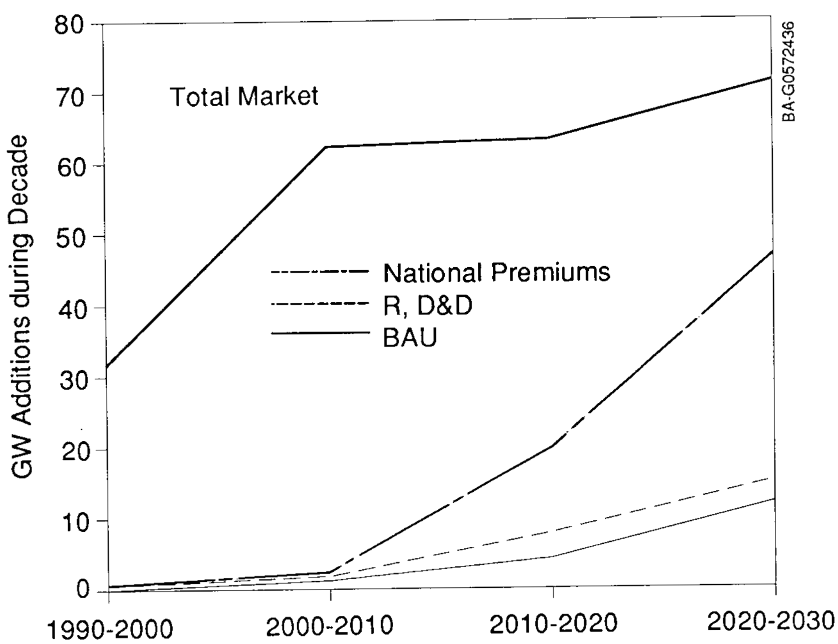

Figure G-3. Photovoltaics incremental market penetration
(North Central; unconstrained)

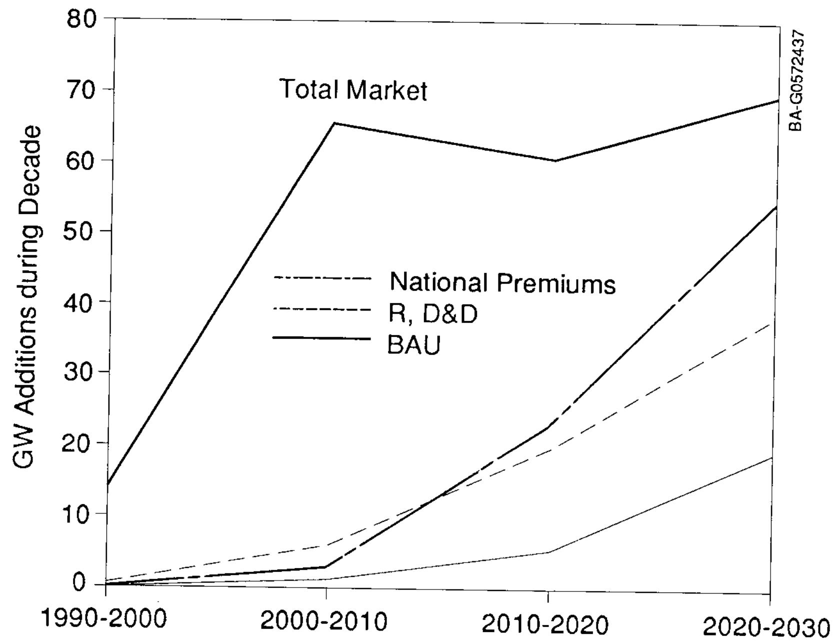

Figure G-4. Photovoltaics incremental market penetration (West; unconstrained)

Table G-2
PV Penetrations

	Primary Energy (quads)				
	1988	2000	2010	2020	2030
BAU Scenario					
Northeast	0.00	0.00	0.03	0.09	0.35
South	0.00	0.02	0.06	0.35	1.41
West	0.00	0.00	0.03	0.17	0.65
North Central	0.00	0.00	0.03	0.14	0.44
Total	**0.00**	**0.02**	**0.15**	**0.75**	**2.85**
R,D&D Intensification Scenario					
Northeast	0.00	0.02	0.12	0.39	0.90
South	0.00	0.03	0.32	0.60	3.50
West	0.00	0.02	0.17	0.66	1.62
North Central	0.00	0.02	0.06	0.26	0.63
Total	**0.00**	**0.09**	**0.67**	**1.91**	**6.65**
National Premiums Scenario					
Northeast	0.00	0.00	0.06	0.38	1.10
South	0.00	0.02	0.17	1.37	4.41
West	0.00	0.00	0.08	0.66	2.03
North Central	0.00	0.02	0.08	0.57	1.74
Total	**0.00**	**0.04**	**0.39**	**2.98**	**9.28**

Table G-3
Uniform Cost and Performance Data:
Photovoltaics Technology

	Capital Cost ($1988/kW)	O&M (¢/kWh)	Capacity Factor	Fuel Cost ($/MilBtu)	Heat Rate Btu/kWh)	Levelized[a] Cost (¢/kWh)	Energy Supply (Quads)
1988	7000	0.5	25.0%	--	--	32.0	0.00
2000 - BAU	3500	0.2	27.5%	--	--	15.0	0.02
- R,D&D	2325	0.2	27.5%	--	--	10.0	0.09
2010 - BAU	2100	0.2	27.5%	--	--	9.0	0.15
- R,D&D	1625	0.2	27.5%	--	--	7.0	0.67
2020 - BAU	1400	0.2	27.5%	--	--	6.0	0.75
- R,D&D	1150	0.2	27.5%	--	--	5.0	1.91
2030 - BAU	1175	0.1	27.5%	--	--	5.0	2.85
- R,D&D	930	0.1	27.5%	--	--	4.0	6.65

[a]Over 30 years at 6.1% discount rate (EPRI TAG)
(Levelized annual fixed charge rate of 0.1007)

1988–2000

- Capital cost reduced by 1/2 in BAU Scenario and 2/3 with intensified R,D&D primarily because of anticipated improvements in cell efficiencies and designs and development of low-cost manufacturing and materials processing capabilities.
- Output, as measured in capacity factor, improves by 10%.
- O&M costs reduced by 50% through learning.

2000–2010

- Capital cost reduced an additional 30% to 40% because of continuing efficiency and processing improvements, as well as production economies of scale.

2010–2020

- Capital cost continues to drop as large-size modules near commercialization, i.e., the DOE goals of 15% modules at $50/m^2 (30-year life) are met.

2020–2030

- Continued advances toward theoretical potential (higher than 15%, less costly than $50/m^2) allow for increased cost reductions. Thin-film multijunctions advance to full maturity.

For more extensive market penetrations (especially beyond the year 2030), storage or new hybrid systems would be needed. At present, batteries are used for storage in small PV systems. Options for large systems are batteries, pumped hydro, compressed air, flywheels, superconductors, and hydrogen production via electrolysis of water. Each of these has its own problems (inefficiency, geographic limits, or high cost) and advantages. Nevertheless, the development of efficient, low-cost storage capability for electricity provides an important avenue for PV electricity to be used on a much larger scale. The kind of costs that we ultimately expect PV to reach--as low as 4¢/kWh (without premium)--suggest that PV *with* storage to meet almost any electrical load will be affordable. In fact, a recent study by Princeton's Center for Energy and Environment suggests that inexpensive PV would be capable of providing hydrogen fuel via electrolysis[9]. Hydrogen fuel could be competitive for most fuel uses, (e.g., the transportation sector). Ogden and Williams also point out that PV has advantages in terms of fuel production: (1) it is efficient enough to minimize the need for large tracts of land, and (2) it uses so little water that it can be located on land with few competing uses (e.g., the desert). But because these important future possibilities remain speculative, we have not included *any* PV market contribution from them. However, our cost projection of 4¢/kWh in 2030 is largely consistent with the Princeton analysis and suggests that the ultimate role of PV may be far larger than most assume.

The ultimate performance characteristics of PV are not well known. Purely physical limitations would allow much higher efficiencies and much lower manufacturing costs than those assumed in these projections. Theoretical efficiency limits are as high as 70% to 80%, although semiconductor material limitations reduce these values. Ultimate cost limits are driven by support structures and the cost of glass. Although there are many concepts for providing environmental protection for the semiconductor layers for periods of 20 to 30 years, encapsulating the layers between two sheets of glass is the most likely concept. Another likely concept is a front sheet of glass with a tedlar encapsulant on the back. In the limiting case of a fully developed technology where production costs are negligible and material costs predominate, it is feasible that module costs could significantly decrease.

Research opportunities abound for improving PV to reach our ambitious cost projections. The R,D&D Intensification Scenario will have a large-scale market entry 7 years earlier than the BAU Scenario. Earlier market entry will be the result of knowledge from process research. Process research activities will be important to maximize the yield of high-efficiency PV modules and to reduce production costs through identification of lower cost processing technologies. At present, the manufacturing cost of the PV module can be as much as 75% of the total cost of an intermittent PV system. Even when improved to the levels associated with the DOE long-term goals, the module cost will remain almost 50% of the total system cost. Present costs of modules vary from about \$200 to \$500/m^2, depending on technology (more efficient modules generally cost more). Near-term expectations (next 5 years) are for costs to drop to about \$100 to \$300/m^2, again depending on technology. The long-term goals appropriate to reaching PV energy costs of 4¢ to 6¢/kWh are in the \$40 to \$100/m^2 range[2,3]. Intense R&D is needed to address fully optimized approaches to reducing the cost of manufacturing PV panels[3].

G.5 Other Perspectives on Photovoltaics

Over the years numerous organizations have projected the potential impact of photovoltaic technology on both domestic and international energy supply. The primary difference between these assessments was the timing of the cost reduction necessary for the impact to occur, and the resultant rate of market penetration. In essence, all of the studies assume the basic tenet of the photovoltaic program--an energy cost of approximately 6¢ to 12¢/kWh is necessary for economic operation in the utility environment. However, in almost every case, the timing of this cost reduction and resulting market penetration is more optimistic than projected in this report.

In a 1984 assessment[10], the Edison Electric Institute (EEI) described a "PV breakthrough" scenario that included a rapid buildup of manufacturing capability to 10 GW in the year 2000 and very low system cost. In this analysis, PV accounted for 17.7% of the U.S. installed capacity in 2010, with further penetration dictated by plant retirement rates.

In a 1985 publication the Office of Technology Assessment, predicted that photovoltaics would be primarily a centralized generation source capable of providing more than 4.5 GW by 1995 nationwide[11]. The cost of the photovoltaic system and the resultant cost of energy were identified as the key challenges facing the technology. A market assessment published by Frost and Sullivan, Inc., in the same year predicted annual domestic PV sales of 306 MW in 1990[12].

EPRI performs periodic assessments of photovoltaic technology development status and costs but does not analyze potential market penetration. EPRI's technology assessments are generally in agreement with those of the U.S. DOE National Program. The Japanese have analyzed the potential for photovoltaics in Japan and predict a potential market of "several ten thousand MW," with the annual demand increasing from 100 MW/year to a few hundred MW/year in the 1990s[13]. In his analysis of the beneficial effects of using wind and photovoltaics, Hohmeyer projected the contribution of photovoltaics as high as 6% of the total energy production for Germany[14].

The greatest impact for photovoltaics is predicted in a recent publication of the World Resources Institute[9]. In this analysis, photovoltaic systems are used to generate hydrogen. The hydrogen is stored and either converted to base-load electricity or distributed for use as a transportation fuel. The authors project that for very inexpensive photovoltaic systems, characterized by energy costs in the 3¢/kWh range, the potential market for photovoltaics in U.S. base-load electric power (with storage) is 600 GW. They project that the market for photovoltaics to produce hydrogen fuel would exceed this value, reaching 1100 GW.

Two representatives of the U.S. PV industry who reviewed this white paper believe that the levelized cost of PV will drop substantially faster than projected here. In addition, input we received from other reviewers suggested the same thing, i.e., that our expectations about future reductions in PV prices are too pessimistic. In fact, two cost studies from PV manufacturers predict \$1/W PV module costs by 1995--equivalent to about 12¢ to 15¢/kWh at the system level. The reviewers made cogent arguments in favor of more rapid price reductions, especially in the case of intensified R&D (Table G-1). As one reviewer stated directly, PV is a research-driven technology--perhaps more so than any other renewable technology--and should be expected to respond with great sensitivity to an enhanced R&D budget.

