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Solar Energy Research and Development: Program Balance

Annex, Volume II

February 1978

Prepared for

**U. S. DEPARTMENT OF ENERGY
SOLAR WORKING GROUP**

Under Contract No. EA-77-C-01-2693

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I INTRODUCTION

Volume II is designed both to be a companion piece that provides detailed backup and support for the first volume and also to be a report that can stand alone. This volume treats each of the seven solar energy technologies that have been assessed in the study--photovoltaic devices, solar thermal power systems, wind energy systems, solar heating and cooling systems, agricultural and industrial heat processes, biomass conversion technologies, and ocean thermal energy conversion systems in Sections II through VIII respectively.

Section IX contains a brief technical overview of storage for solar electric technologies and discusses some principles concerning how different levels of success on electrical storage can affect the commercial viability of solar electric options. Although the discussion in Section IX is of a preliminary nature, it points the way toward a critical area of analysis that is needed to increase our understanding of the potential contribution of solar energy systems: their interaction with existing components of the energy system and the complex role of storage in smoothing the inherently fluctuating solar energy resources.

Section X provides a description of the solar penetration model that was developed and applied as an analytical tool in the study. This computer model has served the primary purpose of evaluating the competitiveness of the solar energy systems in the markets in which they are expected to compete relative to that of the alternative energy sources. This is done under a variety of energy supply, demand, and price conditions.

The seven sections treating the solar energy technologies contain discussions on each of six subject areas: description of the technology; economic projections; the potential contribution of the technology in different marketplaces; environmental considerations; international potential; and the present and possible future emphases within the RD&D program. In some instances, no additional attention was devoted to subject areas beyond that presented in Volume I, the summary and analysis portion of the report. In these cases, the discussion is repeated in Volume II for the sake of completeness.

The priority item for each of the technology sections has been the documentation of the economic projections. In addition, there were areas within many sections that were judged worthy of special attention. Thus, the section on solar heating and cooling includes a discussion of factors that are likely to affect the commercial potential of solar heating systems in the near term. The section on biomass contains an extensive review of the existing RD&D program and suggests possible new areas of RD&D within the program. The section on thermal power contains a discussion of how attention within the RD&D program can usefully be

placed on thermodynamic matching of collectors and heat engines to improve the integration of different parts of the solar thermal power system.

This volume of the report is thus meant to provide an overview of the solar energy technologies that includes both technical detail and a consideration of other factors affecting the commercial viability of the technologies. It also contains information on selected topics likely to be of special interest. Finally, this volume provides documentation for analysis that is contained in Volume I.

II PHOTOVOLTAICS

Introduction

Photovoltaic devices convert light (photons) directly to electricity. When sunlight falls on a semiconductor, some of the photons in the light-beam create pairs of electrons and holes in the semiconductor. If these opposite charges are produced in the vicinity of an electric field (such as that produced at a p-n junction, or a metal-semiconductor barrier) they will move in opposite directions, producing a net electric current. The process is totally electronic, with no moving parts. It works at ambient temperatures and pressures and produces no by-product except heat from the sunlight that is not converted to electricity. Consequently, photovoltaic cells are quiet, easy to operate, and extremely reliable.

The photovoltaic effect, first observed by Becquerel¹ in 1839, can occur in gases, liquids, and solids; but acceptable levels of efficiency have been observed only in solids. The first photovoltaic cell to convert solar energy into electrical energy with an efficiency greater than 1 percent, discovered in 1953, consisted of a silicon p-n junction.² Since that time, silicon solar cells have been extensively studied and developed as energy sources for the space program. More than 500 satellites currently in orbit around the earth depend on silicon solar cells as their main energy source. As an example, Skylab uses a 20-kW photovoltaic system with silicon solar cells which have efficiencies between 10 and 15 percent.

With the growing concern for the world's energy problems, increased effort has been put into developing solar cells for terrestrial energy sources. This approach seems feasible when one considers, for example, that the yearly average of solar energy incident on the face of the United States is more than 500 times the current annual U.S. energy use,³ and more than 5,000 times the annual use of household electricity.⁴ Five hundred square feet per person of 10 percent solar cells could have delivered the 2×10^{12} kWh (7×10^{15} Btu) electricity consumed in the United States in 1975. Cost is the main hindrance to the use of photovoltaic cells as terrestrial power sources.

One can currently purchase a complete solar panel that will produce 19 volts DC at 1.3 amps with peak noontime sunshine (1 kW/m^2) for a cost of \$420.⁵ This amounts to approximately \$17,000 per kW-pk for this 12 percent silicon array. If the panel were to be used continuously for 20 years with no further costs entailed, the electricity produced would cost nearly 50 cents per kWh, compared with 3-1/2 cents per kWh, which is the current utility rate for domestic electricity. However, even at this high rate,

many economically viable terrestrial applications exist for photovoltaic arrays, mostly for use at remote locations, such as battery chargers for mountain top weather stations, radio repeater stations, forest lookout towers, warning lights for offshore structures and channel buoys, and cathodic corrosion inhibitors for pipelines.

The following is a review and evaluation of the various research and development activities that have been directed toward reducing the cost of photovoltaic power sources. Most of this work has been funded and directed through the Division of Solar Energy of ERDA (now DOE).

The information used in this report has come from the general technical literature and from discussions and interviews with individuals from industry, universities, and governmental agencies. Specific references are made throughout. We have found References 6 through 12 to be extremely useful, especially the OTA Report,¹² which summarizes many of the earlier results.

Technology Description

Materials

Silicon has been the basic constituent in solar cells for the past 20 years; however, it will not necessarily remain the most cost-effective photovoltaic material for future cells. Currently, silicon cells are made with single crystal material by a multistep, energy-intensive process that is both wasteful and time consuming. One approach to reducing cell costs is to streamline the silicon cell processing procedures, reducing the number of steps and making each step more efficient. Another approach is to develop cells with different materials which are either inherently more efficient energy converters or require less expensive, simpler processing methods. DOE is simultaneously pursuing each of these approaches.

P-n junction solar cells can be made with the junction occurring between two portions of the same material, one of which has been doped n-type, the other p-type, or the junction can be between two different species of semiconductors. Materials considered to be good candidates for junction cells include¹³ Si, GaAs, InP, CdS, ZnS, CdSe, CdTe, Cu₂S, AlGaAs, ZnCdS, and CuInSe₂. The number of possible junction types is limited only by the imagination. To date, four types of junction solar cells have been made with efficiencies greater than 10 percent: Si, AlGaAs/GaAs, InP/CdS, and CuInSe₂/CdS.

When the sunlight creates electron-hole pairs in the semiconductor, they must be separated by an electric field to produce an electric current. The field produced by a p-n junction can also be produced at a junction between other dissimilar materials. A metal-semiconductor junction, known as a Schottky barrier, also has a built-in electric

field at the junction, as does the triple junction between a metal, oxide, and semiconductor (MOS structure). Becquerel's original observation of the photovoltaic effect¹ was the result of a junction between a semiconductor and an electrolyte solution. Solar cell research is not limited to p-n junctions in semiconductors. For example, a Schottky barrier device using silicon as the semiconductor has been produced with an efficiency of 12 percent.¹⁴

Efficiency

The search for a cost-effective solar cell will ultimately be a contest between efficiency and material cost. If a 30 percent efficient cell is ten times more expensive to make than a 10 percent cell, it clearly will lose. Soon after the discovery of the silicon cell, theoretical physicists were able to show which p-n junctions would produce the most efficient cells.¹⁵ The efficiency was found to be a function of the electric potential barrier between the two materials at the junction, which is simply related to the gap between the energy of the electrons on one side of the barrier and the holes on the other side. Figure II-1 shows the theoretical maximum efficiency that can be achieved as a function of this energy gap. These theoretical results have played an important role in solar cell research. For one thing, Ge with an energy gap near 0.7 eV was shown to be inherently inefficient. The theory directed researchers to seriously consider GaAs and InP as solar cell materials. Today GaAs cells are being produced with efficiencies near 22 percent.* The best silicon cells are currently 18-20 percent efficient.

Production and Costs

While GaAs solar cells are the most efficient, they are also the most expensive, and this fact precludes their replacing conventional Si cells in flat plate panels. The cost of the materials used in the cells is an important basic consideration. Semiconductor-grade silicon costs \$65 to \$70/kg compared with \$800/kg for gallium. (This is the cost for the pure material before the processing necessary to convert it into a solar cell.) Cadmium is \$7/kg, and sulfur is many times less expensive than that, leading to the low-cost appeal of CdS devices. These materials prices can be compared with those of copper, \$1.50/kg; In, \$225/kg; and Se, \$30/kg.

*The efficiency of a cell depends on its temperature and the spectrum of incident radiation. The efficiencies quoted correspond to a device at 25°C in sunlight which has traveled through one thickness of the earth's atmosphere, often called air mass one (AM1).

FIGURE II-1. THEORETICAL EFFICIENCY OF A p-n JUNCTION SOLAR CELL AS A FUNCTION OF THE ENERGY GAP

The cost of semiconductor-grade silicon is not related to its abundance (there is certainly more than enough sand, SiO_2), but it is a result of the complicated purification processes that are necessary to produce material with less than one part per billion impurity. At this point, solar cell producers do not really know how good the starting material must be to produce efficient cells, and this leaves an important area for cost reduction which is currently being closely examined. It is now felt that the stringent requirements of the electronic industry can be relaxed for the production of silicon solar cells. ERDA projects a reduction of the price for "solar grade" silicon to less than \$10/kg in the near future.

Table II-1 is a partial breakdown of present and projected costs for silicon solar arrays as seen by ERDA's Low-Cost Silicon Solar Array Project which is managed by NASA's Jet Propulsion Laboratory. It is quite clear that the goal of 50¢/W-pk can never be met if the starting material costs \$2/W-pk. The \$2/W-pk is due to two factors, the \$10/kg materials cost and the large amount of processing waste. Currently, nearly 80 percent of the silicon that goes into cell manufacturing is lost, mostly as "saw dust" in the slicing process.

The current method of crystal growth entails a process in which 3-inch diameter solid rods of silicon are pulled from a 1400°F melt at a rate of 4 to 6 inches per minute. New methods are being pursued that require less time and energy. Efforts are being made to grow silicon ribbons, sheets, webs, and films which obviate crystal slicing and other fabrication processes. Automated assembly that could also greatly reduce costs is actively being studied. Laser annealing with a single 30 nanosecond ($3 \times 10^{-8}\text{s}$) pulse and ion-implantation were among the developments reported at the 1977 Photovoltaic Solar Energy Conference in Luxembourg. In 1977 more than \$25 million was spent in these activities on the JPL low-cost silicon project.

Another promising approach to inexpensive processing is the chemical spray technique. For example, thiourea and cadmium acetate when sprayed on glass or a metal at 300°C will produce a film of CdS. A related spray process is the method for making Electrofax photocopy paper where 1/4 μm ZnO particles are sprayed with a binder to a thickness of 10 μm onto a paper substrate. The cost of Electrofax paper is less than 1¢/ft². To date, CdS solar cells made by film processing techniques have shown efficiencies up to 5 percent; however, they continue to improve.

Polycrystalline silicon cells are now being produced in the laboratory. Ten percent efficiencies for cells a few square centimeters in area are regularly achieved. Amorphous silicon cells, a film version distinct from the crystalline or polycrystalline form, are being pursued in several laboratories in Great Britain, two in France, and one in Italy. Cells made from amorphous silicon can be produced with over 5 percent efficiency; however, the areas are yet small, of the order of 1 mm².

Table II-1

ERDA COST GOALS FOR ONE PEAK WATT OF ENERGY
FROM SILICON SOLAR ARRAYS

(1975 Dollars)

	<u>Ingot Technology</u>				<u>Non Ingot Technology</u>	
	<u>Representative Data For 1976</u>	<u>1978</u>	<u>1980</u>	<u>1982</u>	<u>1984</u>	<u>1986</u>
High grade polysilicon	\$ 2.01	\$1.16	\$0.76	\$0.28	\$0.13	\$0.06
Crystal growth and cutting	4.18	2.50	1.43	0.67	0.23	0.10
Cell fabrication	5.97	1.87	1.01	0.58	0.34	0.19
Encapsulation materials	0.78	0.22	0.12	0.09	0.07	0.03
Module assembly and encapsulation	3.99	1.25	0.68	0.38	0.22	0.13
Price	\$16.93					
Goal	20.00	7.00	4.00	2.00	1.00	0.83

Source: Jet Propulsion Laboratory: Low Cost Silicon Solar Array Project

Concentrations

Another approach to reduce the cost of photovoltaic converters is to concentrate the sunlight by focusing it with mirrors or lenses. Concentrating by 10 times reduces the amount of active photovoltaic material required by a factor of ten which can amount to significant savings. However, when high concentration is used, the focusing of the optical system becomes critical and the motion of the sun must be tracked to keep the focused sunlight on the active cell area. The sophistication and accuracy of the tracking optical system increase with concentration and so does the price. High concentration also increases the amount of waste heat at the solar cell, and the cell must be cooled, since it loses efficiency with rising temperature. For low concentrations, less than 10 times, systems have been designed that do not need tracking and, therefore, are less expensive for the optical components and structures.

A 5 times concentrator, for example, might use an acrylic Fresnel lens or parabolic reflector, with the solar cell located off the focal point in a position that always gets some concentrated light.

Concentration systems are extensively discussed in the OTA Report;¹² the economic optimization of concentrator systems is discussed under the economics section of this chapter.

Breakthrough Technology

To this point, emphasis has been on the trends and activities in terrestrial solar cell production that have been established over the last ten years. The field is in its infancy and ripe for significant breakthrough technology.

Much of this breakthrough could come by increasing the conversion efficiency. If ERDA's 1985 goal of \$500/kW-pk (50 cents per peak watt) were to be achieved with a 10 percent cell, that would correspond to an areal cost of \$50/m². Since simple window glass costs \$5/m² (in large quantities), it is difficult to see how a sophisticated multilayer electronic device could cost much less than \$50/m². If the efficiency of photovoltaic devices could be increased to 50 or 60 percent, 10 cents per peak watt would even be a reasonable goal.

The theoretical maximum efficiency for a single p-n junction is near 25 percent. Several research teams¹⁶ have investigated cells made with several p-n junctions stacked on one another so that the light that is not absorbed at one junction can produce electricity at the next. Devices of this type undoubtedly will have higher efficiencies.

Another approach is that taken by Dr. Richard Swanson at Stanford University.¹⁷ This entails concentrating sunlight to heat a plate to 2000K and then collecting the radiation from this glowing hot plate at a p-n junction. This is called the thermophotovoltaic method, and researchers claim a possible efficiency near 50 percent.

Not just two new directions are possible. Experience from the field of electronics and electronic materials tells us that there can be many more.

Solar Supply and Storage

Since the demand for electricity continues when the sun is not shining, a solar electrical system must either have storage or depend on an alternative electrical source or use both. The complicated interplay between photovoltaic source, storage, and alternative source and the optimization of such systems is the subject of this discussion. Since the problem is economically and politically complicated as well as being site specific, we can only hope to clarify the variables. Optimum solutions will take time.

Both the supply of solar energy and the demand for electricity are regional, temporal, and system dependent. From Figure II-2, one sees that the average daily U.S. insolation varies by more than 60 percent from Massachusetts to Arizona. Some of the subtleties of the regional and seasonal dependencies can be seen in Figures II-3 and II-4, which show the residential demand for Southern California and Central Arizona, respectively. The demands in these two regions behave in a similar manner over the course of a day. Notice the strong evening and morning peaking for Southern California. The sun, which rises some time between 5 and 7 a.m. and sets 10 to 15 hours later, is certainly not in phase with the demand. On the other hand, Figure II-5, which shows the demand for a department store, is much more in phase with the solar supply. These few examples of the relationship between solar supply and electrical demand clearly indicate the geographic variability of the need for either storage or alternative electrical sources for most users. Figure II-6 schematically shows how the utility and the solar electrical source might be interfaced in, for example, a residential system. The utility can either supply energy directly to the demand or it can charge the storage system. The variability of the cost of electricity is an important factor. Usually electricity can be purchased from the utility at a cheaper rate during off-peak-demand periods. (In some cases this could be desirable even without a photovoltaic array.)

A homeowner may wish to charge his batteries at night during periods of low insolation. There is also the possibility that the homeowner could sell his excess solar electricity to the utility.

The size of the photovoltaic array and the amount of the storage will determine the percentage of solar energy displacement relative to the total demand. This displacement will also depend on the insolation and demand curves. A concrete example of such a displacement calculation is that presented in the Aerospace report prepared for NSF. Using the weather bureau records for the insolation of Phoenix and demand curves similar to those of Figures II-3 and II-4, the authors calculated the displacement as a function of array and storage size. The results are shown in Figure II-7. The average electrical demand for the residence in their model was 3.47 kW with peak demand of 8.19 kW. Figure II-7 shows that for a given array size there is a maximum array area for the amount of effective storage; however, it does not tell us the size of the most cost-effective system. The Aerospace Corporation report determined that the most cost-effective system was one with 8.1 hours (28.5 kWh) of storage with an array size of 113 m². This system resulted in a 60.7 percent solar displacement, requiring a utility backup capacity of 2.1 kW.

The energy displacement presented for any particular residence will vary with geographical region. Figure II-8 shows the displacement as a function of storage for Cleveland, Phoenix, and Miami for an 84 m² array. This figure is the result of a computer simulation General Electric performed for ERDA.⁸

SOLAR HEAT, Btu/ft²/AVERAGE DAY

Source: I.F. Hand, HEATING AND VENTILATING (1953)

FIGURE II-2. DISTRIBUTION OF AVERAGE DAILY INSOLATION IN THE UNITED STATES

FIGURE II-3. SOUTHERN CALIFORNIA RESIDENTIAL DEMAND PROFILES

FIGURE II-4. CENTRAL ARIZONA RESIDENTIAL DEMAND PROFILES

FIGURE II-5. DAILY DEMAND PROFILE OF A SOUTHERN CALIFORNIA DEPARTMENT

Figure II-9, also from the General Electric Report,⁸ shows very clearly the photovoltaic contribution to the residential demand for an all-electric house in the three locations. The same size system, 84 m² of array and 48 kWh of storage, was considered for all three locations.

Development Schedule

Photovoltaic solar energy converters for terrestrial use are currently commercially available. In 1976 over 350 kW-pk of silicon cells were sold, and the projected 1977 sales will be over 750 kW-pk.¹⁸ As already mentioned, most of this use is for remote locations. Forest lookout towers and cathodic corrosion inhibitors for pipelines are two examples.

Currently ten manufacturers are producing silicon solar cells in the United States and two pilot plants for the production of cadmium sulfide cells are being set up. The Motorola Corporation has invested over \$3 million in its silicon cell assembly line.

FIGURE II-6. SCHEMATIC OF PHOTOVOLTAIC/UTILITY INTERFACE

Source: Aerospace Corporation, Ref. (7)

LOCATION: PHOENIX, ARIZONA
DEMAND: ARIZONA RESIDENTIAL,
3.5 kW_{AV}

COLLECTOR: FLAT PLATE, TILT
ARRAY EFFICIENCY (20 C): 0.1125

⊙ = OPTIMUM POINT

LEGEND: THE INTERSECTION OF A LINE ON THE CHART INDICATING ARRAY SIZE WITH A LINE INDICATING STORAGE CAPACITY GIVES THE ENERGY DISPLACEMENT

FIGURE II-7. ENERGY DISPLACEMENT AS A FUNCTION OF STORAGE CAPACITY AND ARRAY SIZE FOR A RESIDENTIAL SITE

FIGURE II-8. SYSTEM PERFORMANCE AS A FUNCTION OF STORAGE CAPACITY FOR PHOTOVOLTAIC SYSTEMS IN THREE LOCATIONS

Source: GE Study, Ref. (8)

FIGURE II-9. MONTHLY LOAD, PHOTOVOLTAIC OUTPUT, AND UTILITY MAKEUP FOR PHOTOVOLTAIC SYSTEMS IN THREE LOCATIONS DURING ONE YEAR

A recent study by the BDM Corporation for DOD¹⁹ indicates that photovoltaic devices are currently economically competitive for a large amount of remote military uses, at least 100 MW per year. The military and other governmental sectors are now experimenting with the use of photovoltaic solar energy converters for normal daily use.

The solar photovoltaic systems that are currently being used are of the flat plate variety and use silicon cells. In the near future, concentrating systems will become more economical for installations that can afford a technician; however, in the long run when the cells become less expensive, nonconcentrating systems will probably be more economical. This is discussed under Economics.

A schedule for commercialization, along with various development stages, is presented in Figure II-10. It indicates that concentrating systems will probably become commercial in the early 1980s but will be phased out in favor of either more advanced systems or cheaper silicon cells by the end of the 1990s.

Economics

Generic System Types

The economics of three types of systems are analyzed. These are (1) small systems that might produce power from several watts to 10 kW, typical of residential needs; (2) intermediate sized systems from 10 to 500 kW, as might be used to power a school or shopping center, and (3) central power stations, which would produce 1 megawatt or larger.

Within each of these generic categories, costs per unit energy are expected to be comparable since the type of equipment and its deployment would be similar. For instance, the installation of solar cell panels for small independent (residential) systems will not entail any expense for land, and the owner could be expected to maintain the system unless he had to call in a technician, much as we currently maintain home appliances. On the other hand, a central power station would require its own dedicated land; it would have its own technical and maintenance staff and would require special high voltage and switching equipment for connecting into the transmission network.

Both the intermediate-sized power source and the central power station would be large enough to employ at least one full-time technician. If they involve tracking systems with high concentration of sunlight, they could require additional maintenance personnel. Tracking would be inappropriate for residential use.

Unit Costs

The basic unit costs for the components of photovoltaic systems are described for both the present and projected to the year 2020. All

FIGURE II-10. PHOTOVOLTAIC DEVELOPMENT SCHEDULE

costs are in constant 1975 dollars. Installation costs are described for cell arrays, optical and support structure, and power conditioning and storage. The numbers presented are summarized in Table II-2.

Table II-2

PROJECTED UNIT COSTS FOR PHOTOVOLTAIC COMPONENTS

	<u>1975</u>	<u>1985</u>	<u>2000</u>	<u>2020</u>
Cell array* (\$/kW-pk)				
Si (12%)	\$ 25,000	\$ 1,500	\$ 500	\$ 200
GaAs (20%)	> 200,000	45,000	15,000	10,000
CdS (7%)	--	1,500	500	200
Breakthrough (40%)		1,200	250	75
Support structure (\$/m ²)				
Nonconcentrated	\$ 15	\$ 15	\$ 15	\$ 15
5X concentrated nontrack	--	60	40	25
1000 X concentrated	150	120	100	80
Power conditioning (\$/kW)	200	150	70	50
Storage (\$/kWh)	80	55	30	30

*Cell conversion efficiencies are shown in parentheses.

Cell Costs

Encapsulated silicon solar cells mounted and interconnected in an array on a panel can be purchased (in quantity) for less than \$17,000/kW-pk.⁵ A typical photovoltaic panel may use 3-inch diameter silicon cells and have an array efficiency of 12 percent, i.e., 12 percent of the light that is incident on the active cell area leaves the panel as electrical energy when the panel has the correct electrical load. ERDA's price goal for this same panel in 1985 is \$500/kW-pk, smaller by

a factor of 36. Most silicon manufacturers and workers in the field believe that this goal may be too optimistic, and they currently project costs ranging between \$1,000 and \$1,500/kW-pk, with a few people estimating \$2,000/kW-pk. As Table II-2 shows, the \$1,500 value is taken for the cost estimates and the \$500/kW-pk is reserved for the year 2000. We seriously doubt that conventional single crystal silicon cells can ever produce arrays that cost less than \$1,000/kW-pk because of the amount of energy and the complexity of the processing. However, polycrystalline or amorphous silicon cells, which involve planar technology processing and lower temperatures, will most likely be the most cost-effective in the future.

Gallium arsenide cells with efficiencies of 23 percent or greater can currently be made; however, the basic materials are many times more expensive than silicon and the cells will always be more expensive as reflected by the projected prices in Table II-2. (Currently Ga sells for \$800/kg compared with \$70/kg, the price for the most expensive electronic grade of Si.) The 1985 price for GaAs cells is that suggested by Varian for a production rate approaching a million cells per year.²⁰

Cadmium sulfide shows great promise as a material for inexpensive cells since the cells can be made in thin film form using chemical spray techniques. John F. Jordan of Photon Power Inc., El Paso, Texas (a company owned jointly by Compagnie Francaise de Petroles and Libby-Owens-Ford) projects that 5 percent CdS cells sprayed on float glass at the rate of 1 million ft²/year will be available at less than \$500/kW-pk in a few years.²¹ SES Corporation of Newark, Delaware, is currently selling CdS arrays at prices competitive with Si arrays.²² The values for CdS cells shown in Table II-2 are conservative estimates taken from the many projections currently available.

A number of materials demonstrate photovoltaic effects, and those shown in Table II-2 are meant only to represent a reasonable range of costs. We won't be surprised if some other combinations of chemical elements are used for the most cost-effective photovoltaic array in the year 2000. A lower limit can be put on the array costs by considering a hypothetical p-n junction made of two of the cheapest building materials that exist, plywood and glass. (It won't produce electricity, but the materials are cheap.) Window glass on 1/2-inch plywood can be purchased in large quantities for 60¢/ft² or \$6/m². If it were 10 percent efficient as a solar cell, the cell cost would be \$60/kW-pk.

Since breakthrough technologies are a very real possibility for solar photovoltaic devices, an economic scenario is included that considers this possibility. In this breakthrough case, the cell arrays are projected to cost \$1,200/kW-pk in 1985, \$250/kW-pk in 2000, and \$75/kW-pk in 2020. The last number could correspond to a 40 percent efficient cell at a cost of \$30/m², six times the cost of glass.

Support Structures

Several types of systems are considered from simple tilted flat panel construction to tracking systems with optical systems that concentrate the sunlight by a factor of 1000. The designs and therefore the costs of such systems are still being developed. The numbers presented in Table II-2 are typical of those found in the OTA report.¹²

The support structure for a nonconcentrating panel might consist of aluminum tubing, clamps, and mounting brackets. The cost of a foundation or land is not considered. A residential system will require no foundation cost; it is considered as a separate item for the central power station.

Up to concentrations near 5 times, a photovoltaic array can operate without tracking. At 1,000 times, precision optical alignment and tracking are essential. This is reflected in the higher cost of the highly concentrating system. Considerable effort is currently being made to reduce the costs of the optical systems for concentrating systems. One approach has been to use acrylic Fresnel lenses, which can be mass produced from master impressions. Lenses several meters in diameter have been made this way.

Power Conditioning

The output from an array will be dc, and the voltage for maximum power will vary with the strength of the sunlight. The extent to which the output will have to be conditioned to interface with the load or with other systems will be strongly system dependent. The system is assumed to interface with the utility lines and the dc power from the array will be inverted to ac. In this type of system, greater than 85 percent of the conditioning cost is in the inverter. Switching, regulation and rectification make up the remainder of the cost.

Since power conditioning equipment of the type envisioned is not currently mass produced, determining costs is difficult. The numbers presented in Table II-2 result from discussion with two companies that make ac-dc converters and uninterruptible power systems.²³ They are in general agreement with values presented in a Westinghouse report prepared for EPRI²⁴ and a report prepared by Bechtel Corporation.²⁵

Storage

Extensive effort is being put into energy storage research and development; however, lead acid batteries are currently the most practical method for storing electrical energy in distributed systems. The costs for five hours of storage in Table II-2 are those presented in a recent OTA report.¹² These costs are based in part on a SCAATT study by James R. Birk.²⁶

The Economics of Concentration

This discussion focuses on finding the minimum cost for a concentrating array. The basic question will be whether high concentration systems with efficient, although expensive, materials are more cost-effective than flat panel or low concentration arrays. We want to know how much it will cost to install a concentrating solar array with a geometrical concentration factor, K , with a cell of efficiency E which costs an amount $CELL (\$/kW\text{-pk})$, along with a support structure and optical concentrating system costing $OPTIC (\$/m^2)$. The optical efficiency of the concentrator system is considered to be 85 percent. For solar radiation of intensity $1 kW/m^2$, $(0.85E)^{-1} m^2$ of collection area is required to produce 1 kW of output. Therefore, the cost for the optics and support will cost $OPTIC/(0.85E)$ dollars per kW output. The cell cost will be reduced by the optical concentration factor $0.85K$ (where allowance is made for the inefficiency of the concentrator), and will cost $CELL/(0.85K)$ dollars per kW output. Allowing an installation labor cost of 10 percent of the structure cost gives the formula in Equation (1) for the installation cost per peak DC output $INSTALL (\$-kW\text{-pk})$:

$$INSTALL = \frac{1.1 OPTIC}{0.85E} + \frac{CELL}{0.85 K} \quad (1)$$

Using this formula and the range of unit costs presented in Table II-2, a chart, Figure II-11, was constructed of the installation costs as a function of concentration for low-cost cells, \$500 and \$1,500/kW-pk, with efficiencies of 12 percent and high-cost cells, \$10,000 and \$45,000/kW-pk with efficiencies of 20 percent. The shaded areas represent a range of structure and optics costs from \$30 to \$60/m² for low concentration and from \$80 to \$150/m² for high concentration.

The results of this analysis indicate that by 2000, systems with cells that cost \$500/kW-pk and have 5X concentration at \$40/m² will produce more power per dollar than high concentrator systems. The reason for this is that the first term in equation (1)--for the support structure and the optical concentrating system--thoroughly dominates the array cost of the high concentrator, tracking systems. Unless cells considerably more efficient than 20 percent are developed for these systems, the costs of the optical and tracking components of the concentrating photovoltaic system are estimated to be significantly higher than the cost of the entire array for the 5X concentrating system in 2000. [In 1985 the costs of the two types of systems could be comparable; this is shown by applying equation (1) with the cost estimates in Table II-10.] Thus, the low-concentration systems with inexpensive (and less efficient) cells without tracking are projected to be economically more attractive over the long term than the highly concentrated, tracking systems. This important result is the key to much of the following analysis.

FIGURE II-11. PHOTOVOLTAIC ARRAY COST AS A FUNCTION OF CONCENTRATION, OPTICAL-STRUCTURE COSTS AND CELL COSTS

Analysis Results

Results of the economic analysis for the costs of a residential, intermediate-sized, and central power station are presented. In the previous discussion we found that nontracking systems are likely to be the most cost-effective; therefore the residential and intermediate-sized systems have very similar economics and no attempt is made to distinguish between these two generic cases. Instead, they are combined into one category called "distributed systems." The central power station, which has the added expenses of land, special structures, and switching gear is considered separately.

The conceptual design and analysis performed in studies by the Aerospace Corporation,⁷ General Electric Corporation,⁸ Westinghouse Electric Corporation,⁹ Spectrolab Inc.,¹⁰ and the Mitre Corporation¹¹ have been of great benefit. The detailed cost accounting found in the Mitre report, along with its comparison of the costing methods used by GE and Westinghouse, proved very useful. The fact that SRI's results are somewhat higher than those found in these reports reflects the higher cost taken for cells and structures. It also is because field distributable items, engineering home office costs and fees, and contingencies that usually amounted to an extra 50 percent in direct costs are included.

It is important to emphasize that SRI's economic analysis has been done on a conceptual basis, with little or no detailed design to support the results. A number of factors must be considered before a close tolerance can be placed on the cost of photovoltaic systems. A worksheet for a 1975 residential system using flat plate silicon cells and five hours of storage is presented at the end of this section. The solar insolation values appropriate for Phoenix, Arizona are used.

The installation costs for both distributed systems and the central power station are presented through the year 2020 in Table II-3 for the case of nominal costs. If the breakthrough costs shown in the exhibit were to occur, we would have the lower installation costs shown in Table II-4. All these systems deliver electrical energy at the bus bar. Transmission and distribution costs would have to be considered separately and added.

From the discussion of the electrical energy displacement factor and storage, it is clear that the amount of energy that is actually used from a particular photovoltaic system depends on the phasing between the solar insolation and the demand with a lag factor supplied by the storage. The displacement depends on geographical location, system design, and the individual load in a complicated way. The optimum design from the standpoint of economics must be found separately for each system. Using the projected installed costs in Tables II-3 or II-4 to find the cost of electricity assumes that all the electrical output would be used. For the distributed system, installation costs are presented for systems without storage and with nominal five-hour storage. The appropriate choice will depend on the system. The central power station has been considered as a peak day time source only and does not use storage.

Exhibit

COST ESTIMATING WORKSHEET

10kW-peak

Technology PHOTOVOLTAICS - RESIDENTIAL Si FLAT PLATEYear (1975 Dollars) 1975 Effic. 12% Area 83m²Load factor 0.21 Annual energy output 18,400 kWh = 62.8 x 10⁶ BTU.

ITEM	PURCHASED MATERIAL AND EQUIPMENT		INSTALLATION LABOR COSTS		TOTAL
	Units	\$()	MH	\$()	\$()
CELL PANEL	\$25/W	,000			000
SUPPORT STR.	\$15/m ²	1,250	4	100	1,350
PWR COND'T'G	\$200/kW	2,000			2,000
STORAGE	5 hr @ \$80/kWh				
		4,000	4	100	4,100

SUBTOTAL DIRECT COSTS

257,450

Field Distributables - 10% of Direct Costs (Support) ✓	} 128,725
Engineering Home Office Cost and Fee - 10% of Direct Costs ✓	
Contingency - Standard Items 15%	
- Specialty Items 30% ✓	

TOTAL CONSTRUCTION COSTS *

Owner Costs - 7% of Construction Costs	100.
Interest During Construction	

TOTAL PROJECT COSTS

*Construction Period - Amount

1 Year	4%
2 Years	8%
3 Years	12%
4 Years	16%

CAPITAL COST / ANN. ENERGY OUT

O&M = \$100/yr.

\$38,630/kWp ←

\$386,275

\$20.99/kWh

\$6,151 / 10⁶ BTU

5 mills/kWh

\$1.6 / 10⁶ BTU.

Table II-3

PROJECTED INSTALLED COSTS OF PHOTOVOLTAIC SYSTEMS
(1975 Dollars)

	<u>1975</u>	<u>1985</u>	<u>2000</u>	<u>2020</u>
Distributed systems, residential, or intermediate power system				
Without storage				
\$/annual kWh	\$21	\$0.85	\$0.46	\$0.25
\$/annual 10 ⁶ Btu	\$6,100	\$250	\$140	\$74
With storage (5 hours)				
\$/annual kWh	\$21	\$1.1	\$0.85	\$0.37
\$/annual 10 ⁶ Btu	\$6,100	\$310	\$170	\$110
O&M				
Mills/annual kWh	5.4	5.4	5.4	5.4
\$/annual 10 ⁶ Btu	\$1.6	\$1.6	\$1.6	\$1.6
Central power station				
\$/annual kWh	\$21	\$0.91	\$0.52	\$0.31
\$/annual 10 ⁶ Btu	\$6,100	\$270	\$150	\$91
O&M				
Mills/kWh	3	3	3	3
\$/10 ⁶ Btu	\$1	\$1	\$1	\$1

Insolation: Phoenix, Arizona

Life: 20 years

Load factor: 0.21

Table II-4

PROJECTED INSTALLED COSTS OF
PHOTOVOLTAIC SYSTEMS--BREAKTHROUGH CASE
(1975 Dollars)

	<u>1975</u>	<u>1985</u>	<u>2000</u>	<u>2020</u>
Distributed systems, residential, or intermediate power system				
Without storage				
\$/annual kWh	--	\$0.65	\$0.24	\$0.14
\$/annual 10 ⁶ Btu	--	\$192	\$71	\$40
With storage (5 hours)				
\$/annual kWh	--	\$0.88	\$0.36	\$0.26
\$/annual 10 ⁶ Btu	--	\$257	\$107	\$76
O&M				
Mills/kWh	--	5.4	5.4	5.4
\$/10 ⁶ Btu	--	\$1.6	\$1.6	\$1.6
Central power station				
\$/annual kWh	--	\$0.71	\$0.30	\$0.19
\$/annual 10 ⁶ Btu	--	\$208	\$88	\$57
O&M				
Mills/kWh	--	3	3	3
\$/10 ⁶ Btu	--	\$1	\$1	\$1

Insolation: Phoenix, Arizona

Life: 20 years

Load factor: 0.21

Since the installed costs per unit of energy must depend on the insolation, they will vary with location. The installed costs for the nine SRI solar zones are higher by the following factors:

	<u>Region</u>	<u>Factor</u>
1.	New England	x 1.61
2.	Middle Atlantic	1.61
3.	South Atlantic	1.27
4.	E. S. Central	1.37
5.	E. M. Central	1.59
6.	W. S. Central	1.20
7.	W. N. Central	1.45
8.	Pacific	1.37
9.	Mountain	1.20

These factors were determined from the ratios of the average solar insolation in the given regions, as tabulated in the Project Independence Report.⁶

Potential Energy

The solar energy that annually arrives at the surface of the United States is more than 500 times the yearly demand for energy in the United States. Solar cells with 10 percent efficiency would supply all this energy from 1,000 square miles of land. The potential energy contribution from photovoltaics is largely a question of economics.

The potential energy contribution that can be expected from photovoltaic energy systems depends highly on the ability of technological advancements to reduce the production costs of photovoltaic devices. A major breakthrough allowing a large cost reduction would permit these systems not only to compete very well in distributed applications but also to capture a share of the electric power market as peak and intermediate load central station power systems. Less dramatic cost reductions would likely limit the installation of photovoltaic devices to distributed applications.

In comparison with the other electricity-providing solar technologies, photovoltaic systems are inherently well suited to distributed applications. This is due to the potential economic viability of these systems even in very small sizes and their very low maintenance requirements.

Photovoltaic systems have an advantage over several other solar energy technologies in that they are able to use indirect sunlight. Solar thermal power stations, on the other hand, require direct insolation for operation. This is an important consideration that may allow photovoltaic energy contributions in areas in which other solar technologies cannot compete because of the problem of frequent cloud cover.

Environmental Considerations

Since photovoltaic systems have no moving parts or products other than heat (which would normally be transferred to the earth), relatively few environmental problems are associated with this technology.

The main environmental questions are associated with the supply and toxicity of the materials that constitute the cells, such as arsenic and cadmium. Since there has been no widespread commercialization of photovoltaic devices, many of these factors can only be estimated.

Cadmium is a highly toxic poison believed to increase cancer risk, heart disease, and birth defects and to accelerate aging. Present controls on cadmium release may be inadequate. However, its use in solar arrays would not result in a large increase in the amount of cadmium entering the environment. Both gallium arsenide and arsenic are highly toxic and are recognized carcinogens. However, it has been estimated that the amounts of arsenic material used per square meter of 1,000X concentrating array is 250 to 1,500 times smaller than the concentration of As_2O_3 recommended for weed control by the USDA. These statements are made to describe the uncertainty of these problems and not to minimize their important nature.

ERDA has drawn up an environmental work plan. To be investigated are the effects of Cd, CdS, GaAs, and As release during production and into the environment in general, as well as effects caused by doping compounds such as phosphine gas and boron trichloride. Consumer and utility relationships as well as the regulation of solar industries and land use also are items to be investigated.

International Market Potential

In many parts of the world there are communities that are not reached by an electrical grid. This is particularly true of rural communities in developing countries. Currently, if electricity is needed for a school, health center, or tourist center in such a community, it is supplied by a gasoline generator or batteries. Photovoltaic electrical energy sources can make a significant impact on the electrical use in such areas.

For a remote location in a developing country, the cost of electricity from a gasoline generator varies from \$4 to \$8/kWh, depending on the price of gasoline. Battery sources are two to three times more expensive. Photovoltaic sources currently appear to be economically favorable with costs near \$1/kWh. The main reasons why they have not yet made an impact in these areas is the higher initial investment cost and the lack of engineering and marketing effects.

The international market is expected to be a driving force for commercial development of solar cells in the near future. For example, the

need for remote photovoltaic sources to power educational TV sets in the Ivory Coast, Malaysia, and India, a rather modest demand, is estimated at 1/2 MW-pk, of the same magnitude as the 1977 world production of 3/4 MW-pk.

Research, Development, and Demonstration Programs

As much as 90 percent of the financial investment in terrestrial solar photovoltaic energy RD&D has been that administered through ERDA's Division of Solar Energy (DSE), which is now a part of the Department of Energy. DSE's stated objectives were to demonstrate by the mid-1980s that solar electric energy can have a significant contribution to the projected national energy needs by the year 2000. The strategy has been to (1) stimulate industries' manufacturing function through selected development projects, (2) recommend and develop incentives to alleviate barriers in the marketplace, and (3) create aggressive RD&D activities. Up until the summer of 1977 these goals and schedules of DSE were those presented in Table II-5. In August 1977, Dr. Henry H. Marvin, Director of DSE, made a rather expensive review of the photovoltaics program and concluded that, although the work done by JPL for low-cost silicon had been progressing reasonably well, the goal of \$2/W-pk projected for 1982 would not be practical for a production of 20 MW annually. Since he felt that the flat plate technology might not possibly develop at a sufficient rate, he proposed a modification in the program to emphasize concentrator programs with a goal of \$2 per peak watt by 1980 rather than 1982. These revised goals are shown in Table II-6.

The main emphasis in ERDA's photovoltaic program has been on silicon technology. This is reflected in the 1977 program which is outlined below.

Silicon Technologies Branch (\$25 million*)

- Low-cost silicon materials
- Processing (slicing, annealing)
- Ribbons, sheets, films

Advanced Materials Branch (\$8 million)

- CdS, GaAs, amorphous Si, etc.

Outside programs (\$13.3 million)

- Mission and systems analysis and engineering (\$4.1 million)
- Test and applications (\$6.7 million)
- Concentrators (\$2.5 million)

*Numbers indicate amount of funding of R&D programs by DSE.

Table II-5

SCHEDULES AND GOALS FOR PROJECTS OF THE
NATIONAL PHOTOVOLTAIC CONVERSION PROGRAM
(1975 Dollars)

Goals	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986
Market price (dollars per kilowatt)										
Silicon solar array		\$7000	\$5000	\$4000		\$2000		\$1000		\$500
Concentrator systems		\$2000		\$1000		\$500				\$250
JPL low-cost silicon array										
Project purchases	150kW	270kW	500kW	1MW	2MW	3MW	4MW			500MW
Total installed peak										
Capacity in demonstra- tion projects	170kW	285kW	600kW	1MW	2MW	4MW	7MW	10MW		
Thin film cells										
				10% efficiency						

Source: Leonard M. Magid, "The U.S. Photovoltaic Conversion Program," presented at the International Colloquium on Solar Energy, Toulouse, France, March 1-5, 1976.

Table II-6

PROPOSED PRODUCTION AND PRICE GOALS
FOR PHOTOVOLTAIC ARRAYS

Objectives	1977	1978	1979	1980	1981	1982	1983	1984	1985	1986	After
Market goals											
Total annual production (MWe)	0.7	2	8	20	40	75	120	195	310	500	50GWe (by the year 2000)
Cost/price goals (dollars per kWe)											
Array prices	\$12,000	\$7,000	\$3,000	\$2,000	\$1,500	\$1,000	\$900	\$750	\$600	\$500	\$100-300 (by 1990)
System busbar Energy costs				100-200 mills/ kWhr						50-80 mills/ kWhr	40-60 mills/kWhr (by 1990)

Source: H. H. Marvin, letter August 1977.

The majority of the materials-oriented activities in the outside programs were in silicon-related research.

Silicon has been the basic constituent in solar cells for the past 20 years, and approximately 70 percent of the photovoltaics budget has been directed toward silicon-related projects. Currently, silicon cells are made from single crystal material by a multistep energy-intensive process which is both wasteful and time consuming. ERDA's 1985 price goal for silicon cells is 50¢/W-pk. The current cost for the starting material alone is nearly \$2/W-pk. The activities of the Silicon Technologies Branch, along with those of at least half of the outside programs, are designed to meet this 50¢/W-pk goal.

Silicon will not necessarily remain the most cost-effective material for future cells. Another approach to reducing cell costs is to develop cells with materials that are either inherently more efficient energy converters or require less expensive, simpler processing methods. This work is being directed through the Advanced Materials Branch.

The great majority of the silicon projects are being pursued by commercial companies. Most of the outside programs are being contracted through Sandia Laboratory. Additionally, NASA's Jet Propulsion Laboratory monitors a good share of the low-cost silicon projects. Research contracts on advanced materials have mainly been awarded to universities. In FY 1977, the University of Delaware received \$2 million, mainly for research on cadmium sulfide-related cells.

The ERDA photovoltaics program to date has been conservative, even though its management has constantly tried to be receptive and responsive to change and new ideas in technology. A major problem with the structure of DSE has been the absence of channels for response to unsolicited proposals, and it often is more than two years before a new concept receives financial support. A suggestion is that in the DOE structure additional mechanisms be provided to handle new ideas in a manner similar to the processing of proposals by the Materials Science Division of NSF.

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III SOLAR THERMAL POWER

Introduction

General Description

Figure III-1 shows the solar thermal system collectors that DOE is currently investigating. The collector type, optical principle used, type of receiver used, degree of tracking, collector form, and tracking element, if any, are indicated. The DOE contractors for FY 1977 participating in the investigation program are listed under each form. This taxonomy cuts across organizational lines and departments by including all the solar thermal collector systems being developed without regard to their application.

