266
11-78

14.2044

SAN/1101/PA8-1/3

MISSION ANALYSIS OF PHOTOVOLTAIC SOLAR ENERGY CONVERSION
VOLUME 3

Major Missions for the Mid-Term (1986-2000)

By
S. L. Leonard
E. J. Rattin
B. Siegel

December 1977
(TIC Issuance Date)

Work Performed Under Contract No. EY-76-C-03-1101

The Aerospace Corporation
Energy and Transportation Division
El Segundo, California

MASTER

U.S. Department of Energy

Solar Energy

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency Thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

DISCLAIMER

Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.

NOTICE

This report was prepared as an account of work sponsored by the United States Government. Neither the United States nor the United States Department of Energy, nor any of their employees, nor any of their contractors, subcontractors, or their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness or usefulness of any information, apparatus, product or process disclosed, or represents that its use would not infringe privately owned rights.

This report has been reproduced directly from the best available copy.

Available from the National Technical Information Service, U. S. Department of Commerce, Springfield, Virginia 22161.

Price: Paper Copy \$9.25
Microfiche \$3.00

Aerospace Report No.
ATR-77(7574-07)-1
Vol III

SAN/1101/PA8-1/3
Distribution Category UC-63

MISSION ANALYSIS OF PHOTOVOLTAIC
SOLAR ENERGY CONVERSION

Volume III

Major Missions for the Mid-Term (1986-2000)

S. L. Leonard, E. J. Rattin, and B. Siegel

Energy and Transportation Division
THE AEROSPACE CORPORATION
El Segundo, California

NOTICE

This report was prepared as an account of work sponsored by the United States Government. Neither the United States nor the United States Department of Energy, nor any of their employees, nor any of their contractors, subcontractors, or their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness or usefulness of any information, apparatus, product or process disclosed, or represents that its use would not infringe privately owned rights.

Date Published -- March 1977

Prepared for
THE UNITED STATES ENERGY RESEARCH
AND
DEVELOPMENT ADMINISTRATION
DIVISION OF SOLAR ENERGY
UNDER CONTRACT NO. EY76-C-03-1101
PROJECT AGREEMENT 8

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

PSA

THIS PAGE
WAS INTENTIONALLY
LEFT BLANK

FOREWORD

This document constitutes the third volume of a four-volume final report on a study carried out under Contract No. EY76-C-03-1101, Project Agreement 8, "Mission Analysis of Photovoltaic Solar Energy Systems" for the Division of Solar Energy in the U.S. Energy Research and Development Administration. This volume covers the work on Task 2, Analysis of Major Mid-Term Missions. The other volumes in the report are: Vol. I, Executive Summary; Vol. II, Survey of Near-Term (1976-1985) Civilian Applications in the United States; and Vol. IV, Supplementary Studies.

The study was conducted by the Energy Systems Group of the Energy and Transportation Division of The Aerospace Corporation. Dr. Leonard Magid, Acting Chief of the Silicon Technology Programs Branch, was the ERDA Program Manager for this contract, and Dr. A. B. Greenberg, General Manager of the Energy and Transportation Division, was the Principal Investigator. Dr. M. B. Watson is the Director of the Energy Systems Group, and Dr. S. L. Leonard, Director, Photovoltaic Projects, provided the program management.

This volume was prepared by Dr. S. L. Leonard, E. J. Rattin, and B. Siegel.

The authors wish to express appreciation for the support of the project by a number of other personnel of The Aerospace Corporation. These include W. E. Ellis, O. J. Mead, J. A. Neiss, P. L. Merryman, Dr. C. M. Randall, H. Wong, and H. H. Yoshikawa. The help of Janet Hallett in overseeing the production of the report is also gratefully acknowledged.

THIS PAGE
WAS INTENTIONALLY
LEFT BLANK

SUMMARY

This volume presents the results of analyses of potentially attractive missions (applications) for photovoltaic solar energy systems in the 1985-2000 time period. Primary emphasis has been given to studies of central station power plant applications, largely because it is believed that photovoltaic systems will have to achieve an appreciable penetration of that market if they are to make a significant (1-2%) contribution to the nation's energy supply by the year 2000. Earlier analyses (Ref. 1) of such applications have been extended in the current study in order to develop information on such issues as:

- a. The desirability of concentrating systems. (Systems with parabolic troughs and silicon arrays and systems with central receiver concentrators and water-cooled AlGaAs/GaAs arrays were compared with systems using flat plate silicon arrays).
- b. The feasibility and economics of using the waste heat available from high concentration water-cooled systems.
- c. The effect of geographic location and fossil fuel prices and price escalation rates on allowable array prices, i.e., array prices at which photovoltaic systems are competitive with coal-fired generating plants. (The previous study had considered only locations in the southwestern United States and a single fuel price.)
- d. The attractiveness of electrical storage.
- e. The effect of relaxing utility reliability requirements.

In order to conduct these analyses, a number of supporting activities were completed, including:

- a. Modification of the existing photovoltaic system simulation model to permit simulation of high concentration systems. Hourly simulation of central receiver and parabolic dish concepts as well as flat plate and parabolic trough systems is now possible.

- b. Incorporation into the photovoltaic mission analysis methodology of five different regional utility system models. Each model is based on a generalized projection, to the year 1990, of the demand characteristics and the types and numbers of generating plants in a representative utility system within the region. These models were originally developed in the companion Aerospace Corporation Solar Thermal Mission Analysis studies (Refs. 2-4) and are considered to adequately represent the range of system demand and capacity characteristics that is observed in U.S. utility systems. The use of these models, in conjunction with the already-available margin analysis procedures described in Ref. 1, provides the capability of estimating the amount of conventional backup capacity that would be required for a photovoltaic power plant in most regions of the United States.
- c. Development of cost information and economic analysis procedures for rapid estimation of the performance and cost figures that are required in order that photovoltaic systems may be competitive with coal-fired intermediate load plants. These procedures permit evaluation of the effects of fossil fuel price and escalation rate on photovoltaic system cost and performance requirements (see Section 2.4, Figure 5).
- d. Development of analysis procedures for evaluation of high concentration ratio central receiver systems in which profitable use is made of the thermal energy deposited in the array coolant. Present capabilities permit evaluation of system performance at a fixed insolation. In future studies, these existing analysis procedures will be integrated with the photovoltaic system simulation model. This will permit hour-by-hour simulation of the system operation, including the effects of using the thermal energy in the coolant to generate additional electricity in a "bottoming cycle" turbine or of using this heat for industrial processes, space heating, or domestic hot water.

These analyses of central station missions for photovoltaic solar energy systems have led to several tentative conclusions:

- a. Photovoltaic power plants with flat-plate silicon arrays are likely to be economically competitive with coal-fired intermediate load plants by about 1990 in U.S. sunbelt locations

(and perhaps as far north as Washington, D. C.), provided that array costs can be brought down to the \$100-200/kW_{pk} range.

- b. High-concentration photovoltaic plants using collectors in the central receiver configuration and AlGaAs/GaAs arrays are also likely to be competitive with coal-fired plants, if profitable use can be made of the thermal energy that is removed in cooling the arrays. If this thermal energy can either be sold directly (a net revenue of \$2/10⁶ Btu, above the cost of distribution and storage, appears feasible in many locations) or used to generate additional electricity in a low-pressure turbine, such systems may be able to produce electricity at a cost comparable to that of the energy generated in a flat-plate system when the array price is \$100/kW_{pk}. Even if no economic benefit is derived from the thermal energy, however, the energy cost would be about the same as that of electricity generated in a flat-plate photovoltaic plant when the array price is about \$370/kW_{pk}. Additional studies are needed of the operational characteristics and economics of a photovoltaic thermal-electric system incorporating a bottoming-cycle turbine and of the distribution cost and potential market for thermal energy.
- c. When the cost of electric storage (present value cost for 30 years of service, including replacement batteries) is \$40/kWh or more, photovoltaic plants without storage can provide electricity at lower cost than can systems with storage.
- d. The array price at which flat-plate photovoltaic power plants are economically competitive with coal-fired plants is very sensitive to array efficiency, to plant location, and to future coal prices and escalation rates. The figures given below are representative values (read from the graphs in Figure 23 of this volume) of the allowable array price at two locations and for three fuel price scenarios. (The 1975 price of coal for steam-electric power generation ranged from \$0.23 to \$1.24 per 10⁶ Btu.)

