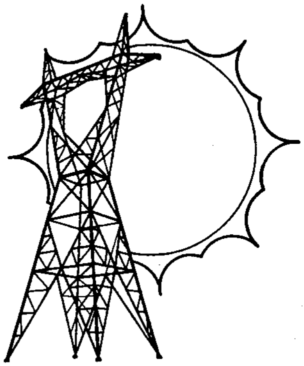
DSM Pocket Guidebook



Volume 5: Renewable and Related Technologies for Utilities and Buildings

Western Area Power Administration
and
U.S. Department of Energy

Conversion Table

To convert from	To	Multiply by
Btu (British thermal unit)	kWh (kilowatt hour)	2.928×10^{-4}
cfm (cubic feet per minute)	m^3/s (cubic meter per second)	4.719×10^{-4}
°F (degree Fahrenheit)	°C (degree Celsius)	(°F-32)/1.8
ft (foot)	m (meter)	3.048×10^{-1}
ft^2 (square feet)	m^2 (square meter)	9.290×10^{-2}
ft^3 (cubic feet)	m^3 (cubic meter)	2.831×10^{-2}
gal (gallon)	m^3 (cubic meter)	3.785×10^{-3}
gpm (gallon per minute)	m^3/s (cubic meter per second)	6.309×10^{-5}
hp (horse power)	w (watt)	7.460×10^{2}
in (inch)	m (meter)	2.540×10^{-2}
lb (pound)	kg (kilogram)	4.536×10^{-1}
psi (pounds per square inch)	Pa (pascal)	6.895×10^{3}
ton (short, 2,000 lb)	kg (kilogram)	9.072×10^{2}

DSM Pocket Guidebook

Volume 5: Renewable and
Related Technologies
for Utilities and Buildings

prepared by
National Renewable Energy Laboratory
1617 Cole Boulevard
Golden, Colorado 80401-3393
(303) 275-4099

prepared for
Western Area Power Administration
Energy Services
1627 Cole Boulevard, P.O. Box 3402
Golden, Colorado 80401
(303) 231-7504

and the
U.S. Department of Energy
Office of Utility Technologies
Washington, DC 20585
(202) 586-9839

Printed in the United States of America
Available from:
National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road
Springfield, VA 22161

Price: Microfiche A01
Printed Copy A08

Codes are used for pricing all publications. The code is determined by the number of pages in the publication. Information pertaining to the pricing codes can be found in the current issue of the following publications which are generally available in most libraries: *Energy Research Abstracts (ERA); Government Reports Announcements and Index (GRA and I); Scientific and Technical Abstract Reports (STAR);* and publication NTIS-PR-360 available from NTIS at the above address.

CONTENTS

Page Intentionally Blank

FOREWORD

In previous years of low-cost energy, renewable resource technologies were not cost effective for generating electricity on a utility scale. Today, however, with rising concern for the environment and Western Area Power Administration's (Western's) emphasis on developing integrated resource plans, the use of renewable resources, as part of an overall mix of technologies, can provide utilities with a cost-effective means to meet the Western customers' increasing demand for reliable and environmentally clean power.

This series of guidebooks is intended for utility personnel involved in demand-side and supply-side planning, programs, and services. Both the novice and expert can benefit from this information. Using renewable resources to generate utility-scale power and in on-site building applications increases efficiency of resource use from a systems perspective. Efficiency through the use of renewable resources helps Western meet two of its objectives—the elimination of wasteful energy practices and the adoption of energy-efficiency programs that meet customer needs in an era of diminished resources and increased environmental concern.

Page
Intentionally
Blank

PREFACE TO THE POCKET GUIDEBOOK

INTRODUCTION

Renewable energy sources, including wind, sunlight, water, plants, and geothermal energy, represent a massive energy resource that could provide Americans with energy from clean, safe sources.

The future contribution of renewables is vast and, if properly managed, virtually inexhaustible. The ultimate contribution from renewables will depend on the emphasis that the United States places on the development and application of these resources. Growing evidence of significant customer demand, coupled with a willingness to pay for power from a clean energy source, suggests that utilities need to become familiar with the renewable technologies applicable in their service territory.

Renewable resources are generally diffuse and intermittent, and all have different regional availability. These conditions present utilities with challenges in developing and using these resources.

INTENDED AUDIENCE

This guidebook is intended to be a quick reference source for utility field representatives in their customer interactions and for utility planners in the early stages of developing an integrated resource plan. It is designed to allow a quick screening of supply-side generation options and end-use building applications of renewable resources.

This guidebook is directed primarily at small municipal utilities and rural electric cooperatives within the Western Area Power Administration service area. Large utilities with more abundant staff capability may find the guidebook useful as a starting point. Their technology selection process will undoubtedly include review of other source documents and detailed system and engineering analyses of the options.

ORGANIZATION AND USE OF THE GUIDEBOOK

This guidebook is the fifth in a series of five pocket-sized volumes. The first four volumes address demand-side management (DSM) measures. The first volume considers end-use technologies for the residential sector. The second volume includes technologies for the commercial sector and covers motors and variable-speed drives applicable to the commercial, industrial, and agricultural sectors. The third volume discusses energy-efficient technologies for the agricultural sector, with an emphasis on the central and western United States. The fourth volume covers technologies for industrial applications.

This volume is divided into three major sections. The first section describes renewable resources available to utilities for generating electricity. The second section covers energy storage, fuel cells, and inverter technology. The storage options are included because they can be used in conjunction with renewable utility power generation technologies in some circumstances. Fuel cells are an emerging fossil-based electric generation technology. They are not a renewable technology, but they might be powered by hydrogen in the future. Inverter technology is included because it is used with photovoltaic systems.

The third section describes renewable resources that can be used as DSM measures. The potential for solar energy in the buildings sector is enormous. Where buildings have adequate access to the solar resource, many renewable technologies are cost-effective today.

Utilities can apply renewable resources to meet customer energy needs, such as water heating, passive solar design, daylighting, and the use of photovoltaics in remote locations. The introduction to Section 3 of this guidebook contains a matrix that refers the reader to renewable briefs in other volumes of this pocket guide series.

METHODOLOGY/DATA

For each renewable technology, the guidebook presents a short numbered "technology brief" that describes the technology, its potential applications, resource assessment, market outlook, industry status, construction lead time, environmental issues, and land area requirements. Each brief also includes a summary table containing information on capital costs, O&M costs, levelized energy costs, average size per installation, capacity factor, and life. Historical and future cost projections or trends are presented for the technologies, where known. Costs are expressed in 1990 dollars, unless noted.

In all cases, the costs were taken from existing sources, including documentation of utility procurements, case studies, or national or state studies. In some cases, manufacturers were contacted directly to obtain cost data. The sources used varied, depending on the availability of data and the complexity of the technology.

As might be expected, costs drawn from different sources are frequently inconsistent. The authors attempted to reconcile such inconsistencies.

The guidebook is not intended to substitute for a detailed analysis, but it points the reader toward those technologies most likely to benefit both the end user and the utility. For more details, the reader should consult the references at the end of each brief.

DATA VARIABILITY AND UNCERTAINTY

A problem with guidebooks such as this is that the data present only a simple overview of each technology. Yet many volumes have been written describing the application of these technologies. Consequently, the cost estimates presented here should be used with a clear understanding of the variability and uncertainty of the source.

Cost is dependent on many factors, including:

- Size of system
- Economies of scale
- Location
- Quality of the resource
- Access to transmission lines
- Technology maturity.

For these reasons, specific cost estimates ore difficult to generate.

There ore significant sources of uncertainty in cost data found in the literature. The uncertainties, which lorgely result from drawing cost statistics from o number of different sources, include:

- Differing assumptions among studies
- Lack of complete documentation of the assumptions, data, and methods used in many of the studies
- Lock of statistically valid generalizations because of small som-ple sizes (i.e., the results in the referenced studies ore frequently based on only o few applications or systems.)
- In some cases, the systems hove not been built and the costs ore based on estimates. These cases ore noted os estimates.

SECTION 1

RENEWABLE RESOURCES FOR UTILITY APPLICATIONS

INTRODUCTION

Electricity is a key to the country's economic health and quality of life. Through the integrated resource planning (IRP) process, Western Area Power Administration (Western) customer utilities need to plan the next generation of power supplies. Utilities need to investigate the integration of renewable resources in the supply-side and demand-side management (DSM) options chosen for the future.

Historically, the bulk of utility electric generation has been dispatchable and based on economies of scale. Large power plants offered the best economics. Today, legislators, utility regulators, and consumers are promoting improved efficiency in the use of our energy resources, reduced dependence on fossil fuels, and a course of action that will lead to a more sustainable and secure energy future.

Utilities can consider many kinds of renewable energy technologies for power generation; each technology has different operating and cost characteristics. Consider these examples:

- Hydro-generation and geothermal steam-powered generation are both long-established, inexpensive technologies that can be dispatchable, depending on the quality of the resource.
- A solar thermal power plant can produce as much energy as a conventional central station power plant. The time of maximum power output may be coincident with a utility's peak power needs.
- Burning biomass—such as wood waste—became an economical fuel alternative under the encouragement of the Public Utilities Regulatory Policy Act of 1978 (PURPA), and the prevalence of these fuels makes them renewable sources.

However, just as utility planners would not build a system using only one fuel source or plant, no utility planner should build a future system using only solar, wind, or biomass energy sources. These technologies should be used as elements of an integrated portfolio of fuel types and technologies, exploiting the advantages of each while compensating for their respective disadvantages.

Many renewable sources of energy offer significant environmental advantages in terms of reduced levels of carbon dioxide, sulfur oxides, and nitrogen oxides compared to conventional technologies. Some states have recently passed regulations requiring utilities to consider the cost of environmental impacts when choosing new sources of electricity. Other states have regulations or are considering policies to add environmental costs to the cost of power generation. These developments are still in their infancy and very controversial, but they could have a significant impact on the power planning process.

Dispersed generation, modularity, and short construction lead times are additional advantages of renewable resources. Renewable resources can be sized in many capacity ranges and can be procured quickly. Utilities are interested in dispersed and modular facilities that track load growth.

Many utilities are finding cost-effective ways to use renewables for nongrid applications. For example, in certain applications, photovoltaics (PV) can supply power more economically than installing a transformer, or stringing distribution lines to low-power applications such as sectionalizing switches, cathodic protection devices, nuclear warning signs, or water pumps—even if the power lines are relatively close by. In addition, utilities can apply renewable resources to meet customer energy needs, such as solar water heating, passive solar design, or the use of PV in remote locations.

■ TODAY'S ECONOMICS

The economics of solar technologies and their comparison to conventional technologies involve many factors. The reader is referred to the first reference at the end of this section for a full discussion of the economics of solar energy systems.

Renewable and fossil technologies tend to have opposite cost structures. The renewable plant generally has a higher capital cost and lower operating costs versus a natural-gas-fired plant, which generally has a low initial cost and a higher operating cost. Table R-1 provides a summary of the economic status of renewable resources including capital cost, operation and maintenance cost, levelized energy cost, and capacity factors. Additional information and supporting documentation can be found in the individual sections on renewable resource technologies. Because some renewable technologies are rapidly evolving, the end-of-decade cost is expected to be much lower than today's cost. Today, using traditional financial planning methods, the cost of generating power from central-station-based renewables is generally higher than from a comparable plant fired by coal. However, the recently passed National Energy Policy Act of 1992 includes several financial incentives for renewables. It includes a permanent extension of the solar and geothermal 10% investment tax credit. It also includes a production tax credit to power facilities equal to $0.015 for each kWh of electricity produced from solar, wind, biomass (excluding municipal solid waste), or geothermal energy. The definition of biomass requires that biomass facilities use biomass grown exclusively for energy production, to qualify for the credit.

The levelized energy cost represents the present value of a resource's cost (including the initial capital cast, annual operating and maintenance costs (O&M), replacement costs, and as appropriate, cost of feedstock and auxiliary fuel. It also includes the cost of financing. By levelizing costs, resources with different lifetimes and generating capacities can be compared. The costs presented in Table R-1 and the individual briefs do not reflect the environmental or societal benefits of using renewable resources.

A capacity factor is the amount of energy a system produces as a percent of the total amount that it would produce if operating at its rated capacity throughout the year. Higher values indicate an ability to meet a load for a greater portion of the year, assuming the plant is dispatched as fully as possible. Because many renewable resources are intermittent resources, their capacity factors are on the low end of the range when measured using traditional methods. In some circumstances, renewables can be combined with advanced storage options. In other cases, depending on resource availability and the utility load profile, some renewable resources may have their time of peak output coincident with the time of the utility peak demand. Other renewables such as biomass, geothermal, and hydropower, under some circumstances, are fully dispatchable. With good planning, utilities can maximize the benefits of intermittent renewable resources without storage.

The cost of energy for new generating facilities depends on the type and purpose of the facility. Cost of generation for base load, intermediate, and peaking facilities is shown in Figure R-1. Today, the cost of hydropower is cost effective. Figure R-2 illustrates cost trends for four renewable technologies: solar thermal, biomass, wind, and PV. In particular niche markets, they are cost effective today on a levelized life-cycle cost basis. Projections indicate that on a levelized cost basis, many more renewable options will be cost effective for peaking, intermediate, and some base load power generation by the year 2000.

When analyzing the system costs of renewables, planners are exploring valid approaches to the difficult task of incorporating the most significant element in utility planning—risk. Since the 1970s, fuel cost variability, environmental policy shifts, regulatory condemnation of fully functioning plants, and siting difficulties appear to provide some strategic advantage to the increasing use of renewables because they are generally immune to these influences. Intuitively, it is dear that a technology that does not require a fuel, such as solar or wind, has a value because of its immunity from unforeseen fuel price increases. The difficult task is incorporating such facts in thoughtful utility planning. At a minimum, we can say that every utility should begin now to enhance its familiarity and "hands-an" exposure with at least some of these technologies.

FOR MORE INFORMATION

PUBLICATIONS

American Solar Energy Society, *Economics of Solar Energy Technologies*, Boulder, CO, December 1992.

Hamrin, J., and N. Radar, *Investing in the Future: A Regulator's Guide to Renewables*, National Association of Regulatory Utility Commissioners, Washington, D.C., February 1993.

Brower, Michael, *Cool Energy: Renewable Solutions to Environmental Problems* (revised edition), The MIT Press, Cambridge, MA, 1992.

Idaho National Engineering Laboratory, et al., *The Potential of Renewable Energy: An Interlaboratory White Paper*, SERI/TP-260-3674, Solar Energy Research Institute, Golden, CO, March 1990.

Table R-1. Economics of Renewable Options for Utility-Scale Generation

	Capital Cost ($/kW)		Current Operational Cost ($/kWh)[1]	Levelized Cost of Electricity ($/kWh)		Capacity Factor (%)	Typical Size per Installation
	Current (1990s)	Projected (2000)		Current (1990s)	Projected (2000)		
Conventionol Hydropower	1700–2070	—	0.002	0.028–0.063	0.028–0.063	40–50	>34 MW
Direct Biomass Combustion	600–2400	—	83.00/kW/yr	0.079	0.074	70–85	30 MW
Municipol Solid Waste (direct burn)	3100–5100	—	—	—	—	50–80	9-80 MW
Geothermal Flash	1690–2130	1900	0.02–0.04	0.057–0.064	0.047 0.055	80–90	Under 50 MW
Geothermal Binary	2400	2087	0.02–0.035	0.057–0.064	0.047 0.055	80–90	Under 50 MW

Solar Thermal Central Receivers	—	3300	—	—	0.080– 0.10	40 (estimated)	100–200 MW (planned)
Solar Thermal Parabolic Trough	3010	2200	0.018	0.09– 0.13	0.08– 0.10	36	Up to 80 MW
Solar Thermal Parabolic Dishes	—		—	—	0.15 0.30	23 (estimated)	5–25 kW (projected)
- Small Systems		3000–6000					
- Large Systems		1700					
Solar Ponds	1,900[2]	—	0.01	0.015– 0.30	0.08– 0.10	70–90	70 kW
Wind	1010	750	0.016	0.075	0.040 0.050	20–30	150–500 kW (machines)
Photovoltaics	8000– 15,000	4000– 5000	0.005	0.36– 0.68	0.18– 0.22	25–35	Up to 500 kW

Note: dashes indicate that data is not available (see the individual briefs for more information)

1. Unless otherwise noted.
2. Cost of engine only. See Brief B.

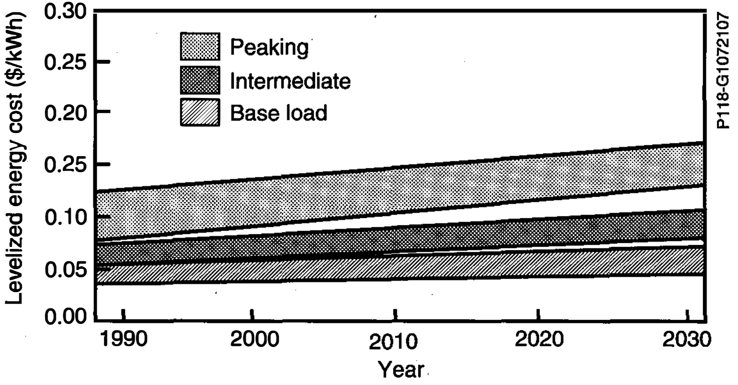


Figure R-1. Cost trends for conventional energy

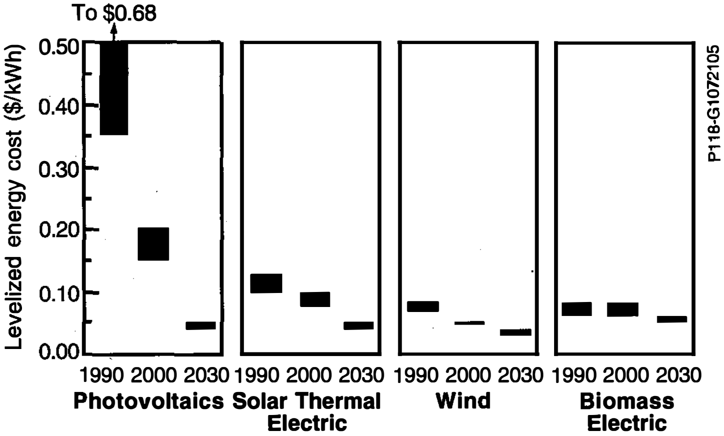


Figure R-2. Cost trends for renewable energy

HYDROELECTRIC POWER

INTRODUCTION

In 1991, hydroelectric facilities generated 275 billion kWh or about 10% of the total net electrical generation in the United States. Hydroelectric capacity includes 18 GW of pumped hydro capacity, and 73.4 GW of conventional hydro capacity.

TECHNOLOGY DESCRIPTION

Hydroelectric technology converts the kinetic energy contained in falling or flowing water into electrical energy through the use of a turbine and a generator.

The capability of a hydropower plant is primarily a function of two main variables of the water resource: (1) flow rate expressed in ft^3/s or gpm, and (2) hydraulic head, which represents the elevation differential through which the water falls. Usually a low-head plant is less than 100 ft (30.5 M), a medium-head plant ranges from 100 to 800 ft (243.8 M), and a high-head plant is 800 ft (243.8 M) or more. Because power generation is dependent on both head and flow, similar generation capacities can be developed by either a low-head, high-flow or a high-head, low-flow facility or some combination of the two.

Hydropower technology can be categorized into two types: conventional and pumped storage. Conventional hydropower uses the available water from a river or reservoir to produce electricity. The annual amount of electrical generation can depend indirectly or directly on the amount of rainfall in a river basin and whether water storage facilities are part of the project. A pumped storage facility stores electrical energy by pumping water, usually through reversible turbines, from a lower to an upper reservoir. Electricity is generated when the water flows back through the turbines to the lower reservoir. More energy is required in the pumping than is produced by the plant, (typically 1.25 kWh to 1.4 kWh required for each kWh generated), but the pumping is done during the low-power demand hours. Pumped-storage facilities are valuable to the utility because they can operate economically and be brought on-line quickly during the high-power demand periods. The amount of annual electrical energy generation from the reservoir depends on the utility's need for energy storage and the facility's capacity.

The main types of conventional hydropower plant operation are: run of river, peaking, and storage:

- The run-of-river project uses the river flow with very little alteration and little or no impoundment of the water.
- In a peaking project, the hydropower plant is operated at maximum allowable capacity for part of the day and is either shut down for the remainder of the time or operated at minimal capacity level.
- A storage project stores water during high-inflow periods to augment water during low-inflow periods. Storage projects allow the flow releases and power production to be more flexible and dependable. Many hydropower project operations use a combination of approaches.

Conventional hydropower plants generally have the following components:

- Dam—controls the flow of water and increases the water elevation to create the hydraulic head. The reservoir has created, in effect, stored energy.
- Penstock—a large pipe to carry the water from the reservoir to the turbine in the power plant.
- Turbine—turns by the force of the water pushing the blades. The types of turbines and their applications are identified in Table R-2.
- Generator—connects to the turbine and rotates to produce electrical energy.
- Transformer—converts the generator's low-voltage electricity to higher voltage levels for transmission to the load center, such as a city or factory.
- Transmission lines—transmit high-voltage electricity from the transformer at the hydroplant to the electric distribution system.

Figure R-3 illustrates these components.

Hydroelectric technology is highly developed. The efficiency of the turbine, which is based on losses of effective head in the turbine, normally range from 80% to 90%.

DEFINITIONS AND TERMS

BULB TURBINE The entire generator is mounted inside the water passageway as an integral unit with the turbine. These installations can offer significant reductions in the size of the powerhouse.

PELTON TURBINE Water passes through nozzles and strikes cups arranged on the periphery of a runner, or wheel, which causes the runner to rotate, producing mechanical energy. The runner is fixed on a shaft, and the rotational motion of the turbine is transmitted by the shaft to the generator.

FRANCIS TURBINE Contains a runner that has water passages through it formed by curved vanes or blades. As the water passes through the runner and over the curved surfaces, it causes rotation of the runner. The rotational motion is transmitted by a shaft to the generator.

PROPELLER TURBINE Contains a runner that has blades similar to a propeller used to drive a ship. As water passes over the curved propeller blades, it causes rotation of the shaft to which the blades are attached.

KAPLAN TURBINE Equipped with two blades whose pitch is adjustable. The turbine may have gates to control the angle of the flow into the blades.

RESOURCE ASSESSMENT

In 1992, the Federal Energy Regulatory Commission (FERC) and the Idaho National Engineering Laboratory identified the undeveloped hydropower potential at 71,399 MW—approximately 9% at developed sites that currently generate power, 47% at undeveloped sites with dams, and 44% at undeveloped sites without dams. The undeveloped potential is located at 4540 sites ranging from small to large. The undeveloped potential for pumped storage is 1,632,919 MW at 1405 sites, an an average 1162 MW/site.

Figure R-4 shows hydropower capacity in the United States.

MARKET OUTLOOK FOR HYDRO-ELECTRIC POWER

Hydroelectric is an established technology. It has been in use in the United States since the 1800s. Rather than building new large dams, current markets include increasing output at existing plants, adding generation capabilities to existing dams, developing small low-head plants, and developing pumped storage systems.

The FERC predicts that pumped storage will likely represent most of the growth in U.S. hydroelectric generating capacity over the next few decades.

INDUSTRY STATUS

Efficient turbine designs for various head and discharge conditions are available from a large number of manufacturers. Hydroelectric industry directories such as *Hydro-Review* and *Independent Energy* list many manufacturers and services available to developers.

CONSTRUCTION LEAD TIME

The hydropower licensing process for a major facility averages 4 to 7 years. For small facilities it averages 2 to 4 years. Construction lead time is estimated to be 4 years for large hydroelectric plants and 2 years for small facilities.

ENVIRONMENTAL ISSUES

Hydropower plants can have impacts on the environment. The streamflow is a renewable resource, and hydroelectric generation is not a consumptive use of water, although large surface areas of reservoirs increase the evaporative loss of water. No greenhouse gases are produced, and no solid waste is generated by a hydroelectric plant. However, impoundment of a river or stream alters the riparian habitat, and, in some cases, the water temperature, and the dissolved oxygen content of the released water; it may block the migration of fish. By proper design, many of these problems con be mitigated, but siting difficulties con be expected to remain significant.

LAND AREA REQUIREMENTS

Large hydroelectric plants often require vast amounts of land for their reservoirs; however, many existing dams may be suitable for hydro-electric development. Small projects require less land.