Collector systems that deliver fluids at temperatures high enough to drive electric generating equipment efficiently are considered for application to solar thermal electric power. Therefore, in general, nontracking or nonconcentrating collectors are excluded.

An estimate of the "best thermal use" collection temperature* is also shown for each form in Figure III-1. This best thermal use temperature is discussed later in this section. Variations from this optimum temperature for a given type of collector will exist, depending on the design conditions, such as degrees of tracking, rim angle, half acceptance angle, amount of glazing, receiver shape or envelope, amount of insulation used, orientation, absorptivity, reflectivity, and solar insolation.

In addition to the collector component, a solar thermal power system requires heat transfer fluids, fluid transmission elements, some form of heat engine, rotating electric generating equipment, heat dissipation equipment, and a variety of station auxiliary equipment.

Applications

The primary prospective application for solar thermal power is for central station electric generating service--a type of central receiver ("power tower")-heliostat (reflector) field. Because of the relatively limited daily availability of radiant energy, service will ordinarily be limited to fuel saving or intermediate load. In the fuel saving mode, no

* Best thermal use of a solar collection system is the system's use at the temperature that gives the lowest delivered energy cost.

carryover storage would be provided. In the intermediate load case, some storage (5 to 7 hours) would be provided, permitting 10 to 12 hours of daily service. In all central thermal station service, the plant would be connected to a wide area network. Individual commercial plant sizes being considered at present are up to about 100 MWe.

Another potential application is for total energy systems in distributed situations such as for shopping centers and light industrial parks. In these applications, the waste heat can be utilized for space heating or cooling, rather than being dissipated to the environment as in the case of the central station. Plant sizes in the range of perhaps 100 kW to 10 MW are being considered. Although plants of this size would ordinarily be uneconomical for electric operating service alone, the utilization of the waste heat makes them potentially more attractive.

Another potential application is for land irrigation pumping service or other similar remote use. In this case, a size range of perhaps 5 to 200 hp is applicable. Application would be through direct pump drive with a solar driven heat engine or through electrical conversion.

Current Status

All the types of solar thermal power collectors shown in Figure III-1, and all their various applications in systems are now technically feasible. With the availability of relatively low-cost fossil fuels, however, the practicality and economics of solar power systems have yet to be demonstrated. Of the various applications of the several types of solar thermal power systems, some are closer to being competitive with conventional fuel systems than others because of higher relative efficiency and potentially lower relative cost.

It is always difficult to assess the future relative potential for providing energy in the marketplace with a developing technology--especially with solar thermal power technology, because future commercially installed system costs are unknown. The current solar thermal energy cost estimates and projections are considered "soft" for the following reasons:

- Since each contractor's solar concept is competing for DOE development funds, each contractor tends to give optimistically low construction costs for "his" solar thermal system. He dares not admit to costs greater than his competitors.
- Conventional distributor and retailer mark-ups are not being included in the cost estimates.
- Realistic land values for the heliostat field required for commercial solar power applications on industrially zoned property are not always used.

- Optimistic production experience, or "learning curves," are being used for heliostats, some of which are relatively large devices that may not lend themselves to significant long-term improvements over present day field manufacturing and assembly automation techniques.
- The efficient useful life and production and maintenance costs of the heliostat reflective surfaces are not known.
- The actual but unknown present cost of solar thermal power may be reduced in the future by property tax credits, low interest loans, investment tax credits, advanced depreciation, direct grants or subsidies, and other use incentives deemed desirable in the nation's interest. In addition, the future cost of fossil and nuclear fuels, and the future cost of land, materials, labor, and money are unknown.

Within this context of unknown costs, however, some useful quantitative observations can be made.

Point concentrating solar power systems are capable of generating higher useful temperatures than line concentration systems. This is true for both the central receiver systems and the distributed systems, although there is a cost penalty for this capability. Point concentration systems require that the heliostats (reflectors) in the central receiver systems and the collectors (reflectors plus receivers) in the distributed systems track, or follow, the sun on two axes. This is in contrast to line concentration systems, which require motion about only one axis. Certain lower temperature, line concentration, stationary trough systems require no tracking or, at least, only periodic or seasonal position adjustments. In other words, there is an inherent complexity and therefore a cost penalty that must be paid to achieve higher fluid temperatures. Since the efficiency of thermal engine cycles improves with higher cycle temperatures, it appears economic to use each particular type of solar thermal power system at its most efficient temperature application. The economic performance of certain applications currently being considered for the two axis systems could probably be enhanced by using heat engines with even higher cycle temperatures and thereby nearer to their best thermal use temperature.

Conversely, to use a less complex device with inherently lower concentrations to provide a high-temperature fluid in lesser volume is not its best thermal use. These are inherently lower temperature applications such as for the supply of hot water and hot air.

Some opportunities may still exist in this best thermal use state of the art development, such as the development through a vigorous research program of a Stirling engine/generator for the distributed point focus system and the development of a low cycle-temperature cooling system for flat plate collector applications.

The implications of the best thermal use temperature for the future of the ERDA solar thermal program are far-reaching. The allocation of funds within the solar thermal RD&D program will affect the contribution of solar thermal systems to the nation's energy needs in the future. The following analysis of the thermodynamic/cost interrelations implicit in the best thermal use concept should help show what emphasis and timing of funding for the various solar thermal technologies will have the greatest payoff for the nation when oil and gas become more costly than at present.

Best Thermal Use

The amount of energy collected in a solar collection system decreases as the collection temperature increases. This principle is illustrated in Figure III-2. At ambient temperature, almost all the solar energy is collected, because the convection and radiation losses are low.

In collection devices, the collection efficiency upper limit at ambient temperature depends on the glazing and reflectivity losses. As the collection temperature increases, the solar energy collected is reduced further by radiation and convection losses. At stagnation, with no fluid flow in the collector, the radiation and convection losses equal the solar energy input, and the net energy collection is zero. The solar furnace is an example of this limiting case.

Figure III-2 shows that if the stagnation temperature in a collector is raised from T_1 to T_2 (for instance, by the use of a cavity-type receiver), the collection efficiency increases from η_1 to η_2 at the same collection temperature, t_1 . In addition to the optimum heat collection temperature being considered as a function of the collection efficiency, the heliostat/receiver system cost for achieving the higher stagnation temperature and the temperature-dependent heat engine efficiency and cost of heat utilization also must be considered.

The cost of collecting heat from the sun usually increases with higher stagnation temperatures. This increase results from the additional cost of glazing for flat plate collectors, more complex receivers, better reflective surfaces, selective coatings, more insolation, and sun tracking mechanisms of increasing degrees of complexity.

Figure III-3 illustrates the general relationship of collection cost to collection temperature. Collection costs at ambient temperature are low, but not zero, since land and material handling costs must still be considered. The cost per unit of energy collected becomes prohibitive as the additional cost of increased reflective surface, rim angle, insolation, and other factors produces a smaller proportionate increase in the available stagnation temperature.

The increased cost associated with the achievement of higher fluid temperature collection can often be justified, because there is usually

Source: SRI

FIGURE III-2. SOLAR COLLECTOR EFFICIENCY

Source: SRI

FIGURE III-3. SOLAR COLLECTION COST

a beneficial increase in heat engine efficiency, or efficiency of energy utilization, with higher temperatures. The Carnot efficiency of conventional heat engines increases with maximum cycle temperature but at a decreasing rate at higher temperatures, as shown in Figure III-4.

If the collection temperature effects on the amount of energy collected (Figure III-2) are combined with the resulting amount of energy converted for use (Figure III-4) the curve shown in Figure III-5 is obtained.

The useful energy from a heat engine is zero at ambient temperature, and also zero near stagnation temperatures because there is no working fluid flow. The useful energy approaches zero slightly below the stagnation temperature because of heat lost during transmission and transfer. The useful energy rate over the entire collection temperature range is greater for the system with the higher stagnation temperature.

Taking into account the higher costs needed to achieve the higher recovery of useful energy produces the relationship of collection temperature and dollars per unit of useful energy as shown in Figure III-6. These curves are obtained by dividing the collection cost by the converted energy rate. The use of the more expensive solar system with stagnation temperature T_2 at collection temperature t_1 is less likely to find economic justification than the less expensive system with the lower stagnation temperature T_1 .

The more expensive system has more economic justification as a fuel saver when it is used at a higher collection temperature and for use in a heat engine with a higher maximum cycle temperature. These relationships are assembled and replotted on the same chart in Figure III-7 for better perspective.

The relationships shown in Figure III-7 can be used to guide the allocation of limited solar RD&D funds. A collection system should be coupled and used with the heat engine inlet temperature that provides for its best thermal use. These relationships can be used, for example, to determine which heat engines and heat collection fluids need a vigorous technology development program to match the high temperature (or low temperature) collection systems.

In simple heat collection systems, the optimum temperature is determined by the collection efficiency and cost as functions of the collection temperature. In systems in which the energy is converted, the optimum collection temperature is determined in the same way, plus the heat engine efficiency and cost as functions of cycle temperature.

The point focus collector systems are capable of higher effective collection temperatures than line focus systems. Therefore, the point focus collection systems should preferably be used with heat engines whose inlet temperatures are limited only by material strength and durability limitations. The high concentration ratio ($\sim 60/1$) tracking

Source: SRI

FIGURE III-4. HEAT CONVERSION EFFICIENCY

Source: SRI

FIGURE III-5. POWER CONVERSION

Source: SRI

FIGURE III-6. UNIT POWER COST

FIGURE III-7: SUMMARY OF EFFICIENCIES AND COSTS OF SOLAR ENERGY COLLECTION AND CONVERSION

line focus systems would probably best be used with collection temperatures no higher than 950°F, and the low concentration ratio ($\sim 40/1$) line tracking systems should be used in a temperature range no higher than the 600°F.

Conversely, the very low concentration ratio ($< 20/1$) systems should not be used with conventional heat engines, because they require high inlet temperature conditions for good efficiency. Rather, novel heat engines and novel refrigeration systems using a lower maximum temperature should receive technological development attention for use with these collectors.

A review of Figure III-2 illustrating efficiency versus collection temperature demonstrates that the average collection efficiency can be improved by using less expensive collectors with lower stagnation temperatures for collecting the low grade heat and "topping off" with a higher stagnation temperature collector. This points to the use of collector fields of different design rather than fields of all one type of collector. It also points to the use of a single collector with increasing degrees of concentration, the use of glazing insulation along the collector as the temperature increases, or an increased degree of tracking in the case of heliostats or collectors. This principle is illustrated in Figure III-8.

Generic Technologies

Three major solar thermal power program elements are discussed to illustrate the state of the art and the potential for future development. They are:

- Central receiver
- Distributed total energy
- Irrigation.

The central receiver program has passed the stage of subsystem design, development and testing. A pilot plant design has been selected. The distributed total energy and irrigation programs are both in the demonstration plant testing stage.

Central Receivers

The central receiver concept of the point focus-type uses a large field of two-axis tracking heliostats aiming reflected light onto a boiler on the top of a tower. The central tower with its related solar thermal systems is the largest program element in funding, \$99 million in FY 1977.

(a) SINGLE PASS SOLAR COLLECTOR

(b) TWO TYPES OF SOLAR COLLECTORS IN SERIES

FIGURE III-8. ENERGY COLLECTED BY SINGLE AND SERIES COLLECTORS

Three versions of boilers and heliostats have been funded. Because heliostats north of the tower have been found more cost-effective, the "central" tower has been gradually shifted south of the field center. One concept uses only the more cost-effective north field heliostats. All three versions studied were designed for the generation of steam at about 510°C (950°F) and 105 kg per cm² (1500 psia). A cost of \$2,100 per installed kilowatt of peak capacity for the nth commercial 100-MW plant is projected.¹ This is based on an optimistic cost of \$100 per m² (\$9.29 per ft²) for the two-axis heliostats.

The heliostat field cost accounts for about half the total plant cost at this price. The resulting power production cost in 1977 dollars, including interest during construction, is estimated at 95 mills per kWh¹ at a capacity factor of 0.50. These costs include seven hours of storage at 70 MW net.¹

The McDonnell Douglas Astronautics Company's version, using an external boiler with single pass, has been selected for construction of a 10-megawatt solar steam power pilot plant at Barstow, California. A concurrent DOE-sponsored study by Sanders Associates, Inc.² is investigating a central receiver design for generating 1600°F hot air for use in an air-cooled Brayton cycle turbine.

The estimated receiver heat recoveries and temperatures for both the steam and air cycles are shown in Figure III-9. Although the 1600°F air cycle receiver has a goal of recovering only 84 percent of the total heat,² it has a higher usable temperature than the steam cycle. Also, the overall gas turbine, recuperator, and electric generator efficiency is approximately 40 percent³ compared with approximately 34.5 percent⁴ gross conversion efficiency for the steam turbine/generator system. The recuperated air cooled system at 1600°F turbine inlet has a projected busbar cost of 95 percent of the steam cycle at 950°F.⁵ At 1900°F inlet, it has a projected busbar cost of about 90 percent of the steam cycle cost as shown in Figure III-10.

DOE is also investigating a high-temperature line focus central receiver system. This system uses a long cavity-type receiver on a row of steel towers 200 feet high. Using only the more effective north field of long single-axis focusing heliostats, the contractor estimated system costs are about 22 percent lower than the point-focus central tower system.⁶

The projected cost of electrical power from these central receiver system concepts is highly dependent on the estimated cost of the large heliostats. Since about half the cost of the system is attributable to the heliostats, the projected power costs are very sensitive to a decrease in the cost of heliostats.

A major DOE contractor has quoted the two-axis heliostat estimated cost for the 10 MW steam pilot plant at Barstow, California, at about \$250 per m².⁷ This compares with the nth commercial plant DOE goal of \$100 per m² that was cited earlier.

FIGURE III-9. ERDA GOALS FOR CENTRAL RECEIVER SOLAR COLLECTOR EFFICIENCIES

FIGURE III-10. COMPARATIVE SYSTEMS ANALYSIS, PRELIMINARY ASSESSMENT

All forecast energy costs are highly dependent on estimates of production and construction costs. Production costs of commercially sold products are probably the best held secret of U.S. industry. However, industry has long used fairly well documented "learning curves" to project costs of future production quantities. Representatives of the Lockheed California Company,⁹ for instance, have proposed that large Wind Turbine Generating Systems, which include some large structural manufacturing, controls, and field erection, will have no learning curve for the first ten units, a learning curve of 85 percent (the cost drops 15 percent each time cumulative production is doubled) for the units between 10 and 100, and an 87 percent learning curve for units between 100 and 1,000.

Private communication with representatives of Boeing have confirmed justification of the 85 percent learning curve for large airplane wings. The learning curve for the much higher production of large, bulky, field-assembled systems such as heliostats cannot be associated with the experience of completely automated production systems. For instance, Ford Motor Company¹⁰ uses a learning curve for planning and budget purposes during each yearly model-change period. The learning curve is steeper (75 percent) for an entirely new vehicle model and less steep (90 percent) for the "face lift" model years.

Distributed Total Energy

The concept of total energy is a system in which solar energy is collected at a central area and provides electrical power, heating, air conditioning, and hot water to a wide spectrum of users. By this means, the waste heat that is normally rejected by the cooling tower in the central receiver electric power system is used. Shopping centers, motels, office buildings, and small communities are examples of potential total energy users.

A small central receiver system probably would be more efficient and give a better return on investment if used for total energy.¹¹ The main thrust of the total energy research has been toward using a group of collectors, each with its own receiver.

A total energy system has been completed in Albuquerque, New Mexico. It is designed to supply the electricity, heating and cooling, and hot water demand for a Sandia Laboratory building shown in Figures III-11 and 12. The collectors being considered for total energy include all types of tracking devices. The nontracking devices generate lower stagnation temperatures than the tracking devices and, consequently, are penalized by the inherently lower useful cycle temperatures for the generation of electricity.

Typical nominal costs estimated for the tracking type collectors range from \$130 per m² for the 1-axis parabolic cylinder to \$194 per m² for the 2-axis paraboloid.¹² (The New Mexico Solar Irrigation Experiment purchased 6,900 square feet of single-axis collectors from bids for \$156 per m².) These costs are based on rather large devices to benefit

Source: Reference 13

FIGURE III-11. SOLAR TOTAL ENERGY SYSTEM TEST FACILITY

Source: Reference 14

FIGURE III-12. SOLAR LINEAR ARRAY THERMAL SYSTEM

from the economy of size. Some of them, including the large parabolic cylinders and parabolic dishes, have their relatively high wind loadings supported at rather concentrated ground support points. Therefore, they require substantial concrete mounting pads for ground support. To be mounted on roofs, additional structural provisions would be required to accommodate the wind loads associated with these large collectors.

Total energy systems are being considered for industrial parks, offices, motels, and shopping centers where the land values are high. For example, land, including utilities, that is zoned for commercial use on the San Francisco Peninsula is selling for \$2.75 to \$3.25 per ft², or an average of \$130,000 per acre (\$3.00 per ft²). The cost of paving with asphalt adds another \$1.25 per ft². Industrial chain link fence adds another \$0.10 per ft². These add up to a land cost of \$4.35 per ft². Considering that about three times the area of the heliostats is required for the surrounding land to minimize shading and provide maintenance clearances, the land cost per square foot of heliostat is $3 \times \$4.35$ or \$13.05 per ft². This is equivalent to an added heliostat cost of \$140.75 per m².

Several variations of the Fresnel reflector construction lend themselves to roof-top utilization because of their relatively low wind loading and low distributed support loading.

Current performance and cost analyses of the distributed collector total energy systems have near zero return on investment (ROI) over and above the return on equity included in the weighted cost of capital. They show costs comparable with the estimated cost of conventional energy for the period 1985-2015.¹⁵ These costs were based on an industrially zoned land cost for the heliostat field of \$25,000 per acre. More realistically priced industrially zoned land would delay their market penetration.

The total energy system considered for an example of projected costs is for a meat packing plant.¹¹ Electricity is produced by a concentrating system of collectors. Thermal energy is used in the process as well for heating and cooling. The system called "C" is the example chosen for economic analysis.¹¹ It is the largest and most cost-competitive of three meat processing plants analyzed. The total annual heat (electric plus thermal) produced by system "C" is $536,000 \times 10^6$ Btu. This is composed of 58.35×10^6 kWh of electric power (199×10^6 Btu) and 337×10^9 Btu of useful thermal heat.

System cost is \$82,374,000 with a capacity of 12,160 kW. Therefore, the capital cost is $\left(\frac{82,374,000}{12,160 \text{ kW}} \right) = \$6,744 \text{ kW}$.

The load factor is $\left(\frac{58.35 \times 10^6 \text{ kWh}}{365 \times 24 \times 12,160} \right) = .55$ plus a 337×10^9 Btu heat credit.

The conclusion of the McDonnell Douglas Study¹¹ on industrial applications of solar total energy was that system efficiency must be raised for distributed total energy applications. It was found that "a reduction in collector costs alone would not be sufficient to make distributed concentrating systems competitive with central receiver systems."

Solar Irrigation Systems

About one-half the value of agricultural products sold from the 17 western states is from irrigated land. The use of natural gas for powering irrigation pumps is widespread in the western United States. The increase in gas prices and the threat of its unavailability require replacement energy sources. Solar energy appears promising because of its general availability where and when crops are being grown and irrigated.

A shallow well demonstration system began operation in July 1977 on a working farm near Roswell, New Mexico. The farm has approximately 3,000 acres under irrigation and currently has 18 irrigation wells as shown in Figure III-13. The system heats a hydrocarbon fluid to 215°C (420°F) that is used to store heat. This fluid heats an organic fluid for use in a closed cycle heat engine at 93°C (200°F) inlet temperature.

The economics of the irrigation application of solar energy are severely penalized by only part time use of the solar equipment. An effort is being made to add other uses for the solar energy (e.g., heating, cooling, crop drying) to improve the economics of solar irrigation.

Development Schedule

The estimated development schedule for the three generic technologies previously discussed is shown in Table III-1.

The indicated dates are by no means precise events and considerable overlap among development stages is to be expected, particularly because of the several available approaches to each generic technology.

Commercial application depends on the development of efficient new heat engines and storage systems. The central receiver and solar irrigation concepts are rather old, although the U.S. effort in the central receiver case is more recent. Design and pilot plant activities for all three technologies were initiated in the 1970s, ignoring experimental irrigation systems constructed in the early part of the century.

Development of all the technologies should continue indefinitely in search of major advancements; however, the dates shown in Table III-1 refer to concepts currently under development.

Source: Reference 16

FIGURE III-13. ERDA NEW MEXICO SOLAR IRRIGATION SYSTEM

Table III-1

DEVELOPMENT SCHEDULE FOR
SOLAR THERMAL POWER SYSTEMS

<u>Generic Technology</u>	(Scheduled Start Date/Scheduled End Date)				
	<u>Concept</u>	<u>Design</u>	<u>Pilot Plant</u>	<u>Demonstration</u>	<u>Commercial Application</u>
Central receivers	1964/ Ind*	1974/Ind	1985/ 1990	2000/2020	2020/Ind
Distributed total energy	1975/ Ind	1975/Ind	1977/ Ind	1985/2000	2000/Ind
Irrigation	1915/ Ind	1976/Ind	1977/ 1980	1980/2000	2000/Ind

*Ind = Indefinite

The barriers to the practical realization of the schedules shown are mainly economic. In this respect, construction of pilot or demonstration plants found with the passage of time to be uneconomic will be deferred or eliminated. The limited available funds can be more effectively used for continued research and development in the more promising concepts such as the use of higher cycle temperatures, improved and lower cost collectors, and so forth. This could avoid disappointment from failing to meet the currently held high expectations of the Congress and people for solar energy. Emphasis on research until the economics appear relatively favorable (or at least not clearly unfavorable) will also probably result in earlier commercialization.

Economics

The economics of solar thermal power systems are complex functions of systems capital costs; efficiencies and durabilities; operations and maintenance costs; and the cost of capital, taxes, and other financial considerations. At the present time, an economic analysis of these systems is speculative at best.

Capital and Operating Costs

The previous descriptions of generic technologies included a discussion of unit capital costs and the prospects for reduction as a result of volume production and "learning curves." Here, overall capital and operating costs are estimated for various time periods in the future.

Table III-2 gives estimated capital costs and operating and maintenance (O&M) costs in terms of capacity (\$ per kW) and in terms of output

Table III-2

ECONOMICS FOR SOLAR THERMAL POWER SYSTEMS
(1975 Dollars)

Generic Technology	1985	2000	2020	Comments
Capacity and Operating Costs				
Central receiver				
Capital cost (\$/kW)	--	\$2,900	\$2,100	Capacity factor = 0.5
O&M (mills/kWh)	--	3.3	2.4	
Total energy				Nominal size = 12 MWe
Capital cost (\$/kW)	\$6,800	\$6,000	\$5,500	Capacity factor = 0.55
				By-product hot water
By product hot water credit				Rate = 340×10^9 Btu/Yr.
At \$1.00/MM Btu	\$13.0	\$11.5	\$10.4	
At \$0.50/MM Btu	10.1	8.6	7.5	
At \$1.00/MM Btu	7.2	5.7	4.6	
Irrigation				Size = 150 kW
Capital cost (\$/kW)	\$20,000	\$11,000	\$11,000	Capacity factor = 0.42
O&M (mills/kWh)	109	60	60	
Specific Capital Costs				
Central receiver				
Specific capital cost (\$/annual MM Btu)	--	\$194	\$140	Capacity factor = 0.5
O&M (cents/MM Btu)	--	97¢	70¢	
Total energy				Nominal size = 12 MWe
Specific capital cost (\$/annual MM Btu)	\$413	\$365	\$334	Capacity factor = 0.55
				By-product hot water
By product hot water credit				Rate = 340×10^9 Btu/yr.
At \$1.00/MM Btu	\$381	\$337	\$305	
At \$0.50/MM Btu	296	252	220	
At \$1.00/MM Btu	211	167	135	
Irrigation				Size = 150 kW
Specific capital cost (\$/annual MM Btu)	\$1,600	\$875	\$875	Capacity factor = 0.42
O&M (cents/MM Btu)	3,200¢	1,760¢	1,760¢	

Notes: MM Btu = Million Btu.

O&M = Operating and maintenance cost.

(specific capital cost or \$/annual MM Btu). The 1985 estimates are based on published information, either by the DOE or its contractors. The O&M costs for the total energy system are significantly reduced if the by-product hot water is credited at a nominal \$1.00 per million Btu. Higher by-product hot water values (which exist generally today) give more favorable results.

The estimates for the cost of electricity are based on systems used in the southwest United States. The capacity factor shown will normally decrease for other parts of the United States, while the cost per Kwh of electricity will be higher.

To meet the capital cost estimates listed in Table III-2, the emphasis in research and development programs should be toward reduction of costs for the line-focus, single-axis system and the improvement of efficiencies of the energy collection and heat conversion to electricity processes in the point-focus, two-axis system. Also, if solar thermal power is to be more than a fuel saver, considerable effort will be required to reduce the costs of storage.

Basis of Estimates

The basis of the cost estimates appearing in Table III-2 for the three solar thermal power technologies is explained in the following paragraphs by technology.

Central Receiver

Table III-2 shows the estimated capital cost of the central receiver solar plant in the year 2000 as \$2,900 per kW. This was taken from a commercial plant cost estimate by Martin Marietta.¹⁷ The total cost of the first 150 MWe commercial power plant was estimated at \$453.3 million with a nonrecurring cost of \$17 million, giving a second plant estimated cost of \$436.3 million. Dividing by 150,000 kW gives an installed cost of \$2,908 per kW.

The value of \$2,100 per kW for the year 2020 was taken from a Sandia Laboratories estimate of the cost of the "nth" commercial plant in 1977 dollars for a first-generation technology plant.¹ The collectors, the major cost item, were estimated at \$100 per m². This estimate is probably realistic for two-axis heliostats under high production levels. The FMC/SRI estimate for larger (1,200 ft²) single-axis heliostats is \$61 per m² in production quantities large enough for a 100-MWe plant. The O&M costs were estimated on the basis of one-half percent of the capital cost. This may be optimistic, since the resulting 3.3 mills per kWh is lower than Martin Marietta's estimated O&M costs of 6.2 mills per kWh.¹⁷ The O&M cost estimate for the year 2020 was also based on one-half percent of the lower capital cost.

The specific capital costs are calculated on the basis of the capacity factors listed; thus, the specific capital cost for the central receiver in the year 2020 is estimated to be:

$$\begin{aligned}\text{Total capital cost} &= \$2,100 \times 150,000 \\ &= \$315,000,000 \\ \text{Annual output} &= 150,000 \times 24 \times 365 \times 0.5 \times 3413 \text{ Btu} \\ &= \$2,242,341 \times 10^6 \text{ Btu} \\ \text{Specific capital cost} &= \$315,000,000 \div 2,242,341 \times 10^6 \text{ Btu} \\ &= \$140/\text{Annual MM Btu}\end{aligned}$$

Total Energy System

The capital cost for the total energy system was based on the application of a central receiver system generating electricity and heat for a meat packing plant in Texas.¹¹ The case used was system "C", which was the largest analyzed and showed the highest return on the investment for the three sizes of meat packing plants analyzed. The system uses Dowtherm® at the collector and for storage, with toluene as the working fluid. The system generates electricity and provides both refrigeration and hot water. The costs were reduced by 10 percent for the year 2000 and another 10 percent for the year 2020. Credit is given for the hot water by-product. Specific capital costs were calculated in the same manner as for the central receiver system.

Irrigation

The capital cost for solar irrigation is based on a \$3 million cost for a 150-kW deep well pump, distributed collector, and installation.¹⁶ This cost is considered high, because it is the first of its kind. For this reason, the potentially lower cost of succeeding units in the year 2000 is halved. This represents a learning curve of about 93 percent for the 1,000th unit. A more optimistic learning curve of 85 percent would reduce the capital cost to \$4,000 per kW for the 1,000th unit.

The less optimistic learning curve was used, since much of the cost includes field installations, probably by different contractor crews. In addition, a significant portion of the cost will be for standardized high production equipment (e.g., pumps, pipes, motors, valves) for which the more optimistic learning curve value of 85 percent is not appropriate.

Potential Energy Contribution

The potential energy contribution for all types of solar thermal power systems are functions of cost compared with available alternative systems. Of the three technologies, the central receiver electronic

generating system has by far the greatest potential, given economic parity or advantage, with distributed total energy systems and irrigation systems following in that order. Until low-cost storage is developed, central receiver systems will be limited to fuel saver applications only, thus further limiting potential application to land areas receiving relatively high insolation.

Institutional factors that might limit the realization of a large market for solar thermal power can be overcome. Although utilities might not favor community owned and operated distributed total energy systems, economics will determine the eventual penetration of these systems. The problems of sun rights, building codes, taxation policies, and zoning laws may initially impede implementation, but economic factors will be the fundamental determinant.

Quantitative estimates of the potential energy contribution from solar thermal power systems are given elsewhere in Volume I.

Environmental Considerations :

The solar thermal power systems all have the advantage of producing electric power without emitting SO_x , NO_x , particulate matter, and ash. Thus, any substitution of solar power for fossil fuel generated power would be an advantage.

Compared with nuclear generated electric power, solar power generation would avoid the nuclear hazard, be it real or imagined.

The principal environmental problems occurring from solar thermal power are associated with the large areas required for heliostat fields. For example, an area approximately one kilometer square is required for a 100 MW-sized plant. Apart from aesthetic considerations, this area could be seriously affected by vegetation loss, and so forth.

International Market Potential

The potential for export of solar thermal energy equipment and technology is problematic and depends on the eventual economic viability of such systems compared with available alternative systems, both here and abroad.

If found competitive with alternative systems, a substantial potential may exist initially elsewhere as a result of U.S. development experience and the high cost of fuel in other nations. This observation is based on the very high development costs required to make solar thermal power systems technically viable, an expenditure that few countries can afford.

The potential for international markets is also affected by the fact that a very large portion of the total plant capital cost will be

associated with on-site construction and conventional equipment such as pumps, piping, electrical generators, condensers, cooling and towers. These are both areas in which the United States is not especially competitive today.

Some potential does exist for licensing agreements and for U.S. companies having foreign subsidiaries.

Research, Development, and Demonstration Programs

Federal support of RD&D programs in the solar thermal power area are based on guidelines contained in Public Law 93-473, the Solar Energy Research, Development, and Demonstration Act of 1974, and several subsequent acts.

The major program guide to RD&D in this area is contained in "Solar Thermal Energy Conservation--Program Summary", October 1976, ERDA Document 76-159.¹⁸ This guide organizes the program into the following elements:

- Central receiver power plant
- 5-MW(th) solar test facility
- Total energy systems
- Distributed collection systems
- Hybrid systems
- Research and development.

The central receiver power plant element consists of RD&D activities required to support the development, design, and construction of a 10-MWe pilot plant estimated to be ready by 1980. The purpose of the pilot plant is primarily to establish or verify economic factors. Included in the element is the design of a candidate 100-MWe plant to be ready in 1985. Parallel research and design approaches have been established for the 10 MWe plant, with the most favorable to be selected for construction.

The 5-MW(th) solar test facility element will provide a means to test components and subsystems on a relatively large scale. The primary test objects will be experimental receiver designs although heliostats and storage systems will also be tested. The facility is largely completed and was recently dedicated.

The total energy systems element consists of several study and design projects to assess economic factors. Also included is a total energy system test facility which is to be used to identify and resolve systems problems and provide support to large-scale experiments and demonstrations. This facility is also largely completed and is in use.

The distributed collection system element includes RD&D activities designed to lead to the development of improved collectors for application to electric generating and heat recovery systems in small or dispersed locations. Projects include development and testing, with the objective of improving collector efficiencies and economics.

The hybrid systems element includes RD&D activities designed to maximize the utilization of solar thermal systems in conjunction with fossil fuel and other energy systems, with the objective of reducing fossil fuel use.

The research and development element includes a variety of RD&D activities required for support of the other program elements and to advance the state of knowledge. Areas of concentration include:

- High-temperature materials
- Manufacturing processes
- High temperature heat transfer systems
- Latent and sensible heat storage
- Improved heat engine designs
- Systems studies
- Market potential studies
- General program support.

The primary objective of each of the program elements is to establish economic factors. Solar thermal systems will not enter commercial application until economic parity or advantage is reached with competing alternative systems. The probable success in reaching this objective is by no means certain and presents a major obstacle to the commercial utilization of solar thermal power.

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IV WIND ENERGY SYSTEMS

Introduction

Background

The extraction of useful energy from the wind is an old and widely used technology. Stationary wind units have been traced back to 200 B.C., while the use of the wind to drive water craft is probably more than 5,000 years old. Although more modern windmills are frequently associated with the Dutch, the United States has had considerable experience with wind power. Over the last 100 years, more than 6 million small windmills (less than one horsepower) were built and operated; more than 150,000 are still in operation. These units frequently have been used for agricultural water pumping. Before the Rural Electrification Administration brought electricity to remote U.S. farms in the 1930s, they were also used to provide electricity for farmhouses.

These electrical systems usually included batteries to provide reliable power during calm periods. The use of wind to produce electricity, instead of only milling grain or pumping water, gave rise to the new terms wind turbine generators (WTGs) or wind energy conversion systems (WECS).

The largest wind machine to date was built in the early 1940s in the United States. Able to produce 1.25 MW of power in wind speeds of 30 mph, this unit was the product of extensive design and development by the most foremost U.S. aerodynamicists and structural engineers. Located on a mountain top in Vermont, the unit produced electricity for the local utility until in 1945 when it failed as a result of a known structural defect. In addition to the U.S. experience, several other nations, including Germany, France, Great Britain, Denmark, and the USSR, have built large (over 100 kW) wind units. Thus, the commercialization of WECS is more the updating and reintroducing a technology with which there is wide experience than the developing of completely new systems. In this context it might be suggested that the only reason the wind is not more widely used today is that the "temporary" availability of fossil fuels has made wind uneconomic. As fossil fuels are consumed and thereby become more expensive, wind then might return to its earlier major role.

In examining wind use, two somewhat separate issues need to be examined--the wind resource and the wind machines. After these are understood, a third issue, the integration of the resource, the machine, and the application, must be examined as well.

The Wind Resource

An understanding of the wind resource is very important because of the wide variation in the availability of wind energy. Whereas direct solar insolation varies across the United States by less than a factor of 2, the availability of wind power varies by a factor of more than 20. This wide variation occurs because the power that can be obtained from the wind is proportional to the cube of the wind velocity. Thus twice as much power is available in a 12.5-mph wind than that available in a 10-mph wind. This is shown graphically in Figure IV-1.

Because of the strong dependence of wind power on velocity, the wind availability is frequently presented in units of power per unit of vertical area (e.g., watts per square meter) instead of velocity. Figure IV-2 is one such mapping.

The significance of these values becomes apparent by comparison with direct solar insolation. The sunniest areas of the southwestern U.S. have mean insolation of less than 300 watts per square meter (95 Btu per square foot per hour). In contrast, many sites have mean wind fluxes of over 500 watts per square meter. Individual sites where wind speeds are enhanced by topography can have even higher wind fluxes. For example, White Face Mountain, New York, has a mean wind flux of 1,500 watts per square meter.

These comparisons between insolation and wind power are particularly interesting where conversion to mechanical power (or electricity) is concerned. As discussed later, modern WTs can convert more than 30 percent of the power in the wind into useful power. Because, for example, photovoltaic and thermal power systems are expected to be considerably less efficient than this, they would require deployment of a considerably greater collection area than a wind unit. Furthermore, the area of the blade itself is less than 10 percent of the area of wind intercepted; this contrasts with solar collectors, where material for the entire collection surface is needed.

Thus the attraction of wind power is based on two considerations. The power available per unit area is frequently greater than direct insolation, and this power can be converted into a useful form at higher efficiency and with smaller surfaces than direct insolation can be converted.

Technology Description

Machines can be designed to extract useful energy from the wind in countless ways. Figure IV-3 shows possible designs, most of which have been built and tested. As might be expected, each of these designs has features that would make it advantageous under certain situations. For example, horizontal multiblade units usually have higher starting torque but lower efficiency than high speed double blade units; consequently,

DOUBLING THE SPEED INCREASES THE WIND POWER BY 8

Source: Reference 1

FIGURE IV-1. POWER DENSITY OF A WINDSTREAM FOR VARIOUS SPEEDS

FIGURE IV-2. MEAN ANNUAL WIND POWER(W/m^2)

HORIZONTAL AXIS

Single-Bladed

Double-Bladed

Three-Bladed

Up-Wind

Down-Wind

Multi-Rotor

TAXONOMY

U.S. Farm Windmill
Multi-Bladed

Bicycle Multi-Bladed

Enfield-Andreau

Sail Wing

Counter-Rotating Blades

Cross-wind Savonius

Cross-wind Paddles

Diffuser

Concentrator

Unconfined Vortex

Source: Reference 1

FIGURE IV-3. SCHEMATIC DESCRIPTIONS OF WIND ENERGY CONVERSION SYSTEMS

VERTICAL AXIS

PRIMARILY DRAG-TYPE

Savonius

Multi-Bladed
Savonius

Plates

Cupped

TAXONOMY

PRIMARILY LIFT-TYPE

ϕ -Darrieus

Δ -Darrieus

Giromill

Turbine

COMBINATIONS

Savonius/ ϕ -Darrieus

Split Savonius

Magnus

Airfoil

OTHERS

Deflector

Sunlight

Venturi

Confined Vortex

FIGURE IV-3. SCHEMATIC DISCRIPTIONS OF WIND ENERGY CONVERSION SYSTEMS (Concluded)

they are common in water pumping applications. Among the vertical axis designs, the Savonius rotor is self starting in contrast to the Darrieus rotor which is not. However the Darrieus rotor is the more efficient of the two. The vertical axis designs do not need to rotate to remain constantly facing the wind as do the horizontal machines.

On the other hand, the lift-type vertical axis machines, such as the Darrieus rotor, have difficult structural problems, since they are exposed to continuously changing loads on the blades as they cycle from lift to stall on each revolution. For regions of low wind velocities, augmentation schemes such as diffusers and vortex generators can be used at the expense of higher cost and greater complexity. Other considerations in choosing a WTG design are site characteristics such as frequency of very high winds, the frequency distribution of gusts, and the wind direction pattern (the so-called "wind rise"). Similarly, the needs of the application must be considered such as seasonality of demand versus wind, availability of external starting torque, and power and rotational speed requirements.

One of the most important characteristics of the WTG design is its efficiency. For WTGs, efficiency is usually expressed as the power coefficient, C_p , which is the ratio of the mechanical power delivered to the power available in the area swept by the WTG blades. This is an important parameter since the higher efficiency unit will produce more power for the same size. The high speed, horizontal axis two-blade and the vertical axis Darrieus rotor, shown in Figure IV-4, are the two most efficient designs. The federal program has focused most of its efforts on these two designs.

The three generic designs selected for more detailed discussion in this work are a 1.5-MW horizontal axis unit, a 500-kW vertical axis Darrieus unit, and a 15-kW horizontal axis. These are selected to span the range of designs that are most likely to be commercialized.

A 1.5-MW horizontal axis wind unit is typical of the type of unit that would most likely be integrated into an electrical utility grid to provide supplemental power to centralized supply systems. In the spectrum of WTGs, this is a "large" wind unit with a rotor diameter of between 200 and 300 feet. ("Large" is relative, since the output of such a machine is still extremely small compared with a 1,000-MW central nuclear or coal power plant.) This machine, which is similar to the MOD I and MOD II designs currently being developed under the federal wind program, is in the size range that most investigations have identified as being the most economical.

A 500-kW Darrieus machine is included as an example of vertical axis designs. The Canadian government, which has been supporting research in this type of WTG for several years, is currently building a 200-kW unit of this design on Magdalen Island in Quebec Province. Two smaller units of this design are in operation at Sandia Laboratory in New Mexico. As noted earlier, the advantage of the Darrieus design is

FIGURE IV-4. TYPICAL PERFORMANCES OF WIND MACHINES

that it has high efficiency without the need to be turned into the wind. Because the generator can be placed on the ground and because the wind blades can be largely supported by wires rather than by a free standing tower, the cost of the tower is reduced in this design relative to that of a horizontal axis unit. Because this design is not self starting, it is most conveniently connected to a utility grid. This permits the generator to be momentarily operated as a motor to drive the rotor to a self-sustaining speed.

The smaller 15-kW horizontal axis unit is included as representative of the type that an individual homeowner, farmer, or small community might install. Although most studies indicate this unit would be more expensive (per unit of capacity) than the larger megawatt scale units, it could serve in a more expensive market--that of the off-grid, remote applications. Whereas the larger units hope for economic viability through sophisticated design and materials, the smaller units would be more sensitive to realizing economics of mass production. Considerable private effort has been directed toward such small-scale wind units. Only recently has the federal program shifted its emphasis to include more work applicable to these smaller designs.

Development Schedule

The development schedule for the three generic wind units is shown in Table IV-1. These five categories for describing the stages of development are not appropriate for wind units, since, for example, the distinctions between "pilot" and "demonstration" are not particularly meaningful for machines as small as these. Nevertheless these somewhat arbitrary classifications are used here for consistency with the other technologies to indicate a likely development scenario.

The schedule of development of the megawatt scale wind unit is mainly determined by the time required to move a new design through the steps to commercial use. No new technical breakthroughs are needed; rather, engineering development and operational experience are the required prerequisites to commercialization. Numerous recent studies have indicated that there will be cost competitive applications of these units when they are available. As such, the national program has focused on supporting the required engineering development. Although it is reasonable to anticipate some commercial installations by 1985, the growth after these early units depends on the "learning curve" to reduce costs of subsequent units (discussed later), the costs for units in lower wind sites, and the operational success of the initial units.

The design issues remaining for the large wind units concern the blades. The economic tradeoffs will be between cost and life. For example, should the blades (and hub) be designed for a 30-year life or should they be designed for periodic replacement? The wind shear (the difference in the wind velocity between the top and bottom of the rotor) and tower shadow are principal factors that must be considered. Design

Table IV-1

DEVELOPMENT SCHEDULE FOR WIND ENERGY SYSTEMS

<u>Generic Technology</u>	<u>Concept</u>	<u>Design</u>	<u>Pilot</u>	<u>Demon- stration</u>	<u>Commercial</u>
1.5-MW horizontal axis WTG	1940/1980	1976/1980	1977/1980	1980/1985	1985/ind.
500-kW Darrieus vertical axis WTG	1920/ind.	1970/1985	1980/1985	1985/1990	1990/ind.
15-kW 3-blade horizontal axis WTG	1890/ind.	1910/1980	1910/1980	1910/1980	1914/ind.

Notes: Ind. = Indefinite

Schedule Start Date/Schedule End Date

alternatives such as three-blade rotors and placement of the rotor up-wind (instead of downwind) of the tower are options for reducing certain structural problems.

The development of the Darrieus system lags behind that of the more conventional horizontal axis WTG, both because it is a newer concept and because over the past few years it has not had the RD&D resources devoted to it that the horizontal axis designs have. The development program will need to continue emphasizing the structural characteristics of the blades. Experience gained on the Sandia and Canadian units should be extremely valuable.

Successfully commercialized large vertical axis units will compete with large horizontal axis units in supplying the same market (i.e., utility electricity). However, in practice, this competition is not likely to be as real as might be imagined, since each of these units and possibly other designs will fit a particular niche of the market. For example, the horizontal units might be preferred at sites with strong, steady winds (e.g., coastal sites), whereas vertical axis units might prove best where winds are lighter and more variable.

The development schedule for small scale WTGs, such as the 15-kW design specified here, is unique in that these units are commercially

installed today. In fact, there are currently at least ten suppliers of such systems around the world. Expanded use of these units will depend on technical design advances, improved manufacturing techniques, and the development of a receptive market for on-site power. This last concern includes institutional barriers such as availability of financing for individual owners, the establishment of equitable utility rates for grid connected wind units, and zoning standards.

Economics

In assessing the economics of wind power, it is important to carefully consider both the cost of the WTG itself and the nature of the market that the WTG would be serving. The analysis focuses on the installed costs of WTGs that could produce conditioned electricity suitable for introduction into a utility grid. Subsequent uses of such power, including off-grid electrical applications, recharging storage, or non-electrical applications, are discussed later.

The range of uncertainty in the future cost of WTG units is probably smaller than that of the other solar-electric options. This is because the technology of the components is relatively familiar (e.g., towers, blades, transmissions, controls) and considerable experience exists in actually integrating these components into operating commercial units (at least in the smaller sizes). The uncertainty in costs that does exist can largely be traced to uncertainties in the economies of scale and uncertainties in cost reductions attributable to production rate (the learning curve effect).

Most studies have indicated that lowest costs occur for units rated in the range of 1 to 3 megawatts, as indicated in Figure IV-5. Although many factors enter into the economics of WTGs, an important factor behind this type of cost/size relationship for WTGs is that doubling the diameter of the blade increases by four the area of wind intercepted, so that up to a certain size, increases in rotor diameter lower cost. Beyond a certain size structural problems in the blade increase costs again. There is disagreement concerning the size at which the cost curve begins to rise. Some would claim that, if nothing else, the finding of lowest costs for WTGs in the size range of 1 to 3 MW is the natural conclusion of studies done by aerospace firms accustomed to thinking in terms of structures that are hundreds of feet in size, costing several million dollars per unit, and manufactured in production runs of several hundred. These same people might argue that under different assumptions the most economic approach would be to produce millions of smaller units at a few thousand dollars each.

