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Economic Feasibility and Market Readiness of Solar Technologies

Draft Final Report

Volume I

SERI

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ECONOMIC FEASIBILITY AND MARKET READINESS OF SOLAR TECHNOLOGIES

DRAFT FINAL REPORT
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Division of Solar Technology
Under Contract EG-77-C-01-4042

PREFACE

This draft report was prepared in compliance with Contract Number EG-77-C-01-4042 for the U.S. Department of Energy. The report marks completion of the economic feasibility and market readiness assessment portion of Joint Task 5213/6103 in the Economics and Market Analysis Branch and Technology Evaluation Branch of the Solar Energy Research Institute. The final portion of this Joint Task will assess the costs and market readiness of the solar technologies evaluated in this report and make commercialization recommendations.

SERI staff members contributing to this report were: R. Witholder, biomass and SPS costs, and market assessments, and computer costing models; D. Buchanan, passive costs and market assessment; S. Christmas, photovoltaic costs and market assessment; C. Fellhauer, wind costs and ocean thermal costs and market assessment; S. Flaim, process heat and total energy costs, total energy market assessment, cost and market methods of assessment; B. Glenn, edited, proofed, incorporated revisions, and rewrote several sections of the report; P. Ketels, markets for industrial process heat and process heat systems, market readiness assessment; A. Levary, SHACOB costs and market assessment, and SPS market assessment; P. Mourning, market readiness and the commercialization process; P. Steggerda, market readiness assessment for solar thermal electric and WECS; and H. Trivedi, solar thermal electric costs.

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ABSTRACT

Systems descriptions, costs, technical and market readiness assessments are reported for ten solar technologies: solar heating and cooling of buildings (SHACOB), passive, agricultural and industrial process heat (A/IPH), biomass, ocean thermal (OTEC), wind (WECS), solar thermal electric, photovoltaics, satellite power station (SPS), and solar total energy systems (STES). Study objectives, scope, and methods are presented. The cost and market analyses portion of Joint Task 5213/6103 will be used to make commercialization assessments in the conclusions of the final report.

ECONOMIC FEASIBILITY AND MARKET READINESS OF SOLAR TECHNOLOGIES

Joint Task 5213/6103

I. INTRODUCTION

A. OBJECTIVE, SCOPE, AND PURPOSE

To successfully commercialize solar technologies, a continuing assessment of economic and market factors is required. Accelerating this process places a premium on careful, thoughtful planning. The objective of this report is to compile current cost estimates and conduct technical and market readiness assessments for solar commercialization planning.

Ideally commercialization activities begin early, during technology development, in order to stimulate the development of a healthy, growing, self-sustaining industry. This report seeks to provide a foundation for establishing priorities for the augmentation of commercialization plans for solar technologies as well as for establishing a cost data base for the design of particular commercialization strategies. The objective of this report is to assess the current economic feasibility and commercial readiness for ten solar technologies: Solar Heating and Cooling of Buildings (SHACOB), Passive, Process Heat, Biomass, Ocean Thermal Energy Conversion (OTEC), Wind Energy Conversion Systems (WECS), Solar Thermal Electric, Photovoltaics, Solar Satellite Power Stations, and Total Energy Applications. Commercial readiness is defined in terms of the technical status of the technology and of the extent to which particular market characteristics exist.

Computed costs will be used for comparative cost and economic feasibility analyses for each of the solar technologies. Comparisons will be drawn between solar and conventional alternatives competing in specific markets on the basis of 1978 cost and market characteristics; however, these costs are preliminary estimates only.

This introduction outlines the costing and market assessment methods employed in the following analysis. Cost methods are explained in more detail in Section XIII of this report, but special cost considerations for each technology are noted here. For SHACOB and Passive solar the market readiness assessments were covered in considerably less detail because these two technologies are already well into the market introduction phase of commercialization.

B. METHODS AND LIMITATIONS

Costs

Each technology subsection outlines the principle of operation and typical systems currently available to consumers. Some systems considered have never been built and are conceptual designs only. Data for these systems are taken from DOE contractors' engineering designs and cost estimates. Costs for all systems should be interpreted with caution because the methods were selected to minimize bias when comparing dissimilar systems. Thus, costs presented as a point estimate are averages of different systems within a typical system category. The cost methods employed in this analysis are explained in the Appendix, Section XIII, of this report.

The limitations of the cost analysis should be noted. These limitations will be discussed in the order that the technologies are presented in this report. This report surveys cost studies on each of the technologies. Capital costs, operation and maintenance expenses, and other costs are inputs to our costing models which have standard economic assumptions regarding interest rates, debt-equity balances, etc.

Sources of data for SHACOB costs are from the MITRE Corporation SPURR* Market Penetration Model, interviews with manufacturers of these systems, and engineering cost estimates for systems currently available to consumers. Costs are presented for both homeowners and commercial applications for 14 regions and 9 building types and for both new and retrofit applications. Examination of the tables in Section II reveals that the costs (in terms of dollars per million Btu) are much higher for homeowners than for all other applications. This difference is due to the deductibility of fuel costs and fuel expenses related to the operation of a business.

Costs for passive systems were particularly difficult to obtain. Passive heating systems performance is highly variable and depends on location and other characteristics of the home. This variability in turn, greatly affects cost. No satisfactory method for calculating passive costs is yet available, but several are under development. Passive costs were obtained from a large number of research studies. They do not represent costs calculated through our models. In some cases, costs are available on a dollar-per-million-Btu basis; however, where these costs were not available, costs are reported on dollars per million Btu delivered during an average year ($/MBtu/yr).

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*SPURR is the acronym for A System for Projecting the Utilization of Renewable Resources.

Costs for agricultural and industrial process heat systems were obtained from interviews with manufacturers and engineering cost estimates from government contractors. The process heat systems cost analysis, performed by MITRE Corporation, represents updated costs of delivered energy from systems within the SPURR Model.

Two types of costs need to be considered for biomass. These are the costs of feedstocks and costs of converting these feedstocks into useful products. The model employed for this method is a required revenue model which derives the price necessary for the product to pay for itself, including a minimum profit return. (The advantages and limitations of a required revenue model are noted in Section XIII of this report.) The calculations presented in this section strictly follow the specifications recorded in the studies surveyed. Some assumptions appear unrealistically optimistic, and these assumptions are identified. Since the cost of conversion depends on the cost of feedstocks, feedstock costs are parametrically varied to obtain dollars per million Btu, mills/kWh, or dollars per gallon for biomass fuels. A survey of the availability of biomass feedstocks is also presented.

The costs of wind energy conversion systems are highly dependent on location and wind characteristics for a given area. Two types of systems are considered: small (less than 100 kW) and large (more than 100 kW) wind energy systems. Remote market applications for small wind energy systems make costs noncomparable with most conventional cost data available for electricity. For these systems, costs are presented in terms of dollars per kilowatt of rated capacity. Large wind energy conversion systems or wind farms, however, are anticipated to be used in utility markets. These costs are expressed in mills per kilowatt hour.

Solar thermal electric power systems costs were obtained from engineering cost estimates based on systems currently being considered by the Department of Energy. Although one solar thermal electric system is currently under construction, no actual system performance and cost data were available at the time of this report.

Cost comparisons of some photovoltaic systems face problems similar to small wind energy conversion systems. Many photovoltaic systems are in remote markets that are not currently supplied by large utility systems. Utility applications for photovoltaics are presented in terms of mills per kilowatt hour.

Costs for solar satellite power systems (SPS) are based on conceptual designs and engineering cost estimates only. The costs of satellite power stations are highly dependent on the future cost of photovoltaics and the development of a suitable economical transport system from Earth to outer space.

Solar total energy systems are generally defined as systems that provide electricity and thermal heat. System costs are available from contractors' estimates. Contractors' models were used to simulate the performance of these systems to deliver electricity and process heat.

Energy Markets

The commercialization or market penetration of solar energy technologies may be viewed from two perspectives. In the first, the potential market and its characteristics are identified. Then solar energy systems are designed to meet the special requirements of a particular market. Alternatively, the most promising technologies (in terms of cost and efficiency) are selected, and these systems are moved from technological feasibility through market acceptance to substantial use. Technologies are commercialized by assessing markets in an effort to satisfy demands and requirements, while a simultaneous attempt may be made to change the characteristics of the market (lifestyles, per capita consumption, and attitudes).

This section will outline the market for solar energy and the process of commercialization to meet special market requirements. The technology assessments that follow will refer to this market description and will discuss commercialization efforts in 1978.

Market Description

Table I-1 presents U. S. energy consumption by market sector from 1950-1976. Electricity generation consumes the most energy, 28.8%; industry and transportation consume about 25% each, and commercial/residential use accounts for about 20% of total energy consumption. The following description centers on industrial markets because (1) temperature requirements and loads are least understood in this sector, (2) industrial processes are least dependent on liquid fuels, and (3) special market factors may accelerate solar energy system adoption, despite present costs, e.g., natural gas curtailments.

Commercial/Residential. Many solar heating and cooling systems are available for space and water heating in commercial and residential applications. Life-cycle cost comparisons with conventional fuels are favorable in some regions, especially for new construction and when competing fuels are electricity or propane. Substantial reductions in retrofit installation costs will be required before SHACOB systems will be a large contributor in this market. The current stock of housing in this country largely consists of older, tract-type homes which are thermally

TABLE I-1

DOMESTIC ENERGY CONSUMPTION BY MARKET SECTOR

		Percent of Total				
Year	Year (Quads)	Commercial/ Residential[a]	Industrial[a]	Trans- portation[a]	Electricity Generation[b]	Miscellaneous and unaccounted for[a]
1950	34.0	22.3	36.3	25.3	14.7	1.4
1955	39.7	21.6	35.2	24.8	16.6	1.8
1960	44.6	22.8	32.9	24.3	18.5	1.5
1961	45.3	22.9	32.3	24.2	18.8	1.8
1962	47.4	23.1	32.2	24.0	19.2	1.5
1963	49.3	22.3	32.3	24.3	19.6	1.5
1964	51.2	21.7	32.6	23.9	20.3	1.5
1965	53.3	22.2	32.2	23.8	20.8	1.0
1966	56.4	22.0	32.0	23.6	21.4	1.0
1967	58.3	22.3	31.3	24.1	21.8	0.5
1968	61.8	21.2	31.4	24.5	22.5	0.4
1969	65.0	20.9	30.9	24.3	23.5	0.4
1970	67.1	20.8	30.1	24.6	24.2	0.3
1971	68.7	20.7	29.1	24.8	25.1	0.3
1972	71.9	20.3	28.5	25.1	25.8	0.3
1973	74.7	19.1	28.6	25.3	26.6	0.4
1974	73.0	19.1	27.9	25.3	27.4	0.3
1975	70.6	19.2	25.4	26.3	28.7	0.4
1976	74.2	20.2	25.4	25.6	28.8	(2)

[a]Does not include electricity.
[b]Distributed throughout other sectors.

Sources: FEA, Energy in Focus, May 1977.

inefficient and unsuitable for solar systems without substantial modification.

Industrial Process Heat. Historically, the consumption of energy within the industrial market sector for process heat applications has accounted for a large portion of the total amount of energy consumed in the United States. The quantity of energy consumed within each market sector, as a percentage of the total, is shown in Table I-1, for the years 1950-1976. Although the relative amount of energy consumed has decreased, industrial energy consumption has increased from 12.3 quads* in 1950 to 18.8 quads in 1976. This increase represents a 3% annual rate of growth. At the same time, the total amount of energy consumed increased annually up to 1973--the year of the imported oil embargo. In the three years following, the amount of energy consumed was below the level of 1973. The reduction in the quantity of energy consumed can be attributed to increased conservation efforts and to the nonavailability of additional supplies of energy within some market sectors.

Industrial process heat can be generally defined as thermal energy which is used either directly or indirectly in the treatment or preparation of mined and manufactured goods and materials. The temperatures required for various industrial processes range from as low as ambient for such applications as drying to as high as 3300°F in refractory kilns. The basis for selecting an energy source for a specific industrial application is a combination of the temperature requirement and the desired specific performance characteristics. In some processes the source of direct heat must have no pollutants and must otherwise be clean, (e.g., the preparation of baked goods and refining certain metals). Some industrial processes are possible only because of a combination of

*A "quad" equals 10^{15} Btu.

certain chemical properties and flame or temperature characteristics of the energy source. An example is the use of natural gas in the heat treating of metals to achieve certain physical properties. Other variables considered in the selection of an industrial energy source are dependability, degree of temperature control, environmental standards, and cost.

Transportation. The transportation sector represents a large potential market for renewable energy technologies. However, except for biomass, solar alternatives are limited unless a major shift to electric cars or mass transit occurs. Ocean thermal systems can produce hydrogen which may be used as a transportation fuel if technical problems are overcome. The use of liquid fuels from biomass will also require some modification of the internal combustion engine.

Utilities (Electricity Generation). Utilities are the largest consumers of energy in the U. S. and represent a large market for solar technologies. Candidate technologies are ocean thermal, wind, solar thermal electric, photovoltaics, satellite power stations, biomass, and total energy systems.

There are two distinct markets for electric generating systems: large central plants and remote applications. All of the above technologies can be used in the former capacity, but only wind and photovoltaics are presently designed for use in small remote applications. Cost comparisons of low-maintenance solar systems are often favorable with the alternatives of diesel or gasoline generators.

Other Products. Solar energy collector systems generate thermal and electrical energy. Biomass may also be converted to products used for their nonenergy characteristics--ethanol, methanol, and ammonia. Ocean thermal systems may prove most economical for manufacturing and processing aluminum rather than utility grid generation. These other products have not been investigated thoroughly but do represent potential markets for solar technologies.

Market Readiness and the Commercialization Process

The degree to which solar will contribute to national energy needs will depend not only on action by the federal government but also on parallel action by individual states and the private sector. These actions need to be aimed at producing a program which recognizes regional variations in the solar resource and which provides specific solar applications appropriate to particular users. Some solar technologies are already reasonable alternatives to conventional energy technologies and can be considered--with some confidence--as viable future sources of heat, fuel, and electric power in dispersed and/or centralized applications.

The private sector is already participating in the development and application of solar technologies, but it is unlikely that this effort alone will lead to the rate of solar implementation required to contribute effectively to a prosperous economy, a clean environment, a growing job market, improved national security, flexibility in foreign affairs, or decreased reliance on foreign energy resources. Through commercialization--the acceleration of near-term and widespread use of solar systems--the federal government can set the stage for expanded private sector solar involvement. Commercialization is the process of moving a new technology from technical feasibility to market acceptance. Commercialization in the public sector context corresponds to innovation in the private sector; in the former, government funds are used to stimulate technological flow. The commercialization process is deemed successful when the predominant source of financing is from private sources and when the use of the new technology is widespread.

Any attempt to stimulate the adoption of solar energy systems through government commercialization efforts should be preceded by an assessment of the commercial or market readiness of each technology. This assessment is a critical step in the commercialization process because it is the point from which commercialization planning programs can begin. It is also an appropriate point for identifying and evaluating other market tools directed at increasing the acceptance of a solar technology.

Assessment of market readiness requires a clear understanding of the commercialization/innovation process and the technological changes it involves. The private sector of the economy goes through sequential stages of the innovation process leading to the first application and to subsequent diffusion of a new technology. Several private sector models describe as many as 14 distinct stages of technological flow.

These commercialization/innovation stages can be grouped conveniently into four phases: applied research, development, market introduction, and diffusion. These phases roughly correspond to the points at which firms and government administrators make key investment decisions (Figure I-1).

Applied Research	Development	Introduction	Diffusion
Research Plan	Resource Allocation	Equipment Procurement	Increased Production
Experimentation	Breadboard Models	Plant Construction	Licences
Lab Feasibility	Equipment Design	Installation	Imitators
Development Proposals	Prototypes	Product Tests	Widespread Adoption
	Pilot Plants		

Figure I-1. Phases in the Commercialization Process

The applied research phase includes devising a research plan for investigating the technology concept. It also involves experimentation, data collection and analysis, and laboratory-scale feasibility demonstrations. This phase proceeds with formulating conclusions from the experiments and making recommendations for development projects. Basic research is purposely omitted from this phase because such prior work may not have been directly connected with any specific technology and can be viewed as an effort to attain general knowledge.

The applied research phase continues with a description of both the technical concept of a proposed development project and the potential uses of the project results. Technical feasibility studies and cost estimates are also applied research activities. Finally, the results are evaluated in terms of the potential value of continuing with the idea.

The development phase usually involves substantial investment. It includes allocating resources to the project and producing successful breadboard or bench models. Designs of each component of equipment necessary for product performance are completed. Successful operation of a prototype and pilot plant testing to develop desired product characteristics typically complete the development phase.

The market introduction phase includes procurement and installation of full-scale production facilities and achievement of an acceptable rate and quality of production under plant conditions. This stage is successful when all planned production facilities are built and operating.

Successful introduction is followed by the diffusion phase, where adoption of the product incorporating the new technology becomes widespread. Production of the system may expand from the first company to licensees, and to other companies imitating the technology.

Failure to complete any one stage in this process may result in abandonment or shelving of the technology. The concept may be revived when the necessary technical, economic, or social barriers have been surmounted or when additional resources become available.

The introduction phase is the critical point for market readiness. If research and development have been completed to such an extent that technical uncertainty is significantly decreased, then the technology may be ready for introduction into the marketplace, provided one other condition exists. The service supplied by the technology being examined must be cost competitive with existing sources for that service.

In subsequent chapters, each solar technology is described; these descriptions attempt to relate current status and activities to the stages of the commercialization process. Comparisons of life-cycle costs (solar vs conventional) and market readiness considerations are used as a basis to characterize the commercialization potential of these solar technologies.

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II. SOLAR HEATING AND COOLING OF BUILDINGS

A. INTRODUCTION

This section presents "typical" solar heating and cooling systems (SHACOB) currently available to consumers. These systems are used to represent typical system costs that are used for heating and cooling of buildings and hot water. All costs are reported in ranges to reflect widely varying labor charges for installation as well as design and collector cost differences. The systems' configurations presented below represent broadly defined types of the many different systems available today. These systems are analyzed for 9 building types and 14 climatic regions to account for the different systems used in different climate zones. These typical systems have been preoptimized for each region and building type on the basis of efficiency and cost. No attempt is made to obtain costs for one system in all regions. With the exception of the thermosiphon hot water system, all systems discussed here are active systems. An active system is characterized as a system in which an additional energy source is used to transfer thermal energy. This additional energy source is needed to drive pumps, blowers, and other devices needed for heat circulation.

Principle of Operation

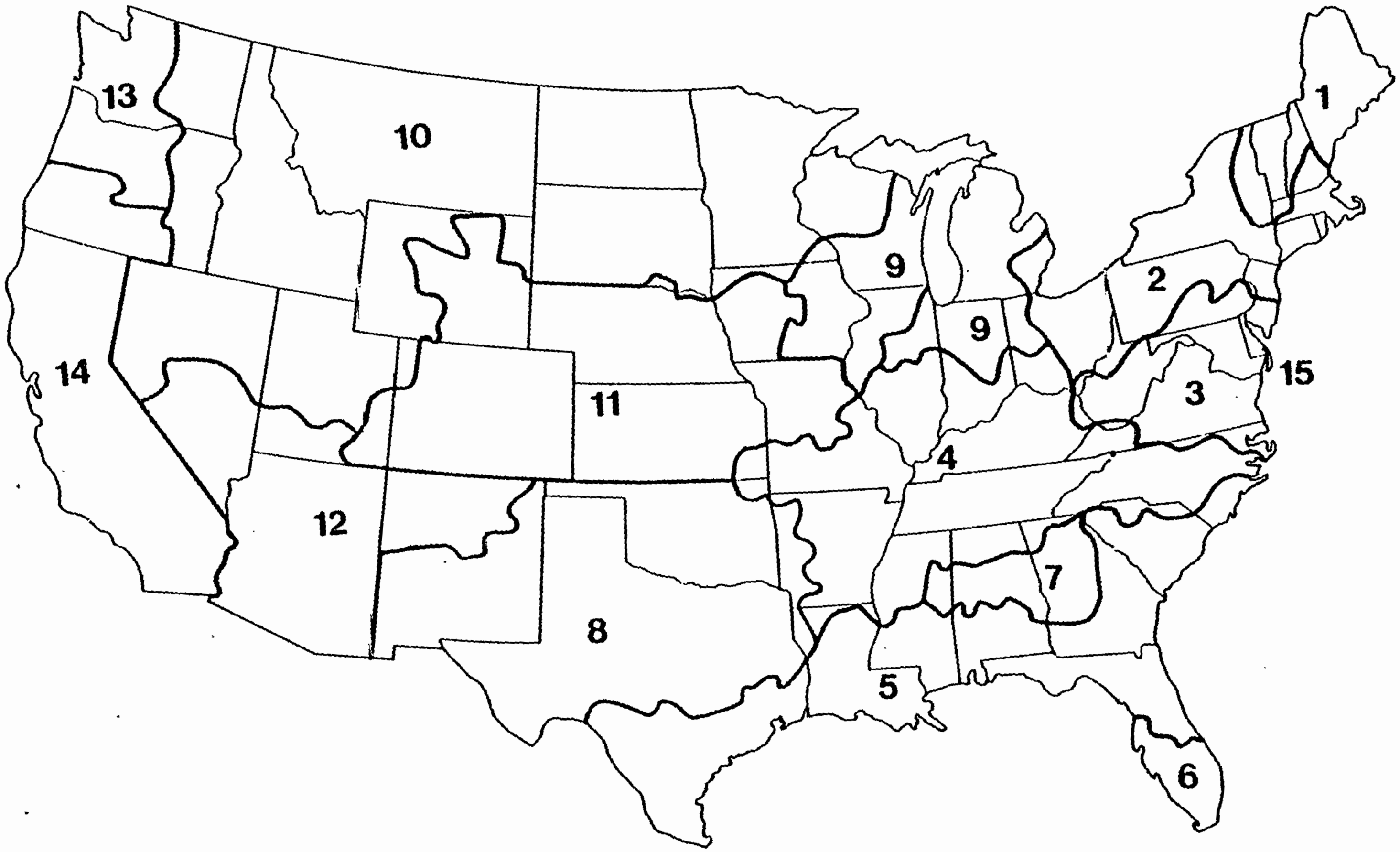
Solar heating and cooling systems collect sunlight and transfer the radiant energy in the form of sensible heat via a liquid or gaseous heat transfer medium. The heat is then transferred to the system's "load." The loads considered in this analysis are water heaters, space heating systems, a space cooling system, and storage units. The storage unit stores heat in either its sensible or latent form. Latent heat is the heat given off or absorbed in a process, other than change of temperature, such as heat of fusion or vaporization.

All SHACOB technologies collect and convert solar radiant heat to sensible heat by a solar collector. This heat can be used immediately or transferred to storage. The performance of each operation in the system is maintained by automatic or manual controls. An auxiliary system is usually available to supplement the output provided by the solar system.

Regional and Building Type Considerations

Since the economics of SHACOB systems depend on climate and building characteristics, life-cycle cost estimates are derived for 14 regions and nine building types. The 14 regions outlined on Map 1 represent climatic as well as cost regions. Regional costs vary because of climatic conditions, labor for installation, and the number of competitors bidding to install SHACOB systems. The nine building types represent the wide range of SHACOB applications from residential to commercial and industrial structures.

Costs in the following tables are based on manufacturers' quotes, actual systems built and operating, and MITRE Corporation's cost estimates presented in its SPURR model documentation. Costs were calculated using the SPURR-SHACOB model to account for building size and regional considerations. In most cases, costs for large systems were unavailable. These costs were based on engineering estimates of size and efficiency and reflect discounts for large quantities purchased. The limitations of market penetration models are well known. However, use of the SPURR model for this analysis is limited to the insolation data base and buildings inventory. The market penetration algorithm of SPURR is not used.



Regional Map for SHACOB Analysis

History

Solar energy has been used for centuries. In the United States, use of solar energy for SHACOB applications dates back to the late 1800s. In California, blackened water tanks were placed on rooftops exposed to the sun as a means of heating water. Later, these blackened water tanks were placed inside glazed wooden boxes to increase their efficiency. During the late 1920s, an estimated 10,000 solar water heaters were in use in California. However, by 1930, sales of solar water heaters had dropped considerably. Gas water heaters were more convenient and less costly. During the 1930s, high electricity prices made solar water heaters economically attractive and increased their use once again. By the end of the 1930s, electric rates had declined causing yet another decline in the use of solar hot water heaters.

At present, research and development work is underway to improve efficiencies and reduce the costs of SHACOB systems. Major research efforts are devoted to evacuated tube collectors and to desiccant cooling.

An Overview of Typical SHACOB Systems

Eight system designs are considered for SHACOB. These designs are based on studies of the systems' efficiencies and costs. Although SHACOB equipment varies widely, these system designs describe SHACOB systems in a way that normalizes results of the system cost analyses. In addition, absorption cooling is included in the typical system descriptions, but it has been deleted from the economic analysis at present because prototype systems require more electrical energy than conventional cooling systems do.

Three different hot water systems are considered in this analysis: a pumped system circulating potable water, a pumped system using a heat exchanger, and a thermosiphon system. Two space heating and hot water systems are considered: liquid and air heat transfer mediums. Two systems are presented below that provide space heating, hot water, and cooling. One system uses an absorption cooler for the cooling function; the other uses a heat pump as an auxiliary. Cooling for the latter is achieved by reversing the heat pump. All systems described here include storage. Storage size varies according to the system design, application, region, and building type. For cost reasons, storage is usually designed for one day carryover.

B. TYPICAL SYSTEMS DESCRIPTION AND COSTS

Hot Water

Three types of hot water systems are considered: a system with drain down freeze protection; a system with antifreeze as freeze protection; and a thermosiphon system. Drain down and thermosiphon systems circulate potable water; the system using antifreeze circulates a water/antifreeze solution and requires a heat exchanger. These systems are described in Figures II-1, II-2, and II-3. Storage tanks for homeowners are usually 60, 80, or 120 gallons depending on hot water consumption. Total annual loads for hot water are presented in Table II-1. Loads vary according to building type but are assumed not to vary from region to region.

Pumped system circulating potable water--The system considered for the cost analysis is a closed-loop, copper tube in aluminum fin, single-glazed, flat-plate collector circulating potable water from its storage tank. Hot water output from the storage tank becomes the input water to the demand tank. Freeze protection for this

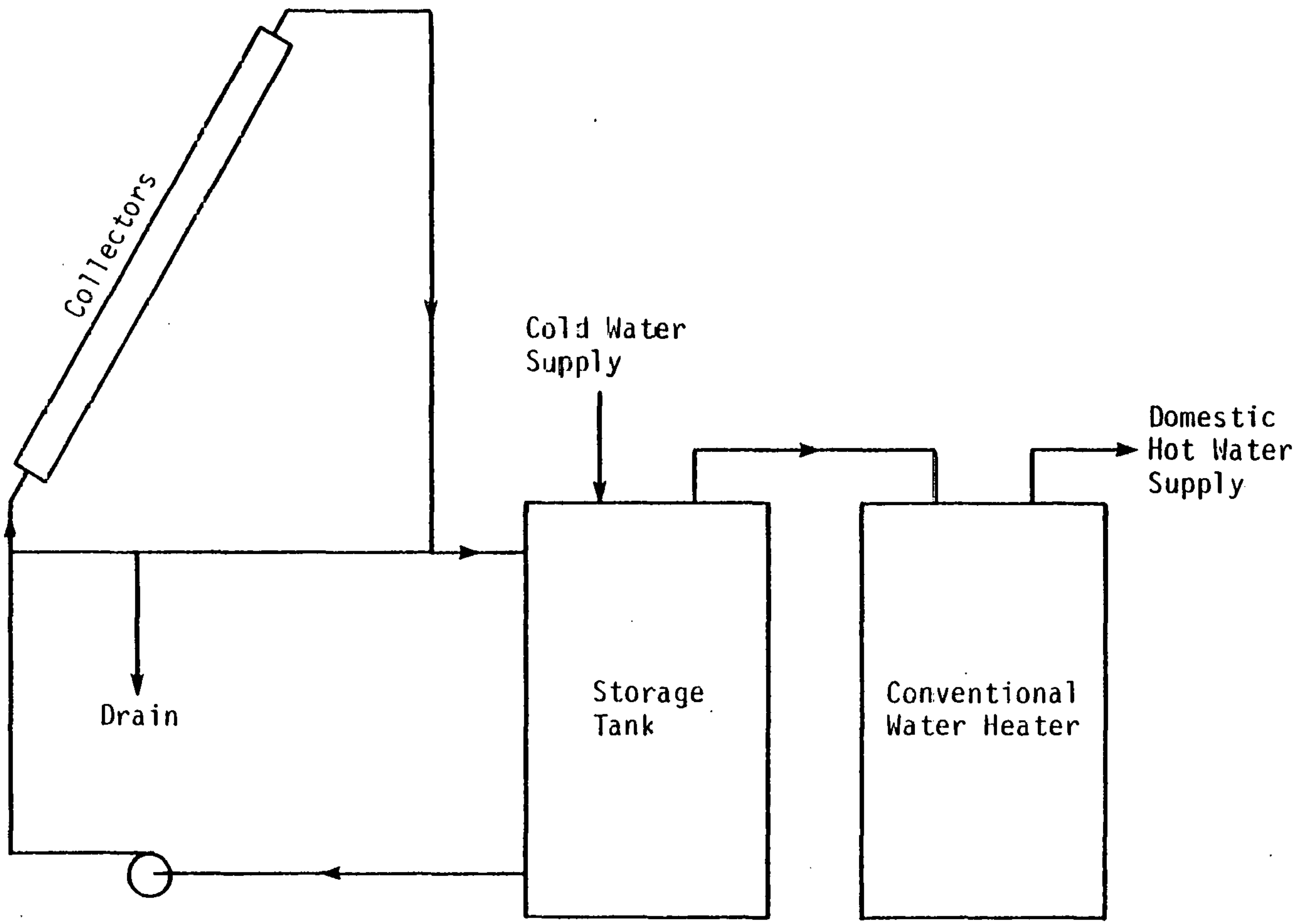


Figure II-1. Solar Hot Water System with Drain Down Freeze Protection

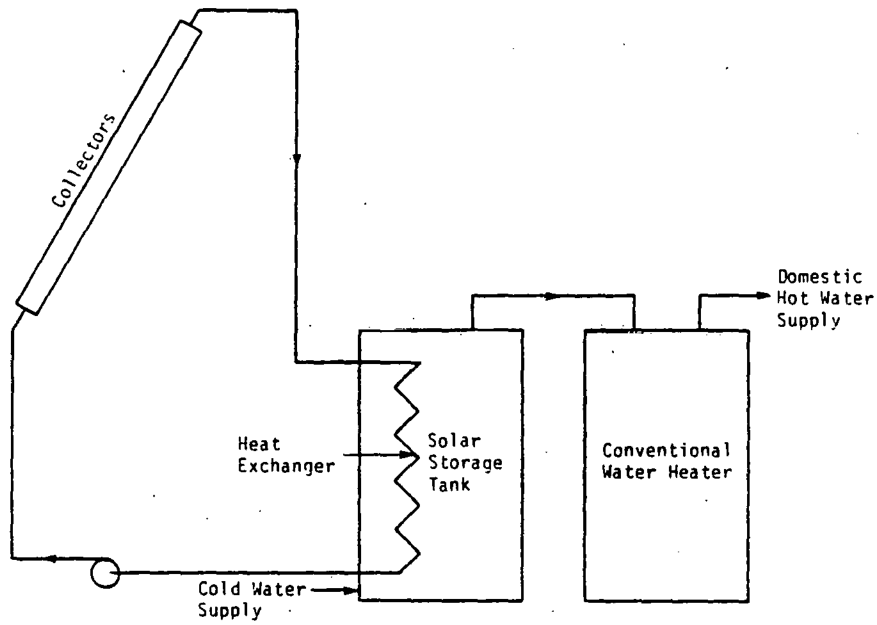


Figure II-2. Solar Hot Water System with Antifreeze as Freeze Protection

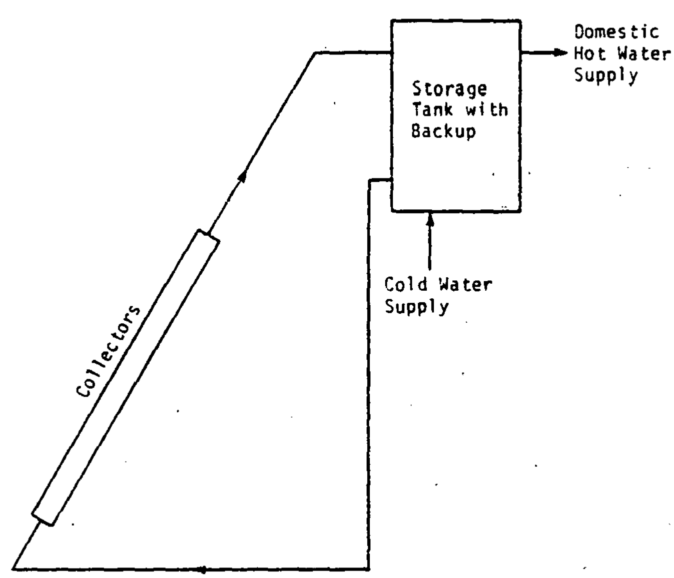


Figure II-3. Solar Thermosiphon Hot Water System

TABLE II-1

HOT WATER, TOTAL ANNUAL LOAD (MILLION BTU) IN 1978, NEW AND RETROFIT APPLICATIONS

	HOT WATER SYSTEM *	1 & 2 FAMILY	LOW RISE	AUDITORIUM	STORE, CLINIC	EDUCATIONAL	HOSPITAL	MALL	MOTEL	WARE-HOUSE
REGION 1	A.F.	21.	548.	13.	13.	645.	1562.	269.	269.	27.
REGION 2	A.F.	21.	548.	13.	13.	645.	1562.	269.	269.	27.
REGION 3	A.F.	21.	548.	13.	13.	645.	1562.	269.	269.	27.
REGION 4	A.F.	21.	548.	13.	13.	645.	1562.	269.	269.	27.
REGION 5	A.F.	21.	548.	13.	13.	645.	1562.	269.	269.	27.
REGION 6	T.S.	21.	548.	13.	13.	645.	1562.	269.	269.	27.
REGION 7	A.F.	21.	548.	13.	13.	645.	1562.	269.	269.	27.
REGION 8	P.W.	21.	548.	13.	13.	645.	1562.	269.	269.	27.
REGION 9	A.F.	21.	548.	13.	13.	645.	1562.	269.	269.	27.
REGION 10	A.F. or P.W.	21.	548.	13.	13.	645.	1562.	269.	269.	27.
REGION 11	P.W.	21.	548.	13.	13.	645.	1562.	269.	269.	27.
REGION 12	P.W.	21.	548.	13.	13.	645.	1562.	269.	269.	27.
REGION 13	P.W.	21.	548.	13.	13.	645.	1562.	269.	269.	27.
REGION 14	T.S.	21.	548.	13.	13.	645.	1562.	269.	269.	27.

* A.F. represents antifreeze hot water system costs, double glazed collectors with liquid storage.

P.W. represents potable water, hot water systems costs with double glazed collectors and liquid storage (Drain down freeze protection).

T.S. represents thermosiphon systems, single glazed collector with liquid storage.

system is provided by draining water from the collectors. This system is described in Figure II-1. Costs for this system appear in Tables II-2 and II-3 for new and retrofit applications respectively. This system is suitable for regions 8, 11, 12, and 13 and costs range from $2.00 to $15.00/MBtu across applications.

Pumped system using a heat exchanger--This system is a closed-loop, copper tube in aluminum fin, single-glazed, flat-plate collector using a water/antifreeze/corrosion-inhibitor heat transfer medium which transfers heat to a thermal storage tank via a dual walled heat exchanger. Hot water output from the storage tank becomes input water to the demand tank. The demand tank contains an auxiliary heater. This system may have only one tank, the demand tank that contains both heat exchanger and auxiliary heater. This system is described in Figure II-2, and costs are presented in Tables II-2 and II-3 for new and retrofit applications respectively. This system is analyzed for regions 1, 2, 3, 4, 5, 7, and 9. Costs range from a low of about $2/MBtu to a high of nearly $25/MBtu.

Thermosiphon systems--This system is suitable for operation in nonfreezing areas and, therefore, has limited use. The system does not require pumps, heat exchangers, or controls. Circulation occurs by the thermosiphon effect, wherein the storage tank is situated above the collector. The system is described in Figure II-3, and costs are presented in Tables II-2 and II-3. Thermosiphon systems are analyzed for California and Florida only and were assumed not to be reliable enough for large commercial applications. Costs range from a low of about $4/MBtu for new installations to $12/MBtu for retrofitting older homes.

TABLE II-2

HOT WATER, LIFE-CYCLE COST OF DELIVERED ENERGY (DOLLARS PER MILLION BTU) IN 1978, NEW INSTALLATIONS

	HOT WATER SYSTEM *	1 & 2 FAMILY	LOW RISE	AUDITORIUM	STORE, CLINIC	EDUCATIONAL	HOSPITAL	MALL	MOTEL	WARE HOUSE
REGION 1	A.F.	21.45	6.74	7.06	7.06	14.57	6.96	6.37	6.37	6.52
REGION 2	A.F.	19.61	6.00	7.04	7.04	11.98	5.89	5.77	5.76	6.11
REGION 3	A.F.	16.34	4.71	4.51	4.51	11.07	4.41	4.06	4.06	4.13
REGION 4	A.F.	10.97	2.87	2.63	2.63	8.66	2.99	2.71	2.71	2.39
REGION 5	A.F.	12.03	3.16	2.94	2.94	9.94	3.33	2.68	2.68	2.64
REGION 6	T.S.	7.52	1.83							
REGION 7	A.F.	10.79	2.46	2.38	2.38	8.95	2.56	2.35	2.35	2.17
REGION 8	P.W.	13.41	3.88	3.83	3.85	7.07	3.98	3.36	3.36	3.39
REGION 9	A.F.	17.79	4.51	4.73	4.73	12.39	4.66	4.24	4.24	4.37
REGION 10	P.W. or A.F.	13.43	3.86	4.35	4.36	9.84	3.96	3.72	3.72	4.00
REGION 11	P.W.	10.04	2.13	2.31	2.33	6.72	2.30	2.01	2.01	2.11
REGION 12	P.W.	6.58	1.98							
REGION 13	P.W.	10.52	3.11	3.41	3.41	8.43	3.16	3.03	3.03	3.12
REGION 14	T.S.	8.81	1.93							

*A.F. represents antifreeze hot water system costs, double glazed collectors with liquid storage.

P.W. represents potable water, hot water systems costs with double glazed collectors and liquid storage (Drain down freeze protection).

T.S. represents thermosiphon systems, single glazed collector with liquid storage.

TABLE II-3

HOT WATER, LIFE-CYCLE COST OF DELIVERED ENERGY (DOLLARS PER MILLION BTU) IN 1978, RETROFIT APPLICATIONS

	HOT WATER SYSTEM *	1 & 2 FAMILY	LOW RISE	AUDITORIUM	STORE, CLINIC	EDUCATIONAL	HOSPITAL	MALL	MOTEL	WARE HOUSE
REGION 1	A.F.	23.48	9.12	9.68	9.68	17.43	9.02	8.65	8.64	8.82
REGION 2	A.F.	20.73	7.53	8.53	8.53	13.40	7.34	7.19	7.19	7.59
REGION 3	A.F.	17.47	6.21	7.11	7.11	13.39	6.07	5.96	5.96	6.29
REGION 4	A.F.	13.49	4.75	5.40	5.40	10.54	4.61	4.55	4.55	4.85
REGION 5	A.F.	13.76	5.24	5.80	5.80	11.06	5.11	5.00	5.00	5.22
REGION 6	T.S.	8.92	3.84							
REGION 7	A.F.	11.92	4.24	4.97	4.97	9.52	4.09	4.09	4.09	4.43
REGION 8	P.W.	14.61	5.68	6.10	6.73	8.38	5.37	5.57	5.57	5.46
REGION 9	A.F.	18.91	6.62	7.54	7.54	14.82	6.52	6.35	6.35	6.68
REGION 10	P.W. or A.F.	14.67	5.46	6.09	6.11	10.70	5.35	5.26	5.26	5.49
REGION 11	P.W.	11.26	3.89	4.84	4.84	8.47	3.84	3.72	3.72	4.07
REGION 12	P.W.	9.48	4.39	4.41	6.38	3.48	3.58	3.58	3.58	4.21
REGION 13	P.W.	12.13	4.61	5.15	5.17	9.26	4.64	4.56	4.56	4.62
REGION 14	T.S.	10.26	3.71							

*A.F. represents antifreeze hot water systems costs, double glazed collectors with liquid storage.

P.W. represents potable water, hot water systems costs with double glazed collectors and liquid storage. (Drain down freeze protection).

T.S. represents thermosiphon systems, single glazed collector with liquid storage.

Solar Heating and Hot Water with a Liquid Heat Transfer Medium

The typical systems for space heating and hot water using a liquid heat transfer medium are copper tube in aluminum fin, double or single glazed collector closed loop system. Heat is transferred through a water-to-water heat exchanger for domestic hot water. A water-to-air heat exchanger supplies heat from the storage to the building. The storage system consists of a water tank sized to containing 1.5 to 2.5 gallons per square foot of collector. This system is described in Figure II-4, and costs appear in Tables II-6 and II-7 for new and retrofit applications respectively. Costs range widely from about \$5/MBtu to \$28/MBtu. Loads (Tables II-4 and II-5) differ because of different assumptions about housing insulation for new and older homes.

Solar Heating and Hot Water with Air Heat Transfer Medium

This system uses a flat-plate, double-glazed collector with a steel absorber plate. An air handling unit transfers hot air from the collector to the building or to a pebble bed storage unit. An air-to-water heat exchanger heats the water for domestic use. This system is described in Figure II-5, and costs are in Tables II-10 and II-11. Costs range from about \$3/MBtu to \$30/MBtu. Loads are presented in Tables II-8 and II-9.

Solar Heating and Hot Water with Absorption Cooling

This system provides solar heating, hot water, and cooling and uses an evacuated tube collector. To provide cooling, hot water is circulated to the absorption cooler. The auxiliary heater provides hot water for heating, hot water, and the absorption cooler. Storage for this system is similar to the heating and hot water system using a liquid heat transfer medium (HTM). The system is described in Figure II-6.

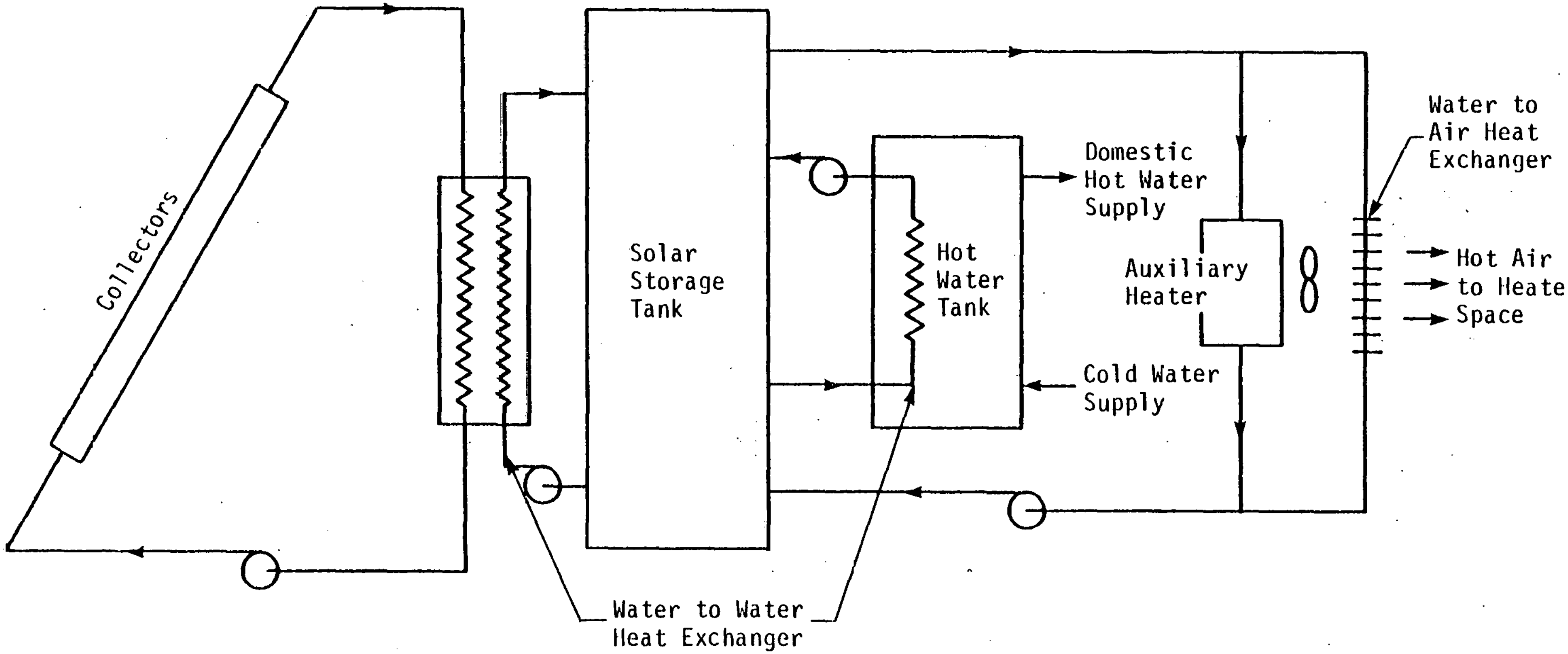


Figure II-4. Solar Space Heating and Hot Water System with Liquid Heat Transfer Medium

TABLE II-4

HEATING AND HOT WATER, TOTAL ANNUAL LOAD (MILLION BTU) IN 1978, LIQUID HEAT TRANSFER MEDIUM

	1 & 2 FAMILY	LOW RISE	AUDITORIUM	STORE, CLINIC	EDUCATIONAL	HOSPITAL	MALL	MOTEL	WARE-HOUSE
REGION 1	144.	1211.	3385.	997.	6685.	5559.	55961.	2011.	12785.
REGION 2	144.	1207.	3374.	993.	6663.	5541.	55775.	2004.	12743.
REGION 3	102.	857.	2394.	705.	4726.	3931.	39567.	1422.	9040.
REGION 4	94.	791.	2211.	651.	4366.	3631.	36549.	1313.	8350.
REGION 5	44.	367.	1025.	302.	2025.	1684.	16951.	609.	3873.
REGION 6 *	5.	43.	121.	36.	240.	199.	2008.	72.	459.
REGION 7	72.	608.	1699.	500.	3355.	2790.	28090.	1009.	6418.
REGION 8	66.	556.	1553.	457.	3067.	2551.	25678.	923.	5867.
REGION 9	155.	1306.	3650.	1075.	7207.	5994.	60337.	2168.	13785.
REGION 10	192.	1612.	4505.	1326.	8896.	7398.	74473.	2676.	17015.
REGION 11	141.	1181.	3300.	972.	6517.	5420.	54558.	1960.	12465.
REGION 12	44.	372.	1041.	306.	2055.	1709.	17204.	618.	3930.
REGION 13	115.	965.	2698.	794.	5327.	4430.	44592.	1602.	10188.
REGION 14*	44.	369.	1032.	304.	2038.	1695.	17060.	613.	3898.