CURRENT COSTS AND TRENDS

Table R-3 provides information on current costs for hydroelectric plants.

FOR MORE INFORMATION

PUBLICATIONS

Hydro Review Magazine and *Hydrowire* Newsletter are available from HCI Publications, 410 Archibald St., Kansas City, MO 64111-3046, (816) 931-1311.

Hydroelectric Power Resources in the United States: Developed and Undeveloped, 1992, Washington D.C., Federal Energy Regulatory Commission.

Independent Energy Magazine, available from Marier Communications, Inc., 620 Central Avenue North, Milaca, MN 56353, (612) 983-6892.

ORGANIZATIONS

Notional Hydropower Association, 555 13th St., NW, Suite 900 East, Washington, D.C. 20004, (202) 637-8115.

Table R-2. Types of Turbines versus Application

System Type	Efficiency	Power Capacity (kW)	Application	Design Head (ft)	Flow (ft^3/s)
Impulse Pelton	90%	7–300,000	200 ft (61 M) to several thousand ft of head	40–6,500	1–1,000
Reaction Francis	90%–95%	7–600,000	25 ft (7.6 M) to 1000 ft (305 M) of head can be mounted horizontally or vertically	12–2,300	4–25,000
Propeller or "axial flow" Turbine Kaplan	<94%	15–200,000	100 ft (30.5 M) of head or less operates at high efficiency over a wide range of head	7–260	4–23,000
Bulb	69%–91%	4–60,000	< 60 ft (18.3M) of head or less	3–82	7–27,000

Source: Chappell, J.R., *Hydropower Hardware Descriptions*, EGG-M-09382, EG&G Idaho, April 1984.

Table R-3. Hydropower: Costs

System Type	Capital Cost ($/kW)	Operational Cost	Levelized Cost of Electricity ($/kWh)	Typical Size per Installation[4] (MW)	Capacity Factor (%)	Life (yr)
Conventional	1700–2070	Fixed $6.40/kW/yr Variable 0.002/kWh	0.028 –0.063[2]	34	40–50	50+
Pumped Storage	800–1200[1]	Fixed $5.30/kW/yr Variable 0.005/kWh	0.086 –0.11[3]	464	30	50+

1. Capitol and operotionol costs for conventional ond pumped storoge (in 1986 dollars) were token from Idaho Notionol Engineering Loborotory et ol., *The Potential of Renewable Energy*, SERI/TP-260-3694, March 1990.
2. Radar, N., *Power Surge*, Washington D.C., Public Citizen, Moy 1989 (1989 dollars).
3. California Energy Commission, *Energy Technology Status Report* Appendix A, June 1991 (1987 dollars).
4. Idaho Notional Engineering Laborotory and the Federol Energy Regulatory Commission, Hydropower Resource Assessment Data Bose, 1992.

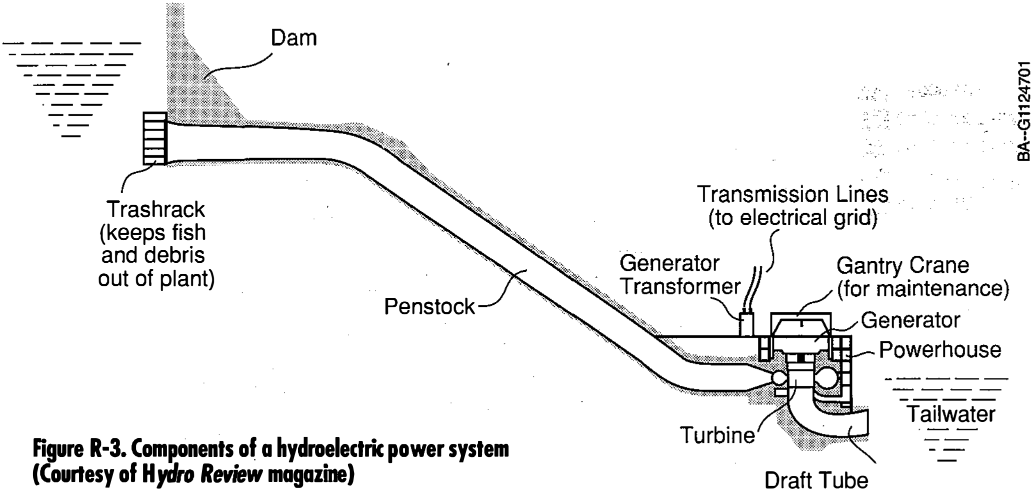


Figure R-3. Components of a hydroelectric power system (Courtesy of *Hydro Review* magazine)

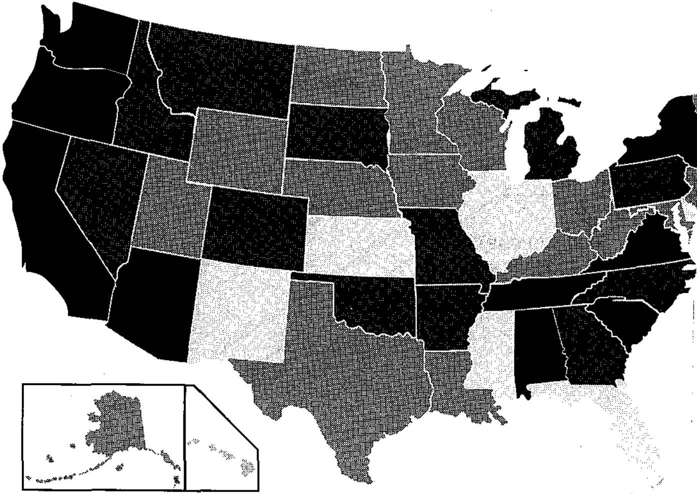


Figure R-4. Hydropower capacity

<100 MW
100-1000 MW
1000-2500 MW
>2500 MW

BIOMASS POWER, DIRECT CONVERSION OF AGRICULTURAL AND WOOD WASTES

INTRODUCTION

Today's biomass resources ore essentially byproducts from agriculture, forestry, and food processing. Wood-fired systems account for 88% of today's total biomass capacity, followed by landfill gas (8%), agricultural wastes (3%), and anaerobic digesters (1%). Wood con be classified as harvested or nonharvested. Harvested wood includes wood from logging and forest management activities, land clearing, and "clean" mill residue such as slobwood from primary forest mills. Nonhorvested wood includes wood waste from municipal, industrial, and commercial waste streams. Agricultural wastes include prunings from local orchords, vineyards, bagasse, rice hulls, rice straw, nut shells, crop residues, and manure.

TECHNOLOGY DESCRIPTION

Most of the existing installed capacity is conventional, where biomass is burned to produce steam, and the steam is used to produce power in a steam turbine. Approximately 4% of today's primary energy demand is met by biomass.

The electricity produced from biomass is generally dispotchoble rather than intermittent in nature; it is, therefore, available on a demand basis. Most of the installations to dote ore small-scale cogeneration systems operated by independent power producers or industrial entities such as pulp or paper mills. Utilities hove been involved in only a handful of dedicated wood-fired plants in the 40- to 50-MW range.

For continued growth in the biomass power industry, utility experience is confirming that a reliable and abundant supply of low-cost biomass feedstock is required. Biomass energy forms, or dedicated feedstock supply systems (DFSS), will satisfy this requirement and limit the need to harvest natural forests. The feedstock potential could easily lead to more than 20 GW of new capacity by 2010.

DEFINITIONS AND TERMS

ANAEROBIC DIGESTION The process by which organic matter is decomposed by bacteria that work in the absence of air.

COGENERATION The process in which fuel is used to produce heat for a boiler-steam turbine or gas for a turbine. The turbine drives a generator that produces electricity, with the excess heat used for process steam. Refer to Brief 31 in the *Pocket Guidebook, Volume 4: Industrial Technologies* for more information.

ENERGY CROPS Grown specifically for their fuel value. These include food crops such as com and sugarcane, and nonfood crops such as poplar trees and switchgrass. Currently, two energy crops ore under development: short rotation woody crops, which ore fast-growing hardwood trees harvested in 5 to 8 years; and herbaceous energy crops, such os perennial grasses, which ore harvested annually after taking 2 to 3 years to reach full productivity.

GASIFICATION A process in which o solid fuel is converted into o gas. Production of o clean fuel gas makes o wide variety of power options available.

PYROLYSIS The thermal decomposition of biomass at high temperatures (over 400°F) in the absence of air. The end product of pyrolysis is o mixture of solids (char), liquids (oxygenated oils), and gases (methane, carbon monoxide, and carbon dioxide) with proportions determined by operating temperature, pressure, oxygen content, and other conditions.

RESOURCE ASSESSMENT

Biomass wastes ore currently the primary fuel source for biomass power facilities. Enough wastes ore economically available to allow the biomass industry to expand modestly through the 1990s. The U.S. Department of Energy (DOE)-sponsored energy crop development program is expected to dramatically expand future availability of biomass feedstocks. Figure R-5 shows the location of existing biomass feedstocks, and Figure R-6 shows the location of herbaceous and woody energy crops production potential.

MARKET OUTLOOK FOR BIOMASS

Current markets include

- Sites with a stable and free or inexpensive supply of harvested or nonharvested waste materials, where the source of the waste is generally within 50 miles (80.4 km) of the power plant
- Utilities that have an urgent need to reduce their pollutant emissions
- Municipal utilities where the power station can solve two problems: generation of commercial power and consumption of urban wood wastes that would otherwise be landfilled
- Industrial companies with on-site waste or access to a utility that needs power.

Near-term market considerations:

- Wood and wood wastes will continue to be primary feedstock through the end of the decade. Dedicated energy crops come into use by 2000.
- Utilities willing to comply with Phase III of the Clean Air Act may cofire biomass at existing coal plants.
- Small commercial-scale gasifiers and pyrolysis reactors will be developed and tested.
- Larger-scale projects will be demonstrated that will justify the higher cost of high-efficiency boilers and steam turbine cycles.

Market considerations beyond 2000:

- Dedicated energy crops will serve as the primary feedstock.
- Advanced technology for intermediate and base load generation of power will be available.
- Firing of biomass-derived fuel will be used for peaking and intermediate load applications.

INDUSTRY STATUS

Independent power producers have developed the majority of dedicated wood-burning generating stations in the country and are selling the energy, under the Public Utility Regulatory Policies Act of 1978, to utilities. Although most of these plants burn forest and mill wastes, a few developers have begun building plants designed to burn recycled wood. Power plants that burn a variety of biomass wastes are gaining favor in the United States, particularly with the development of boilers and fluidized bed combusters that can handle multiple fuel types more easily than conventional boilers. As a result, the number of plants that either cofire agricultural wastes with wood or use agricultural wastes as the sole fuel is growing.

The major market forces driving additional development of biomass power include

- Availability of low-cost fuel resources, whether from waste or dedicated fuel crops, coinciding with a regional need for power
- Public reaction to biomass combustion, especially urban waste wood
- The availability of utility power purchase contracts
- The ability of biomass to compete in utility industry solicitations
- Competitiveness of biomass compared with natural gas
- Competition for dedicated biomass crops, such as paper
- The success of some local efforts to recycle or compact waste
- State and public support of the CO_2 neutral concept of biomass power
- The \$0.015 per kWh tax incentive in the Energy Policy Act of 1992 for biomass electric facilities that use dedicated biomass crops.

CONSTRUCTION LEAD TIME

Once a site is selected, permitting takes approximately 0.4 to 1 years for a 5- to 25-MW plant. (The balance of engineering required to bring the plant to startup and commercial operation is about 1.5 years.) The total time from site selection through commercial operation is approximately 2 to 3 years. These estimates do not include the time for obtaining fuel supply contracts and power purchase agreements, and finding o suitable site. The time required for permitting is highly site-specific.

ENVIRONMENTAL ISSUES

In comparison to burning cool, biomass combustion offers significant environmental benefits through reduced emissions of SO_2, NO_2, and ash. Biomass is virtually free of sulfur and thus eliminates the precursor of SO_2 and acid rain. The growth of biomass resources provides o sink for atmospheric CO_2 that offsets the combustion emissions of CO_2 from biomass electricity production—thus providing o power option that is CO_2 neutral. The level of particulates is higher from burning biomass than from cool.

Water quality impacts of biomass systems ore potentially less than cool-fueled system impacts. Water usage by combustion is comparable to cool-fueled systems. Feedstock growth may require lorge quantities of water and petro-chemical-based fertilizer, which raises concerns about nutrient run-off and the absolute renewable nature of the biomass feedstock. The harvesting ond handling of wood presents occupational hozords comparable to cool mining. Biomass power production hos fewer long-term health risks thon cool-fired systems (for example, chronic lung disease). Long-term ecological effects ond the sustoinobility of soil productivity ore issues unique to the biomass fuel resource, but present indications suggest that it is possible to enhance the quality of forests through appropriate monogement techniques.

LAND AREA REQUIREMENTS

To generate 150 MW of electricity, 64,000 acres (25,900 ho) of lond would be required for growing low-cost, high-productivity energy crops such os woody crop fuels or perennial grosses. Approximately 1/7 of the 64,000 acres would be harvested annually. This is approximately 60 acres per MW (24.6 ho/MW).

CURRENT COSTS AND TRENDS

Toble R-4 summarizes current costs. Figure R-7 illustrates the projected future levelized costs to generote electricity from biomass using various conversion processes.

Reduced capital costs will come from improved collection, processing, and fuel feeding systems. Efficiency can be increased and emissions reduced if direct-fired combustion equipment can be fine-tuned to the particular fuel being burned. In addition, the development of small integrated systems could potentially increase resource utilization.

FOR MORE INFORMATION

PUBLICATIONS

Electricity from Biomass: A Developmental Strategy, U.S. Department of Energy, Washington D.C., Office of Solar Energy Conversion, April 1992.

Biomass State-of-the-Art Assessment, Electric Power Research Institute, Palo Alto, CA, EPRI GS-7471, September 1991.

Turnbull, J.H., *PG&E Biomass Qualifying Facilities, Lessons Learned Scoping Study - Phase 1*, Pacific Gas and Electric Co., Report no. 007-91.5, San Ramon, CA, May 1991.

ORGANIZATIONS

Western Area Power Administration, Western Regional Biomass Energy Program, 1627 Cole Blvd., P.O. Box 3402, Golden, CO 80401, (303) 231-1615.

U.S. Department of Energy, Solar Thermal and Biomass Power Division, 1000 Independence Ave. SW, Washington, D.C. 20585, (202) 586-6750.

National Wood Energy Association (NWEA), 777 North Capitol St. NE, Washington, D.C. 20002, (202) 408-0664.

National Renewable Energy Laboratory (NREL), 1617 Cole Blvd., Golden, CO 80401, Richard Bain, Biomass Power Program, (303) 231-7346.

Table R-4. Biomass: Costs

System Type	Capital Cost[1] ($/kW)	Operational Cost[2] ($/kW/yr)	Levelized Cost of Electricity ($/kWh)	Typical Size per Installation[3] (MW)	Capacity Factor (%)	Life (yr)
Direct combustion	600–2400	83	0.079	30	70–85	20–30

1. The cost to build a biomass plant varies tremendously. A small plant (under 12 kW) built with rebuilt boilers and turbines, basic deionizing water-treatment, and stripped down controls would cost in the range of $600 to $800/kW. At the other extreme, a high-tech facility using a fluidized bed to burn agricultural residue with the latest air emission control and zero discharge water system may cost in the range of $2000 to $2400/kW. (Source: Pacific Gas and Electric Co., May 1991, Report No. 007-91.5, San Ramon, CA, Turnbull, J., *PG&E Biomass Qualifying Facilities Lessons Learned Scoping Study - Phase 1*).
2. March 8, 1993 update to U.S. Department of Energy, *Electricity from Biomass: A Developmental Strategy*, Office of Solar Energy Conversion, Washington, D.C., April 1992.
3. Represents the average size of plants in California.

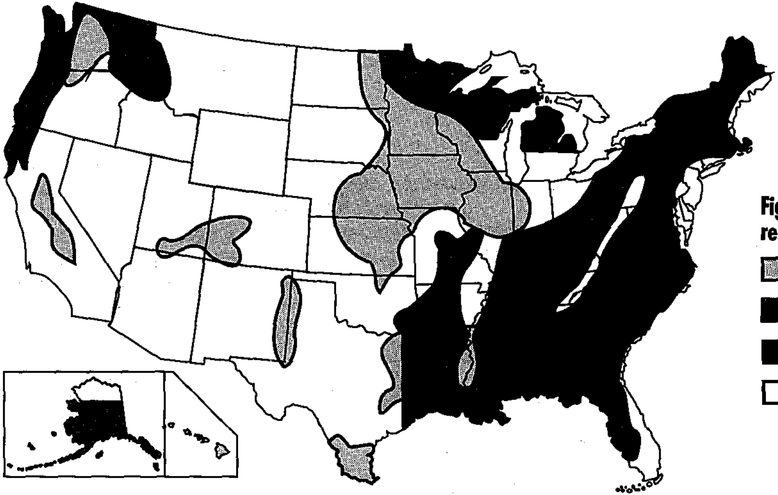


Figure R-5. U.S. biomass resources

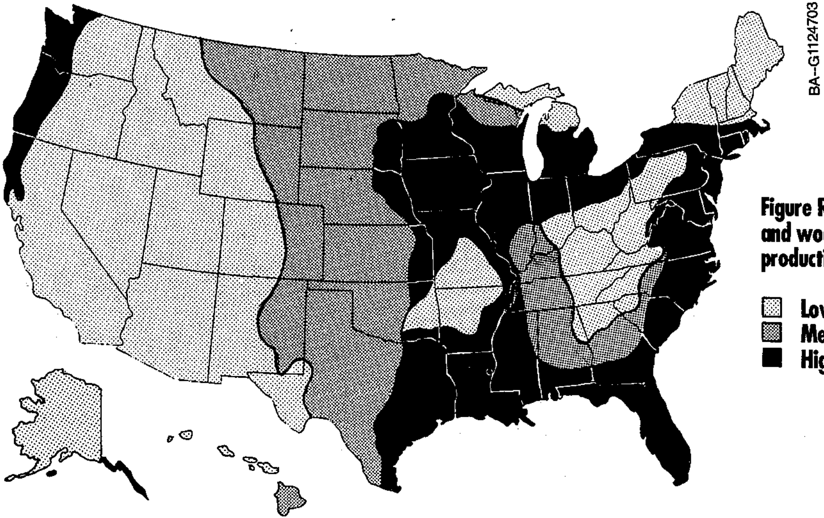
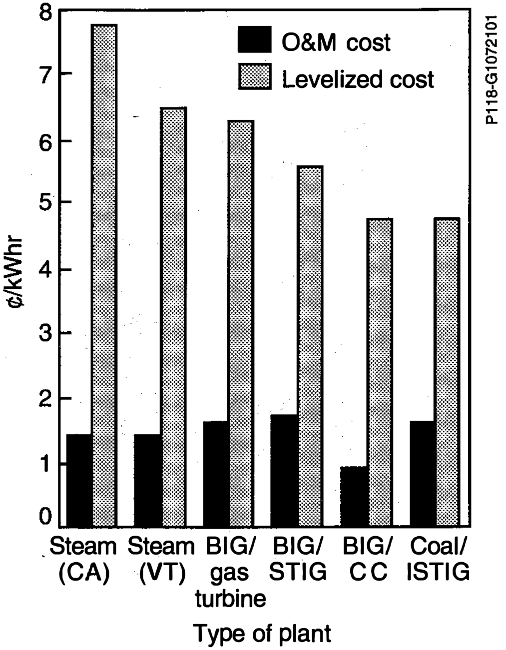


Figure R-6. Herbaceous and woody energy crops production



BIG = Biomass Integrated Gasification
STIG = Steam Injection Gasification
ISTIG = Intercooled Steam Injection Gasification
T = Gas Turbine
CC = Combined Cycle

Figure R-7. Comparative biomass process costs

MUNICIPAL SOLID WASTE

INTRODUCTION

The U.S. Environmental Protection Agency (EPA) has estimated that U.S. municipal solid waste (MSW) totaled 196 million tons (177 billion kg) in 1990 and will grow over the next decade at the rate of 1.5% per year. At present, 67% of all MSW is landfilled, and -17% is combusted in 145 municipal waste combustors.

MSW facilities are typically operated by municipalities, waste management districts, or private companies. Electric utility use of MSW is not widespread, although a few utilities are using it, including one in Minnesota that operates two plants that process MSW into a refuse-derived fuel (RDF). This RDF serves as the fuel source for two of the power plants in the 30-MW range.

TECHNOLOGY DESCRIPTION

The five major technologies commonly used for MSW management are

- Collection/separation of recyclable materials
- Landfilling
- Mass burn for energy recovery
- Production and combustion for RDF
- Composting.

Many communities use more than one technology to manage MSW. A solid waste management strategy should look at volume reduction first, and then reusing, recycling, and the composting of MSW. Although energy is not the primary goal of any MSW management strategy, mass burn and combustion of RDF offer the added benefit of energy recovery. These technologies, and the cofiring of RDF and coal, are the focus of this brief.

DEFINITIONS AND TERMS

MASS BURN FACILITY A facility in which the pretreatment of the MSW includes only inspection and simple separation to remove oversize, hozordous, or explosive moterials. Moss burn facilities con be lorge, with capacities of 3000 tons (2.7 million kg) of MSW per day or more. They con be scaled down to handle the waste from smaller communities, ond modular plants with capocities os low os 25 tons (22.7 thousand kg) per day hove been built. Mass bum technologies represent over 75% of oll the MSW-to-energy facilities constructed in the United States to dote. The major components of o moss burn facility include

- Refuse receiving ond handling
- Combustion ond steam generation
- Flue gos cleaning
- Power generation
- Condenser cooling water
- Residue hauling ond storage.

RDF To produce RDF, mixed MSW is shredded, ond noncombustible materials such os glass ond metals ore generally removed. The residual material is sold os-is or further densified ond/or reduced in size to be used as RDF. The RDF processing facility is typically located neor the MSW source, while the RDF combustion fodlity con be locoted elsewhere because the RDF con be transported more economically.

Existing RDF facilities process between 100 (90.7 thousond kg) ond 3000 tons (2.7 million kg) per day. The notion's largest RDF waste-to-energy facility is in Florida. It processes 18,000 tons (16.3 million kg) per week. A facility in Minnesota processes 1500 tons (1.36 million kg) per day, which serves os the fuel source for two 30-MW power plants.

COFIRING WITH COAL Between 1972 ond 1988, nine U.S. utilities cofired almost 1 million tons (907 million kg) of RDF with cool or oil. The cofiring wos done in facilities ranging from 35-MW to 364-MW in size. Currently, only six utilities cofire RDF with cool. They ore located in Ames, Iowa; Madison, Wisconsin; Lakelond, Florida; Baltimore, Maryland; Big Stone City, South Dakota; ond Tacoma, Washington. The other utilities discontinued operotion for various reasons, including uneconomical production of RDF and the use of boilers not well-suited to RDF cofiring.

RESOURCE ASSESSMENT

The MSW resources vary by regional demographics. Figure R-8 illustrates the relative distribution of MSW.

MARKET OUTLOOK FOR MSW

The current market consists of municipalities responding to the need to manage and reduce the volume of MSW in their community, in addition to responding to increased customer demand for more sustainable approaches.

Using MSW for electricity production frequently is not competitive with the cost of generating electricity from fossil fuels, but the price received for the electricity can be an attractive offset to the cost of waste management. As landfill availability decreases and tipping fees and transportation costs to landfills increase, municipalities may become increasingly interested in these options. Figure R-9 illustrates the range of 1991 tipping fees, by state.

Current projections of decreasing landfill capacity and increasing waste generation will lead to demand for waste volume and weight reduction alternatives such as waste-to-energy combustion.

INDUSTRY STATUS

Most waste-to-energy plants have been developed through an alliance between a developer/vendor and the governmental body responsible for waste disposal—a municipality, county, district, or regional waste authority. A public entity may contract with a full-service vendor to build and operate a waste-to-energy facility for 20 to 30 years.

Numerous power plant engineering companies offer design and construction services.

CONSTRUCTION LEAD TIME

The estimated lead time to build an MSW project is 1 to 2 years. Public opposition can extend the lead time up to 5 years.