The debate over economies of scale continues as if one size were right while another is wrong--as if "large" must lose for "small" to win. In fact, should one size of WTG gain commercial acceptance, the other probably would also be accepted because each would fit different applications. The results of the market penetration studies presented

QUANTITY 10,000 • LARGE WECS - 1975 DOLLARS

FIGURE IV-5. INVESTMENT COST OF WECS, EXCLUDING LAND AND DISTRIBUTION LINE TIE-IN COSTS

in Volume I suggest that it will be the larger wind units (i.e., over 1 megawatt) that will make the largest contribution to national energy supply by gaining access to the central utility market. However, there are sufficient uncertainties in the relative costs of large and small units and sufficient potential applications of each to warrant continued development of each. Recent articles discussing the size issue are found in References 4 and 5.

The issue of manufacturing economies is more difficult. Detailed studies have been made of cost reductions as a result of experience gained through continued production--the "learning curve." Figure IV-6 shows this effect for a 90 percent learning curve (i.e., a doubling of cumulative production causes the cost to drop to 90 percent of its former value). While for some technologies the applicability of this curve as a predictive tool can be seriously questioned, it is reasonably applied to WTGs at least in part because, in contrast to other solar devices, materials costs represent only about 10 to 20 percent of the final cost of an installed WTG.⁵

The cost estimates used in the base case market penetration estimates are shown in Table IV-2. These costs were developed from References 3, 6, and 7 but use indirect expense factors consistent with the other technologies in this report (20 percent contingency and 7 percent owners indirect costs).

The 1985 cost projections for the 15-MW unit are consistent with the cost estimate in the GE analysis⁶ based on a 90 percent learning curve, a \$1,600 per kW first unit cost, and a cumulative installation of 10 units by 1985. This cost estimate of \$870 per kW in 1985 is considerably higher than the corresponding estimate of Mitre (\$1,200 for the first unit)⁷ and is more in line with recent experience of early test units.⁵ The cost estimates for 2000 and 2020 are static estimates and are not the result of feedback to learning curve estimates from the market penetration analysis. A dynamic approach, while conceptually pleasing, cannot be done with any accuracy, since it is not practical to estimate the effect of depletion of desirable sites with increased market penetration. In all likelihood, installed units will not come down in cost as rapidly as the learning curve indicates because, after certain levels of use, it will be necessary to locate WTGs at less desirable sites.

The capital cost of the Darrieus design is also shown in Table IV-2. Compared with the larger 1.5-MW unit, this machine costs more in 1985 because of its smaller size and because its technical development lags behind that of the larger horizontal units. Over time its cost comes down at a faster rate for two reasons: because this machine is smaller, it could be produced in larger quantities, thereby benefiting more from learning curve effects, secondly, there is more room for technical improvements, because it is currently in an earlier stage of development. Considerable uncertainty exists in the cost of vertical axis WTGs because there has been little design and operating experience.

FIGURE IV-6. COST OF 1500 kW WECS - 1975 DOLLARS (0.90 LEARNING CURVE)

Table IV-2

BASE CASE ECONOMICS FOR WIND ENERGY SYSTEMS*
(1975 Dollars)

Generic Technology	1985	2000	2020
1.5-MW horizontal axis WTG			
Capital cost (\$/kW)	\$870	\$830	\$820
O&M (mills/kWh)	6.0	5.7	5.6
500-kW Darrieus vertical axis WTG			
Capital cost (\$/kW)	\$1,200	\$1,100	\$1,050
O&M (mills/kWh)	8.2	7.5	7.2
15-kW 3-blade horizontal axis WTG			
Capital cost (\$/kW)	\$1,200	\$1,200	\$1,200
O&M (mills/kWh)	8.2	8.2	8.2
1.5-MW horizontal axis WTG			
Specific capital cost (\$/annual MM Btu)	\$58	\$56	\$55
O&M (cents/MM Btu)	176¢	167¢	164¢
500-kW Darrieus vertical axis WTG			
Specific capital cost (\$/annual MM Btu)	\$80	\$74	\$70
O&M (cents/MM Btu)	240¢	220¢	210¢
15-kW 3-blade horizontal axis WTG			
Specific capital cost (\$/annual MM Btu)	\$80	\$80	\$80
O&M (cents/MM Btu)	240¢	240¢	240¢

MM Btu = Million Btu

O&M = Operating and maintenance cost

*All systems are based on a mean wind velocity of 7 meters per second and a capacity factor of 0.5.

The cost of the Canadian Darrieus unit looks attractive (second unit cost has been reported to be about \$900 per kW) primarily because of the very favorable site with wind speeds averaging nearly 20 mph.

The cost of smaller units is also subject to considerable uncertainty. Currently such units are advertised at prices ranging from \$1,000 to \$2,000 per rated kW.⁵ Unfortunately, these quotes can be highly misleading, because many manufacturers rate their units at wind speeds that are much higher than would be experienced at a typical site (e.g., as high as 28 mph). A typical unit described as \$1,300 per kW at 28 mph would have an effective price of over \$8,000 per kW if rated at a more typical 15 mph. The assumed installed cost of \$1,200 per kW used here is based on continued development and at least modest levels of production. The learning curve effect of small WTGs is also uncertain because it is not clear where the technology currently is on the learning curve. It could be claimed that, since some 6 million small WTGs have already been built, the next doubling of production and its associated cost reduction would require additional production of millions of units. In the base case, the price of small WTGs does not come down after 1985, because the findings of the market penetration analysis is that the 1985 cost is too high to merit further major production increases. In the low solar price case, this condition is relaxed and prices continue to fall after 1985.

The caution on rated output needs to be repeated. The cost estimates were based on a WTG design that would achieve its rated output at 15 mph (7 meters per second). In Figure IV-2, sites for WTGs would all be in the "500 watts per square meter" regions. Because these locations are remote and thinly populated, few small "on-site" WTGs would in practice display these costs. Most on-site units would be located in areas with considerably lower average velocities. In contrast, many larger units could be remotely sited at favorable locations in regions of high mean wind speed and connected to central grids so that the larger units could more commonly achieve these costs. To facilitate comparison with the other solar electric technologies, the costs are also presented in terms of specific capital cost (dollars of initial investment per million Btu of output per year).

The cost estimates of the low solar price case are shown in Table IV-3. For each design type, this lower cost represents the type of modest cost reduction that could be realized either through a more successful RD&D effort or through larger learning curve effects. The key point is that major breakthroughs are not expected. Rather, continued design improvement and the gaining of commercial experience can result in moderate cost reductions.

The importance of the wind velocity at which WTG output is specified has been discussed. An additional related factor needs to be explained--the capacity factor. The capacity factor is defined as the actual annual energy output divided by the energy output of the unit if it were operated at its rated output continuously for one year. Because

Table IV-3

LOW SOLAR PRICE CASE ECONOMICS FOR WIND ENERGY SYSTEMS*
(1975 Dollars)

<u>Generic Technology</u>	<u>1985</u>	<u>2000</u>	<u>2020</u>
1.5-MW horizontal axis WTG			
Capital cost (\$/kW)	\$780	\$760	\$750
O&M (mills/kWh)	4.8	4.4	4.4
500-kW Darrieus vertical axis WTG			
Capital cost (\$/kW)	\$975	\$900	\$855
O&M (mills/kWh)	6.8	6.1	5.5
15-kW 3-blade horizontal axis WTG			
Capital cost (\$/kW)	\$975	\$945	\$900
O&M (mills/kWh)	6.8	6.5	6.1
1.5-MW horizontal axis WTG			
Specific capital cost (\$/annual MM Btu)	\$52	\$51	\$50
O&M (cents/MM Btu)	140¢	130¢	130¢
500-kW Darrieus vertical axis WTG			
Specific capital cost (\$/annual MM Btu)	\$65	\$60	\$57
O&M (cents/MM Btu)	200¢	180¢	160¢
15-kW 3-blade horizontal axis WTG			
Specific capital cost (\$/annual MM Btu)	\$65	\$63	\$60
O&M (cents/MM Btu)	200¢	190¢	180¢

MM Btu - Million Btu

O&M = Operating and maintenance cost

*All systems are based on a mean wind velocity of 7 meters per second and a capacity factor of 0.5.

the cost of delivered energy from a WTG is inversely proportional to the amount of energy produced, a higher capacity factor effectively lowers the cost of the unit.

Two different WTGs can have the same rated output at the same wind speed and yet display different capacity factors at the same site. This is because many design factors in addition to rated output (at a particular speed) determine capacity factor (thus annual energy output). Of particular importance are the cut-in speed (the minimum wind speed at which power is produced) and cut-out speed (the maximum wind speed in which the WTG will operate before being shut down to prevent structural damage). Generally, the machine with the lower cut-in speed and higher cut-out speed will display the higher capacity factor. Usually the penalty for this wider range of operating speeds is design complexity and structural strength, which translate into higher initial cost. The key point is that simplistic comparisons based solely on cost per rated output can be very misleading in comparing WTG alternatives. Meaningful comparisons need to be based on careful analysis of the machines under the spectrum of conditions at the candidate site.

In making the market penetration estimates, regional variations in wind speed were taken into account. As Figure IV-2 shows, in some regions of the country, few, if any, sites would be available that would have adequate wind to produce the outputs and load factors consistent with the cost estimates of Tables IV-2 and IV-3. To reflect these variations in resource availability in an approximate manner, the costs presented in the tables were increased by 60 percent in regions 4 and 5 (the states of Wisconsin, Michigan, Illinois, Indiana, Ohio, Kentucky, Tennessee, Mississippi, and Alabama). The other regions have at least some sites where wind conditions should be adequate to yield these performances.

Land costs have not been included in these estimates. In general, this should not be a significant factor. Because large wind units will usually be located on inexpensive remote land or on open range land (which can continue its current use), land costs should not be important for these units. Similarly, small wind units would usually be located on a rooftop or on personal land for which the owner would not typically include the cost in his accounting. Issues of land use and availability can be very important and are covered in the discussion of environmental considerations.

Potential Applications

The amount of wind power available in the United States is very large, and the hardware for collecting this power looks technically and economically attractive. In spite of these factors, the issue of finding the best way to use wind power is extremely difficult. In part, this is because wind power has no single niche into which it seems to naturally fit. Thermal power and photovoltaic devices seem particularly well suited for intermediate power because the sun is generally available

during this period. Biomass produces fuels that can be readily marketed or can be burned directly in place of coal. Solar heat can conveniently provide space and process heat. OTEC, with its uniform operation, seems ideally suited to baseload power. Finding similarly suitable applications of wind requires careful analysis because of the fundamentally unpredictable nature of wind.

Wind can be applied to many uses because of the ease of converting the mechanical power of wind into either electricity or heat. Some these are summarized below:

- Mechanical uses
 - Water pumping
 - Compressing air
 - Powering refrigeration
 - Frictional heating
- Electrical uses
 - Distributed electricity
 - Recharging batteries
 - Electrolytic processes
 - Resistance heating

Although all these plans are technically possible, based on current trends of technical and economic development, three of them will find widespread use--residential space and water heating, agricultural water pumping, and the production of distributed electricity. In addition, the use of WTGs to recharge storage batteries, particularly at remote sites, is practiced now and will continue to grow although the total energy in these applications is small from a national perspective.

WTG production of residential water and space heating can be accomplished in several ways. One of the most straightforward is to pass electricity from the WTG through a resistance heater immersed in a water tank. The water tank provides storage of the wind energy for use during calm periods. The advantages of this system are the convenience of storage (hot water is easier and less expensive to store than electricity) and the simplification of the electrical operation since conditioned 60-cycle, 120-volt power is not required (variable voltage dc will suffice). This option has not been specifically evaluated in this study because, except for some special situations, this concept is not likely to be as economical as direct solar heating (based on the preceding economic analysis of small WTGs).

The use of wind to pump water is attractive because the variability of the wind can frequently be accommodated with storage tanks or ponds. Also, as is the case in recharging remote storage batteries, many water pumping sites are distant from other energy sources such as electricity

or gas so that the cost of these conventional options is high. However, because agricultural water pumping is also a small fraction of national energy to demand, these uses would still restrict wind to a minor role.

Table IV-4 presents a relative ranking of the potential wind applications done by General Electric.⁶ This ranking, based on five factors, found the most attractive uses of wind to be utility electricity, residential water and space heating, and agricultural water pumping. Utility electricity ranks considerably above the other alternatives. Unfortunately, this application also raises many technical and economic issues because of the difficulties associated with connecting an unpredictably variable energy source such as wind with an application that must provide power immediately on demand. To analyze in detail all the aspects of integration WTGs with electrical utilities is beyond the scope of this work. However, the important issues will be raised and the direction of future work in key areas will be indicated.

Wind can be integrated into a utility in several ways. Three are considered here--wind with storage, wind with conventional backup, and wind as a fuel saver.

If adequate storage is available, a WTG can be viewed as a reliable, dispatchable power plant because, when the wind is calm, power could be taken from storage. The storage could be any of several types, including batteries, compressed air, hydrogen, and pumped storage. The exact manner in which such a system would be designed is complicated and would depend on relative costs of the storage options (where it is available, pumped storage is now by far the least expensive), the generating mix, the wind pattern, and the utility load pattern. The GE study⁶ found that storage would need to cost less than \$30 per kWh to make this mode attractive. This is less than one-third of current storage costs.

A complicating factor of a WTG/storage system is that if storage were to become inexpensive, it would essentially mean that the WTG electricity would need to compete with the cheapest baseload electricity, the least expensive way to recharge the storage. This would make stiff competition for the WTG. For high levels of penetration (e.g., over 20 percent) this mode of operating WTGs with storage will probably be necessary to maintain system reliability. However, for lower levels of penetration and particularly with current storage costs, this mode is not likely to be preferred.

An alternative way to provide for reliability of a WTG system is to incorporate a conventional generating unit as backup. This might not be as cost prohibitive as it seems, particularly in light of current storage costs. The conventional backup unit would have only infrequent use since it would generally operate only under the simultaneous occurrence of peak demand and calm winds. As with the wind/storage mode, the desirability of this mode increases with level of WECS penetration. In certain regions, it might be preferred because of wind and load patterns.

Table IV-4

CANDIDATE APPLICATIONS FOR WECS AND RELATIVE RATINGS

Candidate High-Potential Wind Energy Applications	Market Size Year 2000 Projection	Wind Availability	Sensitivity to Wind Interruptions	Competitiveness	Other Implementation Factors		Overall Application Rating
					Factor	Rating	
Electrical utilities generating capacity augmentation	5	3	5	3	Rising plant costs	+1	17
Residential sector							
Single family homes	4	2	1	4	Land ownership	+1	12
Low density housing	3	2	1	4	Land/system ownership	-1	9
Low rise apartments	2	2	1	4	Land/system ownership	-1	8
High rise apartments	2	2	1	4	Land/system ownership	-1	8
Mobile homes	2	2	1	4	Land ownership	-1	9
Remote Communities	1	3	1	5	Land availability	+1	12
Other applications - centralized domestic hot water facility	3	2	1	4	Ownership and financing	-1	9
Commercial sector							
Office buildings	3	2	1	4	Urban density	-1	9
Retail stores and shopping malls	3	2	1	4	Ownership and financing	-1	9
Schools	3	2	1	4	Financing	-1	9
Hospitals	2	2	1	4	Land availability and financing	-1	8
Hotels and motels	2	2	1	4	Land availability and financing	-1	8
Other applications - municipal and miscellaneous other buildings	2	2	1	4	Land availability and financing	-1	8
Agricultural sector							
Farm homes	2	2	1	5	Common usage	+1	11
Farm production	2	2	1	5	and land availability	+1	11
Industrial sector							
Chemicals and allied products	3	2	1	2			8
Primary metals	3	1	1	2			7
Petroleum refining	2	2	1	2			7
Paper and pulp industry	2	3	2	2	In place backup	+1	10
Glass industry	1	2	1	2			6
Portland cement industry	1	2	1	2			6
Structural clay industry	1	2	1	2			6
Food and food products	2	2	1	2			7

The third mode of operation is referred to as the fuel saver mode. In this mode the generating system is planned as if no WTG would be incorporated. In the setting of this existing system, WTGs are then added and, as wind generated electricity is available, conventional units are shut down thus saving fuel. In this mode, the value of the WTG is only the value of the fuel not burned (plus any applicable savings in operating and maintenance costs of the conventional system).

Operating WTGs in a fuel saver mode raises both technical and economic considerations. The principal technical consideration is the impact on the generating system of an electrical source whose output is basically unpredictable. Under certain situations, system instabilities could result. The severity of this problem depends on the characteristics of the existing conventional generating mix. For example, the availability of pumped storage or fast response gas turbines could immediately make up for any reduction in wind generated electricity.

The economic considerations of the fuel saver mode centers on the value of fuel saved. This has been extensively discussed in other investigations^{6,7} and so will be only summarized here.

Whenever wind is available, the generating facility burning the most expensive fuel would be shut down. As more wind becomes available, conventional generation would be reduced in sequence from units with the highest fuel cost to those with the lowest fuel cost (expressed in terms of dollars of fuel per kWh of electrical output). The availability of storage would modify this sequence, but this complicating factor is ignored here. If it is assumed that the probability of output of a WTG is uniform throughout the day (i.e., it is just as likely that the wind will blow during the night as during the day), then the value of the fuel saved is approximated by the expression:

$$\text{Value of fuel saved} = T_p C_p + (T_I - T_p) C_I + (1 - T_I) C_B$$

where:

T_p = Duration of peak period (expressed as a fraction of the day)

T_I = Duration of intermediate period (expressed as a fraction of the day)

C_p, C_I, C_B = Cost of peak, intermediate, and base fuels (respectively) in units of dollars of fuel per kWh of output.

This expression gives an approximate average value for the fuel that would be saved by a unit of electricity that is available at a random time during the day. When numerous WTGs are introduced into a utility system, this expression would need to be modified. For example,

as the number of wind units on the system increases, a point would be reached where additional WTGs could not save any peak fuel because the existing WTGs were already permitting the shut-down of all peak plants. This is important because a large fraction of the total value of saved fuel comes from the contribution of saved peak fuel because peak fuel is typically much more expensive (e.g., C_p might be nearly 3 cents per kWh while C_b might be less than 1 cent per kWh). An appropriate expression for the value of fuel savings which takes this into account can be derived by defining four additional terms:

F_p = Fraction of installed capacity that is peaking units
(neglecting any WTGs)

F_w = Total installed capacity of WTG divided by total installed capacity of conventional units

CF_w = Average capacity factor of WTGs

Using these terms, the expression for value of fuel saved is:

$$\begin{aligned} \text{Value of fuel saved} = & \left[F_p - (F_w \times CF_w) \right] \frac{T_p C_p}{F_p} + (F_w \times CF_w) \frac{T_p C_I}{F_p} \\ & + (T_I - T_p) C_I + (1 - T_I) C_B \end{aligned}$$

This expression looks more complicated than its explanation sounds. As wind market penetration increases, it simply reduces the credit for saving peak fuel to saving only intermediate and base fuel. It is only valid as long as $F_w \times CF_w$ is less than F_p (i.e., as long as the effective capacity of the WTG is less than peak capacity). For larger fractions of wind penetration, an additional expression would need to be developed to reduce in a similar manner the credit for intermediate fuel saving. This was not done in this work because the market penetration estimates for wind were never that high.

Evaluating the economics of wind energy solely on the basis of fuel saving, with no capacity credit, is a conservative approach because at almost any site some capacity credit could reasonably be allowed. Some studies have used 10 percent as a nominal value. Undoubtedly for some utilities with good winds, some pumped storage, and with numerous dispersed WTG units, considerably higher capacity credit, perhaps 50 percent, could be allowed. An accurate estimate of an appropriate capacity credit requires detailed studies of individual utility systems which consider actual wind data at specific candidate sites, characteristics of existing generating mix, and load pattern. Although the Electric Power

Research Institute is sponsoring investigations of this type, much more work will be needed in this area to fully understand the value of wind to utilities.

Because the wind resource is so large, and because matching it to suitable applications is so essential, it is difficult to describe in a meaningful and consistent manner the maximum potential use of wind energy in the United States. In estimating the "technical limit" for wind, to be used in the ranking process, many considerations need to be included.

The size of the wind resource is sufficiently large that, in theory, all the energy needed in the nation could be supplied by wind. For example, Lockheed estimated that by siting wind units only over open range land of conterminous United States, electricity equivalent to over 150 quads of primary energy could be generated.³ Open range land was carefully defined to exclude populated areas, privately owned land, national or state parks, military reservations, scenic reserves, and transportation corridors and rights of way. Within 15 miles offshore, an additional 70 quads of primary energy equivalent could be generated. The numbers are obviously large and the technical limit would need to consider more than the resource availability.

The preceding analysis of utility applications of wind showed that the value of wind derives from the intermediate and peak fuel that it saves. This led to the choice of a technical limit equal to the sum of peak and intermediate power in 2020 (29 quads of primary energy equivalent) which corresponded to a break point in the value of wind. That is, above this technical limit, the value of wind as a fuel saver would be so low as to make its use unlikely. This value of 29 quads was selected as a technical limit recognizing that it neglected to include the smaller potential wind uses (e.g., residential heating and agricultural water pumping).

The mission analyses arrived at surprisingly similar figures using different approaches. The market projection in the Lockheed study shows about 22 quads of primary energy equivalent in 1995 for all wind applications.³ Scaling this linearly with total energy consumption in 2020 yields about 30 quads. This 30 quads is not a technical limit as the concept is used here but rather a projection of what could actually occur under economic forces. Thus, the choice of a 29 quad technical limit appears to be conservative for what it is supposed to represent. Similarly, the GE study, taking into account many factors such as site availability, demand size, and economic projections, arrived at a "saturation limit" of 23 quads of primary energy equivalent in 2000 for all wind uses. Again, scaling this linearly with total consumption to 2020 gives an estimate of about 30 quads. Based on these two analyses which were economically dominated, the use of 29 quads as a technical limit, for which economics are only secondarily considered, appears conservative.

Environmental Considerations

The environmental ranking analysis was based on three considerations: air emissions except CO₂, CO₂ reduction, and resource (primarily land) utilization. Although not included in the ranking process, two additional environmental aspects of wind also need to be considered: aesthetics and communication interference.

Wind is very attractive from an air emissions and CO₂ standpoint. It generally displaces combustion fuel and therefore directly reduces air emissions. The land use issue is more complex.

The base case market projections show 3.8 quads of wind energy in 2020. This would require nearly 60,000 1.5 MW WTGs. At a conservative spacing of 2 WTGs per square mile, this would require 30,000 square miles. Of course, to the extent that some of this wind energy would come from small on-site units for which additional land would not be needed, this value overestimates the land requirement.

Both of the mission analyses indicate land availability far exceeding this requirement. For example, the GE results, which appear reasonable, are summarized in Table IV-5. The important conclusion is that for the levels of market penetration projected in this analysis the available land appears to far exceed (by a factor of about 7) the land needed for WTGs.

Large WTGs that have metallic blades can interfere with television reception up to a distance of 1 mile. This fact has received much attention because of the experience with a demonstration WTG at Block Island. In practice it is not likely to be a serious problem. Larger (for example, 1.5 MW) units will be located at such remote sites that interference with TV reception would be unlikely. Small units (e.g., 15 kW) are not likely to cause interference, particularly because many of these units might use non-metallic blades. The interference problem is, in fact, probably most acute for units of the 100 kW size range such as installed at Block Island. These are small enough to be located in populated areas and yet are large enough to cause interference. In summary, interference concerns cannot be ignored, however, these are not expected to be a major constraint on WTG deployment.

Concerns have been raised over the aesthetic impact of large numbers of WTGs. It is difficult to assess the importance of this issue because what is objectionable to one person can be beautiful to another. It is, however, likely that poorly designed and inappropriately sited WTGs can meet with public resistance.

The base case projection of the equivalent of 60,000 large wind units sounds imposing in itself. One way to look at this is to compare it with the estimated 150,000 small windmills in operation today. Few of these utilitarian units were designed or sited with an eye toward aesthetics, and yet few aesthetic concerns have been raised over their

Table IV-5

NET LAND AREAS AVAILABLE FOR WECS POWER SYSTEMS
(thousands of square miles)

<u>Wind Regimes</u>	<u>Total</u>	<u>Institutional Lands</u>	<u>Not Available Due to Other Land Use</u>	<u>Not Available Due to Poor Topography</u>	<u>Net Available for WECS</u>
Low	1,104	202	325	420	157
Moderate	415	86	80	196	54
High	<u>55</u>	<u>2</u>	<u>11</u>	<u>39</u>	<u>3</u>
Total	1,574	290	416	655	214

Source: Reference 6

existence. Large WTGs would obviously be visible from greater distances; on the other hand, such large units are likely to be located at more remote sites than current agricultural windmills. Based on these considerations, it would appear that WTGs may not present an aesthetic problem at the level of use projected here. In fact, the transmission lines leading from these units could be more distasteful than the WTGs themselves. Although modern WTGs might not become tourist attractions like the ancient ones in Holland, there seems to be no reason why careful attention to design (including tower shape and color) and siting cannot meet the aesthetic standards of a majority of the public.

International

Although the international market for WTGs has not been carefully studied, it would appear to be promising. From a hardware standpoint, WTGs have many qualities that should make them attractive in international markets. They are generally economically attractive. They can be of a scale compatible with regional, local, or on-site energy supply systems. They require no exotic maintenance skills. They are compatible with basic energy demands (water pumping, electricity, grain milling, etc.). They can be used as fuel savers in electrical grids to ease the current financial squeeze which many countries face as a result of the high cost of oil imports. At least some of the components are volumetrically dense (e.g., transmission, hub, controls, blades) so that long distance shipment is feasible.

The market opportunities should be strong, but the competitiveness of the United States in the market is uncertain. Currently, European countries such as France, Switzerland and Germany, are major suppliers

of wind systems. Indeed, some of these European products are imported into the United States.

As a WTG supplier, the U.S. might find itself in the same mixed situation as with products that are similar to WTGs. The United States' export position in large WTGs may be similar to its position in the aircraft industry, where advanced technology maintains a strong United States dominance. The United States' export position in smaller WTGs may be similar to its position in automobile exports, which has not been particularly strong. However, even this market should not be ruled out as the United States' ability to mass produce complex mechanical equipment could provide export opportunities. Important qualities to become competitive in these markets will be the ability to competitively mass produce mechanical hardware and to sustain advances in technical design and material. Entry into foreign markets could also be enhanced by foreign patent policies that would protect business investment in foreign sales and service programs. In summary, it would appear that a strong export market could develop for WTGs (both large and small) and that this export capability would strongly be enhanced by significant RD&D efforts and commercialization success within the United States.

RD&D Programs

The historical information presented in Chapter III of Volume I shows that the wind program has not grown in dollar size as rapidly as the other solar electric options. Whereas the budget for all solar electric options increased by a factor of about 3 between 1976 and 1978, the wind budget less than doubled. In spite of modest growth, the wind program has evolved into a diversified effort that involves many contractors and national laboratories pursuing a variety of design options and many technical issues.

Figure IV-7, which shows the structure of the wind program, emphasizes the important role of a variety of organizations including private contractors, NASA, USDA, and the national laboratories. A more detailed picture of the technical program, emphasizing the design options and associated contractors, is shown in Figure IV-8.

Until the past year, the federal program has emphasized the megawatt scale design. In response to considerable public pressure, and recognizing their potential importance, the program has lately increased emphasis on smaller kilowatt scale units. Within this wide size range, the program effort includes a variety of design, demonstration, novel concept development, and support activities.

Because wind systems can be used in so many applications, many of which appear to have economic promise, it would appear that the program would benefit from additional funds. An expanded program would benefit most by concentrating in the following areas.

FIGURE IV-7. WIND SYSTEMS BRANCH PROGRAM ORGANIZATION

Source: SRI

FIGURE IV-8. TAXONOMY OF WIND ENERGY CONVERSION SYSTEMS AND ASSOCIATED CONTRACTORS

The large WTG program has been sequential in that it has focused primarily on staged size increases of the same basic design. This effort would profitably be expanded to include similar development of other designs by other contractors. These other designs could include three-blade and up-wind rotors to confirm the validity of past design choices. Because even large WTGs are small compared to most energy facilities, a variety of avenues can be pursued, even to demonstration, at relatively modest cost. Furthermore, because no single design is likely to be best for the wide variety of sites that will be used, the development of alternative designs would be desirable.

Demonstration of existing designs could be stepped up. The advantages would be to gain fabrication experience, validate the "learning curve" effect, expand utility experience, and demonstrate the wind farm concept of multiple WTG installations.

The efforts in advanced concepts, such as augmentors and vortex designs, are very important and should continue to receive strong support. Funds should be available to demonstrate these as soon as their development success indicates this is warranted.

Finally, additional efforts need to be made to inventory potential sites. The resources devoted today have not been adequate to this major task. These studies need to include all the factors which determine a desirable site including the requirements of potential users. For this reason coordination (and perhaps cost sharing) with utilities would be beneficial to the inventorying process.

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V SOLAR HEATING AND COOLING

Introduction

General Description

Solar heating and cooling refers to the process of using the sun's radiant energy as a source to provide space heating, space cooling, or service hot water heating for application to a complete range of building types. Other purposes are swimming pool heating and greenhouse heating. In the present context, solar heating and cooling does not include provision of energy for process heat in industrial or agricultural applications, which is treated separately in this report, although the processes and equipment are generally similar. It also does not entail the use of wind energy systems to supply heating or cooling loads or photovoltaic systems used for the same purposes, although solar systems may be combined with these systems in hybrid applications.

A solar heating or cooling system generally consists of a radiant energy collection subsystem, an energy storage subsystem, an energy application subsystem, and one or more energy transfer and exchange subsystems. In the case of cooling, an energy conditioning or conversion subsystem is also included.

A fundamental characteristic of solar heating and cooling processes is the relatively low temperatures and system pressures involved compared with other uses such as electric power generation. Maximum temperatures of collection, storage and transfer are generally kept below 212°F to avoid the higher system pressures and thermal losses that increase rapidly with increasing temperatures.

The principal potential of solar systems accrues from the zero cost of the energy source, although the equipment necessary to collect and convert radiant energy to useful heat is complex and considerably more expensive than that required for conventional heating systems. Thus, the total annual cost of delivering solar energy for satisfying the heating or cooling load of a building includes a rather large equipment amortization component compared with conventional systems.

Another limiting factor applying to solar heating and cooling systems arises from the mismatch of radiant energy availability and space heating and cooling energy requirements as a function of time and the random nature of climatological phenomena. These problems generally limit the economical sizing of solar energy equipment to somewhat less than what would potentially fulfill the total energy demand of the application. Therefore, conventional systems are required to back up or supplement the solar system.

The economic degree of solar energy supplied, or solar dependency, is a complex function of climate, energy demand, cost of solar equipment, equipment durability, cost of capital, and present and future costs of supplemental or alternative energy. Optimum solar dependencies are generally found in the range of 30 to 80 percent.

Solar heating and cooling systems may be categorized as active, passive or hybrid. The primary feature of an active system is the use of supplemental energy to move a thermal medium (a liquid or air) between the point of collection and the point of application. A passive system is generally characterized by the combination of the collection and storage subsystems into one body and nonmechanical energy transfer systems to the point of use or for other purposes. A hybrid system combines elements of solar and nonsolar systems, such as the use of a heat pump to extract heat from a solar generated heat store and to move it to the point of application. Other hybrid systems can include water or air-cooled photovoltaic electrical systems in which the heat produced in the cooling fluid is used for space heating or absorption cooling. These categories are not precise. For example, small fans may be used in a passive system to transfer heat by forced convection from a storage body to the point of use. Additionally, mechanically operated shades or insulation panels are applied in passive systems to regulate the collection or rejection of solar energy by the collector-storage body.

Principles

The production of useful thermal energy from radiant energy requires a solar collector that absorbs the full spectrum of the sun's radiation and converts it to heat energy. This heat energy is transferred to some transfer medium (liquid or air) which is then used directly or stored for use in periods of low or zero radiant energy availability. Space heating applications use either direct flow (in the case of hydronic heating systems) or heat exchanger processes (in the case of hot air heating systems). If air is used for the transfer medium, a solid or water to air heat exchange process is used.

Hot water heating systems are generally simple direct flow processes or they use water to water heat exchangers. In the case of space cooling, heat is used directly from collectors, or from storage, to drive refrigeration machinery of the absorption or mechanical type. Auxiliary equipment required in an operating system includes piping, ductwork, storage vessels, pumps, fans, and controls, all of which is conventional, off-the-shelf equipment.

Systems may be designed for space heating only, space cooling only, hot water heating only, or combinations. Combination systems are generally relatively more economical, since common collector equipment will be used productively for larger fractions of the year.

The collector subsystem is the key component of a solar system and generally accounts for the largest portion of the total cost. For this reason, the unit cost of collectors (or efficiency at the same unit cost) is the principal parameter of economic analysis.

History

The theory of application of radiant energy for heating and cooling purposes has long been well known, and sporadic applications appeared in the latter portion of the 19th century and the early portion of this century. The earliest substantial applications were for heating hot water in areas in which alternative energy supplies were not available or were expensive. In this country, such applications were made as early as World War I with hot water heating for army training camps in California. From 1920 to 1950, numerous solar hot water heaters were installed in Florida and Southern California. These applications were largely eliminated by the introduction of low-cost electricity and natural gas distribution systems.

Hot water heating by solar energy has also enjoyed substantial application in other countries in which cheap alternative energy sources are not available. These include Israel, Australia, and Japan where substantial applications have taken place and remain. The present state of technology of solar hot water heating in this country, in fact, can be related directly to developments in Israel and Australia.

Although earlier research and development took place, the current state of technology in solar space heating is based on fundamental analytical and developmental work performed at Massachusetts Institute of Technology from 1939 to 1959. This work established the fundamental principles and techniques for collection and application of solar energy for space heating, which have not been greatly advanced up to the present time. In the interim, the technology was kept alive and further developed by a small but persistent body of pioneer researchers, engineers, and amateur solar enthusiasts. These include Telkes, Bliss, Bridgers, Löf Whillier, Tabor, Hottle, Yellott, Hay, Trombe, Thomason, Jordan, Farber, Moroc, Baer, and Daniels.

In the area of space cooling, early development work with solar driven absorption refrigeration equipment at the University of Florida by Farber established a base for further development.

Passive heating and cooling systems have also received attention in the past by Trombe (Trombe Wall) in France, Hay and Yellott (Skytherm System), and Böer (Drumwall-Beadwall system) in the United States.

The federal government embarked on a major research and development program in 1974. It was initiated by the National Science Foundation and later was largely transferred to the Energy Research and Development Administration (now incorporated into the Department of Energy). The

program, expanded in subsequent years, covers a wide spectrum of research and application areas in the solar heating and cooling field and has generated a substantial increase in the state of the technology.

Current Status

The technological base for space and hot water heating can be classed as well advanced, with further advancements expected to be evolutionary, coming about through further research and development, but more particularly through manufacturing and process developments. Such systems are in an early stage of commercialization, with some 200 enterprises active in system and component manufacture in some degree. Design, distribution, and installation enterprises are also being established at a rapid rate.

The present state of commercialization has been accelerated by federal demonstration programs for residential and commercial systems. Also, large numbers of individual owners are installing heating and hot water systems at their own expense. The systems installed, and being installed, however, are not necessarily economically viable compared with alternative means--in fact, most are not, except perhaps for those installed on a do-it-yourself basis where labor costs are avoided, in cases where the only alternative is very high-cost electrical energy, or where substantial subsidies reduce the out-of-pocket equipment costs.

Problems remaining that affect commercialization are high capital costs, the lack of adequate standards, relatively low reliability and durability of equipment, and the lack of technological dissemination throughout the heating and cooling industry, particularly at the lowest level. These problems will be reduced with time and as the industry matures.

Although a substantial number of solar cooling installations have been made, commercialization cannot be said to match that of space and hot water heating. These existing cooling systems use rather high-cost absorption-type refrigeration machinery which is not at present economically viable compared with alternative conventional cooling systems.

Passive systems have received increased attention recently because of their substantial economic potential. However, they are hindered by architectural and aesthetic considerations as well as a general lack of understanding of their principles and applications. Massive application of passive systems will require a reeducation of the architectural and building professions and some change in living habits of building occupants. Government demonstration programs can hasten the acceptance of these systems.

Major advances have been made in analytical and design processes; however, more needs to be done, particularly for use by the consumer and lower level installation, sales, and service enterprises. For the

professional person, the work done by the University of Wisconsin,^{1,2} Löff and Tybout,^{3,4} and others in optimization and economic analysis of active solar heating and cooling systems provides a firm approach to systems design. More recently, work by the Los Alamos Laboratory^{5,6} has provided an approach to analysis and evaluation of passive systems.

Dissemination of design and evaluation data and procedures has also been expanded through professional associations and other agencies. The American Society of Heating, Refrigerating and Air Conditioning Engineers (ASHRAE) has led in this area and has prepared and published fundamental documents⁷ for the guidance of the heating, ventilating and air conditioning (HVAC) profession.

Guidance to the design and educational professions has also been disseminated through the publication of several comprehensive textbook-design guides. These include References 8 through 11. Comprehensive summaries of the state of knowledge of the several elements of the area are contained in References 12 through 16.

A comprehension assessment of the state of the technology, problem areas, and research and development objectives was made in December 1975 and April 1976.¹⁷ This assessment served as a guide for the preparation of the National Program Plan for Research and Development in solar heating and cooling.¹⁸

The emergence of the industry is also indicated by the establishment of an industrial association, the organization of a largely expanded professional society, the publication of several solar topical newsletters, and the publication of at least two semiprofessional magazines.

Overall, it can be said that the industry is developing rapidly and can support massive solar heating and cooling applications in a degree consistent with their economic viability. The recent entry of very large manufacturers--having not only cost-reducing mass production capabilities but also distribution and sales and service capabilities--is an encouraging note.

Technological Description

Generic Technologies

The technology of solar heating and cooling may also be considered on a generic basis as to end use or application. The generic technologies considered are solar space heating, solar service water heating, solar space cooling, and combined applications. These may be further subdivided on the basis of the type of process and equipment used. The basic processes are collection or rejection, storage, transfer/conditioning, and application. A variety of equipment types are available for each process, thus providing alternative systems approaches or "paths" to each generic technology. Paths of active, passive and hybrid systems

are included. Detailed descriptions of these paths may be found in the National Program Plan for Research and Development in Solar Heating and Cooling.¹⁸ The available approaches, equipment types and processes are illustrated in Figure V-1.

Although several alternative approaches to each generic technology are technically possible, they are limited by practical and economic considerations. For this report and the time range under consideration, generic technologies and their primary features to be considered hereafter are limited to those discussed in the following paragraphs.

Active Systems

Hot Water Heating

Flat plate, evacuated tube, or concentrating nontracking collectors are used with direct flow or heat exchanger application for service hot water or swimming pool heating. Temperature requirements range from 120 to 180°F. For residential service, a preheater storage tank is generally used with transfer to the conventional hot water heater by direct flow or heat exchangers. Thermosyphon flow heat transfer between collector and storage may be used under certain conditions. Back-up or auxiliary is through conventional electric, gas, or oil hot water heaters.

Space Heating

Liquid systems--Flat plate, evacuated tube or concentrating nontracking liquid collectors with liquid storage. Applications may be through direct flow or water-to-water heat exchangers for hydronic-type heating systems or through water-to-air heat exchangers for forced air heating systems. Maximum temperature requirements range from 150 to 200°F. Storage is generally liquid, but phase-change materials may also be used. Back up or auxiliary is through conventional gas, electric, or oil space heaters.

Air systems--Forced air-type collectors with rock, other solid, or phase-change latent heat storage. Application is through air circulation through the storage body. Backup or auxiliary is by means of conventional electric, gas or oil forced air space heating systems. Temperatures are similar to those for liquid systems.

Space Cooling

Absorption type--Flat plate, evacuated tube, and concentrating nontracking collectors with water storage and absorption type chillers. Temperature range is 160 to 200°F. Back up is through gas heat to absorption chillers.

TYPICAL GENERIC TECHNOLOGY PROCESSES

- FOR SPACE COOLING SYSTEMS A COOL STORE MAY ALSO BE INCLUDED OR SUBSTITUTED. IN THIS CASE, THE PATH IS FROM HEAT STORE TO CONDITIONING, TO COOL STORAGE TO APPLICATION
1. FLAT PLATE LIQUID COLLECTOR SERVICE HOT WATER, WATER STORAGE
 2. FLAT PLATE LIQUID COLLECTOR SPACE HEATING AND SERVICE HOT WATER, WATER STORAGE
 3. FLAT PLATE AIR COLLECTOR SPACE HEATING AND SERVICE HOT WATER, ROCK STORAGE
 4. EVACUATED TUBE COLLECTOR, ABSORPTION SPACE COOLING, WATER STORAGE
 5. SINGLE AXIS TRACKING, CONCENTRATING COLLECTOR VAPOR COMPRESSION COOLING, WATER STORAGE
 6. FLAT PLATE LIQUID COLLECTOR, SOLAR ASSISTED HEAT PUMP SPACE HEATING/COOLING, GROUNDWATER STORAGE
 7. FLAT PLATE AIR COLLECTOR, DESSICANT/EVAPORATIVE SPACE COOLING, PHASE CHANGE STORAGE
 8. PASSIVE HEATING AND COOLING USING BUILDING MASS AS COLLECTOR/STORAGE, NIGHT RADIATION COOLING

FIGURE V-1. PROCESS AND EQUIPMENT TECHNOLOGIES: SOLAR HEATING AND COOLING

Vapor compression type--Concentrating nontracking and single axis tracking concentrating collectors with water storage and steam or organic fluid Rankine vapor compression-type chillers. Back up is through electric driven compression operating on the same shaft as the Rankine engine.

Combination Systems

Various combinations may be used. Hot water heating is generally combined with space heating to use the collector subsystem during the nonheating season and gain economy. Similarly, hot water heating, space heating, and space cooling may be advantageously combined in appropriate climates.

Passive Systems

Passive systems are generally used for space heating only; however, hot water heating and space cooling may also be included for certain types. The various types are described below.

Trombe system--This system uses glass covered massive vertical walls (e.g., concrete, brick) which serve as both collectors and storage bodies. Transfer to the heated space is by radiation from the inner surface of the wall and by natural convection from the space between the glass and wall via openings at the top and bottom of the wall. This convection may be enhanced through the use of small fans. Manual or mechanically driven shades or insulation panels to reduce night radiation losses may be used to improve the efficiency of the system. A degree of cooling can be obtained by covering the wall in the daytime and uncovering it at night with heat rejection by radiation. Hot water preheat may be obtained by circulating water through pipes embedded in the wall, although heat transfer is relatively inefficient using circulating water.

Hay system--This system uses a water body on the roof of the structure which serves as a collector/rejector and storage. The water body is covered by movable insulation panels. For heating, the panels are removed in the daytime and heat is collected in the water body. They are then closed at night, with heating to the occupied space occurring by downward radiation. Cooling is accomplished through reversal of the process, with the insulation panels open and heat rejection by radiation to the night sky. This system can provide year around comfort with little or no auxiliary heating and cooling under certain climatic conditions.

Böer system--This system is similar to the Trombe system except that it uses stacked water filled drums (hence Drumwall) as a collector,

storage medium, radiator, and convector. Also included is an automated shading-insulation system in which polystyrene beads are introduced and removed from the space between two panes of glass (Beadwall).

Kalwal system--This system is also similar to the Trombe system except that it uses vertical fiberglass water-filled cylinders as the collector, storage medium, radiator, and convector. A variety of shading and insulation schemes is available.

Greenhouse systems--Attached greenhouses can be used in a variety of ways to provide passive or partially passive heating systems. The most simple system uses water filled drums or other thermal masses in the interior of the greenhouse to provide night carryover heating to the greenhouse and alternatively to residential space through forced convection. The greenhouse may also be used as a collector body with storage in the form of solid materials under the residence. In this case the system becomes partially passive or hybrid.

Hybrid Systems

In hybrid systems various combinations of solar and conventional systems may also be employed. The most common are:

Solar assisted heat pumps--These systems use a collector supplied thermal storage source for an electrical or gas driven heat pump to provide space heat during the heating season. The heat pump operates in the cooling mode during the cooling season with heat rejected into the storage or elsewhere. Hot water heating is generally included.

Fluid cooled photovoltaic systems--Air or water cooled photovoltaic panels may be used to provide both electricity and heat for space heating, space cooling, or hot water heating. The electricity supplied by the photovoltaic panels may also be used for heating or cooling. Thus a variety of combinations or hybrid systems is available.

Active-passive systems--Various combinations of active and passive systems may be used to provide space heat, cooling or hot water heating.

System Selection

The selection of a system for a particular application will be affected by its state of development, economics and other factors. For this report, however, the systems to be evaluated for economic viability and potential energy contributions are limited to the following:

Hot water heating--Flat plate, evacuated tube or concentrating nontracking collector system.

Space and hot water heating--Flat plate, evacuated tube, or concentrating nontracking collector liquid systems and air collector systems.

Space cooling--Flat plate, evacuated tube, or concentrating nontracking collectors for absorption type systems. Evacuated tube, concentrating nontracking or single axis tracking concentrating collectors for vapor compression type systems.