Allowable Array Price
Flat-Plate Photovoltaic Plant Without Storage

Location	1990 Coal Price, 1975 \$/10 ⁶ Btu	Post-1990 Annual Fuel Price Escalation Rate (including inflation)	Allowable Array Price, \$/kW _{pk} (Array effi- ciency = 0.135)
Inyokern, CA	0.75	0.05	75
	1.25	0.06	175
	1.75	0.07	305
Sterling, VA	0.75	0.05	25
	1.25	0.06	105
	1.75	0.07	205

These results are based on the assumption that the photovoltaic plant is constructed by an investor-owned utility company. Future studies might well consider other forms of ownership, such as cooperatives, that might result in higher allowable array prices.

- e. Relaxation of utility reliability requirements slightly increases the amount of conventional backup power required for a given level of solar penetration. This apparently occurs because at low reliability the difference between the utility conventional generating capacity and demand (i. e. the margin) is much smaller than at high reliability. Therefore at low reliability the introduction of a solar generation unit is more destabilizing and requires greater additional conventional backup.

In addition to these analyses of central station power plant applications, an investigation was made of the effect of different ownership options on the break-even array price for residential on-site photovoltaic systems. The evaluation indicates that residential on-site systems owned by homeowners appear to have much higher break-even array costs than if such systems were owned by a private utility. Analyses conducted for all-electric homes in the Phoenix area using flat plate silicon arrays show break-even array costs of \$250-600/kW_{pk} for homeowner ownership and \$80-325/kW_{pk} for utility ownership. This result is a consequence of the fact that private utilities must pay dividends on equity capital and income taxes on revenues.

0 A start was also made on a study of applications for photovoltaic total energy systems. An approach was formulated and a data search was launched with the objective of collecting information about the characteristics of potential applications and about the size of the associated market. Although the data search was not yet complete as of the date of this report, a considerable body of information has been uncovered, especially with respect to applications involving industrial process heat. Preliminary methods have been formulated for screening candidate applications, as they are identified, in order to select the most promising ones for detailed analysis. In addition, procedures for analyzing the more likely candidates have been developed and exercised in a preliminary study of one such application: to a single-family residence in Phoenix, Arizona. This analysis indicates that it may be infeasible to provide all of the thermal and electrical demand by solar energy. For photovoltaic total energy systems available in the 1990-2000 time period and owned by the homeowner, it was found that minimum annual cost of meeting both the electric and the thermal demand is achieved when 20% of the total demand is provided by conventional power. It is planned that future studies will include further examination of residential photovoltaic total energy systems, evaluating some of the many potential system options and considering locations other than Phoenix.

THIS PAGE
WAS INTENTIONALLY
LEFT BLANK

CONTENTS

1.	INTRODUCTION.	1
2.	ANALYTICAL METHODOLOGY	5
2.1	General Approach	5
2.2	Simulation Procedure	7
2.2.1	System Model	7
2.2.2	Insolation Representations	10
2.2.3	Effect of Variations in the Insolation Spectrum	11
2.2.4	Demand Representations	14
2.3	Reliability Analysis	16
2.3.1	Utility System Models	17
2.3.2	Margin Analysis Procedure	19
2.3.3	Effect of Relaxing Reliability Criterion	20
2.4	Economic Evaluation	23
2.4.1	Levelized Fixed Charge Methodology	23
2.4.2	Utility System Financial Planning Model	28
2.4.3	The Conventional Alternative	28
2.4.4	Composite Intermediate Load Plant: A Second Alternative?	31
3.	PHOTOVOLTAIC CENTRAL STATION POWER PLANTS.....	35
3.1	Performance Evaluations: The Effect of Geographic Location and Collector/ Concentrator Type	36
3.2	Economic Evaluations	44
3.2.1	System Cost Assumptions	44
3.2.2	Economic Results	52
3.2.3	Allowable Area-Related Costs: Photovoltaic Plants with Storage	61
3.2.4	Allowable Area-Related Costs: Photovoltaic Plants with No Storage	75

CONTENTS (Continued)

3.3	Central Receiver Photovoltaic Power Plants Incorporating Productive Use of Thermal Energy	90
3.3.1	Introduction	90
3.3.2	Basic Analytic Considerations	95
3.3.3	Photovoltaic-Only Mode	98
3.3.4	Photovoltaic/Thermal Mode	104
3.3.5	Photovoltaic/Thermal-Electric Mode	108
3.3.6	Cost Comparison: Intermediate Load Photovoltaic Plants	115
4.	RESIDENTIAL ON-SITE APPLICATIONS	121
4.1	Procedure	122
4.2	Break-even Array Price Determinations	128
4.2.1	Economic Assumptions	128
4.2.2	Results	130
4.3	Conclusions	133
5.	PHOTOVOLTAIC TOTAL ENERGY SYSTEMS	135
5.1	Introduction	135
5.2	Approach	136
5.3	Data Search	141
5.3.1	General	141
5.3.2	Industrial Process Heat Requirements	143
5.3.3	Residential and Commercial Energy Requirements	152
5.4	Residential Photovoltaic Total Energy Applications	154
5.4.1	Introduction	154
5.4.2	Electrical and Thermal Loads	157
5.4.3	Simulation Methodology	158
5.4.4	Conclusions and Status	188

CONTENTS (Continued)

6. CONCLUSIONS AND RECOMMENDATIONS	191
REFERENCES	193
BIBLIOGRAPHY: TOTAL ENERGY SYSTEMS	197

TABLES

1. Effects of Air Mass on AlGaAs/GaAs Solar Cell Output.	13
2. Characteristics of Regional Utility System Models	18
3. Effect on Backup Capacity Requirements of Relaxation of Generation Reliability Criterion	22
4. Average Prices of Coal Purchased for Use In Steam Electric Plants	30
5. Standard Fuel Price Scenarios Used In Cost Comparisons	30
6. Performance of Photovoltaic Power Plant With Storage Capacity	39
7. Performance of Photovoltaic Power Plant With No Storage	40
8. Collector/Concentrator Cost Figures	47
9. Investment Cost Breakdown for Photovoltaic Central Station Power Plants	53
10. Levelized Busbar Energy Costs for 100 MW Photovoltaic Power Plants with Flat Plate Collectors (Electric Storage Capacity = 5 kWh/kW)	55
11. Levelized Busbar Energy Costs for 100 MW Photovoltaic Power Plants with North-South Parabolic Trough Concen- trators (Electric Storage Capacity = 5 kWh/kW)	56

TABLES (Continued)

12.	Levelized Busbar Energy Costs for 100 MW Photovoltaic Power Plants in Central Receiver Configuration (Electric Storage Capacity = 5 kWh/kW)	57
13.	Levelized Busbar Energy Costs for 100 MW Photovoltaic Power Plants in Sterling, Va. -- Without Storage	58
14.	Comparison of Optimum Conditions for Central Receiver Photovoltaic Plant Options	104
15.	Cost Comparison of Intermediate Load Photovoltaic Power Plants	119
16.	Break-even Array Prices: On-Site Residential Systems in Phoenix	132
17.	Estimated Annual Electric and Thermal Demand - 1600 ft ² Single-Family Residence in Phoenix	163
18.	Capital Cost of Thermal Portion of Residential PTES	180
19.	Baseline Electrical System Characteristics and Cost	185
20.	Characteristics of Example of Residential PTES in 1990-2000 Period	189

FIGURES

1.	General Analytical Approach	6
2.	Photovoltaic System Simulation Model	8
3.	Effect of Diurnal Variations in Insolation Spectrum on AlGaAs/GaAs Solar Cell Output	14
4.	Margin Analysis Procedure	19
5.	Cost Effectiveness of Solar Power Plants as a Function of Fuel Price and Escalation	26
6.	Composite Intermediate Load Power Plant: Conventional Baseload Plant Plus Storage	32
7.	Central Receiver Configuration	37
8.	Photovoltaic Power Plant Performance: Flat Plate Collectors	41
9.	Photovoltaic Power Plant Performance: North-South Parabolic Trough Collectors	42
10.	Photovoltaic Power Plant Performance: Central Receiver Configuration	43
11.	Levelized Busbar Energy Cost: Photovoltaic Plants With Flat Plate Collectors	59
12.	Levelized Busbar Energy Cost: Photovoltaic Power Plants at Inyokern, Various Collector Configurations	60
13.	Allowable Area-Related Cost for Photovoltaic Power Plant With Storage: Fuel Price Case A	68
14.	Allowable Area-Related Cost for Photovoltaic Power Plant With Storage: Fuel Price Case B	69
15.	Allowable Area-Related Cost for Photovoltaic Power Plant With Storage: Fuel Price Case C	70
16.	Allowable Array Price ($\$/m^2$) vs Array Efficiency: Photovoltaic Plant With Storage -- Flat Plate Collectors	72