ENVIRONMENTAL ISSUES

Under Section 306 of the Clean Air Act amendments passed in 1991, the EPA will be required, by 1993, to issue acid gas emission standards for MSW facilities with capacities of 250 tons (22.6 kg) per day or more.

LAND AREA REQUIREMENTS

The maximum capacity of a landfill is determined by volume, not weight. The land area used for MSW management is largest if all waste is landfilled, and smallest if all waste is burned and the ash from combustion is landfilled. A landfill with gas recovery (an increasingly common type of facility) requires 1.6 yd^3 (1.2 m^3) per ton of MSW. In comparison, the waste from mass burning of a ton of MSW only requires 0.2 yd^3 (0.15 m^3) per ton. Direct firing of RDF requires 0.4 yd^3 (0.3 m^3) per ton.

CURRENT COSTS AND TRENDS

Table R-5 presents current cost information for various types of MSW conversion techniques.

FOR MORE INFORMATION

PUBLICATIONS

SRI International, *Data Summary of Municipal Solid Waste Management Alternatives Volume I: Report Text*, NREL/TP-431-4988A, Menlo Park, CA, October 1992.

Solid Waste and Power, Journal available from HCI Publications, 410 Archibald St., Kansas City, MO 64111-3046, (816) 931-1311.

Trash to Cash, Investor Responsibility Research Center, 1755 Massachusetts Ave. NW, Suite 600, Washington, D.C. 20036, (202) 234-7500, September 1991.

1991-1992 Resource Recovery Yearbook, Governmental Advisory Associates, 177 E. 87th St., Suite 400, New York City, NY 10128, (212) 410-4165.

ORGANIZATIONS

Northern States Power Resource Recovery, Elk River Resource Recovery Facility, 10700 165th Avenue NW, Elk River, MN 55330.

Integrated Waste Service Association, 1133 21st St. NW, Suite 205, Washington, D.C. 20036, (202) 467-6240.

National Solid Waste Management Association, 1730 Rhode Island Ave. NW, Washington, D.C. 20036, (202) 775-5917.

Table R-5. Municipal Solid Waste: Costs

System Type	Capital[1] Cost ($/kW)	Capital[1] Cost ($/ton/day)	Net Electrical Production (kWh/T)[2]	Operational Cost ($/ton)[2]	Typical Size per Installation (MW)	Life (yr)
Mass burn	3,100–5,100	30,000–210,000	450–600	26	9–80	20–30
Direct Fired RDF	3,700–4,500	75,000–102,000	770	36	13.5–80	20–30
Cofiring	3,400–3,800	76,000–85,000			40–50	20–30

1. The capital cost is expressed in both $/kW and $/ton/day of design capacity. The data was taken from two different sources. Actual capacity may vary. The capital in $/ton/day, net electricity, and operational costs were taken from Stanford Research Institute (SRI) International (Oct. 1992), *Data Summary of Municipal Solid Waste Management Alternatives*, Menlo Park, CA. The tipping fees are not reflected in the operational cost. This cost is only for the operation and handling of the fuel. The capital costs (in $/kW) are in 1986 dollars and were taken from California Energy Commission (June 1991) Energy Technology Status Report. They are based on the actual cost of only two MSW facilities operating in California.
2. Net electrical production and operational costs were taken from SRI International.

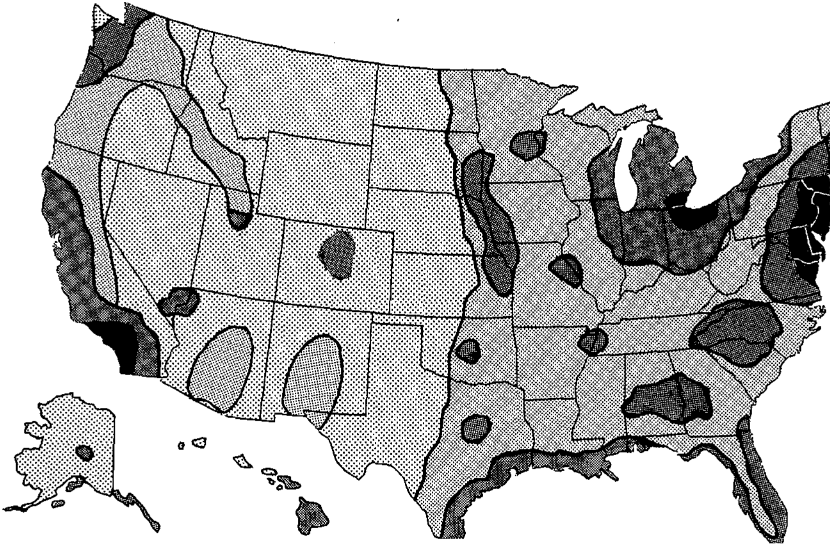


Figure R-8. Distribution of municipal solid waste

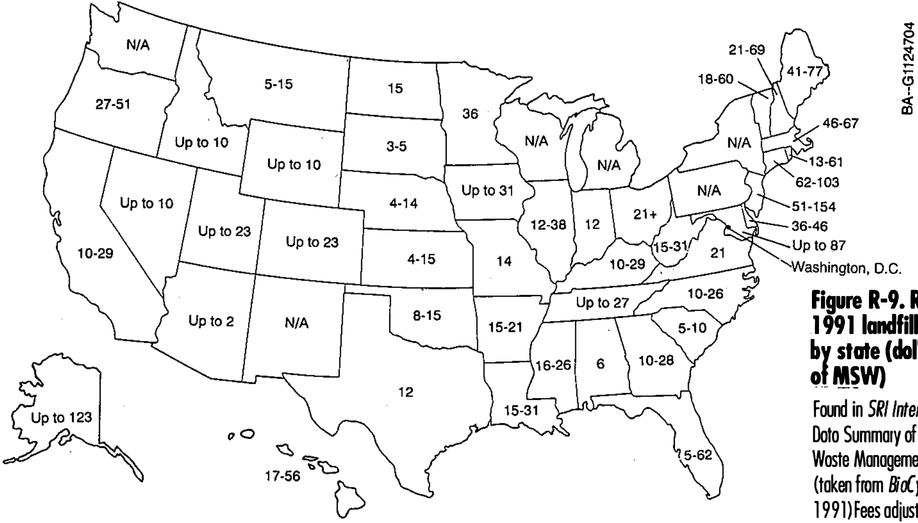


Figure R-9. Range of 1991 landfill tipping fees by state (dollars per ton of MSW)

Found in *SRI International* (June 92) Data Summary of Municipal Solid Waste Management Alternatives (taken from *BioCycle*, p.361, April 1991) Fees adjusted from 1990 to 1991 index.
N/A = data not available

GEOTHERMAL POWER

INTRODUCTION

Geothermal energy is heat energy from beneath the earth's surface. There ore four types of geothermal resources: hydrothermal, geopressure brines, hot dry rock, and mogmo. To date, commercial development is focused on hydrothermal resources, which ore reservoirs of superheated water or steam trapped in fractured or porous rock under o loyer of impermeable rock. In some places, the heat comes to the surface. In most cases, hot water or steam mon-mode wells ore drilled to extract the heot.

At the end of 1990, the U.S. geothermal industry hod on installed electrical copocity of 2719 MW ot 70 hydrothermal power plants located in California, Nevodo, ond Utoh. About 73% of the capocity is located at The Geysers in northern Colifomio.

TECHNOLOGY DESCRIPTION

Depending on the state of the resource (vapor or liquid), its temperature, and its chemistry, one of three different technologies con be used to convert the thermal energy to electric power:

- Dry steam—Conventionol turbine generators ore used with the dry steam resources. The steom is used directly, eliminating the need for boilers ond boiler fuel thot characterizes other steom-power-generoting technologies. This technology is limited because dry-steam hydrothermal resources ore extremely rore. The Geysers is the notion's only dry steam field.
- Flosh-steom—When the temperature of the hydrothermal liquids is over 350°F (177°C), flosh-steom technology is generally employed. In these systems, most of the liquid is flashed to steam. The steam is separated from the remaining liquid ond used to drive o turbine generotor. While the water is returned to the geothermal reservoir, the economics of most hydrothermal flash plants ore improved by using o duol-flosh cycle, which separates the steom ot two different pressures. The duol-flosh

cycle produces 20% to 30% more power than a single-flash system at the same fluid flow.

- Binary cycle—Binary cycle systems can be used with liquids at temperatures less than 350°F (177°C). Flash-steam technology is not economical with fluids in this temperature range. Binary cycle technology incorporates two distinct fluid loops to generate electricity. In these systems, the hot geothermal liquid vaporizes a secondary working fluid, which then drives a turbine.

The flash-steam technology has reached a high level of maturity. The binary power cycle is at the verge of maturity. To date, all commercial development of geothermal energy employs the hydrothermal resource, and for utility-scale applications, the hydrothermal power plants are used primarily to provide base-load power to the electric grid. Current research is aimed at improving the use of the hydrothermal resource and developing the other forms of geothermal energy: geopressured brines, hot dry rock, and magma.

DEFINITIONS AND TERMS

HYDROTHERMAL FLUIDS These fluids can be either water or steam trapped in fractured or porous rocks; they are found from several hundred feet to several miles below the Earth's surface. The temperatures vary from about 90°F to 680°F (32°C to 360°C) but roughly 2/3 range in temperature from 150°F to 250°F (65.5° to 121.1°C). The latter are the easiest to access and, therefore, the only forms being used commercially.

GEOPRESSURIZED BRINES These brines are hot (300°F to 400°F) (149°C to 204°C) pressurized waters that contain dissolved methane and lie at depths of 10,000 ft (3048 m) to more than 20,000 ft (6096 m). The best known geopressured reservoirs lie along the Texas and Louisiana Gulf Coast. At least three types of energy could be obtained: thermal energy from high-temperature fluids, hydraulic energy from the high pressure, and chemical energy from burning the dissolved methane gas.

HOT DRY ROCK This resource consists of high temperature rocks above 300°F (150°C) that may be fractured and have little or no water.

To extract the heat, the rock must first be fractured, then water is injected into the rock and pumped out to extract the heat. In the western United States, as much as 95,000 mi^2 (246,050 km^2) have hot dry rock potential.

MAGMA This is molten or partially molten rock at temperatures ranging from 1260°F to 2880°F (700°C to 1600°C). Some magma bodies are believed to exist at drillable depths within the Earth's crust, although practical technologies for harnessing magma energy have not been developed. If ever utilized, magma represents a potentially enormous resource.

RESOURCE ASSESSMENT

The accessible resource base in the United States (broadly defined as the amount of heat above a minimum useful temperature within drilling distance of the surface), is estimated to be anywhere from 1.2 million to 10 million quads (1.3 to 10.5 exajoules), depending on assumptions of required temperatures, practical drilling depths, and efficiency of recovery.

Figure R-10 illustrates potential geothermal resources (hydrothermal and geopressured brines) and Figure R-11 illustrates geothermol temperature gradients. Areas of high or moderate gradient ore most economical for hot dry rock development.

MARKET OUTLOOK FOR GEOTHERMAL POWER

The geothermal industry tripled its capacity throughout the 1980s due to tax incentives and utility contracts for the purchase of power under the PRUPA regulations. The industry will continue to grow in the 1990s but at a slower pace than during the 1980s.

Planned added capacity through 2000 is approximately 682 MW. Much of the added capacity is planned for California and Nevada. Nevada has a high growth rate and needs new baseload power. It also has recently passed legislation that requires that cleanup of pollutants emitted during power generation be considered in evaluating new power plants. The Bonneville Power Administration is planning to develop 3 to 30 MW plants in the Northwest thot hove expansion potential.

Institutional factors, such os the ability to win competitive bidding solicitotions to supply power to utilities, will impoct the growth of the industry. These factors ore more influential thon technical hurdles.

The ability to develop new hydrothermal resource oreos will olso impoct future growth. Beyond the turn of the century, the odvonced resources (geopressured, hot dry rock, ond mogmo) may come into ploy. Research ond development to overcome the barriers to use these resources is ongoing.

INDUSTRY STATUS

The geothermal industry grew out of the oil industry—portly because of their similarities in resource exploitotion ond drilling. Declining oil ond gos projects hove prompted mony of these companies to slosh geothennol drilling projects or sell off some or oll of their geothermal projects. Utility affiliates become more active os more geothermal projects were developed by nonutility companies. The industry currently consists of about 10 companies, olthough 10 to 20 more companies ore pursuing projects.

CONSTRUCTION LEAD TIME

Geothennol plants con be modular ond con be installed in increments os needed. The lead time at existing geothermal fields, including drilling, is less thon 1-1/2 years. Siting, permitting, ond financing will take 1 to 2 years (concurrent with early production drilling ond testing), with o construction schedule of 2 to 2-1/2 years. Permitting may be difficult if the resource is located in wilderness or recreation oreos.

ENVIRONMENTAL ISSUES

Modern geothermal plants operating on hydrothermal resources hove extremely low levels of sulphur dioxide, carbon dioxide, nitrous oxide, ond particulate emissions compared to conventional energy sources. Hydrogen sulfide (H_2S) concentrations hove been found at vapor-dominated resources. They oppeor to be less of o problem at liquid-dominated sites. At strong concentrations, which could be lethal, H_2S

paralyzes the olfactory nerves and becomes odorless. H_2S can be controlled with abatement systems.

Some geothermal power plants use large quantities of cooling water. For example, a 50-MW water-cooled binary plant requires more than 5 million gal (18.9 million L) of cooling water per day [100,000 gal/MW (378,500 L/MW) day]. This is significant because many geothermal resources are located in arid regions, where water is a scarce and regulated commodity. However, plants can use dry cooling systems at a small increase in capital cost and some net output loss during the summer. Flash steam plants can also have a substantial portion of their water needs supplied by steam condensate.

At The Geysers in California, the cumulative effect of extensive steam withdrawal has caused the steam pressure to decline. This situation could potentially be remedied by injection of water from external sources.

LAND AREA REQUIREMENTS

The typical geothermal electric plant requires, at most, 5 acres/MW (2 ha/MW); this amount can be reduced with space-saving designs, such as multiwell pads.

Many of the most promising geothermal resources are located in or near protected areas such as national parks and national monuments, and wilderness, recreation, and scenic areas. The average amount of surface area disturbed for the development of geothermal resources is slight in comparison to other forms of energy extraction.

CURRENT COSTS AND TRENDS

Table R-6 summarizes current costs.

FOR MORE INFORMATION

PUBLICATIONS

Geothermal Energy in the Western United States and Hawaii: Resources and Projected Electricity Generation Supplies, Energy Information Administration, Washington, D.C., DOE/EIA-0544, September 1991.

Muffler, L.J.P., *Assessment of Geothermal Resources in the United States—1978*, United States Geologic Survey, U.S. Geologic Survey Circular 790, Washington, D.C., 1979.

Reed, M.J., *Assessment of Low-Temperature Geothermal Resources of the U.S.—1982*, United States Geologic Survey, U.S. Geological Survey Circular 892, Washington, D.C., 1983.

Geyer, J.D., *Geothermal Resources*, Staff Issue Paper 89-36, Northwest Power Planning Council, Portland, OR, 1989.

ORGANIZATIONS

Earth Sciences Laboratory, University of Utah Research Institute, 391 Chipeta Way, Suite C, Salt Lake City, UT 84108, (801) 524-3422.

Geothermal Resources Council, 2001 Second St. #5, Davis, CA 95616, (916) 758-2360.

Table R-6. Geothermal Power: Costs[1]

System Type	Capital Cost ($/kW)	Operational Cost ($/kWh)	Levelized Cost of Electricity[2] ($/kWh)	Typical Size per Installation (MW)	Capacity Factor (%)	Life (yr)
Geothermal Flash	1690–2130	0.02–0.04	0.057–0.064	Under 50	80–90	20–30
Geothermal Binary	2400	0.02–0.035	0.057–0.064	Under 50	80–90	20–30

1. All data except levelized electricity costs are taken from: Short, William (November 1991) *Trends in the American Geothermal Energy Industry*, Geothermal Resource Council Bulletin. Costs will vary according to fluid temperatures and related thermal efficiencies and the conversion technologies used. The capacity per installation represents the average size of existing facilities. The operating experience of some geothermal technologies is limited; reservoir life expectancies are an important unknown. The corrosive and scaling potential of geothermal fluids is a significant limiting factor on plant life expectancy. Even though manufacturers try to achieve useful lives of 20 to 30 years, more operating experience is needed to determine if such goals can be attained.
2. Levelized energy cost was taken from both *Renewable Energy Technology Evolution Rationales*, SERI/TP-260-4427, October 1990, and the Energy Information Administration reference cited under Publications. It is based on 1990 dollars and a 50-MW plant.

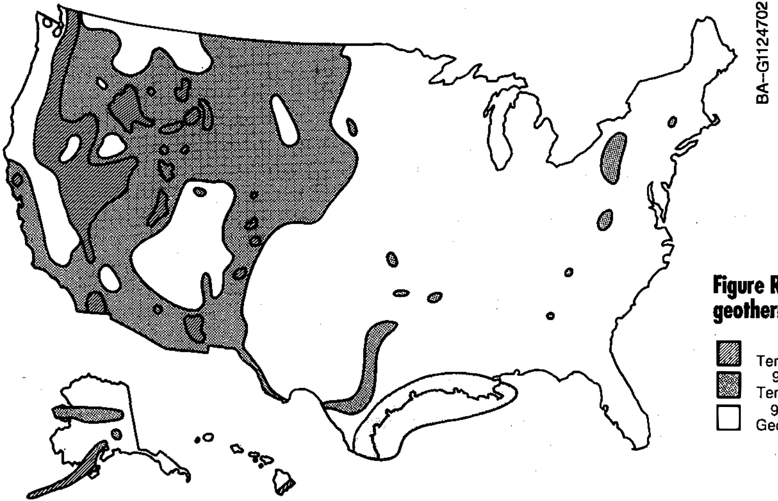


Figure R-10. Potential geothermal resources

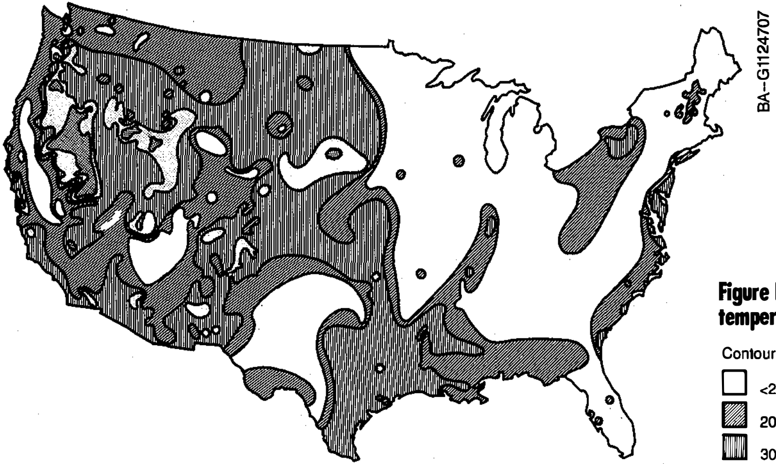


Figure R-11. Geothermal temperature gradient

Contour Intervals (in °C/km)

- <20
- 20-30
- 30-50
- 50-70
- >70

SOLAR THERMAL CENTRAL RECEIVERS

TECHNOLOGY DESCRIPTION

The technology uses fields of two-axis tracking mirrors known as heliostats. Each heliostat is individually positioned by a computer control system to reflect the sun's rays to a tower-mounted thermal receiver. The effect of many heliostats reflecting to a common point creates the combined energy of thousands of suns, referred to as a high energy flux, which produces high-temperature thermal energy. In the receiver, a working fluid absorbs the heat energy and is sent to a turbine generator or storage tank. The heat is then converted to electricity using a standard heat engine. The central receiver technology is currently in the developmental mode.

Many different working fluids and thermal conversion cycles are possible with the central receiver technology. The technology described in this section uses molten nitrate salts as the receiver working fluid and a conventional steam Rankine cycle turbine as the energy conversion system. The advantage of this approach is that it allows the incorporation of inexpensive and efficient thermal energy storage in the design of the plant. This system is shown schematically in Figure R-12. The thermal energy storage system allows the operation of the heat engine to be decoupled from the collection of thermal energy. This allows the plant to dispatch electricity to the grid during times that it has the highest value, and it allows continuous operation of the turbine during cloudy periods.

A consortium of utilities and the U.S. Department of Energy are retrofitting the 10-MW Solar One central receiver that was built in 1982 in Barstow, CA, as a demonstration that may lead to the commercialization of 100- to 200-MW central receivers by the year 2000. The retrofit, called Solar Two, involves upgrading the 10-MW Solar One central receiver from a steam receiver to a molten salt receiver and making other modifications. Molten nitrate salt heated to 1050°F (366°C) and stored in an insulated tank will provide the flexibility to store solar energy for later use. The molten salt will allow the facility to produce electricity for up to 4 hours after the sun sets. Figure R-13 illustrates the load-dispatching capabilities of a central receiver plant with molten salt storage.

RESOURCE ASSESSMENT

Concentrating systems have their best annual output in regions where direct insolation is highest. In regions with lower levels of direct insolation, these systems can be used for energy supply at somewhat higher costs. Figure R-14 shows solar insolation throughout the United States.

Annual conversion efficiencies of direct normal sunlight into electricity will depend on insolation conditions, but for good sites, is expected to be about 14%.

MARKET OUTLOOK FOR SOLAR THERMAL CENTRAL RECEIVERS

Demonstration of the technology at the 10-MW size by a consortium of utilities is scheduled to occur around 1994; demonstration of the technology is scheduled to occur in commercial systems built between 1995 and 2000.

INDUSTRY STATUS

The industry is composed of several large engineering firms and consulting companies that perform research and development under contract to the U.S. Department of Energy.

CONSTRUCTION LEAD TIME

Construction time for a 100-to 200-MW central receiver is estimated to be 3 years, with site selection and design requiring an additional 1 to 2 years.

ENVIRONMENTAL ISSUES

There are minimal environmental issues. Habitat destruction at the plant site is the largest concern.

Central receivers do not produce emissions in the solar-only design. The plants can be designed to operate using a dry-cooling system for areos where water availability is limited, or can use wet-cooling towers for lower energy costs if water is available.

LAND AREA REQUIREMENTS

Central receivers with capacity factors in the 40% to 60% range are projected to require approximately 7.4 to 12.3 acres/MW (3 to 5 ha/MW) in good insolation regions.

The plant site must be contiguous and fairly flat (or a slight south-facing slope). Desirable site characteristics include good soil conditions for the heliostat and tower foundation, low seismic risk, and low winds.

CURRENT COSTS AND TRENDS

Table R-7 identifies current costs. In the long term (beyond 2000), using advanced components and realizing economies of scale, the levelized energy costs are projected to drop from the end-of-decade estimate of \$0.08/kWh to \$0.10/kWh to \$0.05 to \$0.06/kWh.

FOR MORE INFORMATION

PUBLICATIONS

Today's Solar Power Towers, SAND91-2018, Sandia Laboratory, Albuquerque, NM, December 1991.

ORGANIZATIONS

National Renewable Energy Laboratory, 1617 Cole Blvd., Golden, CO 80401, Tom Williams, Program Manager, (303) 231-1050.

Sandia National Loboratory, Albuquerque, NM 87185, Paul Klimas, (505) 844-8159.

Table R-7. Central Receivers: Costs

System Type	Capital Cost ($/kW)	Operational Cost ($/kW/yr)[1]	Levelized Cost of Electricity ($/kWh)[2]	Typical Size per Installation (MW)	Capacity Factor (%)	Life (yr)
Solar Thermal Central Receiver	3300 (estimated)[1]	50 (estimated)[1]	$0.08–$0.10 (estimated)[1]	100–200 (estimated)	40 (estimated)	30

Note: As discussed in the text, o 10-MW molten salt demonstration system is in the planning stages. The information presented here was estimated by Sandia Notionol Loboratory for on initial commercial central receiver to be built in the late 1990s. It is based on o detoiled design study. The capacity factor is high because of the storage capability of the molten solt.