Passive space heating--A Trombe wall system

Hybrid System--A solar assisted heat pump system. Limitation of the technologies to these few generic types will not have a substantial effect on the overall outcome of this study, i.e., on the comparative economics or ranking of the various technologies.

Development Schedule

The equipment and processes in Figure V-1 and discussed in the previous paragraphs are in various stages of development, ranging from the rather well developed flat plate collectors used for space and hot water heating to Rankine cycle space cooling chillers which may be classed as being in the laboratory research stage. In all cases, the theory or concept is well established. Major breakthroughs are not expected because of the nature of the processes involved and the relatively long past period of research and development. However, gains are expected to be made through advances in collection and application efficiencies and cost reductions.

Development Requirements

Specific development requirements leading to economic viability and a more mature degree of commercialization include:

Collector subsystems--The primary problems affecting solar collectors are cost and durability. The development process is expected to alleviate these problems to an appreciable degree, although the time scale is speculative. Major reductions in the costs of flat plate metallic collectors are not expected, although moderate cost reductions are expected through mass production and manufacturing process improvements. Increases in efficiency resulting from improvements in absorber plate selective coating, optical coatings for cover materials, and other improvements will result in lesser scale cost reductions. Other cost reductions are expected to come about through use of collector systems, using much less metallic material than the present flat plate systems. The evacuated tube and concentrating nontracking types are expected to gain supremacy in the future on a cost-effective basis because of lesser use of high-cost metallic materials. Increased durability is a major objective of further development in collectors.

Air conditioning equipment--Solar cooling is not expected to become economical when used alone without substantial cost reductions and efficiency improvements. The currently used absorption equipment does not seem to provide this potential. The more probable future cost-effective system is expected to be some form of mass produced Rankine cycle vapor compression system operating at a much higher coefficient or performance (COP) than can be obtained with the absorption system. Turbine driven "cold air" systems similar to those used to cool some aircraft on the ground also have potential.

Other hardware--Except for storage systems, most other hardware associated with solar heating and cooling systems is "off-the-shelf" and used for conventional HVAC systems. No large cost reductions can be expected although increased volume may produce small cost savings. Further research and development for storage systems is needed with the primary objective being to reduce costs and increase durability.

Passive and hybrid systems--These types of systems have not enjoyed the degree of research and demonstration associated with active systems. They would benefit from demonstration-type projects in which performance and economics could be better assessed.

Schedule

The estimated development schedule for the several generic technologies is shown in Table V-1. The indicated dates are by no means precise events, and considerable overlap among development stages is present and is to be expected. For example, solar hot water heaters are already being sold in significant quantities; however, development work continues toward cheaper, more efficient, and more durable collector systems.

Table V-1

DEVELOPMENT SCHEDULE FOR SOLAR HEATING AND COOLING

<u>Generic Technology</u>	<u>Stage of Development</u>					
	<u>Theory or Design Concept</u>	<u>Laboratory Scale R&D</u>	<u>Subsystem Development</u>	<u>Pilot Plant Testing</u>	<u>Demonstration and Testing</u>	<u>Commercial Application</u>
Hot water heating	Currently established	Substantial work completed in the past; however, work is continuing.			1976- 1980	1975- 1980
Space heating	Currently established	Substantial work completed in the past; however, work is continuing			1976- 1980	1975 1980
Space cooling	Currently established	Absorption process: substantial work completed; development continues			1976- 1980	1980- 1985
		<u>Eankine and Other Processes</u>			1980- 1985	1985- 1990
		1975	1976-1980	1976-1980		
Passive heating and cooling	Currently established	N.a.	1976- 1980	1976- 1980	1976- 1980	1980- 1985
Solar assisted heat pump heating and cooling	Currently established	N.a.	1975- 1980	1975- 1980	1976- 1980	1980- 1985

No significant technical barriers to the development of the listed systems are present. The primary measure of development at any stage is the economic viability of the system compared with both the solar and conventional alternatives. However, there is uncertainty in the eventual economic viability of the various systems within a generic technology, and for this reason various alternative paths are envisioned. In summary, full development does not necessarily mean commercialization and free market sales.

Economics

Introduction and Procedures

The economics of solar heating and cooling systems are complex functions of load, climate, system capital costs, efficiencies, and durabilities; the cost of capital, taxes, and other financial considerations; and the price of alternative energy sources and escalation rates. As previously noted, because solar heating and cooling systems do not provide 100 percent of requirements on a practical basis, the price of auxiliary energy becomes an important factor in economic analyses.

The approach to economic analyses requires the establishment of an optimum system size and solar dependency as affected by the many variables listed above and the calculation of the unit cost of energy produced on an annual basis, including the cost of auxiliary energy. This unit cost is compared with that accruing to alternative conventional systems to determine the economic viability of the solar system.

The procedures used herein include:

- The establishment of optimum solar dependencies based on building heat loss rates and climatic variables. The optimum dependency process was based on methods presented in Reference 2 ("F" chart system). Climatic conditions were obtained from Reference 7 and other publications for a representative city in each of nine regions as summarized by Table V-2. An average building heat loss rate of 10 Btu per square foot per degree day was used. This estimate was based on the assumption that the reduction of heat loss to this level through added insulation and other factors will be more economical than solar energy system applications. The base building used was a 1,700 ft² residence. Hot water heating demand was assumed to be 80 gallons per day at 140°F.
- Theoretical solar dependencies were reduced by 10 percent to account for average conditions of application in new construction and 15 percent for retrofit applications.
- Optimum sizing was established on the basis of an assumed average of system life, interest rates, and energy escalation.
- A range of systems costs was established as later discussed.

Table V-2

REGIONAL CLIMATIC DATA

$\bar{I}$ = Average daily insolation, horizontal surface (Btu/ft² day)
 K_T = Ratio of $\bar{I}$ to radiation on horizontal surface outside earth's atmosphere
 H = Degree days, heating, 65°F base (°F o days)
 C = Degree days, cooling, 65°F base (°F o days)

Region, Representative City, and Latitude		AV/TOT	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
1. New England	$\bar{I}$	1156	505	738	1067	1355	1769	1864	1850	1570	1267	897	536	443
Boston, MA	K_T	0.450	0.410	0.426	0.445	0.438	0.499	0.495	0.507	0.480	0.477	0.453	0.372	0.400
42° 22' N	H	5634	1088	972	846	517	208	36	9	161	60	316	603	938
	C	338												
2. Middle Atlantic	$\bar{I}$	1310	646	893	1280	1568	1819	2044	1985	1716	1432	1081	705	561
Philadelphia, PA	K_T	0.498	0.445	0.470	0.496	0.504	0.516	0.553	0.524	0.516	0.520	0.506	0.464	0.460
40° 00' N	H	5144	1016	889	747	392	118	40	30	60	297	620	965	
	C	989						210	378	305	96			
3. South Atlantic	$\bar{I}$	1504	946	1153	1352	1919	2063	2113	1649	1934	1557	1332	1074	952
Charleston, SC	K_T	0.542	0.541	0.521	0.491	0.584	0.574	0.567	0.454	0.569	0.525	0.554	0.539	0.586
32° 54' N	H	1794	443	367	273	42						34	210	425
	C	1851					226	376	477	456	300	16		
4. East South Central	$\bar{I}$	1397	590	907	1247	1662	1997	2149	2030	1363	1601	1224	832	614
Nashville, TN	K_T	0.502	0.373	0.440	0.472	0.514	0.556	0.573	0.565	0.554	0.556	0.540	0.454	0.426
35° 07' N	H	3578	778	644	517	189	40				30	158	495	732
	C	1368					115	360	490	462	241			
5. East North Central	$\bar{I}$	1291	526	797	1184	1481	1828	2042	2040	1332	1513	1094	662	491
Indianapolis, IN	K_T	0.481	0.380	0.424	0.472	0.470	0.511	0.543	0.544	0.552	0.549	0.520	0.413	0.391
39° 44' N	H	5699	1113	949	809	432	177	39			90	316	723	1051
	C	955						220	344	301	90			
6. West South Central	$\bar{I}$	1669	936	1199	1598	1829	2105	2437	2293	2216	1880	1476	1148	914
Fort Worth, TX	K_T	0.592	0.530	0.541	0.577	0.556	0.585	0.654	0.624	0.653	0.634	0.612	0.576	0.563
32° 50' N	H	2363	601	440	319	90	6					62	321	524
	C	2343					243	484	606	512	376	32		
7. West North Central	$\bar{I}$	1379	713	956	1300	1588	1856	2041	2011	1903	1544	1216	773	643
Omaha, Neb	K_T	0.543	0.542	0.528	0.532	0.506	0.522	0.542	0.547	0.577	0.568	0.596	0.508	0.545
41° 14' N	H	6612	1355	1126	939	465	208	42		12	105	357	828	1175
	C	1044						241	394	357	52			
8. Pacific	$\bar{I}$	1612	599	945	1504	1959	2369	2619	2566	2288	1856	1288	796	550
Sacramento, CA	K_T	0.585	0.416	0.490	0.591	0.617	0.662	0.697	0.697	0.687	0.664	0.598	0.477	0.421
33° 33' N	H	2502	583	414	332	178	72					56	321	546
	C	1038					4	187	339	283	225			
9. Mountain	$\bar{I}$	1473	622	986	1301	1313	2100	2291	2288	2033	1689	1250	753	552
Salt Lake City, UT	K_T	0.575	0.468	0.505	0.529	0.578	0.615	0.630	0.680	0.660	0.621	0.610	0.537	0.467
40° 46' N	H	6052	1172	910	763	459	233	84			81	419	849	1082
	C	792						90	372	305	25			

- A specific capital cost (SCC) concept was used to determine the basic economic parameter. The SCC is the capital cost of the installation divided by the annual output of the system. Units are in dollars per annual millions of Btu. Appropriate financial factors are applied to this value to determine unit costs of the solar energy supplied.
- The final outcome of the economic analysis as a function of interest rate, equipment lifetime, and cost and availability of alternative energy is discussed and presented throughout the discussion of the economic analysis of solar heating and cooling.

Economic Viability

A fundamental problem in determining the future market share and energy contribution of solar energy heating and cooling systems relates to the comparison of the economics of solar systems with alternative conventional systems on some uniform basis, such as total annual cost. The establishment of such comparability requires the use of assumptions of equipment lifetimes, interest rates, cost of alternative energy, and other factors which are speculative for the most part. The choice of these factors can exert a strong influence on the assessment of the economic viability of the solar energy system.

Numerous assessments of the economic viability of solar energy systems have been prepared. Two approaches are contained in References 19 and 20. For the present project, the methodology for estimating economic viability and resulting market penetration is discussed in Section X of this volume and Sections V and VI of the first volume of the report.

Differences between these results for solar heating and cooling technologies and those published elsewhere are primarily due to differing assumptions about equipment lifetime (durability) and the escalation of alternate (i.e. nonsolar) energy costs. Each of these factors is discussed separately.

Most previous economic analyses have assumed equipment lifetimes at least equal to 20 years. SRI does not believe this assumption is realistic, particularly in light of the equipment warranties available today and from comparisons with similar equipment. Durabilities and associated warranties, however, will improve with time through development and increasing industry maturity. The assumptions about the durability of the different solar heating systems used in this analysis are shown in Table V-3. The entries in this table illustrate our assumption that the durability of the solar systems will increase with time through development efforts and an increasing maturity of the industry.

Figure V-2 illustrates the sensitivity of solar unit costs to the assumptions regarding system lifetime and interest rates. The steeply rising solar energy unit costs in dollars per million Btu below about 20-year equipment lifetimes are to be noted.

FIGURE V-2. SENSITIVITY OF SOLAR HEATING UNIT COSTS TO EQUIPMENT LIFE AND INTEREST RATES SPACE HEAT PLUS HOT WATER

Table V-3

SOLAR EQUIPMENT LIFETIME ASSUMPTIONS

Generic Technology	Equipment Lifetime (Years)				
	1975	1980	1985	2000	2020
Hot water heating	10	12	15	20	20
Space and water heating	10	12	15	20	20
Space cooling	10	12	15	20	20
Passive heating	25	25	25	25	25
Solar assisted heat pump	5	10	15	15	15

Figure V-3 illustrates the effect of variable system costs and alternative energy rate escalation (in real terms) on the economic viability of a solar heating plus hot water system compared with a conventional system. In this case, a 20-year life with an 8 percent interest rate is assumed. The basic point of the figure is to illustrate that at a certain initial alternative energy cost and future escalation rate, a given solar system cost is required to produce economic comparability with a conventional system. For example, with an initial alternative energy cost of \$2 per million Btu (appropriate for natural gas) and an escalation rate of 4 percent, a system cost of about \$3.70 per square foot of collector is required. Also, a 3.5 cents per kilowatt-hour (\$10.25 per billion Btu) initial electrical rate with a 6 percent escalation rate would produce solar economic viability with a systems cost of about \$23.30 per square foot of collector.

Certain general conclusions may be drawn from these figures as to the present and future economic viability of solar heating and cooling systems.

At present, solar hot water and space heating systems can be considered as approaching economical viability where the only alternative is electricity at an average initial rate of 3.5 cents per kilowatt-hour, where a system cost of about \$20 per square foot of collector is available, and where system lifetime is 20 years or over. It is noted that the qualifying conditions are not met at present in the majority of the present market. In certain areas (mostly in the Northeast) where high (about 6 cents per kilowatt-hour) electrical rates apply, economic viability is currently found even for system lifetimes of the order of 10 years.

The achievement of economic viability for solar space heating systems competing with conventional oil and gas systems requires either significant increases in oil and gas prices or large reductions in present solar systems costs or, most likely, both. To be competitive at the present time with a conventional gas system (with natural gas costing about \$2.00 per million Btu), the solar system must have collectors costing

FIGURE V-3. ECONOMIC VIABILITY OF A SOLAR HEATING PLUS HOT WATER SYSTEM AS A FUNCTION OF SYSTEM COST AND ALTERNATIVE ENERGY RATE ESCALATION

about \$6 per square foot (or lower, depending on the escalation rate of gas prices) and an equipment lifetime of 20 years. Neither of these conditions is met at present. Collectors costing about \$10 per square foot and having a 20-year lifetime are required if initial natural gas prices are about \$4 per million Btu. Thus, depending on assumptions about future prices of natural gas and liquids and on cost reductions for solar collectors, it could be two or more decades before solar space heating systems can become widely economically competitive with natural gas and liquid fuels.

System lifetime is a major factor in future economic viability. The effect of capital cost subsidies in one form or another* may also be evaluated from the information presented in Figures V-2 and V-3. Assuming a subsidy in the form of an income tax credit of 30 percent on the first \$2,000 and 20 percent on the next \$8,000 of system capital cost, the following results are:

- The solar energy unit cost of \$12.50 per million Btu for a system life of 20 years at 8 percent interest would be reduced to \$10.83, or a reduction of 13.4 percent (Figure V-2).
- The 13.4 percent reduction is also equivalent to a reduction of system cost from \$15 per square foot of collector to about \$13 (Figure V-3).

Another subsidy being considered contains low interest rate loans. One plan provides for a 4 percent loan to be repaid in 15 years. The effect of this plan would be to reduce solar energy unit costs from about \$14.30 per million Btu for a 15-year, 8-percent loan to about \$11.00, or a reduction of about 23 percent (Figure V-2).

Neither of these subsidy plans has a major impact on solar space heating economic viability in competition with oil and natural gas under present conditions of system cost or cost of alternative energy. The plans do affect the solar economic viability in markets where the solar system is competing with electricity for heat.

Equipment Costs

A reduction in solar equipment costs over time is crucial to the economic viability of solar heating and cooling systems as illustrated in Figure V-3. The problem at hand is to establish a realistic forecast of future equipment costs. It has become practice to assess complete solar system costs on the basis of a unit of collector (dollars per square foot of collector) since the collector is ordinarily the highest cost element of the system. This practice is considered satisfactory for general economic studies under average conditions; however, its

*Many states have already established subsidy programs, and some form of federal subsidy is expected soon.

limitations should be kept in mind for individual applications. The primary limitation applies to water heating systems, small space heating systems, and space cooling systems in which the fixed cost of equipment other than the collector may be relatively substantial.

Previous economic studies have been based on cost reductions over time to as low as \$2 per square foot of collector. On the other hand, present costs as high as \$30 and higher are not unknown. As an extreme case, a program conducted by New England Electric for the installation of solar hot water heaters on 100 existing residences resulted in a cost of \$40 per square foot of collector.* This high cost has been charged to industry inexperience, particularly as related to installation costs. Discounting industry inexperience and "growing pains," a recent estimate of about \$20 per square foot of collector on a national basis is considered realistic for combined space heating and hot water systems and \$25 for hot water heating alone. The potential for reduction of system unit costs from these present values to those required to support solar system economic viability (as illustrated by Figure V-3) is discussed in the following paragraphs.

Potentials for unit cost reductions over time exist in several areas: cost reductions through improved manufacturing processes and volume production based on existing flat plate technology; efficiency improvements based on existing flat plate technology (equivalent to cost reduction); and a major departure from current flat plate technology using expensive metallic materials to one based on the substitution of cheaper nonmetallic materials. The probable direction in the latter case is toward evacuated glass tube collector types, concentrating collectors using nonmetallic materials for reflecting surfaces, or single-axis concentrating collectors, also using nonmetallic materials for reflecting surfaces. In all these cases, the principal metallic component remaining will be the absorber that takes the form of a simple metallic tube of relatively small diameter.

No substantial reductions are forecast for components other than collectors, since these components are essentially off-the-shelf and already produced in volume. An exception exists in the case of storage vessels in which standardization of sizes and types will permit a degree of volume production.

In the case of cooling systems, substantial cost reductions are expected to be related to the development of Rankine cycle vapor compression systems which may be mass produced on a basis similar to currently available refrigeration and air conditioning.

Some writers argue that orders of magnitude cost reduction potentials apply to the solar heating and cooling equipment case and cite the

*This program also resulted in much less performance efficiency than forecasted, i.e., an average of 20 percent dependency on the solar system compared with a forecast of 50 percent.

computer industry as an example. SRI does not believe this to be realistic because of the high cost of basic material required.

On the other hand, SRI's belief in the potential for industry to lower costs through more production and technical improvements is reflected in the cost forecasts for future solar heating and cooling equipment costs presented in Table V-4. These projections are based on residential or light commercial service and use the unit concept, i.e., the total system cost is divided by the area of the collector, resulting in a unit system cost in dollars per square foot of collector. All costs are presented on an installed basis. Retrofit cost projections are based on an average of 25 percent more than costs for application to new building construction.

The system unit cost forecasts presented in Table V-4 include various degrees of uncertainty among the several generic technologies. The values for hot water heating and space and water heating contain the least uncertainty, while those for space cooling, passive heating, and solar assisted heat pumps have a relatively large degree of uncertainty and can be classed as speculative because of little actual experience.

Unit Energy Cost Projections

The basic economic parameter to be used in economic analyses is the specific capital cost (SCC). This parameter is the total installed capital cost divided by the annual energy production. Units are in terms of dollars per annual millions of Btu. An annual cost for operations and maintenance (O&M) is added to arrive at total annual specific cost. Total annual system costs are found by applying appropriate interest and equipment lifetime factors.

Unit energy cost projections on a national average basis are presented in Table V-5 for each generic technology for the present and future periods under consideration. Unit costs for both new and retrofit situations are included. Both nominal (expected value) and low (least reasonable expectation) forecasts are provided. Projections on a regional basis are contained in the exhibit at the end of this section.*

An example of the source and derivation of the data listed in Table V-5 follows:

Case: Hot water plus heating - 1985, Region 4
Collector area - 400 ft²
Installed cost - \$4,000 new; \$5,000 retrofit
Annual output - 48.9 MM Btu new; 41.6 retrofit

*Projections for passive and solar assisted heat pump technologies are not included because of the large uncertainties involved.

Table V-4

PROJECTED EQUIPMENT COSTS

	System Unit Costs (dollars per square foot of collector)									
	1975		1980		1985		2000		2020	
	New	Retro	New	Retro	New	Retro	New	Retro	New	Retro
<u>Hot water heating</u>										
Nominal	\$20.00	\$25.00	\$15.00	\$18.75	\$12.50	\$15.63	\$10.00	\$12.50	\$10.00	\$12.50
Low forecast*	--	--	12.00	15.00	10.00	13.28	9.00	11.25	9.00	11.25
<u>Space and water heating</u>	New	Retro	New	Retro	New	Retro	New	Retro	New	Retro
Nominal	20.00	25.00	15.00	18.75	10.00	12.50	7.50	9.38	7.50	9.38
Low forecast	--	--	12.00	15.00	8.50	10.63	6.75	8.44	6.75	8.44
<u>Space cooling</u>	Alone	W/Heat	Alone	W/Heat	Alone	W/Heat	Alone	W/Heat	Alone	W/Heat
Nominal	34.00									
Low forecast	--	--								
<u>Passive heating</u>	New		New		New		New		New	
Nominal†	18.50		18.50		18.50		18.50		18.50	
Low forecast†	--		13.50		13.50		13.50		13.50	
<u>Solar assisted heat pump‡</u>	New	Retro	New	Retro	New	Retro	New	Retro	New	Retro
Nominal	37.00	45.25	32.00	40.00	27.00	33.75	24.00	30.00	24.00	30.00
Low forecast	--	--	25.60	32.00	22.95	28.69	21.60	27.00	21.60	27.00

*Low forecast is based on 20 percent reduction in 1980, 15 percent in 1985, and 10 percent in 2000 and 2020.

†Storage and collector combined.

‡Heating and cooling.

Table V-5

PROJECTED SOLAR HEATING AND COOLING UNIT CCSTS
(National Averages)

Generic Technology	Specific Capital Costs (dollars per annual millions of Btu)									
	1975		1980		1985		2000		2020	
	New	Retro	New	Retro	New	Retro	New	Retro	New	Retro
<u>Hot water heating</u>										
Nominal	\$128	\$167	\$98	\$137	\$83	\$122	\$69	\$108	\$69	\$108
Low forecast	--	--	78	110	67	98	62	97	62	97
O&M costs (\$/MM Btu)	2.50		1.95		1.68		1.36		1.36	
System life (years)	10		12		15		20		20	
<u>Space and water heating</u>	New	Retro	New	Retro	New	Retro	New	Retro	New	Retro
Nominal	162	238	121	178	81	119	61	89	61	89
Low forecast	--	--	97	143	68	95	55	80	55	80
O&M costs (\$/MM Btu)	3.28		2.46		1.64		1.23		1.23	
System life (years)	10		12		15		20		20	
<u>Space cooling</u>	Alone	W/Heat	Alone	W/Heat	Alone	W/Heat	Alone	W/Heat	Alone	W/Heat
Nominal	609	305	457	254	367	203	229	127	229	127
Low forecast	--	--	366	203	312	173	206	114	206	114
O&M costs (\$/MM Btu)	5.78	2.91	4.34	2.43	3.54	1.94	2.17	1.21	2.17	1.21
System life (years)	10		12		15		20		20	
<u>Passive heating</u>	New		New		New		New		New	
Nominal	86		86		86		86		86	
Low forecast	--		65		65		65		65	
O&M costs (\$/MM Btu)	0.86		0.86		0.86		0.86		0.86	
System life (years)	25		25		25		25		25	
<u>Solar assisted heat pump*</u>	New	Retro	New	Retro	New	Retro	New	Retro	New	Retro
Nominal	2.18	2.73	189	236	160	200	146	183	146	183
Low forecast	--	--	151	189	136	170	131	165	131	165
O&M costs (\$/MM Btu)	3.70		3.31		2.60		2.32		2.32	
System life (years)	5		10		15		15		15	

*Heating and cooling.

Specific Capital Cost - New Construction

Nominal: \$81/annual MM Btu
Low forecast: \$68/annual MM Btu

Specific Capital Cost - Retrofit

Nominal: \$119/annual MM Btu
Low forecast: \$95/annual MM Btu

O&M Costs: \$1.64/MM Btu

To develop unit energy costs comparable with alternative energy costs, appropriate interest, equipment lifetime, and O&M factors are applied. For example, the 1985 nominal SCC for new construction of \$81 per annual millions of Btu, at 10 percent interest for a 15-year lifetime (capital recovery factor of 0.13147) would result in a unit energy cost of \$10.65 per million Btu without O&M costs. Adding O&M costs at a rate of about 2 percent of SCC, or \$1.64 per million Btu, would result in a total unit cost of solar energy produced of \$12.29 per million Btu. This value can then be compared with alternative energy costs as a measure of economic viability of the solar system.

Potential Applications

The data presented in Table V-5 and discussed in the previous paragraphs of the section form the basis for estimates of market penetration and potential energy contribution for the solar heating and cooling resource. The approach to potential energy contribution on a regional and national basis and the results of calculations are presented elsewhere in this report (Section VII of the first volume). However, the principles and issues affecting market penetration, regional variations, and the effect of demonstration programs are discussed in the following paragraphs.

Markets

The basic market potential for solar heating and cooling equipment is associated with the residential building sector and low-rise commercial and institutional buildings that have the space necessary for deployment of the rather large collector arrays required. For solar service hot water equipment, an additional potential market is present in medium and high-rise multifamily residential and commercial buildings in which the relatively smaller collector area requirements can be accommodated.

The most important market potential for solar heating and cooling technologies is associated with the single-family housing segment of

the building sector. Some 60 million single family houses exist in the United States, with only about 1 million being constructed each year. The existing stock represents a substantial potential; however, installation costs will be higher and efficiencies lower as a result of poor orientation, lack of available space, and other causes. New construction can be designed for solar, thus decreasing installation costs and improving efficiencies compared with existing buildings.

Actual market penetration will be a function of the economic viability of solar systems compared with conventional alternative systems. While it is true that some portion of the population will procure and install solar equipment having a negative economic viability (as witnessed by the present market activity), massive applications will depend on a favorable viability resulting from substantial cost reductions in equipment, rapid rates of escalation in the price of alternative energy supplies, or most likely both.

Government subsidies in the form of tax credits and the like have the effect of reducing equipment capital costs and therefore favor market increases. However, the exact degree of the effect of subsidies remains speculative.

The primary problem associated with forecasting market penetration is the development of a realistic decision function with relative economic viability as the primary parameter. It is doubtful that any existing buyer decision function is applicable to the solar heating and cooling case. Care should also be taken not to associate the present solar market activity with full economic viability. Much of the present activity is the result of government demonstrations, incorrect assessment of economic viability, and a degree of "first-in-the-neighborhood" or social contribution ethics. These market forces are not expected to be the major factors in the long term, although they may serve the function of providing an impetus to more rapid commercialization of the solar systems.

Regional Variations

The market potential is affected by several regional considerations. One of the most important of these is the availability and cost of alternative energy. For example, where only high-cost electric energy is available for space and hot water heating, solar systems are already economically viable, or soon will be with modest equipment cost reduction and increased lifetimes. On the other hand, areas in which cheap electrical energy is available (such as the Northwest) will have a lower rate of penetration, other factors being equal.

Other regional factors significantly affecting economic viability, marketability, and potential energy contribution include the solar energy availability (insolation) versus heat or cooling demand (in terms of degree days heating or cooling). These factors have been taken into consideration in the estimates appearing in Tables V-6 through V-8 in the exhibit at the end of this section.

Effect of Demonstration Programs

The federal government has several subsidy programs designed to demonstrate solar heating and cooling technology. These include the school program conducted by the National Science Foundation and the residential and commercial programs conducted by the Department of Housing and Urban Development and the Department of Energy, respectively. More recently, HUD has developed a residential hot water heater subsidy program for application to several states having either high cost electrical alternatives or a high degree of radiant energy availability, both serving to improve the economic viability of solar hot water heating.

The overall effect of these demonstration programs is as yet uncertain. Only a few of the installations to date can be classed as economically viable; however, positive benefits in the areas of public education, equipment improvements, and some degree of cost reduction through competition and production volume are certain to accrue.

Limitations

Although the maximum potential energy contribution in terms of existing and new building volume is rather large, several practical factors tend to provide a substantial reduction. These include siting, orientation, and space limitations for existing buildings as previously described. In addition, national economic factors, including capital availability, can tend to retard the overall potential. Thus, there will be technical and economic limits.

Environmental Considerations

The substitution of renewable solar energy for fossil fuels has a substantially positive benefit to the environment through a net reduction in air and water pollution. Offsets in this regard are primarily related to aesthetic considerations, although the energy requirements for equipment production are also a factor.

International

The potential for exporting the technology and products in the solar heating and cooling area is considered to be limited. The area is one of rather low technology, and shipping cost, at least in part, will offset the advantages of mass production. This is particularly true for the industrialized countries, including Europe and Japan; however, potential markets may exist in Asia, Africa, Mexico, Central and South America, and the Middle East. However, competition in these areas by the industrialized countries is expected to be severe. On the other hand, export markets for the basic materials (glass, plastics, copper, aluminum, steel) and appurtenances (pumps, valves, controls) may exist, particularly for basic materials in semifinished form.

Research, Development, and Demonstration Program

National Plan

Past and present RD&D programs sponsored by the federal government (and some state governments) have served to improve the technology and application potential. At least as important is the dissemination of the technology throughout a wide spectrum of the academic, professional, research, and industrial and trade communities. The present R&D program policy (as contained in the National Program Plan for Research and Development in Solar Heating and Cooling¹⁸) is comprehensive and adequate. The plan was developed in coordination with a cross-section of knowledgeable academic, professional, research, and industrial contributors (Reference 17).

The primary objective of the plan is to stimulate the development of industrial, commercial and professional capability for producing and distributing solar energy systems. Major problem areas identified are (1) improvement of cost-effectiveness, (2) the relative lower state of technology for solar cooling, (3) complexity of application analysis resulting from climatic zone differences and other factors, and (4) the requirement for development of cost-effective retrofit systems. A major problem area related to the requirement for development and demonstration of passive systems could be added, although it is noted that passive system research is included in the details of the R&D Plan.

Demonstration Programs

Demonstration programs are perhaps more important than research and development in reaching cost-effective goals, considering the existing state of technology. This is more so in the hot water and space heating technologies than for cooling for which research and development is still a primary requirement. Demonstration programs encourage standardization, industry development, quantity cost reduction, and other benefits even though individual installations may not be economically viable.

Three residential building programs and two commercial (included institutional) building programs have been consummated, and a fourth residential and third commercial program will be announced in the near future. These programs provide for the federal government (HUD in the case of the residential program and the Department of Energy in the case of commercial) to assume the excess costs of the solar installation over that of a conventional system.

Other public demonstration programs include a special hotel and motel hot water heating demonstration program and the residential hot water heating program previously discussed.

The past demonstration programs have emphasized hot water and space heating with a few cooling installations.

In addition to the public sector demonstration programs, various federal agencies have applied solar hot water space heating and space cooling projects to both existing and new buildings owned by the agency. Leaders in this area have been the Public Buildings Service of the General Services Administration and the various military services. These applications are expected to be accelerated.

An expected benefit of the demonstration programs has been slow in materializing. This refers to the recording and publication of detailed cost, performance, and economic information.

The demonstration programs (except for the hot water programs previously mentioned) have emphasized installation with new building construction. Additionally, the residential programs have been restricted to builder-developers, and grants have not been made to individual residence owners, again with the exception of the hot water heating programs. These limitations neglect the 60 million existing single-family residences, which constitute a major potential. Although the cost of application to existing buildings is somewhat higher compared with new construction, significant benefits could result from including this application in the demonstration programs. A variety of retrofit techniques should be applied to ascertain realistic cost and performance data.

Another limitation of the demonstration programs is in the neglect of passive system applications. As indicated in Tables V-4 and V-5, passive systems may be more cost-effective than active systems. Demonstrations in this area are to be encouraged. A passive system is the realm of the architect or building designer as opposed to the equipment manufacturer-installer for active systems.

Private Sector Programs

At least as important, if not more so, are R&D activities conducted by manufacturers at their own expense. In this regard, it is encouraging to note the entry of large companies having not only cost reducing mass production capabilities but also the distribution, marketing, and service capabilities required for eventual national mass application.

RD&D Program Benefit Assessment

No direct association may be drawn between RD&D funds expended and potential benefits in terms of market volume and overall energy contribution. Certainly, RD&D program funds produce benefits, but a quantitative assessment is not possible.

Considerable controversy exists regarding the appropriate position of government (and associated level of funding) in the development and commercialization of the solar heating and cooling resource. The present policy is primarily one of stimulating the commercial sector and

accelerating the time for product commercialization. Under this concept, the government RD&D program in solar heating and cooling can be viewed as having accomplished its mission at some stage in the fairly near future.

The qualitative benefits resulting from the government RD&D program include:

- Advancing the technological base for the benefit of the eventual industry participants and consumers
- Promotion of technological dissemination and education
- Promotion of standards and other industry coordination activities
- Development of fundamental physical and climatic data*
- Advancement of the degree of commercialization through volume procurement, together with associated cost reduction.

The basic issue governing RD&D program policy is related to the present and prospective economic viability of the solar heating and cooling resource. Since viability is a function not only of solar equipment performance and cost factors but also of future alternative energy and availability, there are limitations (as well as dangers) in the practical size of efficient RD&D programs. The principal danger is one of development far ahead of economic viability and overselling to the public.

The solar heating and cooling RD&D policies, programs, and funding levels to date and those proposed appear adequate to efficiently provide the quantitative benefits listed above in a timely manner. If anything, RD&D funding is fully adequate to provide for efficient program execution. Major fund additions would not be expected to result in commensurate returns in the form of benefits.

Overall conclusions regarding the solar heating and cooling RD&D program are:

- The present RD&D program content and level of funding is likely to be adequate and need not be expanded in major degree.
- Expectations of order of magnitude reductions in costs and commensurate improvements in economic viability are not likely to be achieved.
- Massive increases in RD&D funding in the solar heating and cooling program area will not produce commensurate returns.

*At present, the ability to predict the performance of a solar system under a given set of climatic conditions is much greater than the ability to predict climatic conditions at a given location.

Priorities

Given the conclusions listed above, however, certain priorities should be given attention in the present and proposed RD&D program to improve the commercial, economic, and energy contribution potential of the solar heating and cooling resource. These are:

- Development of increased component durability at the same or lower costs
- Demonstration programs involving retrofit and passive systems
- Analysis and dissemination of performance and cost data relating to existing demonstration programs
- Development of cost-effective air conditioning equipment.

Exhibit

ASSUMPTIONS AND BASIS OF SOLAR HEATING AND COOLING COST ESTIMATES

Introduction

Specific Capital Cost (SCC) projections by region for three basic generic systems have been calculated by approximate methods with results appearing in the three tables following. The region number in each table relates to the regions listed in Table V-2 of the main body of this section, which also presents climatological data for a representative city of the region. The assumptions and basis for the SCC projections for each generic system are presented in the following paragraphs.

Hot Water Heating (Residential Service)

Assumptions

Demand - 80 Gals/Day @ 140°F

Efficiency - Annual Average of 0.35

Capital Costs:

Collectors Installed (\$/Ft²)

1975 - \$15.00

1980 - \$10.00

1985 - \$ 7.50

2000 - \$ 5.00

2020 - \$ 5.00

Fixed Costs (storage, pumps, controls, piping, etc.) - \$500

Retrofit - Add \$500

Basis

Dependency and Collector Sizing - calculated by "F" chart method for each region with average national lifetimes, interest rates and costs of alternate energy

Annual Output - Dependency × Annual Demand

Specific Capital Cost - Capital Cost ÷ Annual Output

Exhibit (Continued)
Space and Hot Water Heating (Residential Service)

Assumptions

Heating Load - 1700 ft² Residence with Heat Loss of 10 Btu/ft².
Degree Day Heating

Hot Water Demand - 80 Gal/Day @ 140°F

Efficiency - Mid Range by NBS Method

Capital Costs:

Heating Systems Total Cost per Ft² of Collector

1975 - \$20.00

1980 - \$15.00

1985 - \$10.00

2000 - \$ 7.50

2020 - \$ 7.50

Retrofit - Add 25%

Basis

Dependency and Collector Size - calculated by "F" chart
method with average national lifetimes, interest rates
and costs of alternate energy

Annual Output - dependency × annual demand reduced by 10% to
account for the average new construction case and 15%
for retrofit

Specific Capital Cost - Capital Cost ÷ Annual Output

Cooling, With and Without Heating (Residential Service)

Assumptions

Cooling Load - 1700 ft² Residence with Heat Loss of 10 Btu/ft².
Degree Day Cooling

Heating Load - As in Space Heating

Efficiency:

Collectors - As in Space Heating

Cooling Equipment - 0.25 Average

Capital Costs:

Heating - As in Space Heating Basis

Exhibit (Concluded)
Cooling Equipment -

	<u>1975</u>	<u>1980</u>	<u>1985</u>	<u>2000</u>	<u>2020</u>
Refrigeration Equip.	\$5000	\$4000	\$3000	\$1500	\$1500
Cool Storage	\$1000	\$1000	\$1000	\$1000	\$1000
Collectors Only (\$/Ft ²)	\$15	\$10	\$7.50	\$5	\$5

Basis

Dependency and Collector Sizing:

Cooling Only - Sized for 50% dependency in maximum cooling month (About 67% for the cooling season)

Heating and Cooling - Sized for Heating as in Space Heating Basis

Annual Output:

Cooling Only - Dependency × Cooling Season Load

Heating and Cooling - Heating season output as in Space Heating Basis + Cooling season output based on collector sizing for heating

Specific Capital Cost:

Cooling Only - Capital costs of refrigeration equipment, cool storage and collectors ÷ Annual Cooling Output

Heating and Cooling - Capital costs of heating system, refrigeration equipment and cool storage ÷ Annual heating plus cooling output based on collector sizing for heating.

Table V-6

PROJECTED COSTS FOR HOT WATER HEATING BY REGION

Region	Specific Capital Costs (dollars per annual millions of Btu)									
	1975		1980		1985		2000		2020	
	New	Retro	New	Retro	New	Retro	New	Retro	New	Retro
Nominal										
1	\$154	\$192	\$115	\$154	\$96	\$135	\$77	\$115	\$77	\$115
2	143	185	109	151	92	134	76	118	76	118
3	117	157	91	131	78	118	65	105	65	105
4	131	171	101	141	86	126	71	111	71	111
5	145	188	111	154	94	137	77	120	77	120
6	113	151	88	126	75	114	63	101	63	101
7	124	162	95	134	81	119	67	105	67	105
8	106	142	83	119	71	107	59	95	59	95
9	116	152	89	125	76	112	63	98	63	98
Low Forecast										
1			92	123	77	108	69	104	69	104
2			87	121	74	107	68	106	68	106
3			73	105	62	94	59	95	59	95
4			81	113	69	101	64	100	64	100
5			89	123	75	110	69	108	69	108
6			70	101	60	91	57	91	57	91
7			75	107	65	95	60	95	60	95
8			55	95	57	86	53	86	53	86
9			71	100	61	90	57	88	57	88
O&M costs (\$/MM Btu)	\$2.50		\$1.55		\$1.68		\$1.36		\$1.36	
System life (years)	10		12		15		20		20	

Notes: Low forecast is 20 percent reduction in 1980 and 1985 and 10 percent in 2000 and 2020.

O&M costs are based on 2 percent of regional average, nominal new capital cost.

Table V-7

PROJECTED COSTS FOR SPACE AND HOT WATER HEATING, RESIDENTIAL SERVICE BY REGION

Region	Specific Capital Costs (dollars per annual millions of Btu)									
	1975		1980		1985		2000		2020	
	New	Retro	New	Retro	New	Retro	New	Retro	New	Retro
Nominal										
1	\$194	\$285	\$145	\$213	\$97	\$142	\$73	\$107	\$73	\$107
2	163	239	122	179	81	120	61	90	61	90
3	151	222	113	167	76	111	57	83	57	83
4	164	240	123	180	82	120	61	90	61	90
5	170	250	127	187	85	125	64	94	64	94
6	135	198	101	149	68	99	51	74	51	74
7	169	248	127	186	84	124	63	93	63	93
8	155	229	117	171	78	114	58	86	58	86
9	156	229	117	172	78	114	58	86	58	86
Low Forecast										
1			\$116	\$170	\$78	\$114	\$66	\$ 96	\$66	\$ 96
2			98	143	65	96	55	81	55	81
3			90	134	61	89	51	75	51	75
4			98	144	66	96	55	81	55	81
5			102	150	68	100	58	85	58	85
6			81	119	54	79	46	67	46	67
7			102	149	67	99	57	84	57	84
8			94	137	62	91	52	77	52	77
9			94	138	62	91	52	77	52	77
O&M costs (\$/MM Btu)	\$3.28		\$2.46		\$1.64		\$1.23		\$1.23	
System life (years)	10		12		15		20		20	

Notes: Low forecast is 20 percent reduction in 1980 and 1985 and 10 percent in 2000 and 2020.

O&M costs are based on 2 percent of regional average, nominal new capital cost.

Table V-8

PROJECTED COSTS FOR SOLAR COOLING, RESIDENTIAL SERVICE (WITH AND WITHOUT HEATING) BY REGION
(Three-Ton Capacity)

Region	Specific Capital Costs (dollars per annual millions of Btu)									
	1975		1980		1985		2000		2020	
	Alone	W/Heat	Alone	W/Heat	Alone	W/Heat	Alone	W/Heat	Alone	W/Heat
Nominal										
1	\$1,610	\$1,073	\$1,252	\$894	\$984	\$716	\$626	\$447	\$626	\$447
2	714	357	536	298	417	238	268	149	268	149
3	433	192	320	160	280	128	160	80	160	80
4	475	211	352	176	308	141	176	88	176	88
5	717	370	540	309	421	247	270	154	270	154
6	341	152	253	126	221	101	126	63	126	63
7	732	355	547	296	425	237	274	148	274	148
8	597	341	454	284	355	227	227	142	227	142
9	865	461	654	385	510	308	327	192	327	192
Low Forecast										
1			1,002	715	836	609	563	402	563	402
2			429	238	354	202	241	134	241	134
3			256	128	238	109	144	72	144	72
4			282	141	262	120	158	79	158	79
5			432	247	358	210	243	139	243	139
6			202	101	188	86	113	57	113	57
7			438	237	361	201	247	133	247	133
8			363	227	302	193	204	128	204	128
9			523	308	434	262	294	173	294	173
O&M costs (\$/MM Btu)	5.78	2.91	4.34	2.43	3.54	1.94	2.17	1.21	2.17	1.21
System life (years)	10		12		15		20		20	

Notes: Low forecast is based on 20 percent reduction in 1980, 15 percent in 1985 and 10 percent in 2000.

O&M costs are based on 1 percent of regional average, nominal capital cost.

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VI AGRICULTURAL AND INDUSTRIAL PROCESS HEAT (AIPH)

Introduction

The use of solar energy for process heat in industrial and agricultural sectors needs careful examination, as pointed out in Volume I. The industrial sector is attractive because of its potentially significant size for solar applications while the agricultural sector is interesting because of its frequently modest temperature requirements.

An important consideration in assessing the use of solar energy in industrial processes is the temperature at which the energy is required. Until recently there were no reliable sources for these data. Recognizing the importance of this information, ERDA/DSE commissioned parallel studies by Battelle and Intertechnology Corporation to survey the temperature requirements (present and projected) of U.S. industry. A summary of the results of the Battelle work is shown in Table VI-1.¹ The values in this table are for useful energy delivered into the process (i.e., not fuel used) and temperature requirements for an average process operation. (Actual temperatures used are frequently higher when higher temperatures are in any case available.) Important conclusions are that less than 3 percent of the energy is used at temperatures under 212°F, an additional 32 percent is used at temperatures between 212°F and 350°F, while the remainder, 65 percent, is used at above 350°F. This means that a very large fraction of industrial heat requirements is at temperature levels that would require concentrating collectors. The lower end of the temperature spectrum could be met with simple flat plate collectors. Since waste heat is a potentially attractive alternative in at least some of these processes, the number of potential solar applications could be reduced even further.

Nevertheless, industrial processes have several qualities that make them potentially attractive. Skilled personnel could frequently be available to maintain the complex solar equipment. Nonsolar industrial facilities are usually custom engineered; the engineering thus required for solar systems is not necessarily a large additional expense. Finally, industrial facilities usually operate year-round so that, as with domestic hot water systems, a maximum amount of useful energy can be obtained from the solar system.

The use of solar energy for agricultural process heat entails many additional factors. Figure VI-1 shows that of all the energy flowing into the U.S. food system, over three-fourths is consumed in off-farm activities such as transportation, food processing, and marketing. (Direct process heat applications on the farm are limited to a very small fraction

Table VI-1

SUMMARY OF PROCESS HEAT REQUIREMENTS

(10¹² Btu per Year)

SIC Code	Description	Hot Water <212°F	Steam		Direct Heat/Hot Air			Rounded Totals
			212-350°F	>350°F	<212°F	212-350°F	>350°F	
1211	Bituminous coal and lignite						11	11
1477	Sulfur mining		44					44
20	Food and kindred products	60	275	100	10	95	15	555
22	Textile mill products	19	191	4		69	13	296
24	Lumber and wood products	5	21	4	106	4	70	210
26	Paper and allied products		465				94	559
28	Chemicals		1,400			450	250	2,100
2911	Petroleum refining		120	380			2,600	3,100
32	Stone, clay, and glass	8	20	37		24	1,081	1,170
3312	Blast furnaces and steel mills		65				1,712	1,777
3331	Primary copper	14.2			2.4		55.4	72
3334	Primary aluminum			38.4			63.1	102
3711	Automobile and truck manufacturing	13	1.4		21.3	10	0.9	47
3712								
3713								
	Rounded totals	120	2,600	563	140	652	5,965	10,040
	Percent of total	1.2	25.9	5.6	1.4	6.5	59.4	

Source: Reference 1

Source: Reference 2

FIGURE VI-1. ENERGY USE IN U.S. AGRICULTURE, 1975

of agricultural energy--about 0.14 quad of energy.) These direct applications are considered under the discussion of agricultural energy use. Table VI-2 shows that over 95 percent of this 0.14 quad of energy is used in four applications: drying corn, drying tobacco, warming poultry shelters, and warming greenhouses.