*Systems are identical except for the number of glazings. Only one glazing was required for California and Florida.

TABLE II-5

HEATING AND HOT WATER, TOTAL ANNUAL LOAD (MILLION BTU) IN 1978, RETROFIT APPLICATIONS, LIQUID HEAT TRANSFER MEDIUM

	1 & 2 FAMILY	LOW RISE	AUDITORIUM	STORE, CLINIC	EDUCATIONAL	HOSPITAL	MALL	MOTEL	WARE-HOUSE
REGION 1	192.	1615.	4514.	1329.	8913.	7412.	74614.	2681.	17047.
REGION 2	192.	1610.	4499.	1325.	8883.	7388.	74367.	2762.	16990.
REGION 3	136.	1142.	3191.	940.	6302.	5241.	52756.	1895.	12053.
REGION 4	126.	1055.	2948.	868.	5821.	4841.	48732.	1751.	11134.
REGION 5	58.	489.	1367.	403.	2700.	2245.	22602.	812.	5164.
REGION 6*	7.	58.	162.	48.	320.	266.	2677.	96.	612.
REGION 7	96.	811.	2266.	667.	4474.	3721.	37453.	1346.	8557.
REGION 8	88.	741.	2071.	610.	4090.	3401.	34238.	1230.	7822.
REGION 9	207.	1742.	4867.	1433.	9610.	7992.	80449.	2890.	18380.
REGION 10	256.	2150.	6007.	1769.	11861.	9864.	99298.	3568.	22686.
REGION 11	187.	1575.	4401.	1296.	8690.	7226.	72744.	2614.	16620.
REGION 12	59.	497.	1388.	409.	2740.	2279.	22938.	824.	5241.
REGION 13	153.	1287.	3597.	1059.	7102.	5906.	59456.	2136.	13584.
REGION 14*	59.	492.	1376.	405.	2717.	2260.	22747.	817.	5197.

* Systems are identical except for the number of glazings. Only one glazing was required for California and Florida.

TABLE II-6

HEATING AND HOT WATER, LIFE-CYCLE COST OF DELIVERED ENERGY (DOLLARS PER MILLION BTU) IN 1978, RETROFIT APPLICATIONS, LIQUID HEAT TRANSFER MEDIUM, CONVENTIONAL SYSTEM AS BACKUP

	1 & 2 FAMILY	LOW RISE	AUDITORIUM	STORE, CLINIC	EDUCATIONAL	HOSPITAL	MALL	MOTEL	WAREHOUSE
REGION 1	28.61	10.76	11.11	11.41	25.97	10.30	10.32	10.95	10.15
REGION 2	20.59	14.40	14.81	15.25	20.60	13.74	13.73	14.57	13.93
REGION 3	20.65	7.95	8.86	9.12	20.06	7.42	8.15	8.57	7.64
REGION 4	16.14	12.11	13.45	13.83	17.21	11.22	12.15	12.94	11.52
REGION 5	20.61	7.87	10.53	10.89	22.27	7.31	8.39	8.93	8.24
REGION 6*	24.75	16.59	16.59	55.49	28.79	15.60	35.83	22.81	39.60
REGION 7	15.60	6.19	7.49	7.66	16.94	5.67	6.42	7.03	5.95
REGION 8	19.59	14.28	16.74	17.37	21.04	13.47	14.21	15.36	14.48
REGION 9	20.81	7.64	7.99	8.17	20.36	7.30	7.51	7.90	7.31
REGION 10	16.09	12.02	12.03	12.36	16.80	11.42	11.19	11.95	11.49
REGION 11	15.31	5.45	5.64	5.82	15.14	5.24	5.49	5.55	5.32
REGION 12	15.36	12.04	15.59	16.66	17.49	10.84	11.76	13.31	12.14
REGION 13	14.57	6.25	6.42	6.58	13.86	5.63	6.06	6.55	5.21
REGION 14*	17.39	13.21	10.67	15.76	19.95	12.33	14.26	13.43	14.80

* Systems are identical except for the number of glazings Only one glazing was required for California and Florida.

TABLE II-7

HEATING AND HOT WATER, LIFE-CYCLE COST OF DELIVERED ENERGY (DOLLARS PER MILLION BTU) IN 1978, NEW APPLICATIONS, LIQUID HEAT TRANSFER MEDIUM, ELECTRIC CONVENTIONAL SYSTEM AS BACKUP

	1 & 2 FAMILY	LOW RISE	AUDITORIUM	STORE, CLINIC	EDUCATIONAL	HOSPITAL	MALL	MOTEL	WAREHOUSE
REGION 1	27.17	8.38	8.75	8.99	23.77	8.54	8.06	8.47	9.49
REGION 2	19.50	12.18	12.85	13.25	19.36	12.13	11.81	12.47	13.37
REGION 3	19.65	5.48	6.27	6.49	18.99	5.47	5.60	5.92	6.07
REGION 4	15.28	10.08	11.46	11.85	16.26	9.59	9.97	10.72	10.22
REGION 5	19.01	3.95	5.93	6.15	20.80	4.16	4.95	4.90	5.54
REGION 6*	20.99	12.13	13.68	44.84	24.58	11.43	29.72	16.37	33.61
REGION 7	14.33	3.39	4.31	4.48	15.91	3.34	3.73	3.96	4.10
REGION 8	17.84	11.20	14.44	15.02	19.81	10.94	12.22	12.88	13.34
REGION 9	19.70	5.40	5.61	5.75	19.25	5.59	5.23	5.43	6.29
REGION 10	14.78	10.26	10.43	10.74	15.79	10.17	9.80	10.26	11.06
REGION 11	14.35	3.37	3.73	3.66	14.31	3.69	3.63	3.41	4.45
REGION 12	14.93	9.33	13.12	14.02	16.39	8.74	9.81	10.73	10.66
REGION 13	13.72	4.08	4.24	4.38	13.06	3.82	3.89	4.21	3.57
REGION 14*	15.31	9.64	8.06	12.42	17.46	9.32	11.06	10.11	12.97

*Systems are identical except for the number of glazings. Only one glazing was required for California and Florida

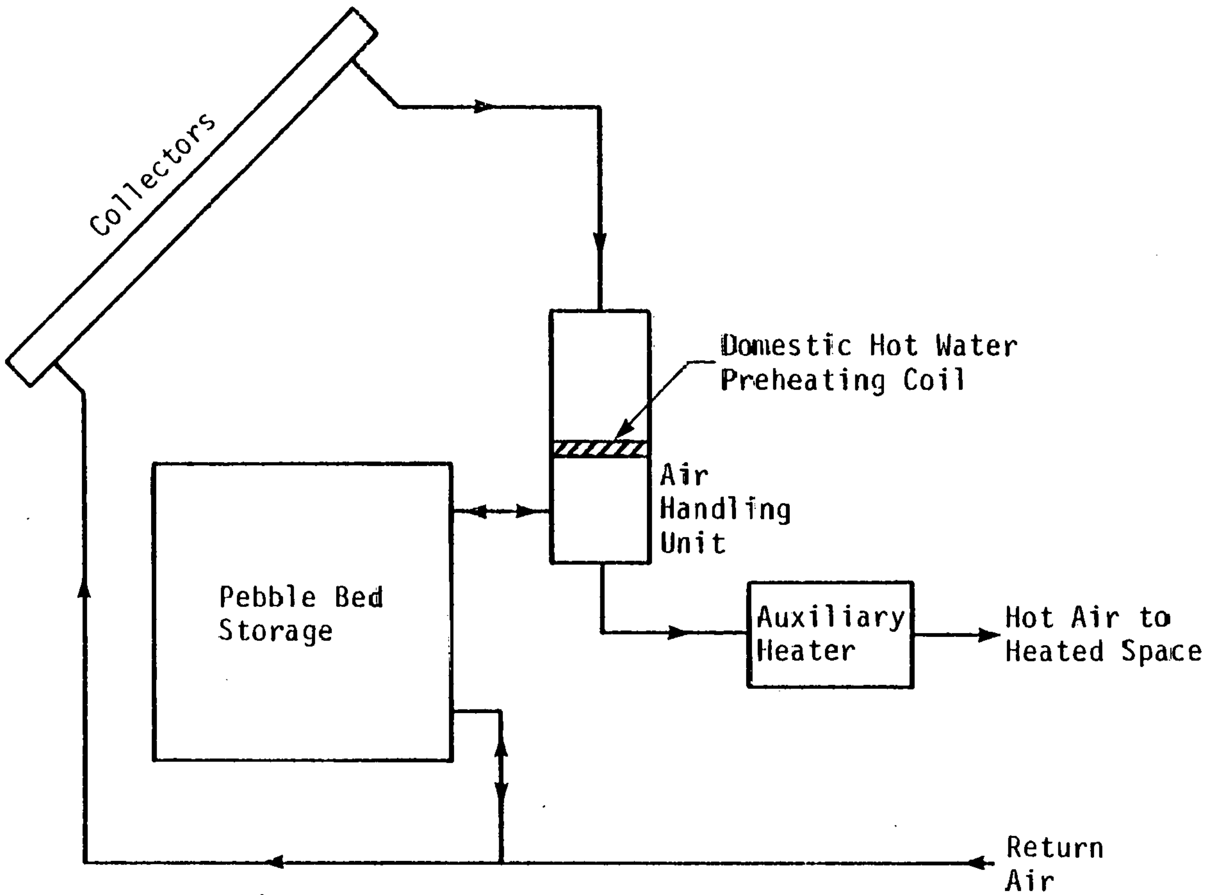


Figure II-5. Solar Space Heating and Hot Water System with Air Heat Transfer Medium

TABLE II-8

HEATING AND HOT WATER, TOTAL ANNUAL LOAD (MILLION BTU) IN 1978,
NEW APPLICATIONS, AIR HEAT TRANSFER MEDIUM

	1 & 2 FAMILY	LOW RISE	AUDITORIUM	STORE, CLINIC	EDUCATIONAL	HOSPITAL	MALL	MOTEL	WAREHOUSE
REGION 1	144.	1211.	3385.	997.	6685.	5559.	55961.	2011.	12785.
REGION 2	144.	1207.	3374.	993.	6663.	5541.	55775.	2004.	12743.
REGION 3	102.	857.	2394.	705.	4726.	3931.	39567.	1422.	9040.
REGION 4	94.	791.	2211.	651.	4366.	3631.	36549.	1313.	8350.
REGION 5	44.	367.	1025.	302.	2025.	1684.	16951.	609.	3873.
REGION 6	5.	43.	121.	36.	240.	199.	2008.	72.	459.
REGION 7	72.	608.	1699.	500.	3355.	2790.	28090.	1009.	6418.
REGION 8	66.	556.	1553.	457.	3067.	2551.	25678.	923.	5867.
REGION 9	155.	1306	3650.	1075.	7207.	5994.	60337.	2168.	13785.
REGION 10	192.	1612.	4505.	1326.	8896.	7398.	74473.	2676.	17015.
REGION 11	141.	1181.	3300.	972.	6517.	5420.	54558.	1960.	12465.
REGION 12	44.	372.	1041.	306.	2055.	1709.	17204.	618.	3130.
REGION 13	115.	965.	2698.	794.	5327.	4430.	44592.	1602.	10188.
REGION 14	44.	369.	1032.	304.	2038.	1695.	17060.	713.	3898.

TABLE II-9

HEATING AND HOT WATER, TOTAL ANNUAL LOAD (MILLION BTU) IN 1978, RETROFIT APPLICATIONS, AIR HEAT TRANSFER MEDIUM

	1 & 2 FAMILY	LOW RISE	AUDITORIUM	STORE, CLINIC	EDUCATIONAL	HOSPITAL	MALL	MOTEL	WAREHOUSE
REGION 1	192.	1615.	4514.	1329.	8913.	7412.	74614.	2681.	17047.
REGION 2	192.	1610.	4499.	1325.	8883.	7388.	74367.	2672.	16990.
REGION 3	136.	1142.	3191.	940.	6302.	5241.	52756.	1895.	12053.
REGION 4	126.	1055.	2948.	868.	5821.	4841.	48732.	1751.	11134.
REGION 5	58.	489.	1367.	403.	2700.	2245.	22602.	812.	5164.
REGION 6	7.	58.	162.	48.	320.	266.	2677.	96.	612.
REGION 7	96.	811.	2266.	667.	4474.	3721.	37453.	1346.	8557.
REGION 8	88.	741.	2071.	610.	4090.	3401.	34238.	1230.	7822.
REGION 9	207.	1742.	4867.	1433.	9610.	7992.	80449.	2890.	18380.
REGION 10	256.	2150.	6007.	1769.	11861.	9864.	99298.	3568.	22686.
REGION 11	187.	1575.	4401.	1296.	8690.	7226.	72744.	2614.	16620.
REGION 12	59.	497.	1388.	409.	2740.	2279.	22938.	824.	5241.
REGION 13	153.	1287.	3597.	1059.	7102.	5906.	59456.	2136.	13584.
REGION 14	59.	492.	1376.	405.	2717.	2260.	22747.	817.	5197.

TABLE II-10

HEATING AND HOT WATER, LIFE-CYCLE COST OF DELIVERED ENERGY (DOLLARS PER MILLION BTU) IN 1978, NEW APPLICATIONS, AIR HEAT TRANSFER MEDIUM, ELECTRIC CONVENTIONAL SYSTEM AS BACKUP

	1 & 2 FAMILY	LOW RISE	AUDITORIUM	STORE, CLINIC	EDUCATIONAL	HOSPITAL	MALL	MOTEL	WAREHOUSE
REGION 1	26.87	7.38	7.43	7.43	21.12	7.92	7.35	7.17	8.88
REGION 2	19.13	10.42	10.92	10.87	16.72	11.08	11.18	10.49	12.36
REGION 3	18.51	4.48	5.17	5.11	15.95	4.82	5.15	4.88	5.42
REGION 4	14.27	7.67	8.88	8.70	13.11	7.94	8.86	8.26	8.61
REGION 5	17.00	3.05	4.28	4.17	15.14	3.52	4.21	3.61	4.59
REGION 6	18.79	7.55	18.97	14.34	15.26	8.21	18.41	8.66	11.92
REGION 7	13.08	2.63	3.38	3.32	12.01	2.12	3.35	3.03	3.52
REGION 8	16.77	8.20	10.71	10.49	15.48	8.89	10.61	9.47	11.10
REGION 9	19.28	4.86	4.86	4.88	16.92	5.27	4.82	4.69	5.96
REGION 10	14.75	8.81	8.87	8.84	13.71	9.32	8.84	8.64	10.30
REGION 11	13.70	2.90	2.97	2.87	11.86	3.32	3.24	2.73	4.13
REGION 12	12.77	5.90	8.09	7.74	10.92	6.22	8.04	6.78	7.11
REGION 13	12.75	3.17	3.27	3.19	10.30	3.18	3.40	3.24	2.97
REGION 14	15.56	6.80	8.34	8.10	13.96	7.69	9.31	7.35	10.93

TABLE II-11

HEATING AND HOT WATER, LIFE-CYCLE COST OF DELIVERED ENERGY (DOLLARS PER MILLION BTU) IN 1978, RETROFIT APPLICATIONS, AIR HEAT TRANSFER MEDIUM, CONVENTIONAL SYSTEM AS BACKUP

	1 & 2 FAMILY	LOW RISE	AUDITORIUM	STORE, CLINIC	EDUCATIONAL	HOSPITAL	MALL	MOTEL	WAREHOUSE
REGION 1	28.26	8.97	9.49	9.43	23.37	9.09	9.49	9.25	9.22
REGION 2	20.24	12.02	12.69	12.62	18.15	12.28	12.67	12.37	12.71
REGION 3	19.81	6.09	6.94	6.77	17.08	6.18	7.15	6.64	6.31
REGION 4	15.23	9.10	10.34	10.04	14.02	9.22	10.59	9.84	9.46
REGION 5	18.57	5.45	7.04	6.69	16.45	5.56	6.98	5.92	5.90
REGION 6	21.82	10.22	22.60	17.51	17.63	10.81	22.13	11.71	14.13
REGION 7	14.36	4.31	5.31	5.03	12.98	4.37	5.40	4.89	4.48
REGION 8	18.35	10.46	12.54	12.22	16.94	10.85	12.48	11.43	11.80
REGION 9	20.41	6.33	6.76	6.68	18.09	6.42	6.86	6.62	6.25
REGION 10	15.93	10.09	10.41	10.36	14.90	10.27	10.38	10.23	10.57
REGION 11	14.64	4.28	4.58	4.53	12.86	4.35	4.88	4.44	4.43
REGION 12	13.76	7.55	9.57	9.15	11.93	7.68	9.51	8.12	8.06
REGION 13	13.89	4.47	4.69	4.50	11.09	4.42	5.14	4.76	4.04
REGION 14	18.25	9.33	10.98	10.73	16.12	9.96	12.13	10.02	12.27

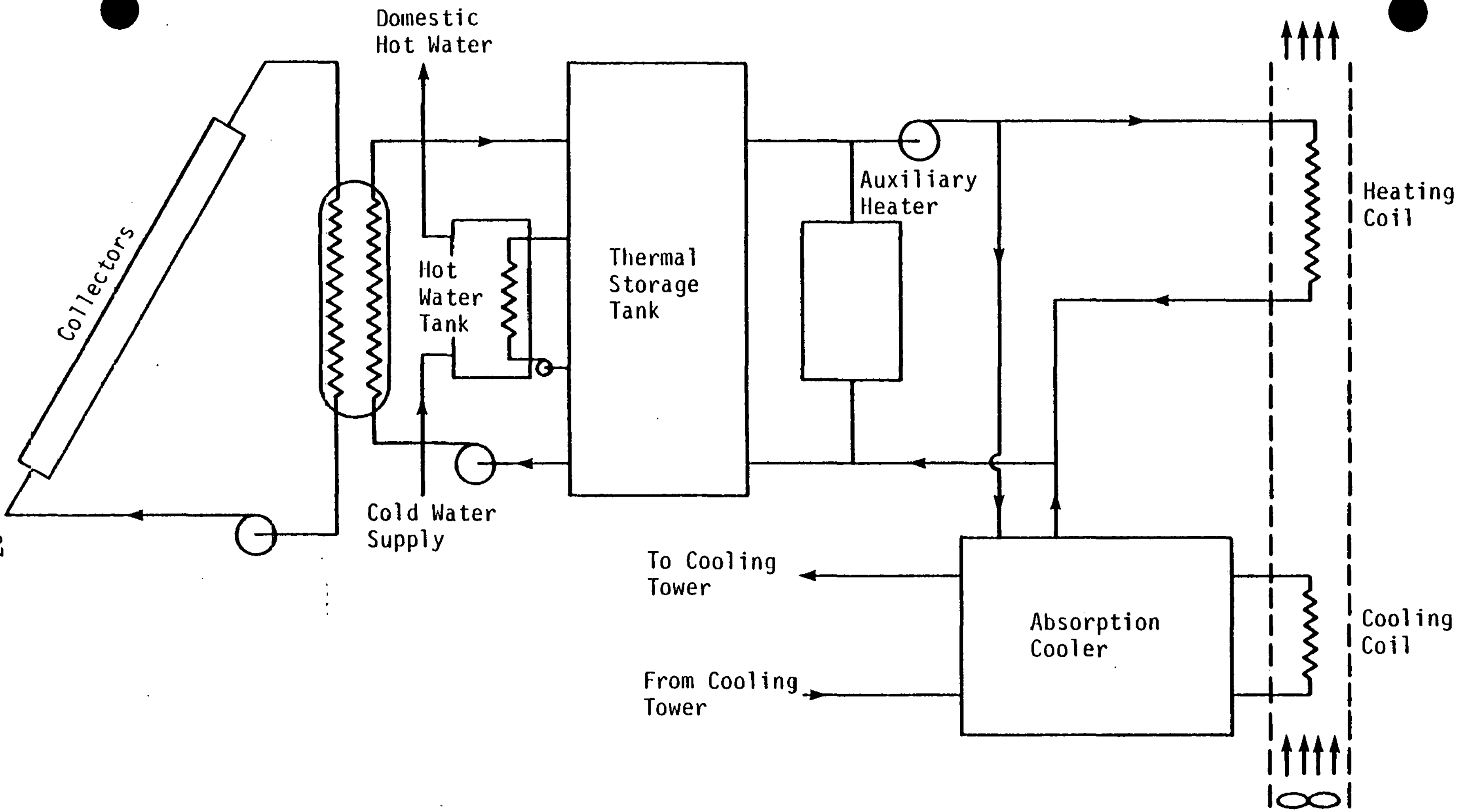


Figure II-6. Solar Space Heating, Hot Water and Absorption Cooling System

Solar Heating and Hot Water with Heat Pump

This system supplies heat directly to the heated space when the available temperature is sufficiently high. When the temperature of the storage is not sufficient to warm the heated space, heat is supplied by the heat pump. The heat pump provides an auxiliary source of heat with high efficiency. When storage temperatures drop below ambient temperature, the heat pump uses the ambient air as a heat source. When the ambient temperature is too low, heat is supplied by electric resistance heating elements. To provide cooling, the heat pump is reversed.

Storage in this system is similar to the heating and hot water system using a liquid HTM. The system is described in Figure II-7, and costs appear in Table II-12. No costs of delivered energy were computed for this system.

C. MARKET READINESS OF SHACOB TECHNOLOGIES

With the exception of absorption cooling, all systems described in this section are technically ready for commercialization. Absorption coolers are technically feasible, but their auxiliary electric energy requirements are higher than the energy requirements of conventional air conditioners.

A small commercial market for SHACOB presently exists in the United States. Large and small companies, government agencies, and utilities have participated in the development of the SHACOB market. The Federal Government's participation includes several legislative actions taken by Congress, such as the Energy Conservation and Production Act of 1976, the Solar Heating and Cooling Demonstration Act of 1974, the Energy Reorganization Act of 1974, the Solar Energy R&D and Demonstration Act of 1974, and the Non-Nuclear Energy R&D Act of 1974. State and local

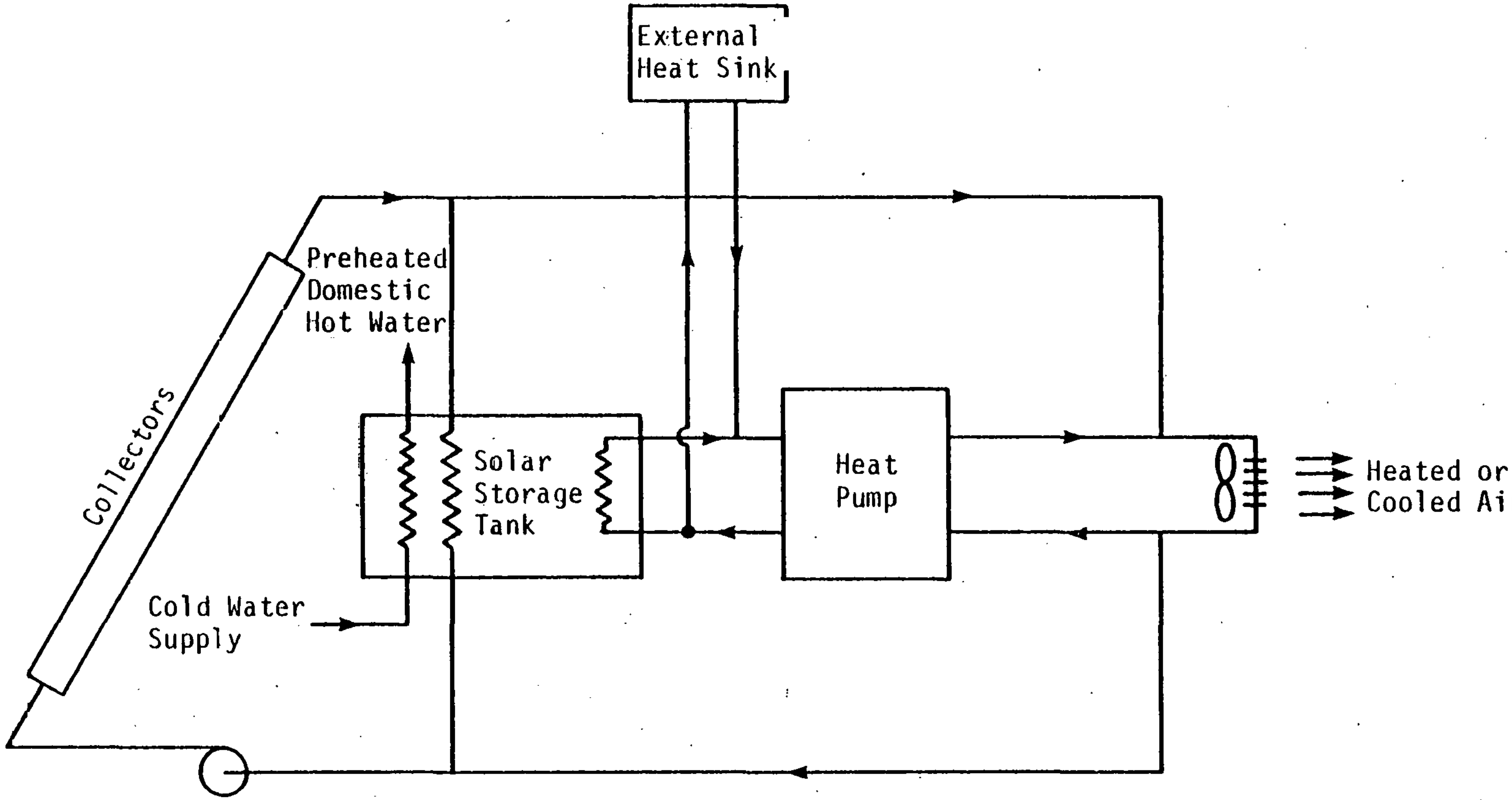


Figure II-7. Solar Space Heating and Hot Water System with Heat Pump Auxiliary and Heat Pump Cooling

TABLE II-12

SPACE HEATING AND HOT WATER SYSTEM WITH HEAT PUMP AUXILIARY AND COOLING

Building Types	Assumed Collector Area Size (sq ft)	Total Costs (1977 $)
1 & 2 Family	350	22,092
Low-Rise Residences	4,500	264,588
Auditoriums	6,500	567,900
Stores, Clinics	700	145,620
Educational Buildings	4,500	1,164,700
Hospitals	6,000	819,600
Malls	4,500	5,164,700
Motels	4,500	314,700
Warehouses	4,000	746,400

governments have also introduced programs promoting SHACOB. These programs include building code modifications, zoning ordinances, tax incentives and funding for R&D.

The utilities' role in SHACOB has been limited to providing backup energy to solar equipped buildings. However, some utilities have also been active in demonstration programs, such as the New England Electric Residential Solar Water Heating Experiment.

One definition of commercialization is "the point in time when the private sector begins to exercise a major initiative in the marketing of a new technology [II-4]." The Solar Energy Industries Association Index [II-15] lists 153 manufacturers of solar water heating, space heating and cooling, and swimming pool heaters. These manufacturers are located in 30 different states and have installed thousands of systems.

To determine the state of market readiness, the innovation process must be understood. (See Section I, Introduction above). SHACOB technologies are developed and are currently being introduced and diffused in the market. The introduction phase includes the establishment of full-scale production facilities which can contribute to low cost and consistent quality production. The market introduction phase is considered successful when volume production facilities are operating. SHACOB technologies are now entering the diffusion phase, in which the new technology is being adopted in selected markets.

To commercialize solar energy for the heating and cooling of buildings, a number of economic, legal, institutional, technological, and environmental problems must be overcome. Four economic barriers have been identified [II-16]: initial high capital costs, small savings over conventional systems, ownership, and banks' reluctance to finance SHACOB systems. Institutional barriers include the lack of building standards and codes for SHACOB systems, lack of installers, consumers' ignorance, and the interface of SHACOB with gas and electric utilities.

Legal barriers include sun rights issues, land use, and zoning ordinances. Technological problems are limited primarily to improving solar cooling systems in regard to life, efficiency, and reliability. Solar heating and space heating technology has demonstrated its technical feasibility. Environmental barriers are minor and most are related to processing raw materials for the manufacturing of SHACOB systems. In other respects, SHACOB systems are clean and environmentally benign.

Although there are barriers to SHACOB commercialization, the SHACOB industry is an increasingly viable one, and the process of SHACOB commercialization is well underway.

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III. PASSIVE APPLICATIONS

A. INTRODUCTION

Many cultures have traditionally made use of thatch, adobe, southern orientation, and other concepts and building materials that are now associated with passive applications. As conventional fuel prices have increased, interest in the design of buildings to complement the sun and climatic conditions has been rekindled.

Nature of Passive Applications

Proper architectural design can insure that a building will remain comfortable with little or no use of auxiliary conventional fossil fuels through the extremes of winter and summer as well as temperature variations from day to night. To insure comfort, building design must permit response to change in the environment. This is accomplished by allowing the building to "open" itself to the environment on sunny cold days (permitting collection of solar heat) and hot summer nights (permitting radiation of excess building heat to the night sky) and by allowing the building to "close" itself to the environment on cold nights; cold, cloudless days, and during hot summer days (to prevent unwanted heat loss and unwanted heat gain, respectively). Such a building collects and stores solar heat. A design employing materials and methods which utilize the sun's energy directly and are responsive to available site energies, is referred to as passive or energy-conscious, climate adaptive design [III-3]. Passive systems can be applied not only to residential and commercial space heating and cooling but to water heating, to food drying, and to some industrial processes as well.

Definitions and Definitional Problems

Passive systems have been subjected to vague and conflicting definitions. Controversies have existed in such areas as whether or not to include control devices within a definition of passive systems and whether to classify systems by type of storage or method of heat transfer. Some definitions include coefficients of performance and specify solar fraction requirements; others do not.

The definition used in this report is: A passive solar heating and cooling system is one in which all thermal energy flows through a building (from collectors to storage to use/load/space) are by natural means, enabling the system to function without external power. Heat flow from collector to storage or storage to space, when assisted by mechanical means such as with a small fan, is considered hybrid. When all heat flows are forced, the system is defined as active [III-2]. This definition does not include the use of insulation and control devices, which may be automated. Thus, a roof pond system whose heat transfer occurs by natural convection only but employs a night insulation system run on electricity is still considered a passive system.

Basic Considerations

Orientation and Architecture

To obtain the benefit of solar heat gain in winter when the sun angle is low, a building should maximize solar collectibility. To provide heat absorption and storage capabilities, architectural design should incorporate the use of appropriately placed massive materials. Concrete, stone, brick, and adobe are examples of massive materials that absorb and store solar heat during the day and radiate it into the structure at night. Eutetic salts and other phase change materials function in the same manner but do not require as much mass. This property of "thermal lag" keeps buildings cool during summer days and warm during winter nights. Most windows should be south-facing and may be constructed of one or more layers of glass or plastic. North-facing windows may be net losers of heat. East- and west-facing windows gain quite a bit of early morning and late afternoon heat; but low sun angles at these times make these windows more difficult to protect from overheating in summer than south-facing windows.

Additional Heat Storage

Collected solar heat may be stored in massive walls and floors. Storage devices include rock beds, waterbed-like plastic bags, concrete slabs, masonry blocks, and water-filled containers made of metal, plastic, or glass. Storage can be built into the interior of the structure by placing containers of water in the ceiling and in walls and closets or by placing a water-filled storage tank in a rock bin, directly inside the living space. Finally, rocks can be walled up in the center of the structure in such a way that cool air from the rooms will circulate naturally up over the solar heated collector and into the top of the rock bin, where heat is drawn off and stored in the rocks; cooler air then filters down to the bottom of the bin and into the rooms, beginning the cycle again (an air loop rock storage system) [III-4].

Shading and Reflection

If properly sized, roof overhangs for south-facing windows are effective protection against summer overheating. Deciduous shrubs and trees can be used to shade east and west walls. If trees are located at the southeast and southwest corners of a south-facing building they will shade both roof and walls. Winter solar gain is not obstructed because of loss of deciduous vegetation. Porches, verandas, or arcades can be used to shade walls in hot climates; but if used in temperate and cool climates, they obstruct desirable winter sun. Shutters, curtains, blinds, and shades can reduce sunlight penetration and, in some cases, redistribute light [III-21].

To increase the amount of solar radiation available to the collector, reflective surfaces may be used. Reflectors are normally placed on the ground beneath a vertical collector or at the top of a building and angled in such a way as to direct solar radiation to collectors or into the interior of the structure through clerestory windows. Reflective surfaces can easily be incorporated with night insulation systems such that removal of the insulation from the collector will expose the reflective surface.

Insulation and Conservation

All passive space heating and cooling applications use insulation, which not only protects the structure from excessive heat loss during cold weather but also acts as a buffer against unwanted summer heat gain. Insulation may be applied to the outside of a structure as well as to the inside [III-4].

Energy conserving actions must be taken to make the best use of solar heat gain by passive means. It is often difficult to distinguish energy conservation from the use of passive solar energy. Passive structures are normally designed to minimize heat load by insulation and architectural design as well as to maximize solar availability.

Overview of Generic Systems

The five passive designs considered are direct gain, thermal storage wall, convective loop (thermosiphon), thermal storage roof (roof pond), and sunspace (greenhouse) systems. (The roof pond system has been redefined as "thermal storage roof" to permit alternate forms of storage.) Within each of these five typical system designs are numerous variations, but the basic method of operation remains the same.

The National Program Plan for Passive Solar Heating and Cooling places the five typical systems in three categories: direct gain, indirect gain, and isolated gain. In the first category, the sun heats the living space directly, and heat is stored in massively constructed interior walls and floors. In the indirect gain category, the sun heats the thermal storage mass directly, rather than the living space, and heat is then transferred to the living space. The storage mass is designed to control heat transfer to the living space. In the isolated gain category, both collection and storage of solar heat are isolated thermally from the living space. The sun heats the collector, and heat is then transferred first to storage and then to the living space. Convective loop and attached sunspace/greenhouse systems are examples of the isolated gain type [III-22].

B. SELECTED SYSTEMS DESCRIPTIONS AND COSTS

Introduction

The following section presents general and system-specific operation descriptions and economic information for residential passive space heating and passive water heating. Five system types are described: direct gain, thermal storage wall, convective loop, thermal storage roof, and attached sunspace/greenhouse.

Most economic data result from engineering performance simulation and cost estimate studies. In only three of the studies reported costs based on actual experience with passive systems construction rather than estimates of incremental costs to be incurred if the system were actually built. These three sources were Yanda's 1977 Solar Sustenance Project (Greenhouse) report [III-30], Total Environmental Action's (TEA) Annual Review of Energy section on convective loop (thermosiphoning) systems [III-5], and Golubov and Leffler's "Thing" direct gain solar water heater [III-19].

Costs of storage, where additional storage other than that inherent in the base case building envelope is employed, are included in total incremental system costs. Wherever possible, these storage costs are broken out from total system costs. Operating and maintenance costs are not given in most of the studies; in some they are considered negligible, and two studies consider a conservative O&M cost estimate to be 1% of incremental system cost per year. Generally, passive maintenance costs run no higher than those for a conventional residence, with the exception of systems such as roof ponds which employ fully automated forms of movable insulation [III-27]. Costs are presented in $/MBtu where reported in such studies. We have not chosen to estimate passive system lifetimes so costs are presented in terms of dollars per million Btu per year.

Direct Gain Systems Descriptions

Direct gain systems are employed for space and water heating. Direct gain space heating systems absorb sunlight through south-facing glazings and store heat in floors (usually brick, plaster, masonry, or concrete) and walls (adobe, gypsum board, masonry, concrete, brick, slate, or plaster). Water containers or other heat-absorbing materials may be used for heat storage. Stored solar heat is radiated through the space at night and on cold days. By design, the building is an efficient live-in solar collector. South-facing clerestory windows and skylights allow rear and centrally located rooms to be heated and lighted by direct solar gain [III-25, III-26, III-27].

There are several direct gain solar water heaters: shallow trough, black plastic bag, and "Bread Box." The shallow trough system is a trough filled with cold water and set in the sun. This design requires the user not only to fill the tank in the morning and empty it in the afternoon or early evening but to put an insulating cover on the heater during cloudy weather. The user must also determine when the water is hot enough to drain.

The black plastic bag water heater resembles a filled water bed liner. Like the trough heater, the plastic bag heater is filled in the morning and drained in the evening. The heater can be set in the sun on a level platform or can be placed in a wooden box with a transparent cover over it, to increase collection efficiency and provide warmer water.

The Bread Box water heater is a glass covered water tank placed in an insulated box; it collects and stores solar heat. The south and top faces of the box should be double glazed to minimize heat loss. Insulated panels over the top and south glazing are opened during the day and closed at night. Reflective surfaces on the insulated panels reflect sunlight to the sides and back of the tank, increasing heat collection. The surfaces also serve to reflect thermal radiation back into the tank when the insulated panels are closed. Less user participation is required with the Bread Box than with the other systems described in this section [III-4].

Direct Gain Systems Costs

Taff et al. [III-28] report direct gain space heating costs based on eight variations of an active-passive hybrid system 300 sq ft in area, for a very well-insulated, new, 1,700 sq ft house. The modeling applies to Burlington, Vermont, and Montreal, Canada, two cities having nearly identical climates. Cost variations were obtained by modeling the absence or presence of night insulation (a thermal drape), a vertical (90°) or tilted (60°) south window, and varying the number of layers of glazing.

Storage for the system consists of additional thermal mass in the chimney, a concrete floor, and additional water storage in the basement. The system uses a differential thermostat and small, 1/10 horsepower fans. The fans create a simple loop duct over two living space levels [III-15].

Costs of system components are "based on estimates within an accuracy of ±10%"; they are not given separately for Burlington and Montreal. Cost of additional storage is included in the calculations. Total incremental first costs range from $1,250 to $2,251; system yields range from 3 to 21.6 MBtu/yr. The authors also calculate cost of delivered energy per year over the expected 20-year lifetime and report a range of $5.21 to $13.29/MBtu [III-28]. Design assumptions as well as these ranges are entered in the direct gain comparative cost chart presented in Table III-1.

TABLE III-1

DIRECT GAIN COMPARATIVE DESIGN ASSUMPTIONS, COST, AND PERFORMANCE RANGES, BY SOURCE

	Design Assumptions												Cost and Performance Ranges				
Source	Glazing Layers	Storage	Space Heat or DHW	Night Insulation	Reflectors	Fans	Optimized System	Estimated Lifetime (Years)	New or Retrofit	Tract or Custom Design	Actual or Simulated System	Number of Locations	Range System Yield (MBtu/yr)	Range Incremental Capital Cost/Sq Ft ($Base Year)	Range Incremental Capital Cost ($Base Year)	Operating and Maintenance Costs	Range Incremental Cost/MBtu/yr
Taff, et al. (1978)	Variable	yes	space	variable	no	yes	yes	20	new	n.a.*	sim.	2	3 - 21.6	$4.17 - $7.50 (1977)	$1,250 - $2,251 (1977)	n.a.	$104 - $538
Booz-Allen/TEA (1977)	2	yes	space	no	no	no	no	30	new	tract	sim.	8	11.4 - 15.8	$13.72 - $21.85 (1977)	$4,700 - $5,990 (1977)	negligible	$313 - $450
Cole & Kinney (1978)	2	yes	space	variable	no	no	yes[1]	20	new	tract	sim.	1	n.a.	n.a.	$4,000 - $7,100 (1977)	n.a.	$84 - $308
Golubov & Leffler (1978)	2	no	DHW	yes	no	no	n.a.	20	retro	n.a.	sim.	1	51.66	$24 (1977)	$10,055 (1977)	$27/year	$193

*n.a. = not available

[1]System size optimized until 400 sq ft area reached; then architectural constraint placed against larger sizes.

A second study reporting cost and performance results for simulated direct gain space heating systems is the Passive Systems report for Booz-Allen and Hamilton, Inc. by Total Environmental Action, Inc. (TEA). The study is based on a new, single family tract home built to ASHRAE 90-75 standards and simulates performance and cost of the system in eight cities across the United States.

The base case single family tract-type residence is a three-bedroom ranch house, 26 ft x 58 ft. It is a light wood-frame structure with a sliding glass door on the south side, the minimum required total window area, and a full basement. The direct gain system designed for the home requires 80% of the south wall area to be double pane glass (and 50% of the south wall area to be double pane glass in Atlanta, Fort Worth, and Los Angeles, to avoid a net heat loss through the glass in these cities).

Passive building performance for the direct gain-modified home is simulated according to an algorithm developed by TEA. TEA bases its cost estimates for passive systems on Means' Building Construction Cost Data, 1977 and Means' Building Systems Cost Guide, both of which give building construction average costs in effect on January 1, 1977. Labor costs are based on trade union agreements which were current at that time. Cost variations among cities are estimated from Means' city cost index, Building Construction Cost Data, 1977.

Yields for this system range from 11.4 to 15.8 MBtu/yr, and incremental costs from $4,700 to 5,990. Costs of delivered energy range from $313.33 to $450.38 per MBtu/yr [III-27]. Cost of delivered energy of the TEA-designed direct gain system is considerably higher than that of the other TEA-designed passive systems; this may be due to the high cost of concrete floor heat storage in the example [III-20]. Design assumptions and cost and performance ranges can be compared with those of other direct gain systems in Table III-1.

Cole and Kinney [III-16] use hourly weather data for Syracuse, New York, for a year to simulate a direct gain passive system for a well-insulated, 1,400 sq ft custom built residence. The passive system has vertical south-facing double pane windows (constrained by architectural considerations to be no more than 400 sq ft in area), additional built-in thermal mass for heat storage, and movable insulation to reduce heat loss at night and during cloudy weather. The building temperature is maintained at a minimum of 65°F between 7 a.m. and 10 p.m. and a 60°F minimum between 10 p.m. and 7 a.m.

Incremental costs for this system represent estimates based on data collected from experiences of individuals who have actually built passive residences. Incremental total system costs and costs of delivered energy were calculated for systems under two different window cost assumptions and three different auxiliary heat cost assumptions. Cost estimates assuming $10/sq ft windows do not appear in the original paper but were obtained through an interview with one of the authors [III-8]. This author feels that the $10/sq ft window cost is perhaps more realistic than the $5/sq ft window cost reported in the paper. In all cases, the incremental cost of thermal mass for heat storage is $3,000 and is included in all calculations. The cost of improved insulation is $1,000; this figure is also included in all calculations [III-16].

Incremental capital costs for the direct gain system across all assumptions (variations in insulation, shutters, cost of windows, and cost of auxiliary heating) range from $4,000 to $7,100. Cost of delivered energy ranges from $84 to $308 per MBtu/yr. Design assumptions as well as cost ranges are entered in Table III-1.

Golubov and Leffler [III-19] provide the only engineering cost and performance estimates for passive domestic hot water applications available at this time. A direct gain solar water heater (called "The Thing") is designed for the roof of a low-rise (five or six story) apartment building in New York City. This water heater is provided with city water (pressure in city lines is sufficient to bring water to a rooftop collector), which is stored and heated by the sun in a series of eight 6-inch diameter, 20-ft long fiberglass tubes. After heating, the water is drained to an auxiliary hot water heater in the basement. The entire series of tubes is insulated and covered by a single layer of glazing and enclosed in a steel truss, which is bolted to the parapet walls of the building.

A solar gain program for thermal analysis was developed for "The Thing" using simulation techniques developed at the University of Wisconsin. System costs are estimated by the designers, based on their experience in design and construction of active flat-plate collector solar hot water systems. Cost estimates are given for materials only and for materials plus labor.

Cost for materials plus labor were obtained by telephone from one of the authors [III-10], and costs for materials only were obtained from the original paper. These costs are for mass produced systems and assume the effect of a learning curve. Estimates are for a retrofit system and would be lower for new construction. First cost for a "Thing" system, materials plus labor, is estimated to be $24/sq ft, or $10,055 total. Cost of delivered energy is $193 per MBtu/yr. The system is expected to pay for itself during its 20-year lifetime. Design assumptions as well as costs (not ranges, since only one design is simulated for one location here) are given in Table III-1.

Table III-1 presents cost comparisons of the various direct gain space and water heating systems reported here. Aggregate data from all available sources indicate that the various systems modeled range from $1,250 to $10,055 on a first cost basis, and cost of delivered energy ranges from $84 to $538 per MBtu/yr.

Thermal Storage Walls Descriptions

The second passive space heating system considered is a massive wall built behind south-facing double glazing. Several types of thermal storage walls are discussed below: Trombe walls, water walls, and concrete-and-water walls. The wall is painted a dark color for increased absorptivity and placed so that several inches of air space separate it from the glazing, thereby reducing heat loss. Solar heat is collected and stored in the wall and radiated into the structure.

The Trombe wall, named for Felix Trombe who was the first to employ this type of wall in his home in Odeillo, France, is a massive thermal wall with vents along the top and bottom to permit natural convection. Cold air from the room behind the storage wall passes through the bottom vents, where it is warmed by solar heat between the wall and the glass. As it warms, it rises until it reaches the top vents, where it again enters the room. The air moves in a thermocirculatory pattern, and the building is continually warmed by convection [III-26]. Dampers and/or one-way vents located at the top and bottom wall openings prevent reverse thermocirculation and heating of the structure in summer [III-27]. Trombe walls, like the convective loop applications described in the next section, employ the thermocirculation principle but include storage as well.

Water walls are collectors filled with water rather than solid concrete or masonry. A well-known water wall is drumwall which is made of 55-gallon oil drums filled with water, painted flat black, and stacked behind south-facing glass. A manually operated movable insulating shutter is used with the drumwall to prevent heat loss at night and during cloudy, cold weather and to prevent unwanted heat gain during warm weather. The shutters are made of aluminum, which acts as a reflector when the shutters are down.

A second type of water wall is made of a single, water-filled metal container placed behind south-facing glass. Insulating shades are drawn at night and on cloudy days to conserve heat stored in the wall.

The third type of water wall collector is a fiberglass-reinforced polyester cylinder collector. These cylinders can be placed directly behind a south wall within the room, or a thin vented wall may be placed between the collectors and the room. Heat is transferred by natural or forced convection through the vents.

A concrete-and-water wall is a masonry block wall whose cavities are filled with vinyl water bags. The water not only increases the heat storage capacity of the concrete wall but serves to better facilitate heat flow by conduction to the interior of the building. Because the wall's outer surface is kept cooler in this manner, the concrete-and-water wall collects more heat per square foot than other thermal storage walls [III-4].

Thermal Storage Wall Costs

A simulation study by Scott Noll at Los Alamos Scientific Laboratory integrates variations in Trombe and solid wall performance and design with considerations of comfort and cost to derive an optimally sized thermal storage wall system.

Preliminary results are reported for both wall types in Albuquerque. Cost estimates for the systems are based upon design work by solar architects.