1. Estimated costs refer to the expected cost at the end of the decode.

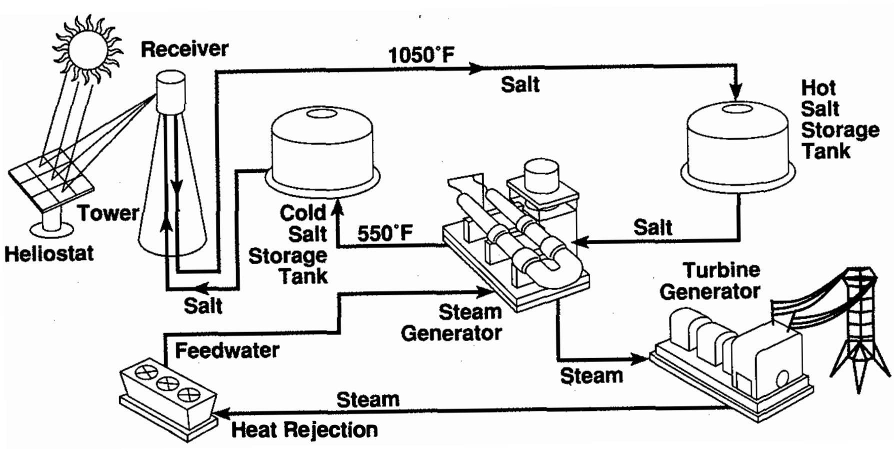


Figure R-12. Schematic of electricity generation using molten salt technology

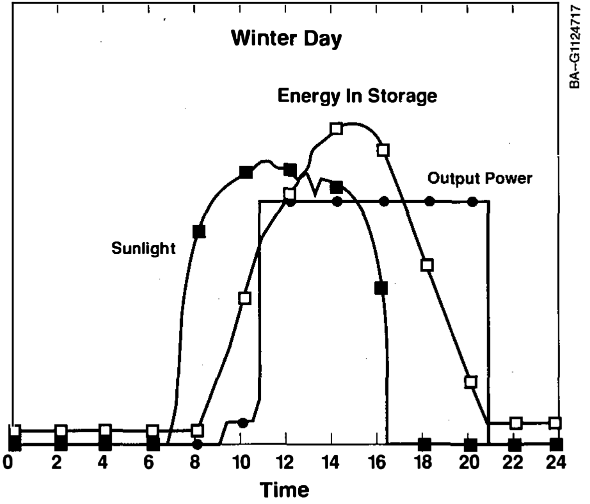


Figure R-13. Load dispatching capability of central receiver plants

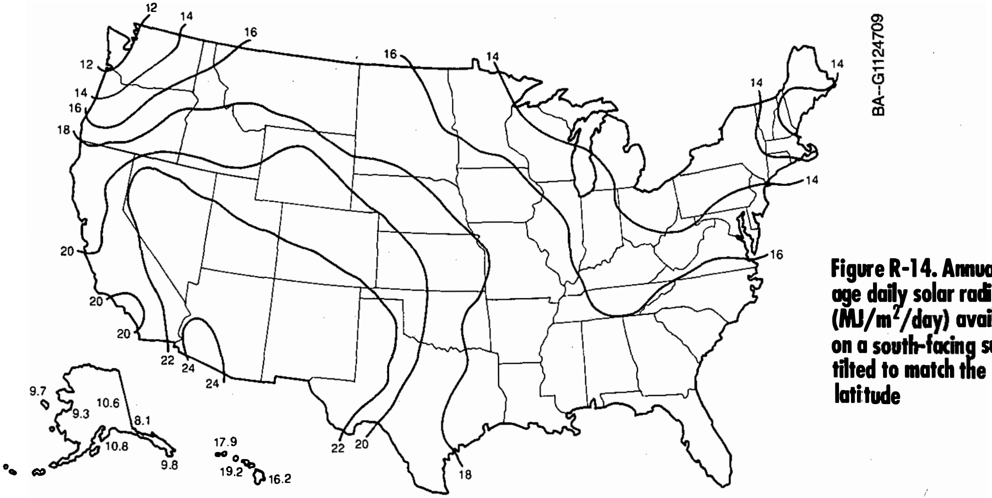


Figure R-14. Annual average daily solar radiation ($MJ/m^2/day$) available on a south-facing surface tilted to match the latitude

SOLAR THERMAL PARABOLIC TROUGHS

TECHNOLOGY DESCRIPTION

This technology uses parabolically shaped, single-axis tracking collectors that ore connected in a series or parallel arrangement. Curved mirrors individually track the sun across the sky with microprocessors and light-sensing instruments. The reflectors focus the sunlight on specially coated metal pipes suspended above the reflectors. Vacuum-insulated glass tubes enclose the pipes; the pipes contain a heat transfer fluid (synthetic oil) that is heated to 736°F (391°C). Once heated, the heat transfer fluid is passed through a heat exchanger network in order to generate superheated steam. The superheated steam is then used to generate electricity. Current solar thermal facilities use conventional steam turbine electric generation technologies. At utility-sized plants, natural gas is used as a supplemental fuel to ensure maximum production during periods of utility peak demand or for power generation during periods of low solar rodiation.

The line-focus parabolic trough technology is used in nine systems that are supplying 354 MW of power to the utility grid in southern California. They have demonstrated high reliability in meeting peak demand during high-demand summer afternoons. These power plants produced 882 million kWh of electricity in 1990. A generic system is shown schematically in Figure R-15. Besides these plants, there ore many parabolic trough plants throughout the country operated for industrial applications. These ore discussed in detail in the *DSM Pocket Guidebook, Volume 4: Industrial Technologies.*

DEFINITIONS AND TERMS

ONE-AXIS TRACKING A system capable of rotating about one axis.

TWO-AXIS TRACKING A system capable of rotating independently about two axes (e.g., vertical and horizontal).

RESOURCE ASSESSMENT

Sites with overage doily global solar radiation levels greater than 1925 Btu/ft^2 (6 kWh/m^2) ore appropriate for the technology. Costs will be higher in locations with lower solar radiation levels.

MARKET OUTLOOK FOR SOLAR THERMAL PARABOLIC TROUGHS

Several possible changes to plant design may improve the efficiency of existing technology over the long term. For example, technology uses steam directly in the solar field at on increased efficiency and without the intermediate heat transfer fluid loop. Another enhancement might be the development of line-focus parabolic trough systems configured as o base-load rather than as o peak-load facility. In this case, the turbine will be sized to accept steam generated by both the solar field and the combustion turbine exhaust. Future solar/combined cycle plants could range from 112 to 135 MW in size.

INDUSTRY STATUS

The Solar Energy Industries Association con provide o listing of U.S. manufacturers of parabolic troughs.

CONSTRUCTION LEAD TIME

Construction lead time for o 80-MW parabolic trough plant is 9 to 12 months, with on estimated 12-month lead time for purchasing components.

ENVIRONMENTAL ISSUES

There ore minimal negative environmental issues. Habitat destruction ot the plant site is the largest concern.

The parabolic trough technology may use o synthetic oil that is o potentially hazardous material. Precautions need to be token for handling and disposol. Cooling towers require make-up water. The solar thermal facility does not produce significant amounts of air emissions. Only the natural gas plant produces air emissions; these will vary depending on the operation of the gas plant and the type of hybrid fuel used.

LAND AREA REQUIREMENTS

Solar electric generating systems require approximately 5 acres (2 ho/MW) of land for each MW produced [assuming insolation of 1925 Btu/ft^2 (6 to 7 kWh/m^2)].

The land must be relatively flat, free from shadow-costing obstructions, ond accessible for lorge-scole system delivery and assembly operations. Sites for hybrid systems must hove access to fuel for both hybrid operations ond down-time freeze protection.

CURRENT COSTS AND TRENDS

Toble R-8 presents cost information on parabolic troughs. Further commercial development of the technology, combined with larger plant sizes, could eventually reduce the copitol cost of the technology to $2200/kW ond the levelized energy cost to $0.10/kWh.

FOR MORE INFORMATION

ORGANIZATIONS

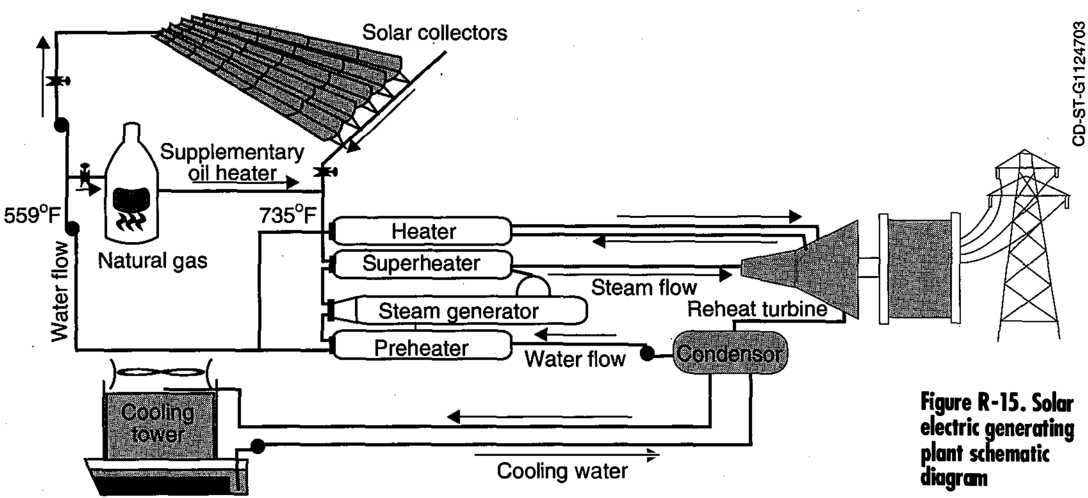
Notional Renewable Energy Laboratory, 1617 Cole Blvd., Golden, CO 80401, Tom Williams, Program Manager, (303) 231-1050.

Sondio National Laboratory, Albuquerque, NM 87185, Paul Klimas, (505) 844-8159.

Table R-8. Solar Thermal Parabolic Troughs: Costs

System Type	Capital Cost[1] ($/kW)	Operational Cost[2] ($/kWh)	Levelized Cost of Electricity[3] ($/kWh)	Typical Size per Installation (MW)	Capacity Factor (%)	Life (yr)
Line-focus Parabolic Trough	3011	0.018	0.09–0.13	Up to 80 to date	36[4]	30

1. Kearney, D. et al., *Status of Solar Electric Generating System (SEGS) Plants*, 1991 Solar World Congress, Vol. 1, part 1, New York, Pergamon Press, August 1991.
2. For an 80-MW SEGS plant, 40 technical and operating personnel are required plus 600 person-hours per week are required for low-skill mirror washing and skilled system maintenance.
3. The levelized energy costs (LEC) vary depending on the assumptions used in the calculations. The low value was taken from Kearney, D. et al. It is based on 1990 dollars and 30-year levelized costs, and calculated on the basis of SEGS financing by private investor partnerships. National Renewable Energy Laboratory calculated the LEC at $0.13.
4. This value is based on the SEGS VIII plant. The plant generates power 8.64 hours per day, of which solar radiation provides 75% of annual output.



CD-ST-G1124703

Figure R-15. Solar electric generating plant schematic diagram

SOLAR THERMAL PARABOLIC DISHES

TECHNOLOGY DESCRIPTION

This technology uses o modular mirror system that approximates o porobolo and incorporates two-axis tracking to focus the sunlight onto receivers located ot the focal point of each dish. The mirror system typically is mode from o number of mirror facets, either gloss or polymer mirror, or con consist of o single stretched membrane using o polymer mirror. The concentrated sunlight may be used directly by o Stirling, Rankine, or Brayton cycle heot engine ot the focal point of the receiver or to heot a working fluid thot is piped to a central engine. The heat receiver ot the focal point includes an integral Stirling cycle heat engine.

The parabolic dish technology coupled to a Stirling engine is currently in the developmental stage. A Stirling engine converts the heot to electricity and rejects heat through an air-cooled radiator. The system is closed (no fuel or cooling water is required) and produces little noise during operation. It could be designed with other types of heot engines, but the Stirling engine appears to be one of the best alternatives because of its high efficiency and potential for long life and low cost, using free-piston designs. The primary applications include remote electrificotion, water pumping, and grid-connected generation. The modules are designed for unottended operation in remote locations. Peak performance of dish/Stirling systems has been measured ot 31% gross and 29% net efficiency. An average annual performance of approximately 21% may be possible for well-designed commercial systems. A hybrid receiver that uses natural gas as o supplemental fuel and allows continuous operation ot maximum output of the system has been developed and is undergoing field testing.

RESOURCE ASSESSMENT

All concentrating systems have their best annual output in regions where direct insolation is highest. In regions with lower levels of direct insolation, these systems can be used for energy supply ot somewhat higher costs. Figure R-14 (under the central receiver brief) shows solar insolation throughout the United States.

MARKET OUTLOOK FOR SOLAR THERMAL PARABOLIC DISHES

Demonstrations and field testing of this technology hove been initiated recently at several sites. Early commercial soles in the 5-kW size range ore expected from 1990 to 1995, and commercial systems in the 5- to 25-kW size range ore expected after 1995.

INDUSTRY STATUS

Several lorge engineering and consulting companies ore doing research and development for the U.S. Deportment of Energy on this technology. One company is developing o commercial application to provide on alternative to diesel generation products.

CONSTRUCTION LEAD TIME

Dish/Stirling systems con be procured in less than 1 year, once the site is selected.

ENVIRONMENTAL ISSUES

Dish/Stirling technologies produce no emissions in the solar-only mode, and they do not require water for cooling. Hobitot destruction at the plant site is the largest concern. In most arid sites (where insolation is high), the installations con be expected to hove o minimal impact on the land.

LAND AREA REQUIREMENTS

A dish/Stirling system requires 1.7 acres for each MW of capacity (0.7 ha/MW) in good insolation regions.

CURRENT COSTS AND TRENDS

Cost information for dish systems is presented in Table R-9. Beyond 2000, costs are projected to drop to the $0.05 to 0.06/kWh range.

FOR MORE INFORMATION

ORGANIZATIONS

National Renewable Energy Laboratory, 1617 Cole Blvd., Golden, CO 80401, Tom Williams, Program Manager, (303) 231-1050.

Sandia National Laboratory, Albuquerque, NM 87185, Paul Klimas, (505) 844-8159.

Solar Energy Industries Association, 772 North Capital Ave. NE, Suite 805, Washington, D.C. 20002-4226, (202) 408-0660.

Table R-9. Parabolic Dishes: Costs

System Type	Capital Cost[1] ($/kW)[1]	Operational Cost ($/kW/yr)[1]	Levelized Cost of Electricity ($/kWh)[1]	Typical Capacity per Installation (kWh)	Capacity Factor (%)	Life (yr)
Dish / Stirling	3000–6000 (estimated)[2]	30–120 (estimated)[2]	0.15–0.30 (estimated)[2]	5–25	23 (estimated)[2]	30

1. The costs represent industry projections for small systems installed in the late 1990s in remote locations. Large systems are projected to cost $1700/kW.
2. Estimated refers to the expected cost and performance at the end of the decade.

SALT GRADIENT SOLAR PONDS

TECHNOLOGY DESCRIPTION

Salt gradient solar ponds consist of three main layers, as shown in Figure R-16. The top layer is near ambient and has low salt content. The bottom layer is hot, typically 160° F to 212°F (71°C to 100°C), and is very salty. The important gradient zone separates these zones. The gradient zone acts as a transparent insulator, permitting the sunlight to be trapped in the hot bottom layer (from which useful heat is withdrawn). This is because the salt gradient, which increases the brine density with depth, counteracts the buoyancy effect of the warmer water below (which would otherwise rise to the surface and lose its heat to the air). An organic Rankine cycle engine is used to convert the thermal energy to electricity. Figure R-17 illustrates the conversion of heat from a salt gradient solar pond to electricity.

Solar ponds have several features that make them an attractive renewable energy technology at appropriate sites. Features include (1) very low collector costs per unit collector area, (2) daily-to-seasonal thermal storage capacity, (3) availability of large quantities of low- to medium-grade thermal energy from a single project, and (4) possibility of disposal of minerally contaminated waste waters that often occur in conjunction with energy production. Solar ponds can be operated to provide baseload power and/or peaking power.

A 0.8 acre (.32 ha) salt gradient solar pond in El Paso, Texas, in combination with an organic Rankine cycle generator, has been providing up to 70 kW of grid-connected power. A food canning plant uses the power for peak shaving. Because the pond provides heat storage, the power is available on demand—even at night or during periods of cloudy weather. Solar ponds are site-specific; they need suitable land, salt, water, and solar resources and are, therefore, not universally applicable. However, due to numerous salt lakes and salt brine sources throughout much of the United States, the potential energy availability from solar ponds is estimated to be quite large.

RESOURCE ASSESSMENT

Solar ponds use the total solar spectrum—direct-beam and diffuse radiation. They absorb solar energy at an efficiency of approximately 20% of the total insolation at the pond surface.

MARKET OUTLOOK FOR SALT GRADIENT SOLAR PONDS

The El Paso system has been operating for over 6 years. The system operators plan to demonstrate long-term continuous operation—leading to more general commercial applications. In the 1995 to 2000 time frame, the technology may be commercialized in applications that involve the use of waste materials (such as reject brine from desalting), and existing salt reservoirs (such as natural lakes) in the Southwest.

INDUSTRY STATUS

There are no companies developing commercial solar ponds.

CONSTRUCTION LEAD TIME

Salt gradient solar ponds will require a 2- to 3-year lead time to complete the necessary site analysis. Construction time could be less than 1 year, depending on the size.

ENVIRONMENTAL ISSUES

Salt gradient solar ponds require significant quantities of brackish water to make up for evaporation losses, and they require the management of salt brines used on-site. Potential exists for contamination of groundwater by the brine solution unless a synthetic liner is used to line the bottom of the pond. Disturbance of large areas of surface vegetation and biological resources is another potential impact, depending on location.

LAND AREA REQUIREMENTS

Solar ponds require approximately 10 acres per MW (4 ha/MW) to meet peak load requirements and 30 acres (12 ha) per MW to meet base-load requirements.

CURRENT COSTS AND TRENDS

Current costs for electricity production from salt gradient solar ponds are shown in Table R-10. When the pond size increases to 247 acres (100 ha), the levelized energy cost can drop to $0.08 to $0.10 per kWh. For industrial processes at sites where land, brackish salt water, and solar insolation are favorable, the levelized energy cost of supplying heat is favorable compared to burning coal or natural gas (for ponds greater than 25 acres [10 ha] in size).

FOR MORE INFORMATION

PUBLICATIONS

The El Paso Solar Pond, brochure produced by the University of Texas at El Paso, Dr. Andrew Swift, Solar Pond Director, (915) 747-6904.

ORGANIZATIONS

University of Texas at El Paso, Department of Mechanical and Industrial Engineering, Dr. Andrew Swift, Solar Pond Project Director, (915) 747-0521.

U.S. Bureau of Reclamation, Advanced Energy Division, Denver Federal Center, Denver, CO 80226, Mr. Stan Hightower, (303) 236-5996.

Table R-10. Solar Ponds: Costs

System Type	Capital Cast ($/kW)	Operational Cost ($/kWh)	Levelized Cost of Electricity 1990 $/kWh	Typical Capacity per Installation (kW)	Capacity Factor (%)	Life (yr)
Solor Ponds[1]		0.01	0.08-0.30	70[1]	70-90	30
Organic Rankine Cycle Engine	1900					
Pond Construction	5388 – 13,139					

Note: The cost data were taken from o masters thesis done by Patricio Esquivel on the "Economics of Salt Grodient Solar Ponds for Process Heat and Electrical Applicotions." The cost to operate o solor pond includes the cost of the engine to convert the heat in the pond to electricity and the cost to build the pond. The cost of the pond could be viewed os o "fuel cost" rother than o capital cost so the costs ore presented separately in Table R-10. The low end of the pond cost range represents o simulation of o lorge, 247-acre (100 ho) pond with o low-cost liner at $0.36/ft² ($3.87/m²) and salt at $2/ton. The high end of the pond cost range is for o small, 24.7-acre (10 ho) pond with o low cost [$0.36/ft² ($3.87/m²) liner and salt ot $2/ton]. The simulotion was analyzed using o program called PONDFEAS. The input wos based on the performance of the El Paso Solor Pond. The costs include the pond construction cost and the cost for on organic Rankine engine.

1. This is the size of the El Paso Salt Gradient Solar Pond, which is o pilot scale project. As the size of the pond increases, the cost/kW goes down.

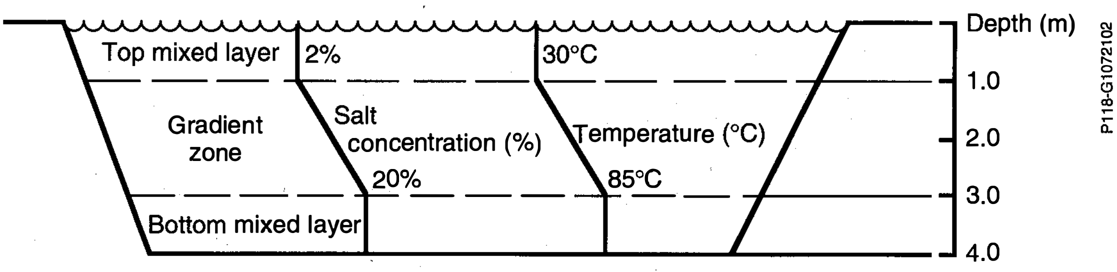


Figure R-16. Typical temperatures and salt concentrations

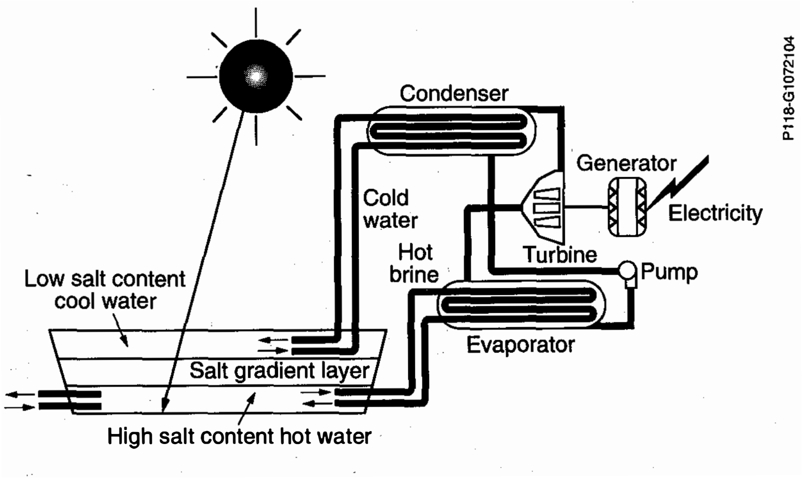


Figure R-17. Schematic of a salt gradient pond with a Rankine cycle generator

WIND POWER

INTRODUCTION

According to the Electric Power Research Institute (EPRI), "wind power offers utilities with good wind resources pollution-free electricity thot is nearly cost-competitive with today's conventional sources." In 1993, the installed grid-connected wind turbine capacity worldwide is over 2500 MW, of which 1700 MW is locoted in California. The California wind turbines generated close to 2.8 billion kWh of electricity in 1991, more than enough to serve the residential needs of San Francisco, CA, or Washington, D.C.

Considerable operating experience has been gained during the lost decade from wind farms (primarily in California), making possible advancements in the obility to operate and maintain turbines. The experience has also led to significant engineering advances. Turbines installed over the last 5 years have availability factors approaching 99%. This is a significant improvement over technology introduced in the mid-1970s and early 1980s, when turbine availability was in the 60% to 70% range.

Wind power plants offer flexibility and modularity. They can be installed in widely varying increments, thereby decreasing the financial risk of adding new capacity. They operate sofely, without pollution, and in harmony with land uses such as farming and ranching.

TECHNOLOGY DESCRIPTION

Wind turbines convert wind energy into mechanical energy, and then electricity. Wind turbines are primorily horizontal-axis machines, but there are also vertical-axis mochines. Both types use a rotor that converts the wind velocity to rotary motion. The rotating shaft turns a generator directly, or through a step-up gear box, to convert mechanical energy to electrical energy. Support subsystems include a tower that supports the rotor, and various control and electrical control systems. These components are shown in Figure R-19.

Utilities can integrate wind power into the utility grid with minimal problems. The hardware used to interconnect wind power plants with the utility grid—such as switchgear, protective relays, and controls—-is the same as for conventional power plants. The experience gained over the last decade with interconnecting wind power to the utility network is providing a better understanding of the effects of wind power production on utility engineering, operations, and planning. In northern California, where wind has accounted for as much as 8% of the capacity during minimum load conditions, minimal problems have been reported with integration of wind power with the utility grid.