As a response to the reviews, we developed a scenario of faster cost reductions within this section of the paper. The reader may consider it a minority opinion stated as part of the "Other Perspectives" section. We do not propose it as the most likely scenario, but it is one that would be consistent with the expectations of many within the PV community. In contrast to the figures given in Table G-1, we suggest the following: Under an enhanced R,D&D scenario, we could see a drop in PV prices to 13¢/kWh in 1995 (instead of 15¢); 8¢/kWh in 2000 (instead of 10¢); and 5¢/kWh in 2010 (instead of 7¢), recognizing that intensified R,D&D could reduce costs faster than originally assumed. In addition, an intensified R,D&D budget would change the investment and market climate enough to accelerate the time in which 10 MW and larger PV plants would come on line, thus allowing for more rapid economies of scale--(i.e., more rapid price reductions).

Reviewers also criticized our market projections as too pessimistic. One introduced the concept of a period of explosive growth. We had assumed steady, incremental growth. The reviewer felt that instead, PV would experience a period in which numerous companies would begin module production simultaneously, allowing for much more rapid growth. This would occur when PV becomes fully competitive. About 8¢/kWh was proposed as the price level at which growth would become explosive. After this period (about 10 years), growth would follow more normal trends. Given the modular quality of PV manufacture and the fact that it is amenable to automation, we agree with the reviewer about the possibility of explosive growth in the PV industry.

A period of explosive growth could occur in every one of the proposed scenarios, but at different times. In our original projections (Table G-1), it would occur about 2020 in the BAU Scenario; 2010 in the R,D&D Intensification Scenario; and 2005 in the National Premiums Scenario. In fact, if progress is more rapid in the R,D&D Intensification Scenario, as we assume in this section, then explosive growth could occur even earlier, around 2000. If a period of explosive growth occurs, all the final market penetrations would be higher. If faster cost reductions are realized in the R,D&D Intensification Scenario, and all scenarios experience a 5 to 10 year period of explosive growth (see Table G-4 for comparison with the baseline projections), then we project the following market penetrations:

- For the BAU Scenario, 4 quads by 2030 (up from about 3 quads)
- For the R,D&D Intensification Scenario, 2 quads in 2010 (up from 0.7 quad), 6 quads in 2020 (up from 1.9 quads), and 12 quads in 2030 (up from 6.7 quads)
- For the National Premiums Scenario, 4 quads in 2020 (up from 3 quads) and 12 quads in 2030 (up from 9.3 quads).

Thus, it is clear that a more optimistic set of assumptions such as those proposed by our minority position would suggest a sizable additional PV market penetration.

PV is a new, untried technology. Its future is uncertain. We can project the success of PV based on the physics of PV devices. We know they will work, and we foresee that they will become inexpensive. However, at this point our tools for projecting cost trends and market penetrations 30 to 40 years into the future are too weak. The reader can use the various projections here as an envelope of possibilities. The main text incorporates a mid-range projection in keeping with the overall white paper approach. The alternative R,D&D Intensification Scenario in this Other Perspectives section is based on the judgment of reviewers who viewed our initial cost projections as too pessimistic. This alternative projection is within the uncertainty band of future projections and may well be correct.

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Appendix H
Solar Heat: Buildings and Industrial Technology

H.1 Description of the Technology

Solar heat and building technologies utilize the radiant energy of sunlight and the thermal energy it produces in applications ranging from low-temperature domestic pool heating, to daylighting, to high-temperature industrial heating. These technologies take advantage of the abundant U.S. accessible solar resource, estimated to be 101 trillion barrels of oil-equivalent energy annually[1].

H.1.1 Solar Building Technologies

Solar building technologies include active and passive heating and cooling systems, as well as daylighting. Traditionally, systems that use pumps or fans for heat distribution and solar collectors distinct from the building structure have been labeled as active systems. Passive systems typically use the building structure directly for collection (e.g., windows) and storage (e.g., walls, floors) and rely on natural convection and radiation for heat distribution.

H.1.2 Active Solar Energy Systems

Active solar energy systems are employed in residential and commercial/industrial buildings for the provision of space conditioning (heating and/or cooling) and/or hot water. Another common application is the heating of swimming pool water.

The basic building block of an active solar energy system is the collector. The collector contains a receiver or absorber that converts the incident solar radiation into heat. The heat collected by the absorber is transferred to a working fluid, such as a water-glycol solution or air, for transport directly to the load or to storage for later use. Transport is usually accomplished with pipes, pumps, and valves for liquid systems and with ducts, dampers, and fans for air systems. For liquid systems, insulated tanks are generally used to store the working fluid until there is a demand for the heat. For air systems, potential storage media include rocks or phase-change materials. Normally, storage capacity is limited to that required to meet the portion of the daily load that occurs when the sun is not shining. To meet these loads during prolonged periods without sunshine, most active solar heating systems are supplemented by a backup conventional system.

The combination of solar cooling with solar heating can provide for year-round utilization of collected solar heat and thereby significantly increase the cost-effectiveness and energy contribution of solar installations. Currently, solar desiccant and solar-driven absorption systems are the active cooling technology options that appear to have the greatest potential. Solar desiccant systems use a desiccant or drying agent to adsorb water vapor in recirculated or ventilated air to reduce humidity levels. The warm dry air is subsequently cooled evaporatively to the required temperature. The solar heat from the collectors is used to dry or regenerate the desiccant so it can regain its moisture-trapping or sorption capacity. A solar absorption system uses the thermal energy from the solar collector to separate a binary mixture of an absorbent and a refrigerant fluid. The refrigerant is condensed, throttled, and evaporated to yield a cooling effect, after which it is reabsorbed to continue the cycle.

H.1.3 Passive and Other Solar Building Technologies

Much progress has been made in the development of passive solar building designs and materials. Passive solar includes a variety of technologies, such as advanced windows that reduce heat losses and advanced thermal storage and transport systems that provide greater flexibility, control, and capacity. These advances have proven successful in contributing solar energy for heating single-family homes and small nonresidential buildings. Measured savings in 48 typical residential applications averaged 39% of heating energy requirements; performance improvements tracked in small nonresidential buildings showed 46% reductions in heating, lighting, and cooling energy use compared with conventional buildings of equal size[2].

Passive solar cooling options, relying primarily on natural ventilation and evaporation to provide a cooling effect, are used in residential buildings in some regions of the United States. Ventilation strategies include proper placement of windows and vents to maximize wind capture, designs that induce air circulation using the chimney or stack effect, and designs that use cool night air to precool building storage elements. Vented mass walls, operable clerestory windows, and vented storage elements (e.g., hollow concrete block floors) have been found to be effective for these applications. To promote occupancy comfort, both natural and forced ventilation are used in the residential sector and have high potential in the nonresidential sector.

Daylighting is the use of sunlight to provide a building's lighting requirements. Daylighting technologies are categorized as either perimeter or core systems, depending on whether natural illumination is provided to the spaces directly adjacent to the building exterior or to interior spaces, respectively. Technologies for naturally illuminating perimeter offices and interiors of single-story buildings (or the top story of buildings) are available in the form of advanced windows, light shelves, skylights, roof monitors, and sidelighting. Atria designs are currently the dominant technology for core daylighting. Atria designs have gained popularity because of their amenity value, as well as energy savings potential.

H.1.4 Concentrating Solar Thermal Technologies for Industry

Solar energy systems that concentrate solar radiation to achieve high temperatures and/or high flux can also be used for electricity generation (electric applications are discussed in Appendix E), industrial process heating (IPH), and a number of specialty industrial applications, such as detoxification of hazardous wastes, surface treatment of materials, and the synthesis of fuels and chemicals. IPH systems generally use parabolic troughs that reflect sunlight onto a receiver achieving flux levels of up to 100 times that of natural sunlight and temperatures as high as 750°F.

One recently identified application, in which industry energy service requirements appear to be matched to the availability of solar, as well as to solar's ability to deliver both heat and high-energy photons, is the detoxification of hazardous wastes. Recent laboratory and field experiments have shown that hazardous wastes in dilute aqueous solutions can be decomposed in the presence of a photocatalyst that absorbs the ultraviolet (UV) portion of the solar spectrum. This process has an advantage over the dominant conventional processes of carbon adsorption and air stripping. The solar process can actually destroy toxic chemicals on site rather than transferring them to a carbon bed or the atmosphere.

Another solar process under investigation uses high-energy photons and high temperatures produced with concentrated solar flux to decompose gaseous or concentrated toxic waste streams. Experiments have been performed with a parabolic dish system capable of concentrating sunlight by a factor of 2000 or more. Results have shown this process is capable of achieving the level of decomposition mandated by the Environmental Protection Agency at temperatures well below those required in conventional incinerators. Furthermore, the photolytic destruction process produces less of the by-product chemicals (possibly toxic) that are typically associated with incomplete combustion in conventional incineration.

H.2 Current Status of the Technology

It is estimated that in the United States today, more than a million active solar heating systems have been installed. More than twice as many systems may be in place in other countries of the International Energy Agency[3]. Most of the U.S. systems were installed in the late 1970s and early 1980s, a result of the combination of rising energy prices and government tax credits. Although many of these systems suffered from hasty designs and poor installation, as well as unreliable controllers and sensors, the reliability of today's systems has improved considerably. However, lower energy prices and the expiration of the federal solar energy tax credits have reduced the rate of new installations dramatically in the United States.

Although a small number of solar desiccant cooling systems were installed in the early 1980s, significant market penetration is not expected until the 1995-2000 time frame. By this time, solar cooling system costs should decrease from the current level of $4,000 to $8,000/ton ($20 to $40/MilBtu of heat removed) to the long-term goal of $2,000/ton ($5.40/MilBtu), with the energy contribution increasing from 40% to 60% of the cooling load in a typical building application[2].

Although it is difficult to determine the number of houses using passive solar technology today and the amount of energy saved nationwide each year, it has been estimated that 250,000 to 300,00 homes in the United States include some passive solar design features[3]. The costs of passive solar heating and cooling are also somewhat more difficult to estimate than those of active solar technologies. Many passive materials and techniques can be incorporated into building construction at little additional cost. Thus, the cost of energy saved from passive solar construction is comparable to that for energy-conserving buildings in general[2].

In the late 1970s, a number of IPH systems were constructed, most of which are no longer in operation because of the relatively low cost of conventional energy today, but also because of reliability and performance considerations. Since that time, the trough system cost has decreased to approximately $200/m^2 of reflector area ($20 to $30/MilBtu)[4]. Performance and reliability problems have been resolved through the successful application of the trough technology in electricity generation.

H.3 Constraints and Opportunities

H.3.1 Institutional Constraints and Advantages

Some of the technology-specific institutional factors that limit use of solar heating and building technologies have been discussed in the previous sections. Factors that affect all the technologies include their high initial capital cost (passive solar is a frequent exception); consumer preferences and aesthetics; lack of public and developer awareness; scarcity of design tools; and in the case of IPH systems, matching industrial processing requirements.

On the other hand, solar heat technologies have significant environmental advantages that encourage their use. Not only do they produce none of the noxious combustion effluents that plague most of the large metropolitan areas of the United States, but they also produce no CO_2 or other greenhouse gases associated with combustion. Furthermore, they constitute a secure source of energy, free from international influences.

H.3.2 Performance Constraints and Research Issues

Many of the technology-specific performance constraints were discussed in Section H.1 and are reiterated in Table H-1. Generally, solar energy system performance constraints are related to the dispersed and transient nature of sunlight. Thermal storage systems can be used to provide uninterrupted operation of heating systems during transients (occasional clouds) and overnight. However, to be cost effective for longer periods, thermal storage systems must be extremely inexpensive. Because light itself cannot be stored, no storage capability exists for daylighting or the photolytic destruction of toxic wastes.

As the cost of energy from both the collection and storage systems decreases, the fraction of the load that can be met with a solar energy system will increase and the requirement for a backup system will lessen. Solar heating contributions in residences are expected to increase from their current level of 40% to 50% of the load to closer to 80%, while 60% of a typical residential cooling load may eventually be met with solar.

As shown in Table H-2, the primary research issues for solar heat technologies concern achieving high conversion efficiency at low system cost; this is especially true for the detoxification technologies, which have only recently been investigated. As the technologies mature, the research and development emphasis will shift more toward manufacturability.

H.4 Contribution Potentials

It is estimated that 26.8 quads of primary energy were consumed in U.S. residential and commercial buildings in 1986[5]. Figure H-1 shows that more than three-fourths of the aggregate energy-consuming activities in buildings are amenable to solar energy use. In residential buildings, the service of heating loads represents the major opportunity, while in commercial buildings both HVAC and lighting applications offer potential. The market projections used for this study suggest that energy demand in buildings may nearly double by 2030, indicating a substantial market for solar technologies in new construction as well as existing buildings.