The building modeled is a new, 1,500 sq ft tract-type residence. Thermal storage walls are solid or Trombe type concrete masonry construction and range from 4 to 20 inches in thickness. Results of performance simulation and cost estimation for eight optimized systems--four solid and four Trombe wall--are as follows: System yields range from 22.68 to 40.32 MBtu/yr; collector areas range from 360 to 1,121 sq ft; thickness ranges from 0.667 to 1.667 ft; total incremental costs range from $3,057 to $8,165; and cost of delivered energy ranges from $106.51 to $213.67 per MBtu/yr. In addition, years to payback range from 8 to 17 [III-11, III-23]. Design assumptions, cost ranges, and performance ranges for these optimized systems are entered in the thermal storage wall comparative table, Table III-2.

A study being undertaken by Noll, Roach, and Ben-David [III-11, III-24] employs a Trombe wall design for a new home developed by solar architects and designed to conform to conventional tract home design, size, and construction. A simulation model is then employed to estimate the performance of the system in one unspecified city chosen to represent each of the 48 continental states. (Weather variability within each state is not accounted for.) The system is standardized over all regions, with the following parameters: a 1,500 sq ft dwelling, an 18-inch thick Trombe wall with double glazing, an allowable temperature range of 70°F $\pm$ 5°F, and no night insulation system. Collector area is variable even though thickness is held constant.

Costs are based on estimates of required materials from detailed architectural drawings of the Trombe wall system and from estimates of labor time and rates for incremental construction

TABLE III-2

THERMAL STORAGE WALL COMPARATIVE DESIGN ASSUMPTIONS, COST, AND PERFORMANCE RANGES, BY SOURCE

	Design Assumptions												**Cost and Performance Ranges**				
Source	Glazing Layers	Storage	Space Heat or DHW	Night Insulation	Reflectors	Fans	Optimized System	Estimated Lifetime (Years)	New or Retrofit	Tract or Custom Design	Actual or Simulated System	Number of Locations	Range System Yield (MBtu/yr)	Range Incremental Capital Cost/Sq Ft ($Base Year)	Range Incremental Capital Cost ($Base Year)	Operating and Maintenance Costs	Range Incremental Cost/MBtu/yr
Noll (1978)	vari-able	yes--variable solid or Trombe wall	space	no	no	no	yes	30	new	tract	sim.	1	22.68 - 40.32	$7.98 - $14.29 (1978)	$3,057 - $8,615 (1978)	1% of total cost/year	$106.51 - $213.67
Noll, Roach & Ben-David (1978)	2	yes--18" thick Trombe wall	space	no	no	no	no	30	new	tract	sim.	48	0.578 - 68.006	$10.75 - $16.61 (1978)	$124 - $47,930 (1978)	1% of total cost/year	$110.69 - $887.43
Booz-Allen/TEA (1977)	2	yes--10" thick Trombe wall	space	no	no	no	no	30	new	tract	sim.	8	8.9 - 18.2	$8.48 - $9.83 (1977)	$2,520 - $2,920 (1977)	negligible	$150.55 - $324.44
Fraker & Glennie (1976)	vari-able	yes--Trombe wall	space	variable	yes	yes	vari-able[1]	40[2]	new	both[3]	sim.	1	20.2 - 31.5	$8.27 - $12.19 (1976)	$5,291 - $7,803 (1976)	n.a.*	$228.67 - $261.93
Fraker (1977)	2	yes--Trombe wall	space	yes	yes	no	yes	20[4]	new	custom	sim.	1	53.06	n.a.	$7,858 (1977)	n.a.	$148

*n.a. = not available

[1]An attempt was made to optimize system performance for that particular residence.

[2]With permission of Larry Lindsay, Princeton Energy Group. This figure is based on conservative estimate by Hila Anderson, Senior Industrial Engineer, National Association of Home Builders Research Lab, May 19, 1978.

[3]Custom prototype with potential tract application.

[4]System expected life is 20 years, but Kalwall tubes may develop pinhole leaks before that time [III-9].

required. Adjustments for the various cities are made, using city indexes provided in the Appendix of Means' Building Construction Cost Data.

The rationale for designing a system with a very thick wall and no night insulation represents an attempt to bring passive concepts to the mass market. A thick wall derives as much comfort as possible without user participation to assure that comfort is maintained. The system's perhaps greater than optimal amount of thermal mass acts as an effective damper against wide temperature swings.

Across all solar fractions and states, system yields range from 0.578 to 68.006 MBtu/yr; incremental capital costs range from $124 to $47,930; costs per square foot range from $10.75 to $16.61; and cost of delivered energy ranges from $110.69 to $887.43 per MBtu/yr. These ranges, along with pertinent design assumptions, are entered in Table III-2.

Total Environmental Action, Inc. (TEA) includes a Trombe wall system in its passive design cost and performance calculations. The "Sunrise" Trombe wall replaces 64% of the south wall area of the tract-type residence described in the previous section on Direct Gain systems. The system is a solid, 10-inch thick concrete block wall with top and bottom vents. The system also includes a one-way vent to prevent reverse thermosiphoning and a manually operated damper to limit excess solar heat collection.

Simulation of system performance is according to the TEA passive performance algorithm described in the previous section. Table III-2 shows cost and performance ranges and design assumptions compared with results of other thermal storage wall studies. System yields range from 8.9 to 18.2 MBtu/yr; first costs range from $2,520 to $2,920; cost of delivered energy ranges from

$150.55 to $324.44 per MBtu/yr. System costs include heat storage [III-27].

Harrison Fraker, Jr. and William L. Glennie [III-17] simulated performance and estimated capital costs of a theoretical passive hybrid Trombe wall system designed for an existing home near Princeton, New Jersey. The home is a one-story, well-insulated, single family frame residence of approximately 1,680 sq ft.

The Trombe wall collector is a solid concrete block, 8 ft x 80 ft, painted black on the outside, and triple-glazed. Eight fans are spaced along the bottom to enhance convective air movement around both sides of the wall. Four 8 ft x 20 ft insulated shutters to prevent heat loss swing down to ground level and serve as reflectors by day, increasing the insolation absorbed by the collector on a typical day by 52%.

Performance of the system was simulated using derived performance equations and hypothetical weather data. Cost figures are based on available estimates of local nonunion contractors' time and wage rates and on suppliers' prices for materials delivered to the site. When costs were not available from the above sources, they were obtained from Building Construction Cost Data, 1976, 1976 Cost Guide for General Building Construction, and Solar Heated Houses for New England (with costs adjusted for Princeton).

Cost and performance results are presented for three Trombe wall case simulations. The three cases are studies attempting to optimize system Btu yield rather than cost. Cost and performance ranges are as follows over all three cases: incremental capital cost, from $5,291 to $7,803; incremental capital cost per square foot, from $8.27 to $12.19; system yield, from 20.2 to 31.5 MBtu/yr; and cost of delivered energy from $228.67 to

$261.93 per MBtu/yr. Results of this study are compared to design, cost, and performance data from other thermal storage wall studies in Table III-2.

Harrison Fraker, Jr. [III-18] simulates performance and estimates costs associated with a proposed East Windsor, New Jersey residence which is to have a passive water wall and focusing roof aperture system.

The water wall consists of twenty 8-ft water storage tubes, 12 inches in diameter, standing between south-facing double glazing and a stud wall. A hinged shutter/reflector swings down from the glazed surface to act as a reflector by day and swings back up to insulate against heat loss at night and on cloudy days.

The focusing roof aperture system components are a double glazed reflective surface with a reflector/shutter and five 18-inch diameter water storage tubes. The water storage tubes are located at the base of the north wall, and the reflectors are angled so as to focus most available daily solar radiation on the storage tubes.

Performance of both the water and focusing aperture systems is modeled, and monthly heating performance figures for the house are estimated and aggregated into a yearly estimate. Cost figures are based on materials and labor (carpenter, glazer, and laborer) estimates for the combined systems. System yield is estimated to be 53.06 MBtu/yr; incremental capital cost, $7,858; and cost of delivered energy, $148 per MBtu/yr. Cost of storage is included in the materials and labor cost estimates. Table III-2 compares design, cost, and performance of this system with other thermal storage wall systems.

From Table III-2 ranges for cost and performance can be derived over all available system data. System yields range from 0.578 to 68.006 MBtu/yr; total incremental system costs range from $124 to $47,930; and costs of delivered energy range from $106.51 to $887.43 per MBtu/yr.

Convective Loop (Thermosiphoning) System Descriptions

Three types of convective loop systems are considered: air walls, water walls, and convective loop water heaters. Convective loop air walls draw cool air from the room behind the collector through the bottom vents. Air is heated in the space between the wall and the south-facing glass and allowed to reenter the room through the top vents. Because no thermal mass is included here to delay heat flows into and out of the building, the glass should be insulated by other means to reduce heat loss when the sun is not shining.

Another type of convective loop air wall (which may include a fan for forced circulation) is made by placing louvers, which are much like venetian blinds, between two layers of glass or plastic. The louvers are sunlight-absorbing black on one side and sunlight-reflecting silver on the other side. The louvers can be positioned in any of a number of configurations to cover a range of maximum to minimum solar gain [III-3].

In the convective loop water wall system, water is the medium which circulates (and stores) heat. A black-painted metal collector and storage tank are placed behind a south-facing glass wall. As the water is warmed by solar radiation, it rises into the heat storage tank, and the structure below receives radiant heat from the bottom surface of the storage tank. Cooled water at the bottom of the tank then flows back down the back of the collector, warms, and begins rising along the heated collector surface to the tank, completing the cycle [III-4].

Hot water can be provided using the convective loop principle. Without the aid of a pump, cool water from the bottom of a storage tank flows to the bottom of a separate collector, where it is heated. Hot water rises and is collected at the top of the collector, channeled back to the storage tank, and drawn off for use from the top of the tank. The system may be drained so that water will not freeze in the pipes during cold weather [III-27].

Convective Loop (Thermosiphoning) Costs

The Total Environmental Action, Inc. (TEA) report describes a new, single family tract home built to ASHRAE 90-75 standards, with a convective loop air system. Performance of the system is simulated in eight cities across the United States, and cost is estimated for the system in each city. The residence is the same three bedroom ranch home described in the direct gain section.

The air panels used in the residence replace 64% of the south exterior wall area in the northern cities and 34% in the southern cities. A one-way vent at the bottom of the panels prevents reverse thermocirculation, and excess heat collection is prevented by a manually operated damper. The system includes no storage other than the existing interior finish of the wall.

First costs range from $1,010 to $2,100 (net of conventional wall construction) across the eight cities; system yields range from 8.2 to 20.1 MBtu/yr; and capital costs per MBtu/yr range from $86.44 to $146.85 [III-27].

Another source of cost data for convective loop air panel systems is a second TEA study [III-5]. The air panel system described in this report is composed of tempered double-pane insulating glass, a corrugated metal black-painted absorber plate, rigid insulation and interior finish, and air grills and backdraft dampers. The air panel system is built into and replaces the lightweight frame south wall of a building.

Based on their experience in design and construction of convective loop air systems, Anderson and Michal [III-6] cite materials cost for such systems ranging from $3.50 to $4/sq ft, in 1976 dollars. Net installed costs range from $3.80 to $7.70/sq ft. No cost information on convective loop water walls was found in the literature. For thermosiphoning water heater costs, see systems descriptions and costs, hot water, Chapter II of this report.

The Total Environmental Action/Booz-Allen and Hamilton report provides the only relevant available convective loop systems cost ranges. First costs range from $1,010 to $2,100; yields range from 8.2 to 20.1 MBtu; and cost of delivered energy ranges from $86.44 to $146.85 per MBtu/yr. (See Table III-3.)

Thermal Storage Roof (Roof Pond)

A thermal storage roof (roof pond) system combines solar heat collection and storage and a solar cooling capacity in a flat roof. One or more plastic or polyethylene storage bags filled with water are placed atop a strong, thermally conductive roof and ceiling to form shallow "ponds" (forms of storage other than water may be employed). Solar heat is absorbed by the storage medium and radiated into the house through the ceiling. Movable insulation is required in thermal storage roof installations because sun and collector angles are wrong for each other. The summer sun, being higher in the sky, provides more input for a thermal storage roof system than does the winter sun. Insulation is moved aside during sunny cool days and moved back into place during cool nights and cold sunless periods. This procedure is reversed in summer. Insulation is kept in place during hot days and moved aside at night, to allow the storage medium to radiate

TABLE III-3

CONVECTIVE LOOP COMPARATIVE DESIGN ASSUMPTIONS, COST, AND PERFORMANCE RANGES, BY SOURCE

	Design Assumptions												Cost and Performance Ranges				
Source	Glazing Layers	Storage	Space Heat or DHW	Night Insulation	Reflectors	Fans	Optimized System	Estimated Lifetime (Years)	New or Retrofit	Tract or Custom Design	Actual or Simulated System	Number of Locations	Range System Yield (MBtu/yr)	Range Incremental Capital Cost/Sq Ft ($Base Year)	Range Incremental Capital Cost ($Base Year)	Operating and Maintenance Costs	Range Incremental Cost/MBtu/yr
Booz-Allen/ TEA (1977)	2	no	space	no	no	no	no	30	new	tract	sim.	8	8.2 - 20.1	$6.13 - $7.07 (1977)	$1,010 - $2,100 (1977)	negligible	$86.44 - $146.85
TEA (1977; Annual Review of Energy)	2	no	space	n.a.*	n.a.	no	n.a.	25	new	n.a.	actual	n.a.	n.a.	$4.80 - $7.70 (1977)	n.a.	negligible	n.a.

*n.a. = not available

excess heat to the night sky [III-25]. The efficiency of thermal storage roof systems in winter can be improved by adding reflectors to the system.

Harrison Fraker, Jr. and William L. Glennie [III-17] estimate performance and capital costs for a theoretical roof pond system designed for an existing home near Princeton, New Jersey. The pond is 12 inches deep, 8 ft wide, and 80 ft long and is separated from the roof joists by a corrugated steel plate. The pond is contained between two layers of plastic, the top layer a PVF film which allows light to enter the pond but prevents evaporation. The bottom plastic layer is a standard plastic roofing material. The glazing system above the PVF-covered pond is composed of one layer of fiberglass and one layer of teflon film.

Performance of the system was simulated using hypothetical weather data and derived performance equations. Cost figures are based on available estimates of local nonunion contractors' time and wage rates and on suppliers' quoted prices of materials delivered to the site.

Cost and performance results were obtained for three roof ponds. The three cases were studied in an attempt to optimize system performance (Btu yield) for this residence. Ranges for all systems are as follows: system yield, from 5.82 to 25.2 MBtu/yr; incremental first cost, from $6,356 to $9,077; and cost of delivered energy, from $366.40 to $1,092.10 per MBtu/yr. Table III-4 presents design specifications and associated cost and performance ranges for all cases.

Total Environmental Action's (TEA) cost and performance study includes a roof pond design whose performance is simulated and cost estimated for the three southern cities of the eight cities considered. System components include metal roof decks and vinyl

TABLE III-4

ROOF POND (THERMAL STORAGE ROOF) COMPARATIVE DESIGN ASSUMPTIONS, COST, AND PERFORMANCE RANGES, BY SOURCE

	Design Assumptions													Cost and Performance Ranges				
Source	Glazing Layers	Storage	Space Heat or DHW	Night Insulation	Reflectors	Fans	Optimized System	Estimated Lifetime (Years)	New or Retrofit	Tract or Custom Design	Actual or Simulated System	Number of Locations	Range System Yield (MBtu/yr)	Range Incremental Capital Cost/Sq Ft ($Base Year)	Range Incremental Capital Cost ($Base Year)	Operating and Maintenance Costs	Range Incremental Cost/MBtu/yr
Fraker & Glennie (1976)	variable	yes	space	yes	yes	yes	variable[1]	40[2]	new	both[3]	sim.	1	5.82 - 25.2	$9.93 - $14.18 (1976)	$6,356 - $9,077 (1976)	n.a.[*]	$336.40 - $1,092.10
Kohler & Putnam (Booz-Allen/TEA) (1977)	2	yes	space	yes	no	no	no	30	new	tract	sim.	3	13.4 - 30.3	n.a.	$5,410 - $6,280 (1977)	n.a.	$178.55 - $468.66

[*]n.a. = not available

[1]An attempt was made to optimize system performance for that particular residence.

[2]With permission of Larry Lindsay, Princeton Energy Group. This figure is based on conservative estimate by Hila Anderson, Senior Industrial Engineer, National Association of Home Builders Research Lab, May 19, 1978.

[3]Custom prototype with potential tract application.

bags containing "ponds" of water 8 inches deep. Heat is radiated from the bags to the living space below in the winter and from the living space to the water in the summer.

Roof pond system costs of delivered energy based on this design range from $5,410 to $6,280, and system yields range from 13.4 to 30.3 MBtu/yr. Additional storage other than that inherent in the base case residence design is not included [III-12,III-20].

The cost of delivered energy for thermal storage roof systems, combining results of reported studies, ranges from $178.55 to $1,092.10 per MBtu/yr. The higher figure is based on a system variation which includes no night insulation; a range for all systems using night insulation is from $178.55 to $468.66 per MBtu/yr. First cost range for both studies is $5,410 to $9,077; and system yield range is 5.82 to 30.3 MBtu/yr. Comparative designs, as well as cost and performance ranges, are given for the roof pond generic design in Table III-4.

Attached Sunspace/Greenhouse Systems Descriptions

The sunspace or solar greenhouse is a combination of the direct gain and thermal storage wall systems. It can be built over windows and doors on the south side of a building, permitting excess heat to enter the building; alternatively, a massive thermal storage wall can be added between the greenhouse and the space to be heated. The greater the quantity of added thermal mass, the greater the control over the interior temperature of the greenhouse [III-27]. If the greenhouse is set over two window levels, such as cellar and first floor windows, a thermocirculatory pattern can be established by opening windows at both levels and allowing cool cellar air to be warmed by the greenhouse. Thermocirculation, by continually bringing cooler air into the greenhouse, is an effective means of keeping heat losses down and efficiency up [III-4].

Attached Sunspace/Greenhouse System Costs

Two economic studies of the attached residential sunspace/greenhouse are reported here. The results of one are based on simulated performance and estimated cost figures; the results of the other, from actual performance.

Taff et al. [III-29] monitored the performance of a 98 sq ft, south-facing, attached solar greenhouse in Hinesburg, Vermont. The north wall and half the east and west walls are insulated and all windows are double glazed. Heat storage is provided by four black drums (208 gallons) of water. Two small (1/20 horsepower) fans and one differential thermostat provide interior temperature control.

The performance of this particular greenhouse, with night shutter added to increase annual net solar gain, is then simulated in 12 cities throughout the United States. Total cost of the greenhouse is $891; costs are not adjusted for geographical area and thus are assumed to be held constant over all areas. Cost and performance ranges for this system are as follows: yield, 15.27 to 26.94 MBtu/yr, and cost of delivered energy, $33.07 to $58.35 per MBtu/yr. The cost of storage is included. The cost of operation is negligible [III-14] because of the small amount of electrical power required for operation of the fans (Table III-5).

An economic analysis of the attached residential greenhouse was prepared by Michael Coca for the Solar Sustenance Project Phase II Final Report [III-30]. The typical Solar Sustenance Project attached greenhouse has a floor area of 160 sq ft; insulated east and west walls with a vent in each; double glazing; a corrugated fiberglass and insulated roof (1/2 clear fiberglass and 1/2 opaque, insulated roof); and thermal storage contained in east and west masonry block walls and in six 55-gallon drums of water painted black and stacked against the north wall of the greenhouse. The greenhouse is vented into the house, and heat transfer is by natural convection [III-31].

Costs are estimated from Solar Sustenance Project greenhouse building experience. They are given in 1975 dollars but they still seem low; one reason for this is that labor costs are based on a wage rate of only $4/hour. If construction were handled by a contractor, wage rates would be much higher. Materials prices also seem low, but an interview with the author of the analysis [III-7] revealed that they reflect market prices at the time.

Greenhouse performance is estimated using solar gain data for a 160 sq ft greenhouse per day, included in the Solar Sustenance Project Phase II Final Report. Cost of delivered energy for the typical Solar Sustenance Project greenhouse, located in Albuquerque, is $12.24 per MBtu/yr. Total incremental cost is $1,040, and cost per square foot is $6.50 (Table III-5).

Based on these sources, greenhouse applications are the most cost-effective of the passive generic designs. It should be noted, however, that contracted attached greenhouses built to complement custom homes can be built of expensive materials such as redwood and glass, and bills of $10,000 or more for these installations are not uncommon.

Table III-5 presents comparative design assumptions and cost and performance data for these two types of greenhouses. First costs range from $891 to $1,040; cost per square foot, from $6.50 to $9.09; system yields, from 15.27 to 84.97 MBtu; and cost of delivered energy, from $12.24 to $58.35 per MBtu/yr (based on nine-month heating season figures for one source). It appears that

TABLE III-5

ATTACHED SUNSPACE/GREENHOUSE COMPARATIVE DESIGN ASSUMPTIONS, COST, AND PERFORMANCE RANGES, BY SOURCE

	Design Assumptions												Cost and Performance Ranges				
Source	Glazing Layers	Storage	Space Heat or DHW	Night Insulation	Reflectors	Fans	Optimized System	Estimated Lifetime (Years)	New or Retrofit	Tract or Custom Design	Actual or Simulated System	Number of Locations	Range System Yield (MBtu/yr)	Range Incremental Capital Cost/Sq Ft ($Base Year)	Range Incremental Capital Cost ($Base Year)	Operating and Maintenance Costs	Range Incremental Cost/MBtu/yr
Taff, et al. (1977)	2	yes	space	yes	no	yes	no	20	both	tract	sim.	12	15.27 - 26.94	$9.09 (not varied with location) (1976)	$891 (not varied with location)	negligible	$33.07 - $58.35
Yanda (1977)	2	yes	space	no	no	no	no	20[1]	both	tract	actual	costs are avg's of several locations; yield is for Albuquerque area.	84.97	$6.50 (1975)	$1,040 (1975)	n.a.*	$12.24

*n.a. = not available

[1]See reference III-13.

for the typical Yanda-type greenhouse, low materials and labor costs and a very sunny location combine to give the system a very favorable initial cost of delivered energy.

C. MARKET READINESS OF PASSIVE SYSTEMS*

Technical Readiness

A number of passive solar heated buildings have been constructed and are operating successfully in the United States. Passive systems' performance varies with climate and building design. Performance is best in sunny climates; but substantial solar heating contributions are obtained even when weather conditions are marginal.

The probability of passive heating system malfunction is very low. System reliability can be attributed to use of common building materials, moderate component operating temperature ranges, and a small number of moving parts. Passive buildings, if properly designed and constructed, are thermally comfortable, operate naturally, reduce conventional fuel bills and are aesthetically pleasing.

Procedures for system design and performance calculation have been developed and validated for some heating systems. Design tools can be, and some are currently being, developed for the building industry.

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*Most market readiness information taken from Draft, "Commercialization Strategy Report for Passive Solar Heating," Department of Energy, August 31, 1978.

Basic passive space heating and hot water systems are technically mature and ready for commercialization. For more advanced heating designs, technical advancement is required in the following areas: (a) controls, materials, and components; (b) simulation, mathematical modeling, and design-performance evaluation techniques; (c) conservation/passive solar design integration; (d) specification of construction standards and performance goals; and (e) instrumentation and acquisition of performance data for actual and test structures in different climates.

State of Solar Design and Equipment Delivery System

Most materials and products for passive heating systems are manufactured by suppliers to the construction industry. Some manufacturers are aware that their products and materials are applicable to passive solar design and have adapted existing products for that purpose and/or developed products aimed specifically at the passive solar market.

Systems are distributed and installed through the existing building and building product design, production, supply, construction, and maintenance infrastructure. However, passive solar design expertise is not widely available to integrate materials, products, and infrastructure components into a functioning system. The lack of qualified designers will slow the market penetration rate of passive solar heating.

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IV. AGRICULTURAL AND INDUSTRIAL PROCESS HEAT SYSTEMS

A. INTRODUCTION

Solar agricultural and industrial process heat systems collect the sun's radiant heat, convert that energy to sensible heat in a working fluid (air, water, or steam), and store the excess heat energy while distributing this sensible heat to a process application. Although biomass may have a large potential for process heat applications, the only systems presented below are collector modules, which may be separated into two generic classes: planar and concentrating collectors. Planar collector systems include solar ponds, flat-plate, and evacuated tube collectors. Concentrators include compound parabolic concentrators, Fresnel lenses, parabolic trough, fixed and tracking segmented mirror tracking absorber, and parabolic dish. The working fluid (after being heated by collectors) is transported via a piping system, duct work, fans, pumps, valves, controls, etc. Heat is then transferred from the working fluid to the process by a heat exchanger.

B. PROCESS HEAT SYSTEMS, DESCRIPTIONS AND COST

Table IV-1 presents the optimal (least cost) solar systems for the process temperature ranges listed. These systems were assumed to be built with sufficient storage and conventional backup to enable 12 hour-per-day operations in any of the nine regions listed in Table IV-2. Many collector configurations were evaluated, and the eight most cost-effective were chosen for use in this analysis. These systems include solar pond with concrete bunker and water storage, for the 40° to 60°C temperature range, water heat transfer medium (WHTM); aluminum flat-plate, black, single-glazed collector, with fiberglass tank hot water storage for 60° to 80°C (WHTM); aluminum flat-plate, selectively surfaced, single-glazed

TABLE IV-1

SOLAR AGRICULTURAL AND INDUSTRIAL PROCESS HEAT SYSTEMS
CURRENT AVERAGE COSTS

Working Fluid	Water			Air		Steam		
Collector Type	Solar Pond	Flat Plate 1G/ Alum	Flat Plate 1G/ Alum	Flat Plate 1G/ Alum	Evac. Tube	Tracking Line Concentrator	Tracking Parabolic Dish	Tracking Parabolic Dish
Operating Temp. Range	40-60°C	60-80°C	80-100°C	50-100°C	100-150°C	>150°C	100-150°C	>150°C
Mode	Fixed Flat	Fixed Tilt	Fixed Tilt	Fixed Tilt	Fixed Tilt	Single-Axis Polar	Dual-Axis	Dual-Axis
Initial Costs ($1978/ft^2) [a]	18.07	32.92	32.92	31.85	22.62	48.75	71.12	73.12
Annual O&M Costs ($1978/ft^2)	2.24	1.33	1.48	1.10	3.48[b]	1.01	1.02	1.83
U.S. Average Annualized Cost ($1978/MBtu)	21.18	19.12	22.63	19.85	26.41	25.32	27.45	29.65
Mass Produced Costs ($1978/ft^2)	6.20	11.70	14.80	11.60	8.10	18.00[c]	12.00[c]	12.80[c]

a Simple average cost of systems presented in Table IV-3

b This estimate is considerably higher than costs listed by the manufacturers due to unanticipated tube breakage.

c Simple average cost of systems presented in L.E. Torkelson, et al., "A Summary of Current Solar Collector Cost and Performance Data," Sandia Laboratory, March 1, 1978.

TABLE IV-2

COLLECTIBILITY FOR SOLAR A/IPH SYSTEMS (MBTU/FT^2/YR)

Working Fluid	Water			Air			Steam	
Operating Temperature	40-60°C	60-80°C	80-100°C	50-100°C	100-150°C	> 150°C	100-150°C	> 150°C
Northeast	.15	.14	.19	.20	.19	.19	.21	.21
Mid-Atlantic	.14	.12	.16	.22	.21	.21	.18	.18
South Atlantic	.21	.20	.23	.27	.26	.26	.33	.33
East North Central	.16	.15	.19	.20	.19	.19	.21	.21
East South Central	.17	.15	.20	.20	.19	.21	.27	.27
West North Central	.23	.23	.27	.26	.25	.25	.28	.28
West South Central	.26	.25	.30	.31	.30	.29	.37	.37
Mountain	.29	.29	.33	.32	.31	.29	.54	.54
Pacific	.33	.32	.36	.32	.31	.32	.49	.49

Source: Taken entirely from: P. Curto, "System's Descriptions and Engineering Costs for Solar-Related Technologies, Volume III, Agricultural and Industrial Process Heat," MITRE Corp. METREK Division, February 1978.

collector, with steel tank hot water storage for temperatures between 80° to 100°C (WHTM); aluminum flat-plate, black, single-glazed or evacuated tube collector, with rockbed and concrete bunker storage for 50° to 100°C and an air heat transfer medium (AHTM); evacuated tube, rockbed and concrete bunker storage for temperatures between 100° to 150°C (AHTM); line concentrator, with rockbed and concrete bunker storage for temperatures greater than 150°C (AHTM); parabolic dish, with oil or rock storage for temperatures 100° to 150°C with steam heat transfer medium (SHTM); and parabolic dish, with oil or rock storage for temperatures greater than 150°C (SHTM).

Table IV-1 also presents systems by their collector type, working fluid, operating temperature range, mode (whether fixed or tracking), and their costs. Four cost figures are reported in 1978: initial costs, annual operation and maintenance cost, average annualized cost in $1978/MBtu, and anticipated costs when these systems are mass produced.

Table IV-2 presents the Btu's collected by each of the systems in Table IV-1 for nine census regions. Collectibility is a measure of the overall systems performance. The costs in Table IV-1 and the collectibility measures in Table IV-2 allow calculation of the cost of delivered energy expressed in dollars per million Btu. These costs in turn may be compared with other solar and conventional systems to project cost feasibility for process heat systems in 1978.

Costs presented in Tables IV-1 and IV-2 are based on manufacturers' quotes listed in Table IV-3, actual operating systems, and proposed designs of systems not currently being built. The SPURR-Process Heat Model was used to calculate costs of delivered energy from these systems. Although flat-plate systems are currently mass produced, many of the high temperature

TABLE IV-3

COSTS OF SOLAR AGRICULTURAL AND INDUSTRIAL PROCESS HEAT SYSTEMS
LOW TEMPERATURE (<100°C)

$\$1978/ft^2$

	Current Collector Costs[a]	Annual O&M Costs	Average Installed Cost
<u>Water</u>			
Solar Pond	16.77-19.37	2.24	18.07
Grumman Airstream Flat Plate/1G/Alum	24.70-28.60	.80	26.65
Solar Craft Flat Plate/1G/Steel	28.60-33.80	1.16	31.20
Solar Stream Flat Plate/2G/Alum	36.40-45.50	1.06	40.95
<u>Air</u>			
Solaron Flat Plate Collector Flat Plate/2G/Alum	29.90-33.80	.65	31.85

a. Includes reflector, absorber, selective coatings, insulation, box glass, glazings, sealants, controls, plumbing and ducting, pumps, controls, storage, valves, engineering and consulting contingency, administration, overhead, installed and calibrated onsite but excludes land charges, if any.

systems are not. The few high temperature systems cost estimates available vary widely and depend on insolation data utilized, recovery of sunk research and development costs, contingency fees, and apportionment of administration and overhead costs. However, most experts agree that the cost of delivered energy from the systems above ranges from \$20 to \$35/MBtu. Low temperature systems costs group near the low estimate and high temperature systems near the upper estimate. The costs presented in Table IV-1 do not reflect costs of any particular system used for a particular application. The point estimates indicate only at which end of the distribution systems costs do fall.

The following sections describe systems which produce hot water, heated air, or steam.

Hot Water Systems

The description of hot water systems is divided into three categories: low, moderate, and high temperature applications. Three types of hot water collector systems are considered: solar ponds, flat-plate collectors, and evacuated tube collectors. Collectors and equipment used for hot water systems closely resemble those used in solar heating and cooling of buildings discussed earlier in this report. Process heat systems include the following subsystems: collectors, plumbing, pumps and controls, valves, storage, and heat exchangers.

The solar pond collector consists of a water-filled plastic bag with a semi-ridged dome cover held in place by a wooden panel and clamped to a concrete curb. After the ground is graded and curbs put into place, a water barrier and insulation are placed on the floor of the pond. A plastic bag which is clear on top and black on the bottom is unraveled in the basin and filled with water. A dome is then placed over the plastic bag to filter out ultraviolet radiation. The pond measures 12 ft by 200 ft and is approximately 4 inches deep. Collection efficiencies are assumed to range from 40% to 60%.

Current cost for solar ponds is approximately $18/sq ft. It is anticipated that these costs may be reduced by as much as one-half if new materials for the bag and cover are developed. Operation and maintenance costs for solar ponds are relatively high due to vinyl deterioration and the need to replace the water bag approximately every three years. The average cost of delivered energy from solar ponds for the nine census regions listed in Table IV-2 is approximately $21/MBtu.

Flat-plate collectors can be used over the entire temperature range for water heat transfer mediums (WHTM) applications. There are many metal absorber flat-plate collectors that can be used. Generally, flat-plate collectors are aluminium, copper, or steel tube and sheet absorbers mounted on 2 or 4 inches of fiberglass insulation with either one or two clear glass or plastic glazings. The absorber of these collectors can be either painted black or treated to obtain a selective surface to improve high temperature performance. The collector assembly is placed in a galvanized steel box and weather-sealed. Current costs for flat-plate collectors, including 12-hour storage and onsite installation, is about $32/sq ft. The average cost of delivered energy from these systems is approximately $21/MBtu.

Evacuated tube collectors have recently been developed by three major manufacturers. These collectors have high collection efficiencies and are currently less expensive ($/sq ft) than flat-plate collectors. Evacuated tube collectors consist of inner and outer tubes which have an evacuated inner space to eliminate convection losses. Operation and maintenance expenses for evacuated tube collectors are currently high because of unanticipated problems with tube breakage. Cost for evacuated tube collectors is currently \$22.50/sq ft. With 12-hour storage, evacuated tube systems' average cost of delivered energy is approximately \$26/MBtu.

Hot water systems plumbing costs are included in Table IV-1. These costs represent charges to interconnect the collector modules only. Pipes are either plastic (for cold water), galvanized steel, aluminum, copper, or glass. Piping size and materials have been selected by the manufacturer based on system size and application.

Other costs for hot water systems are charges for pumps and controls, valves, 12-hour storage, installation, and calibration on-site. Contingency fees, administration, and overhead charges are also included.

Air Systems

Three types of air collector systems are considered below: flat-plate, evacuated tube, and tracking line concentrators.

Low temperature flat-plate collector air systems have collection efficiencies and costs generally comparable to the preceding hot water system designs. Flat-plate air systems do not have tubes but do have fins that protrude into the heating duct under the absorber plate and above the insulation backing. The fins enhance heat transfer from the plate to the AHTM.

Evacuated tube collectors can also be used for air systems. The descriptions and costs of evacuated tube collectors are discussed under hot water systems above.

For high temperature applications using AHTM, line concentrators have been developed. Collection efficiencies for these systems are high, but heat collection is limited to the direct component of sunlight. (Flat-plate and tubular collectors absorb all available direct and diffuse sunlight.) The cost of tracking line concentrator collector systems is currently $48.75/sq ft. The average cost of delivered energy from tracking line concentrator systems is approximately $27.50/MBtu.

A major component of the cost of air systems is ducting. Most air systems use galvanized sheet steel ducting with or without insulation. These costs are included in Table IV-1 and Table IV-2 but only represent costs to interconnect collector modules. Other costs for air systems are charges for fans and controls, valves, and storage. Storage for air systems does not require a heat exchanger. All other storage requirements are identical, and charges for these systems are included in Tables IV-1 and IV-2.

Steam Systems

Collectors for steam systems are similar to those used for high temperature air systems. However, the absorber for the steam system must be designed to withstand pressures up to 250 psi at operating temperatures to 200°C. The production of steam requires elevated temperatures that can only be achieved cost-effectively by concentrating collectors. Collector subsystems considered for steam are tracking parabolic dish collectors. Cost for dual-axis tracking parabolic dish collectors is currently $72/sq ft. The cost of delivered energy from parabolic dish systems is approximately $28/MBtu.

Plumbing costs for steam systems are included in Tables IV-1 and IV-2. The plumbing must be insulated, and only steel pipe will withstand design pressures and temperatures and minimize heat losses. Steam plumbing systems are more sophisticated and more costly than plumbing for hot water systems. Other costs for steam systems are pumps and controls, valves, and storage. These costs are also higher than those for hot water systems because of higher temperatures and pressures during operation.

C. MARKET READINESS OF PROCESS HEAT SYSTEMS

Technical Readiness

Low temperature solar heating systems, Table IV-3, are currently being manufactured and are available for residential and industrial applications. The performance of these systems is well documented. Current research efforts are directed at improving the efficiencies and reducing the costs of these systems.

Medium temperature solar systems are not as readily available as are low temperature systems. They are, however, being manufactured on a limited basis, and quantities are expected to increase in the near term. Some systems have been installed in working situations and performance data are being developed. Current research efforts are directed at obtaining additional performance data and reducing the costs of these systems.

Most high temperature solar heating systems are conceptual designs or prototypes. Systems performance and cost have not been proven. Substantial reductions in cost are required before these systems can compete with conventional fuels, Table IV-1.

State of Equipment Delivery Systems

As noted, low temperature solar heating systems are currently being manufactured and are generally available to interested consumers. More than 1,000 firms manufacture these systems and many are listed in the telephone directories of major cities. The delivery system for low temperature applications is new, but maturing, and includes manufacturers, wholesalers, dealers, and installers. (See Section II of this report.)

Similar to low temperature systems, components for medium temperature systems are currently being manufactured, but not on as large a scale. The delivery system for medium temperature systems is not as mature as that for low temperature systems, and these are usually purchased directly from the manufacturer based on buyer's specifications. Medium temperature systems are more sophisticated than low temperature ones and require more preliminary design effort to integrate the system with existing conventional systems.

High temperature heating systems presently exist as prototypes or are in early conceptual design stages. The manufacture of these systems is highly specialized and currently only for research and development projects. As a result, a delivery system for high temperature systems does not exist yet, and most of the delivery responsibilities are conducted by the manufacturer.

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V. BIOMASS

A. INTRODUCTION

For the past 50 years, use of biomass (cellulose and lignin) for energy production has been small relative to the amount of energy generated annually. Fossil fuels, coal, oil, and natural gas, have been available in large deposits, with relatively low extraction costs. Fossil fuels are easily transported and in general occur in a lower degree of polymerization than those of vegetation.

By comparison, biomass is more widely distributed, necessitating greater expense in collection and transportation costs; and cellulose and lignin require high energy inputs to resynthesize. As a result, biomass (primarily wood) has been used more for its structural and mechanical properties than for chemicals and energy.

A number of factors and developments have made it necessary to reconsider the economics of the use of biomass. These factors are:

- the large concentration of people in urban and industrial complexes which produces pockets of residues and wastes with low extraction and transportation cost;
- agricultural practices which generate numerous types of residues in concentrated pockets (such as manure in feedlots).
- the need to develop renewable, clean energy sources;

- the development of the energy farm concept, which may provide a economical, consistent, and easily transportable fuel; and

- the recognition of social, institutional, and environmental costs as part of the cost of energy.

This analysis of the availability and cost of biomass is separated into two areas. The first section deals with the availability and cost of feedstocks. The second section evaluates the cost of converting the feedstocks into useful energy fuels.

B. AVAILABILITY AND COST OF BIOMASS FUEL

Residues or Wastes

The most readily available biomass sources today are wastes and residues produced by municipal, agricultural, and forestry sectors. Residues are usually available in relatively large amounts at specific sites but may require processing to make them usable. Table V-1 shows estimates of recoverable wastes and residues and their costs.

Municipal solid waste (MSW) represents one of the larger sources of residues. MSW is produced at a rate of about 4 lbs per capita per day. It has a heating value (on average) of about 10 MBtu/ton and could provide about 1.1 to 1.6 Quads. Although MSW represents a large source of biomass, its composition and quality do not make it suitable for most conversion processes without expensive preparation and treatment. The MSW preparation process involves shredding burnable materials and separating glass and metal (on average, 75%, 10%, and 8% wet weight, respectively). Conversion processes applicable to MSW are (a) direct combustion, (b) pyrolysis to produce oil and gas, and (c) anaerobic digestion to

TABLE V-1

ESTIMATES OF BIOMASS WASTE AND RESIDUE

	Millions of Tons/Year	Total Heating Value (Quads)	Cost $/MBtu	References
Municipal Solid Wastes (MSW)	10-160	1.1-1.6	1.00-2.00	V-4, V-12, V-18
Animal Manures	26-210	0.3-2.1	0.20-2.20	V-3, V-4, V-17
Lumber-pulpmill waste (Total)	91	1.4	0.16-1.25	V-1, V-7, V-11, V-19
Currently Used	72	1.1		
Currently Not Used	19	0.3		
Field Crop Residues	100-257	1.5-4.2	0.80-3.33	V-11, V-18
Logging Residues (Total)	72-90	1.1-1.4	0.55-1.81	V-4, V-5, V-21
	GROSS TOTAL	5.40-10.7	0.16-3.33	
	NET TOTAL*	4.30- 9.6		

*This is the energy potential for new fuel source, since there are 1.1 Quads currently in use by the Forest Products Industry.

produce substitute natural gas. There are a number of conversion projects underway which handle from 200 to 2,000 tons of MSW per day.

The total animal population raised for meat and dairy products produces about 200 million tons/year of manures (dry weight basis). However, estimates of the amount actually collectible is as low as 26 million tons/year. The most widely accepted conversion method for manure is anaerobic digestion to make methane. The largest portion of the collectible biomass comes from large animal feedlots which are operated year-around. Economical substitutes for natural gas can be produced from feedlots larger than 1,000 head of cattle or more. Most feedlots in the United States are relatively small. Only 200 have more than 8,000 head, and half of these carry fewer than 16,000 cattle. Most manure is not collected continuously (thus it degrades) and can contain large amounts of dirt. For small milk dairies (40-100 cows), manure is readily available and can provide a source of fuel for farm uses. However, these fuels are not economically competitive with rural electricity or natural gas if it is available.

Bark, sawdust, and other wastes accumulate at lumbermills and pulpmills. Wood processing industries currently use 1.1 Quads of wood residues as a fuel and purchase another 1.5 Quads of energy from other sources. Only 0.3 Quad of mill residues from the industry is not currently used. If the forest industry would utilize logging residues or "slash" (1.1 to 1.4 Quads) and the remaining portion of its residues, it could become energy self-sufficient dependent only upon its wastes and residues.

Logging "slash" averages about 1/3 of the total wood removed. Stumps and roots are about another 1/3. Total logging residues generated domestically approach 200 million dry tons/year (root system and above ground component). About 40% is above ground resulting in a residue of 70 million to 90 million dry tons per year (1.1-1.4 Quads). Development of onsite collection and chipping equipment will be necessary to utilize these residues.

Agricultural biomass (for food, clothing, etc.) has been produced in the United States on over 400 million acres [V-2]. (About 300 million acres are currently planted.) On this acreage about 1 billion total dry tons are produced of which about 1/4 to 1/2 is left on the ground. These residues are widely distributed and bulky (5 to 10 cu ft equals the energy of 1 cu ft of wood). The amount that may be removed or collected is site-specific; and other factors such as moisture content, seasonal availability, local soil and terrain, and development of biomass densification equipment limit the large-scale utilization of agricultural residues. Estimates indicate that 100 million to 200 million dry tons are available for collection (Table V-1).

The energy available from residues and wastes is highly uncertain. Residues could be a large contributor (5-10 Quads) to U.S. energy supplies. But due to handling and transportation costs, residues and wastes are likely to be used by the industries or sites that produce them.

Biomass Energy Farms

The biomass energy farm is an approach to produce fuel from plant matter by choosing planting densities and harvesting schedules that optimize the capture and conversion of solar energy. Energy farms have been studied only on a conceptual engineering basis. Major experiments are being conducted to prove their feasibility. Energy farms are not severely affected by short-term weather changes (i.e., does not need a storage system). Other advantages of energy farms are:

- they produce a clean fuel (low sulfur and little nitrogen);

- they are potentially large sources of energy (20-30 Quads);

- they have the potential to be economically competitive with near-term costs of conventional energy sources (especially true if the biomass fuel has been densified to a standard product that is easily transported);

- growing and burning these fuels will not modify the net carbon dioxide or thermal balance of the earth to the extent that fossil fuels would.

Potential disadvantages of energy farms have been identified:

- food and fiber prices may rise if prime agricultural farmlands are used for energy crops;

- large environmental damages are possible unless crops are grown and harvested in a safe manner;

- energy farm potential is limited until low-cost drying, clipping, and densifying equipment is available.

The type of vegetation grown on energy farms should be local deciduous perennial species that can be cloned and coppiced. Energy farms could use marginal land (for our purposes, land which has not been farmed or forested in the last 10 years) with the following properties:

- at least 21 to 25 inches of rainfall per year, (some concepts have evaluated a farm solely dependent on rainfall without irrigation [see Table V-2]);

- population of less than 300 people per square mile;

- privately owned;

- a sufficiently loamy soil which will retain adequate moisture and support field machinery;

- slope less than 25%, i.e., land not suitable for plowing or other intense soil preparation but where clones can be planted.

The energy farm could be organized into four functions: supervision; field operations; clone or new plant production; and biomass densification. The field operations would consist of weed control, fertilization, irrigation (if required), clearing, planting, and harvesting (coppicing). Clone production includes cutting stock from living plants, cutting stock into clones, packing, and storing. At harvest time (2-3 year cycle), the tree would be coppiced, leaving certain root systems. The cut portion would be chipped, dried, and densified at the farm to a fuel with a specific gravity of 1.00 to 1.45 (coal s.g. is 1.25) and a moisture content of 8% to 10% [V-23]. The densified biomass would then be shipped to the user (either local or distant).

There are two key issues associated with energy farms: land availability that satisfies the constraints listed above and the cost of fuel. Table V-2 outlines land availability studies and their results. Table V-3 outlines the cost of fuel for three studies relative to the energy farm concept. These data show that there are two possible sources of land: (1) converted or <u>not</u>

TABLE V-2

LAND AVAILABILITY SUMMARY FOR ENERGY FARMS

	Reference	Description or Constraints	Millions of Acres	Location
1.	V-1, V-2, V-10	Land that could be converted from present use (livestock, pastures, and ranges)	111-142	South, Midwest
2.	V-9	1) 25" rainfall 2) Arable land 3) Slope < 30% 4) Land is under less pressure than prime cropland	268-324.5	All U.S. except Mountain Time Zone
3.	V-16	1) 20" rainfall 2) Slope < 25% 3) Population <300 people/sq mi. 4) Marginal land (not used for crops, commercial forest, pasture, range, recreation) 5) Loamy soil 6) Privately owned 7) Large tracts	100-200	Eastern and Central Time Zones

TABLE V-3

COST SUMMARY OF BIOMASS FROM ENERGY FARMS

	Reference	Tree Type/Location	Cost $/MBtu	Year of Study
1.	V-4	Eucalyptus-Louisiana	1.20	1978
		Hardwood-S. California	2.00	
		Hardwood-N. California	1.03	
		Sugar Cane-Florida	3.00	
2.	V-13	Unknown	1.00-1.80	1977
3.	V-16	13 Deciduous Perennials studied in 17 acres (Hybrid Poplars, Aspen Hybrids, Black Cottonwood, Red Alder, Sycamore, Eastern Cottonwood, European Black Alder, Green Ash, Sweetgum, Eucalyptus)	1.20-1.45	1976

currently used prime farm land (111-142 million acres) with a potential of producing 18 to 22 Quads of fuel (based upon 10 ODT/acre per year at 16 X 10^6 MBtu/ton); and (2) marginal land (currently not used as forests or farmland) of 100 million to 200 million acres with a potential of 16 to 32 Quads. The studies outlined in Table V-3 indicate that the fuel produced from these farms would cost from $1/MBtu to $2.50/MBtu ($16-$40/oven dry ton).