As the rotor size of the turbine increases, the energy capture increases, and the balance of system cost decreases on a per-turbine basis, up to a point. The average size of a turbine installed in a wind power plant was 200 kW in 1989; in 1988, it was 109 kW. Five years earlier, the average size was 69 kW. In the near-term future, turbines will likely be in the 350 to 750 kW range.

DEFINITIONS AND TERMS

AVAILABILITY Describes the reliability of wind turbines. It refers to the number of hours the turbines are available to produce power divided by the total hours in a year.

CAPACITY FACTOR The amount of energy that the system produces at a particular site as a percentage of the total amount that it would produce if it operated at rated capacity during the entire year. The capacity factor for a wind farm ranges from 20% to 35%. Thirty-five percent is close to the technology potential.

CONSTANT-SPEED MACHINES Machines that operate at a constant rotor revolutions per minute (RPM) and are optimized for energy capture at a given rotor diameter at a particular speed in the wind power curve.

HORIZONTAL-AXIS WIND TURBINES Turbines in which the axis of the rotor's rotation is parallel to the wind stream and the ground.

VERTICAL-AXIS WIND TURBINES Turbines in which the axis of rotation is perpendicular to the wind stream and the ground.

RATED CAPACITY The amount of power a wind turbine can produce at its rated wind speed, e.g., 100 kW at 20 mph. The rated wind speed generally corresponds to the point at which the conversion efficiency is near its maximum. Because of the variability of the wind, the amount of energy a wind turbine actually produces is a function of the capacity factor (e.g., a wind turbine produces 20% to 35% of its rated capacity over a year).

VARIABLE-SPEED MACHINES Machines in which the rotor speed increases and decreases with changing wind speed, producing electricity with a variable frequency.

WIND POWER CURVE A graph representing the relationship between the power available from the wind and the wind speed. The power from the wind increases proportionally with the cube of the wind speed.

WIND POWER PLANT A group of wind turbines interconnected to a common utility system through a system of transformers, distribution lines, and (usually) one substation. Operation, control, and maintenance functions are often centralized through a network of computerized monitoring systems, supplemented by visual inspection. This is a term commonly used in the United States. In Europe, it is called a generating station.

RESOURCE ASSESSMENT

The wind resource is large, especially in the midwestern, northeastern, and western United States. The wind is an intermittent resource, but that does not mean that it is unpredictable. In most regions, the wind follows predictable seasonal and daily patterns. The patterns will vary from region to region. Therefore, resource assessment is a crucial first step in planning a wind power plant.

The resource is characterized by classes, ranging from class 1 (the lowest) to class 7 (the highest), where each class represents a range of wind power densities and associated average annual wind speeds. Class 5 and higher present opportunities for market penetration of wind energy systems in the near- to mid-term. Over the long term, class 4 resources must be used in order for wind-generated electricity to be economically competitive with other forms of electrical generation over large areas of the United States. Figure R-18 illustrates the average annual wind power in the United States.

In most cases, on-site measurement can be done inexpensively using anemometers to verify the site's wind energy potential. Data needs to be collected for at least 1 year. A currently acceptable site meets the following criteria:

- Mean wind speed greater than 13 mph (class 3) at a height of 30 m
- Acceptable diurnal, seasonal, and inter-annual variations of the wind
- Acceptable extreme winds and turbulence levels that affect structural integrity and system lifetime.

The intermittency of the wind resource impacts both power availability and cost. Power availability is currently being addressed by choosing sites where seasonal wind patterns match with utility peaking requirements.

MARKET OUTLOOK FOR WIND POWER

The existing successful wind power plant sites are in locations with class 5 or better wind speeds, relatively high conventional fuel costs, and proximity to transmission lines with adequate capacity. Wind power plant developers operating as independent power producers may own and operate the wind farm on behalf of the utility or the utility can build their own wind power plant. Several western and mid-western utilities have recently announced plans to develop wind energy.

A current market also exists for small (under 20 kW) stand-alone wind turbines to meet Western Area Power Administration's customers' needs, including:

- Remote locations where diesel generators ore commonly used
- Locations where the terrain is too rough or isolated for reliable delivery of diesel fuel
- Small grid applications that use diesel-fired generation
- Some water pumping applications.

With the new generation of turbines coming into the market between 1993 and 1995, electric power generation from wind farms in locations with closs 4 or better winds should be cost competitive.

Continued development of closs 4 or better wind sites is expected to continue beyond 2000. This moy require either building new, or gaining access to, additional transmission lines to increase the distance thot electricity con be transmitted between wind resource sites ond load centers.

INDUSTRY STATUS

The industry is dominated by o few well-established companies offering field-tested designs, high-volume production manufacturing techniques, and utility-grode operations and maintenance programs. Several companies compete in the small, high-reliability, remote systems market. Some companies ore actively pursuing new designs reflecting incremental improvements to existing technology. A few firms ore establishing joint ventures with European or Japanese companies.

The U.S. Deportment of Energy (DOE), EPRI, the wind industry, ond utilities ore involved in developing odvonced wind turbine technology that will improve turbine performance ond reduce the cost of energy from wind. Testing of o prototype vorioble-speed turbine began in 1992.

DOE is working with the wind industry to develop odvonced wind machine technology, which should be ovoiloble within the decode. Testing of o Notional Renewable Energy Laboratory odvonced prototype turbine began in 1993. This technology will reduce the cost of energy even further. Examples include new airfoils, new drivetrains, new aerodynamic controls, ond toller towers.

CONSTRUCTION LEAD TIME

At most, 1 to 2 years would be required for obtaining permits and designing a wind farm. Less than 1 year is required to install a 50-MW wind farm. Because wind is a modular technology, turbines in a wind farm can be installed and operation can begin in phases. The first phase might involve, for example, installing turbines on the flattest portion of the site where wind patterns are easiest to characterize.

ENVIRONMENTAL ISSUES

Wind farms have some environmental impacts. Issues to consider include available land area, interference with bird and wildlife habitats, interference with television and radio signals, visual appearance, and noise. Figures R-20 and R-21 compare the noise emissions from wind turbines to other sources.

LAND AREA REQUIREMENTS

The total power intercepted over a given land area is a function of the number of wind turbines, the rotor-swept area of the wind turbine, and the total available power in the wind. Assuming a 10D by 5D spacing of turbines (where D equals the rotor diameter), a 50-m hub height, 25% efficiency, and 25% power loss—the average power output for a class 4 wind site is 1 MW/45 acres (1 MW/18.2 ha).

In rural areas, landowners receive lease fees and royalties for the use of their land. Wind turbines can share the land with grazing cattle and crops.

CURRENT COSTS AND TRENDS

Table R-11 summarizes current costs. Additional data on the technology status is shown in Table R-12. The trends indicate that the cost is expected to go down, and performance is expected to continue to improve.

FOR MORE INFORMATION

PUBLICATIONS

Wind Energy for a Growing World, American Wind Energy Association, 1992.

Wind Energy Resource Atlas of the United States, Solar Energy Research Institute, U.S. Government Printing Office, (DOE/CH10093-4 DE86004442), Washington, D.C., 1986.

Wind Energy Program Overview, Golden, CO, DOE/CH10093-101, National Renewable Energy Laboratory, February 1992.

ORGANIZATIONS

Utility Wind Interest Group (UWIG), Western Area Power Administration representative, Steve Sargent, A0400, 1627 Cole Blvd., P.O. Box 3402, Golden, CO 80401, (303) 231-1694.

American Wind Energy Association, 777 N. Capitol Street, Suite 805, Washington, D.C. 20002, (202) 408-8988.

Table R-11. Wind Power: Costs

System Type	Capital Cost ($/kW)	Operational Cost ($/kWh)	Levelized Cost of Electricity ($/kWh)	Typical Size per Machine (kW)	Capacity Factor[1] (%)	Life (yr)
Constant Speed Machine	1013	0.016	0.075	150-500	20-30	20

Note: The cost information for wind turbines was taken from Utility Wind Interest Group, (Aug. 1991) *Economic Lessons from a Decade of Experience*. The costs are based on a 250-kW system with a 13-mph wind speed at a height of 32.8 feet (10 M). The costs (in $1990) were calculated using the Electric Power Research Institute technical advisory group (EPRI TAG™) method. Improvements in the technology are expected to drop levelized energy costs for both constant-speed and variable-speed machines.

1. 20% is the average capacity factor. Higher factors are cited for individual sites.

Table R-12. Technology Status

	Before 1975	Current	Goals - 2000
Cost/kWh (Constant 1990)	\$0.50 - \$1.00	\$0.07 - \$0.09	\$0.04 - \$0.05
Operating Life	1-5 yrs	20 yrs	30 yrs
Capacity Factor (Avg)	10%	20%	30%
Availability	60% - 70%	95%	95%+
Avg. Size	<20 kW	150 - 200 kW	300 - 1000 kW

For a 13-mph annual average wind site. Wind speed measured at a 10-meter height

Figure R-18. U.S. wind resource

Wind Class		Speed (m/s) 10m	50m
3	□	5.1—5.6	6.4—7.0
4	▥	5.6—6.0	7.0—7.5
5	□	6.0—6.4	7.5—8.0
6-7	■	>6.4	>8.0

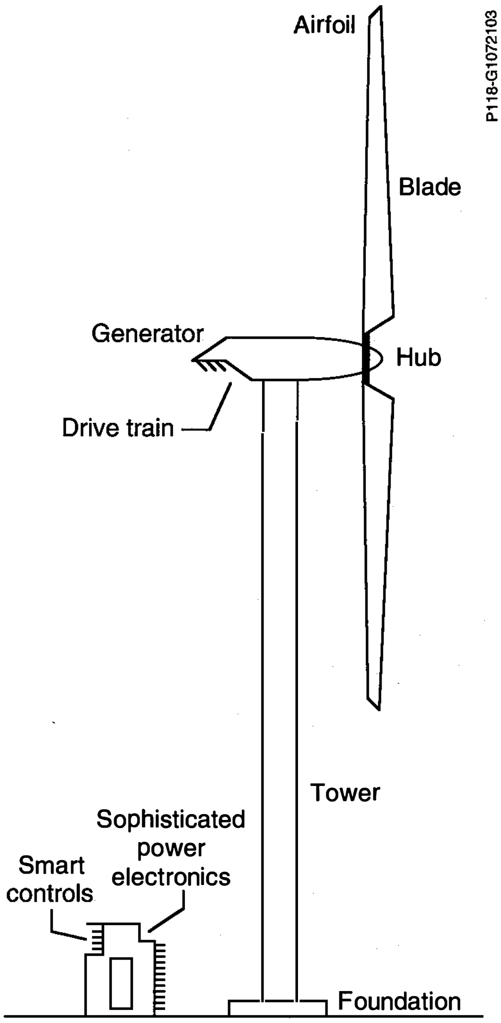


Figure R-19. Components of a wind turbine

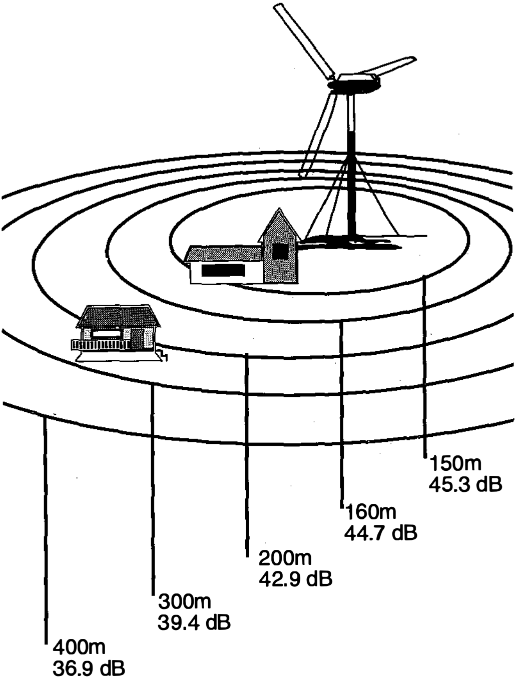


Figure R-20. Noise levels around a 200 kW wind turbine

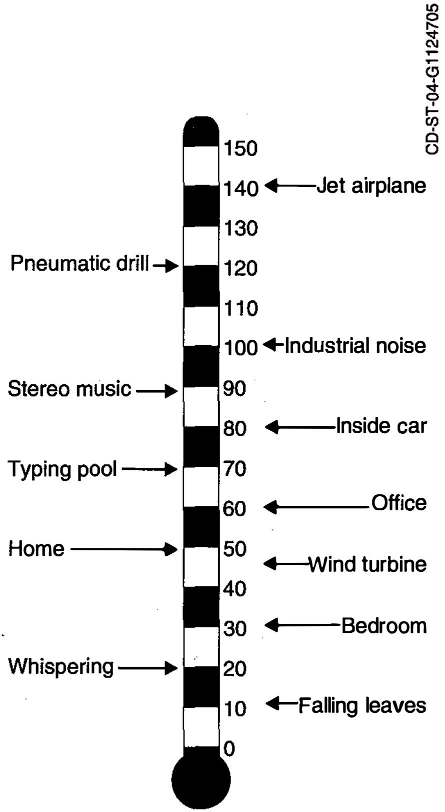


Figure R-21. Noise emissions (dB) from appliances and other sources

PHOTOVOLTAICS

INTRODUCTION

Today, photovoltaics (PV) is quite competitive with many low-power utility applications where the actual amount or cost of energy involved is less important than reliable and trouble-free remote operation. More than 70 utilities today are saving significant capital and operational costs by using PV modules and arrays in low-power service applications, including warning signs; beacons, buoys, and security lighting; water-level sensors; communication links; back-up generator starters; special switches on transmission lines; and remote customer loads. The economic advantage of using a PV-battery unit to serve a remote, low-power load rather than extending a utility distribution line depends on the application's load level and the distance from an existing load. As a general rule, distribution line extensions of more than 500 ft (152 m) for low-power loads will be less economical than applying PV. According to the Electric Power Research Institute, "The smaller the load and the farther it is from an existing distribution line, the more likely that a PV system will be cost-effective for the application."

TECHNOLOGY DESCRIPTION

PV directly converts radiant energy from the sun to direct current (DC) electrical energy. The smallest unit of a PV system is the individual PV device or solar cell. Individual PV cells are connected together to form a PV module. PV modules are the basic solar collectors for PV power systems. Modules are connected together to form arrays. The total area of modules used for an array or field of arrays is determined by the overall PV system power level desired.

Solar cells are made from semiconducting materials, typically silicon, doped with special additives. As long as they are exposed to sunlight, PV devices produce an electrical current that is proportional to the amount of light that it receives. Because electrical energy may be needed when the sun does not shine, storage is often required. Batteries are the most common form of storage. If the load requires alternating current (AC), an inverter is used to convert the DC power to AC. By assembling different quantities of components together, systems can be built with varied power outputs.

DEFINITIONS AND TERMS

BALANCE OF SYSTEM Represents all components and costs other than the PV modules. It includes design costs, land, site preparation, system installation, support structures, power conditioning, operation and maintenance costs, indirect storage, and related costs.

CONCENTRATOR A PV module that uses optical elements to increase the amount of sunlight incident on a PV cell. Concentrating arrays must track the sun and use only the direct sunlight because the diffuse portion cannot be focused onto the PV cells.

EFFICIENCY The ratio of electric power produced by a cell at any instant to the power of the sunlight striking the cell.

FLAT PLATE Refers to a PV array or module that consists of non-concentrating elements. Flat-plate arrays and modules use direct and diffuse sunlight, but if the array is fixed in position, some portion of the direct sunlight is lost because of oblique sun-angles in relation to the array.

PACKING FACTOR The ratio of array area to actual land area.

PEAK WATT Maximum "rated" output of a cell, module, or system. Typical rating conditions are 0.645 W/in^2 (1000 W/m^2) of sunlight, 68°F (20°C) ambient air temperature and 6.2×10^{-3} mi/s (1 m/s) wind speed.

TRACKING ARRAY A PV array that follows the path of the sun to maximize the solar radiation incident on the PV surface. The two most common orientations are (1) one axis where the array tracks the sun east to west and (2) two-axis tracking where the array points directly at the sun at all times. Tracking arrays use both the direct and diffuse sunlight. Two-axis tracking arrays capture the maximum possible daily energy.

RESOURCE ASSESSMENT

The resource base includes primarily sunlight and land area. Sunlight is the most critical. Land area and sunlight issues are interrelated because the total available resource is the product of the density of sunlight and the land (or roof space) available for PV. The most important facts about the solar resource in terms of PV are the following:

- Seasonal sunlight variations are relatively predictable.
- The solar resource is huge in relation to the potential demand.
- PV is not geographically limited in the United States by a lack of sunlight.
- PV output has added value because it is well-matched to summertime peak demand for electricity in many locations.

Maps are available to show how much sunlight is generally available for a flat array, tracking arrays, and PV systems based on concentrating sunlight. Figure R-22 shows the sunlight available for a fixed flat plate, facing south and tilted up at an angle equal to the local latitude. Figure R-23 shows the amount of sunlight available to a two-axis concentrating tracker.

Using Figure R-22, for example, Denver, Colorado, receives approximately 2100 kWh/ft^2/yr (195 kWh/m^2/yr) of sunlight. Assuming a PV sunlight-to-electricity conversion factor of 10%, one ft^2 of PV would provide 19.5 kWh/yr of electricity. A typical U.S. house uses from 5000 to 10,000 kWh per year.

MARKET OUTLOOK FOR PHOTOVOLTAICS

The commercial use of PV in remote power applications has been well established for many years. The following applications are judged to offer utilities the most significant opportunities:

- Battery-coupled, stand-alone (nongrid-connected) systems
- Transmission tower beacons
- Transmission and distribution-sectionalizing switches
- Street lights

- Rest area fans and lights
- Remote residences.

Other stand-alone, cost-effective applications include communications, livestock watering-pumping, warning signals, and cathodic protection.

A major near-term application is village power. A large number of villages exist throughout the world that are powered by diesel engines/generators or have no power at all. Modest scale (10 kW-100 kW) hybrid PV/diesel/battery systems for villages are all a major near-term market.

Emerging applications for grid-connected systems include PV for voltage and energy support on thermally limited (but heavily loaded) utility distribution feeders. Instead of replacing conductors on a line, or upgrading a substation to handle increasing loads, a PV array can be located at the end of a feeder or next to a substation. By offsetting peak daytime loads—which correlate well with customers' demand for power-—a grid-connected PV system can help prevent thermal aging or overloading of transformers or conductors.

Other near-term applications (either grid-connected or nongrid-connected) include buildings applications and village power. Considerable effort is being devoted to developing PV modules into a technology that can be integrated into building roofs, walls, and windows.

For the long term, PV is being evaluated for bulk power generation. Currently, a national cooperative research project called Photovoltaics for Utility Scale Applications is assessing and demonstrating the viability of utility-scale PV electric generation systems. The project is evaluating

- Emerging module technology (EMT) to demonstrate state-of-the-art PV technologies that show promise but have not yet been field tested
- Utility-scalable systems to develop optimized turnkey PV systems.

The EMT systems are about 20 kW each, and the utility-scalable systems ore either 200 kW or 400 kW each. Systems praviding appraximately 1 MW peak AC output have been deployed.

INDUSTRY STATUS

In 1990, there were 17 U.S. companies that manufactured and sold PV madules. Crystalline silican cells and modules dominated the market, accounting for 80% of total 1990 shipments. Thin films accounted for 19% and concentrators accaunted for 0.2% af total shipments. In 1990, the most impartant end uses for PV included

- Cammunications (31%)
- Remote electrical generation applications (22%)
- Consumer goods (18%).

Recently, a utility caalitian known as the Utility Photovoltaic Group (UPVG) has been formed to accelerate the use of cost-effective and emerging high-value applicatians of PV for the benefit of electric utilities and their customers. As of March 1993, UPVG had 60 utility members.

CONSTRUCTION LEAD TIME

Small PV systems (less than 10 kW) can be installed in a few days. Megawatt-scale systems can be installed in several months.

ENVIRONMENTAL ISSUES

PV power is envirannmentally benign, praducing no air ar surface pollutants or noise, consuming no fuels, and requiring no cooling water far noncancentrating systems. To pravide a significant proportion af the U.S. power needs fram PV would require large land areas; however, large systems could be located in the desert Southwest.

LAND AREA REQUIREMENTS

Appraximately 14.5 kW af pawer can be supplied per acre of land area in a sunny dimate such as Denver, Colorado. (This is based an the assumption af a 0.5 packing factor, a 10% sunlight-to-electricity can-version factar, and an average af 8 hours af sunlight per day). A plat of land 100 miles on a side in Nevada could generate sufficient energy to power the entire U.S. electric network.

CURRENT COSTS AND TRENDS

Table R-13 summarizes current costs. Table R-14 provides cost information for different types of modules. Table R-15 shows the technology status and future prospects for U.S. PV.

FOR MORE INFORMATION

PUBLICATIONS

Zweibel, K., *Harnessing Solar Power: The Photovoltaics Challenge*, New York and London, Plenum Press, 1990.

Photovoltaics: New Opportunities for Utilities, DE91002168, DOE/CH 10093-113, National Renewable Energy Laboratory, Golden, CO, July 1991.

Stevens, J.W. et al., *Photovoltaic Systems for Utilities*, Sandia National Laboratory, Albuquerque, NM, October 1992.

Stand-alone Photovoltaic Systems: A Handbook of Recommended Design Practices, SAND87-7023, Sandia National Laboratories, Albuquerque, NM, November 1991.

ORGANIZATIONS

Photovoltaics Users Group, Western Area Power Administration representative, Peggy Plate, Loveland Area Office, P.O. Box 3700, Loveland, CO 80539-3003, (303) 490-7200.

Photovoltaics Systems Design Assistance Center, Sandia National Laboratories, Albuquerque, NM 87185, (505) 844-3698.

National Renewable Energy Laboratory, 1617 Cole Blvd., Golden, CO 80401, (303) 231-7000. Contact John Thornton or Roger Taylor.

Solar Energy Industries Association, 777 No. Capitol St. NE, Suite 805, Washington, D.C. 20002, (202) 408-0660.

Utility PhotoVoltaic Group (UPVG), 1101 Connecticut Ave. NW, Suite 910, Washington, D.C. 20036. Contact Jeff Serfass, (202) 857-0898.

Table R-13. Photovoltaics: Costs

System Type	Capital Cost[1] ($/$W_p$)	Operational Cost ($/kWh)	Levelized Cost of Electricity[2] ($/kWh)	Capacity Factor (%)	Life (yr)
Single oxis tracking/crystalline silicon cells grid-connected					
500 kW	9.00	0.005	0.35–0.49	25–35	15–30
200 kW	11.00	0.005	0.43–0.60	25–35	15–30
20 kW	15.00	0.005	0.59–0.82	25–35	15–30
Flot-plate/crystalline silicon cells stond-alone (off-grid) systems with battery storage[3]					
5–10 kW	13.00[3]	0.005	0.5–0.71	25–35	15–30
1–2 kW	15.00	0.005	0.59–0.82	25–35	15–30

Small remote systems flat-plate crystalline silicon cells/batteries in special enclosures (such as for T&D sectionalizing switches)					
100 W	25.00	0.005	0.98–1.37	25–35	15–30

1. The capital cost equals the initial investment. The cost for the 500 W system represents the 1992 cost/W for the PG&E Kerman substation. The capital costs for systems of other sizes were provided by Integrated Power Corporation in Rockville, MD.
2. The cost per kWh was calculated based on [($/w × 0.12)/(8760 hrs/yr) × capacity factor)] × 1000. The 0.12 in this equation is a levelizing factor. The high value is at a capacity factor of .25. The low value is at a capacity factor of .35. Energy costs vary over a range of nearly 2:1, due primarily to resource availability across the United States.
3. The cost per watt for the stand-alone systems represents the cost per watt of supplying a DC power load. (This represents approximately 80% of the power needed to supply the load using AC power.)