In contrast to industrial process demands, the temperature requirements for agricultural processes are very modest. For example, in-bin grain drying, in which the grain is dried inside the bin where it is stored, can be carried out at only a few degrees above ambient temperature. Building heating, such as for poultry and greenhouses, generally requires temperatures of less than 50°F above the ambient temperature. These modest requirements permit the use of low-cost, simple collectors and/or passive designs.

Technology Description

Figure VI-2 summarizes the spectrum of possible process heat uses of solar energy. From these possibilities, the following representative uses were selected for discussion: low-temperature grain drying, industrial hot water, and industrial low-temperature steam.

Grain drying is the largest use of thermal energy on farms as shown in Table VI-2. The economic analysis is based on a bin-wall collection system that can be installed on new storage bins and retrofitted onto existing ones. The system basically consists of a second blackened wall placed around the grain storage bin. Air is circulated between the two walls and is warmed by the blackened outer wall which itself is heated by the sun. The design is fairly standardized and can be constructed by the farmer during the off-season, thereby contributing to its economic attractiveness. Solar grain drying is most practical in single farm size. Larger commercial units usually operate at higher capacities and temperatures so that solar systems are not practical. Although the subsequent economic estimate is based on grain drying, the economics of building space heating is likely to be similar to this estimate, particularly where passive designs are feasible. Both grain drying and building heating currently use the same conventional fuels: LPG, natural gas, and electricity.

Industrial hot water is likely to be the first widespread use of solar energy in industry because conventional flat plate collectors can be used. Typical applications will be in textile and food processing facilities. Solar ponds, where they are practical, are likely to be the least-cost example of the use of solar for hot water. They are implicitly considered in the market penetration analysis by the alpha factor of the market share curve (Section V, Volume I) which allows for a variation in costs about the average costs of the idealized system that was specifically modeled. Thus, ponds are included in the market penetration estimate without being a distinct generic technology.

FIGURE VI-2.

Table VI-2

REPRESENTATIVE STATISTICS FOR AGRICULTURAL ACTIVITIES
WITH POTENTIAL SOLAR APPLICATIONS

<u>Commodity-Activity</u>	<u>Measure of Magnitude of Activity (tons per year)</u>	<u>Energy Requirements (10^{12} Btu/yr)</u>	<u>Fuel Cost to Product Value Ratio (percent)</u>
Products			
Corn	156×10^6	56	1.7%
Rice	5.7×10^6	2.8	0.4
Tobacco	1.0×10^6	32	5.6
Peanuts	1.9×10^6	0.8	0.5
Other crop drying	NA	0.9	NA
Buildings			
Broilers	5.5×10^6	12.4	2.0
Swine	10×10^6	0.9	0.1
Greenhouses	6,264 acres	35	15-30

Source: Reference 2

Low-temperature steam (less than 350°F) is the third generic technology considered within the process heat group. To meet this demand, higher performance collectors, such as concentrating or evacuated tube collectors, are required. Although these designs will generally be more expensive on a cost per delivered energy basis, they can meet a relatively large demand (about 1.2 quads currently) that waste heat is not likely to satisfy.

The use of solar in higher temperature processes requiring one or two axis concentrating collectors has been described in the section treating thermal power and is not discussed in detail here. In general, the use of solar to produce high-temperature steam will be less promising in industrial applications than in utility power plant applications because of the higher cost of capital in the industrial sector than in the regulated utility sector. Furthermore, high-temperature steam systems will be more expensive than low-temperature steam systems. Because the market penetration analysis documented in Volume I showed modest market potential for low-temperature systems, the market for high-temperature steam systems also appears to be small.

Development Schedule

The three generic technologies, grain drying, water heating, and low-temperature steam, are all based on established technologies. As shown in Table VI-3, grain drying and water heating have been demonstrated and commercial installations of both are being made. Although the hardware exists for industrial steam applications, demonstration and commercial installations await a stronger indication of economic attractiveness.

The dates in the table are somewhat arbitrary, since undoubtedly there were earlier uses than those shown. For example, solar drying of fruits has been common practice for hundreds of years, although recent trends have seen sunlight replaced with combustion dryers.

The current federal program has focused on demonstrating systems that are more or less commercially available in an effort to promote more widespread use. Some commercial installations of both industrial hot water systems and agricultural drying (grain drying) have been made without governmental assistance. For example, Anheuser-Busch is installing such a system in its brewery in Jacksonville. Solar grain dryers are commercially available (for example, the Kuss Soloron unit).

Industrial steam is less developed because of its higher cost. ERDA has conceived one of its water heating demonstrations (a commercial laundry in El Centro, California) as one that could be modified to produce steam, should that appear attractive. The commercialization date of 1985 represents the period by which suitable concentrating collectors should be available commercially and by which time successful demonstrations will have produced reasonable consumer confidence.

Table VI-3

DEVELOPMENT SCHEDULE OF SOLAR PROCESS
HEAT APPLICATIONS

	<u>Concept</u>	<u>Design</u>	<u>Pilot</u>	<u>Demonstration</u>	<u>Commercial</u>
Industrial hot water	--	--	--	1975	1975
Industrial steam	--	--	--	1980	1985
Agricultural drying	--	--	--	1960s	1975

Recent federal demonstrations of industrial process heat are summarized in Table VI-4. A similar program exists to demonstrate agricultural applications.

Economics

For all three process heat generic technologies, the solar system was treated as a "fuel saver," i.e. no specific allowance is made for storage. In general, storage is not likely to be incorporated into these systems because of its high cost (except, perhaps, a small storage unit to smooth out transients), and because backup systems are usually desired to maintain reliability. For example, Table VI-2 showed that for corn drying, the expense of fuel for drying is less than 2 percent of the value of the corn. With this low fuel expense, a farmer would not risk the chance of having prolonged low insolation during the drying period which could ruin his crop for the entire year. Consequently, he would have available conventional (e.g., electrical) drying equipment. Similarly, industrial facilities would want to maintain reliable operation to avoid idle labor and machines. In the case of many if not most of the industrial facilities, the solar energy available from a reasonably sized collector field is not sufficient to provide all the energy to the plant, so that in any case auxiliary heat is needed for normal operation.

System costs are summarized in Table VI-5 for the base case costs in region 9 (the Rocky Mountain states). The installed hot water system costs are based on delivered collector costs falling from \$8 per square foot in 1985 to \$6 per square foot in 2020 while annual efficiency increases from 45 to 50 percent. The installed steam system costs are based on delivered collector costs falling from \$14 per square foot in 1985 to \$10 per square foot in 2020 while efficiency increases from 50 to 60 percent. In both cases, plumbing costs are \$1 per square foot,

Table VI-4

U.S. DEMONSTRATION PROGRAM OF SOLAR INDUSTRIAL PROCESS HEAT

Process	Medium [°C(°F)]	Location	Owner/Operator	Solar System	Supplier
Concrete block curing	Hot water 70 (158)	Harrisburg, PA	York Building Products	Concentrating	AAI
Can washing	Hot water 85 (185)	Sacramento, CA	Campbell Soup	Concentrating	Accurex
Textile drying	Hot water 85 (185)	La France, SC	Riegel Textile	Evacuated tube	General Electric
Commercial laundry	Hot water and steam	El Centro, CA	American Linen Supply	Concentrating	Jacobs Engineering
Uranium milling	Hot water 55 (131)	Grants, NM	Sutro	Solar pond	ERDA/Livermore
Fruit dehydration	Air 65 (150)	Fresno, CA	Lamunuzzi & Pantaleo	Flat plate	California Polytechnic State University
Fabric drying	Steam 150 (303)	Fairfax, AL	West Point--Pepperell	Concentrating	Honeywell
Lumber kiln	Air 90 (194)	Canton, MS	J. A. La Cour	Undetermined	Lockheed

Table VI-5

SOLAR PROCESS HEAT COSTS FOR THE BASE CASE

	<u>1985</u>	<u>2000</u>	<u>2020</u>
Grain drying			
Installed cost (\$/10 ⁶ Btu/yr)	\$39.0	\$39.0	\$39.0
O&M cost (\$/10 ⁶ Btu)	1.5	1.5	1.5
Industrial hot water			
Installed cost (\$/10 ⁶ Btu/yr)	56.0	45.0	40.0
O&M cost (\$/10 ⁶ Btu)	1.0	1.0	1.0
Installed cost (\$/ft ²)	13.50	12.20	10.80
Industrial steam			
Installed cost (\$/10 ⁶ Btu/yr)	8.6	69.0	55.0
O&M cost (\$/10 ⁶ Btu)	1.0	1.0	1.0
Installed cost (\$/ft ²)	23.0	20.30	17.60

installation is \$1 per square foot (\$2 for the steam system), and an allowance is made for a 10 percent architect and engineering fee; a 15 percent contingency fee; and a 7 percent fee for other owner indirect costs. These costs represent significant improvement over current costs. The costs for recent demonstration projects have been running over \$40 per square foot.³

The cost projections discussed in the preceding paragraph and shown in Table VI-5 are based on reconciling cost information in References 1, 4, and 5 with the cost information developed for solar heating of buildings, presented in Section V.

The "low solar price case" uses the same costs but assumes that the price reduction occurs faster because of more aggressive demonstration and development programs as shown in Table VI-6.

The hot water collectors would be developments of current flat plate, single glazed, selective coated designs, while the steam system collectors would be a development of moderately concentrating designs (e.g., parabolic trough). In other regions, the costs are scaled proportional to insolation.

The grain drying system is based on a bin-wall collector costing \$1,400 and providing 34 million Btu of useful energy during the drying season. Since this is approximately what these systems cost now, little prospect is seen for improvements in cost.

Site-specific factors can influence these costs. For example, because no allowance has been made for land costs, the assumption is made that these systems are placed on rooftops or on surplus land. Some economy of scale is achieved in assembling large industrial facilities, compared, for example, with smaller industrial systems.

The most important complementary research will be improvements in collector performance and life time. This includes the areas of selective coatings, high performance glazings, and materials for absorbers. Storage research, while helpful, will not have a large impact on these applications since backup systems will be needed anyway.

Potential Applications

The industrial market has features that both promote and inhibit solar energy use, many of which were mentioned in Volume I. Some of the more important ones are discussed in the following paragraphs.

Because of its large size, the industrial sector is an important solar market. Technical barriers are the high temperature of most industrial processes (about two-thirds is needed at over 350°F) and the high energy requirements of many industrial processes compared with the available space to collect the energy. Of these two, the former is less likely

Table VI-6

SOLAR PROCESS HEAT COSTS FOR THE LOW SOLAR PRICE CASE

	<u>1985</u>	<u>2000</u>	<u>2020</u>
Grain drying			
Installed cost (\$/10 ⁶ Btu/yr)	\$39.0	\$39.0	\$39.0
O&M cost (\$/10 ⁶ Btu)	1.5	1.5	1.5
Industrial hot water			
Installed cost (\$/10 ⁶ Btu/yr)	56.0	40.0	40.0
O&M cost (\$/10 ⁶ Btu)	1.0	1.0	1.0
Installed cost (\$/ft ²)	13.50	10.80	10.80
Industrial steam			
Installed cost (\$/10 ⁶ Btu/yr)	86.0	69.0	55.0
O&M cost (\$/10 ⁶ Btu)	1.0	1.0	1.0
Installed cost (\$/ft ²)	23.00	20.30	17.60

to be the limiting factor. For example, the Intertechnology study⁴ estimated that parabolic concentrating through collectors was less expensive than using even flat plate collectors for heating water; consequently, up to the capabilities of such collectors (600°F), higher temperatures were not a barrier. However, the Battelle study showed heat from parabolic trough collectors to be about twice the cost of heat from flat plate collectors, so the question of cost as a function of temperature seems unsettled.

In contrast to temperature level, the energy intensiveness of industries presents a more complicated dilemma. Using rooftop area alone, solar could meet less than 5 percent of the energy demand of many energy-intensive industries.¹ Adequate land and the expense of preparing it for collector installation could be a difficult problem to solve. Considerations such as these resulted in a technical limit in the ranking methodology of 40 percent of industrial demand.

Some institutional considerations are likely to promote and others are likely to inhibit industrial use of solar energy. On the positive side, many industries are under pressure over the next few years to convert installations using oil and gas to other fuel sources. Coal is frequently mentioned as the most likely candidate. The base case projection (Section V of Volume I) shows industrial coal use growing from less than 40 percent of energy used in 1985 to over 70 percent by 2020. This substantial degree of shifting from one fuel to another in industry presents an attractive marketing opportunity for solar, since many potential customers will be making new energy investments. The most attractive segment of this market will be smaller facilities. Whereas coal boilers display lower costs (per unit of capacity) as size goes up, the cost of solar installations is relatively independent of size. Strict environmental controls in some regions could also do much to encourage solar use.

Several financial considerations inhibit solar use in industry. As pointed out in Volume I, one such barrier is tax policy that permits fuel to be taken as an expense in the current year while capital investment is taken as an expense by depreciating over several years. Because an expense in the future is discounted to a smaller present worth, the depreciation is not as valuable to a company as the current fuel expense.

It is often pointed out that the industrial market is attractive because industry is more inclined to use life cycle costing. While this is probably true, it operates as a barrier in this instance. Because of the uncertainties in the business environment, businesses usually require a short pay-back period for capital investment. In some industries, this can be as short as two years. Many industries are not interested that a solar system might be the most economical choice over a 20-year life cycle basis. They are concerned over whether they will still be viable over the next few years. This tends to discourage investment in capital intensive but efficient equipment, such as solar.

Finally, when industries purchase utility-supplied energy (electricity, gas, and under current regulations, even oil), they pay an average price that is lower than the marginal price of the next available unit of energy. This ability to buy at below replacement cost discourages investment in solar. In contrast, since the utilities themselves usually pay the marginal price, they are exposed sooner to higher costs.

The removal of these barriers should be considered a necessary, but perhaps not sufficient, condition for expanded solar use. The economic analysis here and by others suggests that uses of solar heat to provide industrial process heat will encounter stiff economic barriers. The alternatives, particularly coal, seem frequently to be lower in cost.

Based on the data of Table VI-1, conclusions can be drawn regarding solar uses in some of the more attractive applications. Because of the small potential market for agricultural applications (a fraction of a quad), these were not carried through the market penetration and ranking process. The drying and heating systems are sufficiently attractive that these applications should continue to come into more widespread use. The most attractive applications will continue to be on farm drying of corn because of its favorable economics, standardized design, and size of the market.

Environmental Considerations

As pointed out in Volume I, the environmental impact of solar use for process heat should be strongly positive. Particularly in the longer term when it might replace coal, the environmental benefits are attractive. Industrial areas are frequently the places that stand to benefit the most from environmental improvement. Aesthetics, maintenance, and safety should be fully manageable problems in the industrial environment.

International Potential

The widespread use of solar heat in U.S. industry is not likely to lead directly to important export markets. As with residential systems, the hardware will be generally labor-intensive to manufacture, so that a favorable product position is doubtful. At the same time, since little about the technology is unique, it will be difficult to gain a proprietary capability. Some agricultural systems (such as grain drying, building heating) can be modest cost, labor-intensive systems that can aid developing countries in improving their agricultural productivity; developing these systems can promote international good will even if not export markets.

Research, Development, and Demonstration Programs

The 1977 budget for the Agricultural and Industrial Process Heat Branch was \$7.8 million, less than 3 percent of the entire DSE program. Most of the programs have been directed toward demonstrating industrial hot water and agricultural drying systems. Several studies also have been made to survey potential applications.

The long-term prospects for AIPH use are probably fairly sensitive to RD&D program efforts, because in the long term, use will be determined by solar cost. This solar cost will be determined primarily by collector development, which depends heavily on the success of collector manufacturers. Thus, in the long term, the most effective role of the federal program would seem to be supporting the more fundamental research (for example, in materials and surfaces) that can eventually lead to reducing collector costs by one-half.

Conversely, in the near term, the important factor is to encourage early suppliers to build industrial experience and customer confidence on which to later expand. For this reason, this early federal program can be important in developing the industrial base on which a long-term energy contribution will be established. The current program seems to recognize this by relying on demonstrations in the near term.

Significant increases in RD&D effort in AIPH could most effectively be directed toward high-temperature collectors. Although significant results in this area will be difficult to achieve, they would be important to furthering AIPH uses, because the potential market increases greatly as the temperature capability of the solar collector increases.

Storage, particularly high-temperature storage, is frequently mentioned as a key to facilitating AIPH use. This investigation has found that such storage is not that important. Most industrial processes require very high reliability of energy supply to avoid idle capital and labor, so that a conventional backup system is usually needed anyway. Thus, storage capability is not likely to eliminate the backup expense. Furthermore, many industries are so energy-intensive that supplying their instantaneous energy demand with a solar system of reasonable size can be difficult; consequently, collecting enough solar heat to recharge a storage system for nighttime use can be doubly problematic.

In summary, the AIPH RD&D program as it is currently directed can be depended on to provide systems at the costs described earlier. The program appears reasonably balanced. Reduction in this RD&D program would delay the availability of systems by retarding commercial acceptance. Conversely, increasing the RD&D program, if directed toward demonstrations, would speed commercialization of low-temperature systems without greatly changing the eventual level of use. Alternatively, an increased program aimed at development of higher temperature collectors would increase the eventual level of use, although the chances of such a program's success might not be great.

The schedule of the program as it is currently structured is shown in Figure VI-3. The darkened triangles indicate progress through mid-1977.

	1977	1978	1979	1980	1981
AGRICULTURAL					
EXPERIMENTS	Cycle 2 ▲	Cycle 3 △	Cycle 4 △	Cycle 5 △	
INDUSTRIAL PROCESS HEAT					
EXPERIMENTS AND PROTOTYPE SYSTEMS		350°F △			
HOT WATER	Cycle 2 △		Cycle 3 △	Cycle 4 △	Cycle 5 △
HOT AIR			Cycle 2 △	Cycle 3 △	Cycle 4 △
STEAM	Cycle 1 △	Cycle 2 △	Cycle 3 △	Cycle 4 △	Cycle 5 △
COMMERCIAL AGRICULTURE PROTOTYPE SYSTEMS	Cycle 1 ▲	Cycle 2 △	Cycle 3 △	Cycle 4 △	Cycle 5 △

FIGURE VI-3. AGRICULTURAL AND INDUSTRIAL PROCESS HEAT

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VII BIOMASS

Introduction

General Description

The fuels from biomass program includes both production of biomass and the conversion of biomass to fuel products. Most other technologies begin with an existing resource, such as solar heat or wind, which requires little additional preprocessing before use in conversion facilities.

The program considers all forms of plant materials, both those grown on land (terrestrial) and those grown in or on water (aquatic). It includes forest and crop residues, crops grown for their energy content, on energy farms, and animal manures. The program does not include conversion of municipal solid waste or industrial wastes. (The conversion of urban solid waste and industrial waste to energy has been assigned to DOE's conservation program.)

Figure VII-1 shows the individual elements in the biomass fuels cycle, from the resource through conversion to energy products to the market. Primary concern in this study is conversion technology. Five biomass conversion technologies are evaluated:

- Direct combustion to produce process steam and electricity
- Anaerobic digestion to product intermediate- and high-Btu gases
- Fermentation to produce liquid fuels and petrochemical feedstocks
- Gasification to intermediate- or low-Btu gas
- Liquefaction to produce useful fuels and petrochemical feedstocks.

History

The legislative basis for the program is embodied in several public laws including PL-577, the Federal Non-Nuclear Energy Research and Development Act of 1974. This Act established a national program for research and development in nonnuclear energy sources. Based on this legislation, the National Solar Energy Research, Development and Demonstration Program was set forth in a Definition Report, ERDA-49, issued June 1975. This report included a definition of the ERDA biomass program, the current major elements of which are shown in Figure VII-1. ERDA-49 estimated the energy value to be produced by fuels from biomass as 0.5 quads in 1985, 3 quads in 2000, and 10 quads in 2020. Production at that level would provide on the order of 0.6, 2.6, and 7 percent of our total projected U.S. energy demand for those years.

Source: Reference 1

FIGURE VII-1: ELEMENT STRUCTURE OF FUELS FROM BIOMASS PROGRAM

Current Status and Potential

The program offers a significant potential for reducing this country's dependence on fossil fuels through the conversion of a renewable energy source to useful liquid and gaseous fuels, electric energy, and petrochemical feedstocks. Conversion of residues such as wood to electric power and to steam is currently carried out at competitive costs in several parts of the United States. Biomass supplies electricity to many U.S. industrial facilities and in some cases supplies power to local communities from industrial or central conversion sites.

Because biomass contains 30 to 90 percent moisture and has low densities relative to other feedstocks such as coal, transportation costs become a significant factor in the price of biomass delivered to the conversion site. Therefore, it is usually necessary to locate conversion facilities near the source of the biomass. Economic production of fuels from biomass is possible in locations in which biomass is abundant and alternative fuels are costly. To be competitive, an energy farm-fuel generation complex must achieve a good match among resource production and transportation capabilities, size of conversion plant, location of markets, and product market price.

The size and location of conversion plants thus are subject not only to economies of scale but also to the availability and cost of biomass and to conversion efficiency. Current estimates suggest that practical conversion plants would be those requiring no more than 5,000 dry tons per day of biomass feedstock. Such plants would have a Btu capacity equivalent to 10,000 barrels per day of oil at most, or 60 million cubic feet per day of gas. Practical-sized electric plants using direct combustion of biomass are likely to have capacities of no more than 50 to 100 megawatts and would require no more than 1,000 to 2,000 dry tons per day of biomass feedstock.

The SRI analysis indicates that an aggressive demonstration program could facilitate production of useful energy from biomass at competitive costs in many regions throughout the United States. For example, the 1977 national demand for gasoline is 80 billion gallons per year; for natural gas, 23 trillion cubic feet. Biomass could supply up to 10 percent (3.5 quads) of those 1977 requirements by the year 2000. The most promising market for biomass fuels is the transportation sector, because of its size and the insecurity of liquid fuel supplies. Next in importance is the large industrial, commercial, and residential market for natural gas. Other possible markets for biomass-based energy are (1) some portion of the petrochemical industry, (2) small electrical utility plants that currently use oil or natural gas, and (3) industries that use steam or heat.

Technology and Product Descriptions

Many processing technology options could be applied to the conversion of biomass to energy or chemicals. These range in stage of development from laboratory scale to commercially proven processes. The processing paths from biomass to energy or chemicals are shown in Figure VII-2. Two conversion processes now appear to be both technically feasible and economically viable in certain markets:

- Anaerobic digestion of animal manures to produce SNG
- Direct combustion of wood to produce process heat, steam, or electricity.

Commercial combustion facilities have been in use for a number of years, and anaerobic digestion facilities are scheduled to be operating by 1978. Fermentation to produce ethanol petrochemical substitutes, gasification to produce ammonia, SNG, and methyl fuel, and liquefaction to produce fuel oil are technically feasible but not yet economically competitive. Photochemical processes are being pursued as long-term, low-emphasis projects.

The biomass conversion technologies selected for analysis--direct combustion, anaerobic digestion, fermentation, thermochemical gasification and liquefaction--were chosen on the basis of a subjective evaluation of each of the following factors:

- Residue availability and characteristics
- Potential environmental impact
- Product slate and marketability
- Potential energy output
- Commercialization potential.

Several processes not selected, such as biophototypes and photoelectrolysis to produce hydrogen, are in early stages of development and frequently classed as high-risk/high-potential technologies. These technologies are described below, but were not assessed in detail during the study effort.

After suitable preparation, which may include drying and size reduction, biomass can theoretically be processed using any of the technologies shown. However, the chemical composition of any biomass feedstock and the requirements of any conversion process will often dictate the best path for conversion and utilization. For example, direct combustion or gasification is most likely for low-moisture content biomass; anaerobic digestion and fermentation are more adaptable to high-moisture biomass materials.

The processing paths shown in Figure VII-2 produce a wide range of products. These products are suitable for direct use or can be upgraded

FIGURE VII-2. BIOMASS -TECHNOLOGY OVERVIEW

further to serve markets with critical needs or to produce more economically transportable products. For example, direct combustion of biomass can produce steam for direct use or for electric generation. Also, ethanol from fermentation of biomass can be used directly as a motor fuel or in the long term converted to ethylene, a major petrochemical feedstock for polymers.

Each processing path that produces a unique primary product has a different conversion efficiency, requires a different level of capital investment, and has distinct economies of scale. Because of these unique features, a detailed analysis of market needs and process economics based on each possible biomass feedstock is necessary to evaluate them or put them on a comparable basis.

Direct Combustion

Combustion can be one of the most efficient methods of using the direct energy potential of biomass. Thermal efficiency is limited only by the heat recovery equipment downstream from the combustion chamber. For direct-fired furnaces and steam boilers, thermal efficiencies as high as 85 percent can be achieved. Generally, biomass with moisture content below 30 percent can be combusted directly, while those with higher moisture content may have to be predried or fired with supplementary fuel, either of which lowers the efficiency of the process.

Hot combustion gas from burning biomass can be used for its heat content or to generate steam. The steam, in turn, can be used directly for heat, or indirectly to generate electric power. The overall direct combustion efficiency of biomass used to produce electricity is 20 to 30 percent, depending on feedstock moisture content, ash content, and design of the energy conversion facility. This efficiency is low compared with that of coal conversion facilities, which typically produce electricity at an overall efficiency of 35 to 40 percent.

Direct combustion of biomass is currently limited by the economics of fuel availability or environmental regulations. Stringent particulate emission regulations, such as those in California, could impose severe economic penalties by requiring highly sophisticated equipment for particulate removal from combustion off-gases. However, development work in progress by pulp and paper companies, large timber processing companies, boiler manufacturers, and combustion engineering firms could reduce the cost of meeting environmental regulations.

The successful use of the combustion process option will depend on the cost of power from new coal or nuclear plants in a given area. The relative simplicity of processes for the direct combustion of biomass will tend to make it more attractive than some of the other options, particularly in the next few decades and in certain sites near the biomass resource.

Although the direct combustion process is well established, development work on combustion processes to make them more suitable for using

biomass as fuel is needed. The burning of large, irregular biomass can be inefficient in conventional combustion processes. Labor costs are high compared with the automatic stoking of uniform material (such as coal), and air cannot easily be distributed to achieve uniform or complete combustion. Many coal- or oil-fired units could be converted to the burning of wood or other biomass if uniform biomass feeds were provided.

Thermochemical Gasification and Liquefaction Processes

Pretreated biomass may be converted to useful products by gasification to make synthesis gas, methane, methyl fuel, and other products or by liquefaction to make fuel oil. For example, cellulosic materials such as wood can be reacted with hydrogen or carbon monoxide to give oils equivalent to fuel oil from petroleum. High temperature and pressure are required, and the feed must be well subdivided. The main advantage of a wood-to-oil process is that the product produced can be an immediate replacement for imported oil should supplies be curtailed by foreign sources. Methyl fuel could possibly be blended with gasoline to extend supplies of liquid transportation fuels.

A wide range of processes exist that can decompose organic matter to produce other usable fuels. The types and the amounts of fuel produced depend primarily on the temperature used in the process. Thus, low temperatures (those generally under approximately 1200°F) produce large quantities of char and oil together with lesser amounts of fuel gas, while high temperatures (greater than 1800°F) produce primarily fuel gas, possibly some char, but no oils. Wood or other biomass can be reacted with oxygen and steam to produce a low- or medium-Btu gas or a synthesis gas that can be upgraded to SNG, methanol, ammonia, or hydrogen. Process efficiency of these processes can be as high as 80 percent, but is expected to be about 65 percent for the production of SNG from agricultural or forest biomass.

An experimental facility for the production of fuel oil from cellulosic materials has begun production in Albany, Oregon. It is equipped for the pretreatment of biomass and for reaction with carbon monoxide and hydrogen at elevated temperatures and pressures. The unit, based on a Bureau of Mines process, is sufficiently flexible in design to permit the technoeconomic evaluation of a variety of biomass-to-oil processes with a minimum of equipment modification. Future studies are expected to include varieties of biomass such as corn stalks, rye grass, and other plant materials. Current project objectives include the identification of product oil stability, reactor pressure requirements, and oil recycling practicality.

Anaerobic Digestion

Anaerobic digestion consumes biomass directly to produce methane without first breaking it down to sugars. Almost any material from biological sources can be digested by anaerobic microbial processes to yield carbon dioxide and methane.

The technology is currently commercial and is in common application today as a means of waste treatment for removing organics and destroying harmful micro-organisms in domestic and industrial wastes. The process takes place at essentially ambient conditions (15° to 65°C) and works best on substances with high moisture content (80 percent or greater). Product gases, consisting mainly of methane and carbon dioxide, can be burned directly or can be upgraded to SNG by removal of the carbon dioxide.

Results from recent studies have shown that cattle manure can be economically converted to methane. Experimental and pilot test units for anaerobic digestion are being located on cattle feedlots. A feedlot provides large quantities of manure on a small area so that collection is relatively inexpensive. Experimental facilities will be large enough to illustrate typical operating problems. The results of these projects should enable private companies to manufacture equipment and commercialize services for handling the residues of an entire feedlot.

The present emphasis is on cattle manure because of its concentration and relative ease of collection. However, anaerobic digestion will probably be used for conversion of other biomasses to fuels. The digestibility of several feed materials has been confirmed and others such as kelp are under investigation. Research and development is needed to find optimum yields for anaerobic digestion and is also essential to speed the reactions and achieve shorter retention times. Process efficiency of 40 to 50 percent can be achieved economically for some organic feed materials.

Hydrolysis and Fermentation

Thus far, this aspect of the biomass program has concentrated on hydrolysis of cellulose to sugars and their subsequent fermentation to ethyl alcohol and motor fuel. In general, cellulose can be converted by chemical and biological hydrolysis to glucose (sugar), molasses, or derived single cell protein. Both chemical and biological (enzymatic) hydrolysis of cellulosic raw materials to produce sugars and ethanol have been demonstrated.

Since low yields are obtained by direct fermentation, acid hydrolysis is often carried out under pressure before fermentation. This system usually requires phosphoric or nitric acid as a catalyst, which cannot easily be reclaimed and therefore must be disposed of after neutralization with lime. Careful control of reaction times, temperatures, and acid concentrations is required.

A range of candidate cellulosic raw materials, mainly in the form of agricultural and forest product residues, is being examined, analyzed for chemical composition, and assessed for potential yields of sugars and ethanol under various processing conditions. Processing concepts under study include chemical pretreatment of cellulosic materials to remove lignin and hemicellulose (pentose sugars), enzymatic hydrolysis of cellulose to glucose (hexoses), and conversion of pentoses and hexoses to ethanol by fermentation. Important basic problems include kinetics of enzymatic hydrolysis,

production of hydrolyzing enzymes, enzyme absorption as a basis for potential recovery processes, and microbial systems and techniques for fermentation to ethanol. Major areas of recent progress are development of a highly effective continuous process for production of cellulase enzyme from the fungus T. viride and new ethanol fermentation methods using dense yeast cultures and operation under vacuum.

Major new practical objectives are development of an economical method for removing lignin from cellulosic materials to enhance the enzymatic hydrolysis, development of more powerful mixed-enzyme systems, development of an effective xylose fermentation, and optimization of the processes for ethanol production. When the processing steps have been developed to a sufficiently final stage before full-scale industrial application, small scale pilot plant studies will be conducted to assess problems of continuous integrated operation of the processes for production of sugars and ethanol.

Hydrogen Production

Hydrogen production research is being sponsored by several federal and private U.S. organizations as a long-term, low-emphasis activity. A federal program objective is to develop processes that offer the potential for producing hydrogen from abundant, renewable resources (biomass and water). Hydrogen is a clean fuel, easily stored, readily shipped via pipeline and used in many U.S. energy applications. It can be used for cooking, to provide heat for environmental control, or to produce electrical power in fuel cells or engine generators. Many compounds produced by chemical reactions with hydrogen such as ammonia, ethyl alcohol, and hydrogen peroxide have extensive industrial uses.

Two main approaches, both in early research stages, are being pursued: the first, biophotolysis, entails the encouragement of photosynthetic growth in a biomass species such as algae and the simultaneous alteration of conditions of photosynthesis to maximize hydrogen production. The second, photoelectrolysis, entails the use of solar energy in the presence of catalysts and reacting compounds to induce the electrolytic splitting of water into its elements.

Development, Goals, Schedule, and Issues

Program Goals

The overall goal of the biomass program is to develop and demonstrate technologies that will lead to the production of 10 quads from biomass, or about 7 percent of projected energy demand by the year 2020.

Initially, the program will investigate the technical and economic feasibility of collecting and harvesting significant quantities of biomass by a direct combustion demonstration program. The priority products, however, are liquid transportation fuels, SNG and other energy-intensive fuel products and chemicals.

Development Plans

The general approach for achieving the objectives of the program requires the parallel development of several biomass production and conversion technologies and the use of readily available resources to test or demonstrate those conversion technologies that are relatively near commercialization. These include anaerobic digestion of animal manures and direct combustion of biomass.

The long-term development and demonstration plan is presented in Figure VII-3. As indicated, the series of field experiments to establish promising species and yields will be followed by establishment of test farms for both terrestrial and aquatic biomass, with corresponding conversion experiments and pilot and demonstration plants. Time sequences shown are set to provide both maximum impetus to the program and use of results at each stage as a basis for subsequent research. Table VII-1 provides a more detailed estimate of the state of development of conversion technologies under the program as five-year points through the year 2000. Plants are scheduled by DOE to begin operation on the following dates:

Terrestrial energy farm - silvaculture crop	1980
Terrestrial energy farm - agricultural crop	1985
Aquatic energy farm	1990
Anaerobic digestion plant	1978
Commercial electric power production	1980
Gasification plant (medium-Btu gas)	1981
Fermentation plant	1985
Gasification plant (methanol)	1985
Liquefaction plant (methanol)	1986
Fuel oil plant (Albany, Oregon)	1986

These dates may change as a result of a mission analysis study currently under way for DOE.

Programmatic Issues, Barriers, Breakthroughs, and Thrusts

Several important factors are especially relevant to the progress of the biomass research program. Among these factors are potential barriers to successful commercialization of biomass-based energy production, anticipated breakthroughs in conversion-process technologies, and new program thrusts that offer the opportunity to accelerate the program toward its objectives. Each factor is discussed below.

FIGURE VII-3. ACTIVITY SCHEDULE FOR FUELS FROM BIOMASS PROGRAM

Table VII-1

STATE OF DEVELOPMENT FOR BIOMASS PRODUCTION AND CONVERSION TECHNOLOGIES

Process	Current	1980	1985	1990	1995	2000
Terrestrial biomass production agricultural crops	System studies field tests	Pilot farm recommended	Start-up of demo farm	Demo farm operation	Decision on commercial farm and plant	Completion, commercial scale farm and plant
Silviculture crops	Field tests	Conversion plant and plantation complete	Complete demo farm and plant	Complete demo scale farm and plant	Commercialization complete	
Aquatic biomass production	Lab and field tests	Decision on pilot plant	Complete marine farm and pilot plant	Start-up demo farm and plant	Complete demo operations	Commercialization
Anaerobic digestion to produce SNG	Pilot	Pilot tests complete	Complete commercial plant			
Fermentation to produce petrochemical substitutes or liquid fuels (enzyme-acid hydrolysis)	Lab and field tests	Testing complete demo unit demonstration	Demo unit complete	Possible commercial plant		
Liquefaction to produce fuel oils	Field and process development tests	Decision on pilot plant	Decision on demo plant	Possible commercialization		
Gasification to produce SNG	Equipment and lab tests	Pilot test start-up demo recommendation	Demo plant start-up ?	Possible commercial plant ?		
Direct combustion to produce process steam and electricity	Small-scale units in operation	Complete commercial plant				

Source: Reference 1

Barriers to Commercialization

A number of key factors that could be barriers to the successful commercialization of biomass are listed in Table VII-2.

Institutional Barriers

Table VII-3 lists important potential institutional barriers to biomass production, conversion, and marketing.

Excluding the factors that have economic or technological implications, only a few institutional factors will present barriers to the utilization of agricultural residues or the production of terrestrial energy crops. The most significant of these barriers is the possibility of supply uncertainties caused by weather variations and the lack of irrigation water caused by competing demands or legal barriers to importation. Institutional barriers can rarely be solved by simple governmental actions; many solutions could require large sums of money and could have undesirable impacts on other segments of the agricultural economy.

In general, energy from biomass will be subject to the same institutional factors as are other new energy forms. Development of biomass energy facilities will depend primarily on the cost of biomass compared with the cost of other fuels, the availability of competitive fuels, the security of supply, and the general regulatory environment.

Potential Breakthroughs

Current and planned program research should result in significant reductions (up to 50 percent) in the costs of biomass production and conversion. Table VII-4 shows significant areas in which breakthroughs may be achieved.

The Economics of Production and Conversion

The economics of both feedstock production on energy farms and feedstock conversion to useful fuel and petrochemical substitutes are described below. The rationale for determining future quantities of available feedstock, based on market price and production cost, is described first, followed by a discussion of conversion or fuel product production economics.

Estimated Average Competitive Biomass Feedstock Prices

Biomass utilization is analyzed by comparing supply curves for biomass with estimated future prices of competing fuels. Such an analysis provides an estimate of quantities of biomass that would be used at a competitive cost. The competing fuel is coal. Assuming an energy

Table VII-2

PROGRAMMATIC ISSUES TO BE RESOLVED FOR THE FUELS
FROM BIOMASS PROGRAM

Issue	Question
Conversion economics	What technological feasibilities and costs are associated with alternative fuels from biomass missions? What conversion efficiencies and productivities should be expected?
Land availability	Can marginal lands be used for energy farms and will this use be economic?
Water availability	Will enough water be available in year 2000 to provide reasonable crop yields and are water availability locations consistent with land availability locations?
Species selections	What species have the characteristics appropriate for energy farms--high-Btu content, high growth rate, dry weight density, pest resistance, coppicing and recovery qualities, and drought resistance?
Fermentation	Can acid hydrolysis allow economic production of ethanol? Can catalysts be used to increase conversion process yields?
Energy farm management strategies	Will the use of fertilizers be energy-efficient? What spacing, irrigation, disease control, and harvesting methodologies are required?
Harvesting methodologies	Can whole tree utilization and other techniques be used? What is the effect of preprocessing on site, long-term storage, alternative site layouts, and harvesting energy expenditures? What systems should be developed for harvesting, collecting, storing, and transporting biomass?
Food versus fiber versus energy use of biomass	How can biomass use for energy successfully compete with food and fiber uses? Should new land-use policies and incentives be initiated? How much federal financial support is needed?
Alternative feedstock availability	Should accumulated forest residues be used before energy farm development? Will forestry residues be economically collectible and available on long-term basis? What will be the price and availability of an assured supply of biomass?
Farm production consideration	How should production capacities be balanced with conversion plant capacities to achieve economies of scale?

Source: SRI analysis and Reference 1

Table VII-3

INSTITUTIONAL BARRIERS TO THE FUELS FROM BIOMASS PROGRAM

Item	Action Required to Mitigate
Residues	
Uncertainty in residue supply	Stabilization of profit levels for crops and livestock Modification of weather impacts by collecting residues over wider areas
User attitudes regarding residue removal	Development of cost/benefit analyses and dissemination to users Demonstration of environmental impacts of increasing residue removal
Lack of incentive for investing in residue collection equipment	Development of cooperatives and specialized equipment
Terrestrial energy crops	
Shortage of available land--National Forest System land not available for energy production	Promotion of reclamation and marginal use activities Congressional amendments to existing U.S. Forest Service legislation
Shortage of water (legal and supply constraints)	Promotion of interbasin transfers, drainage and large scale irrigation projects Legal allocation of water to energy production
Lack of information for economies of scale	Conduct of pilot tests and demonstrations
Uncertainties in continuity of supply	Stabilization of profit levels, long-term contracts Modification of weather impacts by spreading production over wider areas Reduction of crop-disease impacts by spreading production over wider areas
Conversion operations	
Regulatory constraints against inclusion of resources acquisition in utility rate base	Establishment of dedicated farming subsidiaries
Fluctuation in energy demand	?
Unacceptable division of residue profits in case of absentee ownership	Payment to tenants for residue collection work Payment of landlords for residue sales
Reluctance to invest in expensive conversion facilities	Guarantee of income by long-term contracts
Competition between biomass products and natural gas for industrial uses	Regulatory limits on the use of natural gas, or regulation to require pricing on incremental cost basis
Unfavorable cost of biomass fuels for electric utilities, compared with costs of coal or nuclear fuels	Provision of fuels which minimize power plant capital costs
Inability of gas utility companies to finance conversion plant	Provision of federal loan guarantee program

Source: SRI analysis and Reference 1

Table VII-4

ACCOMPLISHMENTS AND BREAKTHROUGHS
ENVISIONED FROM THE FUELS FROM BIOMASS PROGRAM

Program Element	Prospects
Biomass production	
Short-rotation forestry	Yields may be doubled within 15 years with generic improvements and the use of coppice management systems.
Research on sugarcane	Yields could increase 100 percent or more by 1985 because of close plant spacing.
Cultivation of aquatic species	Long-term research is under way; results expected in mid-1990s.
Biomass conversion	
Biochemical anaerobic digestion	Key factor and target of RD&D efforts is reducing throughput time.
Biochemical fermentation	Research focuses on enzymatic and acid hydrolysis processes.
Thermochemical gasification	Goal is an increase in gas production rate (more than double the current rate) and an increase in yields of SNG and other fuel products.
Thermochemical liquefaction	Target is reduction in material cost by 1980; reduction of other costs by late 1980s.
Thermochemical magneto-hydrodynamics	Long-term research and a feasibility study is proposed.
Hydrogen production (photoelectrolysis)	Long term applied research is under way--commercialization is uncertain.

converter is a rational decision-maker, he would not use biomass as a feedstock if he had to purchase it for a greater price than coal (\$1.26/MM Btu in 1975).

Estimated Biomass Supplies

Supplies of Agricultural and Forest Residues

In 1973, slightly greater than 400 million tons of agricultural and forestry residues were produced. Figure VII-4 indicates the quantities that may become available for energy feedstock at various price levels (\$/dry ton). In 1973, 28 million tons of biomass were used as fuel for the production of various forms of energy; it is likely that the shape of the supply/price curve can be expected to remain constant through the year 2020. This relationship will be shifted to the right by increased forest and agricultural production. However, plant breeding toward less residue production will tend to force the relationship back to the left.

Based on the relationship between supply of biomass and future prices of coal, the theoretical tonnages of agricultural and forest residues can be estimated. This is the approach that was used in the market penetration estimates reported in Volume I.

Supplies of Terrestrial Crop Biomass

Based on Mitre's study (see Reference 3) of silvicultural biomass farms, biomass farms have the potential of becoming economically competitive in the mid-1980s. This conclusion does not take into consideration the opportunity costs of alternative uses of land that may occur. Opportunity costs are incurred when resources such as land and capital are used in one enterprise that does not produce as much profit as an alternative enterprise. Table VII-5 interprets the available information to estimate future supplies of terrestrial crop biomass.

The critical factor in Table VII-5 is the average acreage devoted to biomass. This analysis subjectively examines the opportunity costs of various crop production enterprises but does not quantitatively examine those costs.

Conversion Costs

The economics of feedstock conversion to useful fuels, based on the technologies described earlier, are shown in Table VII-6. This table lists some of the most important products expected to be produced from biomass, their projected date of commercialization, and their expected cost range. The estimated price data are based on preliminary contractor data and could change significantly as additional research and development are completed and consistent information is received as a

FIGURE VII-4. RELATIVE SUPPLY CURVES FOR TOTAL U. S. AGRICULTURAL RESIDUES

Table VII-5

TERRESTRIAL CROP BIOMASS PRODUCTION

	<u>1975</u>	<u>1985</u>	<u>2000</u>	<u>2020</u>
Biomass price, \$/mil Btu	.80	2.00	1.80	1.60
Biomass yield, tons/acre	10	14.5	16.2	20
Biomass yield, mil Btus/acre	150	217.5	243	300
Production cost, \$/mil Btu	1.84	1.65	1.40	1.00
Profit, \$/mil Btu	(1.04)	.35	.40	.60
(Loss) \$/acre	(156)	76	97	180
Acreage planted to biomass (mil. acres)	0	.5	8	16
Biomass supplied, mil tons	0	7.2	130	320

Source: Derived from References 2 and 3.

result of the program mission analysis effort, which is to be completed in 1978. The data shown assume constant 1977 dollars and costs as of the projected date of commercialization, as well as economic feasibility. As indicated, the production of ammonia, process steam, and SNG by anaerobic digestion of animal manures have early commercialization dates at relatively low costs per million Btu, and the production of fuel oil and SNG from the pyrolysis of woody crops are expected to be commercial after 2020 at relatively high costs per million Btu.