We project that should the low current rate of installations continue, the total active solar energy contribution in the United States in the year 2000 will rise to only approximately 0.06 quad. However, improved materials and system controls, increased freeze protection, stratified tanks in low-flow systems, and innovative configurations integrated within the building (multifunction applications) could lower future active solar energy costs from their current level of $30/MilBtu of delivered energy ($2,000 to $5,000 system cost) to as low as $10 to $15/MilBtu. These cost reductions, together with increases in conventional fuel prices, should produce a situation similar to that of the 1981 to 1984 time frame when annual production of active solar collectors was about 18 million ft^2/year. By 2010 this could result in as many as 5 million active solar systems installed in the United States, displacing 0.2 quad of conventional energy.

Table H-1.
Technology-Specific Performance Constraints

Technology	Constraint
Active solar hot water	• High heat losses and freeze protection requirements in cold climates • Hot water loads when sun is not shining
Active space heating	• Greatest requirement is in northern latitudes where insolation is lowest • Greatest requirement is in winter when insolation is lowest • High heat losses when load is greatest
Active space cooling	• Additional efficiency factor introduced in the form of the cooling subsystem • Competes against conventional chillers/heat pumps, which have high coefficients of performance • Requires higher operational temperatures reduce collector efficiency
Passive heating	• Greatest requirement is in northern latitudes where insolation is lowest • Greatest requirement is in winter when insolation is lowest • South-facing potential glazing area is limited
Daylighting	• Technologies not yet fully developed for lighting building interiors • No storage capability
Concentrating solar IPH	• Requires high direct insolation • No storage capability for photolytic detoxification • Requires collectors that track the sun; moving parts decrease reliability

Table H-2.
Current Research Issues

Active:
- Low heat loss, inexpensive glazings and absorbers (efficiency)[a]
- Innovative configurations integrated with buildings (manufacturability)
- Central storage systems (demand compatibility)
- Improved desiccant materials (efficiency)
- Integrated heating and cooling systems (manufacturability)

Passive:
- Advanced windows with reduced thermal losses (efficiency)
- Phase-change materials integrated with building materials for thermal storage (demand compatibility)
- Improved ventilation strategies (efficiency)
- Integration with active systems (manufacturability)

Daylighting:
- Electrochromic materials and glazing configurations (efficiency)
- New atria materials
- Innovative core daylighting methods (efficiency)

Concentrating solar IPH:
- Low-weight, low-cost, stretched membrane heliostats (manufacturability)
- Multifaceted parabolic dishes with membrane reflectors and low-cost, rim-driven tracking systems (manufacturability)
- Photocatalysts active over a broad spectral band for detoxification of hazardous materials (efficiency)
- High-reflectivity, durable reflective films for detoxification applications (efficiency, lifetime)
- Solar detoxification capabilities over a wide range of chemicals; media, such as water and soil; and conditions, such as insolation, temperature, and contaminant level (efficiency).

[a]Parentheses indicate the area to be improved through the research.

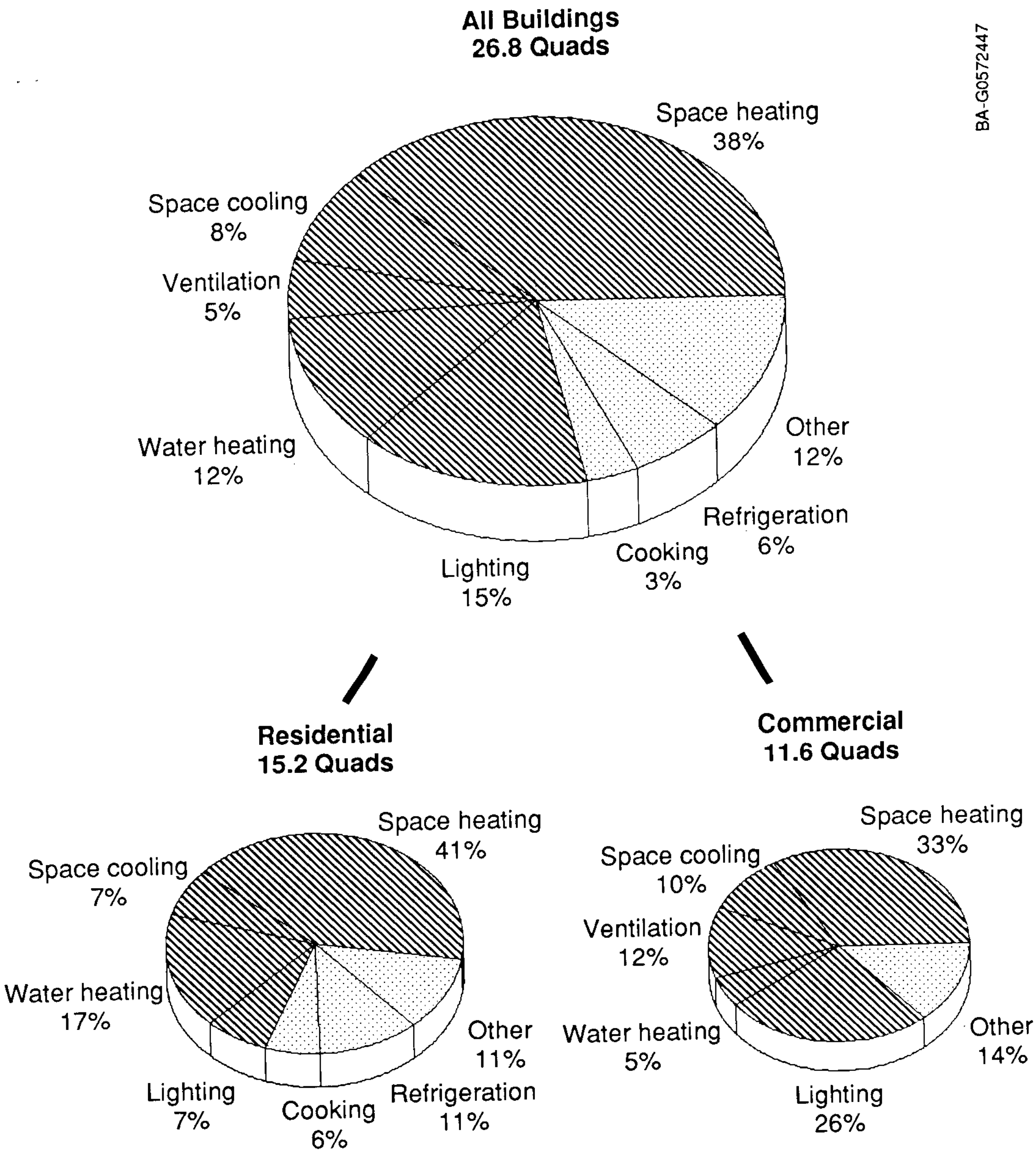

Figure H-1. Primary energy use in buildings by end use (1986)

The number of passive solar buildings will surely increase as windows and thermal storage materials are improved, the public becomes more aware of the energy efficiencies that are possible through good design at no additional cost, and conventional energy prices rise. The potential for passive solar designs includes the majority of new buildings construction. However, market penetration is probably limited not as much by costs as by such factors as consumer aesthetic preferences, street access/building orientations, required occupant interaction, and the interests of developers and architects. The availability of easily implemented, passive solar design tools for developers and homeowners will go a long way toward overcoming many of these noneconomic barriers.

Solar radiation is both a source of heat and light; therefore, daylighting use has implications for heating and cooling loads, as well as electrical lighting requirements. As new technologies emerge to collect, transport, and distribute light to the core areas of buildings, daylighting will play a significant role in reducing the cooling loads currently imposed by artificial lighting systems.

Future market penetration of solar IPH systems will depend on conventional fuel prices and the identification of process applications in which the availability of sunlight is well matched to the industrial load requirements. With the exception of detoxification systems, solar IPH applications in 2010 will be limited.

The growing national problem of toxic material contamination suggests that solar processes for waste detoxification may enjoy rapid penetration of several niche markets in the next few years. More than 25,000 sites have been identified in the United States with contaminated soils and/or groundwater. This problem continues to grow as more than 280 million tons of toxic materials are released into the U.S. environment each year[6]. Decontamination of existing toxic materials in soils and groundwater alone could result in hundreds of solar systems by the year 2010, saving 0.02 quad per year of primary energy. Perhaps, more importantly, these energy savings would be accompanied by a reduced public health risk associated with the toxic by-products of conventional incineration and water cleanup procedures.

Table H-3 summarizes the solar heat deployment projections developed for this study. For buildings, the Business-as-Usual (BAU) Scenario was developed based primarily on historical production levels. In the R,D&D Intensification Scenario, improvements in the cost, manufacturability, and reliability of collectors and controls for solar buildings technologies result in almost a doubling of market penetration relative to the BAU Scenario. In the National Premiums Scenario, solar buildings technology market penetration essentially triples relative to the BAU Scenario because the premium is expected to make these technologies significantly more attractive to deploy.

The BAU industrial market penetration assumes that the bulk of the penetration is related to solar systems for the detoxification of hazardous wastes. R,D&D Intensification in this area is expected to quickly produce catalysts that are photoactivated in the visible, as well as UV regions of the solar spectrum. The efficiency improvements associated with these new catalysts will improve the competitive position of solar detoxification technologies such that market penetration will be increased significantly by the year 2000. The increase in industrial market penetration in the National Premiums Scenario is less than that of the R,D&D Intensification Scenario because the premium alone is not expected to significantly alter the competitive position of the detoxification processes.

Table H-3.
Projected Deployment/Energy Contribution from RETs (quads)
Technology = Solar Heat: Buildings and Industrial

		Business-As-Usual		R,D&D Intensification		National Premiums	
Time	Region	Bldgs.	Industry	Bldgs.	Industry	Bldgs.	Industry
Current (1988)	**Total**	**0.050**	**0.000**				
	Northeast	0.003					
	South	0.020					
	West	0.024					
	Midwest	0.004					
2000	**Total**	**0.150**	**0.002**	**0.225**	**0.022**	**0.338**	**0.004**
	Northeast	0.008	0.000	0.011	0.001	0.017	0.000
	South	0.058	0.001	0.088	0.011	0.132	0.002
	West	0.072	0.001	0.108	0.007	0.162	0.001
	Midwest	0.012	0.000	0.018	0.003	0.027	0.001
2010	**Total**	**0.300**	**0.030**	**0.525**	**0.100**	**0.920**	**0.041**
	Northeast	0.015	0.001	0.026	0.003	0.047	0.001
	South	0.117	0.014	0.204	0.049	0.359	0.020
	West	0.144	0.010	0.252	0.033	0.441	0.013
	Midwest	0.024	0.005	0.042	0.016	0.074	0.007
2020	**Total**	**0.405**	**0.079**	**0.675**	**0.215**	**1.200**	**0.106**
	Northeast	0.021	0.002	0.035	0.005	0.060	0.002
	South	0.158	0.037	0.264	0.101	0.468	0.050
	West	0.195	0.027	0.324	0.074	0.576	0.037
	Midwest	0.033	0.013	0.054	0.035	0.096	0.017
2030	**Total**	**0.525**	**0.169**	**0.900**	**0.285**	**1.544**	**0.201**
	Northeast	0.026	0.004	0.045	0.007	0.077	0.005
	South	0.204	0.077	0.351	0.130	0.602	0.091
	West	0.252	0.060	0.432	0.102	0.741	0.072
	Midwest	0.042	0.028	0.072	0.047	0.123	0.033

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Appendix I
Facilitating Options: Resource Assessment, Energy Storage, Hydrogen, and Transmission and Distribution

I.1 Resource Assessment

Resource assessment is the development of data and methods for characterizing the spatial and temporal distribution of the resources and can play a key role in the penetration of renewable technologies by reducing the uncertainties about fluctuating natural wind and solar assessment.

Renewable energy technologies (RETs) are selected for development based, in part, on the assumption that they are a significant potential energy source. This assumption is usually based on large-scale, preliminary surveys indicating the general magnitude of the resource. Some examples of published results of these surveys are

- Solar Radiation Resources: *The Solar Radiation Energy Resource Atlas of the United States*[1], *Insolation Data Manual*[2], *Direct Normal Solar Radiation Data Manual*[3]
- Wind Resources: *Wind Energy Resource Atlas of the United States*[4]
- Geothermal and Ocean Thermal Resources: *Assessment of Geothermal Resources of the United States*[5], *Geographic, Bathymetric, Geologic, and Physical Oceanographic Data of Potential OTEC Sites* (Ocean Thermal Energy Conversion)[6]
- Hydropower Resources: *National Hydroelectric Power Resources Study*[7]
- Biomass Resources: *Location of Biomass Feedstocks*[8].