C. PRODUCTS FROM BIOMASS

This section discusses the conversion of wood biomass to energy-related products and their cost. Seven products are analyzed: Methanol, Ethanol, Medium-Btu Gas, Substitute Natural Gas, Ammonia, Fuel Oil, and Electricity. The feedstocks are either residues or energy farms, and the costs are computed based on feedstock costs from $1/MBtu to $2.50/MBtu. Specifics of the cost analysis are presented in the appendix.

Methanol

Natural gas is currently the principal source (feedstock) for methanol. Methane can be converted into CO/H_2 stream and resynthesized using a process similar to the one described below. On an energy content basis, the amount of methanol currently being produced is about 1% of the gasoline produced in the United States. Methanol can be burned in internal combustion engines with higher energy efficiency and less pollution than gasoline. (Gasoline engines would require modifications.)

Methanol can be manufactured by a catalytic combination of carbon monoxide and hydrogen ($2H_2 + CO \rightarrow CH_3OH$). The CO/H_2 stream can be produced by making medium-Btu gas from the gasification of wood-biomass (described below). Methanol could also be produced as by-products in the pyrolysis or hydrolysis of wood-biomass.

To produce methanol from medium-Btu gas, the gas is compressed to about 385 psia and passed to a shift reactor (to generate the desired ratio of CO/H_2) containing a sulfide catalyst. Steam is supplied for the shift, and the product passes to a waste-heat recovery unit and a purification system for CO_2 removal. The purified gas is compressed to 1,500 psia and the mix passes through a fixed-bed catalytic converter to produce crude methanol. The crude methanol is distilled to produce a fuel-grade or a chemical-grade product.

Five cases were analyzed and costs are shown in Tables V-4 and V-5. The costs were analyzed using two costing strategies. A levelized cost and a first year cost approach were used. For methanol, the levelized cost ranges from a low of \$12.52/MBtu to \$27.44/MBtu for the cases analyzed. The first year cost of methanol ranges \$7.78/MBtu to \$16.09/MBtu which indicates that production of methanol would be competitive now, but this condition would be dependent upon continued increase in this methanol price to be profitable. The cost of conventionally produced methanol is about \$8.40/MBtu. The cost of the medium-Btu plant was included in this calculation.

Ethanol

About 80% of all ethanol is produced by the synthesis of ethylene. Fermentation of grains, fruits, and molasses accounts for about 20% of ethanol production. Ethane extracted from natural gas wells is dehydrogenated to produce ethylene and the ethylene extracted from petroleum refiner gas streams provides the major source of feedstocks. In 1976, about 200 million gallons were produced in the United States. Total domestic installed capacity is 365 million gallons/year [V-25].

TABLE V-4

LEVELIZED PRODUCTION COST SUMMARY FOR METHANOL

	Biomass Input ODT/Day	Biomass-Fuel Cost			
		$ 1.00/MBtu	$ 1.50/MBtu	$ 2.00/MBtu	$ 2.50/MBtu
Case #1	1,500	13.26/MBtu	16.86/MBtu	20.45/MBtu	24.04/MBtu
Case #2	300	16.95/MBtu	20.45/MBtu	23.94/MBtu	27.44/MBtu
Case #3	850	16.59/MBtu	19.55/MBtu	22.51/MBtu	25.46/MBtu
Case #4	1,700	14.13/MBtu	17.08/MBtu	20.03/MBtu	22.49/MBtu
Case #5	3,400	12.52/MBtu	15.47/MBtu	18.42/MBtu	21.37/MBtu

TABLE V-5

FIRST YEAR PRODUCTION COST SUMMARY FOR METHANOL

	Biomass Input ODT/Day	Biomass-Fuel Cost			
		$ 1.00/MBtu	$ 1.50/MBtu	$ 2.00/MBtu	$ 2.50/MBtu
Case #1	1,500	7.78/MBtu	9.89/MBtu	11.99/MBtu	14.09/MBtu
Case #2	300	9.44/MBtu	11.99/MBtu	14.04/MBtu	16.09/MBtu
Case #3	850	9.73/MBtu	11.46/MBtu	13.20/MBtu	14.93/MBtu
Case #4	1,700	8.29/MBtu	10.01/MBtu	11.75/MBtu	13.48/MBtu
Case #5	3,400	7.34/MBtu	9.07/MBtu	10.80/MBtu	12.53/MBtu

Like methanol, ethanol may be used as a motor fuel additive. Small-scale tests in Nebraska using gasoline with 10% ethanol have shown satisfactory performance. Brazil has been engaged in a major program to encourage the domestic production of ethanol for motor fuels from new sugarcane plantations.

Processes for converting wood-biomass to ethanol involve two steps. The first is the hydrolysis of wood to sugars; and the second, the fermentation of the sugars to ethanol. Numerous approaches exist for processes utilizing different hydrolytic agents (strong and weak sulfuric acid, hydrochloric chloride gas, and certain enzymes). One of the most advanced processes is the Scholler process which uses dilute sulfuric acid. The Scholler process has been modified experimentally by the U.S. Forest Products Laboratory to improve yields, reduce residence time, and permit a semicontinuous operation. The cost data in this report are based on this process.

The Scholler process introduces biomass feedstocks into a digester, where steam increases the temperature to about 257°F. Sulfuric acid, recycled hydrolyzate, and hot water are then added. The temperature is increased to 300°F for 15 minutes. The prehydrolyzate is drained, and dilute sulfuric acid is introduced in the digester in conjunction with high-pressure (250 psig) steam in order to perform the main hydrolysis. After digestion for 70 minutes, the main hydrolyzate is flashed to the atmosphere in stages to separate out the lignins, furfural, and methanol.

Lignins are returned and used as fuel, and the mixture of methanol and furfural is separated in a distillation tower to recover the methanol. The hot hydrolyzate is neutralized in a lime slurry tank, and the calcium sulfate precipitate is separated in a clarifier. A wash cycle is used on this precipitate to recover sugar. The sugar solutions are combined and passed to fermenting tanks for alcohol production. After fermentation is complete, the yeast is removed. The crude alcohol water stream passes to distillation towers which separates out pentoses and concentrates the ethanol to 190 proof (95% purity). (Higher purities are required for mixing with gasoline.)

Four cases were analyzed to determine the cost of producing ethanol from biomass feedstocks. The levelized cost ranges from a low of $21/MBtu to $48.30/MBtu, and first year cost ranges from $12.56/MBtu to $28.30/MBtu. First year cost of ethanol is competitive with conventionally made ethanol, but a profitable position is dependent upon continued increase in the selling price. This production of ethanol compares with projected cost of ethanol in 1981 at $19.60/MBtu. The levelized costs are summarized in Table V-6, and first year cost is summarized in Table V-7.

Medium-Btu Fuel Gas

The gasification of wood-biomass in conjunction with gaseous oxygen produces a medium-Btu gas. This gas has a heating value of about 300 to 400 Btu/scf and consists primarily of mixtures of carbon monoxide and hydrogen. Its sulfur content is negligible. The product gas can be compressed and shipped economically over distances up to 200 miles to be used as a fuel source (like natural gas) or a feedstock in production of other fuels.

In the past, medium-Btu gas has been produced from coal, with a heating value of approximately 550 Btu/scf, to supply town gas distribution systems. These systems disappeared in the United States after World War II with the advent of large-scale natural gas production, transmission, and distribution.

TABLE V-6

LEVELIZED PRODUCTION COST SUMMARY FOR ETHANOL

	Biomass Input ODT/Day	Biomass-Fuel Cost			
		$ 1.00/MBtu	$ 1.50/MBtu	$ 2.00/MBtu	$ 2.50/MBtu
Case #1	1,490	21.42/MBtu	27.15/MBtu	32.88/MBtu	38.62/MBtu
Case #2	850	39.72/MBtu	42.56/MBtu	45.42/MBtu	48.27/MBtu
Case #3	1,700	34.71/MBtu	37.57/MBtu	40.43/MBtu	43.30/MBtu
Case #4	3,400	31.52/MBtu	34.37/MBtu	37.23/MBtu	40.08/MBtu

TABLE V-7

FIRST-YEAR PRODUCTION COST SUMMARY FOR ETHANOL

	Biomass Input ODT/Day	Biomass-Fuel Cost $ 1.00/MBtu	$ 1.50/MBtu	$ 2.00/MBtu	$ 2.50/MBtu
Case #1	1,490	12.56/MBtu	15.92/MBtu	19.28/MBtu	22.64/MBtu
Case #2	850	23.29/MBtu	24.95/MBtu	26.63/MBtu	28.30/MBtu
Case #3	1,700	20.35/MBtu	22.03/MBtu	23.71/MBtu	25.39/MBtu
Case #4	3,400	18.48/MBtu	20.15/MBtu	21.83/MBtu	23.50/MBtu

Near-term markets for medium-Btu gas may arise with natural gas curtailments to industrial users. The choices will be either to replace natural gas fired furnaces with oil fired or coal fired furnaces (neither oil nor coal can be used in a natural gas furnace) or to substitute a medium-Btu gas (generated by coal or biomass gasification) directly for natural gas. Biomass medium-Btu gas is preferred because:

- It can be burned and produced in an environmentally acceptable manner (i.e., no sulfur).

- The size of the furnace needed for burning medium-Btu gas is identical to that for natural gas, and the furnace is smaller by a ratio of 1.35 or 1.85 when compared to oil and coal fuel systems, respectively [V-22]. This means that few modifications are required for an existing furnace that uses natural gas.

- Gas fired systems have lower maintenance expenses.

- Essentially no steam (i.e., water) is required for wood gasification whereas steam requirements for most coal gasification processes are high.

- Lower shift reaction cost requirements--H_2/CO ratios in biomass medium-Btu gas are somewhat higher than those in coal gas.

Selecting medium-Btu gas as a substitute for natural gas has definite advantages over coal or oil. This substitution can be accomplished without loss of thermal efficiency (at 300 Btu/scf the efficiency of a boiler is higher than when using 1,000 Btu/scf natural gas) or modification of the boiler and support systems (less air required and less combustion products produced) [V-22].

Two processes are available that can produce a medium-Btu gas from biomass; these processes have been demonstrated in pilot plant size operations.

1. Purox-Union Carbide has operated a 200 ton/day pilot facility in Institute, West Virginia. The major system components are a shaft kiln and an oxygen plant.

2. Pyrox Process has operated a 50 ton/day pilot facility in Japan.

Both systems have used municipal waste to produce medium-Btu gas, and the Pyrox unit has been operated on biomass. Since the organic portion of municipal waste is primarily cellulose, comparable performance may be expected from solid waste or biomass. (Using wood-biomass, the ash handling facilities are simplified and the equipment is freed from the potential corrosion of the chloride content of municipal solid waste).

Both processes pyrolyze the organic portion present in the solid fuel. To produce a medium-Btu gas, it is necessary that the atmosphere involved in the process is not diluted with nitrogen. In the Purox Process this is accomplished by separating the oxygen from the nitrogen in an air separation plant. In the single shaft kiln reactor, both a combustion reaction and pyrolysis occur. In the Pyrox process the combustion reaction and the pyrolysis take place in separate fluidized bed reactors. Solids (usually sand) circulate between the two beds to provide the heat needed for the pyrolysis reaction. The Purox Process was analyzed in this report since cost data were available for this system.

Three cases were analyzed using a levelized and first year costing strategy for the production of medium-Btu gas, and these costs are summarized in Tables V-8 and V-9. The levelized cost for

TABLE V-8

LEVELIZED PRODUCTION COST SUMMARY FOR MEDIUM-BTU GAS

	Biomass Input ODT/Day	Biomass-Fuel Cost $ 1.00/MBtu	$ 1.50/MBtu	$ 2.00/MBtu	$ 2.50/MBtu
Case #1	850	7.07/MBtu	8.85/MBtu	10.64/MBtu	12.42/MBtu
Case #2	1,700	6.10/MBtu	7.88/MBtu	9.66/MBtu	11.52/MBtu
Case #3	3,400	7.51/MBtu	9.89/MBtu	12.26/MBtu	14.64/MBtu

TABLE V-9

FIRST-YEAR PRODUCTION COST SUMMARY FOR MEDIUM-BTU GAS

	Biomass Input ODT/Day	Biomass-Fuel Cost $ 1.00/MBtu	$ 1.50/MBtu	$ 2.00/MBtu	$ 2.50/MBtu
Case #1	850	4.15/MBtu	5.19/MBtu	6.24/MBtu	7.28/MBtu
Case #2	1,700	3.58/MBtu	4.62/MBtu	5.67/MBtu	6.75/MBtu
Case #3	3,400	4.41/MBtu	5.80/MBtu	7.19/MBtu	8.58/MBtu

producing medium-Btu gas ranges from a low of \$7.07/MBtu to \$14.64/MBtu and the first year cost ranges from a low of \$3.58/MBtu to \$8.58/MBtu. In cases where natural gas is not available, the medium-Btu gas offers an attractive option.

<u>Substitute Natural Gas</u>

Several conversion alternatives are possible for producing methane-rich pipeline natural gas. A substitute natural gas (SNG) can be produced by gasifying wood biomass to produce medium-Btu gas and converting this gas by methanation to a substitute natural gas. Methane-rich gasses can also be produced by anaerobic digestion of the cellulosic content of wood biomass (including manures) and by the action of carbon monoxide and catalysts on cellulose at severely high pressure and temperature conditions (carboxylolysis). The product gas is almost entirely methane and, therefore, is equivalent to natural gas. The net heating value ranges from 900 to 950 Btu/scf.

Anaerobic Digestion

Generation of methane gas by anaerobic digestion is not a new concept. It has been studied extensively for over a hundred years, and many full-scale operating systems were installed on farms in Europe and other areas in the 1930s and 1940s.

Pilot-scale agricultural waste fermentors and full-scale sewage sludge anaerobic digesters were in use by 1935. Subsequently, a number of different types of reactors were constructed mainly on farms in Europe. These units combined many different designs including varying the principal design parameters such as mixing, heating, and substrate concentration. There were 15 plants installed in West Germany by 1957. The prevailing feeling about these units is that they could not justify their cost on the production for energy only [V-3].

Numerous other types of units have been installed in small-scale operations in Asia. India has had an active development program for several decades. In the past 12 years, 7,000 plants serving small farms and households have been erected in India. Although it is unclear how successful these have been, there appear to be no better alternatives to attempt to provide a high quality fuel to rural areas while preserving the valuable plant nutrients. Therefore, the Indian government is now embarking on a large-scale effort to build 100,000 additional units.

The Republic of Korea is reported to have 29,000 family-sized units with digesters of 5 to 6 sq m. Incomplete data from China indicate that 12 or 13 provinces are presently making widespread use of anaerobic fermentation as an energy source and nutrient conservation technique.

Until recently, very little activity has taken place in the area of anaerobic fermentation of agricultural wastes in the United States. Although many sewage sludge digesters are in operation, their purpose is primarily to stabilize or decompose organic solids. However, it is probably rare to find a state that is not currently considering this topic, and many have several farmers or others actually building full-scale units. Two feedstocks of sewage-sludge and manure offer considerable advantages over other biomass sources (solid waste, wood, and crop residues) for anaerobic digestion due to the requirement for extensive preparation prior to the utilization of other sources. Manure can be treated in a manner similar to sewage, and methane production can be as relatively simple process. A process utilizing manure as a feedstock was analyzed for this study.

The system components of a conventional process include a predigestion tank, manure feeding components, and an anaerobic reactor tank. The predigestion tank should be designed for a two-day holding capacity of all the manures generated. Dilution water is added to the animal manure in the predigestion tank so that a slurry of 10% solids results. A centrifugal type pump provides predigestion tank agitation, waste feed drive, and mixing. After agitation, the feed manure slurry is transferred from the predigestion tank to the digester (reactor tank). Intermittent recirculation of digester contents prevents scum formation. At approximately 32°C the methane fermentation begins.

Methane fermentation is a microbial process that involves three major groups of bacteria which complete decomposition in three stages. First, complex insoluble biodegradable organics are converted to soluble organics. The predominant reaction is conversion of insoluble polysaccharide to soluble carbohydrates. The second group converts various soluble organics to acetate or propriate and CO_2, or acetate and H_2. The methanogenic bacteria then utilize the hydrogen gas and CO_2 to make methane.

The methane generated in the reactor tank is then compressed and stored. The stored methane can be used for heating hot water that maintains the fermentation reaction temperature and for running a compressor/generator for electricity. The parasitic energy for running the system is about 25% to 39% of gross energy production [V-3].

Gasification/Methanation

Converting a medium-Btu gas made from wood (described above) by the Purox Process to a substitute natural gas involves the conversion of the carbon monoxide and hydrogen to methane. The technology to achieve this has been intensively researched for coal-to-SNG processing and is independent of the source of the medium-Btu gas. The processing step is called methanation.

In methanation, medium-Btu gas enters a waste-heat recovery and wash system. The flow is then split to direct approximately two-thirds of the gas to a shift converter at about 550°F, after which it is recombined with the unshifted stream in a waste heat recovery system. The gas then passes to a Rectisol System where H_2S and CO_2 components are removed. The gas then passes to a methanator where H_2 and CO are reacted in the presence of nickel catalyst to form CH_4 and H_2O at about 900°F. The cooled product is recycled for temperature control. Next, the gas is cooled and dried to reduce moisture to trace amounts. The two heat recovery systems produce the steam necessary for the process. Additional compression of the methane to transmission-pipeline inlet conditions is then performed.

The approaches to methanation on a commercial scale involve combinations of techniques to bring the reaction catalyst in intimate contact with the gas stream and to remove exothermic heat of reaction.

The process approaches in varying stages of development are (1) Raney Nickel Catalyst, (2) Fixed Bed Adiabatic Reactors, (3) Packed-tube Reactor, (4) Liquid Phase Methanation, (5) Fluidized Bed Methanation, and (6) Combination Shift Methanation.

There were seven cases analyzed for production cost of methane (or substitute natural gas). The levelized and first year production costs are summarized in Tables V-10 and V-11. The first three cases are based on anaerobic digestion conversion in an agricultural application where the manure would be virtually free. The remaining four cases cover gasification/methanation and include the cost for production of medium-Btu gas from wood.

TABLE V-10

LEVELIZED PRODUCTION COST SUMMARY FOR SUBSTITUTE NATURAL GAS

	Biomass Input	Biomass Fuel Cost $1.00/MBtu	$1.50/MBtu	$2.00/MBtu	$2.50/MBtu	References or Remarks
Case #1	40 cow farm	9.23/MBtu				Biomass is free. Anaerobic Digestion
Case #2	100 cow farm	5.59/MBtu				Anaerobic Digestion
Case #3	1,000 cattle feedlot	1.90/MBtu				Anaerobic Digestion
Case #4	2,154 ODT/Day	9.44/MBtu	12.59/MBtu	15.74/MBtu	18.89/MBtu	
Case #5	850 ODT/Day	9.95/MBtu	11.97/MBtu	14.00/MBtu	16.02/MBtu	
Case #6	1,700 ODT/Day	8.75/MBtu	10.77/MBtu	12.79/MBtu	14.82/MBtu	
Case #7	3,400 ODT/Day	7.61/MBtu	9.63/MBtu	11.66/MBtu	13.67/MBtu	

TABLE V-11

FIRST-YEAR PRODUCTION COST SUMMARY FOR SUBSTITUTE NATURAL GAS

	Biomass Input	Biomass Fuel Cost				References or Remarks
		$1.00/MBtu	$1.50/MBtu	$2.00/MBtu	$2.50/MBtu	
Case #1	40 cow farm	7.56/MBtu				Biomass is free. Anaerobic Digestion
Case #2	100 cow farm	4.58/MBtu				Anaerobic Digestion
Case #3	1,000 cattle feedlot	1.55/MBtu				Anaerobic Digestion
Case #4	2,154 ODT/Day	5.54/MBtu	7.38/MBtu	9.23/MBtu	11.08/MBtu	
Case #5	850 ODT/Day	5.83/MBtu	7.02/MBtu	8.21/MBtu	9.39/MBtu	
Case #6	1,700 ODT/Day	5.13/MBtu	6.31/MBtu	7.50/MBtu	8.69/MBtu	
Case #7	3,400 ODT/Day	4.46/MBtu	5.65/MBtu	6.83/MBtu	8.02/MBtu	

In the case of anaerobic digestion, the levelized and first year costs are competitive with natural gas when a large number of cattle are present. For gasification/methanation the levelized and first year costs are higher than for natural gas.

Ammonia

Anhydrous ammonia is produced by catalytically reacting hydrogen and nitrogen at high pressure. The nitrogen is delivered from air; the hydrogen can be manufactured from any one of a series of feedstocks--coal, natural gas, naphtha, heavy oils, or coke oven gas. Natural gas is the primary feedstock for ammonia produced in the United States. Significant foreign production of ammonia occurs from coal. Production of ammonia in the United States (1975) was 15.781 million tons, with an installed capacity of 17.445 million tons.

In the United States, the prices of natural gas and ammonia are related. With the increase in the price of natural gas and the curtailment of its use, alternative feedstocks are being considered.

An alternative feedstock is coal, and as already noted, a significant coal-based ammonia production currently exists outside the United States. It is considered that the gasification of coal, removal of sulfur, and shifting to hydrogen is more costly to perform.

Another alternative is converting medium-Btu fuel gas produced from wood biomass by the Purox Process to a hydrogen steam. The technology for conversion of a medium-Btu gas to produce the hydrogen is well established and widely practiced (the medium-Btu gas is currently made using natural gas as the feedstock).

For this cost analysis, the approach selected utilizes a medium-Btu gas generated by the Purox Process to produce the hydrogen steam. (The Purox Process requires a liquefaction plant to provide pure oxygen. A byproduct of the liquefaction is nitrogen which can be used later in the process to make ammonia.) The cost of the plant to produce medium-Btu-gas is included. The plant receives medium-Btu gas from the gasification plant at a pressure of about 200 psia. The gas along with steam is fed to a shift converter where an iron oxide catalyst is used to reduce the carbon monoxide content to less than 1% via a water-gas reaction ($CO + H_2O \longrightarrow CO_2 + H_2$). The gas then passes to a purification section where carbon dioxide is removed by absorption, and then to a finishing methanator where the remaining carbon monoxide is converted to methane. The hydrogen produced is mixed with nitrogen and the mixture is compressed to the pressure (200 Atm) for ammonia synthesis ($N_2 + 3H_2 \longrightarrow 2NH_3$). The reactants are then condensed to a liquid state at 175 psia and at room temperature. The nitrogen is derived from the liquid air facility used to produce oxygen for the gasification plant (Purox Process for the medium-Btu gas feedstock).

Three cases were analyzed using levelized and first year costing strategies for producing ammonia, which are summarized in Tables V-12 and V-13. Levelized costs range from \$8.69/MBtu to \$18.10/MBtu. The first year cost ranges from \$5.09/MBtu to \$8.67/MBtu. The projected cost of ammonia in 1981 is \$7.40/MBtu.

Fuel Oil

Fuel oil is any liquid, usually viscous in nature and combustible, which can be burned to liberate its heat energy without the addition of other fuels. Fuel oils are principally derived from petroleum as residues of refining processes. In this category are oils such as No. 2 heating oil for residential and commercial

TABLE V-12

LEVELIZED PRODUCTION COST SUMMARY FOR AMMONIA

	Biomass Input ODT/Day	Biomass-Fuel Cost			
		$1.00/MBtu	$1.50/MBtu	$ 2.00/MBtu	$ 2.50/MBtu
Case #1	850	12.00/MBtu	14.04/MBtu	16.07/MBtu	18.10/MBtu
Case #2	1,700	9.80/MBtu	11.83/MBtu	13.86/MBtu	15.89/MBtu
Case #3	3,400	8.69/MBtu	10.72/MBtu	12.75/MBtu	14.78/MBtu

TABLE V-13

FIRST-YEAR PRODUCTION COST SUMMARY FOR AMMONIA

	Biomass Input ODT/Day	Biomass-Fuel Cost $1.00/MBtu	$1.50/MBtu	$ 2.00/MBtu	$ 2.50/MBtu
Case #1	850	7.04/MBtu	8.23/MBtu	9.42/MBtu	10.61/MBtu
Case #2	1,700	5.75/MBtu	6.93/MBtu	8.13/MBtu	9.32/MBtu
Case #3	3,400	5.09/MBtu	6.28/MBtu	7.47/MBtu	8.67/MBtu

heating use, distillate oils which have been produced in the petroleum refining process (Nos. 3, 4, and 5), and No. 6 oil which is a residue from the refining process and the most viscous. These oils may contain small or large amounts of sulfur and varying amounts of nitrogen.

The demand for residual fuel oils in the United States had risen over the past 25 years until the price increases in petroleum in 1974. At present, alternative sources primarily center around the use of coal. However, fuel oils can be made from wood-biomass.

Fuel oils derived from wood may be produced by two processes: (1) pyrolysis and (2) aqueous processing using carbon monoxide, a catalyst, and extreme conditions (carboxylolysis, a process now beginning pilot operations in Albany, Oregon).

The carboxylolysis process involves the reaction of carbon monoxide and steam with organic material in the presence of sodium carbonate catalyst at temperatures of 250°C to 400°C and 2,000 to 4,000 psig pressure. The reaction takes place continuously under these conditions. The liquid flow from the reactor is cooled to 200°C, and pressure is reduced. As the pressure is reduced, some liquid will flash, and the remainder is collected in a bottom tank and pumped to a centrifuge where oil and water are separated. The oil is finally filtered to remove any solids and transferred to a holding tank.

Although the carboxylolysis process has been known for a long time (1921), the process is still in the RD&D phase and, therefore, was not used for analysis in this study from wood biomass.

The second alternative for production of fuel oils is pyrolysis. Pyrolysis is the thermal decomposition (destructive distillation) of organic matter by indirect heating, or with air or oxygen supplied at far below the mixture ratio required to have complete combustion. Pyrolysis had considerable usage in the past as a source of creosote, gases (producer gas, town gas, and power gas), charcoal, and methanol. It is employed today in modified forms (delayed and fluidized cokers) in the manufacture of metallurgical coke, coal tar, and charcoal.

Three pyrolysis processes are available, which are either fully developed or are in an advanced stage of development. They are Nichols-Herreshoff Furnace Process (charcoal production); Tech-Air Process (prototype exists--produces solid, liquids, and gases); and Occidental Flash Pyrolysis Process (plants using municipal solid waste are in operation--produces liquid fuel).

The Occidental Process was used for analysis in this study. Wood biomass enters front-end wood-handling equipment to a live-storage hopper and then to a rotary kiln type dryer to reduce the moisture content of the wood to about 3%. The dried feedstock then passes to a shredder which reduces the chip size to the equivalent of a fine sawdust. This material is mixed with recycled solids from a char burner at a weight ratio of about five to one, char to wood, and the mixture is carried into a vertical transport flash pyrolysis reactor by recycled product gas. Rapid mixing occurs within the reactor as the suspension passes upward under turbulent flow. This achieves high heat-transfer rates within the mixture during a very short residence time and minimizes excessive thermal degradation of the materials and maximizes liquid yields.

Material leaves the pyrolysis reactor and passes through a cyclone separator to remove the char. Outlet gases from the quench system are cooled to 180°F in a gas/oil separator to produce fuel oil and process gases. A portion of the process gases is heated by a process heater and used to carry feed material into the flash pyrolysis reactor. The remainder of the gases is burned in the process heater to heat the carrier gases. These pyrolysis gases have a heat content of approximately 200 to 300 Btu/scf and have enough heat to eliminate the need for additional fuel.

Three case studies were analyzed using levelized and first year costing strategies for the production of fuel oil from biomass. These costs are summarized in Tables V-14 and V-15. Levelized costs range from \$5.86/MBtu to \$14.95/MBtu. The first year cost ranges from \$3.44/MBtu to \$8.76/MBtu compared to the projected cost of \$3.20/MBtu for conventional fuel oil in that first year.

Electricity

Direct Combustion

Electricity is now being generated by the direct combustion of wood in steam generators by the wood processing industry. In general, these wood burners produce high-pressure superheated steam that is expended in turbines to generate electricity.

Electricity is similarly produced in the electric utility industry by the combustion of coal, liquid residual petroleum fuels, and fuel gases or by the nuclear fission of uranium. A modern coal-fuel cycle may have a 880 MW generating capacity, for which a steam-generation capacity (at 3515 psia, 1000°F superheat, and 1000°F reheat) of 6,400,000 lbs per hour is required. The furnace is normally a vertical suspension type requiring pulverized coal. Direct substitution of pulverized wood (140 micron diameter) for pulverized coal is not feasible at this time without additional research. An approach for pulverizing municipal solid waste (metals removed) has been developed (Echo II Fuel, Combustion Equipment Associates) [V-24], and this fuel has been substituted for pulverized coal without derating the boiler. However, this technique has not been tried with wood, and the use of larger wood

TABLE V-14

LEVELIZED PRODUCTION COST SUMMARY FOR FUEL OIL

	Biomass Input ODT/Day	Biomass-Fuel Cost			
		$ 1.00/MBtu	$ 1.50/MBtu	$ 2.00/MBtu	$ 2.50/MBtu
Case #1	850	8.40/MBtu	10.58/MBtu	12.77/MBtu	14.95/MBtu
Case #2	1,700	5.86/MBtu	7.65/MBtu	9.44/MBtu	11.24/MBtu
Case #3	3,400	6.65/MBtu	8.89/MBtu	11.13/MBtu	13.38/MBtu

TABLE V-15

FIRST-YEAR PRODUCTION COST SUMMARY FOR FUEL OIL

	Biomass Input ODT/Day	Biomass-Fuel Cost $ 1.00/MBtu	$ 1.50/MBtu	$ 2.00/MBtu	$ 2.50/MBtu
Case #1	850	4.93/MBtu	6.20/MBtu	7.49/MBtu	8.76/MBtu
Case #2	1,700	3.44/MBtu	4.49/MBtu	5.54/MBtu	6.59/MBtu
Case #3	3,400	3.90/MBtu	5.21/MBtu	6.53/MBtu	7.84/MBtu

particles (saw dust) in the boiler would require derating of the boiler capacity.

Existing steam generators using hogged wood (1/4" diameter) range in size up to 600,000 lbs of steam per hour (1350 psi and 900°F) and are currently used by the wood processing industry. This seems suitable for smaller utility applications and most industrial applications. A plant generating 600,000 lbs of steam per hour would need approximately 850 ODT/day of feedstock. There appears to be no technical problem (rather the lack of demand for such equipment appears to be the problem) in designing a double furnace to handle the 1,700 ODT/day plant size. In these furnaces the hogged wood fuel is spread pneumatically or mechanically across the combustion chamber onto the surface of a traveling grate. Small fuel particles burn in suspension while larger pieces fall onto the grates. The flame over the grates radiates heat back to the fuel to aid combustion. Both underfired and overfired air are used for controlling the combustion character. The furnace walls normally are lined with heat exchange tubes. Because there is little refractory material, the furnace can respond to load variation quickly.

The grate systems themselves may vary substantially. Three types of grates are commonly used: dump grate, stationary grate, and traveling grate. Dump grates have the advantage of being more easily cleaned than the stationary grate. The stationary grate is equipped with water tubes tied into the steam generator circuit. Stationary grates may be inclined so that the fuel slides to the discharge point for the ash. Traveling grates are the most common, and the continuous dumping of ash by traveling grates provides more effective ash cleaning and thus a longer grate life.

The capability of stoker-firing equipment limits the maximum size of a steam generator that can be built today to 600,000 lbs per hour. If a double grate were to be used side-by-side, which requires two feed streams for the wood fuel, this capacity could be doubled.

Other types of boilers have been used industrially, such as a dutch-oven type of water tube steam generator. Both underfire and overfire are used to insure complete burning of the wood biomass that is formed as a pile in the dutch oven. This type of boiler is limited to small application and is generally not considered for new installations in the United States.

Small capacity boilers for wood firing tend to be shop fabricated units, dimensions limited to transport clearances, and of the water tube design. The vertical design reactor can adapt to different stoker designs, horizontal and inclined, and can be packaged in a unit with capacities of 75,000 lbs per hour of steam at 650 psig and 750°F final steam temperature. A horizontal designed reactor employs stationary grates and can be packaged in a unit with a capacity of 40,000 lbs per hour at 540 psig and 650°F final steam temperature.

Combined Cycle Gas Turbine Power Plant

The concept of combining a gas turbine in tandem with a steam cycle has been applied with considerable success in oil and gas fired utility applications. Fuel fed to the gas turbine (which operates at a higher temperature than a steam plant) is used to generate electricity directly from the turbine shaft. The turbine exhaust heat is then recovered in a boiler, and the steam then produces additional electricity by means of a steam turbine-generator. Overall efficiencies in excess of 40% are achieved with large combined cycles without the sophisticated complications required to maximize the efficiency of large steam plants.

The exhaust fired gas turbine cycle using biomass can be used in a combined cycle mode and avoids the destructive effects of feeding biomass directly into the turbine. Air entering the compressor is pressurized in the usual way. Instead of passing to an oil or gas burner, it is directed through the tubes of a ceramic heat exchanger where its temperature is raised. (The heat exchanger has been heated by the hot gases from the biomass furnace.) The heated air then continues through the turbine and provides the power to drive the turbine compressor and the generator load. On leaving the turbine, the air is routed to an external biomass furnace as combustion air. The combustion gas from the furnace passes over the exterior surfaces of the ceramic heat exchanger tubes transferring the heat through the tube walls to the high pressure air within. The combustion gases leave the heat exchanger as exhaust flow which is then used for raising steam in a heat recovery boiler. The steam can be used to meet process heat requirements, to power mechanical drive steam turbines, or to generate additional electric power by means of a steam turbo-generator. A combined gas turbine/steam turbine power plant using the exhaust fired cycle can be produced with existing technology. It improves conversion efficiency over steam systems by 25% to 40%. Power generation costs with this system burning wood-biomass are analyzed for plants generating 3.5 MW and 22 MW (V-20).

Cost of Electricity

Seven cases were analyzed using a levelized costing strategy for producing electricity. Costs are summarized in Table V-16 and may be competitive with conventional costs of electricity which range from 30 to 60 mills/kWh. The costs are shown for a municipally owned utility (no federal taxes) and for a publicly owned utility.

TABLE V-16

LEVELIZED PRODUCTION COST SUMMARY FOR ELECTRICITY
(in mills/kWh)

	Biomass Input ODT/Day	Biomass-Fuel Cost $ 1.00/MBtu	$ 1.50/MBtu	$ 2.00/MBtu	$ 2.50/MBtu
Case #1 Municipal	1,095	85.42	111.26	137.03	162.88
Case #1 Public		96.45	124.44	152.35	180.34
Case #2 Municipal	125	121.37	166.80	212.47	256.79
Case #2 Public		133.45	182.64	232.11	280.10
Case #3 Municipal	485	67.02	94.64	122.45	150.06
Case #3 Public		73.46	103.37	133.49	163.40
Case #4 Municipal	745	72.81	86.66	100.57	114.43
Case #4 Public		81.56	96.57	111.64	126.64
Case #5 Municipal	850	91.69	107.82	123.96	140.20
Case #5 Public		103.99	121.46	138.94	156.52
Case #6 Municipal	1,700	69.78	84.67	99.56	115.24
Case #6 Public		78.33	94.46	110.58	127.56
Case #7 Municipal	3,400	56.36	70.52	84.68	98.86
Case #7 Public		62.86	78.19	93.53	108.89

D. MARKET READINESS OF BIOMASS

Technical Readiness of Biomass Technologies

A number of issues relating to the technical readiness of biomass are being addressed in research programs conducted by DOE, private industry, and some nonprofit institutions. These are discussed relative to the production (including residues) and conversion of biomass feedstocks.

Production

DOE has awarded a total of $1.5 million of contracts and grants to 20 universities and firms to perform research on how to improve the productivity and reduce the costs of wood energy farming. Tentative plans indicate large increases in funding in the future [V-26]. Much of the research is directed towards instilling in potential users confidence regarding costs of biomass and the ability to provide an uninterrupted source of fuel. Some of the key technical issues related to production of biomass feedstocks from energy farms are:

- yields (dry tons per acre) from land and aquatic energy farms [V-14];
- demonstration of the technical feasibility of energy farms [V-4];
- environmentally safe energy farm management practices;
- selection of species for energy farms and genetic improvement [V-30];

- land availability and water utilization [V-30]; and

- directed nitrogen efficiency and nitrogen fixation through crop rotation with legumes [V-30].

Most economic studies of energy farms have assumed yields per acre year of 7 to 10 oven dry tons per acre-year to produce biomass for $1 to $2.50/MBtu [V-9, V-15]. Current research is examining costs and returns using fertilizer, soil prepared with municipal solid waste, local species, hybrid-species, irrigation, and reliance on natural rainfall. Many researchers feel that 10 ODT/acre-year yields can be achieved. Recognizing plant breeders' successes with grain yields through genetic improvements, this could increase by a factor of 2 to 3.5; however, much additional research is needed. Another aspect of species selection will be to pick species that have nitrogen fixing properties.

At present, the energy farm concept has undergone extensive engineering analysis but lacks concrete evidence of its practicality. Most of the data to support the analyses are hypothesized or come from small experimental projects on elements of the concept. Within the next few years, projects will begin to provide management experience of this system and verify the costs associated with this concept. Two major projects on energy farms are currently being implemented or planned. The first project, the Silvicultural Plantation Contract, funded by DOE, will be a 1,000 acre plantation on the Savannah River in South Carolina to gain experience in plantation management and to verify cost of crop production. A second project, funded by Gas Research Institute and DOE, will install (in the fall of 1978) a 1/4 acre aquatic farm in the Pacific off the coast of Santa Barbara, California. The aquatic system will grow kelp at an accelerated rate, harvest, dry, and deliver the kelp to an anaerobic digestion system with a capacity of 300 litres. The cost goals of this project are $3 to $5/MBtu for SNG. These types of projects will serve to eliminate many of the uncertainties associated with the energy farm concept.

As discussed in section A, land availability to support energy farms has been a major consideration. DOE will continue this research but also study the availability of water.

Conversion

In general, most of the technology for bioconversion is off-the-shelf due to extensive use during World War II and current use in Europe. A major bioconversion program by DOE's "Fuels from Biomass Program" is underway. Funding levels have increased from $0.6 M in FY75 to $12.7 M in FY77. Additional research benefits will be received from coal conversion research, such as gasification, since the primary difference in the conversion of coal and biomass to liquids and gases is only the front end of the process.

Biomass conversion by direct combustion to produce electricity is currently limited to small generators of 50 MW or less. Technical readiness as well as economic feasibility has been demonstrated at the small scale by the forest products industry and the large number of MSW demonstrations currently underway in the United States [V-4]. Size limitations are primarily due to the limits on boiler sizes that can be built today for biomass. Current boiler technologies that generate large amounts of electricity (of the 500-1,000 MW capacity) require a much finer feedstock (such as pulverized coal) to operate efficiently and satisfy combustion rates. A process for producing an equivalent fuel to pulverized coal has been tested using processed MSW mixed with coal. Another study by Aerospace Corporation indicates that by adjusting temperatures of primary combustion air to 500°F (180°F required for coal) and secondary combustion air to 1060°F (650°F required for coal) a burning rate equal to that for pulverized coal can be achieved. The wood size in this study is wood particles that will pass a half-inch screen. DOE has funded experiments on a small scale in 1977 to verify these combustion properties prior to retrofitting a full-size central power utility. The combustion module for conducting the experiments will simulate the combustion of a chamber needed for firing a 300 to 500 MW boiler. Experimental data are not available at this time [V-28].

A major demonstration plant for production of 50 MW electricity and industrial steam (200,000 lbs/hr) is in site selection and design phase and is being funded by DOE. It will convert 1,000 ODT/day to 8 GBtu/day. A plant owned by the Eugene Water and Electric Board, Eugene, Oregon, has used wood since 1941 and currently provides 34 MW of electric power at a cost of 9.75 mills/kWh and 450,000 lb/hr of steam capacity at a cost of $0.81/thousand lb for wood [V-27].

Pyrolysis and gasification of biomass to produce a number of end products (low- or medium-Btu gas, liquid fuels, and charcoal) received extensive research at the turn of the century and during the 1920s as a means to produce "town gas" from coal and to become independent of imported oil. In more recent years, gasification and pyrolysis of MSW have received more R&D attention resulting in a number (20) commercial processes in advanced stages of development (Union Carbide--Purox; Occidental Research Corporation--Flash Pyrolysis; Ando-Torrex Processes, etc.). Using MSW in pyrolysis or gasification is more difficult than using biomass because inorganic materials and plastics interfere with pyrolysis. Research by DOE is concentrating on the development of catalysts that can increase the rate of the process to reduce overall cost. Currently in the United States, there are 15 processes at the commercial or demonstration stage and 31 active process development or research programs. To date, a majority of the commercial or demonstration programs has been privately funded, some with minor government assistance. Few developers are seriously considering using a solid waste or residue feedstock to produce synthetic gas for methanol or ammonia [V-29].

An additional technical question is the optimum size of pyrolysis-gasification units. The size of commercial units ranges from 50 to 1,000 tons/day, with most processes being in the range of 100 to 300 tons per day (TPD). These sizes are considered the minimum range for economic processing of MSW. Large-scale coal gasification or liquefaction systems being proposed are about two orders of magnitude larger. Economies of scale for biomass synthesis gas processes (for use in gas turbines or for making ammonia or methanol) require much larger units, greater than 1,000 tons/day. Development of large conversion systems must be coupled to the development of energy farms that can provide continuous supplies of feedstocks.

Anaerobic digestion has a long history of use and development in the 20th Century. These systems were developed because of fuel shortages rather than being more economical than natural gas or other fuel sources. This is still the situation today. In recent times, anaerobic digestion has been widely used in sewage treatment plants in the United States. Large digesters (1 million gallons) have been developed and are equipped with heat exchangers (to maintain temperatures) and mixers. With the recent increases in the price of natural gas, interest in these systems for producing natural gas has grown. At $3/MBtu, some systems are marginally economic although considerable use may arise from natural gas curtailments than from favorable costs. To reduce costs of these systems, improvements in the rates of reaction and development of low-cost digesters is needed [V-4]. Generally, cost for large digesters is $1/gallon per unit of capacity.

State of Equipment Delivery System

Equipment for collecting and handling residues and energy farms is well established as part of existing harvesting systems for forestry, agriculture, aquaculture, and MSW [V-30]. Minor refinements and optimization will be achieved as market demand for these systems increases. For land-based energy farms, special collection and handling equipment must be developed. This is especially true if special management practices such as coppicing and densification are employed. It would be desirable to have a portable farm implement that can chip, dry, hammermill, and densify biomass at a rate of 20 to 30 ODT/day. This "ideal" machine should be trailer mounted and use biomass fuel to run itself (parasitic energy). If a biomass conversion plant is located within an unknown radius of the farm, then densification may not be necessary. Densification becomes necessary if the farm or biomass source is decoupled from the conversion plant. In this case, densification enhances the storage properties of biomass, standardizes the fuel, and lowers transportation costs. Densification of wood can be accomplished today, but these units are not transportable and require major capital investments, as much as $1 million. A portable densification machine is currently being developed; however, it has not yet proved successful in the field. Similar to production, a growing list of equipment suppliers is associated with the collection of residues [V-30].

Conversion

As discussed in the technical readiness assessment section, one primary limitation on conversion is the size of conversion systems. Most manufacturers supply biomass conversion systems with capacities of less than 1,000 ODT/day. Until larger systems are demonstrated, this will continue to be the case.

For anaerobic digestion systems, the opposite is true. Due to the influence of sewage treatment requirements, many suppliers of large anaerobic digesters (1 million gallon) exist. Development of much smaller units to support feedlots and farms is being funded by DOE.

Institutional Barriers to Biomass Market Readiness

Environmental Impacts

The key environmental issues related to use of biomass are as follows:

- The large land and water requirements of land energy farms can restrict competing uses of land and water in some regions. This impact is not viewed as being acute in the near term or necessarily in the long term either [V-31]. Environmental costs can be minimized by use of marginal land not suitable for crops or fiber production and indigenous species.

- The potential exists for erosion and depletion of soil organic content if too many residues are removed [V-30]. In the case of agriculture residues, research at Iowa State University indicates that leaving 30% to 50% of the residues on the ground is sufficient to control erosion and depletion of soils [V-32]. These studies indicate that long-term soil fertility may be improved by residue management.

- Direct combustion of biomass generates air pollutants similar in nature but different in degree to those generated by combustion of fossil fuels [V-31]. Due to a low sulfur content in biomass, sulfur oxides from combustion are not a primary concern. However, pollutant particulates, nitrogen oxides, and carbon monoxide may be emitted in greater quantities during combustion than during fossil fuel combustion. An advantage of energy plantations is that the carbon and nitrogen released will be re-fixed during the next growing cycle (two to three years) making the net release of these elements small.

- Thermochemical biomass conversion produces a number of wastes in the form of gases, tars and oil, unconverted biomass, and ash in varying amounts depending upon the process employed. These pollutants can affect air, water quality, and land use and present possible health and safety concerns. Research conducted on coal conversion will provide control strategies for these pollutants that are similar in kind but significantly less than combustion or conversion of fossil fuels.

- Anaerobic digestion serves to reduce the pollution potential of some biomass feedstocks which would be considered waste. Nevertheless, the process does produce a sludge which must be disposed [V-30, V-31]. A number of studies and experiments have been conducted to use sludge as a fertilizer and as a feed supplement for animals [V-33].

Several other barriers exist that must be resolved before biomass can become a significant contributor of energy. These are summarized as follows:

- The existing level of uncertainty relative to cost of biomass conversion can be mitigated by proper demonstration. As a result of the historical usage of certain conversion processes to produce electricity, process steam, and SNG, these uncertainties are small compared to other solar technologies, and biomass should achieve early commercialization status prior to 1990. Newer conversion systems that produce ethanol, fuel oil, ammonia, and methanol are expected to fall in the 1990 to 2000 time frame [V-30].

- As discussed earlier in this report, a major barrier to commercialization is land availability, water resources, and the use of that land. Demonstrations using marginal land which is not suitable for crop or fiber production but receives adequate rainfall (with backup irrigation) should overcome this barrier.

- Plantation management strategies are uncertain as to type of species, method of spacing, yields per acre, long-term storage, use of fertilizer, and irrigation. Near-term research by DOE should eliminate many of these uncertainties by 1981 [V-30].

- The lack of acceptance of biomass as a valid renewable fuel source has delayed funding of many biomass projects. This barrier could be overcome by increasing the funds allocated to biomass and increasing the awareness of biomass by the research community and potential users.