FIGURES (Continued)

17.	Allowable Array Price (\$/kW _{pk}) vs Array Efficiency: Photovoltaic Plant With Storage -- Flat Plate Collectors	73
18.	Maximum Allowable Array Price: Photovoltaic Central Receiver Power Plant With Storage, Fuel Price Case C	76
19.	Allowable Area-Related Cost for Photovoltaic Plant Without Storage: Fuel Price Case A	81
20.	Allowable Area-Related Cost for Photovoltaic Plant Without Storage: Fuel Price Case B	82
21.	Allowable Area-Related Cost for Photovoltaic Plant Without Storage: Fuel Price Case C	83
22.	Allowable Array Price (\$/m ²) vs Array Efficiency: Photovoltaic Plant Without Storage -- Flat Plate Collectors	85
23.	Allowable Array Price (\$/kW _{pk}) vs Array Efficiency: Photovoltaic Plant Without Storage -- Flat Plate Collectors	86
24.	Maximum Allowable Array Price: Photovoltaic Central Receiver Plant Without Storage, Fuel Price Case B	88
25.	Maximum Allowable Array Price: Photovoltaic Central Receiver Plant Without Storage, Fuel Price Case C	89
26.	Photovoltaic - Only System	92
27.	Photovoltaic/Thermal System	93
28.	Photovoltaic/Thermal-Electric System	94
29.	Receiver/Array Geometry: Photovoltaic Central Receiver Plant	99
30.	Net Array Efficiency vs Coolant Flow Rate	101
31.	Water Exit Temperature vs Coolant Flow Rate	101
32.	Net Array Efficiency vs Average Array Temperature	102

FIGURES (Continued)

33.	Net Array Efficiency and Water Exit Temperature vs Coolant Flow Rate	106
34.	Capital Cost of Transmitting Thermal Energy	108
35.	Turbine Generation Efficiency as a Function of Inlet Temperature of Working Fluid	110
36.	Overall Net System Efficiency and Water Flow Rate Per Unit Area vs Width of Flow Channel in Photovoltaic/ Thermal-Electric System	112
37.	Net Efficiency of Photovoltaic/Thermal-Electric System vs Average Array Temperature	113
38.	Net Efficiency of Photovoltaic/Thermal-Electric System for Alternative Operational Strategies	114
39.	Methodology for Determining Break-even Array Price in On-Site Photovoltaic Applications	123
40.	Break-even Array Price: On-Site Residential Photovoltaic Systems in Phoenix	134
41.	Mission Analysis of Photovoltaic Total Energy Systems: Dimensions	137
42.	Mission Analysis of Photovoltaic Total Energy Systems: Approach	138
43.	Cumulative Distribution of Process Steam Requirements: Chemical and Allied Products Industry	145
44.	Cumulative Distribution of Process Steam Requirements: Petroleum Industry	146
45.	Cumulative Distribution of Process Steam Requirements: Food and Kindred Products Industry	147
46.	Cumulative Distribution of Process Steam Requirements: Paper and Allied Products Industry	149
47.	Cumulative Distribution of Process Steam and Hot Water Requirements: Other Industries	150

FIGURES (Continued)

48.	Cumulative Distribution of Industrial Process Steam and Hot Water Requirements	151
49.	Distribution of Industrial Process Heat Usage, By Temperature	153
50.	Schematic of Residential Photovoltaic Total Energy System	156
51.	Baseload Electric Power Requirements: 1600 ft ² Residence	159
52.	Power Requirement for Residential Air Conditioning	160
53.	Thermal Energy Requirements for Domestic Hot Water: Single-Family Residence, Four Persons	161
54.	Power Requirement for Residential Space Heating	162
55.	Residential PTES: Simulation/Analysis Approach	165
56.	Residential PTES: Thermal Simulation	169
57.	Residential PTES: Electrical Simulation	170
58.	Thermal System Simulation Results, Phoenix	176
59.	Levelized Annual Cost of Thermal Energy, Residential PTES in Phoenix	178
60.	Electrical System Simulation Results, Phoenix	182
61.	Levelized Annual Cost of Electric Energy, Residential PTES in Phoenix	183
62.	Effect of Array Price on Levelized Annual Cost of Electric Service	186
63.	Effect of Backup Energy Cost on Levelized Annual Cost of Electric Service	187

SECTION 1

INTRODUCTION

This volume contains a report on investigations carried out and results achieved under Task 2, "Analysis of Major Mid-Term Missions," as part of the Mission Analysis of Photovoltaic Solar Energy Systems project. The objectives of this task were to:

- a. Identify and evaluate the missions (applications) in which photovoltaic solar energy conversion is most likely to make a significant contribution to the U.S. energy economy in the mid-term (1985-2000) period.
- b. Determine the conditions under which photovoltaic systems would be economically competitive, in these preferred missions, with alternative energy sources.

This part of the project represents a continuation of work carried out in an earlier NSF-sponsored study with the same title (Ref. 1). Much of the effort in the earlier study was devoted to the task of developing and testing the analytical tools needed in order to make technical and economic evaluations of candidate photovoltaic applications. These tools included:

- a. Computer simulation models for use in evaluating system performance in a given mission.
- b. Appropriate representations for the insolation and other relevant weather parameters that are characteristic of representative sites.
- c. Representations for the magnitude and temporal variations in the electric power demand that are characteristic of the candidate applications.
- d. Margin analysis procedures for determining the amount of conventional capacity that must be provided as backup to a photovoltaic system in order to maintain utility system reliability.
- e. Models for representative utility systems in the southwestern United States in 1990, including representations for system demand and for the mix of generation plants.

- f. Methods for determining the busbar cost of energy from photovoltaic power plants and the break-even array price for on-site residential photovoltaic systems (the array price at which the use of the photovoltaic systems is economically competitive with conventional energy sources).

These methods were then used in the analysis of some illustrative examples of candidate on-site (residential) and central station applications in the Southwest. Only flat-plate systems with silicon arrays were considered, and it was tentatively concluded that photovoltaic solar energy conversion will be economically competitive with alternative energy sources in either application when array prices reach the \$100-\$200/kW_{pk} range.

In the present study, these procedures have been extended in several respects (Section 2) and have been used in the analysis of a number of additional applications. The emphasis has continued to be on central station power plant applications (Section 3) because it seems clear that if photovoltaic solar energy conversion is to reach the ERDA objective of making a significant contribution to the U.S. energy supply (1-2% of the total) by the year 2000, an appreciable penetration of the central power plant market will be required. The new analyses have included technical and economic evaluations of photovoltaic power plants incorporating several different kinds of collector systems (both flat plate arrays and concentrators) and operating in five different parts of the country. The results of these analyses have also been used in the formulation of generalized graphs that permit a quick estimate of the maximum cost of the area-related elements of the system that can be tolerated if the plant is to be economically competitive.

Since the evaluations of photovoltaic plants using concentrators indicated that profitable use of the thermal energy that is also collected would probably be required in order to make such plants cost-competitive, a preliminary investigation was made of the economic impact of such uses of thermal energy. The system that was studied incorporated a concentrator in the central receiver configuration and utilized water-cooled AlGaAs/GaAs

cells. The effects on plant economics of either selling the thermal energy directly or using it to generate additional electricity in a low-pressure turbine were separately evaluated (albeit in a fairly approximate manner).

In the preceding study (Ref. 1), the analysis of the economics of on-site residential photovoltaic applications was conducted in a manner that was essentially independent of who owned the photovoltaic system. In the present study, the impact of alternative ownership options (specifically, homeowner ownership vs. utility ownership) was briefly investigated (Section 4).

Finally, a start was also made on an investigation of applications for photovoltaic total energy systems, i. e. systems that provide both photovoltaic electricity and solar thermal energy to meet the combined demand for electric and thermal energy at a single load point or group of related load points (Section 5).