These broad-scale resource inventories give us some information on regional variability, but are inadequate for site selection and design purposes or for economic analysis necessary to invest dollars in the RETs.

As the definition and deployment of the RET become more specific (e.g., site-specific), the resource information must become more specific and comprehensive. For example, solar radiation is the resource for solar thermal technologies; however, for applications of solar concentrators that detoxify hazardous wastes, it is necessary to characterize the magnitude and spectral, temporal, and spatial distribution of the direct-normal component of solar radiation in the ultraviolet region of the solar spectrum. As another example, if photovoltaic-generated energy is proposed to match hourly peak load utility demands, the hourly distribution of solar radiation for a particular season and location must be understood. Specific characteristics of the resource with respect to the RET determine the usable energy content of the resource; for example, the sustained wind speed required to activate a particular wind machine.

When an actual application of a RET is considered, factors such as legal, political, environmental, and cost constraints affect resource availability and use. At this stage, we need site-specific details about the resource and development constraints; for example, we may exclude land areas for energy crop production because of topography, unfavorable climate (solar radiation, precipitation, temperature), or land use restrictions.

In the final analysis and energy system design, we need specific data on the resource, with defined uncertainty limits. This information is combined with the RET conversion efficiency to predict the cost of delivered energy and assess economic viability. We increase the reliability of our energy projections (i.e., reduce economic risk) by reducing the uncertainty in our resource data. If questions such as, "What happens when the sun doesn't shine?" are addressed with very specific information about sunshine duration and variability with respect to the operation of a RET, we can increase the investor's confidence in the RET as a viable alternative.

At the same time that the RETs are being developed, details of the renewable energy resources should be developed. Then the information required for site-specific analysis is available when utilities perform economic analysis for investment risk. Unfortunately, many of the resource inventories have not progressed much beyond the initial broad scale inventory. The methodology, characteristics of the resource with respect to the RET, and information on constraints are not sufficiently developed for site selection, comparison of RETs, or assessment of hybrid systems. This is true domestically and internationally.

Currently, the capability does not exist to incorporate relevant resource information into a common data base and iterate through various RET options. For each RET, it would be useful to create and maintain a dynamic systems model (with shared data bases) that integrates key variables of the resource and RET performance. Key variables can be identified by resource and RET experts, and the interactive systems model is used to perform sensitivity analysis and identify critical information needs. Using a dynamic approach, it would be possible to assess the impacts of RET changes (such as new multijunction photovoltaic [PV] devices with extended spectral responses) or resource changes (such as new energy crops) using an established methodology and up-to-date resource data bases.

At present, very limited renewable resource data of varying quality and content are spread out among experts around the country and world. Our national energy strategy may want to anticipate the resource needs, establish long-term data collection and resource characterization programs, and seek consensus on analysis methods for RETs with respect to resource variability and development constraints. This will significantly enhance and facilitate the development and deployment of the RETs nationally and internationally.

I.2 Energy Storage

Storage allows energy to be made available *when* it is required. This contrasts with transmission and distribution, which provides energy *where* it is required. Renewable energy technologies, such as solar and wind, have predictable characteristics on average, but the available power cannot be predicted at any defined time in the future. Similarly, many loads may have a predictable profile on average but random behavior in actual practice. A storage system allows any generated energy that is in excess of "instantaneous demand" to be saved. This is later used when the primary energy source may be either unavailable or insufficient to satisfy demand.

A complete energy dependent system is typically composed of collection, conversion, transmission, distribution, and utilization sectors. Storage may follow any or all of these sectors, depending upon the specific case. In general, the number of times storage is used and the amount of storage employed must be carefully determined. This determination minimizes the cost of providing some defined energy-related service or work, which is required with some minimum acceptable probability. The cost of delivered energy *increases* as the amount of storage associated with providing that energy increases. Storage is particularly useful for small loads, which often have demands that are either poorly matched to the typical supply profile and/or have large variations about their average.

Numerous energy storage technologies are currently available or are under development. Among these are the following:

Batteries: They are especially well suited for photovoltaics and wind fixed site applications and may be used in transportation applications as well.

Thermal: It is especially well suited for solar thermal applications. A heat storage medium, such as water, oil, molten sodium, or molten salt, is used.

Flywheel: Electrical or mechanical energy is stored as kinetic energy in the rotating machine.

Pneumatic: Mechanical energy is used to pressurize a gas (usually air) in a vessel; the gas can be discharged to drive a piston or a turbine. Large salt domes or rock caverns can be used as the vessel.

Chemical: In addition to batteries, energy can be stored by generating chemical species, such as hydrogen, by electrolysis or thermal decomposition of water. Hydrogen can be subsequently burned or used in a fuel cell.

Superconducting Magnetic Energy Storage (SMES): Electrical energy is stored in a superconducting coil and removed as needed.

Pumped Hydro: Water is pumped into a hydro reservoir and used later for hydro generation.

There are many examples of storage technologies used with renewable energy systems. Some of these are as follows:

Storage Technology	*Application*
Batteries	Tens of thousands of $\leq$ 100 W PV systems Thousands of 100 to 1000 W PV systems Hundreds of > 1000 W PV systems
Thermal Storage	
Oil	Willard and Coolidge irrigation systems
Rock/Oil	10 MW_e Solar One, Shenandoah Total Energy System
Molten Salt	Solar Central Receiver Test Facility
Chemical	Solar Thermal Test Facility: Carbon dioxide and steam reforming of methane to produce hydrogen and carbon monoxide

The following are other energy storage applications that have potential for use with renewable energy systems.

Storage Technology	*Application*
Compressed Air Energy Storage	A pilot plant for utility load leveling is being built using a salt dome in McIntosh, Alabama.
Flywheels	High power density, low energy density units are used in conjunction with diesel-electric drive on public buses.
Superconducting Magnetic Energy Storage (SMES)	Small (8.4 kWh, 12 MW) SMES are used to dampen low frequency power oscillations on the Bonneville Power System.
Chemical	Hydrogen is generated by electrolysis of water and subsequently used to operate a fuel cell.

RETs can be a source of intermittent generation, which affects system reliability and operation. The deployment of intermittent power generation on the electric utility network makes it that much more important to consider the benefits of various energy storage technologies, such as advanced batteries, compressed air energy storage, and SMES. Energy storage, such as SMES, can be used to store energy generated by intermittent RETs and other nonutility power producers so that the utility can have better control over power generation and delivery to loads. The energy stored from nonutility generation can be used for load-leveling and as backup for the utility generation systems that fail (spinning reserve), for the moment-to-moment balancing between the utility's generation and load demand (system regulation). Traditionally, electric utilities control central generation to follow the load. Storage can also be used to firm up and provide the capacity value that intermittents may need to allow utilities to reliably serve their loads.

I.2.1 Institutional Constraints

There are relatively few institutional constraints that limit the use of the storage systems described. In general, the institutional constraints are pertinent to the renewable energy technology, independent of the choice of the storage system. The most important determinant for use of a renewable technology is the comparison of the cost of the energy delivered for an available load without storage with the cost of competing energy supply options. If this comparison favors the renewable option, then storage technologies can extend the opportunity of the renewable supply by making it available to loads not well matched to the temporal characteristic of the primary source. Institutional constraints on pumped storage are similar to those for hydropower, discussed in Appendix A.

It should be pointed out that hybrids of certain renewable technologies with fossil-supplied systems or with other types of renewables often provide the most cost-effective system option. An example of this is a PV system with battery storage and a diesel electric backup. The diesel backup allows an inexpensive way to cover about 5% of the energy demand, which may be characterized by periods of prolonged cloudiness or by high demand rates.

The PV/battery system can supply up to 95% of the load demand and, consequently, greatly extend the lifetime of the diesel, lower the operation and maintenance costs, and eliminate the bulk of fuel-related expenses.

I.2.2 Technology Constraints

Although improvements in all performance measures are important for most cost-effective applications of battery technology, perhaps the most important to expanded application of renewables are cost-per-unit energy capacity and cycle life. These factors, along with storage efficiency, are key to determining the life cycle cost of the delivered energy. The Ni/H_2 battery is a good example of an advanced system with improved cycle life, low maintenance, and adequate specific energy and power but with high cost-per-unit capacity. Present costs are about $700/kWh (as compared with $110/kWh for lead/acid); however, projections are that advanced production engineering can lower the costs to less than $400/kWh in approximately 3 years. This would allow a greatly improved storage system when lifetime costs are considered.

Thermal storage is well understood although good design practice is necessary for adequate performance, and high-temperature systems often suffer from poor reliability of pumps and valves. Maintenance of environmental quality is also a design issue with some of the fluids used for heat transfer and/or storage because they may be classified as toxic. Almost all high-temperature fluids are expensive (~$10/gal.); this tends to inhibit their use and require hybrid storage systems using crushed rock or other inexpensive material.

Improvements in material strengths, magnetic support systems, and power takeoffs are still necessary to make high energy density flywheels competitive.

Adequate super-cooling and safe containment are significant remaining issues for SMESs. High-temperature superconductor development may reduce cooling costs; however, safety containment will always tend to constrain the system specific energy and its application.

I.3 Hydrogen

I.3.1 Description of the Technology

Hydrogen is both a fuel and an energy carrier. In contrast to electricity, hydrogen may be transported as a material flow through pipelines or in containers, and may be stored directly. At the point of end use, hydrogen is easily converted to electricity. As a fuel it can be used in many applications now being satisfied by fossil fuels. Currently, hydrogen is produced from fossil resources, particularly natural gas. This use of hydrogen contributes to global warming and limits the potential of hydrogen as a fuel. In the future, it is anticipated that hydrogen from renewable sources will predominate. The production of hydrogen from renewable sources consists primarily of splitting water into its elemental components. This can be done by electrolysis or by photoconversion processes.

Approximately 1% of current hydrogen is produced by electrolysis of water, with the remainder from fossil sources. Water electrolysis represents the most mature of the water-splitting technologies. Renewable energy resources, such as PV or hydropower, can be used to provide electrical energy for the electrolysis of water.

Direct photoconversion processes use light energy to split water without going through a separate electric generation step. Processes can include photoelectrolysis or photobiological approaches. Photoelectrolysis is a hydrogen production process that converts optical energy into chemical energy using photoactive semiconducting electrodes in a photoelectrochemical cell. The maximum theoretical efficiency of such systems is estimated to be greater than 35%, but efficiencies of 10% to 15% would make them economical. With photobiological hydrogen production, several approaches are possible because a variety of microorganisms are available.

Initially, renewable hydrogen will be used in high-value applications where the feedstock costs can be justified. Such applications would include the use of hydrogen as an energy carrier in power peaking operations. As research lowers the cost of renewable hydrogen, it would then have impact in intermediate-value applications such as a chemical feedstock. Finally, as the research goal is met, hydrogen would be used as a clean fuel. Fuel uses potentially include automobiles, aerospace applications, and others.

Hydrogen also has a significant role as a facilitating technology. Hydrogen can serve as an energy carrier in electric generation systems to help with peak load demands. The role has extensive impact on a variety of electricity generation systems including biomass, PV, wind, and others. Hydrogen can also serve as a facilitating technology in the generation of liquid fuels from renewable resources. Biomass, for example, is hydrogen deficient for methanol production. Generating renewable hydrogen for a biomass-to-methanol process rather than steam reforming part of the feedstock will double the amount of methanol produced from each unit of biomass. Thus, hydrogen is very crucial as a facilitating technology in a number of systems.

I.3.2 Current Status of the Technology

The resource base for the production of photolytic hydrogen is solar energy (sunlight) and water. Both of these resource bases are abundant and will not be depleted using this technology. The key issue is the economic, efficient collection of sunlight to provide the energy to dissociate water into hydrogen and oxygen.

Projected costs of producing renewable hydrogen are currently about $28/MilBtu, and, under the R,D&D Intensification Scenario, this cost can be reduced to about $8/MilBtu by the year 2030.

Significant progress has been made during the last 15 years to raise the conversion efficiency from less than 1% to 8% to 10% in the laboratory. To achieve the cost goal of $8/MilBtu, it is necessary to obtain efficiencies of 15% or greater, a photocatalyst cost of $10/m^2 or less, and system life expectancies of at least 15 years. Overall system costs must be less than $100/m^2 of collection area.