Table R-14. Comparison of Primary PV Types

System Type	Characteristics	Module Efficiency[1] (%)	1990 Module Cost[2] ($/Wp)	Reliability
Crystalline silicon and poly-crystalline	• Accounts for approximately 75% of today's production • High reliability • Proven product	10–12	5.66	10-year warranties have been provided
Ribbon silicon	• Growth of silicon sheets or or ribbons is one approach to reduce cost • Less silicon is used in the process	9–11	5.68	Highly reliable product
Thin-film cells[3]	• Less material and much thinner layers • Made by depositing a semiconductor material on a substrate • Manufacturing process can be more fully automated	4–6	5.65	Energy technology with limited long-term field exposure

Concentrators	• Concentrators use large lenses to focus sunlight on small cells • Concentrators cannot use diffuse sunlight—they work well in very sunny regions • They use fewer PV cells with the highest efficiencies and highest costs	14–17	12.28	Limited production capability and field experience

1. National Renewable Energy Laboratory, *Photovoltaics Program Plan. FY 1991 -FY 1995*, NREL (DOE/CH10093-92), Golden, CO, 1991. Cell efficiency in the laboratory is much higher, up to 32% (see Table 3).
2. Energy Information Administration, *Solar Collector Manufacturing Activity 1990*, DOE/EIA-0174 (91). The cost of all modules was actually lower in 1989. These are average costs. Some observers say that the slight price increase represents the fact that there is a stronger market today for the modules. It is generally assumed that thin-film materials will reduce cost over time as the market grows because of their potential ease of manufacture and very low material usage. Cost represents module only, balance-of-system costs are excluded.
3. Amorphous silicon is the only currently available thin film material in the marketplace, but other materials have demonstrated high efficiency in the laboratory, including copper indium diselenide, cadmium telluride, and gallium arsenide.

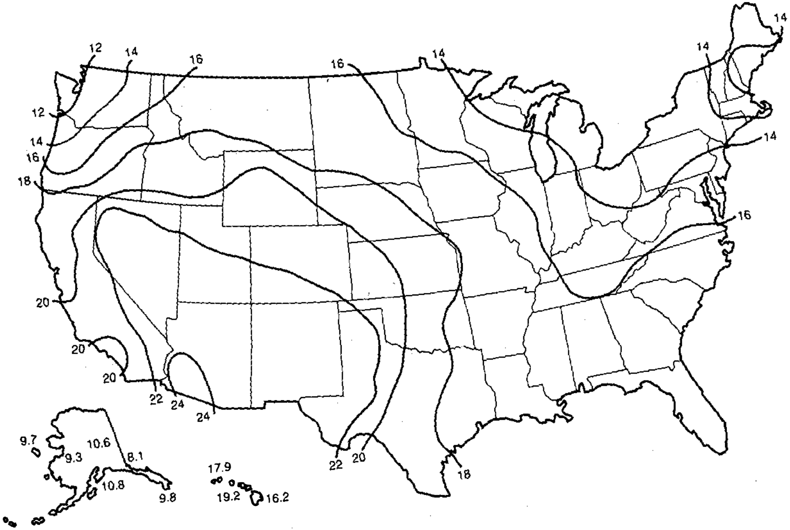
Table R-15. Technology Status and Future Prospects for U.S. Photovoltaics

	Today (1991)	Mid-1990s (1995)	Future (2010-2030)
PV Technology Efficiency			
Flot-Plote Crystolline Silicon	22%–23% loborotory cells 11%–13% commercial modules	25% loborotory cells 14%–15% commercial modules	> 26% loborotory cells > 18% commercial modules
Flat-Plate Thin Films	12%-14% loborotory cells	15%–18% laboratory cells 8%–10% commercial modules	> 20% laboratory cells > 15% commercial modules
Concentrators	27%–32% laboratory cells 14%–17% commercial modules	35% laboratory cells 18%–20% commercial modules	> 40% laboratory cells > 25% commercial modules
Balance-of-Systems (BOS) Components	In engineering development; $0.40/W power-related costs	Fully engineered: $0.20–$0.30/W power-related costs	Large scale production; $0.15/W power-related costs
Component Reliability	5–15 years for modules 5 years for BOS components	15–20 years for modules 15 years for BOS components	> 30 years

PV Industry			
Module Manufacturing Capacity (MW/yr)	15–20	50–100	1000
Manufacturing Characteristics	0.5–5 MW lines Batch; labor-intensive	5–20 MW lines Partly automated	20–50 MW lines Fully automated
PV Systems and Markets			
Utility Power Systems (MWtotal)	10–15	50–100	10,000–50,000
Typical Systems	Consumer remote, stand alone	Distributed; high-value utility applications	Central utility power
($/kWh, 1990 $)[1]	$0.35–$0.49	$0.18–$0.22	$0.05–$0.06

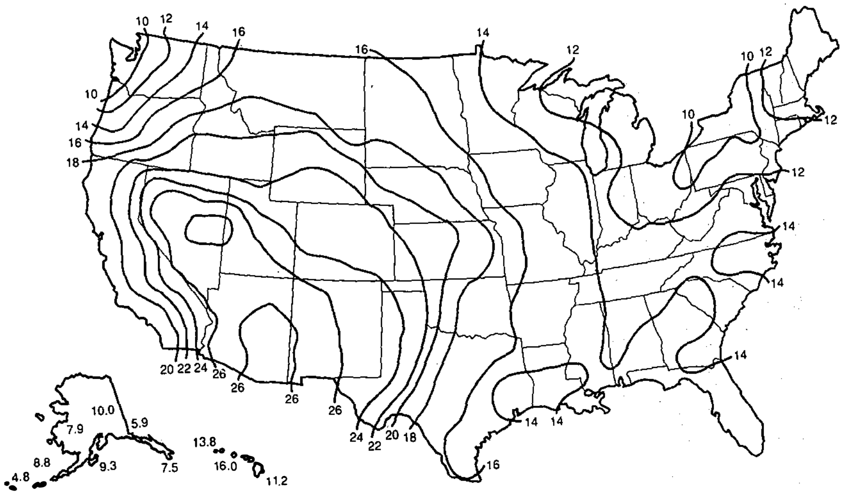
Source: National Renewable Energy Laboratory, 1991, *Photovoltaics Program Plan FY 1991–FY 1995*, Golden, CO.

1. The costs are for 500 kW or larger systems.



BA–G11124711

Figure R-22. Average annual global solar radiation available at tilted surface equal to latitude (in Mj/m²/day)



BA--G1124706

Figure R-23. Average annual direct sunlight available to two-axis tracker or concentrator (in Mj/m²/day)

STORAGE AND RELATED TECHNOLOGIES

INTRODUCTION

This section describes several energy storage options, fuel cells, and invertor technology. The storage options are included because, under some circumstances, they can be used with renewable power generation technologies. In other cases, adding storage to existing facilities provides a means to defer building new-generation transmission and distribution equipment. Fuel cells are an emerging fossil-based electric generation technology. They are not a renewable technology, but they might be powered by hydrogen from renewables in the future. Invertor technology is included because it is used with photovoltaic systems. Table R-16 illustrates the economics of storage options and fuel cells.

Table R-16. Economics of Storage Options and Fuel Cells

Technologies	Capital Cost ($/kW) Current 1990	Capital Cost ($/kW) Projected 2000	Levelized cost of Electricity ($/kWh) Current 1990s	Typical Size per Application
Pumped hydro	800—1200	—	0.052—0.189	464 MW
Lead-acid batteries	1300	425–635	0.20–0.25	up to 10 MW (4 hr storage)
Compressed air energy storage	460–630	—	—	110 MW
Fuel cells	2000–2500	1500	—	200 kW (largest to date)

ELECTRIC ENERGY STORAGE OPTIONS

INTRODUCTION

Energy storage technologies store energy generated by the utility system and/or energy generated on the user-side of the meter, and discharge it for use at another time. The most common application is large-scale load leveling, in which the storage unit is charged at a low-cost time period and then discharged to supplement energy being generated to meet high load requirements at some other time. Load-leveling can lower emissions or shift the location of emissions. It can allow better management of multiple suppliers, better accommodation of less dispatchable types of energy generation—such as solar and wind—reduce dependence on fossil fuels, and provide a utility-added flexibility. Compressed air energy storage (CAES) and pumped hydro storage are examples of load leveling storage technologies. Pumped hydro is discussed in Brief 1, "Hydroelectric Power."

The second general application of storage is fast dynamic response. These systems are characterized as systems with rapid response for charging and discharging devices that improve the control of voltage, frequency, and power quality. Batteries, flywheels, and superconducting magnetic energy storage (SMES) are examples of dynamic energy storage. Table R-17 compares the typical energy capacity, typical power rating, and the commercial status of six energy storage options. The most attractive energy storage for a given situation depends on the benefit desired by the utility or the end user from storage and the associated cost.

This brief focuses on electric energy storage technologies including batteries, CAES, and SMES.

TECHNOLOGY DESCRIPTION

BATTERY STORAGE Leod-acid battery technology is currently being pilot tested by several utilities in the United States. Advanced batteries—including sodium-sulfur and zinc-bromide—are in the developmental stages. The three main applications for battery energy storage systems include spinning reserve at generating stations, load leveling at substations, and peak shoving on the customer side of the meter. Battery storage has also been suggested for holding down air emissions at the power plant by shifting the time of day of the emission or shifting the location of emissions. It also provides voltage regulation and stability.

Battery storage has excellent dynamic response capability and siting flexibility. Dynamic response chorocteristics include low start-up costs, short start-up time, fast changeover from energy storage to power generation, efficient operation at a wide range of loads, fast load-changing copobility, and high unit-ovoilobility. Batteries offer siting flexibility for several reasons. The small unit sizes of battery systems, their compatibility with surrounding architecture, and their favorable environmental characteristics allow them to be sited near the load. Several benefits accrue (sometimes in combination), such as saving or deferring transmission copitol costs, reducing transmission losses by decreasing peak currents, increasing delivered output of the plant to the customer, and improving system reliability to the consumer because a battery located close to customers con provide power while a transmission line failure is being repaired.

Several utilities ore now using battery storage for load leveling, and a consortium of utilities has formed for the purpose of developing and applying the technology farther.

CAES CAES plants use off-peak electrical energy to compress air into underground storage reservoirs for storage until times of peak or intermediate electricity demand. Wind power offers a good opportunity for charging CAES storage. The storage is typically underground in natural aquifers, depleted oil or gas fields, mined salt caverns, or excavated or natural rock caverns. Figure R-25 illustrates three types of CAES storage. To generate power, the compressed air is first heated by gas burners, then passed through an expansion turbine.

In June 1991, an Alabama utility completed construction of a 110-MW capacity CAES plant that can run 26 hrs on a full charge of compressed air. Other CAES plants are in use in Germany and Italy.

SMES SMES technology involves using the superconducting characteristics of low-temperature materials to produce intense magnetic fields to store energy. Currently, large-scale SMES technology is in the research and development stage; Bonneville Power Administration built a prototype unit in 1983. SMES has been proposed as a storage option to support large-scale use of photovoltaics and wind as a means to smooth out fluctuations in power generation. Compared to other energy storage systems, SMES offers high efficiency and fast, dynamic response. Small-scale SMES is generally considered an experimental technology.

At a California utility, researchers are conducting one of the first tests of a small-scale SMES device for utility application. The device is designed to improve customer power quality and reliability by providing short bursts of energy to overcome momentary outages and voltage sags. Mini-SMES can be of particular benefit to customers with a need for a higher degree of reliability and power quality, such as manufacturing production lines.

Mini-SMES systems use low-temperature [-425°F (-254°C)] superconductors to store enough energy to meet relatively small (0.5 to 2.0 MW) customer loads for short periods of time (0.1 to 5 s). Applications of the technology include voltage support, load smoothing, momentary carryover, regenerative support, and volt-amperes reactive support.

DEFINITIONS AND TERMS

SUPERCONDUCTIVITY The pairing of electrons in certain materials when cooled below a critical temperature where the material loses all resistance to electricity flow.

POROUS MEDIA A solid that contains pores; normally, it refers to interconnected pores that can transmit the flow of fluids. (The term refers to the aquifer geology when discussing sites for CAES.)

RESOURCE ASSESSMENT

BATTERIES Batteries are the most modular storage technology, but maintenance requirements limit their size to power ratings in the range of several hundred kWh to tens of MW, and energy storage ranging from several hundred kWh to 100 MWh.

CAES The Electric Power Research Institute has prepared maps that identify potentially favorable sites for CAES. A U.S. map is shown in Figure R-24. State-by-state maps with potential areas for hard rock caverns, salt caverns, depleted gas fields, and aquifers are found in the CAES reference identified under the Publications section that follows.

SMES Small-SMES is a room-sized system that can be installed at any industrial site. Large-SMES requires a large site with a low water table, low seismic activity, uniform soils, and a remote location.

MARKET OUTLOOK FOR ELECTRIC ENERGY STORAGE OPTIONS

EPRI predicts that storage will play an increasingly important role in electric generation systems late in this century or early in the next.

BATTERIES The utility battery systems developed to date have been within budget and technically successful. These systems should spur additional interest and applications. The development of advanced batteries for electric vehicle applications may accelerate technology development for utility applications as well.

CAES According to EPRI, 12 to 15 utilities are now conducting studies related to the economics of CAES in their service territories.

SMES In addition to ongoing research for utility applications, a pre-engineering and economic feasibility study is ongoing to assess the potential of mini-SMES to correct voltage sags on the Bay Area Rapid Transit system by detecting voltage sags and injecting current into the track.

INDUSTRY STATUS

BATTERIES Lead-acid batteries for utility-scale applications are available from several vendors. There is no established commercial industry for installing battery energy storage systems, but suppliers of components and firms with the capability to perform system integration exist. Advanced batteries for commercial applications are now only available from suppliers outside the United States.

CAES There is no well-defined CAES industry, but there are various suppliers for CAES plant equipment. The oil and gas industry has extensive experience in the geological aspects of locating and building the reservoir required for a CAES plant.

SMES There is currently no established SMES industry, although one firm in the United States manufactures mini-SMES systems and is working with the utilities that were previously mentioned to develop, test, and market a device for motor, power quality, and transit applications.

CONSTRUCTION LEAD TIME

BATTERIES Construction lead time for the largest lead-acid battery storage plant in the continental United States for utility application was 1 and 1/2 years, including permitting and licensing. This plant has 8256 batteries and can provide up to 4 hr storage at a peak output of 10 mW.

CAES The licensing and design lead time for an Alabama 110-MW CAES plant was about 2 years. Plant construction time ranges from about 2 years for a 25- to 50-MW plant to 4 years for a 50- to 100-MW plant. The construction time will depend on the geology at the site.

SMES Unknown.

ENVIRONMENTAL ISSUES

BATTERIES Batteries have minimal environmental impact. They have no combustion products and generate no significant waste heat. They can be sited easily at any industrially zoned location. The disposal of batteries is a concern.

CAES Because gas is used to drive the turbine, the technology is not pollution-free. The emissions are about three times lower than for comparable combustion turbines because of the higher efficiency of gas use. If salt domes are mined for the storage reservoir, the resulting dissolved brine may create problems for disposal.

SMES A possible environmental issue related to SMES is the external direct current magnetic field associated with large plants. While environmental effects from this field are projected to be minimal or nonexistent, they are uncertain. Public concern regarding electromagnetic fields is an issue.

LAND AREA REQUIREMENTS

8ATTERIES A 10-MW to 50-MW plant requires 2 acres (.81 ha), at most.

CAES A 110-MW plant requires less than 20 ocres (8.1 ho). Above-ground land could be used for grazing, agriculture, and some commer-ciol enterprises.

SMES Small SMES is room-sized. For o 400 MW/h large-scale plant, the entire site would require 6200 acres (2508 ho). (This indudes o 1300-ocre [526 ho] exdusion zone.)

CURRENT COSTS AND TRENDS

Toble R-18 provides information on current costs of storage technologies.

A major difference in developing the cost of storage technologies rather than generation technologies is that the total plant cost depends not only on the plant's MW copocity, but also on the MWh of energy that the plant is designed to deliver in o charge-discharge cycle, as shown in the following equation:

$$C_t = (C_p + C_s) \times t$$

where: C_t = total plant capitol cost ($/kW)

C_p = cost of power component ($/kW)

C_s = cost of the stored energy component ($/kWh)

t = storage time in hours.

For batteries, the number of charge and discharge cycles per year will also affect cost.

FOR MORE INFORMATION

PUBLICATIONS

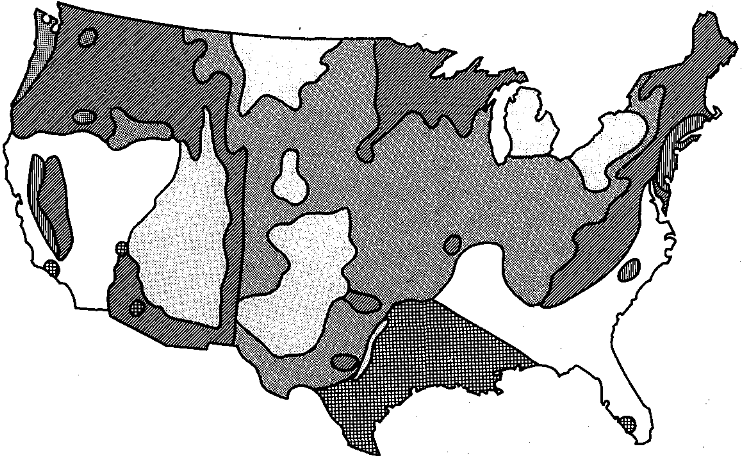
Potential Economic Benefits of Battery Storage to Electrical Transmission and Distribution, (EPRI Report GS-6687), Electric Power Research Institute, January 1990.

Proceedings: Geotechnology Workshop on Compressed-Air Energy Storage in Porous Media Sites. Detroit, MI: ANR Storage Company (EPRI AP-5301, Project 2488-10 Proceedings) Electric Power Research Institute, July 1987.

Birk, J. R., "The Future of Battery Storage for Electric Utility Application," *Proceedings of the Symposia on Stationary Energy Storage: Load Leveling and Remote Applications*, The Electrochemical Society, Inc., Proceedings Volume 88-11, pg. 22, 1988.

ORGANIZATIONS

The Energy Management Consortium (Battery Consortium), P.O. Box 12036, Research Triangle Park, NC 27709, 1-800-551-BESS.



BA–G1124712

Figure R-24. Locations of geologic formations potentially suitable for CAES development

- Salt
- Rock
- Aquifer
- All of Above
- Rock and Aquifer

Table R-17. Energy Storage: Characteristics

Technology	Typical Energy Capacity	Typical Power Rating	Status
Batteries	100s kWh to 10s MWh	10 kW to 10 MW	Commercially available
Compressed air energy storage	10s to 1000s MWh	10 to 100s MW	Components commercially available
Superconducting magnetic energy storage	MWs to 1000s MWh	1 to 10,000 MW	Under development; near-term availability
Pumped hydro	100s to 1000s MWh	100s to 1000s MW	Mature technology
Thermal energy storage	1 kWh to 100 MWh	100 kW to 100 MW	Commercially available
Flywheels	1 to 100 MWh	10 kW to 10 MW	Developmental, long-term availability

Source: McCormack, K., *Storage Technologies. Making the Most of Renewables,* Environmental Protection Information Conference, October 24, 1991.

Table R-18. Storage Power: Costs

System Type	Capital Cost ($/kW)	Operational Cost	Levelized Cost of Electricity (1987$/kWh)[2]	Typical Size per Installation (MW)	Efficiency (%)	Life (yr)
Lead-acid batteries[1]	1300	$5.20/kW/yr 1.0/kW/yr for power conditioning	0.20–0.25[2]	Up to 10	70	30[3]
Lead-acid and advanced batteries EPRI target costs[4]	425–635 (estimate)	Fixed $0.40–0.60 /kW/yr Variable 0.58–0.86 /kW/yr		20	74	30
CAES[5]	460–650	Fixed 1.2–2.3/kW/yr Variable 0.09–0.19/kW/yr	0.084–0.098	110	[5]	30
SMES[6]	925–1720 (estimate)	Fixed $4.30/kW/yr[7]		1000 (target)	90+	30

1. The capitol ond operating costs ond the efficiency o r e based on the Chino substation operated by Southern California Edison Co.
2. The levelized energy costs ore taken from: Colifomio Energy Commission, Energy Technology Status Report Appendix A: Volume II, P500-90-003A, June 1991. The cost represents the current cost of custom fobrication for o 10 MW/40 MW/h bottery system. The system is designed for 4 hrs of storage.
3. The botteries ore not expected to lost os long os the battery plant. The cost for battery replacement is not included in the system costs.
4. The Electric Power Research Institute (EPRI) target costs for leod-ocid botteries assume o production rote of ten 20-MW units per yeor. The numbers were token from o presentation by Dr. R. Schoinker of EPRI entitled "Superconducting Mognetic Energy Storage (SMES)," Benefit Assessment Workshop, Oct. 18, 1990. The costs assume $125/kW plus $170 (lead-acid)/kWh or $100/kWh (advanced) operating for 3 h.
5. It is difficult to estimote on efficiency of compressed oir energy storage. The efficiency is o function of two factors: the charging energy rote ond the heot rote. The charging energy rote ronges from 0.8-1.2 kWh/kWh. The heat rate varies from 4800-6500 Btu/kWh. This is based on using notural gos to heat ond expand the olready compressed oir to generote electrical power.
6. Information on superconducting mognetic energy storoge (SMES) taken from Storoge Technology's *Making the Most of Renewables*. Presented ot the Environmental Protection Information Conference, October 24, 1991. The numbers ore based on 10 hrs of storage.
7. Based on the estimoted cost for o 1000 MWH focility with 4 h of storage.

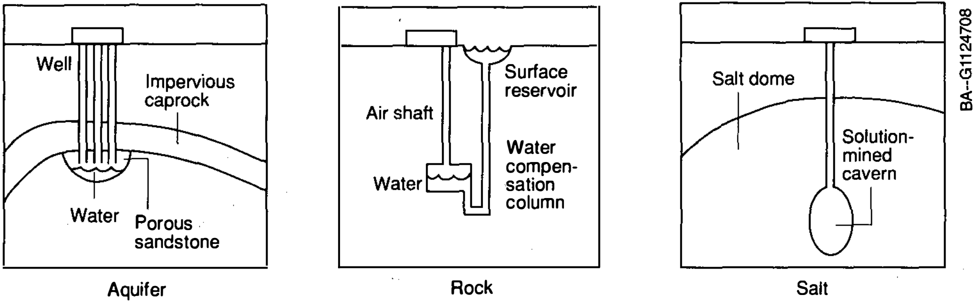


Figure R-25. Three types of underground air storage for CAES generating units

FUEL CELLS

TECHNOLOGY DESCRIPTION

A fuel cell is not a renewable technology, as such. However, a fuel cell can be considered a renewable energy technology if it uses a renewable fuel such as fuel gas derived from biomass. It is a device that converts the energy of a fuel directly to electricity and heat, without combustion. Because there is no combustion, fuel cells give off few emissions; because there are no moving parts, fuel cells are quiet.

A fuel cell has three basic components: a fuel processor, a power section, and a power conditioner. The fuel processor converts hydrocarbon fuel into a hydrogen-rich gas that is fed into the fuel cell in the power section. The power section combines oxygen from the atmosphere with the hydrogen produced by the fuel processor to produce both direct current (DC) electricity and heat. The power conditioner uses solid-state technology to efficiently convert the DC power to alternating current (AC) power—at the voltage required for transmission. The steam or heat produced in the process can be used at the site of the fuel cell installation. Figure R-26 shows a basic fuel cell.

Currently, hydrogen is produced from fossil fuels, particularly natural gas. Other potential fuels include gas from coals, landfills, biomass, methanol, various petroleum distillates, or solar energy. In the future, the production of hydrogen from solar energy by splitting water into its elemental compounds may become an important base of our energy system, and fuel cells could be an integrated part of that approach.

Several types of fuel cells are under development for utility purposes and/or on-site industrial and commercial applications. Each uses a different type of electrolyte—an electrically conductive chemical to react with the fuel. The types of fuel cell systems that are currently under development include molten carbonate (MCFC), phosphoric acid (PAFC), and solid oxide. Table R-19 compares the characteristics of each. PAFC cells are now commercially available.

Fuel cells offer some significant opportunities for utilities. They con be sited near centers of load growth because they ore small and produce low emissions. Eventually, they con use gas produced by the gasification of cool, which will be the most efficient means of generating electric power from fossil fuels. They con respond to load changes in seconds, which makes them attroctive for serving peak loads. They ore modular, so utilities con odd them os demand grows, and when sited appropriately, they con be used to defer costly transmission and distribution facilities.