THIS PAGE
WAS INTENTIONALLY
LEFT BLANK

SECTION 2

ANALYTICAL METHODOLOGY

2.1 GENERAL APPROACH

The methodology that has been used in the mission evaluations discussed in this volume is essentially identical to that developed in the earlier study (Ref. 1) referred to in the previous section. The logical structure of this methodology is illustrated in Figure 1. Its three central elements are:

- a. Simulation computations of system performance within the constraints that characterize the site (insolation) and the type of mission (mission demand)
- b. Reliability analysis to determine the amount of conventional backup capacity that must be provided in order to ensure that overall service reliability is not degraded by the introduction of photovoltaic generation
- c. Economic analysis to determine the total cost of meeting all or part of the mission demand by means of photovoltaic solar energy conversion.

This cost, which includes the cost of providing the required backup capacity, is then to be compared with the cost of meeting the mission demand by more conventional generation methods. It is useful, on the basis of this comparison and of an analysis of the different elements that contribute to the cost of photovoltaic power, to identify the performance and cost goals that must be met by the critical subsystems in order that photovoltaic power can be economically competitive. Of particular importance, of course, are the price and conversion efficiency of the photovoltaic array itself.

Figure 1

GENERAL ANALYTICAL APPROACH

2.2 SIMULATION PROCEDURE

The simulation computations of system performance have utilized a mathematical model for the photovoltaic system in conjunction with representations for the insolation input (characteristic of the site) and for the electric power demand (characteristic of the mission). Since system performance displays very substantial variations with time (as a result of diurnal, seasonal, and random variations in both insolation and demand), evaluations based on average values are likely to be significantly in error. For this reason, the system performance computations are carried out on an hourly basis and for at least a full year of simulated operation.

2.2.1 System Model

The simulation model that has been used both in this study and in the previous one is illustrated in block-diagram form in Figure 2. The blocks and flow paths indicated by solid lines represent the basic elements of the power production system and the flow of energy from one element to the next. The dashed lines represent an optional rectifier system and the energy flow that would occur if conventional power were used to charge the photovoltaic storage system during off-peak hours. The dotted lines represent energy flow, if any, required for collector tracking and for array cooling.

The insolation input is provided in the form of a magnetic tape containing an hourly record of direct (normal incidence) insolation, total hemispheric insolation, and a variety of other weather data (including, in particular, ambient temperature). The Tracking/Geometry subroutine then computes the amount of solar energy (both direct and diffuse) that is actually accepted by the collector. From this amount the collector system subroutine subtracts losses resulting from (a) less than perfect reflectance of concentrator surfaces, (b) shading and other forms of interference between elements of a distributed collector system, and (c) imperfect focussing of off-axis incident radiation.

Figure 2

PHOTOVOLTAIC SYSTEM SIMULATION MODEL

The output of the Collector System subroutine represents the energy that actually falls upon the photovoltaic array. The Photovoltaic Conversion subroutine then computes the DC electric output of the array on the basis of an array efficiency, which is calculated as the product of the cell efficiency (as a function of array temperature) and the array packing factor. The relationships used for the dependence of cell efficiency on temperature were:

$$\begin{aligned}\eta(T) &= \eta(70^{\circ}\text{C}) [1 - .005(T - 70)] && \text{Si} \\ \eta(T) &= \eta(70^{\circ}\text{C}) [1 - .0024(T - 70)] && \text{AlGaAs/GaAs}\end{aligned}$$

where T is in $^{\circ}\text{C}$. A subsidiary loop computes the array temperature, as a function of incident energy and ambient temperature, when passive cooling is being simulated. When active cooling is simulated, the array temperature is kept fixed at a preset (input) value.

After correction for DC ohmic losses (within the array or between the array and the storage or power conditioning systems), the model then introduces a logical decision point. Energy that is needed to satisfy mission demand is dispatched to the power conditioning system. Any excess is directed to the storage system. The Power Conditioning subroutine corrects for energy losses that occur during conversion of the input DC power into output AC power (including any voltage transformation that may be required). The Electric Storage subroutine applies a (fixed percentage) correction for the energy lost in the charge-discharge cycle of an electric storage battery. This subroutine also incorporates a maximum-storage limitation and an overflow (surplus) provision. When power directly from the array is insufficient to meet mission demand, the deficit is made up, to the extent possible, by discharging energy from the storage system.

In the Power Requirements subroutine, the AC power from the power conditioning system is diminished by the amounts needed in meeting the requirements of the array cooling and collector tracking systems. After a further correction, in the Transmission Losses subroutine, for ohmic losses in the AC transmission between the power conditioning system and the overall

system output, the net power production is then matched to the electrical demand (in the form of a magnetic tape record of hourly energy requirements) on an hour-by-hour basis. For those hours in which photovoltaic power (either directly from the arrays or from storage) is insufficient to meet demand, energy is provided by conventional power sources. (A magnetic tape record of these hourly amounts of conventional backup energy is one of the principal inputs to the reliability analysis procedure discussed in Section 2.3.)

A much more complete description of this photovoltaic system model, including the algorithms on which the various subroutines are based, was given in Vol. III, Appendix C, of the report on the earlier study (Ref. 1). Although the model has been upgraded in several respects (e.g., through the introduction of an improved procedure for calculating shading losses in the Collector System subroutine) since this description was prepared, it still provides a reasonably accurate representation of the model used in the current study.

This system model has also been adapted for use in simulating the operation of photovoltaic total energy systems (in which the thermal energy collected by the array is used, along with the photovoltaic output, to meet the combined thermal and electrical demands at a single load point). This adaption is discussed in Section 5.

2.2.2 Insolation Representations

The insolation representations used in this study were taken from the extensive insolation data base that has been assembled at The Aerospace Corporation over a period of several years to provide required input data for a number of different studies of solar energy utilization. This data base (described in some detail in Vol. II of Ref. 1) now includes hourly data for the two-year period 1962-63 for 33 locations distributed over the United States. Included for each hour are values for (a) total hemispheric insolation (direct plus diffuse) on a horizontal surface, (b) direct normal-incidence

insolation, and (c) a variety of relevant weather variables. (In some cases these weather variables are only provided for daylight hours.)

For 26 of the locations, the total insolation values are based on actual pyranometer measurements at the site in question, corrected in some cases (notably, Inyokern, California) for known instrument drift or calibration errors. For the remaining seven locations, the total insolation values are estimated on the basis of an observed correlation with opaque sky cover, as measured by the National Weather Service. This correlation has also been used in filling gaps in the data records at sites where measured data are normally available.

For five of the sites, normal incidence insolation (pyrheliometer) measurements were made but were recorded only for hours corresponding to certain air-mass ratios. For those sites, where possible, the hourly normal incidence insolation values in The Aerospace Corporation data base were obtained by interpolation between the measured values. For all other sites, and when needed to fill gaps in records from the five pyrheliometer stations, normal incidence insolation values were estimated on the basis of a correlation with the percent of possible total insolation (the ratio, expressed as a percentage, of the observed or estimated total insolation to the extra-terrestrial insolation on a horizontal surface at the same hours).

2.2.3 Effect of Variations in the Insolation Spectrum

In the simulation procedure outlined above, the electrical output of the photovoltaic array is computed essentially by multiplying the incident solar energy by an efficiency which depends only on the temperature. This procedure neglects the well-known facts that (a) the response of a photovoltaic array displays a marked dependence on the spectrum of the incident light and (b) the spectrum of insolation at the earth's surface varies substantially with time of day and with changing meteorological conditions. In the course of the earlier study (Ref. 1), an investigation was made of the magnitude of the error that might be expected to arise if these spectral effects were

neglected in computing the response of arrays assembled from either Si or CdS/Cu₂S solar cells. It was determined that these errors would not significantly affect the outcome of the simulation computations, and, accordingly, spectral effects were not included in the model.

Since it was planned in the current study to investigate photovoltaic systems employing collectors with very high concentration ratios (500-1000) in conjunction with AlGaAs/GaAs solar cells, it was necessary to determine whether or not spectral effects would introduce significant errors in computing the response of AlGaAs/GaAs arrays.