I.3.3 Constraints and Opportunities

I.3.3.1 Institutional Constraints

A primary institutional constraint to hydrogen use is a concern about safety. Negative publicity more than 50 years ago about lighter-than-air dirigibles gave the impression that hydrogen was unsafe. While appropriate precautions must be taken, hydrogen is routinely used in the petroleum and chemical industries. With appropriate precautions and advanced materials, this constraint should be readily overcome.

A second institutional constraint is the form of the fuel. At ambient temperature and normal pressures, hydrogen is a gas rather than a liquid. The lower energy density would require changes in fuel systems. Pressurized gas could be used. Liquid hydrogen, hydrogen slushes, and other physical forms have been considered. The distribution considerations for hydrogen are directly related to the physical form of the fuel and will have impacts on the deployment of the technology.

I.3.3.2 Technological Constraints

To achieve significant deployment of hydrogen fuels, research progress in production, storage, distribution, and utilization systems must be made. Of these elements, production is the least advanced and has the highest potential for reducing costs. While costs of renewable hydrogen are expected to range from about $28/MilBtu currently to about $8/MilBtu by the year 2030, storage and handling are expected to cost about $3-$5/MilBtu; thus, technical advances in the area of storage will be of secondary importance.

Conversion Efficiency. In the production area, current performance constraints are related to the efficiency of present photoconversion systems.

Improved Compatibility of Supply with Demand. Present storage, distribution, and utilization systems also serve as economy constraints to this technology. Safe, economical storage systems ranging from underground caverns to metal hydride systems are under investigation. Slurry and liquid hydrogen storage systems may be used in applications where high energy densities are critical, such as aerospace planes. Distribution systems, such as pipelines, must be compatible with the hydrogen product. Finally, engine systems must be adapted to the fuel.

I.3.4 Energy Supply Potential

The use of hydrogen to displace liquid fuels will require numerous changes in the existing infrastructures for storage, distribution, and utilization. Therefore, there are many barriers to the transition to hydrogen for transportation energy, large-scale storage, and distribution. It is important to identify as many of these issues as possible to select the best integrated systems for development. Under the current program and the anticipated funding, it will take many years to advance the technology of hydrogen production from renewable resources to attain practical application. Many different photoconversion approaches are candidates for future hydrogen production processes, but funding has not allowed for the investigation of more than a few. The demand for hydrogen in high-value applications will define the production methods that best meet these needs. For example, production and distribution requirements for utility consumption will be vastly different from requirements for transportation use. The range of applications for hydrogen will depend on its value in each, relative to other alternative forms of energy and other factors, such as environmental or health benefits of decreased fossil fuel use. Based on the available resources for the production of hydrogen (sunlight and water) in photoconversion processes, it is an unlimited resource. The recent attention given to hydrogen is the result of concern over global warming, acid rain, and detrimental effects of fossil fuels. If these benefits are considered sufficiently important, then changes in policy should be implemented that will include such factors in the real cost of increased use of hydrogen. There are fewer technical barriers to an early shift to hydrogen energy if a policy decision were made to move in this direction. The longer term technical issue is the production of hydrogen from water using solar energy, and this could be significantly accelerated if funding were increased. Much progress has been made in the last 15 years to improve the efficiency of such systems. The performance of photocatalysts has reached the point that systems research is necessary to evaluate their potential in practical systems.

With proper support, hydrogen could emerge as a viable alternative to fossil energy for essentially all current energy applications during the next 40 years. Because of the widespread changes in the current energy infrastructure that will be required, it is unlikely that the assimilation of the technology could occur at a faster rate (see Table I-1).

Table I-1.
Potential Contribution of the Energy System

	(Quads)				
	1990	2000	2010	2020	2030
Business-as-Usual Scenario					
Hydrogen	0	0	0	0	0.2
R,D&D Intensification Scenario					
Hydrogen	0	0	0	0.2	1.0
National Premiums Scenario					
Hydrogen	0	0	0	0.01	0.30

I.3.5 Performance and Research and Development Steps

Improvements in performance through R&D advances will be continuous or realized in small increments. The first step will be the increase of photoconversion efficiency to 15% or more in practical systems. This will initiate a development of lower cost and long-life systems that will further reduce hydrogen costs. In addition, improved hydrogen utilization systems that take advantage of hydrogen's unique characteristics will be developed.

I.3.6 Industry Structure and Growth

A future industry that develops photolytic hydrogen production systems will be an expansion of existing capabilities. The production of sufficient quantities of these photocatalyst surfaces will most likely control capability growth. Little or no growth in capability will occur until the technology is sufficiently attractive to draw large amounts of capital. Federal leadership could greatly increase this through policy and incentives.

I.4 Transmission and Distribution

I.4.1 Description

The transmission and distribution systems carry the power and energy produced in generating units to users or customers. Transmission lines provide the bulk long distance transport of electricity between plants and loads between utilities. Transmission lines deliver to substations where the distribution system provides the delivery path to customers.

Historically, electric utilities have maintained complete control over the generation, transmission, and distribution of electric power, except for a few cogeneration facilities. This control has resulted in a high level of safe and reliable operation of electric power systems. With the connection of RETs to the transmission and distribution (T&D) system, electric utilities no longer have complete control of dispatching power throughout the electric system. For this reason, utilities specify, in most cases, that fairly stringent interconnection requirements be met before a RET can be operated on the T&D system.

Utility distribution systems are generally designed for radial operation, in which power flows only from the utility substation toward the customer load. In general, protection schemes specified by electric utilities for interconnecting renewable sources to the T&D system are designed to automatically disconnect the device whenever abnormal system conditions occur.

I.4.2 Constraints and Opportunities

Large renewable energy sources have been integrated into the utility grid without much difficulty. In general, the level of engineering expertise incorporated in the design of large RETs parallels the design effort that utilities invest in their own generation. As a result, in some regions of the country, large RETs have little difficulty interconnecting with the grid.

In the early to mid-1980s, federal tax incentives sparked interest in very small facilities (less than 50 kW). These small facilities are particularly difficult for utilities to cope with because they are often accompanied by characteristics perceived as dangerous. Small RETs still have difficulty interconnecting with the grid because of stringent utility interconnection requirements and procedures. These interconnection policies appear arbitrary to RET owners. While there is general recognition and agreement on the technical problems, there is argument concerning the significance and solution to these problems.

In both large and small RET cases, a great deal of research has gone into the interconnection question. Many data are available on technical interconnection problems related mostly to low penetration levels of nonutility power generation. Studies have addressed protection, safety, and power quality concerns of small penetration levels of nonutility power generation[9-12]. Some work has been done on the effect of photovoltaic systems on utility operations[13,14]. Very little has been done on the integration of a significant penetration of nonutility power generation. Technical problems that have not been completely resolved that could make use of additional research, development, and demonstration (R,D&D) include

- The effects of high penetration levels of renewable energy sources on T&D power quality, especially with greater numbers of sensitive electronic loads appearing on the system

- The effect of renewable energy sources on short-term and long-term T&D operations and planning

- Procedures for resolving technical disputes between utility companies and RET owners

- The communications and data needs of the utility required to continue to operate with a high level of reliability when a significant level of nonutility power producers are present and

- Design and facility changes, real-time tools, and monitoring and control procedures needed to fully integrate nonutility generation into the T&D network.

An important factor affecting the market penetration of RETs is the availability of transmission in the region of the United States where the renewable power producer is located. The regional mix of existing generating facilities and existing T&D capacities will affect the ability of the renewable power producer to compete with alternative power generation and to interconnect with the T&D system. At present, renewable power producers and other independent power producers (IPPs) are locating where there is sufficient T&D capacity to handle the power generation from the nonutility power source. Existing T&D systems are already near capacity because of interutility power transfers and interregional power transfers. In 1988, 2500 IPPs were waiting to interconnect to Pacific Gas & Electric's T&D system because of insufficient T&D capacity in northern California to handle the IPP generation[14]. Also, the rate of new transmission line additions has slowed significantly in recent years. The reduced growth of existing transmission access may be a constraint on market penetration of renewables. Any increases in the power transfers among utilities using existing T&D capabilities will be limited unless newer transmission systems are used. The newer systems will require the utilities to obtain new T&D rights-of-way or to use higher T&D voltages or new transmission methods, such as high-phase order transmission, to increase capacities of existing T&D systems. However, some regions, such as the West and Midwest, are continuing to expand generation and T&D facilities in anticipation of providing bulk power transfers. In addition, major transmission projects are under way in the Northeast, the Midwest, and the Pacific Northwest to allow for the purchase of lower cost hydroelectric power from existing and proposed generation plants of northwest utility companies in the United States and in Canada.

The addition of renewable power producers using solar, wind, and geothermal sources will vary regionally because of the cost of alternative electric generation and the availability of renewable sources. Wind turbines are being developed primarily in California where the utility avoided costs are high and state taxes encourage renewables and other IPPs under the Public Utilities Regulatory Policies Act. Photovoltaics and geothermal renewable power producers are primarily limited to the West. Solar thermal appears to be viable at present and in the near future only in the Southwest and Southeast. In those areas, where land is available for development, insolation characteristics make solar thermal competitive with alternative electric generation.

A real concern is who should pay for the new transmission facilities that benefit only renewables and other IPPs. The requirement that IPPs pay for this new transmission capacity will discourage IPPs from constructing generation facilities in areas without existing T&D systems and restrict IPPs to sites located near existing T&D systems for meeting only local load requirements[14].

Greater diversity among power generation types and an increase in wheeling between electric utilities and from renewables and other IPPs will require methods for greater coordination of power transfers and for T&D capacity evaluation on a systems, regional, and nationwide level. Increased power wheeling will require system studies to determine constraints and bottlenecks of power transfers. The amount of additional access that can be accommodated with existing T&D systems will also need to be determined. R,D&D could provide help in reducing constraints and in maximizing the use of the transmission systems. The potential impact of increased competition in the utility marketplace, including transmission-related matters, is discussed in a recent report by the Congressional Office of Technology Assessment[15].

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Appendix J
Market Construct for Estimating RET Deployment Potential

J.1 General Comments

Projections of energy demand and prices out to 2030 were required for development of the market construct. Regional detail was essential because of the dispersed nature of many renewable energy resources. At the time this study was initiated, uniform guidance on the market construct was unavailable from DOE. Thus, it was necessary to draw from several sources. The primary sources used to define the market construct to 2000 were the *Annual Energy Outlook 1989* (AEO) and *Annual Outlook for U.S. Electric Power 1989* (AOEP), prepared by the Energy Information Administration (EIA). For the post-2000 period, national energy price and demand projections were taken from a preliminary run of the DOE-PE Fossil2 model (dated 7/26/89). Also used were sectoral and regional energy price and demand trend extrapolations provided by EIA in a PC spreadsheet file (NEWELF.WK1, dated 8/15/89).

The following sections describe the key elements of the market construct.

J.2 Fossil Fuels

Projections of the average world oil price and the U.S. natural gas wellhead price, taken from the Fossil2 output, are shown in Figures J-1 and J-2, respectively. Both oil and gas prices are projected to triple in real terms over the 40-year study period, translating into average annual growth rates of 2.8% and 3.1%, respectively. The average real minemouth coal price (not illustrated) is projected to increase by about 50% over the 40-year period, at an annual compounded rate of just over 1%.

J.3 Electric Generating Capacity

Through 2000, capacity requirements were taken directly from the EIA-AOEP. However, for the post-2000 period, it was necessary to calculate capacity needs from the Fossil2 projections of national electric utility sales. Because Fossil2 does not provide regional detail, the national electricity sales projections were apportioned to the 10 federal regions (see Figure J-3) based on the relative growth rates for regional sales projected in the EIA-AOEP for 1988-2000. The sales data were then converted to gigawatts (GW) of installed capacity using the implicit load factor for each region as supplied in the EIA-AOEP for 2000. Finally, the 10 federal regions were aggregated into four larger regions to facilitate the calculations of the renewable energy technology (RET) penetration potentials and be more consistent with the regional construct used for the end-use energy projections (described later).

In the EIA-AOEP projections to 2000, utility capacity needs are net of imports and nonutility supply. Post-2000 capacity needs, as calculated from the Fossil2 output, include capacity that might be supplied by imports and/or nonutility generators and thus represent gross electricity supply needs. Following EIA-AOEP assumptions, 8% or 15% of incremental supply needs are for peaking capacity, depending on the region; the remainder is for intermediate and baseload capacity.