The major research and development issue involves extending the lifetime of the cell components.

RESOURCE ASSESSMENT

Other than fuel ovoilobility, fuel cells ore not very site-sensitive. Because of low noise, low profile, minimal emissions, low water consumption, and their relatively safe nature, fuel cells con be located virtually anywhere. They ore well-suited to locations near load centers.

MARKET OUTLOOK FOR FUEL CELLS

A gas company in Los Angeles, California, has purchased and, in 1992 to 1993, is installing 200-kW PAFC fuel cells in 10 commercial facilities including o hotel, hospitals, and o county jail. In on effort to promote commerciolization of the technology, the company will own and maintoin the cells, while the companies pay for natural gas.

In 1991, o Californio utility built o 100-kW MCFC demonstration test facility and is currently testing the readiness of o 70-kW MCFC.

A group of 20 utilities hove formed the Fuel Cell Commercialization Group (FCCG). Each of the FCCG members represents o potential buyer of precommercial 2-MW MCFC units or major financial porticiponts in o demonstration unit. This group plons to develop available mature and cost-competitive MCFCs by 1997 under on innovative commerciolizotion plon that will include completion of o demonstration plon by 1994, shored risks for eorly production units, and shared royalties on future sales for utilities that become involved in early efforts.

A site has been selected in Santa Clara, California, to build the first 2-MW power plant by 1994. Six major financial participants have pledged financial and staff support to the demonstration. Contract negotiations have begun.

The FCCG plans to obtain orders for 100 MW of the 2-MW fuel cells power plants that support the manufacturers' efforts to build a commercial manufacturing facility, and begin commercial operation of commercial units.

Electric Power Research Institute studies indicate that the market for the 2-MW MCFC power plants is conservatively 12,000 to 14,000 MW—at a rate of 900 MW per year once commercialization is achieved.

INDUSTRY STATUS

There are approximately eight companies in the United States, Europe, and Japan that are developing fuel cells.

CONSTRUCTION LEAD TIME

Only PAFCs are commercially available now. If, as projected, fuel cells are developed to the point of commercial competitiveness late in this century and manufacturing capability is developed, fuel cells will be available in modules so utilities and managers of large facilities can add single units quickly, as demand warrants.

ENVIRONMENTAL ISSUES

There are virtually no SO_2 and NO_x emissions. Emissions of CO_2 are significantly lower than other generating alternatives. Systems are air-cooled.

There are no water pollution concerns for fuel cells. The plants are extremely quiet because they have no moving parts. They are compact and low far reduced visual impact.

LAND AREA REQUIREMENTS

The land area required for a 2-MW MCFC is 4500 ft^2 (418 m^2). Early applications of fuel cells will probably be in dense urban areas facing severe environmental constraints, at substations where fuel cells can offset overloaded capacity, and in industrial parks that offer opportunities for cogeneration.

CURRENT COSTS AND TRENDS

Costs are provided in Table R-20 for PAFC and MCFC.

FOR MORE INFORMATION

PUBLICATIONS

Molten Carbonate Fuel Cell Program—1991 Status. Electric Power Research Institute Technical Brief, #RP3058, 3059, 3195.

ORGANIZATIONS

Fuel Cell Commercialization Group, 1101 Connecticut Ave. NW, Suite 910, Washington, D.C., 20036, (202) 296-3471.

Electric Power Research Institute, P.O. Box 10412, Palo Alto, CA 94303, Rocky Goldstein, Project Manager, (415) 855-2000.

PG & E, 3400 Crow Canyon Road, San Ramon, CA 94583, Fuel Cell Program Manager, Department of Research and Development, (510) 866-5391.

SoCal Gas Company, Box 3249, Los Angeles, CA 90051-1249, David Moard, Fuel Cell Market Development Marketing Manager, (213) 244-3731.

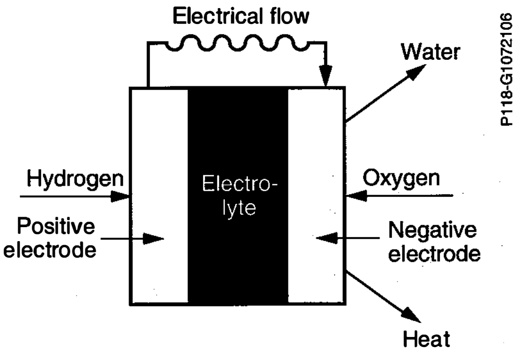


Figure R-26. Components of a fuel cell

Table R-19. Comparison of Fuel Cell Types and Characteristics

Characteristics	Phosphoric Acid (First generation)	Molten Carbonate (Second generation)	Solid Oxide (Third generation)
Operating temperature	400°F (204°C)	1200°F (649°C)	1800°F (982°C)
Applications (near-tenn)	On-site dispersed, utility generotors	On-site dispersed, utility generotors	On-site dispersed, utility generators
Applications (long-tenn) existing power plants	Repowering at existing power plants	Repowering at existing power plants	Repowering ot existing power plants
Module size (near-tem)	200 kW-11 MW	2-10 MW	5-100 MW
Efficiency	36%	52%-60%	80%[1]
Largest module built	4500 kW pilot plant	70-kW stack	3 kW module
Market entry	Early 1990s	Mid- to late-1990s	2000

Advantages	Most technically mature Low emissions Low noise Air-cooled Low height Good operation characteristics	Low noise Low emissions Low noise Air-cooled Compact Simpler system than phosphoric acid fuel cell	Highest plant efficiency Low noise
Key issues	Competitiveness Reliability O&M Cost Cell stack durability	Scale-up Manufacturing cost Durability Reliability	Scale-up Manufactring Durability Reliability

1. This is a combined-cycle efficiency. It includes heat used to power tuibines.

Table R-20. Fuel Cells: Costs

System Type	Capital Cost ($/kW)	Operational Cost	Typical Size of Installation	Capacity Factor (%)	Life (yr)
200 kW PAFC[1]	2000-2500[3]	—	200 kW	65	30
2-MW MCFC[2]	1500/kW[5] (estimate)	Fixed $9.80/kW/yr Voriable 1.7 mills/kWh (estimate)	2 MW (estimated)	65	30

1. Token from the Energy Technology Status Report (June 1991) Colifomio Energy Commission. The levelized energy cost is in real 1987 dollars. The PAFC cost assumes 1993 operation. The MCFC cost assumes mid-1990 operation.
2. Phosphoric ocid fuel cell (PAFC)
3. This is the current cost of the commercially ovoiloble PAFC. As more of these ore monufoctured, the cost is expected to drop to $1500/kW.
4. Molten corbonote fuel cell (MCFC)

INVERTER TECHNOLOGY

INTRODUCTION

The electric power available from the utility is generally generated by a synchronous generator driven at a constant speed to produce a constant frequency. The output of the generator is a smooth alternating current (AC) signal. The AC signal enables the utility to use the transformer to step up and step down the voltages. Thus, a high voltage transmission can be accomplished. With high voltage transmission, the size of current flowing in the transmission lines is smaller than the voltage transmission. As a result, the transmission losses and the size of wires can be minimized.

In general, the electrical source found in buildings is an AC voltage source at constant voltage and constant frequency. Most industrial equipment and appliances that are operated by electric motors require an AC source. With the emergence of renewable energy sources, some of the power-praducing systems, such as photovoltaics and many wind-generating systems, produce a direct current (DC) signal. For this reason, it is necessary to convert the DC electricity to AC electricity with the use of a DC to AC converter, which is called an inverter.

TECHNOLOGY DESCRIPTION

Inverters either provide AC power to stand-alone systems (not connected to the grid) or provide power to the grid. Among many systems, the inverter can be categorized into three systems. The three classifications of a voltage source inverter depend on the type of the AC waveform output signal: square wave, modified square wave, and pulse width modular wave.

SQUARE WAVE INVERTER The inverter consists of a DC source, four switches, and the load. The switches are power semiconductors that can carry a large current and withstand a high voltage rating. The switches are turned on and off at a correct sequence, at a certain frequency. The square wave inverter is the simplest and the least expensive to purchase. However, it produces the lowest quality of output waveform. The output of a square wove inverter consists of the sinusoidal (fundamental) component and the nonsinusoidol component (which is called the ripple or higher harmonics component).

For on AC electric motor, only the fundamental component is useful to produce the torque. The higher harmonics will only produce the torque pulsation (which translates into vibration and noise) and resistive losses (which translate into higher temperatures that con lead to insulation failure and then to a short circuit).

MODIFIED SQUARE WAVE INVERTER Another method of turning the switch on and off is by modulating the switching pattern in a different way. The modified square wove is one way to reduce the harmonics.

PULSE WIDTH MODULATED (PWM) WAVE INVERTER PWM inverters ore the most expensive, but produce a high quality of output signal at minimum current harmonics. The switching pattern for this inverter normally follows what is called pulse width modulation—where the switching pattern follows the crossing point of a triangular waveform (at a carrier frequency) and a sine waveform at a fundamental frequency. (The carrier frequency is normally much higher than the fundamental frequency.) By doing so, the higher harmonics voltage occurs at much higher than the fundamental frequency. As a result, the higher harmonics output current will be much smaller than the square wove inverter and the modified square wave. In general, a series inductor and capacitor filter is also included in the system to filter out the higher harmonics; thus, the output voltage after the filter will be very close to sinusoidal.

DEFINITIONS AND TERMS

TOTAL HARMONIC DISTORTION The measure of closeness in shape between a waveform and its fundomental component.

POWER FACTOR The ratio of the average power and the apparent volt-amperes.

WAVEFORM The shape of the curve graphically representing the change in the AC signal voltage and current amplitude, with respect to time.

MARKET OUTLOOK FOR INVERTER TECHNOLOGY

Inverters are commercially available in different sizes. For domestic or other applications where the quality of output waveform is less of a concern, the square wave inverters are often used. For industrial use (especially for variable speed drives), three-phase PWM inverters are more widely used. With the advance of power electronics technology, the price of semiconductor devices becomes cheaper; thus, the inverter prices will become more affordable.

SECTION 3

RENEWABLE OPTIONS FOR BUILDING APPLICATIONS

INTRODUCTION

Renewable resources con be used like energy efficiency technologies for demand-side management (DSM). Renewable resources provide a utility with a means to manage demand by substituting on-site power generation for conventional power generation and distribution or, in the case of passive cooling technologies, provide load avoidance strategies to reduce the need for conventional energy. Renewobles may serve as a peak clipping strategy or, if storage is provided, they may serve as a strategic conservation strategy. The use of renewable resources increases the overall efficiency of the conventional electric supply system.

Renewable resources ore capable of providing heating, cooling, daylighting, and electrical power on the customer side of the meter. Yet, renewable resources hove been largely untapped by utilities for their DSM potential. The ovoilobility of renewable technologies in the marketplace is growing, the products ore reliable, the technologies ore cost-effective in niche markets, and a number of progressive utilities ore using or testing renewobles for consideration in their DSM programs. As utility planners gain more experience with DSM programs and begin to exhaust the most eosily attainable means of demand reduction through energy conservation, they will need to look for new measures that allow them to reduce building energy ond demand even further. Demand-side renewobles represent on untapped potential.

A recently completed study by the American Solar Energy Society (December 1992) compares the cost of four renewable technologies for buildings on o levelized life-cycle basis. The 1990 cost ranges ore as follows:

- Solar water heating — $0.04-$0.06 per kWh
- Passive heating — $0.02-$0.04 per kWh
- Solar swimming pool heating — $0.06 per kWh

- Daylighting — $0.025 per kWh

The levelized life-cycle cost basis allows one to begin to compare the cost for buildings technologies to conventional supply-side technologies. The methodology does not reflect the considerable benefits of renewables, including modularity, reduced risk, and reduced environmental impact. New economic methodologies are emerging and gaining acceptance to include these benefits. Comparing these numbers to Figure P-1 (in Section 1) illustrates the fact that renewable resources for buildings are cost-effective today where buildings have adequate access to the solar resource.

Many of the renewable technologies have been addressed in other volumes in this series. In this section, a series of new briefs and updates to existing briefs are presented on the following topics:

- Solar water heating
- Ground-source heat pumps
- Passive solar residential design
- Integrated building design for new commercial construction
- Dispersed photovoltaics.

A number of other demand-side renewable briefs can be found in the other volumes of the pocket guide series. Their location is shown in Table R-21.

Table R-21. Demand-side Renewable Briefs

Title	Brief #	Volume
Solar pool heaters	27	1
Commercial passive solar design	17	2
Daylighting	15	2
Solar industrial process heating	33	4
Solar preheating of ventilation air	34	4
Solar detoxification of hazardous waste	35	4

Table R-22 identifies the load management objectives that can be achieved by renewable systems included in this section. Table R-23 shows the simple payback for the renewable options evaluated under average conditions. Paybacks for residential applications are based on electricity costs of $0.08/kWh. For commercial systems, paybacks are based on $0.07/kWh.

Table R-22. Demand-side Management Strategies: Renewable Measures

	Load Management Objectives					
	PC	VF	LS	SC	SG	FLS
Solar water heaters				■		
Drainback systems						
Integral collector/storage						
Thermosyphon						
Integrated solar/conservation				■		
Design for new commercial buildings						
Low-rise office	■			■		
Retail						
Passive solar design			■	■		
Direct gain						
Sunspace						
Thermal storage						
Ground-source heat pumps	■		■			
Dispersed photovoltaics	■		■			
Swimming pool pumping	■		■			
Residential buildings	■		■			

PC=peak clipping; VF=valley filling; LS=load shifting; SC=strategic conservation; SG=strategic growth; FLS=flexible load shape.

Table R-23. Payback for Demand-side Management Strategies Renewable Measures

	No. of Years to Payback			
	<2	2-5	6-10	>10
Solar water heaters			■	
Drainback systems			■	
Integral collector/storage			■	
Thermosyphon				
Integrated solor/conversvation				
Design for new commercial buildings				
Low-rise office		■		
Retail		■		
Passive solar design				
Direct gain		■		
Sunspace			■	
Thermal storage			■	
Ground-source heat pumps		■—	—■	
Dispersed photovoltoics				
Swimming pool pumping		■		
Residential buildings		N/A		

■ = The payback falls in the category indicated.

■—■ = The payback falls in the range of time indicated. For ground-source heat pumps, it depends on the climate.

Note: The paybacks shown were determined based on conditions described in the text. Paybacks will vary based on climate, fuel, cost, systems characteristics, and other factors.

(update to RESIDENTIAL BRIEF 19) SOLAR WATER HEATERS

TECHNOLOGY DESCRIPTION

Solar water heating systems con be designed to operate in nearly any climate. The performance of o system varies based on the amount of solor insolation incident on the collectors and on the outdoor temperoture. In most ports of the country, o solar system is designed to meet 100% of o home's water heating requirements in summer months. In winter months, the system may meet only holf the home's water heating requirements. Therefore, o backup water heater or heating element is necessary to supplement the solar system.

Active solorwoter heating systems use pumps to circulate water or other heat-transfer fluid from the collectors (where it is heated by the sun), to the storage tonk (where the water is kept until it is needed). Low-flow systems hove configurations similar to conventional active systems, but their low flow rote enhances thermal strotificotion in the storage tonk and improves the system's thermal performance.

For freeze protection, active systems con be separated into two general groups: those that use o fluid with o low freezing point (generally on antifreeze solution of ethylene or propylene glycol in the collector loop), and those thot use water in the collector loop (which must be protected from freezing). The reliability of active solar systems was problematic in the early 1970s, but today it is greatly improved.

Passive water heaters use the natural convection of the solar-heated water to create circulation. Passive systems ore typically integral collector/storage (ICS) or thermosyphon systems. The major odvontoge of these systems is thot they do not use controls, pumps, sensors, or other mechonicol ports, so little or no maintenance is required over the lifetime of the system.

The Solar Rating and Certification Commission (SRCC) now has a standard in place for solar water heaters. To comply with the standard, a manufacturer must

- Have each system model rated
- Allow SRCC factory and field inspections
- Comply with a three-person design review.

Systems meeting the standard will have a label stating compliance with the SRCC OG-300 standard. This standard should improve consumer and utility confidence of product reliability.

Figure R-27 illustrates the impact of solar water heaters on utility demand-based on the results of three field studies. The studies are all described in the publication identified at the end of this brief. In all three of these studies, the greatest coincident demand occurred in the winter. This is because hot water use is a strong component of the utilities' early morning winter peak but is not as critical during the summer peak period, which is typically in the afternoon. Figure R-28 illustrates the energy impact of homes with solar water heating (with electric auxiliary) and a similar set of homes with conventional electric water heaters.

Several utilities in the western states are now offering some type of solar water heating program as part of their demand-side management program. The programs generally include rebates or low-interest loans. The programs include system standards tied to performance or warranties. A utility solar water heating interest group is being formed to define utility needs for information and to establish the readiness of solar water heating as a demand-side measure. Costs and benefits for solar water heaters are shown in Table R-24.

DEFINITIONS AND TERMS

DRAINBACK SYSTEMS In these systems, water in the collector loop drains into a tank or reservoir whenever the pump stops.

DRAINDOWN SYSTEMS In these systems, water from the collector loop and the piping drain into a drain whenever freezing conditions occur.

ICS ICS systems are also called "batch" or "breadbox" water heaters. They combine the collector and storage tank in one unit. The sun shining into the collector strikes the storage tank directly, heating the water. The large thermal mass of the water, plus methods to reduce heat loss through the tank, prevent the stored water from freezing.

LOW-FLOW SYSTEMS The flow rate in these systems is 1/8 to 1/5 the rate of conventional solar water heating systems. The low-flow systems take advantage of stratification in the storage tank and theoretically allow the use of smaller diameter piping to and from the collector and a smaller pump.

RECIRCULATION SYSTEMS These systems circulate warm water from storage through the collectors and exposed piping whenever freezing conditions occur.

THERMOSYPHON SYSTEMS Thermosyphon systems use a separate storage tank located above the collector. Liquid warmed in the collector rises naturally above the collector, where it is kept until it is needed. The liquid can be either water or a glycol solution. If the fluid is water, freeze protection is provided by electric heat. If the fluid is glycol, the heat from the glycol is transferred to water in the storage tank.

■ APPLICABILITY

CLIMATE ICS, recirculation, and thermosyphon systems are not recommended for cold climates.

FACILITY TYPE All.

DEMAND SIDE MANAGEMENT STRATEGY Strategic conservation.

FOR MORE INFORMATION

PUBLICATIONS

Carlisle, N., C. Christensen, L. Barrett, ***Opportunities for Utility Involvement with Solar Domestic Hot Water***, NREL/TP-432-4799, Golden, CO May 1992.

ORGANIZATIONS

American Public Power Association, 2301 M Street, N.W., Washington, D.C. 20037-1484, Barry J. Moline, (202) 467-2932.

Edison Electric Institute, 701 Pennsylvania Avenue, N.W., Washington, D.C. 20024-2696, Richard S. Tempchin, (202) 508-5558.

Solar Energy Industries Association, 777 No. Capital Street, N.E., Suite 805, Washington, D.C. 20002, (202) 408-0660.

Table R-24. Solar Water Heaters: Costs and Benefits

System Type	Costs[1] ($/ft²)	Energy Savings[1] (kWh/ft²/yr)	Cost Savings ($/ft²/yr)	Simple Payback (yr)	Life (yr)	Confidence[2]
Drainback solar system	65	88	7.04	9.2	20	M
Low-flow system	42	81	6.50	6.5	20	M
Integral collector/storage (ICS) system	55	93	7.40	7.4	20	M

1. The costs and savings for the three systems were based on the following ossumptions:

	Collector orea	Starage volume
Drainbock	39.8 ft^2 (3.7 m^2)	62.2 gol (235 l)
Low flolw	56.0 ft^2 (5.2 m^2)	71.9 gol (272 l)
ICS	26.9 ft^2 (2.5 m^2)	42.3 gol (160 l)

2. M stands for medium.

The savings for the drainback ond ICS were based on TRNSYS simulations for Denver, CO. The savings for the low-flow system wos based on o WATSUN simulotion for Denver, CO.
Note: Larger systems (i.e., low flow) hove lower energy savings per ft² of collector oreo but deliver greater overall energy savings.

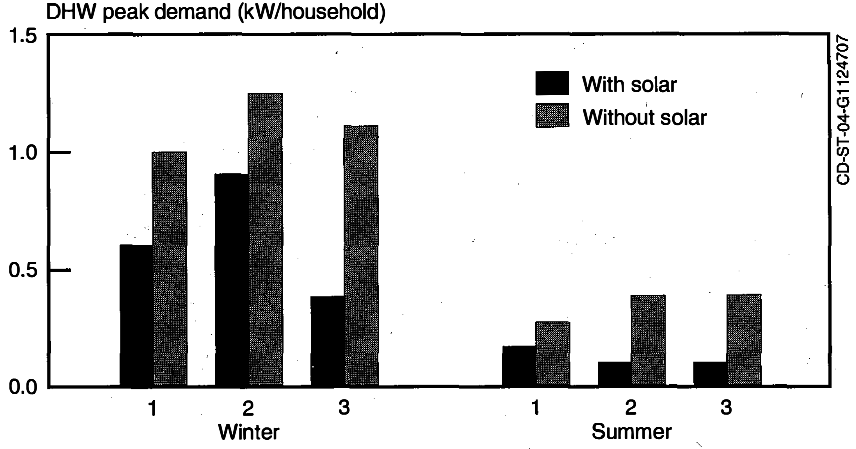


Figure R-27. Coincident diversified demand of residential solar domestic hot water system on electric utilities

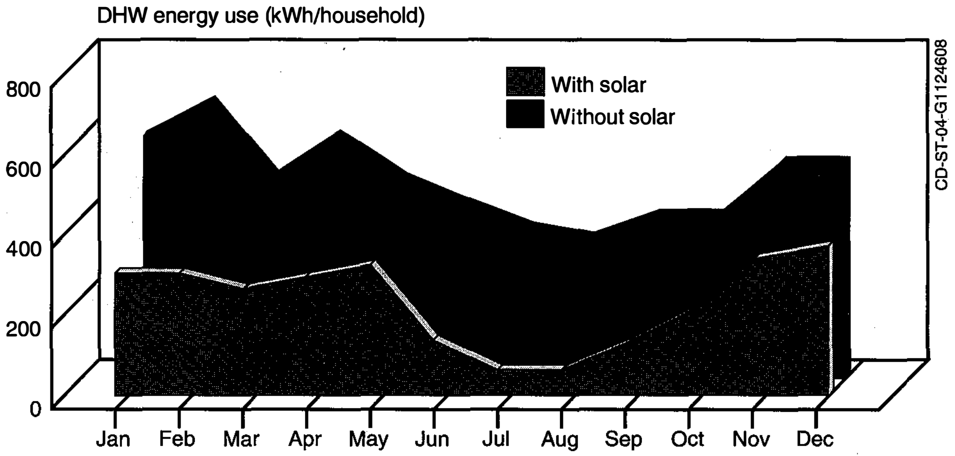


Figure R-28. Energy savings from residential domestic hot water systems in Austin, TX

(update to RESIDENTIAL BRIEF 8) PASSIVE SOLAR DESIGN

TECHNOLOGY DESCRIPTION

A passive solar building is designed to maximize useable solar heat gain in the winter and minimize heat gain in the summer to create a comfortable interior living environment. A passive solar design is site specific, varying with the local climate and building type. System components to increase heat gain may include south-facing windows and moveable insulation, walls or floors that use masonry or water to store heat, and a sunspace or greenhouse. System components to prevent heat gain include overhangs or shades, landscaping, and vents. Good passive design involves a balance of conservation and solar design features. Conservation makes the passive solar system's job easier; likewise, passive solar features reduce the need for auxiliary heat.

U.S. utilities are beginning to recognize that programs focused on new construction are a popular way to capture what is otherwise a "lost opportunity" for gaining energy efficiency over and above current building practice. By employing passive solar design and encouraging no-cost steps such as siting for solar access and natural cooling, utilities can significantly reduce a building's heating and cooling requirements.

Costs and benefits for residential passive solar systems are shown in Table R-25.

DEFINITIONS AND TERMS

ANNUAL SOLAR SAVINGS The annual solar savings of a solar building is the energy savings attributable to a solar feature relative to the energy requirements of a nonsolar building.