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VI. OCEAN THERMAL ENERGY CONVERSION SYSTEMS

A. INTRODUCTION

History

Ocean Thermal Energy Conversion (OTEC) is a means of capturing the sun's energy absorbed by the waters of the ocean. As early as 1881, Jacque D'Arsonval, a French physicist, proposed the concept of producing energy by using the ocean's temperature difference between warm surface water and cool, deep ocean water [VI-10]. In the early 1930s, Georges Claude, a French engineer, built a shore based open-cycle power plant in Cuba that produced 22 kW of electricity [VI-5]. Economic and technical problems curtailed his effort. The ocean thermal concept was revived in 1965 by Anderson and Anderson [VI-3]. Since 1965, several configurations of OTEC plants have been developed by university researchers, aerospace companies, and shipbuilders.

Principle of Operation

Warm surface water of the ocean is used to vaporize a low boiling point working fluid, usually ammonia, in an evaporator. The vapor is expanded into a turbine which operates a generator to produce electricity. The working fluid is then condensed by cool, deep water and returned to the working cycle. A temperature difference of at least 34°F to 40°F is required to operate the low-pressure turbines, thus necessitating the location of plants in semi-tropical or tropical waters. The system described above is a closed Rankine system. An open Rankine system operates in much the same way except seawater is used as the working fluid, eliminating the need for heat exchangers. Five locations with temperature differences of $\geq$ 38°F have been identified near population centers.

OTEC plants can be either moored (anchored via a cable to the ocean floor) or dynamically positioned via thrusters to counter the wind and ocean current forces.

System Components

Ocean Thermal Energy Conversion systems consist of a power subsystem, an ocean subsystem, and the energy transmission subsystem. The power subsystem includes: heat exchangers (evaporator and condenser); fluid transfer systems (warm water and cold water pumps and working fluid subsystem); turbine-generator; and electrical and control systems. The ocean subsystem consists of a platform, cold water pipe, anchoring/dynamic positioning, deployment, and miscellaneous subsystems. Electrical energy can be transmitted to shore via an underwater cable.

B. PROPOSED OTEC SYSTEMS AND THEIR COSTS

Proposed Systems

It should be emphasized that OTEC systems are conceptual designs only. Excepting Claude's plant built in the 1930s, no plants have been constructed or are under construction. As previously mentioned, D'Arsonval proposed closed-cycle systems, and Claude proposed open-cycle systems. Recently, Dr. Clarence Zener, Carnegie-Mellon University, has been researching a lift/foam cycle system. The three concepts will be discussed in detail.

Closed Cycle

A visual description of a closed OTEC system is presented in Figure VI-1. Approximately half the temperature difference from the ocean is available for conversion in the heat engines. The

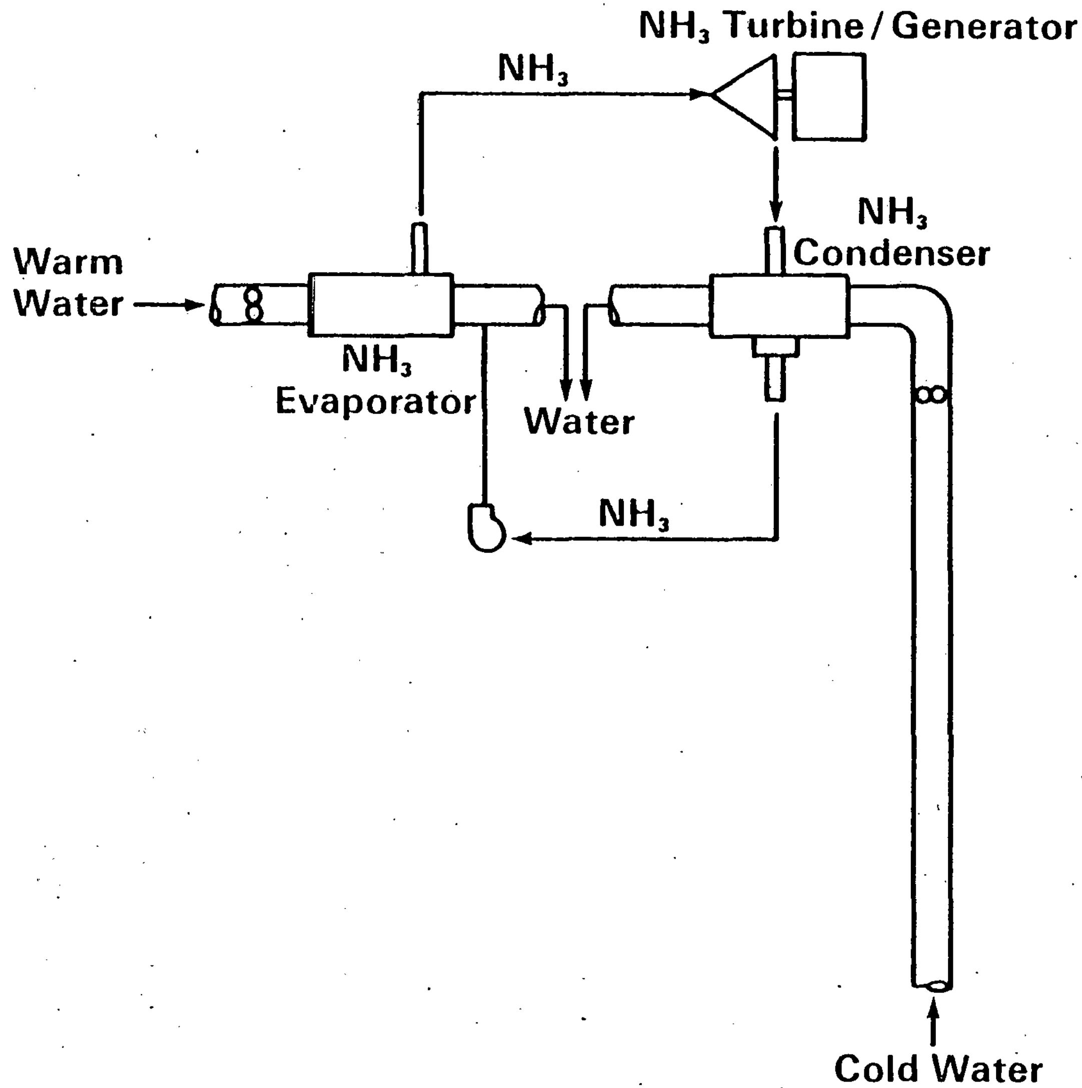

Figure VI-1. Ocean Thermal Energy Conversion Closed-Cycle System other half is used to transfer heat from the sea to the working fluid in the heat exchangers. Although conversion efficiencies are near 3%, parasitic auxiliary power requirements reduce the net efficiency of the closed-cycle system to approximately 2%.

Although the closed-cycle process is quite simple, numerous component and subsystem changes can be made for a given requirement. Unfortunately, the optimum economic and technical efficiency mix has not been identified. A discussion of the components and materials of closed-cycle systems follows.

Power System. The performance of an OTEC power system is primarily dependent upon the heat exchanger, the working fluid, turbine, and electric generator. The heat exchanger has two units--the evaporator, which uses warm seawater to supply heat to vaporize the working fluid, and the condenser, which uses cold seawater to cool the vapor back to liquid. Both are crucial since the temperature difference is small.

Two major heat exchanger designs are the shell-tube and plate-fin. The shell-tube evaporator and condenser have seawater on the tube-side (inside) and the working fluid on the shell-side (outside). It is similar to a liquid refrigeration system. The surface area per cubic foot of volume is much larger in the plate-fin than in the shell-tube design. The water inside the flat-plate has straight and rectangular passages while the working fluid crosses finned surfaces which increase the effective transfer area. The shell and tube design is presently favored because the manufacturing technology is well established, and development work can center on heat transfer enhancement. However, plate and fin exchangers are more compact, probably have better performance but are more expensive to manufacture [VI-2].

Several heat exchanger enhancement techniques are being studied to increase the heat transfer efficiency while reducing the size and cost of the units. Two proposed techniques are: incorporating axial grooves on the water side to double the effective heat transfer area and fluting the wall on the working fluid side.

There are several criteria for selecting heat exchanger materials: conductive and corrosive properties, compatibility with other liquids, and cost. The two metals being considered are aluminum and titanium. A comparison [VI-20] of the two reveals:

Aluminum	Titanium
• good conductor	• poorer conductor
• more corrosive in seawater	• less corrosive in seawater
• believed to be compatible with ammonia (not proven in the presence of seawater)	• compatible with ammonia
• less expensive	• more expensive
• abundant, but must be imported	• abundant, but not mined extensively due to low demand
• easily fabricated	• more difficult to fabricate

Working fluids considered include ammonia, propane, and freon. Ammonia is conceptually preferred by most contractors because of its superior heat transfer properties, lower cost, and availability. Environmentalists believe that ammonia has the smallest potential for environmental damage [VI-11].

The conversion machinery for a closed-cycle system is a turbine and an electric generator. Auxiliary machines include pumps for warm and cold water circulation. A pump is required to raise condensate working fluid pressure from its low value at the condenser exit to the pressure required at the evaporator inlet. Start-up machinery is also required.

Ocean System. The ocean system is made up of the platform and the cold water pipe (CWP). Platform types being examined are a ship, spar buoy, circular barge or disc, and semisubmersibles. Materials proposed for the cold water pipe are fiber reinforced plastic, steel reinforced fly ash concrete, and reinforced rubber. The platform and cold water pipe must be compatible. The pipe must support itself and also withstand top loads from the platform and side loads from ocean currents. To achieve the greatest temperature difference a CWP 3,000 ft long is being considered. A 100 MW plant might require a pipe 50 ft by 3,000 ft for a flow as large as 5 million gallons per minute.

Modularizing closed-cycle OTEC plants would alleviate design, manufacturing, and deployment problems of large heat exchangers, pumps, and turbogenerators. This concept also enhances assembly line techniques. However, there appears to be no way to cut the size of the CWP. One pipe must serve the entire system.

Open Cycle

Georges Claude first demonstrated the use of seawater vapor as the working fluid in his open-cycle system in the 1930s. His design is presented in Figure VI-2. Open-cycle systems do not require heat exchangers; therefore, biofouling problems are minimized. Open-cycle systems do require large turbines. The greatest problem of the open-cycle system is controlling power losses from pumping and removing air from seawater. The vast amounts of water that must be transported require that losses be carefully controlled. Trade-offs to minimize pumping power losses could necessitate evaporators, degasifiers, and condensers much larger than would be economically feasible.

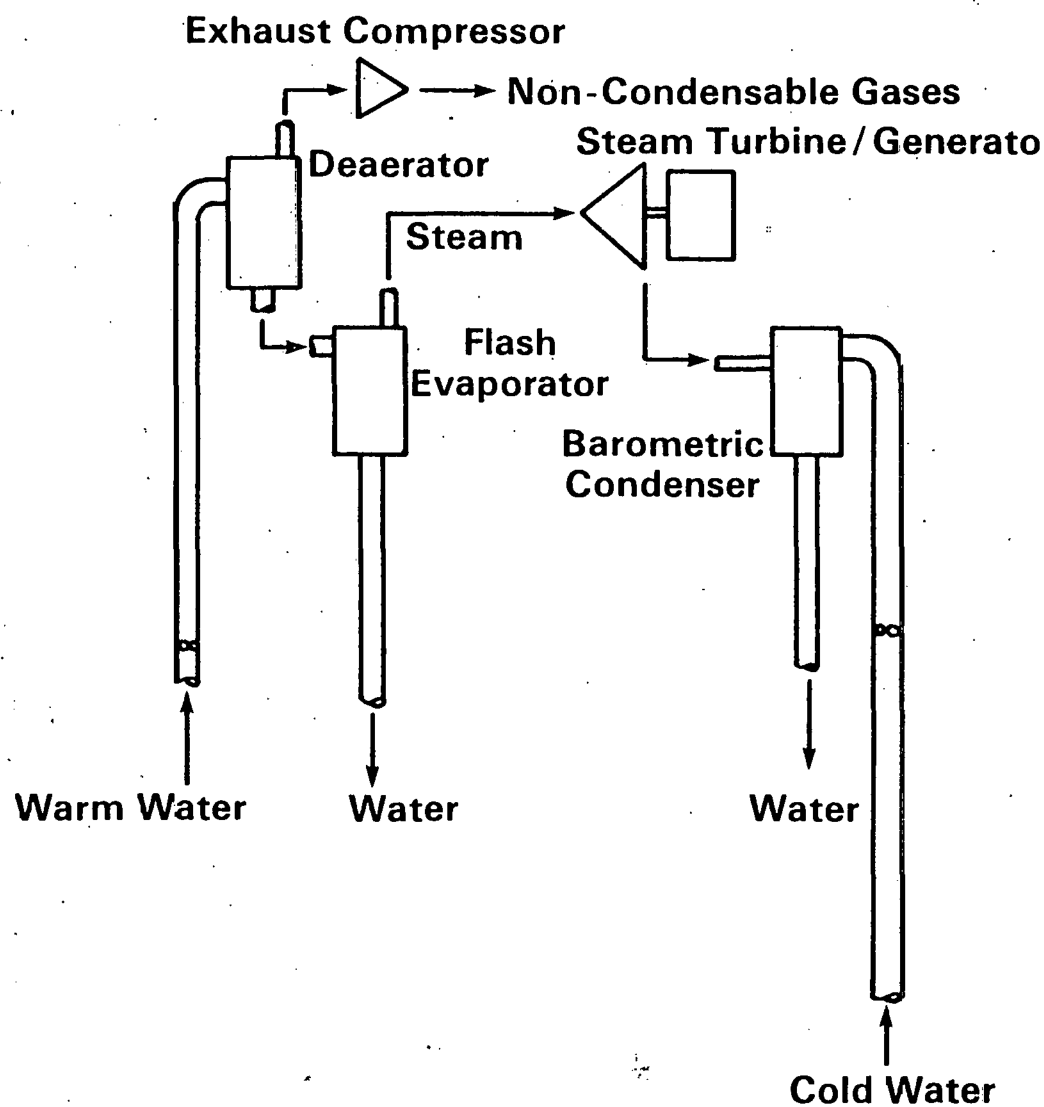

Figure VI-2. Ocean Thermal Energy Conversion Open-Cycle System

Lift/Foam Cycle

Both closed-cycle and open-cycle systems release warm and cold ocean waters into the ocean. Some proponents of the lift/foam system claim that the system has no warm water exhaust [VI-34]. (See Figure VI-3.) After air is evacuated, warm water is drawn into the system by the partial vacuum created by the water which is foamed and rises past foam breakers. The freed vapor flows down a central pipe and is condensed by cold deep water. The liquid is collected and used to drive a hydraulic turbine.

Advantages of the lift/foam system are (1) the absence of heat exchangers, (2) the replacement of gas turbines with high head hydraulic turbines, and (3) the automatic elimination of the water recirculation problem.

Cost Estimates For OTEC Plants

Although three OTEC systems have been identified, multiple cost estimates are available only on closed-cycle systems. These cost estimates are discussed below. Costs for open and lift/foam cycle systems are not backed by a detailed engineering analysis of equipment requirements.

Closed Cycle

Most current cost estimates from major contractors focus on closed-cycle systems only. These cost estimates depend on the following design assumptions:

- Temperature differences - 34°F or 40°F
- Working fluid - ammonia, propane, freon

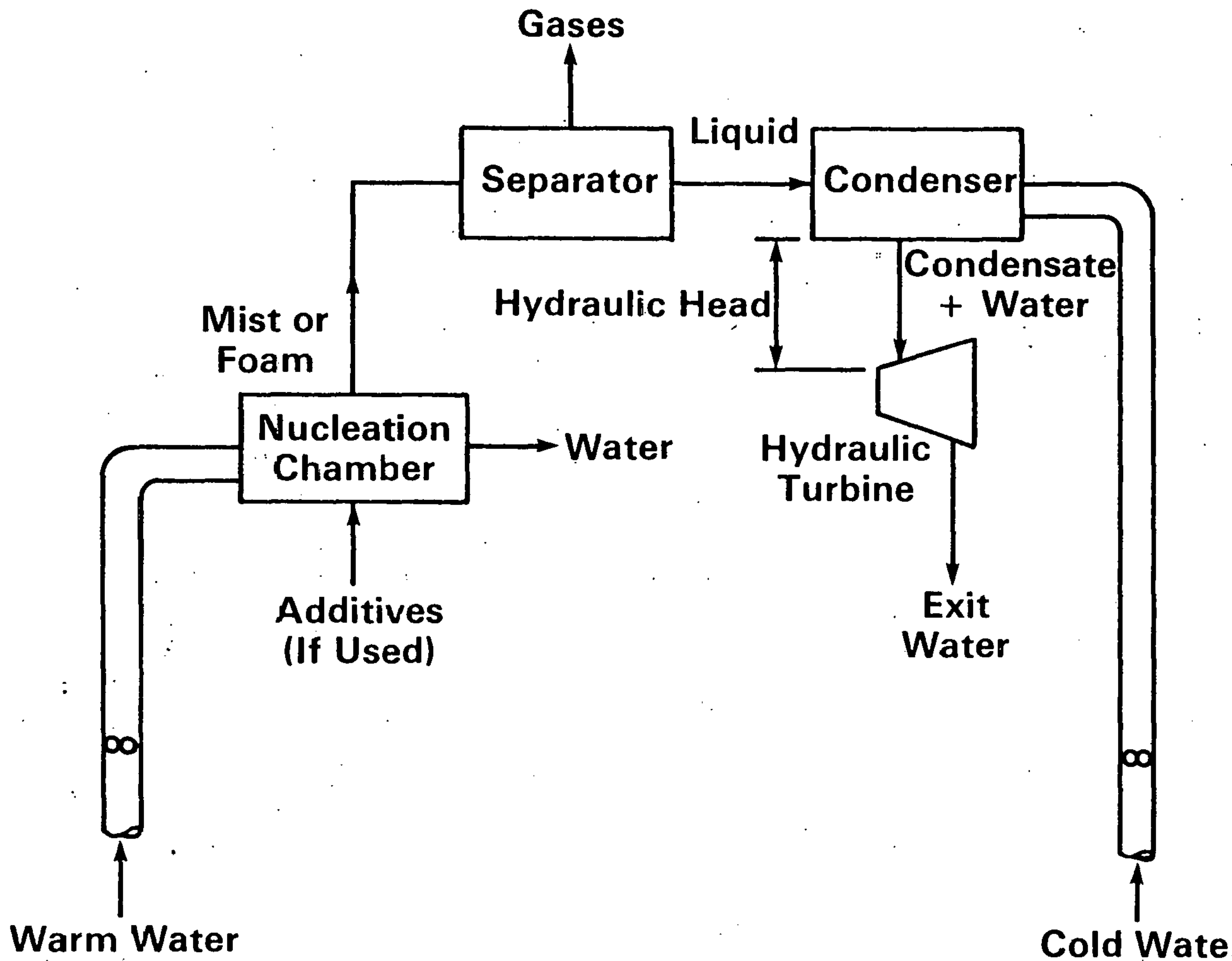

Figure VI-3. Ocean Thermal Energy Conversion Lift/Foam Cycle System

- Heat exchanger material - aluminum or titanium
- Moored or dynamically positioned platform
- Load capacity factor - .8 or .9
- Size of the system - 100 MW, 400 MW, or 3,200 MW
- Distance of delivered energy.

The design representing closed-cycle OTEC systems was chosen because of the reliability of contractors' cost estimates and the availability of materials. The closed-cycle OTEC plant is composed of 8 to 50 MW power modules for a 400 MW system rated at 40° ΔT. The working fluid is ammonia, and titanium shell and tube heat exchangers are used. A concrete ship houses the power modules. The cold water pipe, 100 ft in diameter and 3,000 ft long, is made of steel-reinforced fly ash concrete.

Although the optimum plant size appears to be 400 MW, cost estimates for 3,000 MW plants are available. Table VI-1 shows cost estimates compiled by MITRE Corporation in February 1978 [VI-9].

The most expensive single item of the plant is the heat exchanger. Estimates for titanium heat exchangers ranged from $470/kW (46% of the total system) to $820/kW (34% of the total system). Titanium is believed to be the most expensive material for heat exchangers. Although aluminum costs are slightly less (ranging from $400/kW to $700/kW), the aluminum exchangers need replacing more often. The high and low estimates for the total power system varied by a factor of 2.

Estimates for the ocean system showed a much larger range--$171/kW to $577/kW. Although the cold water pipe represents the most expensive item in the low estimate, the platform cost estimates ranged from $50/kW to $300/kW, a factor of 6. Appendix Table VI-A contains the most recent ocean system cost estimates available from DOE.

TABLE VI-1

COST ESTIMATES FOR CLOSED-CYCLE OTEC SYSTEMS
(3,000 MW, $\Delta T=40°F$)

	1977 $/kW
Power System	
Heat Exchangers (Titanium)	470 - 820
Demisters	7 - 40
Turbogenerators	70 - 112
Seawater Pumps	95 - 200
Other Power Systems	108 - 195
Subtotal	750 - 1,367
Ocean System	
Platform	50 - 300
Cold Water Pipe	71 - 80
Mooring/Deployment	50 - 197
Subtotal	171 - 577
Transmission	100 - 450
Total System	1,021 - 2,394
Average	$1,711/kW
Modal Value	$1,320/kW

These estimates are from four contractors and DOE personnel.

Source: P. A. Curto and Grant Miller, "An Update of OTEC Baseline Design Costs," METREK Division, MITRE Corporation, McLean, Virginia, February 20, 1978.

Power subsystem cost estimates varied less than other subsystem costs. Research in the past two to three years has reduced uncertainties associated with the power system. Other problems and uncertainties will be reduced when OTEC plants are actually constructed and deployed.

Transmission cost estimates ranged from \$100/kW to \$450/kW. Operation and maintenance cost estimates are from TRW [VI-28] and Lockheed [VI-21] reports of 1975. TRW estimated O&M costs of 1.4%; and Lockheed, 0.45% of total capital investment. These estimates translate into 4.78 and 1.91 mills/kWh, respectively.

Dr. Avriham Lavi in March 1978 discussed estimates of operation and maintenance costs for cleaning processes only. These estimates were [VI-12]:

Method of Cleaning	Mills/kWh
M.A.N.	1.7
Amertap	3.6
Chlorine	0.4

Open Cycle and Lift/Foam Cycle

The most recent cost estimates for open-cycle OTEC systems place open-cycle costs 25% to 30% above closed-cycle costs [VI-13]. Cost estimates for the lift/foam cycle are approximately \$1,800/kW [VI-33].

Cost of Electricity and Products

A required revenue model was used to estimate busbar costs for OTEC electricity from MITRE estimates of capital costs. Table VI-2 shows electricity costs for a 3,000 MW OTEC plant in 1978 mills/kWh. Assuming a plant capacity factor of .9 and the use of titanium heat exchangers, busbar costs range between 26 and 62 mills/kWh. Estimates are given for both a municipally owned and publicly owned utility. Incremental transmission cost estimates for power to shore are <5 mills/kWh for less than 25 miles of transmission and increase to about 10 mills/kWh for 100 miles of transmission [VI-23].

TABLE VI-2

OTEC ELECTRICITY COSTS FOR 3,000 MW PLANTS IN THE YEAR 2000
(1978 mills/kWh)

PLANT	Capacity Factor		
	.75	.8	.9
OTEC Plant with Aluminum heat exchanger			
Municipal	30 - 57	28 - 54	26 - 49
Public	35 - 69	34 - 65	31 - 59
OTEC Plant with Titanium heat exchanger			
Municipal	31 - 60	29 - 56	26 - 51
Public	37 - 72	35 - 68	31 - 62

MITRE has estimated the cost of producing aluminum using OTEC power [VI-8]. OTEC aluminum plant costs include the OTEC system, transmission link, aluminum processing facility, and a bauxite mine. Cost estimates were based on an OTEC facility five miles off shore with an AC transmission line to the plant capable of producing 150,000 tons of refined aluminum per year. The OTEC aluminum plant would cost between $800 million and $1.1 billion. The O&M costs are assumed to be $1,000/ton. This leads to product costs of from $1,700 to $2,000/ton for OTEC produced aluminum (See Table VI-3 for comparison with conventional costs.)

TABLE VI-3

COST ESTIMATES FOR ALUMINUM SMELTING IN THE YEAR 2000

Location	Conventional Fuel: Feedstock	Conventional Fuel: Comparative Cost in 2000 1975 $/ton	OTEC Cost $/Ton: 10% Tax Credit	OTEC Cost $/Ton: 20% Tax Credit
Island Complex	Coal (Mainland)	2,000-3,000	1,700-2,000	1,500-1,800
(Puerto Rico)	Oil (Island)	3,000-4,000		

Source: Curto, P. A., "An Update of OTEC Baseline Design Costs." The MITRE Corporation, METREK Division, McLean, Virginia, February 1978.

Cost estimates by IGT [VI-4] for OTEC-produced liquid ammonia are shown in Table VI-4. The estimates are site-specific and assume a range of from 10 to 40 mills/kWh for power. The range of estimates reflects various destinations(e.g., Key West to New York or Key West to Miami). Estimates range from $170/ton to $500/ton.

Costs for OTEC-produced ammonia assuming a 500 MW OTEC plant with electricity cost of 20 mills/kWh range from $260/ton to $320/ton. Costs of ammonia from conventional sources are presented in Table VI-5.

Comparison of OTEC Costs to Conventional Costs

Conventional cost estimates for aluminum smelting and ammonia are shown in Tables VI-3 and VI-5. OTEC is only in the R&D stages of the commercialization process. With the successful completion of the program recommendations for technological advance and the imposed incentives for commercialization, OTEC could become a viable renewable energy source by the turn of the century.

C. MARKET READINESS OF OTEC SYSTEMS

No ocean thermal energy conversion plant has been built or operated since the experiments of Claude during the 1930s, nor have many of the system components been proven reliable in a marine environment. Therefore, it is somewhat academic to discuss an OTEC delivery system. However, one can speculate on the potential actors in the manufacture and distribution of the OTEC plants.

TABLE VI-4

COST ESTIMATES OF OTEC PRODUCED LIQUID

AMMONIA FROM VARIOUS SITES[a]

$/ton

OTEC SITE	Cost of OTEC Electricity per kWh			
	10 mills	20 mills	30 mills	40 mills
Key West	179-199	264-284	349-369	435-454
West Florida	184-189	269-274	354-359	439-444
Miami	173-188	258-273	344-359	429-444
New Orleans	196-207	282-292	367-377	452-462
Brownsville	197	282	367	452
Puerto Rico	188-197	273-282	358-374	444-453
Hawaii	198	283	363	453
Brazil	227-239	312-324	397-409	482-494

[a]Figures vary depending upon distance of shipment and the site-specific capacity factor.

Source: Biederman, Nicholas; Sinnott, John; Talib, Abu; and Knopka, Alex; "OTEC: Mission Analysis, Energy Carrier Cost and Market Penetration Analysis, Final Report." Institute of Gas Technology, IIT Center, Chicago, Illinois 60616.

TABLE VI-5

ESTIMATED AMMONIA PRODUCTION COSTS

FROM CONVENTIONAL FEEDSTOCKS[a]

(1976 $)

Feedstock	Production Costs, $/ton 1985	Production Costs, $/ton 2000
Coal	150-225	220-270
OPEC Natural Gas	220-260	260-330
Conventional Natural Gas	160-210	260-330

[a]In making the above estimates, IGT assumed the following costs:

	1985	2000	Destination
Coal (lignite) $/ton	5.00-20.00	35.00-40.00	Mississippi Valley
OPEC Natural Gas $/MBtu	4.50- 5.00	6.00- 6.50	Texas Gulf
Conventional Natural Gas $/MBtu	3.00- 3.50	6.00- 6.50	Texas Gulf

Source: Biederman, Nicholas; Sinnott, John; Talib, Abu; and Konopka, Alex. "OTEC Mission Analysis, Energy Carrier Cost and Market Penetration Analysis, Final Report. "Institute of Gas Technology, IIT Center, Chicago, Illinois.

Currently, several large corporations, TRW, Lockheed, and Westinghouse, are under contract to DOE for the design of the OTEC power system. The major ocean engineering contractors include Rosenblatt & Son, Inc., and Gibbs & Cox; the major cable firms are Pirelli and Simplex.

The OTEC Program has been criticized for too much aerospace involvement in configuration design, layout, and deployment. Critics believe that the offshore oil industry should get involved. Their planning approach would focus on materials, structural, and other key engineering problems.

OTEC plants could be built in shipyards by the shipbuilding industry, towed out to sea, and installed. Some ocean engineering consultants feel that shipyard construction facilities and practices would allow an OTEC system to go from order to delivery in five years [VI-26]. Shipowners are, therefore, an obvious part of the technology delivery system. Shipowners have the working relationships with the ship classifiers and insurance companies that are also necessary parts of the delivery system. Lending institutions that provide the working capital and investment capital for shipowners and shipbuilders are another component. Naval architects will be needed to synthesize the technical designs from R&D contractors, equipment manufacturers, and consulting engineers. Nonfederal markets (utilities, aluminum producers, fertilizer producers, etc.) must also get involved [VI-13].

<u>Risks Associated with OTEC</u>

The uncertainties surrounding <u>cost</u> estimates and <u>technological performance</u> make OTEC a high-risk technology. Variable costs (fuel and O&M components) for OTEC appear low, but the initial capital investment costs are high. At this stage the component cost estimates are extremely difficult to substantiate. The wide difference in estimates indicates high uncertainty.

Beyond these capital cost uncertainties lie the busbar cost estimates of producing electricity. Variables to be determined for reliable busbar cost estimates include [VI-22]:

- thermal resource availability,
- capacity factor of the plant,
- fixed annual charge rate,
- cost of fuel, and
- operating and maintenance costs.

Progress in the program will be determined by the increasing accuracy of cost estimates for the system as more R&D funds are invested.

The major overwhelming problem with the technology is that many components required are at present beyond the state-of-the-art--especially regarding magnitude of sizes, materials, and deployment. It is impossible at this point to predict how reliable an OTEC plant can be once it is sited and operable. There are great uncertainties about lifetime reliability and the effects of interruption should an OTEC plant fail on power generation or production.

<u>Institutional Considerations</u>

The acceptance of OTEC as a viable energy source is as dependent upon institutional factors as on technological factors. Institutional factors range from government programs to international law. The issues that will be discussed focus on government policy, the utility sector, the legal sector, and private organizations.

The possibility of OTEC becoming an alternative energy source is contingent upon DOE funding of the OTEC Program. At the research stage, the uncertainty of financing for OTEC has been a result of uncertainties in roles, missions, and funding priorities of federal agencies involved in energy development. The budget for future demonstration and operational phases of OTEC development is contingent upon success in the research phase [VI-32]. Table VI-6 shows OTEC funding from 1972 through 1978. In FY78, $35 million was budgeted for OTEC research [VI-22].

The most influential sector in the acceptance of ocean thermal power will be the end-users themselves--the utility or product processing industries. There are barriers to OTEC's acceptance by these end-users. As David Jopling, Florida Power and Light, has stated: "One of the most fundamental problems is that the utility industry does not have confidence in the present OTEC research program" [VI-25]. Industry confidence is crucial to the future of OTEC. Jopling proposes that this lack of confidence stems from utilities not being involved from the early conceptual planning stages of the OTEC program as well as utilities, equipment suppliers, large private industry groups, companies, and consulting firms who have had the most experience with the construction, deployment, and operation of large marine structures. The whole question of acceptance of OTEC by utility companies must be assessed in light of the decision criteria they use when deciding to adopt new technologies. Southern California lists the following criteria in decreasing order of importance [VI-15]:

- capital costs of new capacity (investment),
- long-term availability of fuel,
- operating cost estimates,

(Budgetary Obligations in Thousa of Dollars: ERDA and NSF combined)

Program Activity	Fiscal Year						
	1972	1973	1974	1975	1976*	1977	1978**
Program support	...	...	...	111	2,062	2,381	...
Definition and systems planning							
--Systems studies and workshops	85	230	530	786	237	1,440	...
--Test program requirements	...	...	...	...	1,091	...	...
--Mission analysis	...	...	...	...	360	328	...
--Energy utilization	...	...	...	360	202	...	...
--Marine environment	...	...	...	36	312	10	...
--Environment impacts	...	...	...	205	457	136	...
--Thermal resources assessment and siting studies	...	...	50	172	...	77	...
--Legal and institutional studies	...	...	...	61	145	33	...
Engineering development							
--Heat exchangers	...	...	...	...	250	1,721	...
--Electric cables	...	...	...	...	...	200	...
Advanced research and technology							
--Heat exchangers	...	...	150	435	1,669	2,834	...
--Exploratory power cables	...	...	...	27	...	118	...
--Submarine electrical cables	...	...	...	50	...	...	...
--Biofouling and corrosion	...	...	...	207	1,303	2,702	...
--Ocean engineering	...	...	...	505	497	25	...
Engineering test and evaluation	...	...	...	...	...	1,498	...
TOTALS	85	230	730	2,955	8,585*	13,500	35,000

* Includes funding for Transition Period (July 1, 1976 to September 30, 1976).
**Breakout not available for FY78.

Source: Department of Energy

- cost of capital (interest rates),
- environmental impact,
- reserve and reliability criteria,
- capacity forecast,
- construction and licensing time,
- site costs,
- transmission cost estimates, and
- candidate site selection.

It seems obvious from the above criteria that utilities would shy away from OTEC based on the paucity and unreliability of cost data alone. Before they adopt OTEC they must have some conviction that OTEC investments will yield clear cost savings over competing sources of energy.

Problems associated with OTEC include (1) capital budgeting adjustments for front end financing, (2) the complexity of regulatory structures [VI-32], and (3) a change in staff skill requirements with associated potential labor problems. Florida Power and Light experienced these problems with their investment in nuclear power plants. The delay in the plant certification alone cost FP&L hundreds of millions of dollars [VI-16].

Historically, utilities have relied on either the power plant equipment manufacturers or the Electric Power Research Institute (EPRI) for research and development of technological innovations. Utility regulatory commissions have allowed companies some independent research money based on their operating capacity. The smaller utilities have traditionally spent their research money on product improvement tasks, and the larger utilities have invested in new technology development. To date, none of the utility or EPRI monies has been spent on OTEC [VI-32].

International Barriers to OTEC Market Readiness

Within the newly formed 200-mile economic resource zone, there will be a need to control the location of OTEC plants so they do not present a hazard to shipping. The deployment, implementation, and regulation of OTEC plants on the high seas--thought of as the common heritage of mankind--will present problems. Developing nations have made a number of demands relating to the mining of the seas which could impact direct costs and control of OTEC operations. The U.S. State Department, along with the various international agencies, will become involved in the regulatory process of assessing these demands [VI-15].

Current legal issues surround the establishment of a "reasonable" licensing fee. Future issues after deployment of OTEC plants will be the costs levied for operating fees and the demands by other countries for shared products, shared technology, or other sizable payments for use of the oceans [VI-15].

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VII. WIND ENERGY CONVERSION SYSTEMS

A. INTRODUCTION

History

Since the 1850s wind energy has been used extensively in the United States primarily for water pumping. Of six million small machines (<1 kW) operable around the turn of the century, some 150,000 are still in use today [VII-30]. Low-cost electricity through the Rural Electrification Act of 1936 and inexpensive fossil fuels caused a decline of U.S. interest in wind machines after WW II. This decline continued for decades.

Around the mid-1970s, public concern about availability of energy sources led to a renewed effort to investigate the development of wind power for electricity. Renewed interest was manifest in a 50% increase in the manufacture and sale of electric wind generators in 1976 from a base of 750 units in 1975. Estimates of the number of manufacturers vary. The Federal Energy Administration reported 23 manufacturers and distributors active in 1976, of which 11 companies both manufactured and distributed wind machines, seven were distributors only, one produced prototypes, and four were system designers [VII-8].

Principle of Operation

There are several different designs of wind energy conversion systems, but the common component is the rotor. The rotor is turned by the windstream and transforms the power of the windstream into mechanical power. The transmission system transmits the mechanical power from the rotor to a point where the power may be used, either in mechanical form or to generate electricity.

B. SYSTEM DESIGNS, APPLICATIONS, AND STORAGE

Systems Designs

The primary classification of designs is by the orientation of the axis of rotation of the rotor relative to the windstream. In horizontal axis wind turbines (HAWT), the axis of rotation is parallel to the windstream; in vertical-axis wind turbines (VAWT), it is perpendicular. (See Figure VII-1.)

Horizontal Axis Wind Turbines

The generic design for a horizontal-axis wind turbine consists of the rotor (including blades, hub, and pitch change mechanism); drive train (shaft, speed increaser, and generator); nacelle (shroud, bedplate, and gear mechanism); tower; and electrical and control systems. Most horizontal-axis wind turbines in manufacture today for electricity generation are of the two- or three-blade design rather than the multiblade design common in water pumping applications. The wind machine blades catch the wind either in front of the tower (upwind rotors, Figure VII-1, Id) or in back of the tower (downwind rotors, Figure VII-1, Ie). Most HAWT have a yaw mechanism to orient the machine into the wind, and most turbines rotate on a stationary tower in order to "track" the wind's changing direction. The machines are all designed with a safety mechanism to slow or stop the blades at a designated "cut out" wind speed. Beyond this speed the generator is incapable of absorbing the energy removed by the rotors from the windstream. The extra energy is spilled by "feathering" the blades, either in a stalled condition (with resulting high bending loads in the blades), or by turning the rotor sideways.

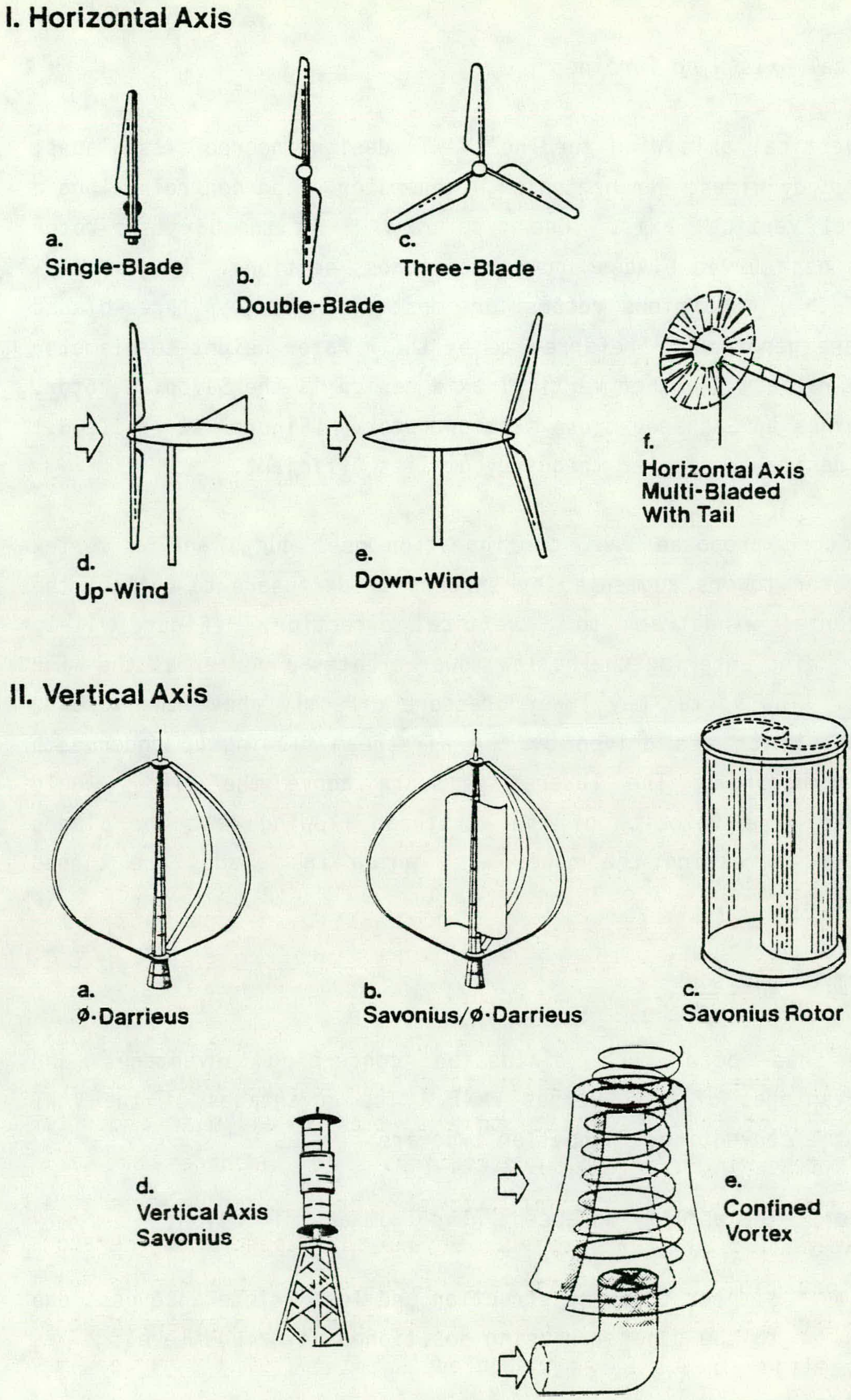

Figure VII-1. Types of Wind Machines

Vertical Axis Wind Turbines

The vertical axis wind turbine (VAWT) design incorporates blades, tower, guy wires, transmission, generator, and controls along a central vertical axis. One type of VAWT is the Darrieus rotor which has curved blades and airfoil cross sections. (Figure VII-1, IIa,b.) Darrieus rotors are most often two- or three-bladed and are generically referred to by their rotor height-to-diameter (H/D) ratio. Another vertical axis design is the Savonius rotor, which has an S-shaped cross section rotor. (Figure VII-1, IIc,d.) This design is simpler to build but less efficient.

One other proposed VAWT configuration uses ducts and/or vortex generator towers augmented by shrouds or diffusers to deflect the horizontal windstream to a vertical direction. (Figure VII-1, IIe.) Wind entering the hollow tower creates a vortex as the wind spins. The vortex may lower pressure directly above the turbine blades, which are driven by the airstream flowing up underneath the structure. The lowered pressure above the blades would increase the velocity of the airstream flowing past the blades thereby increasing the power with which the blades are turned [VII-5].

<u>System Comparisons</u>

There has been much discussion concerning advantages and disadvantages of HAWT versus VAWT. The advantages of the VAWT over the conventional propeller type are:

- the ability to accept wind from any direction;
- simpler tower construction and less maintenance cost due to the generator being positioned at ground level;

- lower fabrication costs which may result in high power output per given rotor weight and invested dollars.

The disadvantages of the VAWT relative to the HAWT are:

- less extensive developmental work and historical performance data;

- the curved blade Darrieus is not self-starting and must have an auxiliary device (Savonius rotor or small motor) to start the rotor turning. An induction machine can act as the auxiliary device to start the machine or it can generate electricity when the rotor is moving.

Applications and Storage

Large wind energy conversion systems (defined for this analysis as 100 kW or more) are almost solely designed for use by utilities to generate electricity to complement their conventional sources. Most utility analyses to date have considered WECS in a fuel saver mode (i.e., when the wind is blowing, the power is utilized directly by the utility to replace conventional fuels or save water in a hydroelectric facility). In the fuel saver mode the utility still must build the same conventional generating capacity thus not saving on capital costs. Recently, JBF Scientific Corporation has shown that WECS should be given capacity credit resulting in a savings in capital investment as well as fuel cost. Preliminary work has estimated a WECS capacity credit of between 19% and 26% [VII-14].

Wind systems can also be coupled with supplemental backup or storage to meet power demand during periods of low wind and to provide storage during wind surplus. Backup and storage system types are:

- compressed air storage in existing caverns or holes in the ground--rock salt caverns, mixed caverns, depleted gas and oil wells, or aquifers;
- pumping water into a storage reservoir above a hydroelectric power plant; or
- use of gas turbines for backup [VII-31].

Small wind systems (for our analysis assumed to be less than 100 kW) are considered for dispersed applications such as:

- rural electricity generation with or without synchronous inverter;
- rural electricity generation with onsite energy storage;
- irrigation pumping;
- remote electricity generation to replace onsite generation by diesel fuel.

Small systems can be used in a fuel saver mode or with storage. Small wind systems usually produce direct current (DC) power which can be stored in batteries or used directly for heating and lighting. The user has the option of using DC to operate motors and appliances, or couple the small wind systems with a synchronous inverter which accepts DC electrical power and converts it to AC. (A synchronous inverter is used only when tied to a power grid. Otherwise, a regular inverter is used). If more power is available from the DC source than is required by the load, the excess flows into the power grid. If less power is available than is required by the load, the difference is provided by the power grid in the normal fashion.

C. COSTS OF WIND ENERGY CONVERSION SYSTEMS

Site Selection

Several factors affect the cost of wind systems, including machine rated power, production quantities, wind characteristics, and cost of money. The most critical variables determining the cost effectiveness of a WECS are those describing the wind regime at the selected site. Therefore, the site selection process is very important.

To effectively evaluate the wind regime at a site, it would be ideal to have hourly wind speed over a five-year period. Another important part of the wind regime is the vertical wind profile: this describes how the wind varies with altitude above the site. The daily variation in the wind is also important since it determines when the wind energy will be available. Unfortunately, data of this nature are very seldom available.

Computing Delivered Energy

Wind machines are rated by power delivered at a given mean wind speed. The amount of energy delivered is derived from the formula:

$$\text{delivered kWh/yr} = \text{rated power output} \times 8{,}760 \times \text{capacity factor}$$

where 8,760 is the number of hours in a year.

The capacity factor (C.F.) is defined as the ratio of the energy the WECS actually delivers in a year to the amount it would deliver if operated at its rated capacity for 8,760 hours. The capacity factor is a function of the wind regime, the WECS design utilized, and the load characteristics, whether for a utility or other application. The capacity factor typically ranges from 10% to 55% [VII-39].

Dispersed Wind Energy Conversion Systems Costs

Dispersed WECS range from 1 kW machines to 100 kW machines. For purposes of this analysis six systems were chosen for this range. (See Table VII-1.) These systems were selected on a combination of least cost and market availability criteria. The systems are 2.0 kW HAWT, 4.0 kW HAWT, 5.0 kW VAWT, 6.0 kW HAWT, 15.0 kW HAWT, and 40.0 kW VAWT.

The 2.0 kW, horizontal-axis, 3-bladed machine is rated at 25 mph. The wind turbine rotor is upwind, and costs include batteries for storage. Current capital costs obtained from manufacturers and distributors for 2.0 kW machines range from $2,704/kW (for the turbine and tower only) to $4,000/kW (an average of $3,526/kW, which is somewhat low since installation and inverter were not included in two estimates). These cost data were collected directly from four manufacturers of 1.0 kW to 2.0 kW wind machines. One 2.0 kW HAWT produced by a foreign manufacturer costs $6,125/kW (Table VII-1). This price includes an inverter excluded from the calculations above. This machine's cost per kilowatt hour was much higher than others because of the cost of the tower.