Conservative rates of capacity retirements were assumed. By 2030, about one-fourth of the approximately 700 GW of existing electric generating capacity, or 180 GW, is retired. These retirements are spread evenly over the 2000-2030 period such that a national capacity increment of 60 GW is required as a retirement replacement in each decade (this increment was later apportioned to the four regions based on relative installed capacity weights). For comparison, utility industry sources have estimated that some 327 GW of capacity will be candidates for either retirement or life extension by 2005[1].

The calculated capacity requirements are provided in Table J-1.

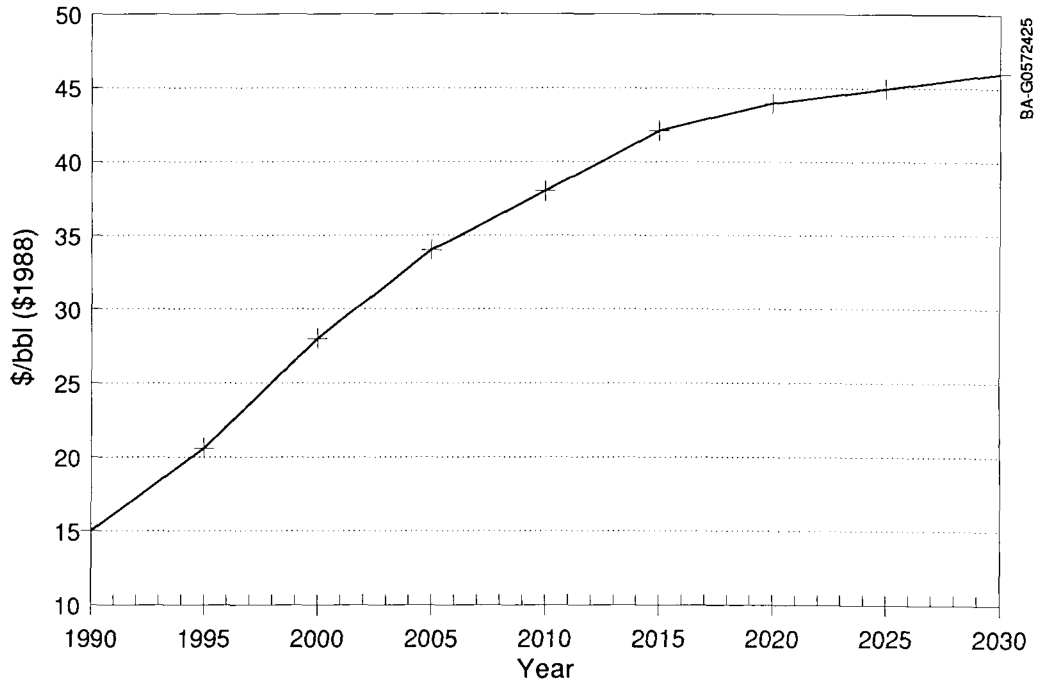


Figure J-1. World oil price

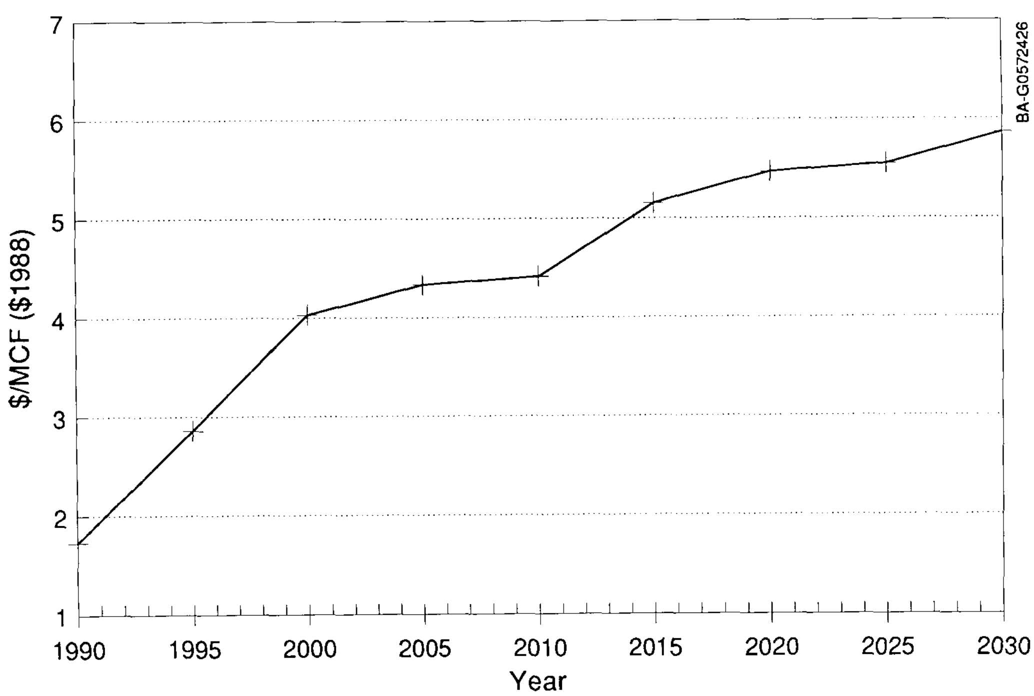


Figure J-2. Natural gas wellhead price (U.S.)

Table J-1.
Projected Generation Capacity Need by Region (GW)

(INCREMENTAL CAPACITY NEED)

NORTHEAST	1988	2000	2010	2020	2030
(1) – NEW ENGLAND	22.1	1.6	10.6	4.5	4.8
(2) – NEW YORK/NEW JERSEY	44.2	0.8	14.2	8.0	8.6
(3) – MID-ATLANTIC	71.9	9.8	24.3	21.2	24.1
(TOTAL ADDITIONS)		12.2	49.2	33.7	37.5
(CUMULATIVE ADDITIONS)		18.9	68.1	101.7	139.2
(TOTAL IN PLACE)	138.2	157.1	206.3	239.9	277.4
SOUTH	**1988**	**2000**	**2010**	**2020**	**2030**
(4) – SOUTH ATLANTIC	145.0	13.5	48.3	48.3	56.4
(6) – SOUTHWEST	103.6	16.4	59.4	65.6	84.3
(TOTAL ADDITIONS)		29.9	107.7	113.9	140.6
(CUMULATIVE ADDITIONS)		45.2	152.9	266.7	407.4
(TOTAL IN PLACE)	248.6	293.8	401.5	515.3	656.0
NORTH CENTRAL	**1988**	**2000**	**2010**	**2020**	**2030**
(5) – MIDWEST	120.2	18.1	37.4	37.7	43.5
(7) – CENTRAL	37.7	5.6	12.9	13.5	15.8
(TOTAL ADDITIONS)		23.7	50.3	51.2	59.3
(CUMULATIVE ADDITIONS)		31.6	81.9	133.1	192.5
(TOTAL IN PLACE)	157.9	189.5	239.8	291.0	350.4
WEST	**1988**	**2000**	**2010**	**2020**	**2030**
(8) – NORTH CENTRAL	29.6	2.0	11.1	11.1	13.2
(9) – WEST	65.3	6.4	30.4	27.0	32.2
(10) – NORTHWEST	39.2	0.4	12.1	10.7	12.2
(TOTAL ADDITIONS)		8.8	53.6	48.7	57.6
(CUMULATIVE ADDITIONS)		14.1	67.7	116.5	174.0
(TOTAL IN PLACE)	134.1	148.2	201.8	250.6	308.1
U.S. TOTAL	**1988**	**2000**	**2010**	**2020**	**2030**
(TOTAL ADDITIONS)		74.6	260.8	247.5	295.0
+ REPLACEMENTS			60.0	60.0	60.0
(GROSS NEED)		74.6	320.8	307.5	355.0
(CUMULATIVE ADDITIONS)		109.8	430.6	738.0	1093.1
(TOTAL IN PLACE)	678.8	788.6	1049.4	1296.8	1591.9

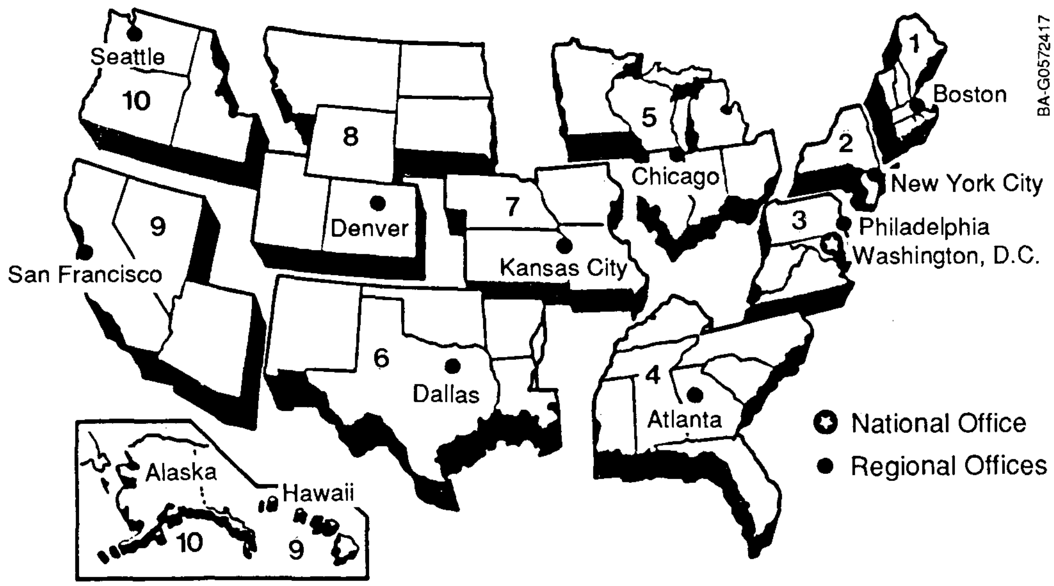


Figure J-3. The federal regions

J.4 Electric Generation Costs

Guidance was also required on the cost of conventional, fossil fuel-based generation to frame the RET electric market competition. The following 30-year levelized costs for conventional fossil fuel generation technologies were calculated from the Fossil2 fuel price projections and capital and operation and maintenance (O&M) information contained in a recent SERI report[2].

A cost of displaced utility energy was also developed, using the same data sources, for RETs that might have little capacity value and thus must compete instead on the basis of relative energy prices. The upper bound of displaced energy costs is set by natural gas-fired generation; the lower bound is set by coal-fired generation. Both sets of costs are illustrated in Figure J-4.

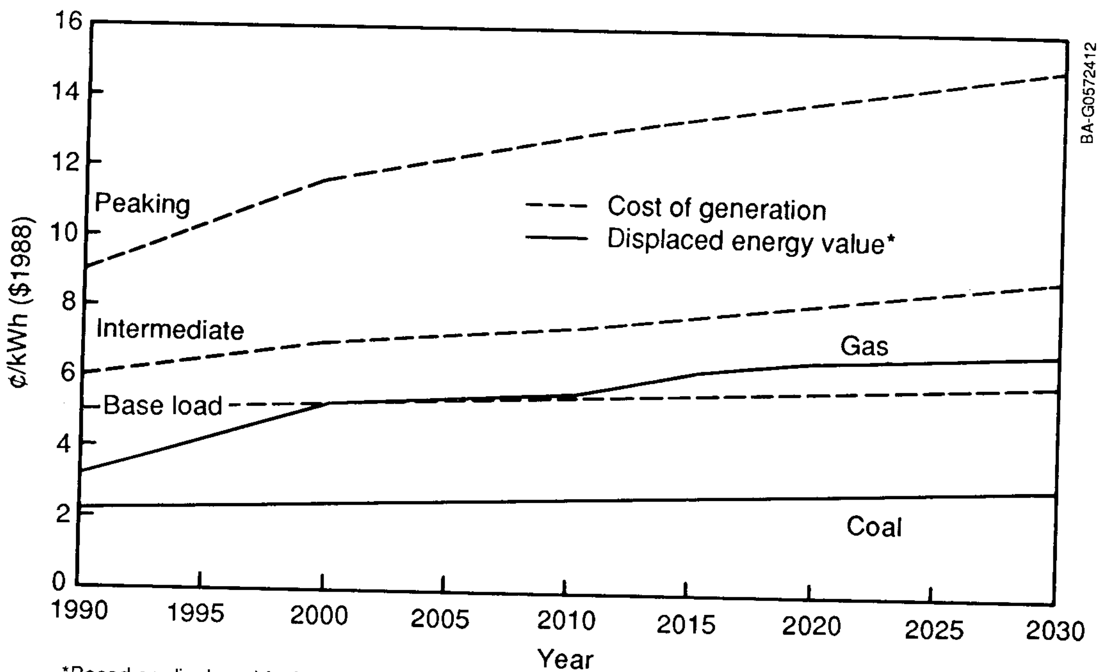
J.5 Buildings/Industrial Energy Demand

Projections of sectoral end-use energy demands to 2030 were taken from the EIA spreadsheet because of its regional detail. The aggregate sectoral demand levels in the EIA spreadsheet do not differ radically from the national Fossil2 projections and thus were determined to be consistent for the purposes of this study. The sectoral demand projections are provided in Table J-2 by census regions. Figure J-5 displays the four census regions.