Each cost estimate was prepared to reflect total life cycle costs, including initial investment, operating expenses, maintenance, interest expenses, feedstock costs, and other expenses. Important costing assumptions and cost data are summarized in Table VII-7, which indicates data sources and provides a breakdown of projected product production costs for the year 2000.

The main point of the discussion of the economics of conversion technologies for this comparative analysis is that selected technologies will be available to process and convert the biomass as increasing quantities of supplies become economically competitive over time.

Potential Applications

The analysis of the market penetration potential of biomass treated the biomass supply as competing with coal. Thus, the simplifying assumption was made that biomass would be used as a substitute for coal.

Table VII-6

SUMMARY OF PRODUCTION COSTS FOR FUEL FROM BIOMASS

Generic Technology	Product	Potential Product Cost			Expected Commercialization Date
		1985	2000	2020	
Acid hydrolysis and fermentation of woody crops	Ethanol	\$17.7	\$16.8	\$15.8	1990
Pyrolysis of wood	Fuel oil	6.1	5.8	5.5	2030
Catalytic conversion of medium-Btu gas	Methanol	6.8	6.5	6.4	1990
Anaerobic digestion of cattle manure	SNG	2.7	2.5	2.3	1979
Gasification of woody crops [†]	Medium-Btu gas	3.3	3.1	2.8	1990
Gasification and methanation of woody crops	SNG	5.0	4.7	4.5	2025
Direct combustion of gin trash or wood	Process steam	1.9	1.9	1.9	1977
Shift conversion of medium-Btu gas from wood	Ammonia	4.6	4.2	4.2	1985
		Cents per kWh			
Direct combustion technology	Electricity	3.2¢	3.0¢	3.0¢	

* 1977 Dollars per million Btu.

[†] Union Carbide Purox Process.

Source: References 1, 3, 4, and 5

Table VII-7

MAJOR COSTING ASSUMPTIONS AND COMPONENTS

Process	Product	Plant Initial Investment (10 ⁶ Dollars)	Installed Cost per 10 ¹² Btu (Year 2000) [†]	Plant Capacity per Day	Feedstock Type	Projected Production Costs (\$/MM Btu Year 2000)*				Data Source Refer- ences
						Capital Cost	Feedstock Cost	Operating Cost	Total Cost	
Catalytic conversion	Methanol	\$ 64.0	\$14.0	670 tons	Medium-Btu Gas from cellulose	\$2.2	\$3.3	\$1.0	\$ 6.5	3,6
Acid hydrolysis and fermentation	Ethanol	218.0	46.0	560 tons	Sugars from woody plants	7.4	1.9	7.5	16.8	3,4,7
Anaerobic digestion	SNG	2.2	4.6	1.2 × 10 ⁶ scf	Cattle manure	0.7	1.4	0.4	2.5	5,7
Pyrolysis methanation	SNG	45.0	9.4	11 × 10 ⁶ scf	Wood	1.5	1.8	1.4	4.7	3,8
Pyrolysis	Medium-Btu gas	34.0	7.0	48 × 10 ⁶ scf	Woody crops	1.0	1.8	1.0	3.8	3,8
Shift conversion	Ammonia	63.0	9.5	980 tons	Medium-Btu gas from cellulose	1.5	1.4	1.5	4.2	3
Pyrolysis	Fuel oil	24.0	4.3	Oil, 2 × 10 ⁶ lbs Gas, 7 × 10 ⁶ scf Charcoal	Woody plants	3.7	1.4	0.7	5.8	3,8
Direct combustion	Process steam	9.0	2.6	8500 × 10 ⁶ lbs	Wood or gin trash	0.4	1.3	0.2	1.9	3
Direct combustion	Electricity	60.0	24.0	1920 MWh (100 MW)	Wood or gin trash	3.8	3.0	2.2	9.0	3,8

* Assumes feedstock cost of \$1.00 per million Btu (except for cattle manure at \$0.60 per million Btu), a 30-year plant life, a 16 percent capital recovery factor, consumption of 1,200 to 1,700 dry tons of feedstock per day except for anaerobic digestion at 250 dry tons per day and process steam at 700 dry tons per day. Constant 1977 dollars are used.

[†] Millions of dollars.

In the near term, the primary use of biomass is expected to be for direct burning applications, either to produce process heat or to generate electricity. In the intermediate and long term, biomass can be converted to gaseous or liquid fuels.

The capability of biomass to substitute for coal in these uses depends in part on an effective RD&D program to demonstrate the technical and economic viability of altering some processes that were designed for coal so that they function effectively with biomass. Based on the analysis of the RD&D program, economic viability appears to be a reasonable and achievable objective.

Because of the extensive discussion of the potential applications of biomass in earlier sections covering technology and product descriptions, development goals, and economics, no further discussion of this topic is presented.

Environmental Considerations

The environmental impacts of biomass collection and utilization are worthy of investigation. The biomass program gives special attention to the following issues:

- Land and water availability
- The potential for erosion and depletion of soil organic content if too many residues are removed
- Secondary impacts associated with large-scale farming and conversion operations
- Particulate emissions from direct combustion
- Disposal of residuals from conversion processes

Production and Conversion Impacts

The potential environmental impacts of biomass-based energy production are small compared with those associated with the use of most other energy forms. Depending on species grown, much of the nutrient value removed from the soil can be returned in the form of leaves and other residues not needed for energy conversion. Furthermore, energy farm crops will be selected to maximize coppicing and natural replenishment of the resources extracted. Particle emissions from direct combustion and disposal of residuals from conversion processes present an economic constraint in some cases, but in general, emissions and residuals are much lower in volume than those obtained with competing feedstocks. In biomass conversion processes, sulfur and carbon dioxide emissions do not usually present the major problems associated with other feedstocks because of the low sulfur content of biomass and typical conversion process molecular interactions. Particle emissions present difficulties, but they can be overcome with investments in scrubbing, filtration, and

similar devices. Residual materials often can be used as fertilizers or recycled to improve process efficiency.

Land and Water Availability

The most important environmental issue facing the production of terrestrial energy crops is the availability of land and water resources to be allocated to such an enterprise. If water could be made available at reasonable cost, marginal lands including desert lands could be used for energy farms. Unfortunately, water is a relatively scarce resource in many parts of the United States, and its lack may seriously restrict the use of marginal lands.

Of the 2.3 billion acres of land in the United States, 78 percent, or 1.8 billion acres, is devoted to cropland, forestland, or grassland. Figure VII-5 shows the major uses of land in the United States (50 states) in 1969. Current estimates indicate no significant changes in that utilization.

Because of the intense utilization (e.g., urban, transportation) of other lands in the United States, the land resources necessary for production of terrestrial energy crops must be allocated from the categories of cropland, forestland, or grassland. Of the 740 million acres of usable land* in these categories, approximately 35 percent offers some economic and physical potential for biomass production.

A 1967 inventory and a complementary survey in 1975 by the U.S. Department of Agriculture revealed that of the total U.S. land area, 265 million additional acres of land (with and without limitations) could be considered suitable for conversion to cultivation. However, as shown in Table VII-8, of this total, only a portion can be considered currently well adapted. Usage for cultivation will depend on general water availability and public programs to provide irrigation water, drainage improvement, and soil conservation.

No lands in the medium or low potential categories in Table VII-8 are likely to provide resources for biomass production. In many cases, the cost of reclamation would be too great to make biomass production a profitable enterprise. Therefore, the remaining 95 million acres of high potential lands (short and long run) probably offer the greatest opportunity for terrestrial energy farming.

Wetland problems in the U.S. Southeast are so widespread that large scale drainage outlet works are necessary for reclamation. However, a potential exists for land reclamation through additional public investment in on-farm drainage projects in many delta and coastal regions.

*Usable because of physical characteristics such as slope, fertility, and climatic factors (see Reference 3).

Source: Reference 9

FIGURE VII-5 MAJOR USES OF LAND IN 1969*

Table VII-8

POTENTIAL FOR CONVERSION TO CROPLAND
(Millions of Acres)

Region	High		Medium		Low †	Totals
	Short Run	Long Run	Short Run	Long Run		Short and Long Run
1. Plains	48.1	4.1	--	--	2.6	54.8
2. North Central	15.3	13.8	--	--	7.7	36.8
3. Florida	1.3	2.9	--	--	--	4.2
4. Miss. Delta-Gulf Coast	3.5	6.7	--	--	0.8	11.0
5. Coastal Plain-Piedmont	--	--	18.2	19.8	27.3	65.3
6. Atlantic Coast Lowlands	--	--	1.3	7.4	0.5	9.2
7. Texas-Okla. Prairies	--	--	9.7	0.6	2.0	12.3
8. Appalachian-Ozark ‡	--	--	--	--	24.9	24.9
9. Northeast-No. Great Lakes §	--	--	--	--	32.4	32.4
10. Rocky Mtn.-Far West *	--	--	--	--	13.6	13.6
Total	68.2	27.5	29.2	27.8	111.8	264.5

*Water shortage.

†Forest and other land with erosion problem. Regions 1 through 7.

‡Fields small and scattered.

§Short growing season.

Source: Reference 9

Studies comparing dry versus irrigated farming techniques have shown that irrigation permits higher economic returns, sometimes as much as 17 times as great.¹⁰ Controlling both the amount and time of water application can have dramatic effects on yields. In addition, irrigation can reduce the risks of crop quality loss resulting from poor soil conditions and salt accumulation in soils in arid areas.

The severe water shortage in the U.S. western and midwestern states is currently a limiting factor to additional cultivation in these areas. Interbasin transfers could alleviate such water shortages, given economic incentives and the removal of sociopolitical-legal constraints on such transfers.

Although water resource limitations are very important, they must be considered in light of other factors. High production costs, small farm units, higher value cropping alternatives, climatic limitations, and other economic considerations would all influence the decision to convert land to biomass production. The consolidation of currently fragmented acreage in some U.S. areas into profitable units depends on the size of tracts, their proximity to existing farmlands, and the types of owners. A considerable amount of the land will require special conservation projects and practices to minimize soil and water erosion. Also, energy farm investors will have to be assured of a long-term profit to offset the capital costs associated with bringing marginal lands into production. If biomass farming is to represent a viable alternative energy source, it must not only be economically competitive with other energy sources but must also provide a favorable return in comparison with food and fiber crops.

International Market Potential

Many of the technologies relevant to the fuels from biomass production programs have been in use in European and other countries for many years. Several of the early bioconversion and thermochemical conversion processes were first developed and implemented commercially in other countries. Therefore, the probability of massive exports of U.S. developed processes and conversion equipment to the more advanced countries of Europe and Asia is remote. However, the impact of U.S. conversion knowledge and exchange of information on new techniques and methods could be beneficial. The possibilities for technology transfer programs and the trade of production knowledge are excellent. In addition, the sale of equipment and the licensing of conversion processes to underdeveloped countries that import large quantities of petroleum products seem to be definite possibilities. Several foreign countries have put a high value on the achievement of energy independence and have been willing to subsidize local energy conversion industries. Where the problems of international finance and foreign exchange can be overcome, significant technology exports by the United States to Latin American, African, Indian, and Asian countries can be accomplished.

Research, Development, and Demonstration Program

The current program of the Fuels from Biomass Branch is directed at specific RD&D goals in both the biomass production and conversion areas, and increased RD&D funding could provide increased outputs of energy over the near term as well as the long term. In both areas, processes and technologies are of a near-term potentially commercial nature which could be developed quickly, given increased funding levels. If funding levels were held constant, a reallocation and development of incentive systems to encourage private development of biomass resources and fuel conversion activities could have a more immediate effect on energy availability. The following paragraphs describe current program RD&D objectives and the changes that are recommended to accelerate the availability of future energy production.

Terrestrial Biomass Production R&D

The overall research objective in the growth of biomass on energy farms should be to provide the maximum energy content at the minimum cost. Cost in this context includes all outlays associated with growing the resource and getting it to the conversion point--harvesting, collection, transportation to the conversion point, and storage until the conversion process begins.

Within that objective, the program goals should be to: select and improve the most promising species, select and prepare growing sites, establish growing stock, and obtain optimum yields, while considering costs in terms of dollars and time.

A comprehensive research effort is needed to improve the productivity and cost-efficiency of growing and harvesting plants for fuels and to develop the necessary data base to evaluate the future contribution of biomass to the U.S. energy supply.

The success of all regional programs, studies of management strategies, and genetics research is contingent on the selection of species that show promise--that is, species that have high-Btu content, high dry weight production per unit area, pest resistance, and high growth rates. Under the program, researchers might identify and screen exotic species, but the emphasis should be placed on species, varieties, and ecotypes native and well adapted to the region in which they will be grown.

Although a species screening program can be initiated immediately using such criteria as maximum Btu per unit volume of biomass and maximum dry weight production/unit area/year, there is inadequate justification for limiting selection criteria to these characteristics. Also important are cold-hardiness, disease resistance, and many of the same characteristics used in selecting species and varieties for maximum fiber or saw-timber production. Since the end use of the production will be either combustion or conversion, the desired characteristics will be substantially

different from the criteria used for fiber or sawtimber, and comprehensive research is needed to identify screening criteria. Since the energy inputs required for biomass production will be particularly important in evaluating the potential of biomass as a regional energy source, such characteristics as nitrogen-efficiency and need for irrigation must be considered.

Genetic improvement programs could increase the productivity of promising species substantially. The near-term DOE program will include limited genetics research. Virtually no effort has been made to breed for the characteristics desired in growing wood and other plants for fuel, and little genetic research has been conducted with the species currently considered for short rotations.

Site preparation and the establishment of the young growing stock are among the most energy-intensive, costly, and high-risk processes in the production of wood. There are many widely practiced, as well as experimental, alternatives for establishment of traditional fiber or sawtimber plantations, but little research has been oriented toward the establishment of short-rotation, intensive-culture plantations. Promising techniques are the growth of seedlings for one to two years in controlled environments, containerized planting, and use of coppicing (sprouting) species to eliminate planting costs.

Growing biomass for fuel, fiber, or lumber depends directly on three interacting sets of variables: the site environment, the species, and the management techniques applied. A range of management techniques may be applied to influence the environmental conditions and net productivity: spacing, irrigation, weed and disease control, application of fertilizers, alternate nitrogen-supply strategies, and season of harvest. Both the selection of a site with its set of environmental conditions and the selection of management strategies will depend on the species.

Once species have been selected on a regional basis, harvesting, collection, transportation, and storage strategy studies should be intensified. This research should include optimal spacing studies, growth limitation problems, the use of arid lands, wet or shallow soils, and hilly sites, as well as the impacts of row spacing, nitrogen fertilization, irrigation, and frequency of harvest on yields.

Latex Plant Research

The current program study of latex producing plants should be expanded to pinpoint the problems of growing, harvesting, and converting hydrocarbon-producing plants such as Euphorbia and Asclepias and to evaluate the economics of extracting hydrocarbons. The molecular weight of Euphorbia is about 10 percent of that of the rubber tree (Hevea), indicating a small molecule arranged more like petroleum than rubber. It is apparent that Euphorbia may be a successful candidate for chemical manipulations with a view toward extracting petroleum substitutes and other materials, including sterole, terpenoids, glycerides, waxes, and

polyisoprene. Much remains to be done on the chemistry of latex producing plants, including determination of the most practical solvent and extraction procedure. In addition, it is necessary to explore the possibility of harvesting economic amounts of hydrocarbons from land in dry, sunny regions such as the U.S. Southwest. Increasing R&D expenditures in this area of research could lead to valuable crop yields on marginal land that cannot be used for other food and fiber production purposes (see References 11 and 12).

Aquatic Biomass Production RD&D

The federal biomass program is currently supporting research in three marine resource areas: (1) freshwater land-based systems, (2) open ocean systems, and (3) shoreline-saltwater brackish water systems.

The program entails the screening of various species for yield, potential growth, nutrient assimilation, fermentability, and economic feasibility. The effort also entails the determination of possible sites, energy balances, operating concepts within the three resource areas, and the selection of systems for detailed engineering design and cost analysis. Various salt and fresh water biomass sources are being investigated, including red, brown, green, and blue algae; water hyacinth; duckweeds; kelp; and irish moss.

The cultivation of several of these macroscopic algae (seaweeds) and freshwater aquatic weeds has potential for large scale growth and conversion to energy. These particular plants are being considered because some of them are known to be capable of exceptionally high levels of biological productivity and high organic yields per unit of time and space. Also, they are grown naturally in existing coastal waters and wetlands and are capable of growing in simple impoundments on land areas that are incapable of supporting other crops used for food or fiber and that have little or no other existing or projected use. Although the number of freshwater ponds, rivers, lakes, and reservoirs appropriate for aquatic biomass production is limited, the growth rate of several of the aquatic weeds in the presence of nutrients is so high that these weeds often constitute a hazard to river navigation, and several states spend large amounts annually for waterway clearance.

The aquatic resource effort is considered a long-term, high risk, potential program. Although continued R&D funding is justified to achieve possible future breakthroughs, any attempt to achieve immediate results with large research expenditures is not likely to be cost-effective.

Conversion Process and Product R&D

Gasification

The successful gasification of biomass to produce medium-Btu gas, methanol, and similar products is subject to positive changes in federal regulatory policies. The future demand for methanol is uncertain but could increase by an order of magnitude should national policy require methanol additions to gasoline. However, unused methanol plant capacity appears to exist in the United States, and a future supply of methanol from coal could reduce the need for biomass-based supplies.

Overall, the attractiveness of the markets for methanol and similar products do not appear to justify large expenditures for process RD&D for near-term applications. However, over the long term, the variation between projected production costs and market prices may make gasification a very attractive alternative. Significant investment and operating cost reductions are anticipated as gas production equipment, and procedures are adapted to specific biomass feedstock processing requirements (mainly simpler ash handling facilities and reduced feedstock chloride content).

The production of ammonia from medium-Btu gas appears attractive at both present and projected market prices. Current ammonia demand is close to U.S. capacity, and that demand is expected to increase. Although ammonia may be produced from coal in the future, the lower carbon/hydrogen ratio and sulfur content in biomass could favor this feedstock over coal.

Based on currently available market price projections for the cost of natural gas, the production of SNG by pyrolysis and methanation does not appear attractive until after the year 2000. However, significant process development breakthroughs could change this picture dramatically. Increasing funding to develop more effective catalytic materials and improve the gasification step would yield lower costs and earlier process feasibility dates.

Anaerobic Digestion

Significant process improvements in anaerobic digestion can be achieved with increased developmental funding. The digestibility of several feed materials has been confirmed, and others such as kelp have been tested recently. Research and development is needed to optimize yields for anaerobic digestion and is also essential to speed the reactions and achieve shorter feed retention times. This would permit use of smaller vessels and reduce equipment costs.

Liquefaction

The Fuels from Biomass Program currently places a great deal of emphasis on the production of fuel oils for the transportation market. Preliminary information indicates that some change in this emphasis would be desirable in view of projected high costs of fuel oil production. Major process improvements are not expected, but additional funding could reduce scheduled development time by several years.

Although ethanol from biomass via hydrolysis and fermentation may become economically attractive before the year 2000, current unused capacity could cause ethanol price reductions or weaknesses. However, because of a potentially large demand, given a national directive forcing ethanol consumption as a transportation fuel, R&D efforts to monitor and encourage technological progress in the area seem warranted. A number of alternative conversion routes are apparent, and the need for the development of an effective solvent material is particularly urgent. Acid or enzymatic hydrolysis could serve ultimately to considerably reduce costs of ethanol production.

Direct Combustion

Direct combustion processes are well developed, and major increases in funding are not expected to significantly reduce either costs or the schedule period before commercialization.

Technology Risks and Potentials

In examining the need for funding reallocation, it is necessary to assess (1) the near-term potential for the technology, (2) the risk of process development failure, and (3) the long-term potential for significant increases in U.S. energy output. Each of these factors for each of the technologies is evaluated in Table VII-9.

Fund Doubling

The current budget for the Solar Energy Division's Fuels from Biomass Branch is \$20.7 million in fiscal year 1978. This budget is expected to increase to \$35 or \$40 million in fiscal year 1979. Our best estimates of the impact of a doubling of fiscal year 1979 funding are shown in Table VII-10, provided the funds are allocated in a logical and cost-effective manner. These estimates are derived from the preceding discussion of the elements in the research, development, and demonstration plan that merit additional consideration.

Table VII-9

TECHNOLOGY RISKS AND POTENTIALS

<u>Technology</u>	<u>Near Term Potential</u>	<u>Process Develop- ment Risk</u>	<u>Long-Term Potential</u>
Terrestrial energy farming	High	Low	High
Aquatic energy farming	Very low	High	Very high
Anaerobic digestion	High	Low	Low
Direct combustion to steam or electricity	High	Low	Moderate
Fermentation	Low	Moderate	Moderate
Gasification	Low	Low	High
Liquefaction	Low	Low	High

Fund Reallocation

If the total annual budget for the technologies is held constant, less funding should be placed in options with distant commercialization dates and more funding should be placed in near-term alternatives, providing greater immediate benefits. Therefore, liquefaction processes designed to produce fuel oils and aquatic biomass production options with distant commercialization dates should receive decreased funding. In contrast, more funding should be placed into anaerobic digestion, direct conversion, fermentation, and gasification options, which have greater potential for immediate impacts.

Technology Potential

In general, the fuels from biomass program has a significant potential for relieving a portion of this country's dependence on foreign energy sources. The potential for developing the processes that will allow full commercialization of economically available biomass resources is high. In consideration of the regional resource limits, the price of competing fuels (e.g., coal), the potential for effective RD&D funding expansion, and the economics of process conversion, biomass could provide for as much as 6 to 8 percent of this country's energy needs in the year 2020.

Table VII-10

EFFECT OF DOUBLING RD&D EXPENDITURES

Technology Development	Expected Cost Decrease			Schedule Improvement*			
	Percent By			New Demo Date	Years Saved	New Commercial Date	Years Saved
	1985	2000	2020				
Energy farm - wood	10%	30%	35%	1979	1	1983	3
Energy farm - crop	10	30	35	1979	1	1983	5 to 10
Aquatic energy farm	20	40	50	1987	3	1990	5 to 10
Anaerobic digestion	20	35	40	1978	0	1980	5
Direct combustion electric power	5	10	15	1978	0	1980	0
Fermentation ethanol	35	50	80	1982	3	1985	5
Gasification (medium-Btu gas)	30	50	80	1981	0	1985	5
Liquefaction (methanol)	25	45	70	1983	3	1990	1 to 3
Fuel oil	20	30	40	1985	1	2000	0 to 3

* Estimated improvements in the current DOE schedule. See Development Schedule, Figure VII-3.

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VIII OTEC

Introduction

In 1881, d'Arsonval¹ proposed the possibility of extracting energy from fluids having thermal gradients, and early experimenters such as Claude² in 1930 used an open cycle concept in which seawater was the working fluid. Such efforts confirmed that the normal temperature differences in the oceans represent a vast source of untapped energy, a source so large that it is believed³ to far exceed that available from many of our other commonly used energy sources.

The Department of Energy (DOE, formerly ERDA, Division of Solar Energy) is conducting a multifaceted research program concerning ocean thermal energy conversion (OTEC). The current thrust of DOE's program is to make the products extracted from this resource competitive with alternatives. These OTEC products include electricity as well as a variety of energy-intensive products from industrial complexes that would use this electricity in their manufacture. Current OTEC research began in the early 1970s, under the sponsorship of the National Science Foundation program administration, was subsequently transferred to the Energy Research and Development Administration, Division of Solar Energy, and currently exists as a program in DOE.

Technology Description

Generic Technology

This generic technology description includes the most important features of the technology that are believed to be typical of most future commercial OTEC installations. The description is limited to current thinking in several component areas, since OTEC is at an early stage of development and design concepts are being continually revised and updated.

Emphasis is on moored OTEC installations generating electric power. Ocean energy industrial complexes (OEICs) are also under consideration; these could produce a variety of inorganic and organic chemicals, and may be either moored or grazing. Because of the variety of possible products from OEICs, each of which tends to serve a different end-use market, no generic description of OEICs is attempted here, although reference to OEICs is made, as appropriate, in the sections that follow. For OTEC installations producing electric power, the cost of the transmission cable to shore will be separately treated as adding to the cost of electricity produced on board the OTEC installation.

OTEC denotes a technology that uses the temperature variation between surface and deep ocean waters to generate electric power using either an open thermodynamic cycle or a closed, binary fluid thermodynamic cycle. Since the current cycle efficiencies for this concept tend to lie between 3 and 5 percent, the movement of large quantities of seawater (both warm and cold) is required in the generation of 100 to 200 MWe of electric power. In the open cycle concept,⁴ warm seawater is flash evaporated; the resulting steam feeds a steam turbine; and the turbine exhaust gases are directly condensed using cold seawater. In the closed cycle, warm seawater indirectly vaporizes a working fluid (e.g., ammonia) in a heat exchanger; the working fluid drives a turbine; and the turbine exhaust gases are indirectly condensed in a heat exchanger by cold seawater. Contractor estimates^{5,6} suggest that 130 to 135 MWe of gross electric power output must be generated to achieve 100 MWe of net electric power from the installation. These "parasitic" power requirements (for pumps, auxiliary equipment, life support systems, and the like) of 30 to 35 percent are relatively large compared with conventional power plants which experience about 5 percent "parasitic" power requirements.

The generic OTEC technology considered uses a closed cycle, with shell and tube heat exchangers. Open cycles are candidates for second generation concepts, as are plastic heat exchangers,⁷ plate heat exchangers,^{7,8} and foam OTEC systems.⁹ The closed cycle generic system was selected because its concepts are closest to commercial practice.

The generic OTEC technology operates in tropical or subtropical waters on thermal temperature differences of 38°F minimum. The net electric power output is about 200 MWe, generating baseload power, with no storage (unlike most other solar electric technologies). It operates from a moored location 20 to 200 miles offshore and delivers electric power to an on-shore utility grid by a high voltage AC or DC transmission cable. The plant is assumed to have a 30-year operating lifetime.

The following subsections discuss specific components of the OTEC system.

Heat Exchangers

Numerous concepts have been proposed for basic heat exchanger configurations. Table VIII-1¹⁰ discusses the more prominent concepts, including tube bundles, plate/fin concepts, and serpentine coil concepts; designs in each area have undergone and will continue to undergo changes and refinements as OTEC concepts evolve. Since heat exchangers represent substantial investments for commercial designs, and due to their important effect on the basic operability of open cycle OTEC installations, DOE has placed early program emphasis on heat exchanger design concepts, testing, and allied areas such as biofouling, corrosion, heat transfer enhancement, and materials of construction.

Table VIII-1

CANDIDATE EVAPORATOR HEAT EXCHANGER CONCEPTS

Description	Module Size, Passage Sizes	Flow Arrangement-- Boiling Mechanism	Working Fluid	Materials	Enhancement	Cleaning Method	Proponent
Sprayed tube bundle Horizontal Vertical	25 MWe, net a=63', b=20' 1.5-2" OD TBS	Seawater inside tubes, thin film evaporation, recirculation	Ammonia (Propane)	Titanium (Cu-Ni)	Linde surface on shell side, corrugated on tube side	Amertap or chlorination	Union Carbide Corp. Linde Div.-Lockheed baseline
Falling film evaporator Vertical tubes Pressure-balanced	25 MWe, net 1" 00 tubes, 10 ft long a $\approx$ 23' b $\approx$ 85'	Seawater inside tubes, thin film evaporation, recirculation	Ammonia (Propane)	Aluminum (Cu-Ni)	Fluted tubes (both sides)	Chlorination	Carnegie-Mellon University
Flooded bundle (state of art) Horizontal tubes	Max 12' dia. tube bundles to prevent dry-out 10-50' long tubes	Seawater inside tubes, flooded bundle with natural circulation	Ammonia (Propane)	Titanium (Cu-Ni)	Linde surface shell side, corrugated tube side	Amertap or chlorination	Union Carbide Corp. Linde Div. (state- of-the-art exch.)
Forced circulation shell-and-tube evaporator Horizontal Tubes Evaporation on shell side	1-1/2" OD tubes 25 MWe 50' dia. shell 43' long tubes	Seawater inside tubes, 20 percent cut sequen- tial baffles on shell side, spacing increas- ing with void fraction, recirculation	Ammonia	Titanium	None	Amertap	TRW baseline
Flooded plate-fin Design Recirculation Pressure- balanced	TBS 4' x 4' x 8' ? modules	Plate-fin arrangement with crossflow	Propane or R12/31	Aluminum	Fins on working fluid side	Chlorination or brushing	SSPI, Anderson
Forced circulation shell-and-tube evaporator Vertical tubes Evaporation on tube side	TBS 50-100' long Tubes, ~1" OD	Seawater and working fluid in crossflow, working fluid flowing vertically upward inside tubes; recir- culation in latest concepts Seawater pumped or natural circulation by Gulf Stream outside tubes	Ammonia (Propane)	Aluminum (Cu-Ni)	None	Mechanical	University of Massachusetts
Same as above, but plate-fin							
Submerged coil array Evaporation Inside tubes Recirculation	2.5 MWe, net modules 4" OD tubes a $\approx$ 27' stacked 13' deep	Serpentine coil arrangement; working fluid inside coils seawater outside, counter-crossflow arrangement	Ammonia	Aluminum	None	Cavitating water jets	Applied Physics Laboratory, Johns Hopkins University

Table VIII-2¹⁰ lists qualitative considerations of the performance of various proposed heat exchanger materials in seawater. As candidate materials, titanium and aluminium are presently receiving the most attention with the customary restriction that final materials selection should await long-term site testing. Industrial experience with these materials (except polymers) exists in such areas as power plant condensers, LNG revaporization facilities, and desalination plants. However, these applications possess requirements different from those of OTEC, most notably in the size of the application. Such differences and their limitations should be carefully assessed (including the use of biocides such as chlorine or acrolein) when discussing their applicability to OTEC.

Table VIII-2

GENERAL PERFORMANCE OF CANDIDATE
MATERIALS IN SEAWATER

Material	Corrosion					Fouling		Stress Corro- sion Crack- ing	Corro- sion Fatigue
	Gen- eral	Pit- ting	Gal- vanic	Cre- vice	Ero- sion	Scale	Bio		
Titanium	E	E	E	C	E	E	P	E	E
Aluminum	VG	F-P	P	F-P	F-P	E	P	E	P
CRES *	E	G=F	VG	G-F	G	E	P	E	F
Cu-Ni	E	E	G	E	G	E	G	G	E
Polymers	E	E	E	E	F	E	P [†]	E-P	E

* Austenitic stainless steels.

[†] Polymers may be formulated to contain antifouling ingredients.

E = excellent

VG = very good

F = fair

P = poor

Source: TRW (Reference 10)

Heat exchanger geometries have been evaluated by numerous OTEC proponents. Many analytical techniques have been used to predict the fluid mechanical and heat transfer performance of the seawater and working fluid in the geometry of choice. Emphasis has been placed on the

evaporator, since the condenser designs tend to resemble current experience, as found for example, in the steam-electric power plant industry.

Proposed tubed evaporator designs range from those resembling the state of the art (e.g., Linde)¹¹ to a very large spherical shell and tube design proposed by Lockheed (Figure VIII-1),¹² ranging from 60 to 100 feet in diameter.

When discussing new heat exchanger geometries or new sizes of heat exchangers for OTEC installations, several questions arise:

- How will the heat exchangers be cleaned?
- How will noncondensable gases be safely removed?
- How accurate are the basic correlations for heat transfer, for the geometries and fluids of interest?¹³
- Will there be any fluid distribution problems for the seawater and the working fluid? Such problems may become more pronounced as the size of the exchanger increases and as the proposed geometry departs further from current experience.
- What effects may be anticipated from any two-phase flow regimes? Where will two-phase flow occur?
- Have all the loads to which the heat exchanger will be subjected been analyzed? These would include normal and extreme loads anticipated for exchanger fabrication, transportation, operation, and maintenance.
- Will stress relieving be required?
- What are the fabrication tolerances?

Heat exchanger designs proposed by Lockheed and TRW contain from 50,000 to 100,000 tubes per exchanger bundle, with total heat exchange areas ranging from 1 to 2 million square feet. Seawater flowrates are about 1 million gallons per minute per heat exchanger bundle. Very large power plant condensers currently in use may handle about 300,000 to 600,000 gallons of cooling water per minute, but the bundles are generally sectionalized for convenience of maintenance. For example, Unit 7 of Pacific Gas and Electric's Moss Landing power plant is cooled with 300,000 gpm of seawater, each half of the condenser (27,000 tubes) being cooled with 150,000 gpm. Clearly, the larger sizes of the proposed OTEC heat exchanger designs would require lengthy (5-10 years) development times when compared to current industrial experience. For this reason, it is felt that ultimate commercial OTEC module sizes may not be significantly larger than 25 MWe because of the sizes of the heat exchangers.

A prime issue in heat exchanger cost concerns the allocation of the tooling costs or retooling for the commercial production line. Prototype heat exchanger costs (expressed in \$/kW) tend to be higher than production unit costs because prototype tooling costs are distributed

Source: Reference 13

FIGURE VIII-1. 25-MW HEAT EXCHANGER

over very few prototype units. Also, to the extent that production unit sizes are larger than prototypes, the facility retooling costs for prototypes may be unrecoverable and treated as an R&D expense.

Tooling or retooling costs for the production units may be allocated over the first 40 or 50 production exchangers, resulting in lower costs for the production units compared to the prototype units. This reasoning may not be satisfactory when viewed from the perspective of the owner of the heat exchanger production facility. Rather than waiting to recover his costs over the period of time it takes to produce 40 or 50 exchangers, he may wish to recover his investment more rapidly, given the risks of the venture, and may allocate the costs over the first several production units. Such a decision would cause the costs of the first OTEC plants to be higher than otherwise estimated.

Platform

The platform of the OTEC plant contains the heat exchanger, generating plant and related support equipment. It must be capable of supporting the load weight of the cold water pipe and capable of surviving design storm conditions.

At this point, three DOE contractors are performing tradeoff studies of six hull structure platform configurations. Until the candidate configuration is selected, design requirements defined, and a preliminary design completed, a meaningful design review cannot be made, nor reliable cost estimates prepared. The candidate configurations are basic variations of spar buoy, semisubmersible, and ship form hull designs with basic plant equipment above and below the ocean surface.

OTEC plant equipment and cold water pipes will likely entail adaptations from similar basic designs in use in offshore petroleum rigs or envisioned for floating nuclear power plants. These 1,100-MW nuclear plants will be moored in protected offshore environments, weigh about 160,000 tons, and cost on the order of \$600 million or \$1.90 per pound. OTEC platforms including plant equipment may experience costs in this range.

Cold Water Pipe

A detailed design of the cold water pipe has not been performed, but indications are that the pipe will be 50 to 130 feet inside diameter and 2,000 feet to 3,500 feet in length for a 1,000-MW commercial OTEC plant. Consideration has been given to both concrete and plastics as construction material, but no known structures of the greater length (three times the height of the Empire State building) have been constructed from either candidate material. Gravity structures used in the North Sea are constructed from reinforced concrete and have been installed in water depths approaching 500 feet. The Brent "B" structure has a weight of 350,000 tons.¹⁴ The status of technology in the offshore industry is to have oil producing

structures in 1,000 feet of water in 1978. The tallest structure currently is in 850 feet of water and was installed off California in the Santa Barbara Channel in 1976. Both this structure and that being installed in 1,000 feet of water in the Gulf of Mexico in 1978 are of steel construction.

The offshore structures are all deck loaded with equipment, well casing and tubing, placing the vertical structural columns in compression. In an OTEC plant the cold water pipe will be in tension. A design capable of supporting its own weight and the loads on the platform must be developed. Incorporating buoyancy in the pipe can help reduce the loads imposed on the platform.

An important design consideration is installation of the pipe. Proceedings of the Offshore Technology Conferences (OTC) over the last several years indicate that the requirements of the OTEC cold water pipe are beyond today's state of the art. Experimental investigations on fatigue of offshore concrete structures are discussed in OTC 3009 - 1977: "The fatigue strength of concrete under reversible loading and hydrostatic water pressure is presently not known."

Mooring

Consideration is given to two mooring modes: static, if the OTEC plant is moored in one spot and used for power generation, and dynamic positioning, if used for other purposes.

In static mooring in 4,500-foot water depths, chain and wire rope are being considered, using a multileg mooring similar to that used in floating drill rigs offshore. In this water depth, each leg would be approximately three miles long.

In dynamic positioning, a primary consideration is how much of the OTEC power output will be consumed to hold the plant on station. Mooring forces are being developed under current contracts through Gibbs & Cox by Alan C. McClure Associates in Houston, Texas.

Underwater Transmission Cable

Personnel experienced in transmission cable manufacturing and in transmission and distribution application indicate that cable manufacturing requirements can be met, but laying the cable in about 4,000 feet of water may impose certain requirements and increase costs. This problem has not yet been addressed.

Offshore Power Systems¹⁵ is assuming a cost of \$2.0 million per mile for a 345 kva, 11-mile line from an 1,100-MW nuclear plant. EPRI has calculated²⁰ the cost of a 20-mile line from a 120-MW OTEC plant off

Florida at \$466 per kW. A cost per mile can be calculated at \$2.8 million by

$$\frac{\$466 \times 120,000}{20 \text{ miles}} = \$2,796,000.$$

The Florida site had a surface temperature of 79°F and a bottom inlet temperature of 40°F or a ΔT of 39°F. Since most potential OTEC sites are remote from power grid networks, the cost of the underwater cable plus other transmission costs to the grid and line leases enroute are important considerations.

Rotating Equipment

The major rotating equipment items in proposed OTEC power plant designs are pumps and working fluid turbines. The pumps will be used in the OTEC power plant to move large masses of warm and cold seawater as well as working fluid. The warm and cold water pumps will be used essentially to provide seawater flow through heat exchangers and condensers. The present state of practice of the pump industry is capable of manufacturing warm and cold seawater pumps to the proposed specifications for an OTEC power plant module capacity of 25 MWe (net). The capacity selection for the seawater pumps should be based on an optimization of the heat exchanger and condenser design conditions and the maximum pump capacity which can be produced using state of the practice technology.

The technology used in the manufacture of large seawater pumps is closely related to the manufacture of large ducted ship propellers. Table VIII-3 compares proposed seawater pump design requirements with such propellers. If conventional pumps are not suitable for OTEC, the technology for the manufacture of seawater pumps can be adapted from the shipbuilding industry.

The working fluid pump design does not demand the movement of large quantities of fluids, and the existing technology in pump manufacturing is suitable for direct application without apparent additional research and development effort. However, the use of ammonia as a working fluid may demand special provision for corrosion resistant materials. Proposed design conditions for the working fluid pump for a 25-MWe capacity OTEC module are:

- Flow rate, 1,790 lb/sec
- Pressure rise, 50 psi
- Rated horsepower, 700.

Table VIII-3

SEAWATER PUMP TECHNOLOGY COMPARISON

	Seawater Pump		Examples of		
	Design Requirements		Ducted Propeller Installations		
	Warm	Cold	Tanker Golar Nichi	Tanker Kronoland	Cargo Ship Kemsomol
Flow rate (cu ft/sec)	3,974	3,365	20,875	16,500	4,475
Rated horsepower	3,200	4,100	30,000	25,000	5,200

Source: Reference 16.

The total capital cost of pump units for an OTEC plant represents only a small percentage (generally less than 5 percent) of the total capital investment for an OTEC power plant. Even with the uncertainties in the estimated cost of the pump units, their impact on the overall power plant capital investment is not significant. The main question seems to be whether further development efforts are needed to manufacture these pump units for the testing and eventual commercialization of OTEC installations. From the foregoing discussion, it is obvious that the existing technology is capable of supporting the production of pump units for an OTEC power plant module of 25-MWe (net) capacity.

The turbine units for the OTEC power plant are more complicated in design and performance than the pump units. The complication is due to the low cycle efficiency inherent in the OTEC system. To attain the maximum practical cycle efficiency, it is important to obtain as high an efficiency as possible in the turbine. The turbine efficiency is in turn related to its specific speed and specific diameter, parameters which must be optimized to keep the turbine size within practical limits. Another consideration is the size of the generator coupled to the turbine. The maximum single unit capacity of a turbine for an OTEC system is estimated to be about 30-35 MWe (gross), well within current manufacturing state of practice.

The physical size of the turbine, specifically the wheel diameter, will depend on the working fluid selection and the speed selection. The turbine characteristics for the OTEC system indicate that a maximum rpm with minimum wheel diameter is required, consistent with the requirements for high turbine efficiency.

The present state of the practice in the cryogenics field, from which technology can be transferred to the manufacture of OTEC turbines,

limits the largest capacity turbine to about 10 MWe. Although turbo-expanders using high-pressure hydrocarbons or other gases have been used in the chemical and processing industries for a long time, ammonia turbines in the size ranges discussed here have not been used extensively in commercial practice. Studies performed so far indicate that the use of ammonia in OTEC system turbines is preferable to propane and R-12/31. If a single, large ammonia turbine per module is desired, a scaling up in capacity to about 30 to 35 MWe from the existing capacity of 10 MWe is also required.

Development Schedule

Figure VIII-2 presents program plan information from a Lockheed report¹² showing engineering development and demonstration of heat exchangers and power cycles through a proposed 100-MWe surface demonstration system beginning in 1984. These concepts represent the heart of the OTEC program. ERDA report 76-142¹⁷ shows additional proposed schedules in other important program areas such as biofouling and corrosion R&D (1977-83), biofouling tests (1976-81), systems integration studies (1978-86), early platform-related studies (1977-79), and materials studies and tests (1976-80). Current major contracts awarded for OTEC studies in support of these proposed schedules are platform assessments for the OTEC demonstration unit; conceptual and preliminary designs of the demonstration unit power system; delivery of hardware items for smaller, scaled exchangers and power system modules; studies of compact heat exchanger designs; studies of factors affecting corrosion of aluminum alloys in seawater service; and the development and application of biofouling test apparatus.

The 1976 annual report by Battelle Pacific Northwest Laboratories¹⁸ discusses preliminary results of research on biofouling and corrosion being conducted by Carnegie-Mellon University, Alcoa, Allied Chemical, and others. This research is at an early stage of development; as Battelle suggests, longer term tests are needed before conclusions can be drawn concerning the quantitative effects of biofouling and corrosion on OTEC installations, together with potential mitigating measures.

A major program milestone will be the awarding of a contract to recondition the Hughes Mining Barge to serve as a demonstration platform for a 1-MWe heat exchanger test facility. Figure VIII-3 shows this vessel, the OTEC-1.

The conclusion is that many program activities are currently under way or will shortly be under way in a variety of areas (not all of which were mentioned above) in support of the current OTEC program plan. Figure VIII-4 shows these sharply increasing budgetary activities through FY 1978.¹² At the end of the demonstration phase, it is likely that total program costs (1977 dollars) may be between \$600 and \$900 million. The majority of these funds may be spent in the 1985-95 period, which will be the demonstration phase of the program.

Source: Reference 12

FIGURE VIII-2. OTEC PROGRAM PLAN

BASIC DIMENSIONS

LENGTH, OVERALL	324 - 0
BREADTH, MOLDED	106 - 8
LENGTH, INSIDE WING WALLS	276 - 0
WIDTH, INSIDE WING WALLS MOLDED	76 - 8
HEIGHT, WING WALLS ABOVE BASELINE	62 - 0
RATED PAYLOAD CAPACITY	2500 L,T
DISPLACEMENT, LIGHT	4700 TONS

PRINCIPAL FEATURES

- CONTRCL ROOMS, P/S, AMIDSHIPS 02 LEVEL
- (4) STABILIZING CYLINDERS 10 DIA. 74 L
- (24) VOIDS 02-03 LEVEL
- (4) TRIM TANKS 01-02 LEVEL
- (22) VARIABLE BALLAST TANKS 01-02 LEVEL
- (22) SOFT TANKS

Source: Reference 12

FIGURE VIII-3. CONSTRUCTION BARGE

FIGURE VIII-4. FEDERAL FUNDING OF OTEL RD&D

Three possible deficiencies are noted in the present program organization which may delay the timetable shown in Figure VIII-2. They are:

- The OTEC program currently lacks significant private sector (not contractor) technical involvement. Technologies under development by DOE will ultimately be transferred to the private sector for commercialization. Commercialization will occur if the technology fulfills perceived needs of the private sector. The program should attempt to assess missions that fulfill these needs and orient OTEC RD&D strategies accordingly.
- The present OTEC program structure does not exhibit strong mission-oriented approaches or strong approaches entailing assessment of the benefits of RD&D. The benefits accruing to OTEC commercialization (in economic and noneconomic terms) should be assessed for specific OTEC missions. These benefits should be compared with those of alternative OTEC missions and non-OTEC technology missions expected to be commercialized or ready for commercialization in the same time frame and a decision made as to which alternative strategy or sets of strategies maximize national benefits.
- The original OTEC program plan (Figure VIII-2)¹⁷ shows several design, fabrication, and testing phases for selected components or scaled systems. A complete characterization of the program should be far more detailed, showing important interrelationships between program elements (e.g., the effect of large amounts of biofouling and corrosion on heat exchanger design) as well as sufficient time for the development of alternative strategies and timetables for uncertain experimental outcomes from site experiments. Thus, in Figure VIII-2, insufficient time is allowed for test results from the early ocean test platforms (1-MWe heat exchanger) to be incorporated into the design and fabrication of the 5-MWe power cycle test facility.