The method used in assessing the magnitudes of such errors was the same as that used in the earlier study. Six different models of the atmosphere (tropical, midlatitude winter, and midlatitude summer, each with two different aerosol concentration levels) were used to compute the spectrum of ground-level insolation for a range of solar zenith angles. On the basis of these spectra and a spectral response curve for AlGaAs/GaAs cells, the electrical output of a typical AlGaAs/GaAs cell ("spectral effect included") was calculated for each case. For each case, also, the output of a standard pyranometer (flat spectral response, modified by absorption in the pyrex cover) was calculated. These pyranometer output values were then multiplied by a fixed efficiency to yield "spectral effect neglected" values for cell output. (The fixed efficiency value used was the factor required to make the "spectral effect neglected" value equal to the "spectral effect included" value in one selected case - simulating a calibration.) The difference between the two output values in each case is then a measure of the error introduced by neglecting spectral effects. The results of these calculations are summarized in Table 1. The results for two of the atmospheric models (tropical atmosphere, 5 km and 23 km visibility) are also shown in Figure 3.

It is evident that the absolute differences between the "spectral effect included" and "spectral effect neglected" results are small, although percentage differences are substantial for hazy atmospheres at large zenith angles. It was concluded that the associated errors in calculated array output are negligible in the AlGaAs/GaAs case, as they were in the Si and CdS cases.

Table 1

EFFECTS OF AIR MASS ON AlGaAs/GaAs SOLAR CELL OUTPUT

Atmosphere	Visibility	Spectral Effect	Zenith Angle					
			0°	15°	30°	45°	60°	70°
Midlatitude Summer	23 km	Included	1.0099	1.0	0.9671	0.9002	0.7677	0.6007
		Neglected	1.0112	1.0	0.9628	0.8887	0.7504	0.5881
		Difference	0.0013	0.0	-0.0043	-0.0115	-0.0173	-0.0126
	5 km	Included	0.6201	0.6036	0.5512	0.4535	0.2930	0.1494
		Neglected	0.6445	0.6282	0.5765	0.4812	0.3288	0.1922
		Difference	0.0244	0.0246	0.0253	0.0278	0.0358	0.0428
Midlatitude Winter	23 km	Included	1.0165	1.0066	0.9737	0.9068	0.7740	0.6063
		Neglected	1.0507	1.0391	1.0016	0.9272	0.7867	0.6211
		Difference	0.0342	0.0325	0.0279	0.0204	0.0127	0.0148
	5 km	Included	0.6247	0.6082	0.5555	0.4573	0.2962	0.1515
		Neglected	0.6753	0.6586	0.6057	0.5082	0.3510	0.2085
		Difference	0.0506	0.0504	0.0502	0.0509	0.0548	0.0570
Tropical	23 km	Included	1.0089	0.9990	0.9664	0.8998	0.7675	0.6010
		Neglected	1.0006	0.9891	0.9522	0.8787	0.7408	0.5797
		Difference	-0.0083	-0.0099	-0.0142	-0.0211	-0.0267	-0.0213
	5 km	Included	0.6194	0.6030	0.5506	0.4527	0.2926	0.1491
		Neglected	0.6362	0.6198	0.5685	0.4739	0.3227	0.1880
		Difference	0.0168	0.0168	0.0179	0.0167	0.0301	0.0389

Figure 3
EFFECT OF DIURNAL VARIATIONS IN INSOLATION SPECTRUM ON
AlGaAs/GaAs SOLAR CELL OUTPUT

2.2.4 Demand Representations

In the current study, the new system simulation computations that were carried out primarily represented central station power plant applications. The required demand representations therefore have been those corresponding to total demand in the utility system of which the photovoltaic plant is considered to be a part. Since comparisons of photovoltaic power plant performance in different parts of the country were planned, utility system demand representations corresponding to the different geographic locations were needed.

Fortunately for the purposes of this program, a reasonably representative set of hourly utility system demand models had already been generated

as part of The Aerospace Corporation's continuing investigation of solar thermal power generation (Refs. 2-4). In the course of that investigation, the characteristics of system demand in some 40 different utility systems scattered across the country had been examined and divided (with the exception of three large utility systems having somewhat singular characteristics) into nine groups whose members were quite similar in such basic properties as historical and forecast growth trends, load factors, and seasonal peaking tendencies. The members of the different groups were not randomly interspersed but, instead, those of each group tended to lie in a distinguishable geographical region with roughly similar climatological characteristics (e. g., heating and cooling degree-days) throughout. On the basis of this geographical differentiation, and of the availability of long-term records of hourly data, five utility systems were chosen to represent the range of system demand characteristics that are observed in the United States. These systems were: Southern California Edison Company, broadly representative of the Southwest; Florida Power and Light Company, representing the Southeast and South Central regions; the Pennsylvania-New Jersey-Maryland Interconnection (PJM), representing the East Central region; Consumers Power Company, representing the Northeast and North Central regions; and Pacific Power and Light Company, representing the Northwest.

Projections to the year 1990 were then made on the basis of historical hourly demand records for each of these companies. These projections were made by a procedure (described in detail in Vol. III, Appendix A, of Ref. 1) in which the historical demand record is mathematically decomposed into six component factors: (a) the peak yearly demand, (b) the ratio of total yearly energy to peak demand (essentially the load factor), (c) the ratio of total weekly energy to annual energy, (d) the ratio of total daily energy to weekly energy, (e) the ratio of half-day energy to daily energy, and (f) the ratio of hourly demand to half-day energy. Of these factors, the first is assumed to vary exponentially with time, while the time dependence of the next four factors is assumed to be linear. Values for the coefficients defining

these trends -- load factor trend, the 52 weekly trends, the 364 (52 weeks of seven days each) daily trends, and the 728 half-day trends -- are obtained from the historical data by a least-squares fitting procedure. The final component factor, the hourly index, should be trend-free if the component factors have been chosen properly. The hourly demand forecast for a given year is then generated simply by taking the product of these four factors, properly normalized and evaluated for the year in question, and multiplying by the average value of the hourly index and by the projected peak demand. The result is a forecast in which significant internal trends in the data are automatically taken into account.

It is these projections that have been used in the analysis of photovoltaic power plant performance and the determination of backup capacity requirements, as discussed in later sections of this report.

The analysis of photovoltaic total energy system performance requires demand representations of a quite different sort. Since the computations must take into account the correlation between outside ambient temperature and the thermal and electrical loads arising from space heating and cooling, it is necessary to synthesize the demand representations by means of algorithms derived from studies of these correlations. The procedure used in the very preliminary investigation that has so far been carried out is described in connection with the report on that investigation in Section 5.

2.3 RELIABILITY ANALYSIS

The input to any photovoltaic solar energy system is inherently a variable quantity. Since proven methods of storing electrical energy are costly, it is economically unattractive to provide sufficient storage capacity to isolate such a system from the effects of the diurnal, seasonal, and weather-related variations in the incoming insolation. The system output, therefore, is also inherently variable. As a result, when photovoltaic systems are used to displace a nominally equivalent amount of conventional generation capacity in a utility system, there is generally a reduction in the overall

reliability of power generation in the system. If it is assumed, as it has been in this study, that such a reduction in generation reliability (increase in loss-of-load probability) is unacceptable, then a certain amount of conventional generation capacity must be added to back up the photovoltaic systems. The cost of this backup capacity should then be included in computing the cost of photovoltaic power.

The procedure used in this study for calculating the amount of backup capacity required for a particular photovoltaic system has been described in detail in earlier reports (Refs. 1-3). The methodology involves two main elements. The first of these is a procedure, called margin analysis, for calculating the statistical probability of loss of load (failure of available generation capacity to meet overall system demand) as a result of unscheduled outages of generation plants. The name, margin analysis, is derived from the usual function of this procedure, namely the determination of how large a margin (excess of total generation capacity over peak demand) a utility system must maintain in order to ensure that the probability of loss of load is acceptably small. In this study, as in the earlier ones, the criterion used for acceptability is that there should not be more than 2.4 hours of loss of load in each year of operation.

The other main element in the methodology is a baseline model for the utility system into which the photovoltaic generating capacity is to be introduced. This model must include both a representation for the total system demand and a model for the conventional generation capacity of the system, including the individual rated capacity and probability of unscheduled outage for each plant. Before use, the generation models are adjusted with the aid of the margin analysis procedure, so that the calculated loss of load satisfies the adopted reliability criterion (2.4 hours per year).