J.6 Buildings/Industrial Energy Price

National sectoral energy price projections were taken from the Fossil2 output. Projected regional price differentials for 2000, calculated from the EIA spreadsheet data, were applied to the Fossil2 sectoral price tracks to 2030 to provide some regional variation in energy prices (see Figures J-6 through J-11).

The level trend projected for sectoral electricity prices appears inconsistent with the rising generation costs portrayed in Figure J-5. A reconciliation of these contradictory projections was beyond the scope of this study. The level price projection clearly represents a more restricted competitive environment for end-use-related RET applications.



*Based on displaced fuel and avoided O&M.

Figure J-4. Projected cost of conventional generation (U.S. average)

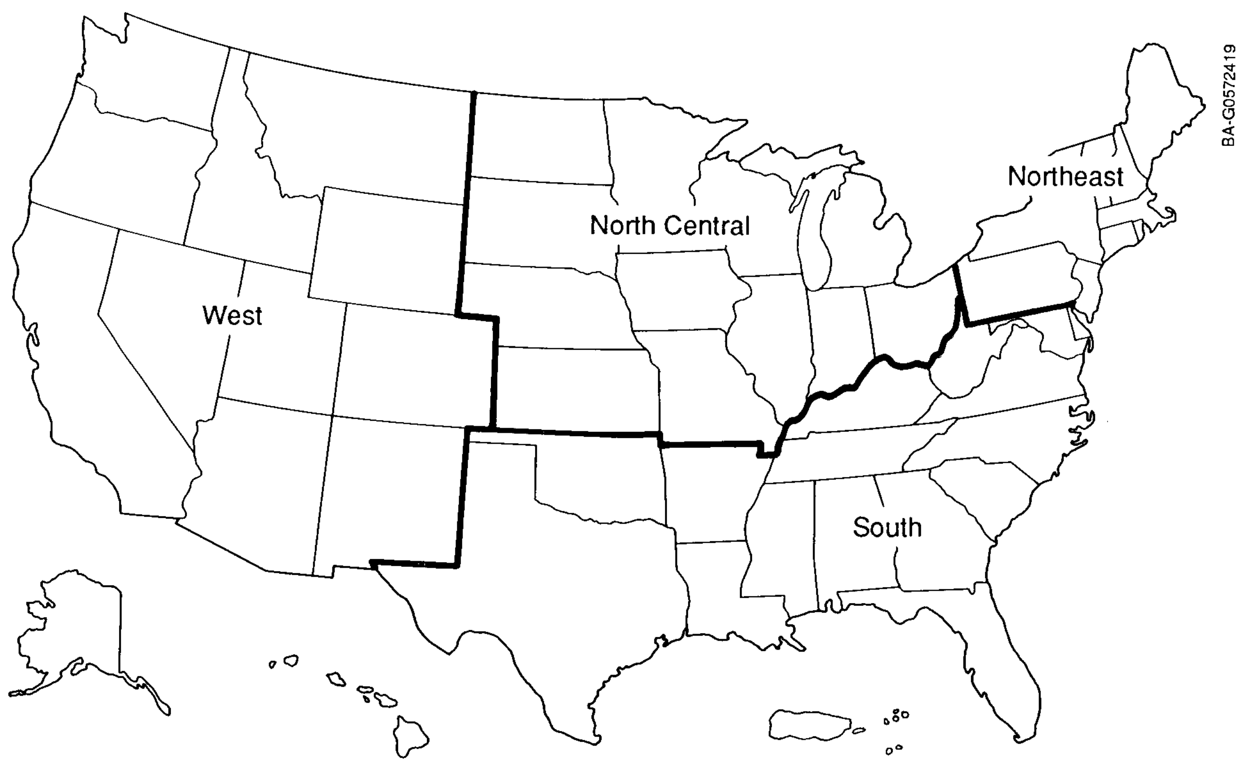


Figure J-5. The census regions

Table J-2.
Projected Energy Demand by End-Use Sector

NORTHEAST	(QUADS)			
Residential	2000	2010	2020	2030
Electricity	1.61	1.89	2.22	2.61
Distillate Fuel	0.63	0.57	0.52	0.47
Liquefied Petroleum Gas	0.06	0.06	0.06	0.06
Natural Gas	1.02	1.12	1.22	1.34
Commercial				
Electricity	1.74	2.04	2.39	2.81
Distillate Fuel	0.20	0.18	0.17	0.16
Residual Fuel	0.07	0.04	0.03	0.02
Natural Gas	0.44	0.44	0.44	0.44
Steam Coal	0.06	0.06	0.06	0.06
Industrial				
Electricity	1.58	2.05	2.66	3.45
Distillate Fuel	0.13	0.15	0.17	0.19
Residual Fuel	0.13	0.12	0.10	0.09
Natural Gas	0.41	0.37	0.34	0.30
Steam Coal	0.17	0.18	0.20	0.22

MIDWEST	(QUADS)			
Residential	2000	2010	2020	2030
Electricity	2.29	2.41	2.54	2.67
Distillate Fuel	0.10	0.06	0.04	0.02
Liquefied Petroleum Gas	0.20	0.20	0.20	0.20
Natural Gas	1.74	1.59	1.45	1.33
Commercial				
Electricity	2.23	2.73	3.33	4.07
Distillate Fuel	0.16	0.19	0.22	0.25
Residual Fuel	0.01	0.01	0.00	0.00
Natural Gas	0.97	1.02	1.07	1.13
Steam Coal	0.10	0.10	0.10	0.10
Industrial				
Electricity	3.91	5.60	8.02	11.50
Distillate Fuel	0.38	0.44	0.50	0.58
Residual Fuel	0.10	0.09	0.09	0.08
Natural Gas	1.45	1.42	1.39	1.37
Steam Coal	0.74	0.84	0.96	1.09

Table J-2. (concluded)
Projected Energy Demand by End-Use Sector

SOUTH	(QUADS)			
Residential	2000	2010	2020	2030
Electricity	5.49	6.91	8.68	10.94
Distillate Fuel	0.15	0.11	0.09	0.06
Liquefied Petroleum Gas	0.17	0.17	0.17	0.17
Natural Gas	0.91	0.87	0.82	0.78
Commercial				
Electricity	4.37	5.73	7.50	9.83
Distillate Fuel	0.29	0.32	0.35	0.38
Residual Fuel	0.04	0.03	0.02	0.01
Natural Gas	0.72	0.84	0.99	1.16
Steam Coal	0.10	0.10	0.10	0.10
Industrial				
Electricity	5.30	7.52	10.67	15.15
Distillate Fuel	0.67	0.76	0.85	0.96
Residual Fuel	0.43	0.43	0.43	0.43
Natural Gas	4.67	4.76	4.86	4.96
Steam Coal	0.81	0.94	1.09	1.27

WEST	(QUADS)			
Residential	2000	2010	2020	2030
Electricity	2.29	2.86	3.56	4.44
Distillate Fuel	0.02	0.01	0.00	0.00
Liquefied Petroleum Gas	0.06	0.06	0.06	0.06
Natural Gas	0.83	0.82	0.81	0.81
Commercial				
Electricity	2.29	2.89	3.63	4.57
Distillate Fuel	0.11	0.13	0.16	0.19
Residual Fuel	0.00	0.00	0.00	0.00
Natural Gas	0.54	0.63	0.73	0.85
Steam Coal	0.04	0.04	0.04	0.04
Industrial				
Electricity	2.36	3.38	4.84	6.94
Distillate Fuel	0.39	0.49	0.61	0.75
Residual Fuel	0.10	0.10	0.10	0.10
Natural Gas	1.13	1.22	1.33	1.44
Steam Coal	0.22	0.26	0.32	0.38