A wind access catalog in Wind Power Digest, Fall 1977 lists six other machines in the 2.0 kW to 2.5 kW range. These machines which have higher costs are supplied by foreign manufacturers. The costs are high because of current exchange rates and installation costs in remote areas.

TABLE VII-1

COSTS OF SMALL WIND ENERGY CONVERSION SYSTEMS

Rating:	2.0 kW Horizontal-Axis	4.0 kW Horizontal-Axis	5.0 kW Vertical-Axis	6.0 kW Horizontal-Axis	15.0 kW Horizontal-Axis	40.0 kW Vertical-Axis
	@ 25 mph	@ 25 mph	@ 24 mph	@ 26 mph	@ 26 mph	@ 30 mph
Cost:						
Turbine	$ 4,000	$ 3,500	$ 6,600	$ 8,000	$ 20,000	$ 75,000
Tower	3,000	900	800	1,000	1,500[a]	b
Installation (includes check out and transportation)	2,750	1,300	1,350	2,000	3,500[a]	6,500
Storage and Inverter or Synchronous Inverter	2,500	800	2,000	5,000	5,000[a]	Not required; produces 60 Hz AC power
Total Capital Costs	12,250	6,500	10,750	16,000	30,000	81,500
O & M (assumed 1%/year of capital[c])	122	65	107	160	300	815
$/kW	6,125	1,625	2,150	2,667	2,000	2,037

a Estimated from break out of other machines

b 30 ft. tower included in turbine cost

c Reference VII-

The 4.0 kW machine is a 3-bladed horizontal axis, upwind rotor rated at 25 mph. The capital cost of the machine coupled with a synchronous inverter is $1,625/kW, and is based on only one source. Two other manufacturers of similarly sized wind machines are listed in the catalog, but the costs are not considered here.

The 5.0 kW, vertical-axis, 3-bladed system is rated at 24 mph. The system is based on one machine with capital cost of $2,150/kW including synchronous inverter. A production version may be available by mid-1978.

The 6.0 kW system is a 3-bladed, horizontal-axis, upwind machine coupled with battery storage and rated at 26 mph. No other cost data were collected for machines in this range; therefore, the $2,667/kW capital cost calculation is also based on one machine. The machine has been manufactured overseas for several years.

The 15.0 kW, 3-bladed, horizontal-axis downwind machine is rated at 26 mph. Cost data were collected from three manufacturers of machine in the 15.0 kW to 25.0 kW range. The generic system's capital cost with synchronous inverter or storage is $2,000/kW based on the sale of 12 machines. Two manufacturers projected more favorable costs of $572/kW and $652/kW. These were excluded because the machine costs were estimates only. Neither manufacturer had begun production as of March 1978. A production goal for the design chosen for 1978 is to bring the cost down to $1,000/kW by improved system design.

The sixth system presented in Table VII-1 is a 2-bladed, vertical-axis, 40 kW wind machine rated at 30 mph. The $2,037/kW capital cost is based on one manufacturer's estimate. No other machines of this size have been produced.

Table VII A-1 in the Appendix identifies some machines and their current costs. Design specifications, production, and cost information are presented.

Cost of Electricity from Small WECS

Small wind energy conversion systems are economical today in remote sites. Electricity from diesel, LPG, or gas units in remote sites costs $0.25 to $0.30/kWh assuming that the units are amortized over six years (which is the lifetime of the system if it were run continuously). Real Gas and Electric Company, Inc., estimates that wind electric power from a 5 to 6 kW machine costs $0.12 to $0.13/kWh assuming 12 years amortization and a good wind site [VII-18]. The lifetime of a wind machine is estimated to be 25 to 30 years.

Large Wind Energy Conversion Systems Costs

Five machine designs have been selected to represent large wind energy conversion systems. The system sizes are 0.2 MW HAWT, 0.5 MW VAWT, 1.0 MW HAWT, 1.5 MW HAWT, and 2.0 MW HAWT. (See Table VII-2.) Most cost estimates for large WECS come from design studies resulting from government contracts, and the estimates are based on projected production quantities. All data have been normalized to 100 units generally assuming a learning curve of 95%. (The 0.2 MW generic design assumed a learning curve of 90%.)

The 0.2 MW, 3-bladed, horizontal-axis upwind machine is rated at 28 mph. The system cost estimate is $1,150/kW assuming a learning curve of 95% to the production of the 100th unit. A more realistic cost is based on an actual prototype contracted by NASA with a capital cost of $4,372/kW. The first machine was manufactured by a private company which optimistically anticipates

TABLE VII-2

COSTS OF LARGE WIND ENERGY CONVERSION SYSTEMS

(Costs Based on Production of 100 Units)

Rating:	0.2 MW Horizontal-Axis @ 28 mph	0.5 MW Vertical-Axis @ 15 mph	1.0 MW Horizontal-Axis @ 22.5 mph	1.5 MW Horizontal-Axis @ 17 mph	2.0 MW Horizontal-Axis @ 15 mph
Cost:					
Rotor	$ 75,000	$ 70,000	$ 107,000	$ 192,000	$ 636,000
Transmission	50,000	40,000	176,000	168,000	691,000[d]
Generator/ Electrical	22,000	42,000	55,000	77,000	217,000
Controls	6,000	b	24,000	c	127,000
Towers and Foundation	10,000	71,000	178,000	103,000	266,000
Site Dependent	36,000[a]	50,000	178,000	124,000	431,000
Total Direct Capital Cost	200,000	273,000	718,000	664,000	2,368,000
Indirect (Assume 15% of direct)	30,000	41,000	108,000	100,000	355,000
Total	230,000	314,000	826,000	764,000	2,723,000
O & M Assume 3% of Capital	7,000	9,000	25,000	23,000	82,000
$/kW	1,150	628	826	509	1,361

N.A. not available
a Assume 22% of capital costs
b Included in tower and foundation costs as are guying supports
c Included in other figures
d Includes yaw drive system and nacelle structure

an installed capital cost of under $1,000/kW at a production rateof at least one machine per month.

The 0.5 MW VAWT is a 2-bladed machine rated at 15 mph. The system capital cost of $628/kW is based on one source. The estimate was calculated from 100 unit production of a prototype machine built under government contract.

The 1.0 MW, 2-bladed, horizontal-axis downwind machine is rated at 22.5 mph. Three machines, all designed under government contracts, were in the range of 1.0 MW to 1.125 MW. The system cost estimate is $826/kW; the high figure for all three is $1,101/kW, and the mean cost is $926/kW. None of the three machines are being produced at this time.

The 1.5 MW generic system incorporates a 2-bladed, horizontal-axis, downwind machine rated at 17 mph. The system capital cost estimate is $509/kW. One other contractor estimated the cost of a 1.5 MW machine at $559/kW. Neither machine is actually being built.

The 2.0 MW system is a 2-bladed, horizontal-axis, downwind machine rated at 15 mph. The cost estimate for the design is $1,361/kW. Three estimates were collected for machines in the 2.0 MW to 2.7 MW range. The costs vary from $205/kW to $1,361/kW. The highest capital cost figure was adopted for the system because it is based on a prototype that has actually been built. The other figures are projected cost estimates.

As mentioned earlier, the cost figures for all large wind machines considered in this analysis are based at best on a prototype built by a government contractor or private manufacturer. Some figures are design study estimates only. Therefore, the range of estimates does not relate to the reliability of the product or to economies of scale associated with machine size. The wide range of estimates only indicates that the technology needs to be advanced, and the performance of machines documented.

Costs of Electricity from Large WECS

A required revenue model was used to annualize large wind machine costs. Electricity costs from large wind energy conversion systems are given in Table VII-3. Appendix Table VII A-4 gives costs for individual machines. Assuming a capacity factor of 30%, electricity can be produced for 38 to 120 mills/kWh. Costs are given for a municipally owned utility and a publicly owned utility.

Large Wind Turbines Costs With Storage or Backup

Large wind energy conversion systems can be used in a fuel saver mode or coupled with storage for capacity credit. Table VII-4 presents capital cost estimates ($/kW) for compressed air and pumped storage and for a gas turbine backup.

In Table VII-5 the average cost estimates of the storage and backup configurations were added to the cost estimates ($/kW) of the HAWT and VAWT systems. The uncertainties associated with the designs used as bases for the systems allow no correlations between cost and machine size. This fact is noted in Table VII-5. The gas turbine backup has a slight dollars per kilowatt cost advantage over storage. The estimates do not vary enough to suggest that a wind turbine coupled with one of the systems is the most economical. The choice must consider site location and availability of water and storage resources. Once again it must be noted the cost estimates are contingent on manufacturers' optimistic projections for the 100th unit of production.

TABLE VII-3

COST OF ELECTRICITY FROM LARGE WIND ENERGY CONVERSION SYSTEMS

(1978 mills/kWh)

MACHINE SIZE	CAPACITY FACTOR				
	.10	.20	.30	.40	.50
0.2 MW HA					
Municipal Sector	255	127	85	64	51
Public Sector	305	153	102	76	61
0.5 MW Va					
Municipal Sector	142	71	47	36	28
Public Sector	171	85	57	43	34
1.0 MW HA					
Municipal Sector	183	91	61	46	36
Public Sector	219	109	73	55	44
1.5 MW HA					
Municipal Sector	112	57	38	28	22
Public Sector	135	67	45	34	27
2.0 MW HA					
Municipal Sector	301	150	100	75	60
Public Sector	360	180	120	90	72

TABLE VII-4

STORAGE AND BACKUP COST ESTIMATES FOR LARGE WIND SYSTEMS (in $/kW)

Compressed Air

Source of Estimates	Capital Cost of Equipment	Cost of Chamber for 10 hours Storage	Total $/kW
MITRE [VII-31]	167	55	222
Bush [VII-4]	167	55	222
JPL [VII-23]	183	52	235 ± 38%
PSE & G [VII-35]	133-166	33-111	166-277

Pumped Storage

	Total $/kW
MITRE [VII-31]	
Sites with moderate modification	105
Sites with extensive modification	210
Merriam, U of C, Berkley [VII-26]	158-316
Bureau of Reclamation [VII-44]	
Pacific Northwest Storage Plant	195
Colorado River and Rocky Mountain area	279

Gas Turbine Backup

	Gas turbine (1985 advanced model)	Power Switching Interface	Total $/kW
MITRE [VII-28]	170	17	187

TABLE VII-5

ESTIMATED COSTS OF LARGE WIND ENERGY SYSTEMS WITH STORAGE OR BACKUP
(in $/kW)

System with:	Compressed Air[a]	Pumped Storage[b]	Gas turbine Backup[c]
0.2 MW HA	1,375	1,355	1,337
0.5 MW VA	853	833	815
1.0 MW HA	1,051	1,031	1,013
1.5 MW HA	734	714	696
2.0 MW HA	1,586	1,566	1,548

a Used $225/kW; the average of four estimates

b Used $205/kW; the average of the estimates

c Used the MITRE figure of $187/kW

Wind Farms Costs

Several conceptual plans have emerged over the past few years for an array of wind turbines to pump water (for irrigation or storage) or to generate electricity into a utility grid. The wind farms use several 0.5 MW to 4.0 MW units located in good wind regime areas. The machines are usually spaced 10 to 15 rotor diameters apart. A 100 MW wind farm system comprised of 67, 1.5 MW wind machines is presented in Table VII-6. The estimates presented are based on seven farms ranging in size from 45 to 2,000 MW farms. Appendix Table VII A-5 gives annualized costs for eight cases.

TABLE VII-6

COST ESTIMATES FOR
100 MW WIND FARM USED IN A FUEL SAVER MODE
(67, 1.5 MW Machines)

Capacity Factor	.40
Capital Costs[a]	$81,600,000
Operation and Maintenance[b]	$ 2,448,000
$/kW[c]	$ 816

[a]Includes machine, site dependent, and land costs
[b]Assumed to be 3% of capital costs
[c]Median figure from seven cases examined

The total cost of the array is $81.6 million with operation and maintenance expenses estimated assumed to be 3% per year of capital cost. The dollars per kilowatt estimates for the seven cases ranged from a high of $2,071/kW for a 300 MW array to a low of $275/kW for a 2,000 MW farm; the $816 figure was the median. As mentioned in the large wind machine section, these cost figures are estimates only and in no way reflect an actual application.

The cost differences are caused by machine design cost estimates, land requirements, and site location.

Cost of Electricity from Wind Farms

The annualized costs of electricity from various wind farm configurations were computed from a required revenue model. Table VII-7 shows that costs for the wind farms with storage/backup range from 42 to 93 mills/kWh. Estimates are given for both municipally and publicly owned utilities.

D. MARKET READINESS OF WECS

Technology Delivery System

The Technology Delivery System (TDS) is composed of various types of public and private institutions, agencies, and individuals that interact to achieve the production and distribution of a particular product or service [VII-2]. The WECS TDS is portrayed in Figure VII-2 which describes the flow of participants who are likely to be involved in or affected by the movement of wind energy machines into the marketplace. It reveals the interactions that should be taking place as a technology progresses through different phases of the innovation process.

The TDS shown here is a useful way of conceptualizing the relationship of activities undertaken by those involved in developing, producing, and using both small and large wind turbine generators for connection to existing electric utility systems. Utilization of both sized machines in this manner would involve decisions and approvals by state and local public utility commissions. It is apparent then that both the large and small machines will have the same TDS. The wind energy machine manufacturers may achieve market aggregation and better prospects

TABLE VII-7

COST OF ELECTRICITY FROM WIND FARMS

(1978 mills/kWh)

Wind Farm* Configuration	Annualized Cost
100 MW Wind Farm as a Fuel Saver	
Municipal	46
Public	55
100 MW Wind Farm as a Water Saver	
Municipal	81
Public	93
100 MW Wind Farm with Compressed Air Storage	
Municipal	61
Public	72
100 MW Wind Farm with Gas Turbine Backup	
Municipal	55
Public	66
100 MW Wind Farm with Combined Cycle Gas Unit	
Municipal	42
Public	49

*All assume initial operation in the year 1983. All assume a capacity factor of .40 except the wind farm with combined cycle gas unit, which has a capacity factor of .70.

USING SYSTEMS INT ITION CONTRACTOR

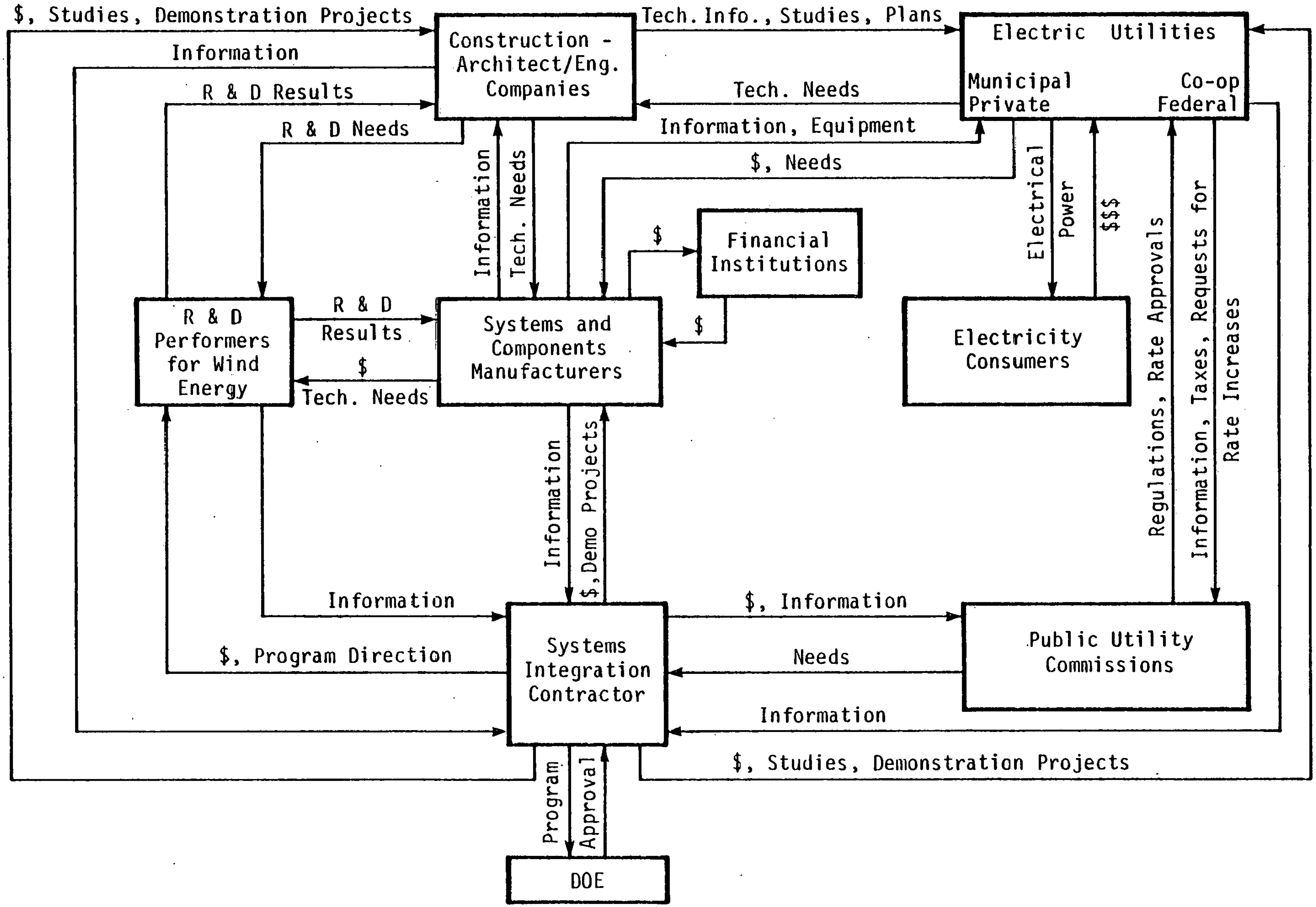

Figure VII-2. Wind Energy Conversion Systems Technology Delivery System for market success if their products are accepted by the public utilities [VII-6].

Description Of Products

In order to develop a better understanding of the state of the market, telephone interviews were conducted with industry manufacturers. The type of information obtained consisted of length of time in wind plant manufacturing, number of models, channel of distribution, sales history, selling price, warranty, and technical description. Table VII-8 relates to large scale wind turbine generators, and Table VII-9 focuses on small commercial wind turbine generators.

Barriers to WECS Market Readiness

Major barriers have been identified and defined which can impede the implementation of Wind Energy Conversion Systems on a large scale. Different barriers exist between large-scale or utility implemented WECS and small-scale rural, remote, or residential WECS. These barriers deserve high priority attention [VII-10].

Two major barriers exist in the large-scale, utility-designed WECS. First and foremost in any product development and widespread use is the question of financing. Financing is a major obstacle to the utility because the incremental revenue requirements needed for the implementation of WECS appear large. This obstacle could be reduced, for instance, by low-cost guaranteed loans, subsidies, tax incentives, or increasing the price of electricity to consumers [VII-10]. Land requirements for utility WECS are also a prime concern. Two actions may reduce land area requirements. First, land needed for WECS may also be used for other

TABLE VII-8

LARGE SCALE WIND TURBINE GENERATORS

CONTRACTOR/ MANUFACTURER	SIZE (kw)	BLADE DIA. (Feet)	# OF BLADES	RATED SPEED (MPH) at Hub Height	CUT IN SPEED (MPH)	CUT-OUT SPEED	GOVERNOR	SURVIVAL WIND SPEED	YEAR PROGRAM STARTED
NASA Lewis In-house	100.0	125'	2	18	10	40 mph	Feathering	150 mph	1974
In-house	200.0	125'	2	22	10	40 mph	Feathering	150 mph	1975
GE	2,000.0	200'	2	33	15	43 mph	Feathering	150 mph	1976
Boeing	2,500.0	300'	2	28	14	53 mph			1977
Wind Power Products	140.0	72'	3	26					
WTG Energy Systems	200.0	80'	3	30	8				

TABLE VII-9

SMALL COMMEFCIAL WIND TURBINE GENERATORS

MANUFACTURER	SIZE (kW)	BLADE DIA. (Feet)	# OF BLADES	RATED SPEED (MPH)	CUT IN SPEED (MPH)	GOVERNOR	COST WIND-PLANT ONLY	# SOLD	YEAR PROD. STARTED	WARRANTY	CHANNEL OF DISTRIBUTION
Aero Power (U.S.A.)											
SL 1,000	1.0	10'	3	20.0	6.0	Centrifugal Feathering	1-17-78 $2,995		1977	12 mos.	Dealer/ Direct
Model "A"	1.0	8'6"	3	25.0	6.0	Feathering	1-1-78 $2,500	125 to 150	1974	12 mos.	Dealer/ Direct
SL 1,500	1.5	10'	3	20.0	6.0	Feathering	$3,750		1977	12 mos.	Dealer/ Direct
Amer. Wind Turbine (U.S.A.)											
AWT-8	0.45	Water Pumper 8'	24	20.0	10.0	Vane Deflect	1-1-78 $1,160	N/A	1975	3 mos.	Direct
AWT-12	0.9	Water Pumper 12'	36	20.0	10.0	Vane Deflect	1-1-78 $1,846	N/A	1975	3 mos.	Direct
AWT-16	1.8	Water Pumper 16'	48	20.0	10.0	Vane Deflect	1-1-78 $2,675	N/A	1975	3 mos.	Direct
AMERNALT (U.S.A.)											
1,500 Series	1.5	8'	24	28.0	8.0	Vane Deflect	N/A	N/A	1975	60 mos.	N/A
2,500 Series	2.5	8'	24	38.0	8.0	Vane Deflect	N/A	N/A	1975	60 mos.	N/A

TABLE VII-9 (Con't)

SMALL COMMERCIAL WIND TURBINE GENERATORS

MANUFACTURER	SIZE (kW)	BLADE DIA. (Feet)	# OF BLADES	RATED SPEED (MPH)	CUT IN SPEED (MPH)	GOVERNOR	COST WIND-PLANT ONLY	# SOLD	YEAR PROD. STARTED	WARRANTY	CHANNEL OF DISRIBUTION
Dominion Aluminum (Canada)											
	2.0	15'	2-Darrieus	23.0	7.0	Spoiler	-	-	-	Varies	Direct
	4.0	15'	2-Darrieus	23.0	7.0	Spoiler	-	-	-	Varies	Direct
	8.0	20'	2-Darrieus	23.0	7.0	Spoiler	-	-	-	Varies	Direct
	8.0	30'	2-Darrieus	23.0	7.0	Spoiler	-	-	-	Varies	Direct
Dunlite (Australia)											
Model 8.1	2.0	13'6"	3	25.0	8.0	Centrifugal Blade Pitching	4,000	N/A	1930's	12 mos.	Distributor
Model 8.2	2.0	10'	3	30.0	10.0	Centrifugal Blade Pitching	N/A	N/A	1930's	12 mos.	Distributor
Dynergy Corp.											
5M VAWT	5.0	15'	Darrius 2 or 3	24.0	-	Mechanical Caliper	11-18-77 $5,800	N/A	N/A	N/A	Direct
Elektro (Switzerland)											
W50	0.05	1.5'	Savonius	39.0							
W250	0.25	2.2'	Savonius	40.0	7.0	-	N/A	N/A	-	-	Distributor
WV05	0.60	8'	2	20.0	7.0	-	N/A	N/A	-	-	Distributor
WV15G	1.2	10'	2	23.0	7.0	Full Feathering	N/A	N/A	-	12 mos.	Distributor
WV25G	1.8	11'6"	2	22.0	7.0	Full Feathering	N/A	N/A	-	12 mos.	Distributor
WV25/3G	2.5	12'6"	3	23.0	7.0	Full Feathering	N/A	N/A	-	12 mos.	Distributor
WV35G	4.0	14'6"	3	24.0	7.0	Full Feathering	N/A	N/A	-	12 mos.	Distributor
WVG50G	6.0	16'6"	3	26.0	7.0	Full Feathering	N/A	N/A	-	12 mos.	Distributor
					7.0	Full Feathering	8,000	N/A	-	12 mos.	Distributor

TABLE VII-9 (Con't)

SMALL COMMERCIAL WIND TURBINE GENERATORS

MANUFACTURER	SIZE (kW)	BLADE DIA. (Feet)	# OF BLADES	RATED SPEED (MPH)	CUT IN SPEED (MPH)	GOVERNOR	COST WIND-PLANT ONLY	# SOLD	YEAR PROD. STARTED	WARRANTY	CHANNEL OF DISRIBUTION
Zephyr Wind Dynamo (U.S.A.) Jacobs Mach.											
Wind Dynamo	15.0	20'	3	30.0	8.0	Aero Spoilers & Automatic Yawing	-	4	1974	-	Direct
North Wind Power Co. (U.S.A.) Jacobs Mach.											
Eagle II-110V.	2.0	14'	3	22.0	7.0	Centrifugal Feathering Flyball	$4,000		1975	12 mos.	Distributor/Direct
Eagle II-32V.	2.0	14'	3	24.0	8.0	Centrifugal Feathering Flyball	$3,300	89	1975	12 mos.	Distributor/Direct
Eagle III-110V.	3.0	14'	3	22.0	8.0	Centrifugal Feathering Flyball	$5,100		1975	12 mos.	Distributor/Direct
Eagle III-32V.	3.0	14'	3	24.0	8.0	Centrifugal Feathering Flyball	$4,400		1975	12 mos.	Distributor/Direct

TABLE VII-9 (Con't)

SMALL COMMERCIAL WIND TURBINE GENERATORS

MANUFACTURER	SIZE (kW)	BLADE DIA. (Feet)	# OF BLADES	RATED SPEED (MPH)	CUT IN SPEED (MPH)	GOVERNOR	COST WIND-PLANT ONLY	# SOLD	YEAR PROD. STARTED	WARRANTY	CHANNEL OF DISRIBUTION
Kedco (U.S.A.)											
Model 1200	1.2	12'	3	22.0	8.0	Centrifugal Blade Pitching	$2,295		1975	12 mos.	Direct
Model 1210	2.0	12'	3	26.0	10.0	Mechanical Blade Pitching	$2,595		1975	12 mos.	Direct
Model 1600	1.2	16'	3	17.0	8.0	Mechanical Blade Pitching	$2,895		1975	12 mos.	Direct
Model 1610	2.0	16'	3	22.0	10.0	Mechanical Blade Pitching	$3,195	12 to 15	1975	12 mos.	Direct
Model 1205	1.9	12'	3	24.0	8.0	Mechanical Blade Pitching	$2,345		1975	12 mos.	Direct
Model 1605	1.9	16'	3	20.0	8.0	Mechanical Blade Pitching	$2,945		1975	12 mos.	Direct
Model 1620	3.0	16'	3	26.0	12.0	Mechanical Blade Pitching	$3,495		1975	12 mos.	Direct
Millville Windmills											
Model 10	10.0	25'	3	25.0	11.0	Mechanical Blade Pitching	-	-	-	3 mos.	Direct
Pinson Energy Co. (U.S.A.)											
Cycloturbine	2.0	12'	Vertical Axis 3	24.0	9.0	Centrifugal Blade Pitching	$6,300	4	-	12 mos.	Direct

TABLE VII-9 (Con't)

SMALL COMMERCIAL WIND TURBINE GENERATORS

MANUFACTURER	SIZE (kW)	BLADE DIA. (Feet)	# OF BLADES	RATED SPEED (MPH)	CUT IN SPEED (MPH)	GOVERNOR	COST WIND-PLANT ONLY	# SOLD	YEAR PROD. STARTED	WARRANTY	CHANNEL OF DISRIBUTION
Sencenbaugh (U.S.A.)											
Model 500	0.5	6'	3	24.0	10.0	Vane Deflect	3-1-77 $2,200	-	1972	12 mos.	Dealer/Direct
Model 1000	1.0	12'	3	23.0	6.0	Vane Deflect	3-1-77 $2,650	-	1973	12 mos.	Dealer/Direct
Grumman (U.S.A.)											
Windstream 25	15.0	25'	3	26.0	8.0	Blade Tip Spoiler	$19,900	9	1976	Limited	Direct
Aerolectric (U.S.A)											
Wind Wizard	0.6	9'	3	26.0	N/A	Vane Deflect	$995	80-100	1975	Limited 12 mos.	Distributor/Direct
Dyna Technology (U.S.A.)-Winco											
Wincharger	0.2	6'	2	23.0	7.0	Mechanical Air Brake	-	-	-	12 mos.	-

applications. Second, the area may be minimized by reducing the separation between units to the smallest possible distance with minimal effect on the power output generated by the WECS [VII-10].

Risks

Another action which can take place in conjunction with the performance tests mentioned above concerning reliability, safety, and life expectancy is the development of standards for the wind energy industry. The objective of such a standards development is the formulation of consensus decisions on the methods of comparing wind machines in terms of safety, reliability, and performance. The American Wind Energy Association (AWEA) is in the initial stages of proposing a program that will be the first step in the wind standards development process. There are four major program elements envisioned by the AWEA. First, in order to compare WECS the terminology employed must be clear and unambiguous. This will be accomplished through a glossary of wind energy terminology. Second, standard performance data will be established to identify system parameters that are critical to understanding the operation of a wind system. This element is dependent on and related to the development of common technology. The primary product of this element will be performance data specifications that describe wind machines on a common basis. Third is the development of procedures for testing. Test standards mean that data will be obtained accurately using recognized techniques and instrumentation. Through the development of test standards, the data obtained are meaningful (i.e., they reflect important factors of a machine's performance which are easily compared to other similar data). Lastly, standard development guidelines must be established. The goal of this program element is to establish an effective working link between members of the entire project team (representing those with major interests in WECS) and appropriate nationally recognized standards-making bodies. This will ensure that the results of the entire program will eventually contribute to the smooth development and adoption of national standards. Three principal areas will be investigated: general procedures for adopting standards, transferability of existing standards, and safety testing procedures [VII-41, VII-46].

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VIII. SOLAR THERMAL ELECTRIC POWER SYSTEMS

A. INTRODUCTION

Solar thermal power systems convert solar energy into electricity by collecting, concentrating, and converting the sun's rays to heat and then to electricity by means of a heat engine or a thermodynamic (e.g., Rankine, Brayton, Stirling) conversion plant. Between WWI and WWII, an experimental solar thermal power system was built in Egypt which converted sunlight to electricity with an overall efficiency of nearly 20%. Dr. Giovanni Francia of the University of Genoa built a solar thermal system in 1966 and achieved a thermal collection efficiency of 60% [VIII-7]. Research in improving solar thermal systems continues today in the United States and other countries.

There are two basic types of solar thermal power plants: central receiver systems and distributed collector systems. Hybrid or repowering systems combine central receiver solar thermal plants with fossil fuel systems as backup. The central receiver system consists of a large field of two-axis tracking heliostats (or mirrors) which concentrate solar energy on a tower-mounted receiver. A heat transfer fluid circulates through the receiver and carries heat energy to an energy conversion system. Storage may be included for backup or peak demand requirements.

Distributed systems collect sunlight on separate modules. Each collector module has its own absorber (receiver), where solar energy is converted to thermal energy. Thermal energy at each distributed collector can be transported, using steam or a hot water, to a central location for electricity generation. Alternatively, thermal energy can be converted through a chemical reaction and the reaction reversed at a central plant. Thermal energy at each collector can also be converted to electricity by heat engine-generator units on or near the collectors. Distributed collector solar thermal power systems may also have storage subsystems: either thermal (latent or sensible heat-storage) or nonthermal (mechanical, electrical, or chemical storage).

McDonnell Douglas Astronautics Company, Martin Marietta Corporation, and Honeywell, Inc., were awarded contracts from DOE (previously ERDA) between 1975 and mid-1977 to study the conceptual design of a commercial size plant. Designs and test reports of major solar components (heliostats, receiver, and thermal storage) were submitted to DOE for 10 MW_e pilot plants [VIII-21]. DOE also contracted Boeing Engineering and Construction Company in 1975-77 to study collector subsystems only for central receiver solar thermal electric power systems. Sandia Laboratory evaluated cost and performance data of each and recommended the McDonnell Douglas design [VIII-18]. The first pilot plant will be built in the Mojave Desert near Barstow, California, at an estimated cost of $120 million [VIII-21].

The major costs for solar thermal electric power plants are collector costs which are nearly 50% of total capital cost. The federal program goal is to reduce collector costs to one-third their present level [VIII-21].

B. STEPS SYSTEM DESCRIPTIONS AND COSTS

Systems Descriptions

Central Receiver Solar Thermal Electric Power Systems

Heliostats. An array of heliostats is controlled to reflect incoming sunlight onto a receiver. The heliostats are focused on the receiver by tracking systems. Several heliostat designs and construction schemes have been proposed. One proposed heliostat concept is a stretched diaphragm heliostat enclosed by a pressurized dome. Its distinctive features are the lightweight reflector and drive assembly and the transport enclosure. Other heliostat concepts proposed use steel frame construction and glass mirrors. Some heliostats are curved; others are flat.

Tower. A tower is used to support the energy receiver in full view of the heliostat field. The height of the tower depends on heliostat spacing, inner and outer rim angles, and rated power level of the array. Either a steel or a concrete tower will suffice for a 10 MW_e pilot plant; a power plant larger than 10 MW_e would require a concrete tower.

Receiver. A receiver is required to absorb the reflected energy from the heliostats and to transfer the energy to a working fluid usually steam, air, helium, or eutectic salts. There are three basic types of receivers: a direct open receiver, planar or cylindrical, and a cavity receiver.

The direct open receiver absorbs heat on an open surface. This surface acts as an unobstructed heat radiator and also convects heat openly to the surrounding air. An aperture is located at the focal point of a cavity receiver and sunlight is diluted before impinging on the absorbing surface. The outside walls of the cavity receiver are well-insulated to minimize energy losses.

Two contractors have proposed a cavity receiver, which provides higher collection efficiency than planar configurations by reducing radiation and convection losses and by improving overall absorptivity of the cavity.

Energy Transport. The transport system, which moves a heated fluid to an energy converter, normally is located at the base of the tower. Proposed heat transfer media are steam, air, and helium. The choice of a heat transfer medium varies with the energy conversion cycle selected. Superheated steam is best for a Rankine cycle. Air and helium are best applied for open-cycle and closed-cycle Brayton energy conversion units, respectively.

Energy Conversion. An energy conversion subsystem converts thermal energy into electricity by using a thermodynamic cycle (e.g., Rankine, Brayton, Stirling). Although a Brayton engine has been proposed, most research groups recommend a superheated steam Rankine cycle for energy conversion with minor variations in operating temperature and pressure.

Storage Subsystem

A storage subsystem is required to maintain energy flow beyond a solar day or to delay production of maximum power to meet a utility's peak demand requirements. All three government contractors have proposed thermal storage for prototype and first commercial plants.

Distributed Collector Solar Thermal Electric Power Systems

Distributed collector systems are less complex than central receiver solar thermal electric power systems. Collectors and tower-receiver field concepts are not applied. Each collector has its own receiver which is located near ground level. System efficiency of distributed collector solar thermal power systems depends on the type of collectors used. Three distributed collector systems have been proposed for electricity generation: point-focusing, line-focusing, and fixed mirror collector systems. Storage requirements and types are discussed after the collector systems have been presented.

Point-Focusing Paraboloid Distributed Collector System. This concentrator is a paraboloid dish reflector focusing on a cylindrical cavity receiver. The receiver is placed at the focal point of the collector. The energy transport and conversion subsystem may use steam, chemicals, or electricity for energy transportation.

- Steam generated by the collectors is transported via insulated pipelines to a central steam Rankine plant, where heat energy is converted into electricity.

- Heat energy can be stored as products of a chemical reaction, usually gases or liquids. Electricity can be generated from these chemicals which are easily stored and transported. According to recent studies, this system may be competitive for large quantities of energy storage, but it requires more research before feasible application.

- Electric transport subsystems use a small heat engine-generator (Brayton or Stirling engine) located at the focal point of a dish collector. An electric collection system, made of cables, switch gear, transformers, etc. brings the power from each collector to a central point in the plant. Brayton cycle gas turbine systems can be used as the engine-generator for the near future. The development of advanced high temperature Brayton or

Stirling engine systems may improve the efficiency of dish-electric distributed collector systems.

Line-Focusing - Single Axis Tracking Distributed Collector System. Two basic types of line-focusing single axis tracking collectors are considered: parabolic trough and variable slat collectors.

- Parabolic Trough: The concentrating surface of parabolic trough collectors rotates as one piece. This design leads to practical limitations on size due to structural requirements and shadowing by the receiver. A cavity receiver cannot be used efficiently because of the curved feature of the concentrating surface. Vacuum-jacketed tube receivers, although inferior to the cavity receivers in performance, have been employed [VIII-10].

- Variable Slat: This design uses segmented mirrors individually articulated to concentrate energy on a horizontally straight receiver. The advantages of segmented mirror concentrators over parabolic trough concentrators are: (1) segmented mirrors are generally easier to manufacture with fewer structural requirements and (2) the reflector can be placed closer to ground level. In addition, a longer focal length can be achieved by locating segmented mirrors in a curved plane (having an effective low rim angle) which will permit use of a cavity receiver. A cavity receiver used with variable slat system obtains higher temperatures and greater efficiencies than would be possible using parabolic trough collectors [VIII-10].

For line-focusing distributed collector systems, hot water, steam, pressurized water, and oil are the primary candidates for the heat transport working fluid. Steam can be efficiently utilized for higher temperatures, pressurized water or organic fluid can be useful for lower temperatures although thicker pipe walls are required for organic fluid systems.

A suitable energy conversion system can be implemented for each working fluid used for heat transfer. A Rankine steam conversion system is most suitable for water/steam heat transport fluid. The organic Rankine system can be used for low temperature working fluids including oil, water, and organic fluids.

<u>Fixed Mirror Distributed Collector Systems</u>. There are two types of fixed mirror systems: distributed focus flat-plate and low concentrating, nontracking systems such as compound parabolic or vee-trough concentrators. Distributed focus flat-plate and point focusing systems have similar designs except the collectors are different.

Fixed mirror flat-plate collector systems do not attain higher temperatures for a working fluid in an optimum way. Low concentrating nontracking fixed mirror systems (vee-trough or compound parabolic reflector systems) can be used for higher temperatures by employing a vacuum-tube thermal receiver. Vee-trough collectors can be asymmetrically designed and need reversing only twice a year which increases annual performance while maintaining simplicity of the design [VIII-10]. High system efficiency can be achieved using vee-trough reflectors. However, this system is not economically suitable for a central power plant.

Chemical transport with organic Rankine cycle conversion systems will probably be most suitable for fixed collector vee-trough power systems because of the low temperatures at the receiver. The organic Rankine cycle uses thermal energy to produce a chemical reaction, which results in other chemical products. These chemical products are transported to central locations where thermal energy for electric power generation is attained by reversing the chemical reaction.

Storage Subsystems. Thermal storage and electric storage subsystems are most suitable for distributed collector systems. Latent heat or sensible heat can be stored in thermal storage subsystems. The sensible heat storage system can be used for commercial implementation [VIII-10]. For some systems, thermal storage increases the weight and size of the absorber at the focal point. As an alternative, electrical energy from each dish-electric collector can be transported and stored at a central location. Electrical energy can be stored in mechanical, chemical, or electromagnetic ways [VIII-10].

Solar Thermal Hybrid Systems. Solar thermal hybrid or repowering plants combine a central receiver solar electric power system (without storage subsystem) with a fossil fuel plant as a backup. These hybrid plants provide higher system efficiency than total solar thermal power plants. Collectors, tower, receiver, master control, and land costs are reduced because the fossil plant provides all necessary backup [VIII-7].

Engineering Cost Estimates

Central Receiver Solar Thermal Electric Power Systems

Three major government contractors (McDonnell Douglas, Honeywell, and Martin Marietta) have estimated engineering costs for proposed central receiver solar thermal electric power systems built as pilot and commercial plants [VIII-4,VIII-9,VIII-2]. Sandia Laboratories [VIII-18] has evaluated all three system designs and proposed revised cost estimates in 1977 dollars for the first and Nth commercial plants. The MITRE Corporation and the Electric Power Research Institute [VIII-7,VIII-25] have also prepared cost estimates in 1976 dollars for commercial plants. The Jet Propulsion Laboratory [VIII-10] has projected costs in 1975 dollars for future 10 MW_e and 100 MW_e plants to be operated in the year 2000. Boeing reports future engineering cost estimates for a 100 MW_e plant [VIII-8] and cost estimates of its lightweight heliostats [VIII-22]. Martin Marietta has recently published its revised engineering cost estimates for 100 MW_e and 300 MW_e plants [VIII-14].

Detailed cost estimates are presented in Appendix Tables VIII A-1 through VIII A-8. Operation and maintenance cost estimates are calculated by multiplying collector area [VIII-18] unit costs by a constant percentage (3%) where O&M cost estimates are not available. A 30-year lifetime is assumed for each plant.

Levelized busbar costs (in mills/kWh) are calculated in 1978 dollars for municipal and public utility sectors. These costs are presented in Table VIII-1.

Distributed Collector Solar Thermal Electric Power System

Engineering cost estimates for distributed collector plants have been prepared by the Jet Propulsion Laboratory (JPL) and the MITRE Corporation. JPL cost estimates are projected for the year 2000 (in 1975 dollars). MITRE cost estimates are in 1976 dollars and are based on mass produced costs of collectors. Detailed costs estimates are given in Appendix Tables VIII A-11 through VIII A-15.

TABLE VIII-1

COSTS OF
CENTRAL RECEIVER SOLAR THERMAL ELECTRIC POWER SYSTEM
in mills/kWh $1978

SOURCE	Levelized Busbar cost (in mills/kWh)				Levelized Busbar cost (in mills/kWh)	
	10 MW_e Pilot Plant		100 MW_e 1st Commercial		100 MW_e Nth Commercial Plant	
	Municipal Sector	Public Sector	Municipal Sector	Public Sector	Municipal Sector	Public Sector
McDonnell Douglas - Aerospace Corp.	244.0	301.0	112.0	134.0	79.5[a]	95.0
Honeywell, Inc.	254.0	315.0	175.0	217.0	-	-
Martin Marietta Corp.	246.0	302.0	102.0[f]	125.0[f]	58.3[b]	78.8[b]
MITRE Corp. (METREK Div.)	-	-	81.6	100.0	58.1	70.4
Sandia Laboratory	-	-	102.0	129.0	64.3	80.3
Electric Power Research Institute	-	-	105.0	127.0	-	-
Jet Propulsion Laboratory[c]	-	-		-	100.0[c]	122.0[c]
Boeing					79.1[d] 73.0[e]	94.0[d] 86.4[e]

[a] The busbar costs are for 20th commercial plant.
[b] The busbar costs are based on 150 MW_e revised cost estimates [VIII-14].
[c] Projected cost for year 2000.
[d] Projected cost for year 2000 (collector cost = $60/sq m).
[e] Projected cost for year 2000 (collector cost = $42/sq m)
[f] The bu r costs are based on 150 MW_e power plant.
Sources: [VIII-4], [VIII-9], [VIII-7], [VIII-18], [VIII-26], [VIII-10], [VIII-8], [VIII-22], [VIII-14], [V

Levelized busbar costs are presented in Table VIII-2 for municipal and public utility sectors. Busbar costs of distributed collector systems are considerably higher than the costs of central receiver systems even though MITRE assumed mass production and not prototype costs. MITRE costs for parabolic dish distributed collector systems with chemical transport and chemical storage subsystems and JPL costs for parabolic dish-electric systems for 100 MW_e plants have the lowest life-cycle costs of all distributed collector systems.

Solar Thermal Hybrid Plant with Fossil Fuel Backup Systems

Hybrid plants operate as fuel savers if the energy from the solar system in a hybrid plant costs less than the fossil fuel it replaces. The Electric Power Research Institute [VIII-26] and the MITRE Corporation [VIII-7] have given engineering cost estimates in 1976 dollars for 50 MW_e and 100 MW_e power plants respectively. Detailed cost estimates are given in Appendix Tables VIII A-9 and VIII A-10. Annual fuel costs are obtained by multiplying annual fuel consumption [VIII-7,VIII-26] by the unit costs of the fuel.

Levelized busbar costs (in mills/kWh) are calculated in 1978 dollars for municipal and public utility sectors. These costs are presented in Table VIII-3. Hybrid plants appear more economical than first commercial central receiver solar thermal plants as these life-cycle costs are considerably lower.

C. MARKET READINESS OF STEPS

Technical Readiness of Solar Thermal Electric Systems

There are no technical barriers to the development of power with heliostats. The technology is available; the challenge behind the commercialization of solar thermal power systems continues to be

TABLE VIII-2

COSTS OF
DISTRIBUTED-COLLECTOR SOLAR THERMAL ELECTRIC POWER SYSTEM
in mills/kWh $1978

SOURCE	TYPE OF SYSTEM	LEVELIZED BUSBAR COST mills/Kwh in 1978 dollars			
		10 MW_e PLANT		100 MW_e PLANT	
		Municipal Sector	Public Sector	Municipal Sector	Public Sector
Jet Propulsion Lab[a]	Line concentrator (I-axis Slat) system	131.0	161.0	113.0	138.0
MITRE Corporation	Line concentrator system	-	-	91.8	112.0
Jet Propulsion Lab[a]	Parabolic Dish-electric system	90.6	110.0	86.9	105.0
MITRE Corporation[b]	Parabolic Dish-electric system	-	-	90.1[c]	108.0[c]
Jet Propulsion Lab[a]	Parabolic Dish-steam system	136.0	167.0	117.0	143.0
MITRE Corporation[b]	Parabolic Dish-chemical transport-thermal storage-system	-	-	91.5	111.0
MITRE Corporation[b]	Parabolic Dish-chemical transport chemical storage-system	-	-	81.9	99.9
MITRE Corporation[b]	Parabolic Dish-saturate steam system	-	-	94.2	115.0
MITRE Corporation[b]	Parabolic Dish-superheated steam system	-	-	96.4	117.0

[a]Levelized busbar costs, based on Jet Propulsion Laboratory cost estimates, are projected for year 2000.

[b]Levelized busbar costs, based on MITRE Corporation cost estimates, are based on mass-produced costs of collectors.

[c]Levelized busbars costs are based on 1000 MW_e ver plant.

Sources: [VIII-7], [VIII-10]

TABLE VIII-3

COST OF SOLAR-HYBRID CENTRAL RECEIVER ELECTRIC POWER PLANT
(in mills/kWh, $ 1978)

Source	Type of System	Plant Capacity	Levelized Busbar Cost	
			Municipal Sector	Public Sector
MITRE Corporation	Solar Thermal-Gas Turbine backup-system	100 MW_e	69.1	81.7
MITRE Corporation	Solar Thermal-Oil-fired backup-system	100 MW_e	45.0	51.2
Electric Power Research Institute	Solar Thermal-Fossil fuel backup-system	50 MW_e	68.8	81.4

Sources: [VIII-7], [VIII-26]

one of establishing economic feasibility rather than technical feasibility. There is no technical limitation to prevent use of solar thermal power concepts. Solar thermal continues to focus its research and development efforts in the areas of collectors and high temperature storage. The impetus in these areas is one of cost reduction and improved efficiency rather than technical uncertainties [VIII-23, VIII-16]

Institutional Influences and Barriers to Market Readiness

Environmental and safety impacts dealing with solar thermal power are not available in any detailed form. A truly detailed assessment of possible impacts will not be known until the completion of the Solar Thermal Test Facility and the Barstow 10 MW_e pilot plant. An attempt will be made to identify and discuss the primary impacts as they are envisioned at this time.