Table VIII-4 is a revised program schedule for OTEC development, incorporating some of the concepts discussed above; as shown, commercialization may not be realized until after the year 2000. The development of Ocean Energy Industrial Complexes may lag OTEC development by ten years or more.

A lesson can be learned from the development of nuclear power. Speculation and investigations of fission reactions began near the mid 1930s, but the first commercial nuclear power production went on stream in late 1956, a lead time of more than 20 years. Today's environment, which requires impact statements, permits, licenses, approvals, and sometimes court actions, would increase the lead times.

For the OTEC program, an organized program management approach, in the government or with a prime contractor, is necessary to address each area requiring development and technical effort in an orderly and programmed manner. Some of the difficulties mentioned above may be procedurally remedied by appointing a prime contractor for the OTEC program.

Table VIII-4

OTEC DEVELOPMENT SCHEDULE

Product: Electricity (Baseload)

	<u>Concept</u>	<u>Design</u>	<u>Pilot</u>	<u>Demonstration</u>	<u>Commercial</u>
OTEC	1972/1980	1980/1985	1982/1990	1988/1995	1997/Ind.

Ind. = Indefinite
Economics

The economics presented here concern OTEC installations producing electricity. No economics are presented for nonelectric products. Additionally, the cost of electricity transmission to shore is treated as being separate from and adding to the cost of electricity produced from the OTEC platform itself.

Since the OTEC program is at an early stage of development, firm definitions of the system, its components, its operation, and its maintainability are lacking with the result that large uncertainties exist concerning the basic economics of OTEC electricity. Several areas of uncertainty concerning OTEC equipment are listed below. Failure to construct or to operate any of these equipment items would cause the significant delays in the OTEC program.

- (1) No directly comparable structures/systems
 - Cold water pipe
 - Mooring weights in deep water
 - Very large heat exchangers and exchanger internals.
- (2) Limited prior experience (not necessarily in the United States)
 - Very large seawater pumps (overseas, e.g., Germany)¹⁶
 - Shells
 - Ammonia turbines and ammonia systems
 - Power cable (overseas, e.g., Norway)¹⁹
 - Large concrete structures.

The (1) items exhibit potentially large variations in cost because the basic requirements are not well understood. In some instances (e.g., heat exchangers), a limited amount of conceptual work has been directed at the assembly-line type of fabrication for these large equipment items.¹³ In other instances, much basic work remains to be done concerning basic equipment fabrication and deployment techniques as well as cost analyses.

Generally speaking, the (1) items are believed to significantly exceed the limits of current industrial experience, and each item may require on the order of a decade or more of expensive predevelopment, development, design, fabrication, and field testing work.

The (2) items are those for which limited prior experience may exist in equipment fabrication and operation. However, in every instance, the present applications differ somewhat from those currently envisioned for OTEC installations. Additionally, where prior industrial experience exists outside the United States, the problems of technology transfer to U.S.-based industry have not been completely analyzed.

As is true for technologies at early stages of development, it is likely that capital costs for OTEC installations will increase with time as system construction, operation, and safety requirements, for example, become better defined and as results from the field testing of components and scaled OTEC systems become available. At every step, costs tend to increase. Similarly, materials of construction may change as may the requirements for spare or redundant equipment items and the requirements for system operation, safety, and maintenance.

The conclusions and recommendations in this section are highly speculative. Table VIII-5 presents OTEC capital costs in 1975 dollars. Initial costs for the first production unit were obtained from Lockheed²⁰ and adjusted to a 38°F ΔT (the generic technology basis for this study) using Lavi's formula.²¹ The costs were increased as follows:

- For the mooring system and cold water pipe, a 100 percent contingency factor was applied because of the uncertainties in these systems.
- For the heat exchangers, a 5 percent allowance was applied for sectionalizing the heat exchanger, following current utility practice for large bundles; and a 30 percent contingency factor was used to account for design unknowns.

Following information presented in the Lockheed paper,¹² line F of Table VIII-5 was assumed to represent 95 percent of the 30 year capital cost in the case of titanium and 74 percent in the case of aluminum. The present value of the cost of replacing pumps and bundles after 15 years of operation is included in line G.*

The subtotals shown in line H represent the present value of the plant cost (initial plus replacement capital) for the assumed 30-year plant life, indicating that no significant cost advantage may exist for aluminum over titanium as a material of construction. Also, should aluminum have a lifetime of less than 15 years, its 30-year cost would exceed that of titanium.

* If constructed of titanium, only the pumps need be replaced.

Table VIII-5

OTEC CAPITAL COSTS
(1975 Dollars per Kilowatt)

<u>Line</u>		<u>Titanium</u>	<u>Aluminum</u>
\ A	Initial cost (LMSC-36.5°F ΔT) of first production unit	\$1,900	\$1,550
B	Corrected to 38°F ΔT	1,730	1,410
	Additions because of increased contingency for:		
C	Mooring	140	140
D	Cold water pipe	70	70
E	Heat exchanger	225	110
F	Subtotal initial cost (B + C + D + E)	2,165	1,730
G	Present value added cost in 15 years	<u>115</u>	<u>550</u>
H	Subtotal (F + G)	\$2,280	\$2,280
I	Owner's costs--7 percent of Line F	150	120
J	Interest during construction--16 percent of line F	<u>345</u>	<u>275</u>
K	Total (H + I + J) cost of first production unit	\$2,775	\$2,675

SPECIFIC CAPITAL COST
(Dollars per Annual MM Btu)

L	$SCC = \frac{\$/kW \text{ (line K)}}{29.9 \times \text{capacity factor (0.8)}}$	\$ 116	\$ 112
M	Learning curve effects: 89 percent of line L	104	100

SUCCESSFUL OUTCOME OF HEAT TRANSFER ENHANCEMENT
EXPERIMENTS OR MANUFACTURING TECHNIQUES FOR
HEAT EXCHANGERS--20 PERCENT REDUCTION IN
HEAT EXCHANGER COST

N	First production unit	\$ 104	\$ 103
O	Later production units--89 percent of line N	93	92

Adding an allowance for owner's costs and interest during construction, the total costs for the first production units range from \$2,700 to \$2,800 per kilowatt.

The remainder of the information in Table VIII-5 shows the conversion of capital costs in dollars per kilowatt to specific capital costs; learning curve effects, which are assumed to be 10 to 12 percent over a 20- or 25-year period;* and costs assuming that heat exchanger costs can be reduced by 20 percent because of successful exchanger manufacturing techniques,¹³ successful heat transfer enhancement research and experiments,^{11,22} or other such concepts. The capacity factor for an OTEC plant was assumed to be 0.8. This suggests the availability factor for OTEC may be 0.85 to 0.90. No current reasons exist for assuming a particular capacity factor because of unanswered questions concerning biofouling, corrosion, seasonal derating,²³ exchanger design and cleaning techniques,²⁴ maintenance outages, and the like. For this work, an 80 percent capacity factor was adopted as nominal, realizing that the first several installations may operate at significantly lower capacity factors²³ and that an 80 percent capacity factor may be considered as a technology goal.

Figure VIII-5 shows specific capital cost information for OTEC installations. Initial units are assumed to be available around the year 2000, while units assumed to be available around 2020 exhibit small cost decreases because of learning. The "optimistic" case presented in Figure VIII-5 represents technological breakthroughs that lead to a 20 percent reduction in heat exchanger costs. The "pessimistic" case involves technical difficulties in achieving the numerous engineering and cost goals for the components of the OTEC system discussed previously. This latter case could postpone the technology development by 20 years or more.

Because of a lack of definition of basic requirements for maintenance, O&M costs are assumed to be about 6 mills per kilowatt-hour. Conceivably, they could be much higher.

Following information presented by Arthur D. Little, Inc.,²⁵ the cost of electricity transmission to shore was assumed to be 8 to 10 mills per kilowatt-hour, assuming an average plant location of 80 to 120 miles offshore.

* If OTEC plants are built at various yard facilities, the amount of learning transferable from one facility to another is questionable.

REGIONS 3, 4, and 6

FIGURE VIII-5. GTEC SPECIFIC CAPITAL COSTS

Potential Applications

Markets

OTEC-produced electricity will enter the market at coastal locations and will be further transmitted to demand regions. The costs and losses involved in long-distance transmission will probably limit the OTEC electricity market to selected regions, such as the Southeastern and South-Central United States. The expected growth in electricity demand for these regions, however, will present a sizable potential market. For example, government-compiled statistics³⁴ have estimated that the three Regional Electric Reliability Councils* comprising the aforementioned regions will require approximately 40 percent of the new electric generation capacity installed in the United States between 1976 and 1985.

A recent SRI report²⁶ prepared for Lockheed Missiles and Space Company, Inc., suggests that between 231,000 and 440,000 MWe of incremental electricity generating capacity (base, intermediate, peak, and reserve) will be needed from 1990 to 2000 in the SERC, SWPP, and ERCOT regions. Information presented in Appendix Table V of the SRI report further permits the disaggregation of incremental generating capacity by equipment type (Table VIII-6).

Table VIII-6

INCREMENTAL BASE AND INTERMEDIATE
GENERATING CAPACITY ESTIMATED TO BE ADDED TO
SERC, SWPP, AND ERCOT REGIONS BY EQUIPMENT TYPE, 1990-2000

<u>Equipment Type-Service</u>	<u>High Projection</u>	<u>Low Projection</u>
Nuclear--base	200.2	112.3
Coal--base	27.5	12.5
Coal--intermediate	<u>141.5</u>	<u>74.3</u>
Total base plus intermediate	369.2	199.1
Total base	227.7	124.8

Incremental generating capacity from the year 1990 is used since few projections suggest OTEC market penetration before 1990.

* These are the Southeastern Electric Reliability Council (SERC), the Southwest Power Pool (SWPP), and the Electric Reliability Council of Texas (ERCOT).

OTEC is inherently a baseload electricity generating technology with no storage; its potential market will be the incremental baseload electricity generating market. Table VIII-6 indicates that the total incremental baseload capacity in the OTEC regions (ERCOT, SWPP, and SERC) will lie between 125,000 and 228,000 MWe from 1990 to 2000. Since OTEC is an emerging technology, its growth in the years 1990-2000 will most likely not be limited by electricity demand growth.

Recent information from Lockheed¹² suggests that the growth in total electric power demand in the OTEC regions from 2001-2010 and from 2011-2020 will be about equal and will be about the same as experienced during 1990-2000. Assuming the same fractional share of the market is baseload electricity generation for these time intervals, the potential market size for OTEC will be between 125,000 and 228,000 MWe for both 2001-2010 and for 2011-2020.

The SRI report²⁶ does not predict a domestic market for OTEC-produced hydrogen or ammonia by the year 2000. Reasons are the structure of the marketplace for these commodities and the distances of the potential OTEC installations from demand regions.

Since the market served by electricity generating OTEC installations will be baseload power, competition will exist from other baseload generation technologies. Those frequently used for comparison are coal-fired and nuclear power facilities. Difficulties arising from the use of these alternatives could make OTEC-produced electricity more desirable. For example, coal mining, transportation to site, the availability of skilled mining personnel, and atmospheric emissions may pose significant obstacles to coal-based power generation. In addition, nuclear power faces an uncertain future due to questions such as environmentalist opposition, licensing difficulties, and future uranium availability.

The greatest single factor influencing the future contribution of OTEC technology will likely be OTEC's economic viability. This viability will depend on the costs of OTEC construction (materials selected, manpower requirements, etc.), on the operability of the technology, on the plant financing methods employed, and the like. In the absence of resolution of these issues, we have made preliminary projections of the cost and market potential of electricity produced from OTEC.

Similar comments may be made concerning the development of Ocean Energy Industrial Complexes (OEIC). Potential OEIC products include ammonia, hydrogen, water (desalination), and a variety of organic and inorganic chemicals, as well as minerals. The costs and future market shares of these products depend heavily on the costs of electricity produced from the basic installation. Until uncertainties regarding the costs of OTEC electricity can be resolved, only speculative comments can be made concerning the costs of nonelectric products.

No attempt is made to predict the variation in costs for OTEC installations at various candidate sites in offshore U.S. waters or around the globe; however, some qualitative statements can be made. From the point of view of capital cost, the temperature difference between hot and cold water sources is clearly a major variable. Other factors are also important; these include differences in fabrication costs in domestic and foreign shipyards, the availability of dedicated production and fabrication facilities for the several OTEC components as opposed to facility re-tooling, and the anticipated sea conditions for which plants must be designed.

Potential regional variation in several site-specific factors may also significantly influence the cost of OTEC electricity because of their effect on OTEC availability at rated capacity. These include biofouling and corrosion; operation of the facility at off design conditions because of seasonal derating or other factors; the frequency of required OTEC forced maintenance outages; and similar factors. These factors have not been adequately characterized for potential OTEC sites.

Significant institutional barriers may exist to impede the development of an OTEC or OEIC industry. Chief among these are:

- The lack of interest in and financial participation in the program by potential customers of the OTEC or OEIC facilities (e.g., electric utilities or chemicals and minerals consumers).
- The lack of interest in the program by the Electric Power Research Institute.
- The relative capital-intensiveness of the first several installations and the acknowledged lack of economic competitiveness of their products (e.g., electricity or ammonia) with available alternatives until (perhaps) the year 2000, or beyond.
- The lack of familiarity of energy decision-makers with the technology and with the marine environment in which it will operate.
- If titanium is the material of choice for heat exchanger tubing, the fact that a single installation of commercial size will require one-third or more of the annual output of the domestic titanium industry.³²
- The uncertainty regarding basic issues of maritime liability, jurisdiction, statutory regulatory authority, and financing options.
- Potential conflicts of ocean use with outer continental shelf oil and gas exploration, fishing, deep sea minerals mining, mariculture, etc.

Environmental Considerations

Major potential environmental impacts of OTEC or OEIC facilities lie in the areas of air pollution, water pollution, land use, climate alteration, safety, noise, socioeconomic, aesthetic, and resource consumption.

OTEC and OEIC concepts are rapidly evolving and dynamic, and although a fairly extensive body of literature is available concerning this program, many environmental considerations have not yet been adequately explored. Work in the biofouling and corrosion areas, for example, are far from complete, as are concepts for materials of construction, technology design and technology operability. As a result, the environmental consequences of a decision to install an OTEC or OEIC facility are not completely understood.

Generally speaking, the environmental consequences of installing OTEC and OEIC facilities, based on current thinking, may be relatively benign²⁸ compared with alternatives (such as baseload coal and nuclear power plants) which have been studied more completely and are currently commercially available. This picture may change as more becomes known about OTEC and OEIC.

Air Pollution

Air pollution may not be a principal concern in the construction of OTECs or OEICs.* Minor amounts of particulate, hydrocarbon, and other matter may be released during the normal functioning of the fabrication facility.

The sources of the energy used in the primary extraction and fabrication of purchased materials themselves may be the major causes of air pollution. Purchased materials may include such items as concrete, reinforcing bars and strands, titanium or aluminum heat exchanger tubing, structural and plate steel, finished steel products (e.g., pumps, vessels, pipe), and many others. For example, GE/TEMPO's work²³ suggests that the manufacture of a ton of steel requires about 840 kilowatt-hours of electricity and 25 to 26 million Btus of thermal energy. If this electricity originated from coal or oil then SO₂, NO_x, hydrocarbon, and other emissions might moderately impact the neighborhood of the electricity generating facility. These impacts may decrease with time as new emission standards and control technologies are implemented.

* Denotes the OEIC work of D.S.S. Engineers, Inc.,²⁹ and also the work on OTEC delivery systems based on chemical energy carriers by the Institute of Gas Technology.³⁰

OTEC installations producing electricity may pose air pollution hazards only from the inadvertent release of the working fluid or during periods of the transfer of the working fluid to the closed cycle. Working fluids considered have been ammonia, propane, and halogenated hydrocarbons. Because of superior thermodynamic properties and decreased combustion potential, OTEC researchers generally have selected ammonia, a valued chemical produced in large quantities throughout the world. However, if the ammonia storage tank ruptures on board the OTEC installation, dispersion of the ammonia vapor cloud may pose serious problems to personnel and the environment.³¹

Water Pollution

In general, minimal water pollution problems should result from the construction of OTECs and OEICs. Potential thermal pollution and salinity gradient impacts, however, are common to their operation. A variety of opinion exists concerning the mixing of cold and warm water layers as a result of OTEC or OEIC operation.²³ For example, will the cold water sink because of slight density differences or will the cold water mix with the warm water because of wave action? Site tests should be conducted to determine the fate of the upwelled cold water. This issue impacts on the viability of marine biomass and mariculture installations adjacent to an OTEC or OEIC and also may affect the long-term temperature of the warm water essential to the operation of OTEC or OEIC plants.

The upwelling of cold water, rich in nutrients, suggests the possibility of reduced bio-oxygen demand (BOD) in areas adjacent to the OTEC or OEIC facilities. This will affect the local ecosystem and merits additional attention. Additionally, the GE/TEMPO²³ report suggests the possible local generation of excessive phytoplankton, a precursor to the "red tide."

For OEICs, the D.S.S. Engineers' report states that liquid waste streams generated from the Sea Chemicals Complex contain chemicals that were initially extracted from the sea. If the temperature and salinity levels of these streams are controlled to be close to ocean ambient conditions, there should be no adverse environmental impacts.

A 90/10 copper-nickel tubed heat exchanger might cause serious ecological problems as the metal is toxic to certain marine life in its ionic state.²⁸ It resists seawater corrosion well, but is incompatible with an ammonia working fluid. Seawater flow at the plant outfall would have a copper-nickel concentration only slightly below EPA limits. Copper is toxic in fairly small amounts to several species of mollusks and to copepods and tubeworms. It can also inhibit photosynthesis.

Titanium would cause fewer problems than 90/10 copper-nickel, since it is highly resistant to seawater and corrosion and is able to withstand high flow velocities without eroding.²⁸ EPA has not established limits for

titanium concentrations in seawater, and little or no testing has been done on its effects on marine life. Its outfall concentrations would almost certainly be lower than that of either copper-nickel or aluminum for similarly sized plants.

Aluminum is more susceptible to seawater corrosion. Also, it would probably erode and corrode at a higher rate than copper-nickel alloys, and little is known of aluminum's toxic effects on specific marine organisms.

Chlorine is commercially used to control biofouling in seawater heat exchangers. If OTEC or OEIC installations use chemical injection to control biofouling (instead of passive coatings, mechanical cleaning, electrochemical procedures, or preventive engineering design procedures),¹⁸ aqueous dispersion modeling and field tests should be conducted to determine which marine species (plant or animal) may be affected.

Land Use

OTEC or OEIC facilities themselves, operating offshore, create no land use impacts. Facility construction would create a displacement of coastal lands if new graving dock or other fabrication facilities (e.g., for heat exchangers) were required. Additionally, coastal land displacement would occur when dedicated receiving terminals were built to receive the products of OEICs, or if dedicated repair facilities were constructed to service this industry. If existing construction, repair, and terminaling facilities can be adapted for OTECs or OEICs, then minimal coastal land displacement would occur. This area has not been covered in detail in previous work.

Climate Alteration

Temperature or rainfall changes caused by OTEC or OEIC operations have not been treated in detail, since the effects attributed to one or two such adjacent installations are likely to be local in nature. The effects attributed to many adjacent installations will be of larger scale and may impact on ocean currents as well. Field tests would be the most likely source of reliable information.

Safety

Personnel-related safety issues are judged to be potentially significant for OTEC or OEIC construction, operation, and maintenance, since new procedures must be developed for these phases of a new or emerging industry. Safety standards are available for mature industries of somewhat similar nature (e.g., chemicals plants, electric power plants, and shipyards), and it is likely that safety standards will evolve for OTEC or OEIC industries as well.

Knight et al.,²⁷ cite numerous examples of potential federal and state regulatory control over the safety aspects of an OTEC or OEIC industry.

- The evaporators, condensers, and heat exchangers of a facility would probably be classified as "pressure vessels" by the Coast Guard and be subject to strict standards of design, construction, and testing.
- The Secretary of Transportation is empowered to prescribe rules and regulations for vessel safety inspection and certification with regard to lifesaving equipment, firefighting equipment, muster lists, and bilge systems.
- The Coast Guard has the authority to establish the minimum number of officers and crew an OTEC or OEIC must have to ensure its safe operation, and it can require the vessel's certificate of inspection to reflect that determination.

It is also likely that the design of OTEC or OEIC facilities, which may have the bulk of their working spaces submerged, will have to be of submarine quality regarding personnel life support systems.

Noise

Noise may present a problem during facility fabrication until mitigation measures are developed. During facility operation, the closed worker environment suggests that noise suppression will be mandatory.

Socioeconomic Impacts

Local economic impacts may be noticed in the area of an OTEC or OEIC construction facility. Such construction-related impacts would tend to be greater than the impacts associated with the maintenance facilities for OTEC or OEICs or with the construction or operation of receiving terminals for chemical or mineral products from OEICs because of the relative number of personnel involved. Unless the OTEC or OEIC industry develops very rapidly, it is considered unlikely that the industry will be responsible for large-scale regional population migration or boomtown phenomena.

Aesthetics

New OTEC or OEIC construction facilities may be designed to minimize visual impacts. OEIC facilities tend to have a greater amount of equipment above the water line and may create a larger visual impact than their OTEC counterparts.

Resource Consumption

Fresh water can be made from OTEC or OEIC installations by desalination. Several proposed OEIC facilities consume ocean minerals or other materials during operation (e.g., chlorine for caustic/chlorine; carbon dioxide for urea; naphtha for organic chemicals and plastics). Except for the materials won from the sea, the impacts of the consumption of other raw materials would not exceed those of comparably sized land-based plants. The electricity required for the OEIC processes originates from ocean thermal energy gradients and not from fossil, nuclear, or other conventional sources, which then become available for alternative uses.

Careful planning may minimize the effects of OTEC or OEIC installations on marine ecosystems, including fish migration. This effect is best verified by site testing. The long-term impact of the corrosion and erosion of heat exchanger material on the ecosystem as well as the effect of long-term thermal pollution requires investigation. Issues regarding the conflict of fishing rights or ocean farming versus facility siting also merit resolution.

Other

Because of the variable nature of an OTEC or OEIC installation's position, careful attention should be given to potential navigational problems. This is especially true of grazing facilities.

The change in ocean temperatures surrounding an OTEC or OEIC installation may create unfavorable chemical equilibrium with the crustacean cycle. In certain instances, the calcium carbonate in the shells of the crustaceans may decompose to calcium oxide and carbon dioxide. The magnitude of this effect is not known and may merit investigation.

Conflicts of ocean use that may merit future attention include international²⁷ as well as national issues regarding the proper use of ocean space for maritime commerce, for fishing, for manganese module mining, for defense purposes, for ocean farming, for offshore exploration of oil and gas, and for OTEC or OEIC installations.

International Market Potential

Washom and others³³ have evaluated the potential international application of OTEC electricity or other OTEC energy products. Their analyses started by surveying 40 countries in the thermal belt region, lying within $\pm 15^\circ$ of the equator, where sufficiently intense thermal gradient zones occur, which could possibly permit OTEC installations (Figure VIII-6). The procedure for reducing the list of nine countries* was:

*The nine countries are Puerto Rico, Singapore, Brazil, Mexico, India, the Philippines, Indonesia, Australia, and Malaysia.

FIGURE VIII-6. ESTIMATED WORLD THERMAL GRADIENT REGIONS

- Countries having a satisfactory supply of alternative domestic energy resources were eliminated (e.g., Nigeria and Venezuela).
- Using a basic concept that no single electric power facility should represent more than 15 percent of the power grid, 29 additional countries were found to have either too small or too diffused a power demand to justify the application of a capital-intensive OTEC facility (of approximately 160-MWe net commercial size).

The analyses further suggest that as the electricity demand continues to grow in these countries, a time (say 25 or 35 years from now) will be reached when an OTEC installation may be justified from the point of view of the 15 percent rule. Two observations are appropriate:

- In the United States and other developed countries, a point is eventually reached at which the demand for electricity in a given sector of the economy increases at a slower rate than the increase in gross domestic product or gross national product. This is referred to as a saturation effect. As lesser developed countries (LDCs) practice increased automation in industry and experience changes in consumer lifestyles (e.g., purchase of television sets and refrigerators), it is likely that the demand for electricity will increase more rapidly (e.g., 12 percent per year) than the increase in real gross domestic product or gross national product (e.g., 10 percent per year). This may well be true until market saturation effects begin to slow the growth in demand for electricity. As a result, it is suggested that any analyses predicated on the 15 percent rule for LDCs also consider saturation effects.
- An OTEC market may exist in certain LDCs for sizes smaller than the 100- to 260-MWe net installations currently considered as reasonable sizes for the future domestic U.S. market. Future international OTEC analyses should consider electric power plants ranging from 20 to 60 MWe net. As OTEC technology evolves, even these smaller OTECs could be modularized.

Table VIII-6 summarizes salient geopolitical statistics for the countries with the greatest potential for OTEC application according to Washom and others.³³ Compared with the United States, these countries have lower gross domestic products per capita, lower annual per capita electricity consumption, and much lower estimated total financial reserves. Additionally, the equity purchase of a single OTEC installation in the 100- to 200-MWe net size range would represent a significant percentage of the estimated financial reserves of these countries. Hence, several investigators have suggested the possibility of international-type debt financing (e.g., Export/Import Bank; International Development Agency; International Energy Agency), with high debt-to-equity ratios, as possible expedients for increasing the economic attractiveness of OTEC installations in LDCs. Also, OTEC installations for

Table VIII-7

GEOPOLITICAL STATISTICS FOR SELECTED COUNTRIES

	Population (Millions)	Gross Domestic Product (\$ Million)	GDP/Capita	GDP Growth Rate, Percent/Year (Rounded)			Estimated Total Financial Reserves (\$ Billion) (1976)	kWh Consumption per Year per Capita (1974)	Home Equity Rule, Percent of Domestic Equity Participation in Public Electric Utility Ventures
Puerto Rico									100%
Singapore	2.3 (1976)	\$ 5,900 (1976)	2,600 (1976)	11-13%	6%	4%	\$3.3		100
Brazil	109.2 (1976)	109,200 (1975)	1,000 (1975)	20-22		10	6.5	540	{ Encourages joint ventures with private sector
Mexico	62.3 (1976)	79,000 (1975)	1,300 (1975)	4-7	6	4	1.4	640	
India	598.0 (1975)	84,500 (1974)	140 (1974)	(-1)-6	Neg.		3.3	120	60
Philippines	43.8 (1976)	15,700 (1975)	370 (1975)	5-9	6	6	1.6	230	70
Indonesia	136.0 (1975)	29,400 (1975)	200 (1975)	7-9			1.5	21	51
Australia	15.0					5			51
Malaysia	11.9 (1975)	9,300 (1975)	780 (1975)		7	2	2.5		100

Neg. = Negligible

Source: First five columns across, SRI

The remaining two, Reference 33.

LDCs may take advantage of lower foreign fabrication costs compared with U.S.-based fabrication costs. However, Washom et al.,³³ conclude that:

- The Export-Import Bank, one of the key elements in assuring favorable financial terms for emerging energy technology exportation, is not currently prepared to deal with the issues in OTEC development.
- Only the International Energy Institute of the International Energy Agency exists as a possible instrument to best assist OTEC to reach its commercial potential abroad.

Washom and others³³ have reviewed, in general terms, other institutional barriers to the commercialization of OTEC installations in LDCs. With the exception of Brazil, the high home equity rules may represent significant institutional barriers to the commercialization of OTEC in the selected LDCs.

Other than selected graphs giving large-scale resource quality variation, little international site-specific work has been done by previous OTEC investigators. As a result, it is not possible at this time to adequately predict the economics of OTEC installations abroad. Key technical issues requiring definition prior to these economic analyses include:

- The incidence of heat exchanger biofouling as a function of the site selected
- The incidence of heat exchanger corrosion as a function of the site selected
- The variability of ocean temperature with depth
- The seasonal variation of temperature differentials
- The development of a maintenance-oriented infrastructure to support OTEC operation.

These variables critically influence the design; capital, operation, and maintenance costs; and operability of OTEC installations.

OTEC learning curve effects¹⁹ have been proposed to demonstrate the future economic viability of the technology. These learning curves depend heavily on dedicated OTEC construction facilities mass producing nearly identical OTEC plants. When viewing learning curves from the perspective of the international market, the concept of a single foreign dedicated graving dock and a single foreign dedicated heat exchanger fabrication facility serving the world community becomes less plausible than this concept for the domestic U.S. market. As a result, use of the concept of learning curves as applied to foreign OTEC construction may be misleading.

Another institutional barrier to OTEC technology transfer is the current lack of a clear-cut mechanism within the U.S. government to

promote this type of transfer to LDCs. Possibly the newly created Department of Energy will remedy this policy deficiency regarding OTEC and other advanced energy technologies.

Research, Development, and Demonstration Programs

This section presents some observations regarding the future directions of OTEC RD&D efforts. Several aspects of the program are considered. The first investigates a number of options for future work and provides cost estimates and schedules. The second considers possible changes in program emphasis at constant funding levels, while the third looks into complementary research that supports OTEC technology.

RD&D Funding Effects on Program Schedule and Cost

Options with estimated schedules and costs that the OTEC program may pursue are listed below.

- Parallel efforts may be pursued more vigorously in the following areas:
 - Heat exchanger R&D in the laboratory--investigating clean-tube performance, materials of construction, heat transfer enhancement, flow distribution problems on shell and tube sides (first generation design), compartments within bundle to permit easier maintenance (such as is practiced by electric utilities with large condenser bundles). Estimated cost--\$500,000 to \$1 million per year for three to five years.
 - Site-specific investigations in several geographic areas, gathering information on currents and circulation, temperature and salinity profiles, marine organisms and nutrients, and seasonal variations of the above. When data describing long-term conditions do not exist for potentially attractive OTEC sites, then it is prudent to suggest observations covering five to ten years ("long-term" would include observations to determine the changes in location of major currents; erratic weather patterns; subsea disturbance activity such as settling or seismic activity; and the like). Estimated cost is \$1.5 to 2.5 million per year per site.
 - Heat exchanger component testing in the field. For potentially attractive OTEC sites, it is suggested that dynamic tests be employed using small numbers of tubes. The tests would be to determine exchanger seawater side biofouling, corrosion, and cleaning methods under actual conditions. Capital cost is estimated at \$1,500,000 to \$3,000,000 and perhaps \$400,000 per year for operating costs per site. Duration of tests: nine to fifteen months per site.

By performing these efforts in parallel, a more complete characterization of heat exchanger performance could be obtained. Additionally, the OTEC-related variations of ocean characteristics per site could be obtained.

- Site testing of heat exchangers that are scaled up in size. The OTEC program currently calls for a test of a 1-MWe exchanger aboard the reconditioned barge, OTEC-1, and later tests of a 5-MWe facility aboard an appropriate reconditioned vessel. It may be desirable to test heat exchangers of 1 to 8 MWe in size at several sites simultaneously. In this fashion, information on a range of biofouling, corrosion, heat transfer, cleaning, and seasonal derating phenomena could be obtained over the same period. A 1-MWe facility may cost several million dollars, while an 8 MWe facility may cost \$15 to \$25 million. If multiple facilities are not constructed, then a single facility could be moved from location to location; the total cost would be lower than the multiple facilities but the elapsed testing time would be lengthened. To provide information for a conservative preliminary commercial design, it may be desirable to test the facility (or facilities) from one to three years per site.
- Site testing a 25- to 60-MWe system. The fabrication and testing of this system would provide definitive information on the fate of the cold water; pollution; the mooring systems; controls and instrumentation; manufacturing problems for the heat exchangers and cold water pipe; and similar items. It is suggested that a demonstration of a 60- to 70-MWe facility would provide sufficient information of system performance and scaling to obviate the need for the test of a 100-MWe facility. From this system, sufficient information should be available on piping, valves, safety, maintenance and operating practices, and the like to permit a definitive commercial design to be made. Estimated fabrication time: three to four years; operating time—one year minimum.

These program changes would permit more time for site testing than is shown on current OTEC program schedules. A greater variety of information would be obtained earlier in the program from site tests, permitting improved criteria for decision making and a more realistic characterization of the environment in which OTEC installations would operate.

If significantly increased funding levels for OTEC were to become available, a greater variety of activities (such as those discussed above) would be permitted to occur early in the program. The intent may be to encourage small-scale component testing experiments at several sites, and to obtain a more complete characterization of the variations in the environment in which OTEC installations would operate. Additionally, more funds could be made available to explore potential environmental impacts of OTEC. It is doubtful that more than one OTEC demonstration

plant will be constructed because of the costs involved. As a result, it is likely that substantial budget increases would tend to affect the early stages of the program and would possibly permit the earlier resolution of technical and operational problems which were uncovered during initial program stages. Depending on the magnitude and severity of these problems, the OTEC demonstration could occur earlier than or at the same time as demonstration with no substantial increases. But, in any case, increases would permit earlier determination of the practicality and viability of OTEC.

If the budget for OTEC were significantly reduced (such as halved) only limited hardware-related studies would be permitted for the foreseeable future. As a result, the OTEC demonstration would be delayed until probably after the year 2000.

Program Emphasis at Constant Budgetary Obligation

The following are meant to provide comments and suggestions on RD&D emphasis appropriate to the present level of funding for OTEC.

- Maintain a record of cost goals for principal alternative technological options, including electricity costs, inorganic chemicals costs, and organic chemical costs attributable to OTEC competitors. Continually update this record as alternative technologies and feedstocks change and as OTEC technology changes. These records should be maintained only for the demand regions that OTEC may reasonably service. If it becomes obvious that a cost goal for an OTEC product can never be achieved, eliminate the product from further consideration.
- Develop realistic estimates for assessing the benefit streams which will flow from the operation of an OTEC installation. These "benefits" (e.g., employment, improved environment, reduced dependency on foreign oil, improved end-use-consumer prices) will also flow from the operation of technologies which compete with OTEC installations for the same end-use markets. If it becomes clear that a non-OTEC application offers greater benefits for a given end-use market compared to an OTEC application, then research on the specific OTEC application should be curtailed.
- Perform additional site-specific characterization studies for possible OTEC installations. The operation of a single type of processing or manufacturing facility on land is fairly well known. This is true whether or not the facility operates at a given location or 10 to 100 miles in any surface direction from that location. The same statement may not be true for an OTEC installation.
- A great many industries maintain laboratory facilities in which bench or pilot scale units operate continually in support of commercial units, or for basic research. Examples are the petroleum, petrochemical, and chemical industries and the

industry/federal laboratories operated in support of coal conversion facilities. More than one such laboratory or bench scale facility should be operated in support of OTEC-related research in such areas as heat transfer, binary cycles, and fluid mechanics/hydraulics.

- Explore the opportunities for OTEC technology transfer abroad. This would include the markets for OTEC products, the capability of foreign shipyards for construction, the capability of foreign industry for component fabrication, and financing considerations. A convenient starting point might be a series of seminars or symposia in selected foreign countries.

Complementary Technology Research or Basic Research That Is Supportive of the OTEC Program

Many areas of OTEC RD&D may represent one-of-a-kind projects that have few counterparts in other federally sponsored research programs. Examples are the cold water pipe, the heat exchangers, and the electricity transmission cable to shore.

A few areas may exist for technology transfer to or from OTEC programs.

- The seawater corrosion research for the OTEC program may find areas of commonality with the high-salinity geothermal resource work sponsored by DOE. Although the temperatures for these applications differ, the basic corrosion and materials research may be complementary.
- The basic concepts of OTEC-related mariculture and the organisms and nutrients involved may be complemented by research concerning the growth of mariculture for fuels or other uses being sponsored by DOE.
- The concept of low-temperature-difference cycles, if successfully demonstrated for OTEC, may find possible applications in the recovery of waste heat from conventional fossil-fired steam-electric power plants, from geothermal or nuclear power plants, or from other industrial or commercial complexes that exhaust low-level heat to air or water cooling. Research in this area should be encouraged.

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IX ENERGY STORAGE

Technology Overview

The required storage time can vary from momentary (to prevent interruption by passing cloud cover) to months of storage for space heating and cooling systems such as the annual cycle energy system (ACES). The quality of the energy to be stored can vary from warm water to electricity. The quantity can vary up to the tens of megawatt-hours required for a central receiver designed for utility electricity generation and down to a few watt-hours for a remote transponder or signal device.

Energy storage systems have been identified in this study on the basis of the input energy form--thermal or electrical. It is recognized that some thermal and most electrical storage systems could be considered as chemical storage on the basis of the changes that occur during the charge and discharge cycles.

Pumped hydro and compressed air storage technology has been demonstrated and can be economical. However, these storage systems are site-specific and depend upon favorable combinations of geology and hydrology. They are therefore excluded from this discussion of generally applicable storage systems.

Flywheel storage and superconducting magnetic energy storage concepts depend on some undemonstrated technology and are likely to be site-specific in economic sizes. These storage concepts are also excluded from this discussion of generally applicable storage systems.

The production of hydrogen by any of a variety of "water splitting" processes is also a commonly cited option. These processes could be driven either by heat (thermochemical processes) or by electricity (electrolysis) from solar energy. These will be briefly discussed later.

The Thermal Energy Storage Systems

Thermal energy can be stored in materials by changing their temperature, by changing their phase, or by rearranging or separating their chemical elements. Heated or cooled water is an example of the first class, steam and ice are examples of phase changes, and sulfur dioxide/sulfur trioxide is an example of the third class. In each instance, of course, charge and discharge of the energy storage system uses a reversal of the condition of the material.

The first two classes of storage have the general advantage of simplicity in system design because the temperature changes and/or the phase changes are accomplished by the simple addition or removal of heat. Their primary disadvantage from a practical viewpoint is their dependence on insulation to achieve usable storage times. The chemical reaction systems of the third class have the major advantage of long term storage at ambient temperature, which is desirable in some applications. A major disadvantage is the catalytic reactors usually required for the endothermic and exothermic reactions that constitute the charge and discharge cycles of such thermal energy storage systems.

A realistic upper temperature limit for thermal energy storage systems is 2000°F. This limit is set by the common alloys used in the fabrication of the energy transport conduits, the storage container, and the using devices (such as turbines) which use the stored thermal energy.

A realistic lower temperature limit for thermal energy storage systems can be set at 32°F, or the temperature of ice. The insulation requirements for much lower temperatures and the good energy storage capacity of ice weigh heavily against regular consideration of lower temperature storage systems.

The Electrical Energy Storage Systems

There are three classes of electrolysis reactions that have general applicability for storage of electrical energy from solar receivers. The regular reference to all three classes as batteries tends to obscure significant mechanical differences that affect the suitability of some of these cells for some of the solar energy storage applications.

The lead-acid and the nickel-cadmium batteries are most familiar. Each is an example of the first class of cells defined in this discussion as those devices that are completely self-contained and operated at ambient temperatures.

The second class of electrical energy storage cells are those that operate at temperatures of about 600°F and require external heat exchanges and/or heat sources to maintain proper temperatures during charge and discharge. The sodium-sulfur cell is the most common example of these advanced systems.

The third class of electrolysis devices circulate the reacting chemicals from external tanks through the charge and/or discharge cells. Some of these systems are self-contained, but others depend on atmospheric oxygen for their operation. Operating temperatures are usually controlled, but are below the boiling point of water. An example of the self-contained type is the zinc-bromine reactant pair, and an example of the atmosphere-dependent type is zinc-air.

The significant advantages of the self-contained, ambient-temperature batteries are their technology status, reliability, and present cost. The

salient disadvantage is their energy density, expressed as the watt-hours that can be stored per pound of battery. The advantage sought in the high temperature class is the significantly higher energy density of these systems. The disadvantages are their technology status and need for external heat transfers. (Perhaps this last-cited disadvantage can be practically eliminated by using solar heat in an integrated system.) Since only a small amount of active material is in the electrolysis cell at a given time, the potential advantages of the circulating energy storage systems are low cell cost and low self-discharge over long periods of storage. This third class of electrical storage carries the disadvantage of pumping and storing relatively large volumes of chemical solutions.

Charge and discharge of electrical energy from these systems always includes some significant loss of energy as heat in the cells. For practical discussions of electrical energy storage applications, it must be noted that the roundtrip efficiency of a charge/discharge cycle is not likely to exceed 75 percent, so it will be necessary to input at least 1.3 kilowatt-hours for each 1.0 kWh to be subsequently extracted. The significant characteristics of representative thermal and electrical energy storage systems are summarized in Table IX-1.

Storage Battery Costs

The SRI projections of battery costs in Table IX-1 are based on consideration of the current and projected costs of certain critical materials used as catalysts in the ambient temperature batteries or to provide electrode or container resistance to the corrosive and/or high temperature environment seen in the high temperature batteries. Such materials include ruthenium, yttrium, thallium, molybdenum, tungsten, chromium, nickel, and antimony. Substantial reductions in the projected battery costs are dependent upon at least one of the following developments:

- Battery research that leads to substitution of much more common and less expensive catalytic or engineering materials for those cited above
- Discovery of major new deposits of the cited materials
- Development of new extraction or recovery processes for the cited materials.

Of these necessary developments, the battery research is the most promising, and it can be stated that the developers of each of the advanced batteries is aware of this need for materials substitution.

Table IX-1
CHARACTERISTICS OF POSSIBLE SOLAR ENERGY STORAGE SYSTEMS

Energy Storage Type	Examples	Storage System Capital Cost				Commercially Available	Energy Density		Roundtrip Efficiency	Useful Temperatures	Storage Period	Comments
		Residential	Commercial	Industrial	Utility		Btu/Ft ³ °F	Btu/Lb °F				
		\$/10,000 Btu										
Thermal												
Sensible Heat	Hot Water	1.75	1.75	1.75	S	1977	62.5	1.0		50-95°C	24 Hours	
	Hot Fuel Oil	4, U	H	2.25	SD	1977	23.3	3.44		215°C	24 Hours	
	Steel Ingots	U	U	10	LD	1977	55	3.1		510°C	24 Hours	
	Magnesium Oxide Bricks/Helium	U	U	53	SD	1977	52	3.23	.72	600-800°C	6 Hours	Conceptual Design (50MWe)
Phase Change	Ice			U	U	1977	8,200	144		0°C		
	Steam					1977				100-200°C		
	Molten Hydroxides	4, U	H, U	50	SD	1977	12,000	103		315°C		Conceptual Designs
	62/37 Sodium/Zinc Fluorides	4, U	H, U	27	SD	1977	35,000	303	.62	600-800°C	6 Hours	Conceptual Design (50MWe)
Chemical Reaction	Nitrogen - Hydrogen Ammonia	4, U	H, U	700 _T	700 _T	1987			.27 _T	325-525°C _T	Unlimited	Theoretical For Reactants
	Sulfur Dioxide + Oxygen Sulfur Trioxide	4, U	H, U	70 _T	75	1987			.52	600-800°C	6 Hours	Conceptual Design (50MWe)
	Zinc Oxide + Sulfur Trioxide Zinc Sulfate	4, U	H, U	7 _T	7 _T	1987			.75 _T	785-900°C _T	Unlimited	Theoretical for Reactants
Electrical												
Ambient Temperature	Lead-Acid	115	95	85	SD	1977	1.30	0.011	.75	Ambient		Present Technology; Mass Production
	Nickel-Cadmium	C	215	195	C	1977	1.47	0.015	.75	Ambient		Present Technology; Mass Production
	Silver-Zinc	C	635	580	C	1977	4.49	0.050	.75	Ambient		Present Technology; Mass Production
Molten Reactant	Sodium-Sulfur	H, U	H, U	6C	55	1982	4.32	0.070	.75	300-350°C		Conceptual Designs
	Lithium-Chloride Sulfide	H, U	H, U	10C	115	1982	6.05	0.085	.75	400-450°C		Conceptual Designs
Circulating Reactant	Zinc-Air	75	60	55	50	1982	2.75	0.065	.75	Ambient		Conceptual Designs
	Zinc-Chlorine	75	60	55	50	1982	1.73	0.045	.75	10°C		Conceptual Designs
	Redox (Iron Nitrate)	S	S	7C	65	1987	2.25	0.080 _L	.70	Ambient	6 Hours	Conceptual Design (20 MWe)

References:

1. Application of Solar Technology to Today's Energy Needs, Vol. 2, Office of Technology Assessment (June 1977).
2. Energy Storage: User Needs and Technical Applications, Conf. 740212, Engineering Foundation Conference Report, ERDA (Feb. 1976).
3. Technical and Economic Feasibility of Thermal Energy Storage, COO-2538-1, General Electric Company (February 1976).
4. SRI International.

H = Too Hazardous U = Unsuitable Temperature
C = Too Costly T = Theoretical for Reactants
S = Impractical Size L = kWh/Liter

General Considerations of the Role of Energy Storage in Solar Electric Systems

A systematic consideration of energy storage, the impacts of storage on the performance of solar electric systems, and their means of interfacing with utility power grids is outside the scope of this evaluation. However, since the questions raised by these topics are complex and interesting ones, several comments are provided to give general guidance regarding these issues.

The design of conventional electrical generating capacity has placed a high value on reliability. Utility systems have been designed to meet instantaneous demand loads. If elements of the utility system cannot be counted on to meet the demand loads, then other means of generating electricity must be brought into play. This means that as the reliability of components in the electrical grid decreases, the "extra" capacity that must be made available to meet demand increases.