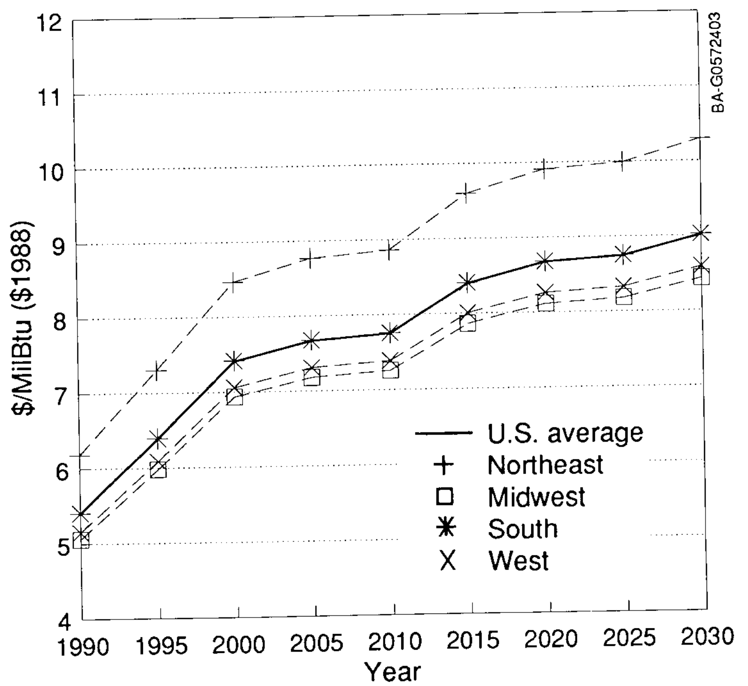


Figure J-6. Residential natural gas price

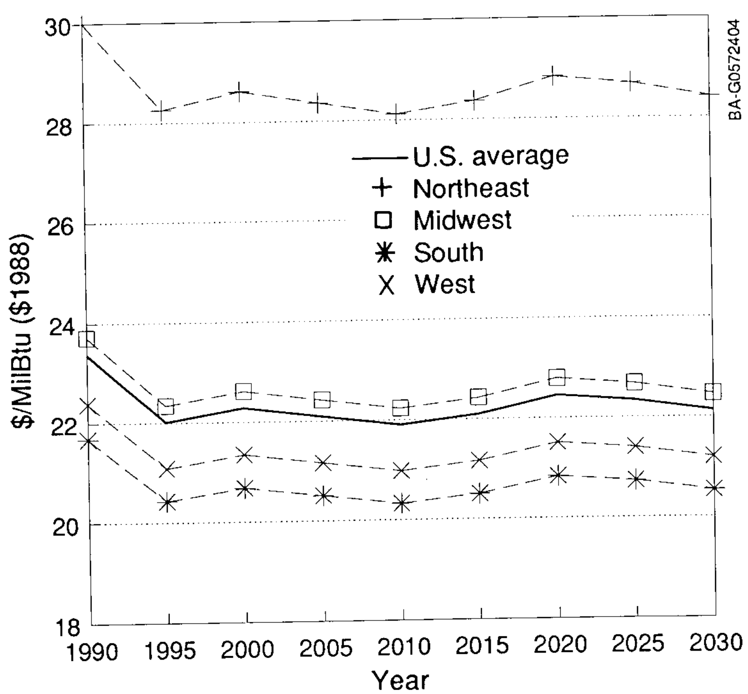


Figure J-7. Residential electricity price

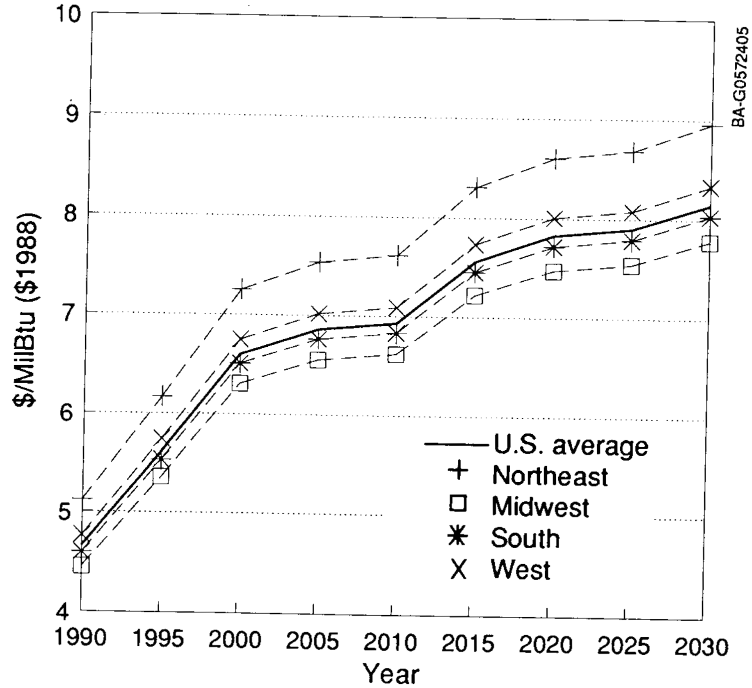


Figure J-8. Commercial natural gas price

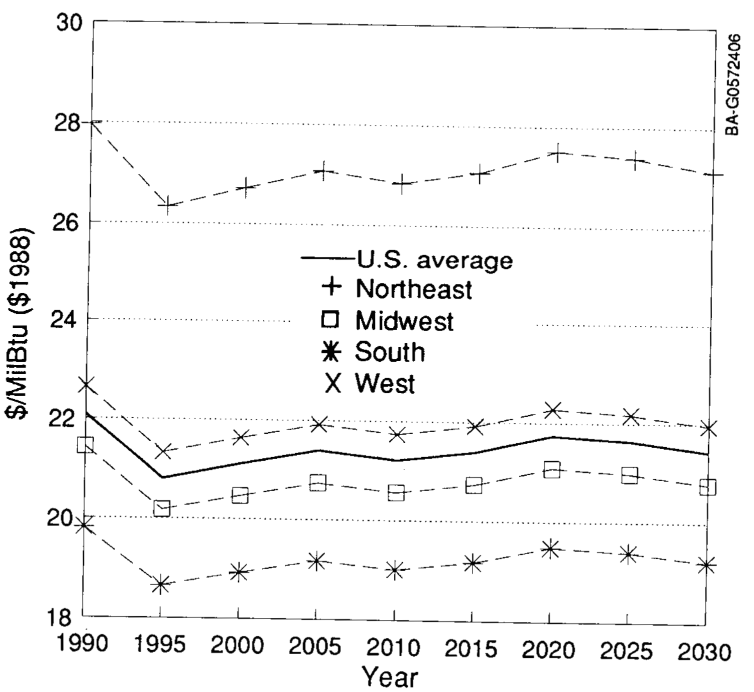


Figure J-9. Commercial electricity price

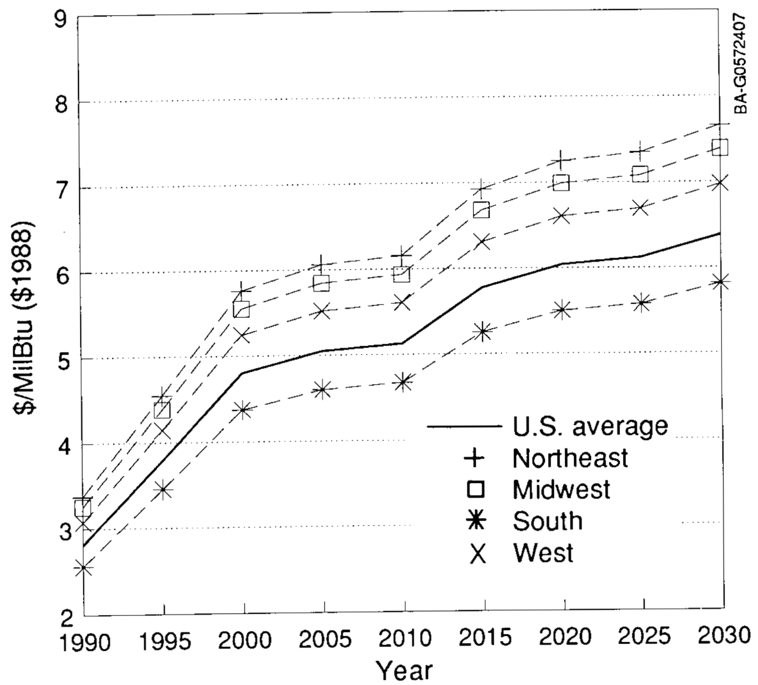


Figure J-10. Industrial natural gas price

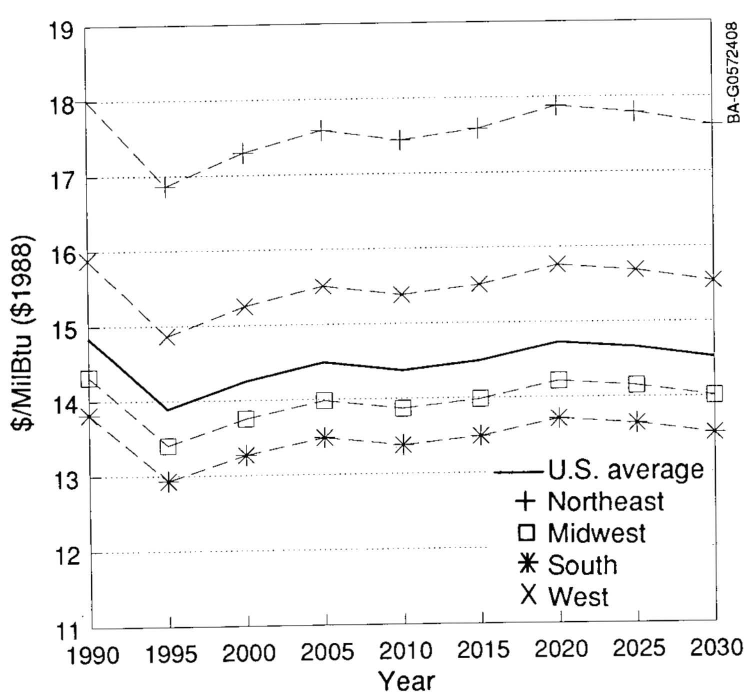


Figure J-11. Industrial electricity price

J.7 Transportation

The potential for biomass-derived transportation fuels is tied to projections of the price of gasoline and the aggregate national demand for transportation fuels. Both projections are taken from Fossil2 and are illustrated in Figures J-12 and J-13.

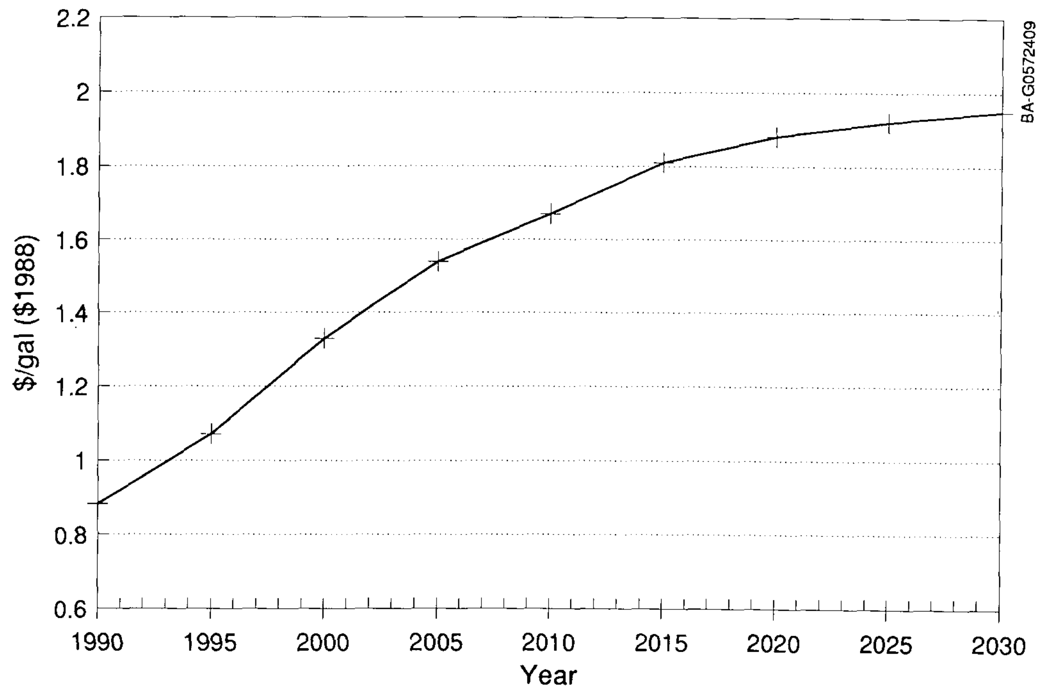


Figure J-12. Gasoline price

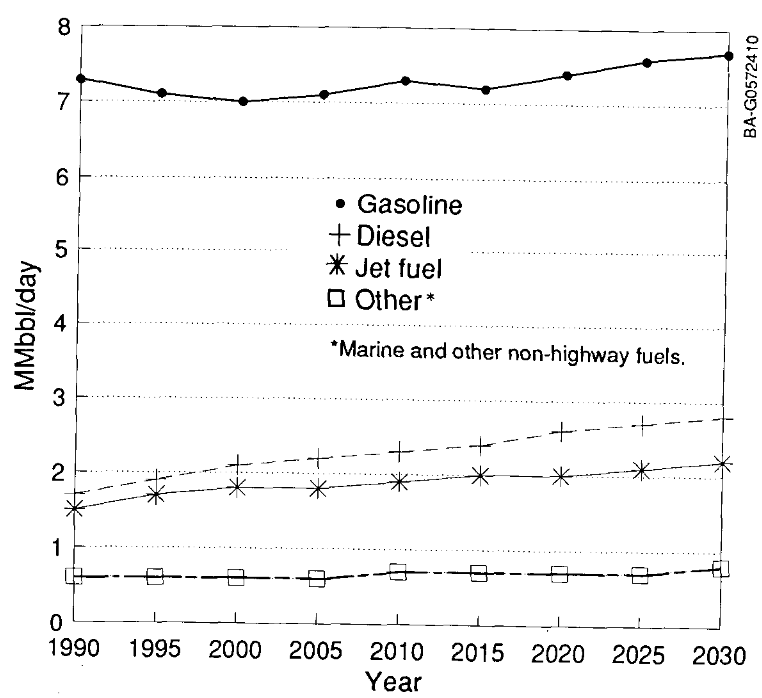


Figure J-13. Transportation fuels demand

J.8 References for Appendix J

1. Gorzelnik, Eugene F., "The Dollars and Sense of Life Extension," *Electrical World*, October 1987.

2. Coles, Lynn R., *Competitive Characteristics of Electric Generating Technologies*, Golden, CO: Solar Energy Research Institute, SERI/MR-160-3444, December 1988.

Appendix K
Peer Reviews

The Laboratories gratefully acknowledge the efforts of a distinguished group of peer reviewers that assisted us in providing a reasonable and balanced view of the potential of renewable energy. The contribution from external peer review has, we believe, significantly strengthened our white paper and made many other energy specialists and generalists aware of the Interlaboratory White Paper's role in the National Energy Strategy process.

Although we considered all comments and suggestions, we were not able to incorporate all suggested changes into the paper. Some we disagreed with; some we agreed with but could not address under the time and resource limitations imposed. Many of the viewpoints that we were unable to directly respond to with changes have been incorporated into the technology descriptions in the appendices under "Other Perspectives."

Our peer reviewers include the following:

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15. Supplementary Notes

16. Abstract (Limit: 200 words)
This white paper evaluates the present and projected performance status of renewable energy technologies and their potential contributions to the nation's energy requirements over the next four decades. It was prepared by a task force consisting of staff at the Idaho National Engineering Laboratory, Los Alamos National Laboratory, Oak Ridge National Laboratory, Sandia National Laboratories, and the Solar Energy Research Institute (the task force leader) for the U.S. Dept. of Energy in support of DOE's National Energy Strategy. Its key findings include the following: (1) technical, economic and institutional constraints, not the availability of renewable resources, are the limiting factors on energy contributions from renewables; (2) the fraction of U.S. energy demand supplied by renewables (8%) will grow only slowly without expanded support for renewable energy; (3) the extent of federal support can greatly influence the rate of expansion of renewables' market share and the success of domestic industry in U.S. and world markets; and (4) expanded federal leadership can result in substantial diversification of the U.S. energy mix, reduce the environmental impacts of energy supply, and lessen the need for foreign energy resource imports.

17. Document Analysis

a. Descriptors: Renewable energy sources; solar radiation; solar energy; technology assessment

b. Identifiers/Open-Ended Terms

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