DIRECT GAIN In direct-gain buildings, sunlight directly enters the home through the windows and is absorbed and stored in massive floors or walls. These buildings are elongated in the east-west direction, and most of their windows are on the south side. The area devoted to south windows varies throughout the country. It could be as much as 20% of the floor area in sunny cold climates, where advanced glazings or moveable insulation are recommended to prevent heat loss at night. These buildings have high insulation levels and added thermal mass for heat storage.

PROJECTED AREA The net south-facing glazing area projected on a vertical plane.

SUN TEMPERING A sun-tempered building is elongated in the east-west direction, with the majority of the windows on the south side. The area of the windows is generally limited to about 7% of the total floor area. A sun-tempered design has no added thermal moss beyond what is already in the framing, wall board, and so on. Insulation levels are generally high.

THERMAL STORAGE WALLS (MASONRY OR WATER) A thermal storage wall is a south-facing wall that is glazed on the outside. Solar heat strikes the glazing and is absorbed into the wall, which conducts the heat into the room over time. The walls are at least 8 in thick. Generally, the thicker the wall, the less the indoor temperature fluctuates.

APPLICABILITY

FACILITY TYPE Primarily new residential construction. Because most passive solar design components are an integral part of the building, application is best suited to new construction. Retrofitting is generally limited to adding a greenhouse or a sunspace.

CLIMATE Passive solar design is applicable to all climate zones. The optimal passive solar system size varies by locotion and is shown in Figure R-29. Figures R-30, R-31, and R-32 show the annual savings from solar for different system types. The sizes are based on the assumption that the building is well-insulated.

DEMAND-SIDE MANAGEMENT STRATEGY Strategic conservation, lood shifting.

FOR MORE INFORMATION

PUBLICATIONS

Balcomb, J.D. "Conservation and Solor Guidelines," *Passive Solar Journal*, 3(3), pp. 221-248, 1986.

Solar Energy Research Institute, *Passive Solar Performance: Summary of the 1982–1983 Class 8 Results*, SERI/SP-271-2362, Golden, CO, 1984.

Aitken, D. and Paul Bony, "Passive Solar Production Housing and the Utilities." *Solar Today*, March/April 1993.

ORGANIZATIONS

Passive Solar Industries Council, 1511 K St., NW, #600, Washington, D.C. 20005, (202) 371-0357.

Table R-25. Passive Solar Design: Costs and Benefits

Options	Cost ($ (Installed)[1]	Energy Savings (kWh/yr)[2]	Cost Savings ($/yr)[3]	Simple Payback (yr)[3]	Life (yr)[4]	Confidence[5]
Direct gain	2,340	6,856	548	4.3	50	M
Semi-enclosed sunspace	7,020	10,020	801	8.8[11.1,12.8]	50	M
Thennal storage wall	5,004	6,856	548	9.1[7.6,9.4]	50	M

1. All costs are added costs for new construction. Retrofit costs will generally be higher. Added cost is based on a 2000-ft² (186 m²) house with 240 ft² (22.3 m²) of glozing (12% of floor area) in a cold sunny climate. For all coses, the passive system equals 360 ft² (33.4 m²) (based on Figure R-29). For direct gain, cost is based on adding 120 ft² (11.1 m²) of glazing at $19.50/ft² ($209/m²) (for good-quality operable windows with low-E coating) to the house. It assumes all existing glazing faces south and the house has adequate storage mass. The cost for the sunspace assumes a cost premium for a sunspace of 30% over standard construction at $65.00/ft² ($699 m²). The cost for the thermal storage wall is based on an added cost of 120 ft² (11.1 m²) of fixed glazing ($1200/ft²) ($12,917/m²) plus 360 ft² (33.4 m²) of masonry at $9.90/ft² ($106.5/m²).
2. The performance is based on a home in Denver, CO. The home is assumed to hove the following level of energy conservation: R-21 walls, R-33 ceiling, R-15 foundotion perimeter, double glazing with night insulotion on the north, east, and west orientotions, and 0.27 air changes per hour. The annual energy savings for each system (in Btu/yr/ft²) of system area is given in Figures R-30, R-31, and R-32. These figures were taken from the article cited.

3. Paybacks in brackets are given for a northern and southern climate in the western regions. The paybacks for direct gain in both climates are omitted because, based on Figure R-30, the systems require a reduction in south-facing windows. The payback for the sunspace in Denver is better than that in either the northern or southern climate.
4. The passive design should last as long as the building. Glazing materials and moveable insulation may have shorter lives (see briefs on these topics in the residential and commercial guides for further details).
5. Confidence is rated medium. The savings varies by location and occupant habits. The cost of the system varies, as well.

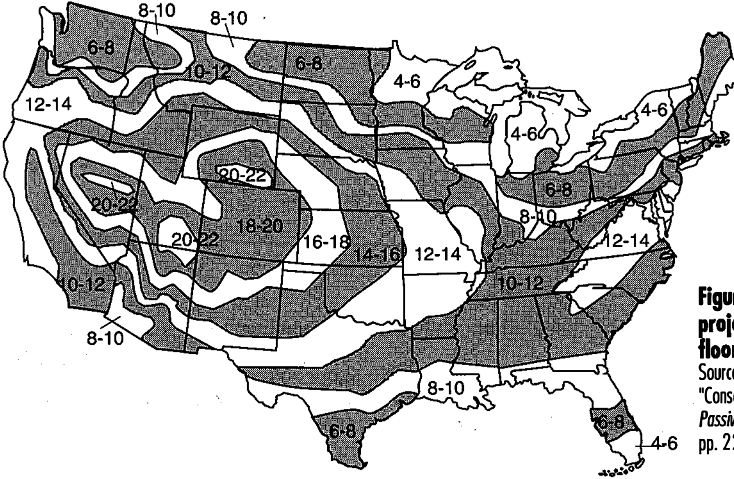


Figure R-29. Ratio of solar projected area to building floor area (%)
Source: Balcomb, J.D. (1986), "Conservation and Solar Guidelines" *Passive Solar Journal*, 3 (3), pp. 221-228

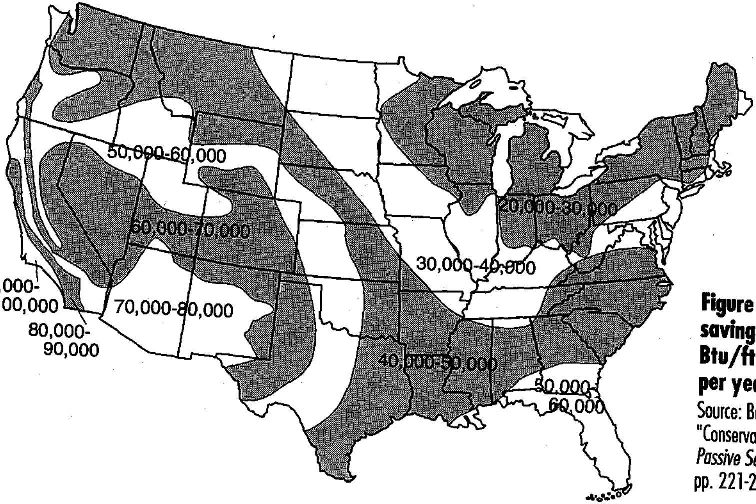


Figure 30. Annual solar savings for direct-gain Btu/ft^2 of projected area per year.

Source: Balcomb, J.D. (1986), "Conservation and Solar Guidelines" *Passive Solar Journal*, 3 (3), pp. 221-228

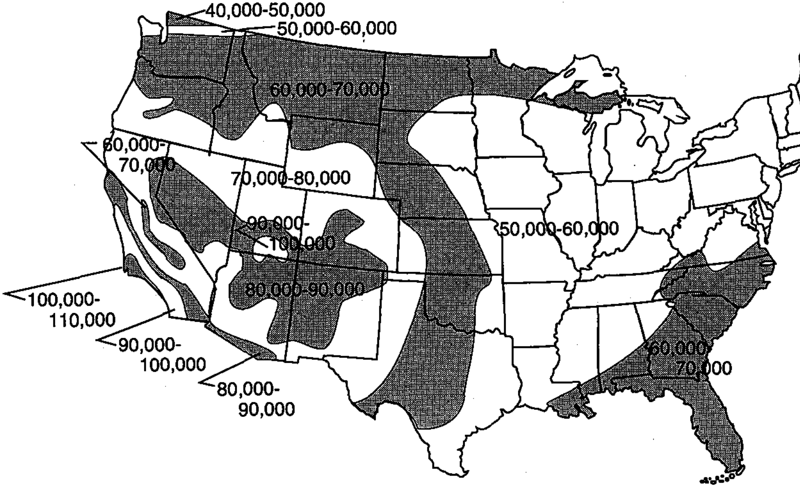


Figure 31. Annual solar savings for semienclosed sunspace system with 50° sloped glazing, Btu/ft^2 of projected area per year.
Source: Bolcomb, J.D. (1986), "Conservation and Solar Guidelines" *Passive Solar Jaumal*, 3 (3), pp. 221-228

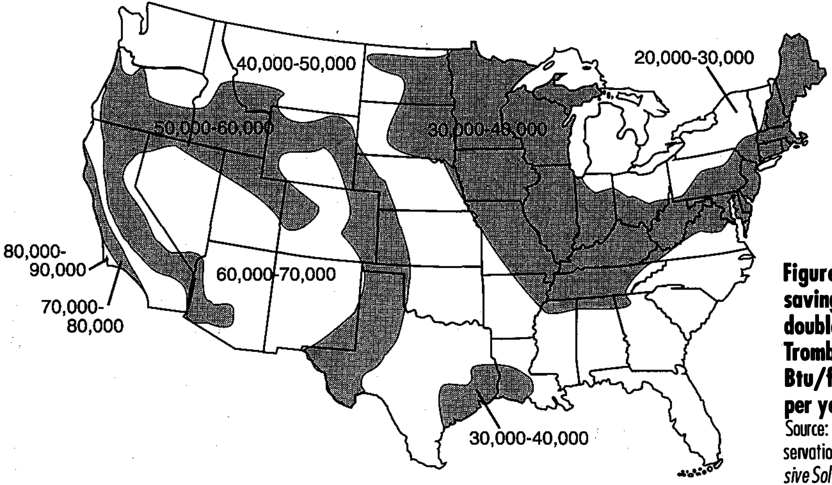


Figure 32. Annual solar savings for unvented, double-glazed, flat-black Trombe wall system, Btu/ft^2 of projected area per year.

Source: Bolcomb, J.D. (1986), "Conservation and Solar Guidelines" *Passive Solor Joumol*, 3 (3), pp. 221-228

INTEGRATED CONSERVATION AND RENEWABLE DESIGN FOR NEW COMMERCIAL BUILDINGS

TECHNOLOGY DESCRIPTION

In new commercial construction, an optimal mix of energy conservation and renewable features con be incorporated during the design phase. The most recommended renewable features in commercial new design include proper design of apertures for daylighting; high performance glazing and proper orientation and shading to either capture or reject heat; and natural ventilation, evaporative cooling, or cool storage. These measures are described individually in detail in the *DSM Pocket Guidebook, Volume 2: Commercial Technologies* (see briefs #1, 2, 28, 31). These renewable features are coupled with efficient lighting; heating; ventilating; and air conditioning; and automated controls for lighting and mechanical systems to reduce energy and demand. These measures are also addressed individually in Volume 2 (see briefs #3–15). If these features are not incorporated in the design phase of a commercial building, then the possible energy savings are lost to the utility.

Utilities are targeting a greater percentage of their demand-side management budgets specifically for the new construction markets. One survey identifies 35 utilities that are currently operating commercial new construction programs in 1991. The programs recognize the complexity of the new construction process and generally offer technical assistance to building design teams and provide computerized energy simulations to show architects and engineers how new construction designs can benefit from integrated design strategies. Changes to specific design features ore analyzed for their overall impact on the energy use of the building.

The costs and benefits presented in this brief represent the cost of adding properly designed apertures for daylighting, high-performance glozing, proper orientation and shading, natural ventilation, and evaporative cooling or cool storage in the design phose of commercial buildings.

Cost ond benefits for incorporating conservation ond renewable features in commercial buildings ore found in Toble R-26.

APPLICABILITY

FACILITY TYPE All. Certain building types such os education ond owner-occupied offices moy be eosier to address thon buildings built to leose or rent.

CLIMATE All climates.

DEMAND-SIDE MANAGEMENT STRATEGY Strategic conservation, peok clipping, volley filling.

FOR MORE INFORMATION

Proceedings of the New Construction Programs for Demand-side Management Conference, May 1992, Sacramento, CA, ADM Associates.

Table R-26. Integrated Commercial Design: Costs and Benefits

Options	Added Cost ($/sf)	Energy Savings (kWh/sf/yr)	Cost Savings[1] ($/sf/yr)	Simple Payback (yr)	Life (yr)	Confidence[2]
Low-rise office	1.95	5.95	$0.41	4.75	30	M
Retail	1.38	3.9	$0.273	5.07	30	M

Note: Holtz, M. et al. "Technology Assessment in Support of Pilot New commercial Building Demand-side Management Program" and Hasson, E. "Design Assistance Non-residential New Construction." Both papers are found in Proceedings: New Construction Programs for Demand-side Management Conference (May, 1992) ADM Associates, Inc. The performance data was based on simulation studies for existing buildings; the cost analysis was prepared for the specific buildings simulated by the contractors who built the buildings.

1. The cost savings is based on $0.07/kWh. The cost calculation and simple payback differ slightly from the numbers presented in the paper because, in the paper, actual utility rates are used and the cost is adjusted slightly to account for the small increase in heating energy required in these buildings. For the low-rise building, the cost represents the added cost for parabolic lighting fixtures, daylighting controls, variable speed drive, and high-performance glazing. For the retail building the measures were the same except indirect-direct evaporative cooling was used instead of a variable speed drive.
2. M stands for medium.

(update to RESIDENTIAL BRIEF 9) GROUND-SOURCE HEAT PUMPS

TECHNOLOGY DESCRIPTION

Like an air conditioner or refrigerator, a heat pump moves heat from one location to another. A ground-source heat pump (GHP) operating in the cooling mode reduces indoor temperatures in the summer by transferring heat to the ground. Unlike an air conditioning unit, however, a heat pump's cycle is reversible. In winter, a GHP can extract heat from the ground and transfer it inside. The energy value of the heat thus moved can be more than three times the cost of the electricity required to perform the transfer process.

This brief supplements residential Brief 9 on heat pumps. A GHP is one type of heat pump. It uses the earth or groundwater for heating during the winter, cooling during the summer, and supplying hot water year round. In most climates, the ground is warmer than the air temperature during the winter and cooler than the air temperature in the summer. GHPs are efficient and, in some climates, can be used with no backup year round because the heat source remains at a relatively moderate temperature all year.

The GHP system includes a ground loop, the heat pump itself, and a heating and cooling distribution system. The heat pump is inside the home. GHPs consist of two major types. One type, the earth-coupled GHP, uses sealed horizontal or vertical pipes as heat exchangers through which liquid is circulated to transfer heat. The second type, the water-source GHP, pumps water from a well, pond, or stream. Because of their simplicity, earth-coupled systems have come to dominate the GHP market. Typical loop installations for the earth-coupled systems are expected to work for 50 years.

More than 100,000 GHPs have been installed in U.S. homes to date. Currently, a few major utilities, hundreds of rural electric cooperatives, and a few states provide incentives valued up to $3000 per installation.

As a result, GHPs are gaining widespread popularity, which is causing the industry to expand 10% to 20% per year.

DEFINITIONS AND TERMS

ENERGY-EFFICIENCY RATIO (EER) Used to compare the performance of cooling equipment—including air conditioners and heat pumps—in the cooling season. EER is calculated by dividing cooling capacity (in Btu/hr) by the power input (in watts) under a given set of rating conditions.

COEFFICIENT OF PERFORMANCE (COP) Used primarily to compare the performance of heat pumps in the heating cycle. For this use, it is determined by dividing the total heating capacity provided (Btu)—including the circulating fans but not including supplemental heat—by the total electrical input in watt hours times 3.413. The higher the COP, the more efficient the heat pump.

SEASONAL ENERGY-EFFICIENCY RATIO (SEER) The ratio of the total seasonal cooling requirement (measured in Btu) to the total seasonal Wh of energy used, expressed in terms of Btu/Wh. (The SEER rating equals 3.413 times the seasonal COP.)

APPLICABILITY

CLIMATE All, including very cold.

FACILITY TYPE Primary markets for GHPs include new homes, apartments and commercial buildings, plus the 25 to 30 million existing homes with no access to natural gas.

In addition to building heating and water heating, GHPs can be used for

- Industrial applications, especially drying and dehydration of fruits and vegetables
- Swimming pools and spas
- Growing commercial crops in a greenhouse
- Aquaculture
- Space and district heating.

DEMAND-SIDE MANAGEMENT STRATEGY Strategic conservation, strategic load growth, peak clipping.

FOR MORE INFORMATION

Notional Rural Electric Cooperative Association, 3333 Quebec St., Suite 8100, Denver, CO 80207, (303) 388-0935.

Earth Energy Association, 777 North Capital Street., Suite 805, Washington, D.C. 20002-4226, (202) 289-0868.

Geo-Heat Center, Oregon Institute of Technology, 3201 Campus Drive, Klamath Falls, OR 97601, (503) 855-1750.

International Ground-source Heat Pump Association, 482 Cordell So., Stillwater, OK 74078, (405) 744-5175.

Earth Science Laboratory-University of Utah Research Institute, 391 Chipeta Way, Suite C, Salt Lake City, UT 84108, (801) 524-3422.

Table R-27. Heat Pumps: Costs and Benefits

Options	Costs ($)[1]	Energy Use[2] (kWh/yr)	Energy Savings ($/kWh/yr)	Cost Savings ($/yr)	Simple Payback[3] (yr)	Life (yr)	Confidence[4]
Cold Climate[2] (6000 HDD, 1000 CDD)							
Electric furnace air conditioning	3020	13,240	—	—	—	15	M
Air-source heat pump	4130	10,005	3190	255	4.4	15	M
Ground-source heat pump	5400	6,600	6579	526	4.5	19	M
Warm Climate (2500 HDD, 2500 CDD)							
Electric furnace air conditioning	3020	15,432	—	—	—	15	M
Air-source heat pump	3920	11,548	3884	311	2.9	15	M
Ground-source heat pump	5620	10,015	5417	433	6.0	19	M

1. Costs indude equipment for heating and air conditioning, installotion, accessories, and ductwork in new construction.
2. Energy use in kWh was calculated as follows:
   Heating furnace $E = 24 \times DHL/(t_1 - t_0) \times (HDD/3413)\ C_d$
   Heot pump $E = 24 \times DHL/(t^1 - t_0) \times [HDD/(3413 \times HPF)]\ C_d$
   The seasonal energy-efficiency ratio of the air conditioner in the base case ond the heot-pump cases remains the some. (DHL refers to the design heat loss, HDD refers to heating degree-doys, CDD refers to cooling degree doys, HPF refers to heating performance factors.)

Assumptions Used to Calculate Table R-27

The Assumed Parameters for the Different Cases	Climate 2500 HDD	Climate 6000 HDD	Climate 8000 HDD
HPF air source	2.05	1.5	1.3
HPF ground source	3.5	3.2	2.9
Design heat loss (DHL)[3]	26,400	26,400	26,400
C_d	0.73	0.61	0.61
Inside design temperature (°F) (t^1)	68°F (20°C)	68°F (20°C)	68°F (20°C)
Winter design temperature (°F) (t_0)	22°F (-5.5°C)	-3°F (-19.4°C)	-3°F (-19.4°C)

3. These were based on computer simulations for 1500-ft² (139-m²) residences in each climate. The R-value for ceilings, walls, and floors were assumed to be the minimum recommended levels for the climate zone (see Table R-4 in the introduction to *DSM Pocket Guidebook Volume 1: Residential Technologies*). The cold and warm climates represent the extremes of all the climatic zones in the western regions where both heating and cooling are used. In an 8000-HDD climate, using the assumptions for a 6000-HDD climate except a heating performance factor of 1.3, the simple payback would be 4.7 years.
4. M stands for medium.

(Update to RESIDENTIAL BRIEF 16) PHOTOVOLTAICS FOR BUILDING APPLICATIONS

TECHNOLOGY DESCRIPTION

Photovoltaic (PV) devices were described in Brief 10 in this guide for bulk power generation and dispersed applications (such as at the substation or service level transformer). Brief 16 in the residential guide discusses the advantages of PV for remote applications. This brief describes the status of grid-connected PV in residential and commercial buildings as a demand-side management (DSM) strategy. This is a relatively new area of potential interest for utilities. The utility studies to date focus on determining the energy and demand impact of PV for various end uses. Most of the possible DSM applications for PV are not cost effective today. These measures are being studied today for future applications based on the expected drop in PV costs between now and the year 2010. Research is also ongoing to better integrate PV into the building structure. The ultimate goal is PV panels that double as building components (e.g., roof shingles, wall panels, or windows).

At mid-day when a PV device is generating at maximum power, utility loads are often at their peak levels. This basic compatibility between the time of maximum output from a PV device and the utility needs for reducing peak demands leads to opportunities for grid-connected PV applications on buildings as a DSM strategy.

For residential and commercial applications, PVs can be used to fully power specific electrical end uses such as swimming pool pumps and solar water heater pumps, or partially power electrical end-uses, including residential and commercial air-conditioning systems and PV-powered lighting systems. PV systems designed to meet these needs are among the simplest, most cost effective currently available for grid-connected end-use applications.

In New England, a large experiment that has been ongoing for 4 years studies the impact of PV on 30 residences and eight commercial sites.

In this experiment, PV provides partial power to the buildings for all end-uses. The primary purpose of the experiment is to examine the interaction of a high concentration of independent PV systems with a single distribution feeder and study the performance, and reliability of the PV systems. Performance data from this experiment is presented in Table R-28.

In California, a municipal utility is installing 4 kW PV systems on 100 residences. The systems are grid-connected. The homeowners will be charged a 15% premium over the standard rate for the energy they use from the PV system. In a very short period of time, the utility was able to identify more than enough homeowners willing to participate in the program. As another example, for remote residences, vacation homes, stock watering wells, sign lighting and communications sites, an Idaho utility has recently launched a three-year pilot program that would enable some of its customers to receive power from a PV electricity generating system rather than the company's electrical grid. The customer pays a monthly facilities charge rather than being billed for energy used.

■ APPLICABILITY

FACILITY TYPE Residential and commercial.

CLIMATE All.

DEMAND-SIDE MANAGEMENT STRATEGY Peak clipping and strategic conservation.

■ FOR MORE INFORMATION

Bzura, J.J., *The New England Electric Photovoltaic Systems Research and Demonstration Project*, New England Power Service Co., Westborough, MA, 1989.

National Renewable Energy Laboratory, 1617 Cole Boulevard, Golden, CO 80401, Photovoltaics Division, William Wallace or Roger Taylor, (303) 231-1395.

Photovoltaics Systems Design Assistance Center, Sandia National Laboratories, Albuquerque, NM 87185, (505) 844-3698.

Solar Energy Industries Association, *Solar Electricity: a Directory of the U.S. Photovoltaic Industry*, Washington, D.C., 1992.

Table R-28. Photovoltaics for End Use Buildings Applications

Option	Capital Cost[1] ($/kW)	Energy Savings ($/kWh/yr)	Demand Savings (kW)	Cost Savings ($/yr)	Simple Payback (yr)	Life (yr)	Confidence[5]
Swimming pool pumping (No storage power)	4420[2]	2200[3]	0.7[3]	$176	25	15–20	M
2.2 kW residential system	Not reported	2195[4]	1.2 avg[4] during peak demand	N/A	N/A	15–20	M

1. The cost of PV is expected to drop significantly over time (See Brief 10).
2. This represents the average cost for 15 photovoltaic-powered swimming pool pumps studied as part of a Florida Power Corporation Pilot Program. The pumps are assumed to be approximately 3/4 HP (559 W) in size and grid connected.
3. Sim, S., "Residential Solar DSM Programs at Florida Power and Light," *Solar Today*, Oct/Nov 1991.
4. Bzuro, J.J., "The New England Electric Photovoltaic Systems Research and Demonstration Project," New England Power Service Company, Westborough, MA, 1989.
5. M stands for medium.