If a solar energy system is placed into a utility grid, storage may be used to avoid degrading the performance of the utility system. This storage can be achieved in any of several ways--it can rely on storage that might already be built into the utility grid (such as pumped storage), it can be associated with the solar electric system and be charged by it, or it can be charged by off peak baseload power. A combination of charging from the grid and from the solar electric system would also, in general, be possible.

A general approach may be taken to understand the conditions under which storage is economically desirable to deal with the problem of unreliability of demand. Storage competes directly with intermediate and peak power. When the cost of electricity discharged from storage is lower than the cost of the intermediate or peak power that it replaces, then storage is a cost-effective way of dealing with variations in the load profile. At the present time pumped storage is the only cost-effective storage means for utilities. But there is presently considerable interest in other systems--batteries and compressed air storage, for example--that may in the future be well suited to utility application.

This general background on storage and the utility system is useful for understanding the role that storage may play in the performance of solar electric technologies. It is generally assumed that improvements in the performance and economics of storage systems will benefit the solar electric systems. But cost reductions in storage can also benefit the conventional generating systems within the utility system. In an extreme case, improvements in storage economics could be more beneficial to conventional systems than to solar electric systems. Consider the hypothetical case in which the cost of energy storage is plentiful and has a zero cost. In this hypothetical case, energy storage devices could be charged entirely from the cheapest form of electric power, baseload electricity. This baseload electricity from the storage system would be used for intermediate and peak loads and the natural markets

for the solar electric options--peak and intermediate load electricity--would disappear.

This illustration makes clear that the role of storage in facilitating the solar electric options is a complex one. Undoubtedly, the proper way to analyze the interaction between different characteristics of storage systems and the solar electric options is in the context of the utility system into which the solar system might be integrated. If this is done, the correspondence between the time variations of solar insolation and those of the demand profile can be analyzed explicitly. Furthermore, the effect of the storage characteristics of the utility system and the interties that the system has with others could be included in the analysis. An additional consideration that received little attention to date is the possibility of utilizing the diversity of solar energy systems to advantage. A combination of wind units and photovoltaic systems, for example, might in certain regions be effective in utilizing solar sources that can provide power in different time periods. The end result could be an increased reliability for the solar-powered portion of the utility system. The use of a large number of physically separated wind installations could be expected to have a similar effect. There is a need for analysis of wind and weather data to better assess methods of building flexibility into configurations of solar energy systems.

Having expressed the complexity of the problem, we now indicate a few factors that differentiate among the solar systems with respect to storage. The easiest case is OTEC, which would compete in the baseload market. Because the temperature gradients that are the source of energy for OTEC are reliable, OTEC has no need of storage.

Wind has been shown in the analysis to have the potential of being competitive in the "fuel saver" mode. As such, wind would not need storage. However, the availability of reasonably priced electrical storage in the utility system could possibly improve the outlook for wind beyond that which has been assessed in the study. It is also possible to envision wind energy systems used to pump water for pumped storage.

Solar thermal systems are expected to use thermal rather than electrical storage systems, because of the economic advantages of the former systems. At present, thermal storage using refined fuel oil can accommodate temperatures up to 530°F without degrading the oil. However, since this temperature is well below the temperature required to achieve an optimum performance of the heat engine that will be used with the thermal power system (by 300°F to 400°F), severe losses in efficiency of operation of the heat engine would occur. There is considerable interest in developing systems relying on such approaches as the latent heat of fusion of inorganic salt mixtures to achieve higher temperature storage capability.

Photovoltaic systems are amenable to the use of electrical storage. Batteries are currently considered as the most appropriate storage devices; attention is also being devoted to compressed air storage. As noted previously, the photovoltaic systems would also be able to take advantage of any inherent storage capabilities of the utility system. In any case, the storage is most likely to be incorporated into the utility system to optimize overall system performance rather than that of the photovoltaic device itself.

Clearly, if any of the solar electric options are not incorporated into the utility system, storage would be expected to play a more critical role in their use. Under these circumstances, the flexibility of a solar-electric system is reduced because of the lack of an instantaneous back-up capacity.

X SOLAR PENETRATION MODEL

Introduction

This section describes the solar penetration model that was developed to analyze the mass of data collected for the seven solar energy systems. Volume I presents both an overview of the model and a summary of results of the calculations that were performed using the model. In the following discussion, the model is explained in detail. The specific areas covered are: the input data required by the model; the methodology used to estimate market penetration; and the end-use markets in which solar energy systems may compete. In addition, this section discusses the approaches that were developed to simulate the markets for the various solar systems. When read along with Section V of Volume I, this section explains the main features of the model and how it has been used in this study to analyze the potential market contribution of the various solar energy technologies under a variety of conditions.

Input Data

The data needed for the market potential calculations consist of projections of energy demands in various markets, prices of energy from the solar and alternative systems; and estimates of market response parameters that describe marketplace behavior.

The expected energy demand and alternative energy price projections form a framework, or base-case scenario, in which the various solar technologies compete. Any such scenario, if extended over the long term, naturally presents a large degree of uncertainty. As a result, the market potential analysis has used not only this base-case scenario but also several different scenarios that consider the effects of variations in solar and alternative energy prices and in energy demand. The base case and other scenarios are described more fully in Section VI of Volume I.

The data format used in the solar penetration model (SPM) parallels that of the SRI National Energy Model, a comprehensive computer code that considers all major energy flows from primary resource to end-use level. A regional breakdown, based on the nine U.S. census regions allows for regional variation of energy demands and prices. Results of the penetration analysis are tabulated regionally and are also summed to provide national totals.

Market penetration calculations are performed on an annual basis over the time frame considered, which is 1975 through 2020. Results are output in five-year intervals; however, particular emphasis is placed on analysis of three periods: the near term (1985), the intermediate term (2000), and the long term (2020).

Fifteen markets have been designated as potentially available for capture by one or more of the various solar technologies. Table X-1 lists these markets and the projected size of each on a nationwide basis. Also listed are price forecasts for the alternative energy forms against which the solar technologies must compete; these are representative data from the Middle Atlantic region. With the exception of busbar electricity, these demand quantities and prices are considered at the end-use level.

As noted earlier, seven major solar technologies have been considered in the overall analysis of this report. However, a further subdivision into specific systems, as shown below, is used in the market potential portion of the analysis. End-use energy price projections associated with each of these systems are necessary inputs to the model. Regional variations of these solar prices are included to consider differences in insolation, biomass availability, and other factors.

- Photovoltaics
 - Central
 - Distributed
- Thermal electric
 - Central
 - Distributed
- Wind
 - Central
- SHACOB
 - Water heating
 - Space and water heating
 - Space cooling
- Industrial indirect heating
- Biomass
- OTEC

Because of the unique supply/price characteristics of biomass systems, the input for this generic technology is treated differently than the others. The basic differences in the biomass analysis are discussed later in this section.

Table X-1

BASE CASE SCENARIO ENERGY DEMAND PRICES: END-USE MARKETS
IN WHICH SOLAR ENERGY TECHNOLOGIES COMPETE, 1985-2020

	Quads (End Use)			Nonsolar End-Use Prices* (in 1975 \$/MM Btu)		
	1985	2000	2020	1985	2000	2020
1. Industrial heat/high Btu gas	2.4	2.0	1.6	\$ 4.6	\$ 5.7	\$ 6.0
2. Industrial heat/coal	2.6	5.0	7.9	1.8	1.9	1.9
3. Industrial heat/liquids	1.8	1.6	1.6	4.3	4.9	5.4
4. R/C cooling/electricity [†]	3.2	5.7	7.7	4.0	4.7	5.2
5. R/C space heat/high Btu gas	2.6	3.2	3.4	4.0	5.2	5.5
6. R/C misc. heat/high Btu gas	2.0	2.5	2.7	5.6	7.2	7.7
7. R/C space heat/electricity	0.7	1.0	1.1	10.8	10.9	11.9
8. R/C misc. heat/electricity	0.3	0.4	0.5	10.8	10.9	11.9
9. R/C space heat/liquids	1.2	1.5	1.5	3.8	4.6	4.8
10. R/C misc. heat/liquids	0.4	0.5	0.5	5.2	6.4	6.7
11. R/C rural heat/LPG	0.6	0.8	0.8	4.5	5.1	5.5
12. R/C rural heat/distillate	0.6	0.5	0.5	3.8	4.6	4.8
13. R/C rural heat/electricity	0.4	0.3	0.3	10.8	10.9	11.9
14. Baseload electricity	6.8	10.3	14.4	9.0	9.7	9.8
15. Intermediate electricity	1.5	3.7	5.2	15.6	17.0	17.4

*Prices are those estimated for the mid-Atlantic region. Average prices are shown for the end use energy (e.g., for market number 1, the price is for heat, not high Btu gas), except for base load and intermediate electricity, where marginal prices at the bus bar (not including transmission and distribution costs) are quoted.

[†]Coefficient of performance of 3 taken for air conditioners.

In addition to the aforementioned price and market demand estimates, a series of market response parameters is also required data for the market penetration analysis. These inputs provide the parameters to describe the expected behavior of market decision-makers, especially regarding reaction to the introduction of a new energy technology. The next section provides a description of the specific market response parameters and the way in which they are employed.

Market Penetration Methodology

General Approach

The basic steps followed in this solar market penetration assessment are presented in Figure X-1. This procedure first entails a static economic analysis based largely on the price competition between solar energy and the alternative source. The result is an equilibrium solar market share, or that expected to obtain during a steady state market situation. This situation does not hold soon after the introduction of a new, cost-competitive technology. The marketplace will be in flux as the newcomer gains wider recognition and acceptance.

This dynamic market behavior is modeled as a "behavioral lag" constraint, which reduces the rate at which a new technology may be introduced. With this information, a dynamic solar market share can then be generated and applied to the market demand forecast to obtain the estimate of potential solar penetration as a function of time.

The potential of a solar technology to penetrate a market depends on a large number of variables that, in turn, themselves depend on other variables. Some of the more important variables are the cost of energy delivered to the end use by the technology relative to alternatives; the magnitude and growth of the market under consideration; institutional barriers and incentives for the new technology (e.g. governmental taxes and/or subsidies, zoning restrictions, depreciation schedules, interest rates, and decisions in the investment community); environmental laws and regulations; and a host of social and consumer variables that are likely to influence the actions of the market's decision-makers. Examples might include a desire to conserve resources or limit energy imports or a preference for known sources of supply or decentralized technologies.

Based on past work, SRI has found that it is possible to estimate the market response to a new energy commodity from three major variables: relative prices, energy market size (demand) and a set of market response parameters. The SRI Solar Penetration Model (SPM) combines these pertinent variables to allow systematic studies to be carried out on the marketability of new energy products and technologies. Although it has not yet been fully developed, the SRI SPM can be used to help estimate the market share that could be expected for the solar technologies under consideration and to provide a framework for sensitivity analysis.

FIGURE X-1. OVERVIEW OF MARKET PENETRATION ASSESSMENT

As an idealization, the share of a particular market that can be attained by a new technology at any particular time under equilibrium conditions can be represented by the curve shown in Figure X-2 and given by:

$$\text{Equilibrium Market Share to Solar Technology} = \frac{1}{1 - \left(\frac{P_s}{P_a}\right)^\gamma},$$

where P_s and P_a are the equivalent prices of the solar technology and alternative fuels, respectively.

This static representation says that, at equal prices and under equilibrium conditions, the market will be shared equally. The gamma (γ) parameter is a measure of market imperfections, price variations, and consumer preferences. In this representation, average prices are used for the solar technologies and alternative fuels, although there are significant individual variations from the average. For example, continued government intervention might introduce significant disparities into the future prices of pipeline natural gas. Also, other sources such as LNC imports and various high-Btu synthetic products will be introduced at yet different prices, causing an even wider distribution of prices around the assumed average.

In addition to these price impacts, decision-makers influence market share. Even if the solar technology is somewhat more expensive than the alternative, some fraction of purchasers will select it, perhaps because of environmental or "energy-independence" considerations. Alternatively, some fraction of purchasers will continue to use their familiar fuel source even if economic considerations dictate a change to a new one. Imperfect price information also affects the market share curve. All these variables are aggregated into the one parameter, gamma. In a perfect market with high price sensitivity and none of these real world effects, gamma would be infinite.

Based on previous work with energy commodities, SRI has found that the characteristic response patterns of various markets can be modeled by a reasonable choice of γ . Large industrial and utility markets, for example, would generally be modeled with a γ value in the range of 25 to 35. These high values reflect the strong response to price variations characteristically displayed by industrial and utility consumers who deal with large quantities of energy and are acutely aware of economic considerations. This study has assumed a γ value of 25 to model centralized electricity producing solar systems that a utility is likely to operate. The lower end of the previously mentioned range was chosen to account for the market imperfections introduced by the wide variations and uncertainties in price that are characteristic of solar technologies.

Lower gamma values, in the range of 8 to 10, have been assumed for the other solar technologies since they include smaller scale energy consumers who typically behave not in a strictly economic fashion.

Factors such as aesthetics and novelty, for example, would be expected to play a much larger role in the decision-making process of a homeowner purchasing a space heating system than of an electric utility executive deciding between alternative types of power plants.

Dynamic Market Response

The market share curve of Figure X-3 is a static representation of real-world variations from average. To assess the dynamics of market penetration, a "dynamic market response curve" can be used to describe how fast the current market will move toward the static price-determined market share curve as a result of real-world behavioral response. This is called the behavioral lag effect.

The curve, given by:

$$\frac{1}{1 + \left(\frac{h}{n}\right)^\alpha}$$

is shown in Figure X-3 where h = half life (time required for one-half of the market to respond to the entrance of a new commodity)

n = years since new commodity introduction

α = response parameter.

This curve tends to slow the introduction of a new technology based on the time that it takes for decision-makers to accept and switch to new energy sources, especially those that are based on unfamiliar processes. The half-life parameters chosen for the various technologies range from 10 to 15 years. These values constitute estimates of how quickly the various technologies would be accepted by the different energy markets. Several factors influence these half-life estimates, the most important of which are the complexity of the new technology and the expected sophistication and familiarity that the market decision-maker has in regard to the new technology. For example, the situation of a knowledgeable utility planner considering the purchase of a relatively uncomplicated solar energy system would be modeled as having less behavioral lag than a community group considering the construction of a solar powered total energy system.

The second behavioral lag parameter, α , fixes the relative shape of the dynamic market response curve once the half-life parameter has been chosen. Based on previous work, an α value of 4 was consistently used throughout this study. Table X-2 shows the response parameters that were used in all evaluations except the specific sensitivity cases in which changes in these values are specified.

To find the share of the open market captured by a new fuel in any particular year, the equilibrium market share and dynamic market response

FIGURE X-2. EQUILIBRIUM MARKET SHARE

FIGURE X-3. DYNAMIC MARKET RESPONSE

Table X-2

MARKET PENETRATION PARAMETERS

	Market Share Parameter (α)	Behavioral Lag Parameters		
		Half-life (h)	Response Parameter (α)	Behavioral Lag Starting Date
Photovoltaic				
Central	25	10	4	1985
Dispersed	10	15	4	1985
Thermal electric				
Central	25	10	4	1985
Dispersed	10	15	4	1985
Wind				
Central	25	15	4	1981
SHACOB				
Water heating	10	10	4	1980
Space and water heating	8	10	4	1980
Space cooling	8	10	4	1985
Industrial indirect heating	10	15	4	1980
Biomass		15	4	1975
OTEC	25	15	4	1985

curve are multiplied. This is done on an annual basis, resulting in a dynamic market share for the new technology that varies with time.

Solar Energy Demand

To find the actual solar energy demand as a function of time, the dynamic market share must be applied to yearly estimates of the size of the market that opens up to capture by the solar technology. That portion of demand open to solar is generated in several ways. An increase in overall demand is one; another is the retirement of systems reaching the end of their useful lives. In certain markets, another mechanism is also considered--the retirement of functional alternative energy systems because of very favorable solar system economics.

The markets penetrated and the way in which the solar market penetration analysis is carried out differs, depending on the solar technology being considered. As a result, the following paragraphs address the major assumptions made concerning each technology.

Photovoltaic and Thermal-Electric Systems

The economics of two different sized electricity producing systems are considered for each of the photovoltaic and thermal-electric generic technologies.* In each case the larger is a centralized system geared toward utility use, while the smaller is a system oriented toward distributed applications. Because of the system designs and load factors, all these systems compete in the intermediate-load electricity market. The alternative electricity price against which they compete, however, depends on the nature of the system. The two centralized systems compete against the expected marginal price of intermediate-load electricity at the busbar, while the distributed system competes at the equivalent distributed electricity price.

Wind Systems

Wind energy systems differ from the other electricity-producing solar systems in that they are considered as fuel savers for electric utilities. Accordingly, they receive no capacity credit, and instead of competing against an expected electricity price, they compete against a "composite utility fuel price." This composite is defined as a weighted average of the fossil fuel prices that are typically associated with base-, intermediate-, and peak-load operation. The weighting is distributed according to the amount of each type of fuel that the wind system is assumed to replace.

* The smaller thermal-electric system produces by-product hot water as well as electricity.

This weighting, in fact, changes with the level of wind system market penetration for the following reason. The initial series of wind systems brought on-line would naturally be used to save the most expensive type of fuel being consumed at any point in time. During peak-load periods, for example, this fuel would be liquids or gas used in peaking units. As more wind machines are constructed, their relative value per machine diminishes, because a larger fraction of them would be used to replace less expensive fuels. (In the hypothetical extreme, if enough wind systems were brought on-line to enable a utility to keep all its peak- and intermediate-load plants shut down, the savings in fuel costs attributable to each additional wind machine would be relatively low, since they would be replacing only the cheaper base load fuels.) This effect is modeled by an algorithm that considers the level of wind system market penetration and adjusts the weighting of the "composite utility fuel price," against which wind competes.

Since wind systems are capable of reducing fuel consumption in the three load categories, they are modeled as competing in the entire electricity market, not only in the intermediate market as for the photovoltaic and thermal-electric technologies.

Solar Heating and Cooling of Buildings

Three different solar heating and cooling systems are considered in this generic technology. One is a hot water system, the second is a combination water and space heating system, and the third is a solar space cooling system. All these systems are considered suitable for application in both the residential and commercial sectors. The two solar heating systems compete against alternative heating supplied by three different sources: gas, petroleum, and electricity. The alternative space cooling system is powered by electricity.

This analysis assumes that all solar space heating systems are accompanied by solar water heating. Since this latter application is generally considered to be at least as economical as solar space heating, this assumption is a reasonable one. Also assumed is that each solar system includes a full alternative backup capacity to account for extended periods without adequate sunlight.

Industrial Heating

The market potential analysis considers a single type of solar heating system supplying industrial low-temperature heat. The competing non-solar alternatives are systems fueled by three sources: gas, coal, and petroleum.

As with the SHACOB systems, the solar industrial heating system assumes a 100 percent alternative backup capacity. However, heat storage capacity is not included in this technology because of the necessity of a full backup and the high cost associated with storage.

Biomass

The market penetration analysis used for biomass is necessarily very different from that used for the other generic technologies. This is because biomass systems, unlike other solar systems, require fuel feedstocks. Although renewable, these feedstocks are depletable over short periods. Therefore, the availability of biomass is best described in a manner similar to that used for a fossil fuel, by the use of a resource curve that considers the quantity of the resource available at various price levels. To account for regional variations, a different resource curve is applied in each of the nine regions. Additionally, estimates of how these curves will vary in time are included to reflect the expected future availability of biomass resources.

In determining the expected quantity of biomass consumed in any particular year, the market share analysis described for the other solar technologies is not used. Instead, it is assumed that biomass competes directly with coal at the primary resource level, and that the quantity consumed is that available, at, or below, the prevailing coal price. Biomass, then, is considered as a substitute for coal in all of coal's uses such as direct combustion, gasification, and liquefaction.

Ocean Thermal Energy Conversion (OTEC)

The OTEC market potential analysis is considered in a manner similar to that of the photovoltaic and thermal-electric solar technologies. The major difference is that OTEC is assumed to compete in the baseload electricity market against the expected marginal alternative busbar price of baseload power. In addition, because of the costs associated with long distance transmission, this technology is modeled as being capable of supplying power only to the South Atlantic, East South Central, and West South Central regions.

Appendix

BASE CASE ENERGY SUPPLY/DEMAND SCENARIO

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Appendix

BASE CASE ENERGY SUPPLY/DEMAND SCENARIO

The amount of energy that solar can contribute to the nation's energy supply is an important issue in assessing the value of solar energy. A method to assess this potential contribution is to assess the solar technologies in the context of some energy scenarios. Each such scenario is itself a self-consistent picture over time of energy demand, energy supply and prices. In fact, because of the wide number of uncertainties that the Solar Working Group (SWG) wishes to take into account in its evaluation, several scenarios are necessary to cover the range of variables.

SRI has assembled the attached "Base Case Scenario" to serve as the framework within which the solar technologies are compared to each other. Other scenarios are also used to assess how intra-solar comparisons depend upon the external energy market.

The procedure for obtaining demand, supply, and price estimates that are internally consistent and correspond to a plausible development of the U.S. energy system over time is based on the use of results of SRI National Energy Model calculations and independent estimates of the variation of these quantities over time. The steps that were followed in devising the base case scenario are:

1. SRI selected an energy demand projection that is consistent with estimates that governmental and private analysis have produced, and is plausible, considering:
 - past energy growth rates and recent downward trends in the growth rates resulting from a combination of higher energy prices, government policies that encourage conservation, and in increasing public awareness of cost effective energy conservation methods.
 - saturation of energy demand for certain end uses over the longer term.
2. Using the energy demand estimates and results of SRI National Energy Model calculations that were recently performed for EPRI, SRI estimated the supply of different energy types (i.e., oil, gas, coal, nuclear fuel) that must be produced to meet the demand.

3. The project team noted the estimated market clearing prices for the different energy types that are consistent with the assumptions of the model run (regarding process economic costs and supply curves) and the levels of energy supply and demand over time. Based on independent estimates of energy prices over time,* the price estimates and quantities of energy supply were revised to more nearly approach consensus estimates of changes of energy prices over time.
4. Steps 1 through 3 were repeated, testing for consistency between energy supply, demand, and price estimates. These tests included testing against intuition and judgment such factors as growth rates in production of specific energy forms, penetration of new technologies, rates of transition over time from one type of fuel to another, etc.
5. The energy supply and price estimates were broken down into the regions of the SRI National Energy Model using, as a basis for this disaggregation, the regional variations in these quantities estimated in model runs.

Figure A-1, Figure A-2, and Table A-1 present the energy demand projections and growth rates that are used in the base case scenario. The annual growth rate of energy demand in this projection is 2.3 percent for the time period 1975 to 1985, 1.6 percent for 1985 to 2000, and 1.0 percent for 2000 to 2020. This leads to annual primary energy consumption estimates of approximately 90 quads (1985), 115 quads (2000), and 140 quads (2020). These projections are compared with the projections that have been developed in independent analyses (Table A-2). The demand projections assume that government policy will continue to support energy conservation and that energy prices (in constant 1975 dollars) will increase over time (as shown in Figure A-5).

Figure A-1 shows the energy supply estimated to meet the base case demand between 1975 and 2020. The results may be summarized as follows:

- Coal production grows continuously between 1975 and 2020, with an average annual growth rate of about 3 percent in this period. The annual coal production increases from about 650 million tons in 1975 to one billion tons in 1985, 1.45 to 1.6 billion tons in 2000, and 1.75 to 2.6 billion tons in 2020. (The lower coal production estimates for 2000 and 2020 correspond to a "moderate" growth of the synthetic fuels industry. The higher coal production estimates for 2000 and 2020 correspond to a rapid growth of the synthetic fuels industry. In the former

*Sources for energy price projections include the Edison Electric Institute, Bureau of Mines, Bureau of Labor Statistics, and the Monthly Energy Review.

case, increased imports of oil and natural gas replace synthetic fuels from coal). Thus, the energy system is undergoing a significant transition in this forty-five year period--from one that was dependent on oil and gas for 75 percent of its energy to one in which oil and gas contribute 29 to 37 percent (for the rapid and moderate synfuels growth) in 2020. Even more significantly, domestic liquids and gases decline from 57 percent of U.S. energy supply in 1975 to 19 percent in 2020 in the base case scenario. Growth in coal makes up a significant portion of the gap between growth in demand and lack of growth in oil and gas production.

- Nuclear fuel use increases from 2 percent of the energy supply (7 percent of electricity) in 1975 to 6.7 percent of energy supply (20 percent of electricity) in 1985, 15 percent of energy supply (38 percent of electricity) in 2000, and 24 percent of energy supply (55 percent of electricity) in 2020.
- Although the base case shows solar capturing about 3.5 percent of the U.S. energy market in 2000 and 6.4 percent in 2020, the results on solar market penetration should be viewed as preliminary since this scenario is used as input data for the detailed market analyses that are performed using the solar penetration model. (See Section X.)
- Natural gas production declines significantly in the base case, particularly after the year 2000. Domestic oil production increases only slightly through 2000 and declines thereafter. Oil imports increase (by about one million barrels per day) between 1975 and 1985, by between zero (in high synfuels case) and one million barrels per day (in moderate synfuels case) in the time period 1985 to 2000, and by another zero (high synfuels case) to two million barrels per day (moderate synfuels case) between 2000 and 2020.

Figure A-3 (derived from Tables A-1 and A-6) shows that the degree of electrification of the energy system increases from about 29 percent in 1975 to 34 percent in 1985, 39 percent in 2000, and 42 percent in 2020. This result is obtained from a growth rate of electricity demand that is approximately double that of total energy demand in each of the three time segments (1975 to 1985, 1985 to 2000, 2000 to 2020) of the base case. Note that the degree of electrification is expressed in primary energy equivalents (i.e., in terms of energy that would be consumed to produce electricity if all electricity were derived from fossil fuels).

Tables A-3A and A-3B and Figure A-4 summarize the potential growth of the synthetic fuels industry. The first of the two tables expresses the quantities of liquids from coal, oil shale, and gas from coal that would be produced under a situation of moderate synthetic fuels growth.

It can be seen that synthetics contribute 11.5 quads of output energy in the year 2020 under this assumption. Table A-3B describes a rapid growth in the use of synthetic fuels, allowing for a total of 24 quads of synthetics at the end of the study period.

The two sets of curves that make up Figure A-4 graphically present the data contained in Tables A-3A and A-3B. In addition, this figure points out an important consequence of a moderate growth in the production of synthetic fuels as compared to a rapid growth; this consequence is an increased demand for imported energy. A combination of oil and gas imports could be expected to fill the gap, 11.5 quads in the year 2020, left by a moderate synthetic fuels growth.

Figure A-5 shows the projected increases in the prices of distributed energy that are estimated to be consistent with the energy supply and demand levels in the next forty-five years. These prices are shown in constant 1975 dollars. Note that gas prices rise relatively rapidly until 1985, under the assumption that the prices are either deregulated or regulated at a price approximately equal to its market clearing price during this period of time.

The remaining tables have been selected because they provide the detailed regional information that will be needed to perform the market analyses of the solar energy technologies.

FIGURE A-1. BASE CASE U.S. ENERGY CONSUMPTION
(1975, 1985, 2000, 2020)

BASE CASE SCENARIO SUMMARY (Continued)

FIGURE A-2. ENERGY DEMAND GROWTH RATES ASSUMPTIONS OF BASE CASE

FIGURE A-3. FRACTIONAL ELECTRIFICATION IN BASE CASE *
(Electricity Expressed in Primary Energy Equivalents)

* Assuming overall thermal efficiencies for base bar electricity of 33, 34, 35, and 36% for the years 1975, 1985, 2000, and 2020 respectively.

BASE CASE SCENARIO SUMMARY (Concluded)

FIGURE A-4. SYNTHETIC FUEL FOR BASE CASE
(End Use or Output Energy)

* DISTRIBUTED LIQUID PRICES ARE APPROXIMATELY EQUAL TO GAS PRICES AFTER 1990

FIGURE A-5. DISTRIBUTED ENERGY PRICES IN BASE CASE

Table A-1

BASE CASE PRIMARY ENERGY CONSUMPTION--TOTAL U.S.
(In Quadrillion Btus/Year)

	1975	1985	2000	2020
Coal	13.0	21	29-31.5	35-52
Domestic Liquids	21.0	23	25	15
Imported Liquids	13.0	15	15+15.5	15-21
Domestic Gas	19.5	20	18	11
Imported Gas	--	--	0-1	0-5.5
Nuclear Fuel	1.5	6	17	34
Hydro and Geothermal	3.0	4	5	6
Solar	.5	1	4	9
TOTAL*	71.5	90	114.5-115.5	136.5-142

Percentage Annual Growth Rates
For Total Primary Energy Consumption

Periods:	1975-1985	1985-2000	2000-2020
	2.3%	1.6%	1.0%

* NOTE: Lower estimate for 2000 and 2020 corresponds to "moderate" growth of synthetic fuels industry; higher estimate corresponds to rapid growth of synthetic fuels industry. The lower conversion efficiency in one latter case increases primary energy consumption.

Table A-2

COMPARISON OF BASE CASE SCENARIO
WITH FORECASTS OF OTHER ENERGY STUDIES*
(In Quadrillion Btus/Year)

Energy Demand Category	Study/Organization	1974/75	1985	2000	2020
TOTAL PRIMARY ENERGY					
A)	Base Case Scenario	71.5	90	114.5-115.5	136.5-142
B)	F.E.A. (1976)-\$13 oil price	73.1	98.9		
C)	SRI (Early 1977)	72	89	119	
D)	Ford Foundation ** (1974)				
	(Self-Sufficiency)	75	92	124	
	(Environmental Protection)	75	92	123	
E)	Bureau of Mines (Revised 1976)	73.1	103.5	163.4	
F)	OECD (1977)	69	90-99		
G)	M.I.T. (1977)		81-107		
H)	C.I.A. (1977)		102-117		
I)	Dept. of Commerce (1977)		87		
COAL					
A)	Base Case Scenario	13.0	21	29-31.5	35-52
B)	F.E.A. (1976)-\$13 oil price	13.2	20.6		
C)	SRI (Early 1977)	14	23	30	
D)	Ford Foundation (1974)				
	(Self-Sufficiency)	13	16	28	
	(Environmental Protection)	13	14	28	
E)	Bureau of Mines (Revised 1976)	13.2	21.3	34.8	
F)	OECD (1977)	13.1	19.7		

* Specific studies are noted at end of table

** Ford Foundation data throughout this table are based on an initial year of 1973, not 1974 or 1975 as for most of the other studies.

Table A-2
(Continued)

<u>Energy Demand Category</u>	<u>Study/Organization</u>	<u>1974/75</u>	<u>1985</u>	<u>2000</u>	<u>2020</u>
DOMESTIC LIQUIDS					
A)	Base Case Scenario	21.0	23	25	15
B)	F.E.A. (1976)				
	\$8 Oil Price	21.1	24.2		
	\$13 Oil Price	21.1	29.5		
	\$16 Oil Price	21.1	32.2		
C)	SRI (Early 1977)	21	21	28	
D)	Ford Foundation (1974)				
	(Self-Sufficiency)	22	31	39	
	(Environmental Protection)	22	29	36	
F)	OECD (1977)	19.9	23.3		
J)	Exxon Corporation (1977)	22	22		
IMPORTED LIQUIDS					
A)	Base Case Scenario	13.0	15	15-15.5	15-21
B)	F.E.A. (1976)				
	\$8 Oil Price	12.4	27.3		
	\$13 Oil Price	12.4	12.0		
	\$16 Oil Price	12.4	6.6		
C)	SRI (Early 1977)	13	13	13-15	
D)	Ford Foundation (1974)				
	(Self-Sufficiency)	12	6	6	
	(Environmental Protection)	12	12	12	
F)	OECD (1977)	11.6	19.1		
J)	Exxon Corporation (1977)	13	22		

Table A-2
(Continued)

Energy Demand Category	Study/Organization	1974/75	1985	2000	2020
DOMESTIC NATURAL GAS					
A)	Base Case Scenario	19.5	20	18	11
B)	F.E.A. (1976)-\$13 Oil Price	21.1	22.9		
C)	SRI* (Early 1977)	19	19	17	
D)	Ford Foundation (1974)				
	(Self-Sufficiency)	23	27	32	
	(Environmental Protection)	23	26	32	
E)	Bureau of Mines* (Revised 1976)	22.2	20.1	19.0	
F)	OECD (1977)	20.0	18.4		
J)	Exxon Corporation (1977)	21	16		
NUCLEAR FUEL					
A)	Base Case Scenario	1.5	6	17	34
B)	F.E.A. (1976)-\$13 Oil Price	1.2	8.7		
D)	Ford Foundation (1974)				
	(Self-Sufficiency)	1	8	11	
	(Environmental Protection)	1	5	3	
E)	Bureau of Mines (Revised 1976)	1.2	11.8	46.1	
F)	OECD (1977)	1.2	9.8		
K)	ERDA (1976)		7-9**	21-35**	

* Includes gas imports

** Assumes a nuclear plant capacity factor of 60%

Table A-2
(Continued)

<u>Energy Demand Category</u>	<u>Study/Organization</u>	<u>1974/75</u>	<u>1985</u>	<u>2000</u>	<u>2020</u>
HYDROPOWER AND GEOTHERMAL					
A)	Base Case Scenario	3.0	4	5	6
B)	F.E.A. * (1976)-\$13 Oil Price	3.3	3.9		
D)	Ford Foundation (1974)	3	3	6	
	(Self-Sufficiency)	3	3	6	
	(Environmental Protection)				
E)	Bureau of Mines (Revised 1976)	3.1	3.9	6.1	
F)	OECD (1977)	3.0	3.8		
OTHER ENERGY SOURCES					
(Including Solar)					
A)	Base Case Scenario	.5	1	4	9
D)	Ford Foundation (1974)				
	(Self-Sufficiency)	---	---	2	
	(Environmental Protection)	---	1	4	

* Includes Solar Energy

Table A-2

(Concluded)

STUDIES

- A) Base Case Scenario
- B) Federal Energy Administration, National Energy Outlook (1976)-Reference Case
- C) SRI International (Early 1977)
- D) Ford Foundation, A Time To Choose (1974)-Technical Fix Scenario
- E) U.S. Bureau of Mines, U.S. Energy Through the Year 2000 (Revised 1976)
- F) Organization for Economic Cooperation and Development, World Energy Outlook (1977)
- G) M.I.T. Workshop on Alternative Energy Strategies, Energy: Global Prospects 1985-2000, (1977)
- H) Central Intelligence Agency (1977)
- I) U.S. Department of Commerce (1977)
- J) Exxon Corporation, World Energy Outlook (1977)
- K) ERDA, World Requirements and Supply of Uranium (1976)

Table A-3A

MODERATE SYNTHETIC FUELS GROWTH

Synthetic Fuels Output from Coal and Shale Oil--Total U.S.
(In Quadrillion Btus/Year)

	1985	2000	2020
HBtu Gas from Coal	--	1.0	4.5
LBtu Gas from Coal	--	0.2	1.0
Oil Shale	--	0.3	2.0
Coal Liquids	--	1.0	4.0
TOTAL	--	2.5	11.5

Table A-3B

RAPID SYNTHETIC FUELS GROWTH

Synthetic Fuels Output from Coal and Shale Oil--Total U.S.
(In Quadrillion Btus/Year)

	1985	2000	2020
HBtu Gas from Coal	--	2.0	10.0
LBtu Gas from Coal	--	0.2	1.0
Oil Shale	--	0.7	4.0
Coal Liquids	--	1.0	9.0
TOTAL		3.9	24.0

Table A-4

BASE CASE DISTRIBUTED PRODUCT PRICES--REGIONALLY DISAGGREGATED*
(in 1975 dollars per million Btu)

	1975	1985	2000	2020
Industrial Sector				
<u>Electricity</u>				
Region 1	5.8	7.6	9.3	10.5
2	5.5	7.6	9.5	10.5
3	5.0	7.2	9.0	10.1
4	5.3	7.2	9.2	10.1
5	4.7	7.0	8.8	9.9
6	5.4	7.8	9.8	10.9
7	4.4	6.5	8.6	10.4
8	6.1	7.7	9.1	10.3
9	6.0	6.9	8.5	9.9
Average U.S.	5.3	7.3	9.2	10.3
<u>High-Btu Gas</u>				
Region 1	1.2	3.8	4.6	4.8
2	1.1	3.4	4.1	4.3
3	.9	3.0	4.0	4.1
4	.8	2.7	3.7	3.7
5	1.0	3.2	3.6	4.0
6	.8	2.6	3.8	4.2
7	.8	2.7	3.1	3.3
8	.9	2.8	3.2	4.1
9	.8	2.3	2.8	3.5
Average U.S.	.9	2.8	3.6	4.0
<u>Liquids</u>				
Region 1	2.3	2.9	3.6	4.3
2	2.4	2.9	3.7	4.0
3	2.2	2.9	3.7	4.2
4	2.1	2.9	3.6	3.7
5	2.2	2.9	3.6	4.0
6	2.1	2.8	3.5	3.7
7	2.1	2.9	3.5	3.7
8	2.2	2.8	3.5	4.1
9	2.2	2.9	3.5	3.8
Average U.S.	2.2	2.9	3.6	4.0

*Demand Regions: 1. New England 4. East South Central 7. West North Central
 2. Middle Atlantic 5. East North Central 8. Pacific
 3. South Atlantic 6. West South Central 9. Mountain

(see attached Figure A-6 for regional definitions.)

BASE CASE DISTRIBUTED PRODUCT PRICES (continued)

	1975	1985	2000	2020
Industrial Sector				
<u>Coal</u>				
Region 1	1.1	1.6	1.9	1.7
2	1.1	1.4	1.5	1.5
3	1.2	1.5	1.6	1.6
4	1.1	1.3	1.4	1.4
5	1.0	1.2	1.3	1.4
6	1.3	1.4	1.5	1.5
7	.9	1.1	1.1	1.1
8	1.3	1.6	1.6	1.6
9	1.0	1.2	1.2	1.1
Average U.S.	1.1	1.3	1.4	1.4
Residential/Commercial Sector				
<u>Electricity</u>				
Region 1	9.8	10.1	11.0	12.3
2	9.3	10.0	11.2	12.3
3	8.8	9.7	10.8	12.0
4	9.2	9.7	10.9	12.0
5	8.3	9.5	10.6	11.8
6	9.2	10.3	11.4	12.6
7	8.0	9.0	10.4	12.2
8	10.1	10.1	10.8	12.1
9	10.0	9.4	10.4	11.8
Average U.S.	9.1	9.8	10.8	12.0
<u>High Btu Gas</u>				
Region 1	2.0	4.5	5.6	6.0
2	1.8	4.0	5.1	5.4
3	1.6	3.7	5.1	5.3
4	1.4	3.3	4.6	4.7
5	1.6	3.6	4.3	4.7
6	1.3	3.1	4.6	5.1
7	1.4	3.2	3.9	4.2
8	1.6	3.3	4.1	5.0
9	1.4	2.8	3.6	4.3
Average U.S.	1.6	3.5	4.5	4.9

BASE CASE DISTRIBUTED PRODUCT PRICES (continued)

	1975	1985	2000	2020
Residential/Commercial Sector				
<u>Distillate</u>				
Region 1	2.9	3.7	4.4	4.7
2	2.9	3.7	4.5	4.7
3	2.8	3.6	4.4	4.7
4	2.8	3.6	4.4	4.6
5	2.8	3.7	4.4	4.6
6	2.7	3.6	4.4	4.6
7	2.7	3.7	4.4	4.6
8	2.7	3.5	4.3	4.6
9	2.7	3.6	4.3	4.6
Average U.S.	2.9	3.6	4.4	4.7
<u>LPG</u>				
Region 1	4.1	4.4	5.1	5.4
2	4.0	4.4	5.0	5.4
3	3.8	4.4	5.1	5.3
4	3.8	4.3	5.1	5.3
5	3.9	4.3	4.9	5.6
6	3.7	4.3	5.1	5.3
7	3.7	3.9	4.5	6.4
8	4.0	3.7	4.3	4.6
9	3.4	3.6	4.3	4.7
Average U.S.	3.8	4.2	4.8	5.4

Table A-5

BASE CASE USEABLE ENERGY DEMAND FOR SEVERAL END-USE CATEGORIES--
 REGIONALLY DISAGGREGATED
 (In Quadrillion Btus/Year)

	1975	1985	2000	2020
Industrial Sector				
<u>Indirect Heat (Steam and Water)</u>				
Region 1	.1	.2	.2	.3
2	.5	.7	.9	1.1
3	.7	.9	1.2	1.5
4	.5	.5	.7	.9
5	1.1	1.3	1.7	2.3
6	1.6	1.9	2.3	3.0
7	.4	.5	.5	.7
8	.4	.5	.8	1.0
9	.2	.2	.3	.4
Total U.S.*	5.5	6.7	8.6	11.2
Residential/Commercial Sector				
<u>Urban Space Heat**</u>				
Region 1	.3	.3	.4	.5
2	.7	.8	1.0	1.1
3	.4	.4	.5	.6
4	.2	.2	.2	.3
5	1.0	1.1	1.3	1.6
6	.2	.3	.3	.4
7	.4	.4	.4	.5
8	.4	.4	.6	.7
9	.2	.2	.2	.3
Total U.S.	3.6	4.0	4.9	5.9
<u>Urban Miscellaneous Heat</u>				
Region 1	.1	.1	.2	.2
2	.4	.5	.6	.7
3	.3	.3	.4	.5
4	.1	.2	.2	.3
5	.5	.7	.9	1.1
6	.2	.3	.3	.4
7	.2	.3	.3	.4
8	.4	.4	.6	.8
9	.1	.1	.2	.2
Total U.S.	2.3	3.0	3.7	4.6

* Columns may not sum to totals due to rounding

** Includes water heating, cooking, etc.

BASE CASE USEABLE ENERGY DEMAND FOR SEVERAL END-USE CATEGORIES (Con't)

	1975	1985	2000	2020
Residential/Commercial Sector				
* <u>Rural Heat</u>				
Region 1	.1	.1	.1	.1
2	.1	.1	.2	.2
3	.2	.2	.2	.2
4	.2	.1	.2	.2
5	.3	.3	.3	.4
6	.1	.1	.1	.1
7	.2	.2	.2	.2
8	.1	.1	.1	.1
9	.1	.1	.1	.1
Total U.S.	1.3	1.3	1.4	1.6
<u>Space Cooling</u>				
Region 1	--	--	--	--
2	--	--	.1	.1
3	.1	.1	.2	.2
4	.1	.1	.1	.2
5	.1	.1	.2	.2
6	.1	.2	.4	.5
7	--	--	--	.1
8	--	.1	.1	.2
9	--	--	.1	.1
Total U.S.	.4	.7	1.2	1.6

REGIONS: 1 New England 6 West South Central
 2 Middle Atlantic 7 West North Central
 3 South Atlantic 8 Pacific
 4 East South Central 9 Mountain
 5 East North Central (See attached Figure A-6 for regional
 definitions.)

* That segment of Residential/Commercial heat demand that cannot be served by gas due to the limitations of gas distribution systems. (Includes both rural space heat and rural miscellaneous heat.)

Table A-6

BASE CASE ELECTRICITY PRODUCTION--REGIONALLY DISAGGREGATED *
(In Quadrillion Btus/Year)

	1975	1985	2000	2020
Base Load				
Region 1	.2	.3	.4	.6
2	.6	1.0	1.5	2.1
3	.8	1.0	1.5	2.0
4	.4	.5	.7	.9
5	.9	1.6	2.5	3.6
6	.6	1.1	1.7	2.4
7	.3	.6	.8	1.1
8	.6	.8	1.4	2.0
9	.3	.3	.5	.8
Total U.S. **	4.8	7.3	11.0	15.4
Intermediate Load				
Region 1	.1	.1	.2	.2
2	.2	.3	.5	.7
3	.3	.4	.5	.7
4	.2	.2	.3	.3
5	.3	.6	.9	1.3
6	.2	.4	.6	.8
7	.1	.2	.3	.4
8	.2	.3	.5	.7
9	.1	.1	.2	.3
Total U.S.	1.7	2.5	3.9	5.5
Peak Load				
Region 1	--	--	--	--
2	--	.1	.1	.1
3	.1	.1	.1	.1
4	--	--	.1	.1
5	.1	.1	.2	.3
6	--	.1	.1	.2
7	--	--	.1	.1
8	--	.1	.1	.1
9	--	--	--	.1
Total U.S.	.3	.5	.8	1.1

* REGIONS: 1. New England 4. East South Central 7. West North Central
 2. Middle Atlantic 5. East North Central 8. Pacific
 3. South Atlantic 6. West South Central 9. Mountain

(See attached Figure A-6 for regional definitions.)

** Columns may not sum to totals due to rounding.

BASE CASE ELECTRICITY PRODUCTION

(Continued)

	1975	1985	2000	2020
Total Electrical Generation				
Region 1	.3	.4	.6	.9
2	.8	1.4	2.1	3.0
3	1.2	1.5	2.1	2.8
4	.6	.8	1.0	1.4
5	1.3	2.3	3.6	5.1
6	.9	1.6	2.4	3.4
7	.4	.8	1.1	1.5
8	.9	1.2	2.0	2.8
9	.4	.5	.7	1.1
Total U.S.	6.8	10.4	15.6	22.0

Figure A-6

REGIONAL DIVISIONS OF THE UNITED STATES