2.3.1 Utility System Models

The five baseline utility system models used in this study are based on (a) projections of 1990 demand, as described in Section 2.2.4 above, for Southern California Edison (SCE), Florida Power and Light (FPL),

Pennsylvania-New Jersey-Maryland Interconnection (PJM), Consumers Power (CPC), and Pacific Power and Light (PPL) and (b) the current and projected capacities in these systems, as revealed by annual reports, other public documents, or as reported directly by utility representatives. In each of the generation models that have been developed on the basis of these data on projected capacities, the wide variety of plant sizes and types that are projected for the real utility have been replaced by a much more limited distribution that has the same total capacity and the same general characteristics. The resulting overall utility system models therefore cannot be, and are not intended to be, representative of the future configurations and characteristics of the specific utility systems to which the raw input data apply. The models instead are considered to be broadly representative of the regions in which the actual utility systems are located: Southwest (SCE); Southeast and South Central (FPL); East Central (PJM); Northeast and North Central (CPC); and Northwest (PPL).

The principal characteristics of these five utility system models are listed in Table 2.

Table 2
CHARACTERISTICS OF REGIONAL UTILITY SYSTEM MODELS

	Capacity, MW	Plant Mix, Number	Outage Rate, %	Total Capacity, MW	Margin, %	Maximum Demand, MW
Southwest	1000	18	7	36,400	13.75	32,000
	500	20	5			
	200	42	3			
Southeast/ South Central	1000	13	7	24,300	13.1	21,500
	500	14	5			
	100	43	3			
East Central	1000	44	7	91,000	10.9	82,000
	500	40	5			
	200	135	3			
Northeast/ North Central	1000	10	7	17,300	31.0	13,200
	500	8	5			
	100	33	3			
Northwest	1000	4	7	8,500	28.2	6,600
	500	5	5			
	50	40	3			

2.3.2 Margin Analysis Procedure -- Loss-of-Load Determination

The margin analysis procedure used in the loss-of-load calculations is illustrated in Figure 4. The curve on the left represents the cumulative probability that the total available generation capacity of the utility system is smaller than a given capacity, x , expressed as a function of x . One such graph is generated for each month of the year by the following method. For a given month, those plants "down" for scheduled maintenance are excluded from consideration. (The maintenance schedule is adjusted for optimum plant utilization). Each of the remaining N plants has a probability, p , of being "down" (in an unscheduled outage) and a probability, $1-p$, of being available for service. For each possible configuration of plant availability

Figure 4
MARGIN ANALYSIS PROCEDURE

(k plants down, N-k plants available) there is an associated total amount of available generation capacity and a configuration probability. Through a consideration of all possible configurations, it is possible to determine the overall probability, $P(x)$, that the total available capacity is exactly x. From such numbers in turn, the cumulative probability graphs are generated.

The loss-of-load computation is then carried out as indicated in Figure 4. For each hour of the year (and its associated system demand), the probability, P_i , that available capacity will be too small to meet demand is determined. The annual loss of load is just the sum of these hourly P_i values.

The determination of backup capacity requirements for photovoltaic systems is then a conceptually straightforward process. The baseline generator model is perturbed by the introduction (substitution, usually) of photovoltaic generation capacity, thereby changing the demand to be met by the remaining conventional plants, and, as a result, the annual loss of load. The total capacity in the conventional generation model is then incrementally increased by the successive addition of conventional plants of predetermined size and operating characteristics. For each addition, new monthly probability curves are generated and a new value for loss of load is computed; the resulting set of points defines the functional relationship between loss of load and incremental capacity. The amount of backup capacity needed in order to reduce the loss of load to the original baseline level is then determined by interpolation.

2.3.3 Effect of Relaxing Reliability Criterion

One of the first issues addressed in the current study was the question of the effect on the apparent competitive position of photovoltaic power generation of the rather stringent generation reliability criterion that was used in the analysis (no more than 2.4 hours of loss of load per year of service). It seemed likely that the adoption of such a strict criterion might penalize solar power generation with respect to the more conventional

generation methods and that, if this were so, it might be appropriate to explore the extent to which the criterion could reasonably be relaxed.

Accordingly, it was decided early in this project to investigate the effect on backup capacity requirements of changing the loss-of-load criterion from 2.4 hours/year to 24 hours/year. Data tapes were already available that contained hourly records of photovoltaic plant performance, generated in several of the simulation computations made for the earlier study (Ref. 1). Each of these tapes was accordingly used, along with the Southern California and Central Arizona utility system models that were available at that time, in two separate backup capacity calculations, one for the original loss-of-load criterion (2.4 hours/year) and one for the relaxed one (24 hours/year).

The results of these backup capacity calculations are shown in Table 3. The cases examined include three examples in which a 100 MW plant in Phoenix was considered to be a part of the model Central Arizona utility system and four examples in which a 100 MW plant at Inyokern was assumed to be part of the model Southern California utility system. Six different on-site residential examples were also investigated, all representing systems in Phoenix; in these cases, the backup capacity requirements were calculated for both utility models, however. The absolute values for backup capacity shown in the table are not directly comparable to the values shown for the same examples in Reference 1, because the utility system models had been modified slightly in the intervening period.

The results in Table 3 indicate that relaxing the reliability criterion does not, as expected, reduce the backup capacity requirement but instead actually increases it by a small amount. This result, though surprising at first glance, is not really as anomalous as it appears. When the reliability criterion is relaxed, the utility system generation model is changed; the total amount of conventional generation capacity is reduced because the margin needed in order to maintain the lower reliability is smaller. The replacement of a conventional plant by photovoltaic power sources, with their associated weather-related outages, in a system that is nearer the "ragged edge" produces a somewhat larger destabilizing effect than in the standard case.

Table 3
EFFECT ON BACKUP CAPACITY OF RELAXATION OF
GENERATION RELIABILITY CRITERION

Array Area (10 ⁶ m ²)	Storage Capacity (10 ⁶ kWh)	Backup Capacity Required			
		Central Arizona Utility		Southern California Utility	
		Maximum Loss of Load 2.4 hr /yr 24 hr /hr		Maximum Loss of Load 2.4 hr /yr 24 hr /yr	
Central Station Power Plants (100 MW)					
2	0	27.2 MW	36.8 MW	48 MW	61 MW
	0.5	14.3	22.5	20	30
	1.0	14.3	22.5		
3	0			47	60
	0.5			3	5.5
Residential On-Site Systems					
2	0	150	158	80	88
	1.0	140	154	60	66
4	0	95	104	48	59
	1.0	59	67	13	18
6	0	72	83	36	48
	1.0	24	32	9	12

2.4 ECONOMIC EVALUATION

2.4.1 Levelized Fixed Charge Methodology

The economic evaluations that are discussed in this report have, in general, been based on the levelized fixed charge approach that is in common use in the utility industry. This procedure has recently also been adopted (Ref. 5) as a required methodology for ERDA/EPRI evaluations of the cost of energy from utility-owned solar electric systems. In this approach, the principal quantity that is calculated is the levelized busbar energy cost, $\overline{BBEC}$, usually expressed in mills per kWh of electric output. This quantity is the constant (levelized) charge for energy that would ensure that the associated stream of constant annual revenue receipts over the life of the plant is exactly enough to defray the total cost of constructing the plant, operating and maintaining it over its service life, and paying the expected return on the capital investment.

The relationship of the levelized busbar energy cost to the other pertinent economic parameters, for any type of plant, is commonly expressed in the simple form (Ref. 5)

$$\overline{BBEC} \text{ (mills /kWh)} = \frac{C_t \cdot FCR}{8.76 \overline{PCF}} + \overline{O\&M} + \overline{FL} \quad (1)$$

where

C_t = total investment cost of the plant as of the first year of commercial operation (including interest during construction) expressed in dollars (1975 dollars, in this study) per kW of rated capacity.

FCR = fixed charge rate, which depends on the internal cost of capital to the utility system (the after-tax discount rate), on the effective income tax rate, and on such other capital-related costs as insurance and property taxes. For most investor-owned utility systems, the value of FCR is between 0.15 and 0.18.

PCF = plant capacity factor, the ratio of the total annual energy output of the plant (in kWh) to the output that would have been produced if the plant had operated at full rated capacity for all 8760 hours of the year.