Solar thermal electric plants will make use of various heat transfer fluids in association with their thermal storage and receiver/boiler subsystems. These fluids could be released inadvertently into the environment and could affect local water quality. A release due to system flushing operations or accidental leakage could contaminate local water supplies which would produce serious toxic effects. Proper chemical management of system flushing operations should prevent serious impacting of local water quality.

Land requirements are an important consideration for solar thermal electric plant design owing to the relatively large land areas required for the collector subsystem. Additionally, prospective sites would have to be located on relatively flat land. Because of the vast land requirements, displacement of agriculture, grazing, and/or recreation could result. However, primary solar thermal sites are located in the arid southwest desert regions where little or no agriculture exists and where none is possible without extensive irrigation. In terms of displacement of agriculture, grazing, or recreation, solar thermal plant deployment may conflict with local, state, or regional land use plans [VIII-25]. To mitigate these potential conflicts, planning officials and the public should be educated on the relative cost-benefits and tradeoffs between solar thermal and other power generating operations, such as: solar thermal does not generate radioactive wastes or solid wastes, and is relatively nonpolluting [VIII-25].

Potential safety hazards can also be associated with central receiver solar thermal plants. The greatest threat is that of misdirected light. This invisible, concentrated, and focused solar radiation can potentially cause fires and burns as well as create serious glare problems [VIII-25]. Some type of protective goggles should be worn by all plant personnel in potential danger areas. The heliostat field should also be located away from roads where there could be glare problems for vehicular traffic. Another issue of concern would be the restricting of aircraft flights over a solar thermal facility to prevent possible glare blindness to passengers.

As stated earlier, there are no technical barriers to the development of solar thermal plants; the challenge continues to be one of establishing economic feasibility. Therefore, in accordance with this statement, a primary barrier to the implementation of the solar central power tower would be that of a financial constraint. Although the power tower concept is technically ready, it is far from being financially feasible. The notion of a solar thermal market will remain elusive until numbers can be assigned to costs and benefits [VIII-21].

Aesthetics can also be construed as a minor barrier to the construction of a solar thermal facility. The completed plant will range over many square miles of typically open desert. Vast arrays of heliostats will create a unique appearance. Additionally, the tall receiver towers will contrast dramatically with the relatively flat desert terrain and will probably be visible for miles. In sum, the solar thermal plant will appear as a large and dramatic industrial installation in a typically stark desert setting [VIII-25].

Risks Associated with Steps

It is difficult to evaluate product reliability warrantees and performance on solar thermal central receiver power plants because the program is essentially still in a research and development mode. Subsystems relating to the overall design of the central receiver power plants are being constructed according to design specifications which are usually applicable to products in a research stage. Therefore, risks concerning reliability, safety, and life expectancy are undefined. Standards and codes relating to this technology have also not been formulated outside of basic design specifications. Upon the completion of the Solar Thermal Test Facility at Albuquerque and the first pilot plant at Barstow, California, an effort can be initiated whereby standards, reliability, life expectancy, and product warranty criteria may be evaluated.

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IX. PHOTOVOLTAICS

A. INTRODUCTION

Photovoltaic conversion--the phenomenon of converting sunlight directly into electricity--is an appealing source of solar power; no moving parts and no intermediate energy conversion are required. However, the current costs of photovoltaics are so high that these systems are not economically feasible except in remote areas inaccessible to conventional power sources.

This report covers three major aspects of photovoltaic conversion: a technology description, costs, and state of market readiness. The first topic is a discussion of general information, system descriptions, and advantages of photovoltaic systems. For the second topic, current costs are detailed by application, and a brief discussion of future costs and applications is provided. Market readiness, the third topic, covers the areas of current R&D, state of the delivery system, institutional influences, and risk.

History

Photovoltaic history began with the discovery of selenium in the early 1800s. The photovoltaic effect was observed in this substance, leading to the development of a selenium cell. In the early 1900s, a copper/copper oxide device was developed but was not able to match the efficiencies of the selenium cells. In 1941, the first single crystal silicon cell was prepared but did not become practical until 12 years later, when conversion efficiencies of about 6% were achieved. Manufacture of single crystal silicon cells began the following year and has continued as the predominant technology in the photovoltaic industry.

The commercial market addressed many applications in the 1950s. Solar cells provided power for transistor radios, flashlights, Army helmets with two-way radios, traffic signals, navigational lights, a remote communications station, highway emergency call box systems, and toys. However, none of the applications created a large or sustained market. The major market for solar cells, the space program, began inauspiciously with the Vanguard I satellite using solar cells to power its backup transmitter. About a year and one-half later (in 1959), solar cells were again used in the space program, but in much greater quantity, to provide power for the Explorer VI. After this time, most spacecraft having missions of over two weeks' duration used silicon solar cells as their major power source [IX-27].

It was not until the mid-1970s that interest in terrestrial applications for solar cells was renewed. The market most feasible today is the remote site or special usage application--described later in this report. In 1977, the total market for photovoltaics was about 750 kWp. This is nearly ten times the annual amount produced in the early 1970s, when NASA provided the only major market.

Principle of Operation

Photovoltaic cells are composed of some type of semiconductor material. This material acts as a conductor only in the presence of sufficient heat or light. (In dark and low temperature conditions, this substance does not conduct.) When light of appropriate wave length and sufficient energy hits this semiconductor material, it frees electrons from their chemical bonds. Freed electrons move, leaving a hole behind that is also capable of moving.

To channel moving electrons and holes into a useful electric current, impurities are added to the semiconductor--a procedure known as "doping." The semiconductor is doped with elements such as arsenic or phosphorus to add electrons (called an "n" type semiconductor), or it is doped with boron to create an excess of holes (called a "p" type of semiconductor). A solar cell consists of "n" type and "p" type regions. When light strikes the cell and frees electrons and creates holes, electrons tend to move to the "n" type regions and holes move to the "p" type regions, resulting in a voltage across the junction between these two different type regions. Conductors placed in front and in back of the solar cells enable the cell's electric current to flow to an external circuit.

System Description

The three major components of a photovoltaic system are the solar collector, a storage system (batteries), and a power conditioning unit.

These components work together in the following manner. Sunlight hitting the solar collector is converted to electric energy by the solar cells and transmitted to the storage system in the form of DC electricity. The power conditioning unit prevents the overcharging of the batteries and, where required, converts DC to AC electricity.

Solar Collectors

Solar collectors can be divided into two different categories: fixed, flat-plate collectors and tracking, concentrating collectors. Flat-plate collectors can be further divided into two subcategories: single crystal cells and thin film. Each flat-plate collector has one predominant photovoltaic material associated with it.

Flat-Plate Collector--Single Crystal Cells. Single crystal silicon cells are the building blocks for this solar collector. As the name implies, single crystals are grown from high-grade silicon. These crystals are then sliced to make silicon wafers--the basic photovoltaic cell. A typical silicon solar panel is composed of the following elements: doped silicon cells, a metallic grid under and over the cells, an epoxy fiberglass board upon which cells are placed, a transparent protective layer which covers the array, and an optional nonreflective coating [IX-9]. Most manufacturers produce this type of solar cell collector.

Although laboratory cells have been fabricated with efficiencies of 18% to 19%, typical efficiencies of manufactured cells are between 12% and 14%. These cells, when placed in an array, have efficiencies between 5% and 8% [IX-8]. This lower array efficiency is due to incomplete coverage of the array area by the solar cells.

The advantages of single crystal silicon cells are: silicon cells exhibit better efficiencies than other cell types at typical temperatures for most applications, and manufacturing capacity has been established.

Flat-Plate Collector--Thin Film. The photovoltaic material most often used in thin film technology is cadmium sulfide. Cadmium sulfide, when in contact with copper sulfide, forms a "p-n" junction similar to that formed in doped silicon. A typical cadmium sulfide array is composed of a conducting electrode coating, a thin cadmium sulfide film over the electrode, a very thin copper sulfide layer deposited over the cadmium sulfide, a metallic grid placed over the copper sulfide, glass to hermetically seal the array, and an optional nonreflective coating [IX-9].

Other materials being studied for thin film development include indium phosphide, amorphous silicon, and several ternary chalcogenides.

Although laboratory efficiencies of between 7% and 8% have been achieved, typical array efficiencies range from 3% to 5% [IX-8]. Because thin film cells cover the entire array area, no efficiency is lost due to packing.

Thin film technology has several advantages over single crystal: (1) any geometry can be defined and produced, resulting in very effective use of the array area; (2) the costly wafer slicing step is eliminated; (3) a smaller amount of photovoltaic material is required; (4) material of lesser purity can be used; and (5) it is more amenable to mass production techniques, resulting in lower production costs [IX-7, IX-8].

Concentrating Collectors. For concentrating collectors, gallium arsenide is most often used due to its relatively low efficiency loss at high temperatures. With solar flux concentration, total cell area per unit output can be reduced. At a concentration of several hundred suns, devices using gallium arsenide have demonstrated efficiencies between 17% and 19% [IX-8]. However, at these high concentrations, a cooling system would probably be required, adding to the total system cost.

Storage Systems

Because the array delivers DC current only in daylight, most applications require storage. Lead-acid batteries, comparatively low in cost and high in performance, are generally used. The particular type of battery depends upon the system application and the depth and rate of discharge required.

Power Conditioning

Power conditioning may consist of three elements--blocking diode, voltage regulator, and inverter. The blocking diode prevents the battery from discharging through the solar array during non-sun periods. The voltage regulator prevents overcharging of the batteries, which would shorten their life. Finally, an inverter converts DC power supplied from the collector or batteries to AC power if required for a specific application.

Advantages of Photovoltaic Systems

There are several advantages of a photovoltaic system. (1) Electricity is produced directly from sunlight, eliminating the need for intermediate conversion to mechanical or thermal energy. (2) The system contains no moving parts. (3) The components potentially have long lifetimes. Government tests indicate 10 to 15 year lives for panels commercially available. In the future, lives of 20 years or more are expected. (4) Maintenance costs are expected to be low. (5) The system can operate with diffuse solar radiation. (6) It is an inherently modular system. A small system will work as efficiently as a large system [IX-23].

With these advantages, why aren't photovoltaic systems in widespread use? The answer is cost; today the solar cell module alone costs between $10 and $25/Wp in $1978. The next section discusses costs by several different applications to demonstrate the current economic feasibility of photovoltaic systems.

B. COSTS OF PHOTOVOLTAIC SYSTEMS

Approach

This analysis considers cost estimates of photovoltaic systems by their potential current and near-term markets. In addition to providing costs, this method provides an understanding of why photovoltaic systems are economical in these cases. These systems are generally located in remote areas where the conventional power alternative--batteries, diesel generators, or power line extensions--is costly to provide.

Markets and Costs

The major markets presented here and associated costs (1976 dollars) for particular applications are based on a BDM study [IX-2]. Table IX-1 gives a summary of the major markets. This analysis looks at four DC applications: navigation aids for offshore platforms, radio repeaters, impressed current protection for pipelines, and water pumping. The two AC applications studied are street and highway lighting and a remote general power source. All array costs are for flat-plate, single crystal silicon cell arrays.

Tables IX-2 and IX-3 show costs for DC applications and AC applications, respectively. From these six examples, and the seven other applications looked at from the BDM study, ranges were obtained for the costs. For the array, cost per peak watt varied between $15 and $20, with the average at $18/Wp. Power conditioning and structure add $3/Wp more, ranging between $1 and $4/Wp. Most battery systems were priced at $100/kWh (as an exception, the batteries for navigation aids were priced at only $50/kWh). Finally, installation ranged from $1/Wp to over $6/Wp, averaging $3/Wp. Looking at total system costs, most of the applications fall in the range between $20 and $30/Wp.

TABLE IX-1

PHOTOVOLTAIC CURRENT AND NEAR-TERM MARKETS

Marking and Warning Devices
- Airport lighting
- Obstruction/hazard lights
- Offshore navigation buoys
- Onshore navigation systems
- Offshore platforms
- Railroad crossings
- Highway signs

Corrosion Protection
- Pipelines
- Well heads and casings
- Marine structures
- Highway bridges

Monitoring and Sensing Devices
- Pipeline controls
- Intrusion alarms
- Pollution monitors
- Gas detectors
- Weather monitors
- Snow/rain gauges
- Flood monitors
- Oceanographic data platforms

Communication Equipment
- Portable radios
- Repeater stations
- Telephone call boxes
- Air navigational systems
- CC and remote TV

Consumer Products
- Watches
- Calculators
- Boating applications
- Flashlights
- Pocket paging systems

Miscellaneous
- Water pumping stations
- Space/satellite applications
- Military test site instrumentation
- Railroad switching
- Government buys

Source: The BDM Corporation, Characterization of the Present Worldwide Photovoltaics Power Systems Market, Draft report submitted to DOE, Volume I, May 1977.

T IX-2

COSTS FOR DC PHOTOVOLTAIC APPLICATIONS
1976 COST DATA

System	Navigation Aids for Offshore Platforms		Radio Repeaters		Impressed Current Protection for Pipelines		Water Pumping	
Array Rating	150 Wp		200 Wp		400 Wp		1000 Wp	
Battery Type	lead-acid		lead-calcium		lead-acid lead-calcium		lead-acid	
Battery Rating	22 kWh		6 kWh		10 kWh		2 kWh	
Equipment Costs	Cost	$/Wp	Cost	$/Wp	Cost	$/Wp	Cost	$/Wp
Array	$3,000	$20.0	$3,400	$17.0	$9,000	$22.5	$18,000	$18.0
Power Conditioning	300	2.0	800	4.0	1,600	4.0	---	---
Battery	1,100	7.3	600	3.0	1,000	2.5	200	0.2
Structure	300	2.0	incl. in PC	---	incl. in PC	---	2,000	2.0
Total Hardware	$4,700	$31.3	$4,800	$24.0	$11,600	$29.0	$20,200	$20.2
Installation	1,000	6.7	800	4.0	1,100	2.8	1,000	1.0
Total System Costs	$5,700	$38.0	$5,600	$28.0	$12,700	$31.8	$21,200	$21.2

Source: BDM Market Study

TABLE IX-3

COSTS FOR AC PHOTOVOLTAIC APPLICATIONS
1976 COST DATA

System	Street and Highway Lighting (175 Watt)		Remote General Power Source	
Array Rating	490 Wp		6300 Wp	
Battery Type	lead-acid		lead-acid	
Battery Rating	6.7 kWh		120 kWh	
Equipment Costs	Cost	$/Wp	Cost	$/Wp
Array	$8,800	$18.0	$113,400	$18.0
Power Conditioning	90	0.2	6,300	1.0
Battery	670	1.4	12,000	1.9
Structure	500	1.0	6,300	1.0
Total Hardware	$10,060	$20.6	$138,000	$21.9
Installation	450	0.9	18,900	3.0
Total System Costs	$10,510	$21.5	$156,900	$24.9

Source: BDM Market Study

Manufacturers Costs

In an attempt to see cost trends from this 1976 survey to today's costs and to see what variability exists between different manufacturers, four companies selling photovoltaic systems were surveyed: all provide silicon cell-based systems. Table IX-4 presents system costs (excluding installation), by company, for the radio repeater system described by the BDM study.

The data present a wide spread of prices among the different manufacturers, which cannot be attributed to materials used to build the modules. The most costly system, uses 3-inch silicon cells encapsulated in void-free silicone, placed on a stainless steel frame and covered with a glass glazing. The least costly system is basically the same--3-inch silicon cells encapsulated in a void-free glass/PVB/Mylar laminate and placed on a stainless steel or aluminum frame. While it appears that more of the structure is built into the first panel than the latter this is still not sufficient to account for a $13/Wp difference in array prices.

Annualized Costs

The 1976 costs provided by BDM were updated using the data from four manufacturers. As no discernible cost trends exist between the 1976 and 1978 cost information, average prices were used. The average of the cost for the array, power conditioning, and structure is $23.40/Wp. Battery costs averaged $120/kWh. For 1978 installation dollars, the 1976 dollars provided by BDM were inflated at 6% for two years. The hardware costs, together with the installation costs, provide total capital costs for each system. Shipping costs are not included.

TABLE IX-4

CURRENT PHOTOVOLTAIC COST ESTIMATES

APPLICATION: Radio Repeater
array rating: 200 Wp
12 V lead-acid batteries
battery rating: 6 kWh

Company	1		2		3		4	
Equipment Costs	Cost	$/Wp	Cost	$/Wp	Cost	$/Wp	Cost	$/Wp
Array	$5,575	$27.9	$3,000	$15	$3,584	$17.9	$4,400	$22.0
Power Conditioning	146	0.7	400	$ 2	174	0.9	incl. in structure	---
Batteries	792	4.0	600*	$ 3	912	4.6	600	3.0
Structure	265	1.3	600	$ 3	incl. in array	---	600	3.0
Total Hardware	$6,778	$33.9	$4,600	$23	$4,670	$23.4	$5,600	$28.0

*assumed value based on $100/kWh

For this analysis, a fixed percentage of capital costs, usually 1%, was assumed for operating and maintenance costs. This amount is considered sufficient for O&M charges and for battery replacement after 10 years. (Because substantial battery storage was required for the navigational aids, O&M here was assumed to be 2% of capital costs.)

No spread of capacity factors based on location was provided here. The available data merely listed output for a typical location. In fact, there should be a distribution of costs around the final mills/kWh to reflect different locations.

A required revenue model was used to annualize these costs over a 20-year lifetime. The results are given in Table IX-5. The spread is from 2,600 to 5,400 mills/kWh for the municipal sector and from about 3,000 mills/kWh to just over 6,500 mills/kWh for the public sector. There are three reasons for this wide range. First, the number of batteries required is a factor, for example, navigation aids. A second reason for this spread is the capacity factor. The street lighting was a system designed for the northeast, hence a low capacity factor (0.08 compared to 0.2 for radio repeaters). Finally, the variation in installation dollars due to array size and site accessibility will affect the mills/kWh.

A factor in array prices not reflected above is the quantity ordered. Array prices provided by the manufacturers were based on a very small order of modules; however, all companies mentioned that their price decreases as quantity purchased increases. To see what effect this has on annualized costs, it was assumed that the array for the remote general power source was of sufficient size to be purchased for $5/Wp less and also for $10/Wp less than the given average price. For these cases, the mills/kWh came out to 3,710 and 2,940 respectively, for publicly owned utilities.

TABLE IX-5

ANNUALIZED COSTS FOR PHOTOVOLTAIC APPLICATIONS
1978 ESTIMATED COSTS

Application	Updated 1978 Capital Costs	O&M (% of capital)	Public Sector mills/kWh	Municipal Sector mills/kWh
Navigation Aids	$ 7,270	2	5,340	4,490
Radio Repeaters	6,300	1	3,150	2,610
Impressed Current Protection	11,800	1	3,700	3,080
Water Pumping	24,760	1	4,140	3,440
Street and Highway Lighting	12,770	1	6,550	5,440
Remote General Power Source	183,000	1	4,480	3,720

Future Costs

For photovoltaic systems to become competitive in markets other than small remote sites, the price of the system must decrease considerably. The Department of Energy (DOE) has established price goals for silicon arrays which are expected to make photovoltaic systems a viable alternative. The goals set are to achieve an array cost of \$2 to \$3/Wp in 1982 and to reach \$0.50/Wp in 1986.

Central Power Stations Costs

At 1985 price levels, photovoltaic systems will enter new, large-scale markets--the utility market and the residential/commercial market. Three companies, General Electric Company [IX-13], Westinghouse Corporation [IX-26], and Spectrolab Incorporated [IX-22], were awarded system contracts by the Energy Research and Development Administration (ERDA) for photovoltaic central power systems conceptual design studies. GE considered three designs--a fixed panel array, a low-ratio concentrator, and a Solar Azimuth Tracker (concentrators rotate around a central hub and track the azimuth angle of the sun), all using silicon cells. Westinghouse considered two designs--a lean to collector/reflector using silicon cells or thin film and a compound parabolic concentrator with vertical axis tracking subsystems, using silicon. Finally, Spectrolab considered one design, a concentrating array with an azimuthal orientation mechanism, using silicon cells [IX-19]. A backup gas turbine plant was provided. This Spectrolab study looked at a system with no storage, a system with three hours storage, and a system with no storage but one that ran the gas turbines an additional 745 hours per year.

Table IX-6 contains total capital costs and O&M costs in 1975 dollars from these studies. All these studies assume higher efficiency solar cells than available today and DOE price goals, not current costs. No attempt is made here to adjust the figures for consistency. (These studies used various assumptions for cell efficiency, shipping costs, design cost, project management, contingency and spares, and O&M costs.) Assuming a 1990 year of operation in Phoenix, Arizona, and a 30-year life, the levelized costs in 1978 dollars appear in Table IX-6. Cost estimates for silicon based systems ranged from about 65 to 125 mills/kWh in the municipal sector and from 80 to 145 mills/kWh in the public sector. Only Westinghouse provided estimates for thin film arrays, with costs substantially lower than their silicon based alternative.

Table IX-7 gives some of the results of the MITRE study. These results were based on an analysis of the General Electric and Westinghouse systems. Three basic designs (without storage) are considered: silicon flat-plate, thin film flat-plate, and concentrating collectors. Because this study compared the General Electric and Westinghouse analyses, (using those numbers but with adjustments), these results can be considered more comprehensive.

Residential Systems Costs

Tables IX-8, IX-9, and IX-10 give the 1975 cost data for residential systems provided by General Electric and Spectrolab. These levelized costs in 1978 dollars were provided by an in-house revenue requirements model, to ensure consistency. Similar to the original central power station data, no attempt was made to compare and adjust costs between the two studies. The General Electric study assumes two applications--with and without battery storage--and a range of array costs. Because these cases assume excess electricity is sold to the utility in the system without

TABLE IX-6

SUMMARY OF UTILITY SYSTEM COSTS

Input: 1975 Dollars
Results: 1978 Dollars

	Rating (MW)	Capacity factor	Capital Costs ($ in millions)	O&M ($ in millions)	Municipal Sector mills/kWh	Public Sector mills/kWh
GENERAL ELECTRIC[1]						
Fixed Panel Array	1,500	0.215	$1,296.4	10.40	80.0	97.7
Low-Ratio Concentrator	1,500	0.215	1,814.1	17.25	114.0	139.0
Solar Azimuth Tracker	1,500	0.215	1,394.0	9.65	84.6	103.0
WESTINGHOUSE [2]						
Lean to Collector/Reflector-Silicon	100	0.203	71.616	0.716	70.9	86.6
Lean to Collector/Reflector-Thin Film	100	0.197	43.289	0.433	45.1	55.1
10X CPC Vertical Axis Tracking	100	0.309	96.672	0.967	63.8	77.9
SPECTROLAB[3]						
No Storage	200	0.308	325.05	3.25*	116.5	140.6
Three Hour Storage	200	0.393	404.26	4.04*	120.0	143.7
Gas Turbine Storage	200	0.393	325.25	3.25*	125.4	146.8

*Assumed to be 1% of capital costs. Fuel costs for gas turbine backup are not included in these figures.

1. General Electric, Conceptual Design and Systems Analysis of Photovoltaic Systems, final report, Volume II, March 19, 1977.

2. Westinghouse Electric Corporation, Conceptual Design and Systems Analysis of Photovoltaic Power Systems, final report, Volume II, March 1977.

3. Spectrolab, Inc., Conceptual Design and Systems Analysis of Photovoltaic Systems, final report, Volume IV, April 1977.

TABLE IX-7

MITRE CENTRAL PV POWER SYSTEM COSTS

1975 Costs
100 MW Capacity
1990 Installation

System Design	Capital Costs ($ in Millions)	O&M Costs ($ in Millions)	Capacity Factor	Municipal Sector* (mills/kWh)	Public Sector* (mills/kWh)
16% Silicon Coll/ref	90	1.86	.28	73.6	88.4
10% Thin Film Coll/ref	100	2.44	.26	92.3	110.0
10X CPC Concentrator Vertical Axis Tracking	190	2.10	.30	127.0	155.0

*Provided by in-house revenue requirement model.

TABLE IX-8

COSTS FOR GENERAL ELECTRIC RESIDENTIAL SYSTEM

1975 Cost Data

Costs (at given $/m^2$ for array)	$200/m^2$	$100/m^2$	$50/m^2$
With Batteries			
Capital Costs	$ 28,699	$ 18,199	$ 12,949
O&M Costs	193	141	115
Battery Replacement	3,700	3,700	3,700
Without Batteries			
Capital Costs	23,509	13,009	7,759
O&M Costs	168	115	89

Output (MWh/yr)	Cleveland	Phoenix	Miami
With Batteries	9.48	16.41	14.86
Without Batteries	12.70	20.34	18.53

TABLE IX-9

LEVELIZED COSTS FOR GENERAL ELECTRIC RESIDENTIAL SYSTEM

Levelized Costs[1] (mills/kWh)	Cleveland			Phoenix			Miami		
With Batteries	$200/m²	$100/m²	$50/m²	$200/m²	$100/m²	$50/m²	$200/m²	$100/m²	$50/m²
Residential Ownership[2]	500	341	261	289	197	151	319	217	166
Municipal Utility	526	358	274	309	211	161	351	239	183
Public Utility	642	434	329	378	255	194	428	289	220
Without Batteries									
Residential Ownership[2]	277	157	97	173	98	61	190	108	67
Municipal Utility	299	170	105	185	105	65	205	116	72
Public Utility	370	210	129	229	130	80	253	143	89

[1] 1978 Dollars

[2] Calculations based on:
20% tax rate
9% discount rate
100% debt financing at 12.5% interest rate
no investment tax credit

TABLE IX-10

COSTS FOR SPECTROLAB RESIDENTIAL SYSTEM

1975 Cost Data

City	Capital Cost	Battery Replacement	O&M[1]	Output (kWh/yr)
Phoenix	$ 6,875	$ 715	$ 84	8270
Riverside	6,160	1,025	81	6820
Washington, D.C.	7,145	1,525	86	6300
Cleveland	12,990	2,531	115	8260

LEVELIZED COSTS (mills/kWh)[2]

City	Residential Ownership[3]	Municipal Utility	Public Utility
Phoenix	145	158	192
Riverside	167	184	222
Washington, D.C.	214	234	280
Cleveland	281	318	384

(1) Spectrolab did not provide O&M costs. Costs assumed the same as GE study: 0.5% of capital cost + $50.

(2) 1978 Dollars.

(3) Calculations based on:
20% tax rate
9% discount rate
100% debt financing at 12.5% interest rate
no investment tax credit

storage, this case actually has higher output per year. The Spectrolab study assumes battery storage. The Spectrolab study compares best with the General Electric study at $\$100/m^2$. The levelized costs from the Spectrolab study range from about 150 mills/kWh to nearly 300 mills/kWh for residential ownership. Municipal ownership increases mills/kWh by 10% to 12%, and public utility ownership increases costs by an additional 20% to 22%. The General Electric results are on the average, about 50 mills/kWh higher (for the case at $\$100/m^2$ array area). In comparison with the results at $\$100/m^2$, $\$200/m^2$ assumption results in about a 50% increase in annual costs, while the $\$50/m^2$ assumptions produce a 25% decrease. The results without batteries provide a lower annual cost because, as mentioned, excess output goes to the utility.

C. MARKET READINESS OF PHOTOVOLTAICS

Technical Readiness

Research

As mentioned, single crystal silicon solar cells have been manufactured for over 20 years. Technical questions center on designing and building these systems economically. Most research is directed toward semiconductor materials, efficiency improvement, manufacturing and production processes, concentrator array design, and system performance. Although each aspect will be mentioned separately, these are highly interrelated.

While silicon, gallium arsenide, and cadmium sulfide are the most well-known materials for photovoltaic cells, other semiconductors are being investigated, as shown in Table IX-11. The emphasis is on finding suitable thin film materials which will ultimately reduce the price of photovoltaic cells.

TABLE IX-11

SEMICONDUCTOR MATERIALS CONSIDERED FOR SOLAR CELLS

Silicon Gallium Arsenide	single crystal and thin film
Cadmium Sulfide Copper Sulfide Cadmium Stannate Indium Phosphide Cadmium Telluride Copper-Indium-Selenide Copper-Indium-Sulfide Silver-Indium-Sulfide	thin film

TABLE IX-12

POSSIBLE MANUFACTURING TECHNIQUES FOR SILICON

<u>Ribbon Growth</u>

- Edge-defined film-fed method (EFG)
- Capillary action shaping technique (CAST)
- Inverter Stepanov technique (IST)
- Web-dendritic growth
- Laser zone ribbon growth

<u>Sheet Growth</u>

- Dip-coating of low-cost substrates
- Chemical vapor deposition (CVD)
- Hot forming to silicon sheet

<u>Ingot Growth</u>

- Czochralski method (current method)
- Heat exhanger method

Directly related to materials is research to improve cell efficiency. The goal for thin film is to achieve a 10% efficiency by 1980. Silicon is striving toward an overall array efficiency of 10%. For concentrating systems, cells which maintain high efficiencies under these higher temperatures are being researched. The benefits of higher efficiency are twofold. First, less semiconductor material is needed. Second, total array area is reduced, providing sizable reductions in system cost.

Most research in production and manufacturing has been executed under the Low-Cost Silicon Solar Array Project (LSSA). Table IX-12 shows the different manufacturing techniques currently under investigation. These encompass single crystal and thin film technology for silicon. Also, several contracts have been awarded which deal with large-scale automated production for silicon arrays.

Research directed by Sandia is investigating array designs and fabrication for concentrating systems. Some of the designs under consideration are parabolic cylinder, paraboloid, cylindrical fresnel lens, spherical fresnel lens, and compound parabolic concentrator. Variations on these systems include different tracking mechanisms and differing levels of cell concentration.

Finally, system performance is being evaluated against a desired life expectancy of over 20 years. Through actual testing in the field, and accelerated life testing, problem areas are being discovered and solutions addressed. An item of primary concern is the encapsulation system. Research is underway to identify a cost-effective material capable of maintaining a 20-year life with little degradation. Also, the interface areas of the system (between the parts of the encapsulation system, and at points where the encapsulation system is penetrated for external electrical connections), are expected to present significant technical problems.

Implications

The above discussion demonstrates that no one method of designing photovoltaic cells has yet been determined to be the best in the long run. Because of its 20-year history, single crystal silicon cells are currently the most widely produced. Concentrating systems are being pursued for their potential near-term cost reductions. Finally, thin-film systems are being investigated as low-cost arrays for the long term. However, a potential problem exists here. Because of anticipated cost reductions with future technology, industry may be hesitant to make large capital investments for automating and improving single-crystal silicon technology. It could be viewed as risky, with little time for return on investment before future technologies make this investment obsolete.

The State of the Photovoltaic Delivery System

A list of photovoltaic manufacturers currently identified is contained in Table IX-13. Because the photovoltaics industry is a rapidly growing and changing one, this list may be incomplete (Texas Instruments, Inc., among others, is expected to enter the market soon), or incorrect in places (changes in types of arrays produced).

Current manufacturers usually supply most of the services--production, sales, system design, all auxiliary components, and occasionally even installation and maintenance. One company representative indicated that links are being formed between themselves and intermediaries already established to serve specific markets [IX-5]. For each different market (communications, impressed current protection, water pumping, etc.), this manufacturer designs the system and provides the equipment, but the intermediary installs the equipment for his

TABLE IX-13

PHOTOVOLTAIC MANUFACTURERS

Company	Flat Plate	Concentrating
Angelia Products Co.		X
ARCO Solar	X	
Columbia Chase	X	
International Rectifiers	X	
Mobil Tyco [1]	X	
Motorola, Inc.	X	X
M-7 International	X	
Optical Coatings Lab Inc.	X	X
Photon Power [2]	X	
Sensor Technology	X	X
SES, Inc. [2]	X	
Silicon Material, Inc.	X	
Silicon Sensors, Inc.	X	
Solarex Corp.	X	X
Solar Power Corp.	X	
Solec, International, Inc.	X	X
Sollos, Inc.	X	
Spectrolab, Inc.		X
Spire Corp.	X	
Sun Track Corp.		X
Vactec Inc.	X	

[1] Not currently manufacturing, evaluating EFG method for silicon.

[2] Not currently manufacturing, planning to manufacture cadmium sulfide cells.

customers. In some instances, particularly marine aids, the intermediary has developed sufficient skills to also design the system.

Another company [IX-6], which provides photovoltaic systems primarily for communication equipment, indicated that they deal directly with the end-user. They have about 50 to 60 sales offices around the country as well as some less-used franchised distributions. (The number of sales offices is expected to vary greatly by company. Companies already well established in fields other than photovoltaics, as this company is, can probably incorporate photovoltaics into their already existing distribution channels.) In general, though, this structure must be developed so that marketing distribution, installation, and maintenance capabilities also exist fully in organizations other than the manufacturer.

Finally, there are no integrated facilities dedicated to the manufacture of auxiliary equipment, such as batteries, inverters, and regulators specifically for photovoltaic arrays. If this equipment is manufactured specifically for photovoltaic systems, cost reductions could occur.

Institutional Barriers to Market Readiness

Numerous institutional and legal barriers exist which must be addressed before widespread application of photovoltaic systems will occur. These issues deal primarily with far-term applications (residential and utility) and will be discussed accordingly. Most of these problems are not unique to photovoltaics, but rather apply to several solar technologies; hence, the discussion will be brief. Because concerns are for far-term technologies, many of these issues will have been addressed by other solar technologies; so, fewer barriers should exist when commercial readiness is achieved.

Risks Associated with Photovoltaics

Costs

A large element of risk in photovoltaic systems can be seen by looking at today's prices, DOE price goals, and a few projected prices. For large volume orders, today's prices generally range between \$10 and \$15/Wp, depending on the company. DOE price goals (in 1975 dollars) have been set to achieve \$2/Wp in 1982, \$0.50/Wp in 1986, and \$0.10 to \$0.30/Wp in 1990. A sizable reduction from current prices is required to reach these goals. Automated production facilities and large volume production are necessary, but will not assure these reduction goals. Price projections from one company show \$0.50/Wp not being reached until 1990 [IX-18]. However, researchers at the University of Delaware's Institute of Energy Conversion indicate that \$0.25/Wp could be achieved by 1982 using cadmium sulfide [IX-25]. They are currently trying to commit five companies to participate in a continuous-process pilot plant. While these are different technologies, there is quite a difference between cost projections over time.

Production

Corresponding to DOE price goals, production goals have also been set. These goals call for an annual production of 20 MW in 1982, 500 MW in 1986, and 10 to 20 GW in 1990. Starting from a producton of 750 kW in 1977, meeting these goals would require a growth rate of nearly 100% sustained over a 13-year period.

Markets

Intricately related to cost and production is the market. Near-term markets have been identified, generally small applications where conventional power is not readily available. The far-term markets, residential and utilities, have a very large potential.

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X. SOLAR SATELLITE POWER STATIONS

A. INTRODUCTION

Since the Solar Satellite Power Station (SSPS) concept was first proposed in 1968, research efforts have examined its various aspects, but no systems or prototypes have been built. As originally proposed, an SSPS may utilize any of several solar conversion technologies--photovoltaic, thermal electric, and thermionic--which produce microwaves that are then beamed down to one or more Earth receiving antennas and then converted to electricity [X-10]. SSPS has the potential for contributing to U.S. energy supplies beyond the 1995 to 2000 time period following a period of development and demonstration. Feasibility is contingent on successful completion of the space shuttle and large reductions in the cost of photovoltaics.

B. SSPS SYSTEM DESCRIPTIONS AND COSTS

System Descriptions

As currently envisioned, the SSPS [X-2] will be located in geosynchronous earth orbit (GEO) (19,323 nmi altitude) and would provide 10 GW of power continuously per SSPS to the utility interface on the ground. The typical satellite would have a collection area of 100 km^2 and a mass of about 5×10^6 kg. It will be necessary to construct basic modules of the SSPS (or modules) at low earth orbit (LEO) where lightweight structures can be built under zero-gravity conditions and then transported to GEO.

In GEO, the SSPS would be exposed to from 4 to 11 times the solar energy available in areas on Earth. The energy is available nearly continuously except for periods around the equinoxes at which time the SSPS would be eclipsed for up to 72 minutes a day resulting in 1% loss of energy over a year. Collected energy would be converted to microwave energy that would be transmitted to a receiving antenna on Earth. At the receiving antenna, the microwave energy will be reconverted to electricity and made available to a transmission network.

The SSPS is currently in the concept evaluation phase (DOE-NASA) that will last until 1980. The objectives of this phase will be to develop an initial understanding of the economic practicality and the social and environmental acceptability of the concept. The first major program milestone in this phase requires the selection of a "Baseline System Concept" in October 1978. However, in order to proceed with initial systems definition, a preliminary baseline concept was chosen. A few of the guidelines for this phase are [X-2]:

- SSPS operational date year 2000 (technology available in 1990).
- A maximum rate of implementation of two SSPS (10 GW) per year;
- All ground receiving antennas sized for 5 GW (2 per SSPS);
- Microwave power density not to exceed 23 and 1 mW/cm^2 at center and edge, respectively, of the ground receiving antenna;
- All materials for constructing the SSPS are derived from Earth resources;
- System life is 30 years (with no salvage value or disposition); and
- Zero launch failure rate.

The highlights of the analysis of the baseline concept are:

- SSPS employs silicon cells with concentration ratio of 1.
- Receiving antenna area is 100 m^2 (including buffer zone).
- Satellite is constructed in LEO in eight elements employing a crew of $\simeq$500.
- Satellite elements are transferred to GEO using electric thrusters (energy derived from solar collection system) with a crew of $\simeq$6 in GEO.
- Four hundred freighter launches to LEO are required per 10 GW SSPS, each with a 400 metric ton payload.
- Freighters are two-stage winged, land-landing vehicles.
- Kennedy Space Center is the launch complex.
- Major material requirements are 2 x 10^6 tons each of steel and concrete for two receiving antennas.
- Satellites require 10,000 tons each of graphite, copper, and silicon.
- Transportation propellants require 15 x 10^6 tons of coal per SSPS (all propellants used are derived from coal, air, and water).
- R&D, facilities, transportation fleets, and first operational 10 GW SSPS with two receiving antennas will cost $86 billion.
- Subsequent SSPS cost is $23 billion at a rate of one 10 GW system per year.
- A plant capacity of .92(allows 87 8-hour down times for planned maintenance; all Earth eclipses are within these maintenance periods).

- Construction Crew:
  * 480 in LEO (250-300 nmi);
  * 60 in GEO;
  * Maximum crew stay time--90 days; and
  * Work schedule = 2 shifts; 6 days/week; 10 hours/day.

Conversion Systems

Two solar conversion concepts have been evaluated in great detail. They are: photovoltaic and thermal-electric. Several photovoltaic energy conversion configurations are being considered, mainly differing in the specific choice of photovoltaic materials (silicon, GaAlAs, GaAs), structural arrangements, solar concentration factors, and methods of minimizing gravity gradients and disturbing torques due to microwave antenna recoil and solar radiation pressure. At present the NASA-DOE baseline concept employs photovoltaic cells with a concentration ratio of one. The solar cells generate electricity directly, and the electrical energy is converted to microwave energy for transmission to Earth. The system is highly modular consisting of 128 structural bays, 660 meters square, with each structural bay supporting a planar photovoltaic array consisting of 50 micron solar cells integrated with 75 micron borosilicate glass frontcover and 50 micron borosilicate glass backcover. The satellite structure is a two-tier graphite epoxy tubular struss structure. The solar cells have an assumed efficiency of 17.3%, and the cost of the solar cells is approximately $\$150/m^2$ (including covers) with the structure costing \$50/kg. The overall dimensions of the satellite are 24.1 km x 5.3 km x 0.47 km. The satellite would be constructed in eight building blocks at GEO. As each building block is completed at LEO it would be transported to GEO using the solar cells to power ionengines for the orbit-transfer.

Thermal-electric conversion is being considered as an alternative method of producing power. In this approach, mirrors focus solar radiation onto a cavity where heat is absorbed by a working fluid such as helium and transferred to heat engines that drive electric generators. Similar to photovoltaic systems, electricity is provided to the microwave power transmission system. A Brayton cycle engine (similar to jet engines on Earth) or Rankine cycle engine would be used for the heat engine. The Brayton cycle does not require boilers and condensers (working fluid is always in the gas phase) and operates at high temperatures (1400°C). The high temperature is required to achieve efficient operation (15%). This approach will require development of high-temperature materials for the engine as well as the optical concentrator for the solar radiation. The Rankine cycle engine utilizes both liquid and gas phase (working fluids being considered are cesium, cesium/steam, and potassium). The Rankine cycle operates at a lower temperature of 1038°C with a maximum efficiency of 12%; however, the Rankine engine is lighter in weight in terms of (kg/kW). The overall size of an SSPS employing this conversion system ranges in overall dimensions from 10.21 km x 3.66 km x 3.05 km to 24.3 km x 18.22 km x 3.66 km. These systems are not as modular as the photovoltaic concept and have additional complexities if operated in GEO (such as articulation of reflectors) along with technical challenges. The key advantage is their relative light weight (one concept uses inflatable parabolic reflectors pressurized to 300 psi to concentrate sunlight) compared to an SSPS employing photovoltaics.

Microwave Transmission System

The key components in the system are the microwave transmitting antennas located on the SSPS. In the baseline concept, there are two transmitting antennas mounted on gimbals to independently point to two ground receiving antennas, each link providing 5 GW of power (at the utility interface). The function of the system is to convert electrical energy into microwave radio frequency energy and to efficiently transmit the microwave beam to the receiving antenna located on the ground. The baseline concept employs klystrons (transistors are still under consideration) integrated with radiating waveguide modules which operate at 2.45 GHz, with an efficiency of 85% and power level of 72 kW. Use of transistors would change the transmitted frequency to 0.915 GHz and require a larger antenna for equivalent beam energy densities and pattern.

Two antenna patterns are being considered that deliver 5 GW of power at the utility interface. The two patterns are a Gaussian shape and a Bessel-J shape. The Bessel-J distribution has a lower minimum power density for the same delivered power. However, the ground receiving antenna requires a 7.5 km radius as compared to a 5 km radius for the Gaussian beam.

The receiving antenna system is comprised of row-on-row of arrays which are oriented normal to the incoming microwave beam and are organized in a large number of subarrays ($\simeq 20\ m^2$). The principal baseline concept employs arrays composed of individual diapole antennas, each requiring a diode rectifier. This configuration requires a large number of diodes, and the diodes operate out of their most efficient region due to low signal levels. Various concepts are being evaluated to improve this part of the transmission system. The total receiving antenna has dimensions of about 9.4 km x 13 km (elliptical) for a 36° Latitude location or about 90 km^2 land area. This receiving antenna would have a power level of 1 mW/cm^2 at the edge of the antenna and 0.1 mW/cm^2 at the fence around the antenna located 1.3 miles around the edge of the antenna. This size meets the U.S. microwave level of less than 10 mW/cm^2 at the outer edges by a factor of 1/100th, but is higher than the international standard of 0.01 mW/cm^2 by a factor of 10.

A closed-loop retro-directive-array phase-front control is used between the subarrays of the receiving antenna and transmitting antenna (SSPS) to achieve the desired efficiency, pointing accuracy, and safety of operation of the microwave beam. In the retro-directive-array design, a reference beam is transmitted from the center of the receiving antenna to a phase comparator at the center of each subarray in the SSPS transmitting antenna and also to a reference subarray in the transmitting antenna center. The central subarray transmits the received reference signal to the subarrays (over calibrated coaxial cables so that when it arrives at the individual phase comparators the reference signal is an integral multiple of 2 π radians) for comparison with the signal received directly from the ground receiving antenna. Any difference in phase results in error signals that may be the result of improper alignment, etc., which is used to correct the primary transmitted power beam.

The diodes in each dipole antenna of the receiving antenna produce a DC output which is accumulated and converted to AC for interface with the transmission network.

Transportation System

To build and maintain SSPS systems in orbit, a space transportation system which provides low-cost transportation ($10-$100/lb in GEO) is required. The key to low-cost space transportation will be the utilization of reusable vehicles. The current Space Shuttle Orbiter program will provide the test-bed for this concept. The shuttle is anticipated to reduce current payload cost of $10,000/lb in GEO to $1,000/lb in GEO.

The currently preferred transportation system is made up of four elements. They are: (1) Personnel Launch Vehicle, PLV; (2) Personnel Orbital Transfer Vehicle, POTV; (3) SSPS Cargo Launch

Vehicle--the heavy lift launch vehicle, HLLV; and (4) the SSPS Cargo Orbital Transfer.

In the reference baseline system, a fleet of two PLVs will be used to establish a construction crew in LEO of approximately 480 people (plus an additional 60 people who will be eventually transported to GEO). This is based upon a 90 day stay time and 80% load factor. Every 14 days it would carry into orbit a crew of 75 passengers and return with an equal number (after they have stayed in orbit for 90 days). This will require 36 flights per year to support construction of a single SSPS. The PLV will not be a new space vehicle but will be a modified Space Shuttle Orbiter. It will require a new second stage using liquified oxygen/methane engines. This new second stage will replace the current solid rocket motors used on the Shuttle Orbiter and will be ballistically recovered after launch. The existing payload bay in the Orbiter will be used to contain the life support capsule for the 75 personnel during transport.

The SSPS Cargo Launch Vehicle, HLLV, will be a two-stage winged launch vehicle with a 424 ton payload capability to LEO. This vehicle is not in the current inventory and will be a new development. However, present concepts show heavy emphasis on the Shuttle Orbiter design. The first stage has "fly back" capability utilizing air-breathing engines with a landing weight of 934 tons (a Boeing 747 has a landing weight of 302 tons). The second stage orbiter flies to the LEO orbital base with the payload and deorbits for an unpowered landing at the launch site with a landing weight of 439 tons. This vehicle will carry into orbit the materials to construct and support the SSPS. To support the construction of a single SSPS per year a fleet of six HLLVs with a four-day turnaround will be required or 391 flights per year (plus 61 additional flights the first year to provide materials for establishing the LEO and GEO construction bases).

To provide for transportation of personnel and resupply to GEO from LEO, a fleet of two POTV vehicles will be developed (they would be fully reusable). The POTV will be a two-stage vehicle (each stage is identical except for the number of engines) and will deliver 65 tons to GEO and can return 41 tons to LEO. A 75 man crew transfer vehicle and resupply module will be the payload. The POTVs would make a total of five flights per year to support construction of a single SSPS per year.

The Cargo Orbital Transfer System will transfer 1/8 sections of the SSPS from LEO to GEO using power generated from that section (such as partially deployed solar cells) of the SSPS. Ion electric argon thruster module panels located at each of the four corners of the 1/8 SSPS module provide the primary thrusters with LO_2/LH_2 thrusters included to provide attitude control during transporting. Two sizes of thruster modules will be developed: (1) for transporting 1/8 SSPS modules and (2) transporting of minor assemblies such as antennas. These thruster modules will be a new development based upon the "space tug" concept which will have been thoroughly evaluated during the Space Shuttle Orbiter program through the use of specialized vehicles called "teleoperators" and larger space tugs.