$\overline{O\&M}$ = levelized cost (in mills/kWh) of operating and maintaining the plant, exclusive of fuel. This is the constant (levelized) amount that would, if applied to every kWh of plant output, generate a stream of revenue that would exactly defray all operating and maintenance costs, with proper allowance for escalation and the cost of money.

$\overline{FL}$ = levelized cost of fuel, if any, expressed in mills/kWh. This is the constant fuel charge that would generate a stream of revenue that would exactly defray all fuel costs over the life of the plant, with proper allowance for escalation and the cost of money.

In determining the value of either $\overline{O\&M}$ or $\overline{FL}$, one must first calculate the present value, as of the first year of operation, of a stream of annual costs that increase with time as a result of inflation but are reduced in value (from the point of view of the first year of operation) as a result of the time-value of money. If the relevant escalation rate, g , and discount rate, k , are constant, the calculation of the present value of these costs over the N years of plant life is accomplished simply by multiplying by the factor

$$G = \sum_{i=1}^N \left(\frac{1+g}{1+k} \right)^i = \left(\frac{1+g}{k-g} \right) \left[1 - \left(\frac{1+g}{1+k} \right)^N \right] \quad (2)$$

To determine the constant annual amount that would exactly pay for this present value cost, one then multiplies by the capital recovery factor

$$CRF_{k, N} = k [1 - (1+k)^{-N}]^{-1}$$

which is the uniform annual payment, as a fraction of the original principal, that will fully repay a loan, including all interest, in N years at an interest rate of k .

Therefore, one can write

$$\overline{O\&M} = (O\&M)_o \cdot G \cdot CRF_{k,N} \quad (3)$$

$$\overline{FL} = FL_o \cdot HR \cdot (10^{-3}) \cdot G \cdot CRF_{k,N} \quad (4)$$

where

$(O\&M)_o$ = operating and maintenance cost in the first year of operation, expressed in mills/kWh (in terms of 1975 dollars in this study).

FL_o = fuel cost in the first year of operation, expressed in dollars (1975 dollars) per million Btu.

HR = heat rate, the ratio of thermal energy consumption to electric energy output, in Btu/kWh.

The use of these relationships in comparing the cost of energy from a photovoltaic power plant with that of conventionally generated energy is illustrated in nomographic form in Figure 5. (As noted in the figure, the value of $\overline{O\&M}$ for all types of power plants was set at 3 mills/kWh in constructing these graphs).

To use this nomogram, one first must determine the total capital cost figures for the solar and conventional plants that are to be compared, as of the beginning of commercial operation, including interest during construction and, in the case of the solar plant, the total capital cost of the required backup capacity. He then enters the chart at the appropriate points on the abscissa of the upper right-hand graph and proceeds vertically to the line for the assumed fixed charge rate and then horizontally across into the upper left-hand chart. At the intersections with the line representing the plant capacity factor, he drops vertically to the abscissa to determine the corresponding values for the busbar cost of energy, exclusive of fuel. If the solar plant is to compete economically with the conventional plant, the difference in the fuel-less busbar energy cost figures must be less than or equal to $\overline{FL}$.

LEVELIZED FIXED CHARGE APPROACH

LEVELING
FUEL PRICE
MULTIPLIER
 $9.2 G \cdot CRF$

Figure 5

COST EFFECTIVENESS OF SOLAR POWER PLANTS AS A FUNCTION OF FUEL PRICE AND ESCALATION

The lower two graphs in Figure 5 permit the identification of the various fuel price/escalation scenarios that will result in the required value of $\overline{FL}$. The lower left-hand chart is entered at the point on the horizontal axis corresponding to this required $\overline{FL}$; the intersections of the vertical line from this point with the various FL_0 lines identify the required values for the levelizing fuel-price multiplier (equal to $9.2 CRF_{k, N} \cdot G$, corresponding to $HR = 9, 200$) in each case. One then proceeds horizontally across into the lower right-hand graph to intersect with a vertical line drawn from the assumed value of the after-tax discount rate, k . Interpolation between the curves in this graph then permits an estimate of the fuel escalation rate that, in conjunction with the corresponding FL_0 value, will yield the required $\overline{FL}$. For each value of the k on the abscissa scale in the lower right-hand graph the corresponding values of $CRF_{k, N}$ (for $N = 30$) and FCR are also shown. (The determination of FCR from the value of k requires that some assumptions be made about the effective income tax rate, τ , and about other tax and insurance costs; the assumptions made in constructing the chart were the same as those used in the nominal case discussed in Reference 5: τ was taken to be 0.4, and the other tax and insurance costs were assumed equal to 0.0225 times the capital cost.)

In using the chart, one should, of course, choose a value for k (in the lower right-hand graph) that corresponds to the same value of FCR that was chosen in using the upper right-hand graph. It may also be argued that k and g are not completely independent, that g is coupled to some extent to the general inflation rate and that this rate influences the prevailing value of k , the expected internal rate of return on capital in a utility system. It seems likely, however, that the fuel escalation rate will be somewhat greater than that of general inflation and that, for example, a value of $k = 0.08$ (a rate of return that corresponds to relatively mild inflation, 3 or 4%) might well coexist with fuel escalation rates of 8% or more.

2.4.2 Utility System Financial Planning Model

The levelized fixed charge approach outlined in the preceding section is perfectly adequate for comparing the energy cost figures for different types of power generation plants. It is not, however, sufficiently sophisticated for studying subtler problems, such as, for instance, the impact of various types of incentive strategies on power plant economics. For dealing with problems of this latter type, a more detailed methodology, recently developed in an Aerospace Corporation company-financed project, has been used. This Utility System Financial Planning Model (which replaces the Aerospace Corporation Power Plant Economic Model used in earlier studies) treats cash flows, taxes, depreciation, working capital allocations, and allowed revenues in a manner which is consistent with the view of power plant economics that is taken by regulatory agencies. A complete description of this new model is given in Volume IV of this report in connection with a discussion of incentive strategies and their effects.

2.4.3 The Conventional Alternative

It is widely believed, and earlier analyses (Ref. 1) have indicated, that the most appropriate role for photovoltaic power plants in the generation mix of a utility system lies in serving the intermediate portion ($PCF \sim 0.4 - 0.5$) of the utility system demand, rather than the baseload ($PCF \geq 0.6$) or peaking ($PCF \leq 0.2$) portions. The high capital costs of the large amount of electric storage (and, perhaps more importantly, the collectors and arrays needed to fill the storage) required for operation at night make it very difficult for photovoltaic plants to compete with baseload nuclear or coal-fired plants. Their lower degree of availability (as a result of insolation outages) and high capital cost put them at a serious disadvantage with respect to gas turbine plants for peaking service. The requirements of the intermediate portion of the load, however, provide a good match to the inherent characteristics of photovoltaic plants, particularly those embodying a modest (5-6 hours) of storage capacity, and it is in this type of service that such plants are first expected to become economically competitive.

In an assessment of the competitive position of photovoltaic power, therefore, it is reasonable to assume that the appropriate conventional alternative for comparison purposes would be a fossil-fuel combined-cycle generation plant designed to serve intermediate loads. Because of the high and rapidly rising cost of oil, it is unlikely that in the 1985-2000 time period will there be many new oil-fired power plants. Accordingly, for the purposes of this study, it has been assumed that the conventional alternative to photovoltaic power will be provided by new combined cycle power plants fired by coal. The total capital cost of such a plant (for a size in the 100-400 MW range) has been taken to be \$550/kW, in 1975 dollars. (This figure is consistent with those given, and discussed in greater detail, in Vol. II of Reference 1, after a correction is made for the difference between 1990 and 1975 dollars on the basis of the 3% general inflation assumed in the earlier study.)