SSPS System Cost

The cost of implementation of the SSPS concept is on the scale that compares with other major energy options (increased use of coal, fusion, etc.). The cost is measured in billions of dollars as opposed to millions. The basic cost data for SSPS are from recent analysis performed at NASA JSC. This analysis is consistent in assumptions with the other analyses used in this report. Some of the basic assumptions are:

- 1978 dollars;
- 500 mission life of launch vehicles;
- 50 mission life of space vehicles;
- Photovoltaic SSPS;
- 30 year lifetime for SSPS;
- Rate of return 15%; and
- Capacity factor .92.

Table X-1 provides the cost breakdown of design, development, test and evaluation for the elements of the SSPS. The total estimated cost is $42.575 billion over a period of 20 years. The peak funding level for DDT&E over this period would be approximately $5 billion per year. The total cost to establish the first operational SSPS is shown in Table X-2. The total cost is $86.693 billion and includes the DDT&E cost of $42.575 billion. The funds for the first SSPS would be spent over a 13-year period with a peak funding level of combined DDT&E and the first SSPS reaching between $6 billion and $7 billion per year. (Current funding level for all NASA programs is at the $4.3 billion level and reached a peak of $5 billion to $6 billion during the Apollo program in 1965 dollars.) The electricity from the first SSPS would have to be sold at approximately 140 to 170 mills/kWh (see Table X-4) at the busbar to recover these costs with adequate return on investment.

If 30 SSPSs were built at a rate of one per year, the busbar cost of electricity to the utility interface would be from 37 to 47 mills/kWh to recover development costs and maintain a profit. This is competitive with present costs of electricty and even more so in the 2000-2030 time frame. Table X-3 shows the average cost breakdown (primary capital investment and O&M) per SSPS if 30 will be built. Table X-4 summarizes the average cost per SSPS to show

TABLE X-1

DESIGN, DEVELOPMENT, TEST, AND EVALUATION PHASE COST FOR SSPS
(in Millions of Dollars)

Power Conversion, Transmission, Reception	$ 3,344
Technology Verification	2,926
Transportation System	
HLLV	11,100
COTV	1,700
OTV	1,500
PLV	1,900
Construction Base	6,939
SSPS Hardware Facilities	10,366
Launch Facilities	2,800
TOTAL	$ 42,575

TABLE X-2

TOTAL COST FOR FIRST OPERATIONAL SSPS
(in Millions of Dollars)

DDTE	$ 42,575
First SSPS	12,829
Construction Base	13,802
Rectennas	4,446
Transportation	13,041
TOTAL	$ 86,693

TABLE X-3

AVERAGE COST PER SSPS IF 30 SYSTEMS ARE CONSTRUCTED
(in Millions of Dollars)

1.	Satellite	
	a. Power Collection (structure, rotary joint, attitude control, instrumentation, communication, solar cells/blanket, power distribution).	$ 4,519.2
	b. Power Transmission (structure, attitude control, instrumentation, communication, klystrons, thermal control, waveguides, power distribution).	2,621.5
	Subtotal	$ 7,140
2.	Transportation System	
	a. 6 HLLVs and Spares	2,268
	1) Fuel	821
	2) Personnel	1,760
	3) Other	1,720
	b. COTV (set of 8)	2,820
	c. PLV (2)	470
	d. POTV (2)	230
	Subtotal	$ 10,089
3.	Construction Facilities	
	a. LEO Base	490
	b. GEO Base	597
	c. Transportation	129
	Subtotal	$ 1,216
4.	Ground System	
	a. Antenna	1,574
	b. Power Collection & Conditioning	580
	c. Structure	1,788
	d. Land and Site Preparation	504
	Subtotal	$ 4,446

TABLE X-4

COST OF ELECTRICITY FROM SSPS

SSPS PRODUCTION UNIT COST (in Millions of Dollars)
One SSPS/Year

Satellite	Ground System	Fabrication & Assembly	Transportation
7,141	4,446	1,216	10,089

TOTAL $22,892 or $2,289/kW

	NASA Analysis	SERI Analysis
First SSPS	164 mills/kWh	139-173 mills/kWh
2nd and Subsequent SSPS	43 mills/kWh	
Average for 30 SSPS @ One/year	47 mills/kWh	36.8-45.6 mills/kWh

a cost for electricity of $2,289/kW for an investment of $22.892 billion/SSPS. In Table X-4, the levelized busbar costs shown are from NASA JSC analysis and SERI costing methodology utilized to evaluate other utility applications in this report.

C. MARKET READINESS OF SSPS

Technical Readiness Assessment

The SSPS program readiness is dependent upon at least seven major areas in which technical developments or improvements are needed prior to commercial deployment (or first operational SSPS). These areas are:

- A successful Space Shuttle Orbiter program;
- Orbital assembly/control of very large space structures;
- Development of major engine assemblies utilizing fuels made from coal (CH_4);
- Improved performance of photovoltaics;
- Development of logistics, facilities, and capability to support 500 to 600 orbital crew continuously;
- Development of transportation system; and
- Resolution of standards for suceptibility to microwaves for humans and other terrestrial systems (atmosphere, birds, etc.)

Many of the concepts utilized in the SSPS will be proven out during the Space Shuttle Orbiter program. The use of glide-back reusable vehicles in the Space Orbiter will provide the foundation of design of reusable vehicles and confidence in turnaround schedules and cost. The shuttle will also provide additional data on man-in-space and certain operations that will be utilized by the SSPS. Some of the experiments slated for the shuttle program will aid in establishing credibility of space manufacturing (tools, restraints, etc.) and construction of large space structures.

It is planned to utilize propellants that can be derived from air, coal, and water. Methane as a propellant has had limited application in major rocket engine assemblies. In addition, the choice of methane is dependent upon coal gasification costs.

The baseline reference analysis by NASA assumed that photovoltaic cells had an efficiency of 17.3% at costs compatible with about $0.37/watt. These are significant reductions in photovoltaics current costs and are highly dependent upon continued improvements in solar cells and increased production to reduce the cost.

The SSPS will require support capability for from 500 to 1,000 people capable of flight status in orbit plus facilities to support at least one or two major launches per day. Typically, the launch rate during Apollo or Skylab ranged from 2 weeks to 30 days. During the Space Shuttle program the rate will increase to one launch per week. The high launch recovery rate of SSPS will require major facility improvements at Kennedy Spacecraft Center and new spacecraft management techniques similar to aircraft operations.

The Space Shuttle program will verify numerous phases of the transportation system as well as provide the basic vehicle for transporting people into orbit. However, the use of a first stage with "fly-back capability" (i.e., powered flight) will be a new development. This will require a set of engines of airbreathing capability and typical rocket engines. The idea was evaluated for the shuttle program; however, it was dropped due to loss of payload capability in the orbiter to carry the additional engines.

Additional research and understanding of the nature of susceptibility of humans and other organisms to microwaves is needed to resolve differences relative to harmless levels of radiation.

State of SSPS Delivery Systems

There are three major areas in the implementation of the SSPS program that relate to the ability of the industry to produce the required products. These are:

- Space vehicle production for the transportation system;
- Solar cell production for the collector system; and
- Propellant production for the transportation system.

It appears that the facilities to produce the required space vehicles exist today. Commitment to the SSPS would require expansion of aerospace industry production capacity. Also required is the development of in-space manufacturing and assembly capability. A major increase in production facilities is required for the production of propellants, photovoltaic arrays, and the production of the electronic components such as klystrons and receiver diodes.

Photovoltaics

The present market delivery system for photovoltaic power systems consists primarily of small-scale remote applications and some large spacecraft applications (Skylab solar panels were the largest application of solar cells in space--6-8 kWp during the 1970s). Most systems are rated at less than 1 kWp. In 1976, the total world market for photovoltaic systems was about 420 kWp. Foreign markets are basically the same as the domestic market with minor differences in applications.

Supply availability of solar cells is of prime importance in terms of the industry's ability to produce solar cells in the quantity required for the SSPS. Current photovoltaic demand is being supplied by a small photovoltaic industry with annual sales of approximately $25 million. The industry consists of about 10 manufacturers of single crystal silicon solar arrays and two pilot production lines for cadmium sulfide (CdS) arrays. With the exception of a few small manufacturers, most manufacturers are not expanding their production capacity at this point due to the uncertainty involved. At present, no large manufacturing facilities exist, and the total world production of solar cells in 1977 was 750 kWp. A single SSPS would require 17 GWp over one year.

The industry response to the recent flat-plate and concentrator program research and development announcement (PRDAs) indicates an extensive interest in solar cell fabrication and in the potential applications. Also, both the semiconductor and chemical industries can apply their current knowledge of production processes to the production of advanced solar cells.

Some of the barriers and constraints to supply availability of solar cells are:

- non-automated production facilities;
- lack of trained manpower;
- materials and equipment availability; and
- time required for development.

Industry development is also constrained due to the undeveloped industry infrastructure. Four of the 10 U.S. manufacturers of solar cell array provide most of the products. These manufacturers do their own marketing, distribution, sales, and services.

Space Vehicles

An important factor in assessing the market readiness of the SSPS is the state of the aerospace industry and its ability to produce the required vehicles for the transportation system.

At present, U.S. launch vehicles can be divided into two categories: Basic Vehicles and Upper Stages. Basic vehicles include (1) Titan (Martin Marietta Aerospace); (2) Saturn V (Boeing); (3) Atlas (General Dynamics); and (4) Delta (McDonnell Douglas). Upper stages include (1) Agena D (Lockheed); (2) Centaur (General Dynamics); and (3) Transtage (Martin Marietta).

In addition, many companies in the aerospace industry have been involved in the production of large- and medium-size boosters, large winged aircraft, manned spacecraft, and the space shuttle. Examples of such industry involvement are:

- Boeing--Apollo Saturn V booster and 747 transport aircraft;
- Lockheed--Polaris medium booster, L1011 large winged aircraft, Agena (upper stage), and C5-A transport;
- North American Rockwell--Apollo Command Module, Space Shuttle Orbiter and rocket engines, and B-70;
- McDonnell Douglas--Skylab Orbital Workshop, Gemini Spacecraft, and DC-10 (large winged aircraft);

- Grumman Aerospace--Apollo Lunar Excursion Module and small aircraft;
- Aerojet General--Medium boosters, rocket engines; and
- Martin Marietta Aerospace--Medium boosters, Titan III booster, Shuttle External Tank, Skylab Manned Spacecraft, Transtage, Space Shuttle payloads, and Teleoperator.

It can be seen that the aerospace industry's involvement in the production of large boosters, large winged vehicles, and manned spacecraft of sizes comparable to the transportation system needs of SSPS indicates the readiness to engage in an SSPS program. The companies mentioned above possess the manpower, facilities, and production capability required for manufacturing the small number of space vehicles required for the SSPS transportation system. The large winged aircraft for the two stages of the HLLV are approximately the size of the C5-A, 747, L1011, and DC-10. The PLV is the Shuttle Orbiter with an add-on stage and a personnel capsule. Five Space Shuttle vehicles are planned at present while the preliminary baseline concept for the SSPS proposed by JSC calls for two such vehicles. Thus, based on the industry's related experience and activity today, it can be seen that the facilities and experience needed for the production of large space vehicles such as the ones required for the SSPS exist today. However, some modifications and expansion of facilities will be required for the aerospace industry to engage in the SSPS program.

Propellant Production

The SSPS program will require large quantities of propellants for the launch vehicles. JSC estimates of propellant requirements are as follows:

$$\text{Liquid } O_2 \simeq 3 \times 10^6 \text{ metric tons/SSPS}$$

$$\text{Liquid } H_2 \simeq 140000 \text{ metric tons/SSPS}$$

$$CH_4 \simeq 700000 \text{ metric tons/SSPS}$$

$$AR \simeq 25000 \text{ metric tons/SSPS}$$

Since oil and gas are projected to increase dramatically in cost, using coal to produce these fuels is being considered. A study of propellant costs assumes coal gasification at the mine and then transportation to the launch site through a pipeline. The large quantities at continuous rates of fuels and cryogens required at the launch site justify the expense of transporting the fluids by pipeline.

Annual coal requirements for the hydrocarbon propellants are estimated at 27.5 million and 203 million metric tons for the minimum and maximum cases respectively. These quantities of coal, if needed now, would constitute approximately 60% of the 1967 coal production. It is estimated that in the years from 1995 to 2000, the coal requirements for the SSPS would amount to approximately 10% of the national ouput at that time and will not impact the national reserves. The gasification and cryogenic industries are not currently capable of meeting SSPS propellant requirements. The investment required for such a plant is estimated at about $1.5 billion per year throughout the SSPS program [X-9].

Another source not considered by NASA would be the use of wood (biomass) as the source for the propellants. (Note that in the production of methane [see Section V of this report] from wood a LOX plant is required.) The biomass production would utilize the same technology required by coal but without the adverse environmental impacts (CO_2 and sulfur) and safety hazards associated with use/mining of coal.

Institutional and Environmental Barriers to SSPS Market Readiness

Numerous institutional and environmental factors could affect SSPS and should be addressed both at the national and international levels. Consideration should be given to public health and safety, ecological balance, communication interference, utilization of space, and political implications.

Orbit and Frequency Assignments

It would be desirable to assign the geosynchronous orbit (GEO) based on international agreements and a request by the United States to the United Nations to assign and record such orbits is being worked on.

The microwave frequency for the transmitting system is to be assigned by international agreement such that any interference with terrestrial radio frequencies will be avoided. Other interference from the beam will be minimized through cooperation at the international level.

Microwave Exposure Levels

Microwave exposure standards for the United States and any other country that may be affected need to be researched to reaffirm or determine the levels of microwave radiation and their effects. At a 10 km radius from the center of the beam, the radiation levels would meet the lowest international standard for continued human exposure to microwaves [X-5]. This standard, at present, is that of the U.S.S.R. which is 0.01 mW/cm^2. The effects on birds and aircraft passing through the beam for short periods is believed to be negligible and will be reverified by NASA research.

Integration with Electric Utility Systems

Due to the amount of energy generated and transmitted by the SSPS, it is required that it be integrated with the utility grid. Since the SSPS has a capacity factor as high as .92 it will provide baseload power. The question of ownership must be worked out to take advantage of this base load capability. One of the proposals concerning ownership has the receiving station and antenna owned by a utility or by a group of utilities. In this case the utility would buy power from the SSPS which would be owned through a government corporation such as that employed with telecomunication satellite systems. This approach has a tendency to use the SSPS as a supplier of peak rather than baseload power (i.e., the utilities use SSPS power only when they need it). Complete ownership of the entire SSPS by a utility consortium seems to overcome this problem. This approach requires a much larger investment by the utility for the SSPS compared with the investment required for a receiving station and antenna. The government could make a loan or loan guarantee to the utility group, who would then pay it back with interest. The cost of SSPS DDT&E would be initially borne by the government, but would be recovered in the sale of future production of SSPSs.

Vulnerability

A practical plan for minimizing the vulnerability of the SSPS to possible hostile actions is required. Included are international agreements to minimize the chance of a hostile attack on the SSPS is required. Such agreements can include usage of the satellite by other countries for the purpose of weather surveillance, communications, relays, space studies, and power [X-4].

Other factors minimizing vulnerability include automated fabrication and assembly where possible to minimize damage by individual workers. The practices employed by NASA in past space programs (such as "no single-point-failures"; modular design; quality control, test, and evaluation) will minimize vulnerability during construction and operation. The design of the SSPS is such that a single component failure cannot cause 100% loss of an SSPS.

To reduce vulnerability and improve ground safety of the ground portion of the SSPS, the receiving antenna area (80 km^2) should be fenced with a buffer zone raising the ground area to 100 km^2. Again, the design of the receiving antenna is such that damage to one portion will not cause outage.

Overall the SSPS does seem relatively safe as opposed to other centralized systems located entirely on the ground (nuclear power plants, photovoltaic plants, solar thermal plants, etc.)

Environmental Impacts

The major environmental impacts of the SSPS in the areas of resource allocation such as land management, required energy for construction and operation, waste heat disposal, and interaction with the upper atmosphere [X-5]. More specific examples of the environmental impacts include:

- Waste heat released at the receiving antenna site from the rectification has an impact on the environment.

- Land use for each solar satellite would be approximately 200 km^2 (two receiving antenna sites per SSPS). As the microwave level beneath the antenna is nonexistent and the receiving antenna is about 80% transparent to sunlight and is impervious to rain, the land can be made productive in a number of ways offsetting the land use.

This means that there is no barrier to productive agricultural or industrial use of the land. There should be no microwave radiation beneath the receiving antenna such that the land can be put to productive use. In addition, the land use of 200 km^2 to generate 10 GW continuously (base load) should be compared to other solar options. For example, to provide 10 GW baseload power (at a capacity factor of .92) on the ground would require $\backsimeq$300 to 500 km^2 for a photovoltaics plant, 425-1,200 km^2 for a solar-thermal system, or a $\backsimeq$15,000 km^2 energy farm (biomass).

- Atmospheric pollution by frequent launching of space vehicles should be studied.

- Microwave interactions with the ionosphere are not expected, due to a low beam density of 23 mW/cm^2. However, further investigation is required in the area of electron density changes that may be caused by densities greater than 23 mW/cm^2 and frequencies greater than 2.45 GHz.

Other institutional barriers include public resistance to large centralized systems and the education of the public regarding microwaves.

In terms of resource availability and energy consumption, conflicting assessments are found regarding the availability of materials for GaAs and CdS photovoltaic cells. However, silicon is the most abundant element on Earth.

If it is assumed that aluminum would be the most widely used material, the studies by NASA indicate a need for one million metric tons for each 10 GW_e satellite station. This translates into approximately 13% of U.S. reserves, and 0.08% of world reserves for each SSPS [X-6].

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XI. SOLAR TOTAL ENERGY SYSTEMS

A. INTRODUCTION

A solar total energy system (STES) is characterized by the use of solar energy for on-site generation of electricity with recovery and reuse of turbine waste heat to meet thermal demands. STES systems currently under consideration are either central receiver or distributed collector configurations for electricity generation and process heat, space heating and cooling, and water heating.

Solar total energy systems applications are not well understood. These systems are often confused with conservation and cogeneration of electricity with conventional fuels. Few STES cost studies exist. For a fair comparison, solar total energy system costs must be compared with conventional total energy system costs in the same application. However, costs are difficult to apportion between electricity generation and thermal demands [XI-7]. Since the number of cost studies are few and are not consistent among applications, this section summarizes solar total energy systems under an ideal application concept as analyzed by the Aerospace Corporation [XI-1, XI-2, XI-3]. The major features of an ideal application concept are:

- The amplitude and duration of the daily and seasonal thermal and electric loads are constant and in a ratio which will use all the available waste heat of the turbine. This maximizes the overall STES efficiency.

- The electric load is in phase with the insolation, thus minimizing high-temperature storage requirements and costs [XI-1, p. III-1].

The ideal application concept presents the most favorable economic picture for STES. The conclusions of the Aerospace study state that STES applications may be cost-competitive with fossil fuel alternatives and can displace fossil fuels.

> Additional analysis has indicated that the technical and economical performance of STES can be attractive for a wide variety of applications. If the ratio of thermal to electric demand is above 1.5 and the turbine inlet temperature exceeds 450°F [XI-1, p. I-2].

However, this conclusion is contingent upon collector costs declining to meet DOE goals and a more limiting factor of achieving high-temperature storage capabilities. High-temperature storage costs are currently five times higher than low-temperature storage costs [XI-1, p. III-5].

B. SUMMARY OF COSTS

An analysis was performed of STES costs as a function of size and operating time. Cost estimating relationships were developed for each subsystem and combined to obtain total capital and operating costs. Subsystems examined include land, structure, solar plant, turbine electrical plant, master controls, miscellaneous plant equipment, and operation and maintenance costs. Costs were calculated for system sizes ranging from 10 kW to 10 MW for the 1985, 1990, and 1995 time periods. Costs ranged from a high estimate of $12,730/kW for a 10 kW plant in 1985 to a low estimate of $1,475/kW for a 10 MW plant in 1995 per unit of capacity. The latter figure reflects the DOE design goal of $65/m^2 for large quantity heliostat production. Relationships were then established between these costs and nominal costs using the ideal application simulations to compare with conventional costs. These relationships are being used in the market penetration model development of the Aerospace study.

Cost estimates developed by Aerospace (in dollars/kW) for STES operations beginning in 1985, 1990, and 1995, and for STES capacities of 10 kW and 100 kW and 1 MW and 10 MW are provided in Tables XI-1 through XI-5. A comparison of the Aerospace costs with current test facility, pilot plant, and commercial plant cost estimates developed by DOE contractors is also presented. The 32 kW STES test facility cost is an Aerospace estimate based on data furnished by Sandia. These data exclude design and development charges. The comparison shows that the 1 MW, 1985 STES cost is close to the Ansaldo/MBB plant estimate (XI-4) and consistent with costs estimated by Atomics International in its STES study (XI-6). The 10 kW and 100 kW STES systems costs, however, are significantly lower than the cost trends shown in the Atomics International study. (Atomics International study used collector costs of $81/m^2 for all size systems; Aerospace collector cost varied with size and operational date.) For the 1 MW STES, collector cost estimates by Aerospace varied from $142/m^2 in 1985 to $71/m^2 in 1995. The 10 MW STES cost estimate reflects the anticipated cost reduction to be gained from construction of the pilot plant and a continuing R&D program. All costs presented in these tables are not presented on a mills per kilowatt hour basis because no attempt has been made to apportion costs to electricity generation or thermal demand.

In summary, cost estimates generated under an ideal application concept are much lower than other contractor's estimates for 1985, 10 kW and 100 kW size plants but consistent with other estimates for a 1985 1 MW STES. This consensus of opinion may be due to the

TABLE XI-1

STES COSTS USED IN INITIAL AEROSPACE SIMULATION STUDIES

500 kW Ideal Application
Central Receiver Configuration
Albuquerque/Phasing Pattern I
1977 Cost Base

			Cost	
	Size	Unit Cost	\$000	%
Collector System	75,000 ft^2	\$14/ft^2	1050	78
Power Conversion	500 kW_e	\$400/kW_e	200	15
High Temp. Storage	10×10^6 Btu	\$4500/MBtu	45	3
Low Temp. Storage	50×10^6 Btu	\$1000/MBtu	50	4
Total	-	-	1345	100

Source: XI-2, p. III-2

Total STES Unit Cost = \$2690/kW_e

TABLE XI-2

SOLAR TOTAL ENERGY SYSTEM

10 kW Central Receiver Configuration
Cost Per kW of Installed Capacity - Aerospace Model (ST-N127)
1977 Cost Base ($)

Description	Year of Initial Operating Capability 1985	1990	1995
Land & Land Rights	50	50	50
Structures & Improvements	350	290	250
Solar Plant Equipment			
Collector Equipment	3410	2280	1710
Receiver	620	300	250
Tower & Platform	3180	2740	2240
Thermal Storage - Hi Temp	135	70	50
Thermal Storage - Low Temp	160	85	60
Total Solar Plant Equipment	7505	5475	4310
Turbine Plant Equipment	1000	700	510
Electrical Plant Equipment	100	70	50
Plant Master Control Equipment	70	35	25
Miscellaneous Plant Equipment	150	80	50
Total Basic Plant Cost	9225	6700	5245
Indirects & Distributables	1845	800	420
Contingency	1660	975	510
Total Solar Energy System	12730[a]	8475	6175

[a]Aerospace cost estimate for a 32 kW_e test facility in 1978, (based on Sandia data) is three times this figure, approximately $40,000/$kW_e$ installed capacity [XI-10].

Source: XI-2, p. III-3.

TABLE XI-3

SOLAR TOTAL ENERGY SYSTEM

100 kW Central Receiver Configuration
Cost Per kW of Installed Capacity - Aerospace Model (ST-N127)
1977 Cost Base ($)

Description	Year of Initial Operating Capability 1985	1990	1995
Land & Land Rights	20	20	20
Structures & Improvements	200	170	150
Solar Plant Equipment			
Collector Equipment	2380	1600	1210
Receiver	510	260	210
Tower & Platform	610	530	430
Thermal Storage - Hi Temp	100	50	35
Thermal Storage - Low Temp	155	80	60
Total Solar Plant Equipment	3755	2520	1945
Turbine Plant Equipment	770	490	355
Electrical Plant Equipment	90	65	50
Plant Master Control Equipment	65	30	25
Miscellaneous Plant Equipment	140	75	50
Total Basic Plant Cost	5040	3370	2595
Indirects & Distributables	1010	405	210
Contingency	910	490	255
Total Solar Energy System	6960[a]	4265	3060

[a]Atomics International cost estimate for a 400 kW_e central receiver plant in 1986 is approximately $8500/$kW_e$ installed capacity (XI-6).

Source: XI-2, p. III-4.

TABLE XI-4

SOLAR TOTAL ENERGY SYSTEM

1 MW Central Receiver Configuration
Cost Per kW of Installed Capacity - Aerospace Model (ST-N127)
1977 Cost Base ($)

Description	Year of Initial Operating Capability 1985	1990	1995
Land & Land Rights	10	10	10
Structures & Improvements	120	100	90
Solar Plant Equipment			
Collector Equipment	1870	1250	940
Receiver	430	220	180
Tower & Platform	290	230	190
Thermal Storage - Hi Temp	90	45	30
Thermal Storage - Low Temp	150	80	60
Total Solar Plant Equipment	2830	1825	1400
Turbine Plant Equipment	530	335	245
Electrical Plant Equipment	85	60	45
Plant Master Control Equipment	60	30	20
Miscellaneous Plant Equipment	130	70	45
Total Basic Plant Cost	3765	2430	1855
Indirects & Distributables	750	290	150
Contingency	680	350	180
Total Solar Energy System	5195[a]	3070	2185

[a]Ansaldo/MBB cost estimate for a 1 MW_e plant in 1977 is approximately \$6,000/kW_e installed capacity (XI-4). Atomics International cost estimate for a 5 MW_e central receiver is approximately \$4,000/kW_e installed capacity (XI-6.)

Source: XI-2, p. III-2.

TABLE XI-5

SOLAR TOTAL ENERGY SYSTEM

10 MW Central Receiver Configuration
Cost Per kW of Installed Capacity - Aerospace Model (ST-N127)
1977 Cost Base

Description	Year of Initial Operating Capability 1985	1990	1995
Land & Land Rights	5	5	5
Structures & Improvements	70	60	50
Solar Plant Equipment			
Collector Equipment	1300	880	650
Receiver	420	220	160
Tower & Platform	80	60	50
Thermal Storage - Hi Temp	85	45	30
Thermal Storage - Low Temp	145	75	60
Total Solar Plant Equipment	2030	1280	950
Turbine Plant Equipment	460	225	150
Electrical Plant Equipment	85	60	40
Plant Master Control Equipment	60	30	20
Miscellaneous Plant Equipment	140	70	40
Total Basic Plant Cost	2850	1730	1255
Indirects & Distributables	670	210	100
Contingency	515	250	120
Total Solar Energy System	3935[a]	2190	1475

[a]Atomic International cost estimate for a 10 MW_e central receiver in 1986 is approximately \$3600/kW_e installed capacity. McDonnell Douglas 10MW_e pilot plant in 1981 cost estimate is approximately \$12,00/kW_e installed capacity (XI-5).

Source: XI-2, p. III-6.

optimistic assumption of collector cost reductions. Ideal application cost estimates are optimistic and substantially higher than conventional costs at present. However, if DOE design goals are met, Aerospace forecasts substantial energy production from solar total energy systems [XI-3].

C. TECHNICAL AND MARKET READINESS

Technical Readiness

Technical readiness of STES systems in the future is dependent upon the success of solar thermal power plants and the achievement of economical high temperature storage. Until these problems are overcome, STES system costs are anticipated to be higher than conventional costs and many technical problems need to be solved. However, if DOE design goals are met, successful implementation of this concept is expected to be achieved. The Department of Energy is currently funding three STES projects. These are an industrial process heat, joint electric generation project in Shenandoah, Georgia; a space heating electric generation facility at Fort Hood in Killeen, Texas; and a space heating electric generation facility to be placed at the Mississippi County Community College in Blytheville, Arkansas.

Market Readiness

Since the solar total energy system concept is still in the research and development stage, no attempt is made to identify the market readiness characteristics of this concept. However, many countries have used a total energy concept with conventional fuels (cogeneration) to meet large industrial thermal loads. However, many technical barriers must be overcome before solar total energy systems are widely accepted.

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XII. CONCLUSIONS

The conclusions of this report have been withheld subject to review and revisions of this draft.

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XIII. COST METHODOLOGY APPENDIX

A. INTRODUCTION

The cost of delivered energy depends upon a technology's maturity, the resource base it utilizes, its interactions with the larger economy, and many other factors. To some degree, the investment decision to purchase a new energy system is based on its perceived cost, since cost projections are never verified until a project is initiated, conducted, completed, and retired after its useful life. The best approach to projecting costs is based on past experience, complemented by expectations of future trends, and an effort to include all aspects of a system's cost. However, costs are also subject to unforseeable changes in the political, environmental, and economic arenas. Further, costs are particularly difficult to estimate for developing technologies when performance characteristics have not yet been determined.

Problems also appear when interpreting the results of comparative cost analyses. The diversity of the available technologies, their resource requirements, and their economic and environmental impacts challenge the analyst who compares dissimilar systems. To further complicate matters, over 30 different costing methods are commonly employed to evaluate the delivered cost of energy. Disputes about the economics of a particular technology are thus obfuscated by variations in methodological approach as well as in data employed. This appendix is provided in an attempt to state clearly and explicitly the cost methodology used in this report for assessing solar and conventional energy technologies.

The cost methodology presented here is based on existing cost methods. No claim is made to a unique analytic approach to or a new costing technique. However, the methods presented below are built on existing methods to provide a comprehensive definition of cost to the end user. Costs in other methods that are implied but not stated explicitly are listed and defined here.

Consistency requires one to assume the same tax, interest, and fuel escalation rates when comparing systems for the same end user. Our objective is not to examine variations in cost when changing taxes, for example, but rather to compare the cost of alternative systems under a fixed set of economic, financial, and environmental conditions that reasonably characterize the systems' application. Particular attention is given to treat consistently those variables exogenous to the systems' performance.

The format for the remainder of this appendix is as follows: Section B outlines the criteria considerations and steps required to obtain an objective assessment of system cost; Section C presents application of the methodology to calculate the costs for the homeowner for new and retrofit situations; Section D, costs for businesses, corporate and noncorporate; and Section E, cost for utilities, privately and publicly owned.

B. COST CRITERIA APPLICATIONS AND CONSIDERATIONS

Criteria

In this cost methodology, the following criteria are imposed:

- Explicitness--all assumptions, judgments, sources, and reliability of data must be stated;

- Consistency--the analysis must be consistent with proven practices and yield reproducible results even when radically different technologies are compared;

- Completeness--the cost accounting must include all relevant items including taxes, fixed and variable charges, and costs of complying with environmental standards;

- Realism--all assumptions, judgments, data, and methods must reflect the experience of the sector in which the project is undertaken.

<u>Considerations</u>

The methodologies for different classes of users must differ somewhat due to differences in income and property taxes and end use application. However, each methodology incorporates the following cost considerations:

- Solar system fixed and variable costs;

- Conventional system fixed and variable costs;

- Financing arrangements--whether internally, externally, publicly, or privately financed;

- Tax considerations--including the user's marginal rate of tax and property tax, investment tax credit, depreciation, interest, and fuel deductions;

- Fuel escalation and inflation rates;

- Backup system and/or storage cost including fixed and variable costs;

- Time conventions for cash flows--construction periods and system lifetimes are noted, cash outlays are assumed to occur at the end of the year, interest is compounded yearly, system service is assumed to begin the first day of the calendar year, all cash flows prior to the initial period of analysis, t_0, are compounded to t_0, and all cash flows after the initial period are discounted to t_0;

- Appropriate interest rates for discounting and compounding.

Although there are many complicating factors in the actual methods employed, five simple steps may be used to arrive at a logically consistent cost procedure:

- Calculate the total after tax cost (fixed capital plus variable costs) generated by the system with backup and/or storage in each year of its useful lifetime;

- Discount (or compound) these to translate each into a present value;

- Sum the discounted values over the system lifetime to obtain system <u>life-cycle</u> cost;

- Convert the life-cycle cost into a levelized <u>annual</u> stream by multiplying by a capital recovery factor;

- Divide the figure above by the total annual output (in MBtu, kWh, or gal.). The resulting value will represent the <u>full</u> cost of delivered energy (with tax considerations).

C. HOMEOWNER APPLICATIONS

The costs of acquiring and maintaining a solar energy system for the homeowner are dependent on location and whether it's a new or retrofit application. Unlike some methods, the cost calculations outlined below do not explicitly provide for optimizing the size of the system for the particular application. However, the approach includes all the cost considerations noted above to arrive at a single after tax cost in figure in \$/MBtu. The following costs are included in the calculations for the full delivered cost of energy to the homeowner. All pre-acquisition and acquisition costs are assumed to occur in the initial period.

Pre-Acquisition Costs

- Search costs, S_C,--the time and money spent examining energy system alternatives before purchase
- Special structural requirements, S_{ST},--this item may include additional roof supports for retrofitting a home for flat plate collectors or insulation, storm doors and windows for a particular application
- Special siting requirements, S_{SI},--for passive applications this may require orienting windows in a southerly direction or landscaping and tree removal to prevent blocking of solar collectors

Acquisition Costs

- Down payment, D_p, for capital costs of the system, including storage and/or backup equipment

- Cost of system delivery, C_D

- Cost of installation, C_I, including labor charges and any additional materials required

- The down payment may be reduced by an investment tax credit, a_2, but the credit is usually returned one period after payment

Operation and Maintenance Costs (Annual Charges)

- Annual mortgage payment, M_{PT}, for solar system/storage/backup increment charge on total home mortgage. This charge includes principal and interest, but it may be reduced if low interest loans are granted for the solar portion. The deductibility of interest payments for tax purposes reduces this charge.

- Maintenance, M_t,--includes materials and labor for maintenance and repair of the solar system with storage and backup.

- Nonfuel operating costs, O_t,--for active systems this includes electricity to drive pumps or fans.

- Fuel costs, C_B,--an additional term is needed for natural gas or electricity used as backup expressed in \$/kWh or \$/ft^3.

- Insurance, I_t,--annual premium to insure the incremental value of the solar system with storage and backup.

- Property taxes, P_t, on the incremental value of a solar system are currently exempted in 17 states but may be a significant factor in others. Property taxes are deductible for purposes of the Federal income tax.

- Additional costs to comply with environmental standards, E_D.

Decommissioning/Refurbishment Cost

- The cost of removing or refurbishing a solar system, C_R, (less its salvage valve)

The total life cycle cost for a homeowner solar system with conventional backup and storage may be expressed:

$$
\begin{aligned}
LCC_H = {} & S_C + S_{ST} + S_{SI} + C_D + C_I \\
& + \left(1 - a_2 \frac{1}{a_4}\right) D_p \\
& + \sum_{t=0}^{N} \left[\frac{(1 - a_{1T}\, a_3)\, M_{PT} + M_t + O_T + I_T + (1 - a_{1T})\, P_T}{(1 + i)^t} \right. \\
& \left. + \frac{C_B\, (1 + e)^t\, L_C + E_{DT} + C_{RT}}{(1 + i)^t} \right]
\end{aligned}
\tag{1}
$$

Where all terms are explained in Table XIII-1. This total LCC_H may be converted to an annual levelized stream.

$$\text{Annual levelized cost} = \frac{(CRF)\ (LCC_H)}{\sum_{t=0}^{N} (L_C + L_S)} \tag{2}$$

TABLE XIII-1

COSTS OF DELIVERED ENERGY IN HOMEOWNER APPLICATIONS

Parameters

a_{1t}	homeowners effective marginal tax rate in year t (federal and state combined)
a_2	income tax credit rate
a_3	interest portion of mortgage payment
a_4	down payment requirement expressed as a percent of total solar system with storage and backup
e	conventional fuel escalation rate (expressed as a decimal fraction)
i	appropriate rate of interest (expressed as a decimal fraction)
N	system lifetime
n	tax lifetime

Variables

C_B	costs conventional fuels used as backup
C_D	costs of system delivery
C_I	costs of installation
C_R	costs of refurbishment
CRF	capital recovery factor defined as:

$$\frac{1}{\sum_{t=0}^{N}\left(\frac{1}{1+i}\right)^{t}}$$

TABLE XIII-1 (cont.)

D_P	down payment
E_D	costs of complying with environmental standards
I_t	insurance
L_C	conventional system output expressed in kWh/yr or MBtu/yr
L_S	solar system output expressed in kWh/yr or MBtu/yr
M_{PT}	mortgage payment
M_T	maintenance expense
O_T	operating costs for solar active systems
P_T	property tax on system
S_C	search costs
S_{SI}	special siting requirements cost
S_{ST}	special structural requirements costs

D. BUSINESS APPLICATIONS

The costs of a solar system for commercial or corporate uses differ from a homeowner's cost only by the current deductibility of business expenses and depreciation of capital expenses in fuel use. Under current federal income tax law, all "necessary" and "reasonable" business expenses incurred while the firm is engaged for profit in a business enterprise are deductible for purposes of the Federal income tax. Assuming the enterprise has positive net income (1) may be rewritten:

$$LCC_C = (1 - a_{1T})[S_C + S_{ST} + S_{SI} + C_D + C_I] + (1 - a_2 \frac{1}{a_4}) D_p$$

$$+ \sum_{t=0}^{N} \left[\frac{(1 - a_{1TC}) [M_{PT} (1 - a_3) + M_t + O_t + I_t}{(1 + i)^t} + \right.$$

$$\left. + \frac{P_t + D_t + C_B (1 + e)^t L_C + E_{DT} + C_{Rt}]}{(1 + i)^t} \right] \qquad (3)$$

where the only additional term added, D_t, is depreciation defined as:

$$D_t = \begin{cases} \frac{1}{n} & \text{for } 0 < t < n \\ 0 & \text{otherwise} \end{cases}$$

for the straight line method and

$$D_t = \begin{cases} \dfrac{2\,(n - t)}{n^2} & \text{for } 0 < t < n \\ 0 & \text{otherwise} \end{cases}$$

for the sum of the years' digits. Here n represents the tax lifetime and N the real lifetime.

As in the homeowner's determination of cost all pre-acquisition and acquisition costs are assumed to be incurred in the first year of the system's life. All other assumptions pertaining to the timing of cost flows, etc. are retained for this application. Other items are explained in Table 1. The total LCC_C may be converted to an annual levelized stream which may be expressed:

$$\text{Annual levelized cost} = \frac{(CRF)\ (LCC_C)}{\sum_{t=0}^{N} (L_C + L_S)} \tag{4}$$

E. UTILITIES

The capital budgeting technique commonly used by utilities for ranking the cost feasibility of a solar investment compares its discounted expected revenues and discounted costs. The basic approach is to derive an estimate of those costs incurred by a utility (publicly or privately owned) for searching, acquiring, assembling, operating, and decommissioning a given solar system. (This estimate excludes transmission and distribution costs which are large for some applications.) The above costs are aggregated over the system lifetime, converted to a yearly basis, and divided by the expected energy output in the particular year the costs are incurred. The result is an estimate of the busbar cost of energy from the system and assumes:

- The system produces (exactly) its expected output;
- All output is sold at the expected price (equal to estimated cost above);
- Total discounted revenues exactly recover total discounted costs of the system;
- Total discounted costs include a return on the investments of the utility's stockholders and creditors.

This approach differs from a conventional discounted cash flow approach because the opportunity cost of investors's capital is included and the revenue stream is derived, not input.

The above cost estimates are "levelized" using a capital recovery factor and account for construction cost flows and escalation of material costs. However, there are two important limitations of this method. First, costs will vary widely if the systems being compared have dissimilar lifetimes. Comparisons between systems require a common time basis and operating period. Second, an evaluation of any energy system should account for indirect costs or savings caused by interaction with the larger utility grid. However, measurement of these costs and benefits is beyond the scope of this analysis.

<u>Required Revenue Methods</u>

The required revenue methodology determines what revenue must be provided by the operation of a system to meet (exactly) the financial obligations associated with the system including taxes, interest, and a specified return to stockholders. It is assumed that:

- The system under consideration is owned by a regulated utility,

- Construction and operation periods are finite,

- In return for providing electricity, the utility converts service payments into a stream of repayments to investors which include competitive rates of return.

For utilities, the appropriate interest rate for discounting cash flows is the weighted average cost of capital, i_u, equal to the internal rate of return because the utility is regulated. With three sources of funds, debt, D_u; common stock, C_u; and preferred stock, P_u; the weighted average cost of capital, i_u, is defined as

$$i_u = (1 - a_o)\, i_D \frac{D_u}{D_{Tu}} + i_C \frac{C_u}{D_{Tu}} + i_P \frac{P_u}{D_{Tu}} \qquad (5)$$

where D_{Tu} is the total capitalization of the company for this system. However, for the case of municipal utilities, there is no income tax, and capitalization is usually debt only. Therefore:

$$\frac{D_u}{D_{Tu}} = 1,\ a_o = \frac{C_u}{D_{Tu}} = \frac{P_u}{D_{Tu}} = 0$$

Thus, i_u for municipal utilities is simply the current cost of financing municipal bonds.

Utilities have two sources of income other than the sale of electric services to finance investment projects: the sale of stocks and bonds. Assuming that the company sells just enough of these instruments to finance the project, the required revenue condition that the present value of all positive cash flows must equal the present value of all negative cash flows may be expressed:

$$PV[R + S_B + S_S] - \qquad (6)$$

$$PV[I_n + S_E + R_E + I_B + P_D$$

$$+ T + T_{Ot} + I + O + M + F] = 0$$

where all terms are explained in Table XIII-2.

TABLE XIII-2

COSTS OF ENERGY IN UTILITY APPLICATIONS

Parameters

a_0	utility tax rate
a_2	investment tax credit rate
a_4	down payment requirement expressed as a percent of total system
a_5	other tax multiplier
a_6	insurance multiplier
e_C	escalation rate for construction
n	tax lifetime
N	system lifetime
PV	subscript for present value
t	subscript period (year) t

Variables

C_u	system capitalization through common stock
D_{Tu}	total system capitalization
D_u	system capitalization through debt
D_{uD}	= depreciation for tax purposes for straight line

$$D_{ut} = \begin{cases} \frac{1}{N} & \text{for } 0 < t < n \\ 0 & \text{otherwise} \end{cases}$$

and for sum-of-the-years digits

TABLE XIII-2 (cont.)

$$D_{ut} = \begin{cases} \frac{2(n - t)}{n^2} & \text{for } 0 < t < n \\ 0 \quad \text{otherwise} & \end{cases}$$

F fuel expense

I insurance, expressed as a constant value of the present value of the investment

$$I_t = a_6 I_{n,PV}$$

I_B the uniform annual payment of interest on bonds is

$$I_{Bt} = i_D \frac{D_u}{D_{Tu}} I_{n,PV}$$

i_C rate of return paid to common stock shareholders

i_D interest rate paid on debt

I_N total capital investment

$$I_N = S_B + S_S$$

i_P rate of return paid to preferred stock shareholders

i_u regulated rate of return of utilities

M maintenance

O operating expense

P_D uniform annual amount to retire debt

$$P_{Dt^2} = \frac{D_u}{D_{Tu}} I_{n,PV} \cdot S_{Fi_u n}$$

P_u system capitalization through preferred stock

TABLE XIII-2 (cont.)

R	revenue from electricity sales
R_E	uniform annual amount that must be allocated to the return on equity

$$R_{Et} = \frac{C_u + P_u}{D_{Tu}} I_{n,PV} \cdot S_{Fi_u n}$$

S_B	sales of bonds for the investment project
S_E	required earnings on stock defined as,

$$S_{Et} = i_C \frac{C_u}{D_{Tu}} I_{n,PV} + i_P \frac{P_u}{D_{Tu}} I_{n,PV}$$

$S_{Fi_u n}$	sinking fund factor

$$S_{Fi_u n} \equiv \begin{cases} \dfrac{i_u}{(1 + i_u)^N - 1} & \text{if } i_u \neq 0 \\ \dfrac{1}{N} & \text{if } i_u = 0 \end{cases}$$

S_S	sales of stock
t	subscript denoting time
T	income taxes defined as

$$T_t = a_0[R_t - (I_{Bt} + D_{uD} + T_{OT} + I_t + O_t + M_t + F_t)]$$

T_O	other taxes expressed as a multiple of the present value of capital investment

$$T_{Ot} = a_5 I_{n,PV}$$

The required revenue condition can be rewritten incorporating the definitions in Table 2 as:

$$R_{PV} = PV\left[\frac{1}{1 - a_o} \left[i_c \frac{C_u}{D_{Tu}} + i_p \frac{P_u}{D_{Tu}} \right.\right. \tag{7}$$

$$\left. + \left(\frac{C_u + P_u}{D_{Tu}} + \frac{D_u}{D_{Tu}} \right) S_{F,i_u} - \frac{a_o}{N} \right] I_{n,PV}$$

$$\left. + \left(i_D \frac{D_u}{D_{Tu}} + a_5 + a_6 \right) I_{n,PV} \right]$$

$$+ O_{PV} + M_{PV} + F_{PV}$$

Using the fact that $D_u + C_u + P_u \equiv D_{Tu}$ and the fact that the present value of a uniform series of amounts is equal to that uniform amount divided by the capital recovery factor (7) can be simplified.

$$R_{PV} = \left[\frac{1}{1 - a_o} \left(i_c \frac{C_u}{D_{Tu}} + i_p \frac{P_u}{D_{Tu}} + S_{F,i_u} - \frac{a_o}{n} \right.\right. \tag{8}$$

$$\left. + (1 - a_o)\, i_D \frac{D_u}{D_{Tu}} \right) + a_5 + a_6 \quad \frac{I_{n,PV}}{\dfrac{1}{\sum_{t=1}^{N} \left(\dfrac{1}{1 + i} \right)^t}}$$

$$+ O_{PV} + M_{PV} + F_{PV}$$

The system life cycle cost is defined as the present value of the sum of all of the system-resultant costs. Since there is no net investment outside the project, the present value of the revenue stream must equal the life-cycle cost;

$$LCC = R_{PV}$$

Using the identity:

$$\frac{1}{\sum_{t=1}^{n} \left(\frac{1}{1 + i_u}\right)^t} = S_{F,i_u,N} + i_u$$

the system life-cycle cost may be expressed:

$$LCC = \left[\frac{1}{1 - a_o}\left[\frac{1}{\sum_{t=0}^{n} \frac{1}{1 + i_u}} - \frac{a_o}{N}\right] + a_5 + a_6\right] \sum_{t=0}^{n} \frac{I_{n,PV}}{\frac{1}{(1 + i_u)^t}} \quad (9)$$

$$+ O_{PV} + M_{PV} + F_{PV}$$

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