In this economic competition between a photovoltaic power plant and a coal-fired one, the cost of fuel will play a very important role. In Table 4 are shown the average prices of coal purchased in 1975 for use in steam electric plants in the various census regions of the U.S. (Ref. 6). Also shown are the 1990 prices (in 1975 dollars) that would result if the real escalation rate (i.e. fuel escalation rate minus rate of general inflation) over the 1975-1990 period were 2%, 3%, or 4%. These numbers were the basis for selecting three "standard" fuel-price scenarios for use, in parametric fashion, in the cost comparisons made in this study. The parameters for these three scenarios are shown in Table 5. The fuel escalation rates shown in the center column of the table represent total escalation rates, including the effect of general inflation. The right-hand column contains values for the levelized busbar energy cost of power produced by a coal-fired intermediate load (PCF = 0.4) power plant if the following assumptions are made:

FCR = 0.15 (this value is consistent with the assumed value for the after tax discount rate, $k = 0.08$)

$$\left. \begin{array}{l} k = 0.08 \\ N = 30 \text{ years} \end{array} \right\} \text{ so that } CRF_{k, N} = 0.0888$$

Table 4
AVERAGE PRICES OF COAL PURCHASED IN 1975 FOR
USE IN STEAM ELECTRIC PLANTS
(1975 Dollars per 10⁶ Btu)

Real Fuel Price Escalation Rate (in excess of general inflation)	1975		1990	
	-	0.02	0.03	0.04
<u>Census Region</u>				
New England	1.24	1.67	1.93	2.24
Middle Atlantic	1.02	1.37	1.59	1.84
East North Central	0.92	1.24	1.43	1.66
West North Central	0.60	0.80	0.93	1.07
South Atlantic	1.00	1.34	1.55	1.80
East South Central	0.80	1.08	1.25	1.44
West South Central	0.23	0.31	0.35	0.41
Mountain	0.32	0.43	0.50	0.57
Pacific	0.57	0.76	0.88	1.02

Table 5
STANDARD FUEL PRICE SCENARIOS USED IN COST COMPARISONS

Scenario	1990 Coal Price, FL ₀ (1975 Dollars)	Post-1990 Escalation Rate *, g	BBEC, mills/kWh
A (Low)	0.75	0.05	38.78
B (Moderate)	1.25	0.06	49.78
C (High)	1.75	0.07	63.80

* Including effect of general inflation

$$HR = 9200 \text{ Btu/kWh}$$

$$\overline{O \ \& \ M} = 3 \text{ mills/kWh}$$

These values were adopted as standard values and were used in nearly all of the analyses discussed in this volume; the few exceptions are clearly indicated

2.4.4 Composite Intermediate Load Plant: A Second Alternative?

Economic evaluations of photovoltaic power plants have indicated that, when array prices reach the \$100-300/kW_{pk} range, such plants will probably be competitive with conventional plants like those described in the preceding section. The most cost-competitive designs for photovoltaic plants capable of serving intermediate loads (PCF ~ 0.4), furthermore, are those incorporating a moderate amount (~5 hours) of storage if the cost of electric storage can be brought down to the \$20-30/kWh range, in 1975 dollars (total present value cost of storage, including any replacements, over the life of the plant). It has been widely suggested, however, that when storage costs reach this level it may be economically advantageous for a utility system to meet intermediate load power requirements by increasing baseload capacity and storing some of the baseload output for use during periods when system demand is above the baseload level. In that event, the cost-effectiveness of a photovoltaic plant should be determined by comparing the busbar cost of photovoltaic electric power with that of intermediate load power produced by such a baseload-plus-storage combination. In Figure 6, the results of a preliminary analysis of this concept are presented.

The analysis considered the hypothetical situation in which a 1000 MW baseload coal plant, operating at a plant capacity factor of 0.8, is combined with a storage facility in such a way that the combination functions as an intermediate load plant with an overall plant capacity factor of 0.4. The operational mode is illustrated schematically in the lower left-hand part of Figure 6. It is postulated that, except for scheduled and unscheduled periods of shutdown, the baseload plant operates 24 hours per day at full rated capacity. During late-evening and early-morning hours, its output is dispatched entirely to storage. Then, during the high-demand daytime and early-evening hours, the output from the baseload plant is combined with

A PRELIMINARY LOOK

BASELOAD COAL PLANT		STORAGE PLANT				COMPOSITE PLANT	
1000 MW PCF = 0.8		665 MW PCF = 0.4 STORAGE CAPACITY = 15 kWh/kW				1665 MW PCF = 0.4	
TOTAL CAPITAL COST = \$450/kW		BATTERY COST	BASIC PLANT COST	TOTAL PLANT COST	Δ BBEC	BBEC	
		\$/kWh	\$/kW	\$/kW	mills/kWh	mills/kWh	
$\overline{\text{BBEC}} = 12.6 + \overline{\text{FL}}$ mills/kWh		20	394	591	28.3	$26.4 + 1.22 \overline{\text{FL}}$	
		50	835	1235	56.6	$37.8 + 1.22 \overline{\text{FL}}$	
		100	1570	2355	103.8	$56.6 + 1.22 \overline{\text{FL}}$	

COMPOSITE PLANT OPERATION

ALTERNATIVE

INTERMEDIATE LOAD COAL PLANT

1665 MW

PCF = 0.4

TOTAL CAPITAL COST = \$550/kW

$\overline{\text{BBEC}} = 25.5 + \overline{\text{FL}}$

CONCLUSION: COMPOSITE PLANT APPEARS UNCOMPETITIVE EVEN WHEN STORAGE COSTS ARE AS LOW AS \$20/kWh

Figure 6

COMPOSITE INTERMEDIATE LOAD POWER PLANT; CONVENTIONAL BASELOAD PLANT PLUS STORAGE

power extracted from storage (minus losses) and dispatched to the load. When allowance is made for losses (storage in-out efficiency ~ 0.70 ; rectification-inversion efficiency ~ 0.95), the average power that can be extracted from the storage facility is ~ 665 MW, so that the total composite power output is 1665 MW. The daily plant capacity factor in this case is 0.5, but since the baseload plant operates only 80% of the time, the annual average PCF value for the composite plant is 0.4.

If the storage capacity is rated in terms of the amount of energy that can be inserted into it, this rated value must be $12 (10^6) (0.70)^{1/2} (0.95)^{1/2}$ or $9.8 (10^6)$ kWh. (This calculation assumes that the rectification and inversion efficiencies are equal and that the efficiency of inserting DC energy into storage equals the efficiency of extracting it again). This represents 14.7 kWh per kW of rated output.

On the basis of the levelized fixed charge approach discussed earlier, the levelized busbar cost of energy from the baseload plant is $12.6 + \overline{FL}$ mills/kWh, where $\overline{FL}$ is the levelized cost of fuel (in mills/kWh). (In this calculation the fixed charge rate was set at 0.15 and the levelized O & M cost was assumed to be 3 mills/kWh). One can use the same approach to calculate the incremental cost for each kWh that is dispatched from storage. Three different unit cost figures for storage were considered (as shown in the upper center portion of Figure 6), and the basic cost of the remainder of the storage plant (including rectification/inversion equipment) was assumed to be $\$100/\text{kW}_{\text{rated}}$. The basic plant cost figures were multiplied by 1.50 in order to allow for spares, contingencies, indirect costs, and interest during construction. (This figure includes 8% for spares and contingencies, 25% for indirect costs, and 12.8% for interest during construction.) When the total cost of all the energy delivered to the load is divided by the number of delivered kWh, the levelized busbar costs shown in the upper right-hand box of Figure 6 are obtained.

When these busbar energy costs are compared with those calculated for the conventional intermediate-load plant described in the preceding

section, it is clear that, even for the lowest storage costs considered, a composite plant of the type considered here would probably not be cost-effective. In evaluating photovoltaic plants, therefore, this approximate analysis suggests that the appropriate conventional alternative is the combined cycle coal plant previously identified.

SECTION 3

PHOTOVOLTAIC CENTRAL STATION POWER PLANTS

In the earlier Aerospace Corporation photovoltaic mission analysis project (Ref. 1), preliminary evaluations were made of the application of photovoltaic solar energy conversion to central station power generation. These evaluations were intended primarily as examples to demonstrate the capabilities of the evaluation methodology and were limited to flat-plate systems at two similar locations in the Southwest: Phoenix, Arizona and Inyokern, California.

In the current study the investigation of photovoltaic central station power plants has been extended in several directions. Evaluations have been made of plant performance and economics in five different locations that were selected as reasonable representations of the principal climate areas and population centers of the nation. Furthermore, in each of these locations, comparative analyses were made of plants employing three different types of collector/concentrator: flat plate, N-S parabolic trough, and central receiver. The results of these evaluations were used in the development of a generalized analysis in which the maximum allowable* cost of the area-related elements of the system is related to array efficiency and to average collected insolation. (This latter parameter depends, of course, both on overall collector efficiency and on the average insolation at the site.) These investigations strongly suggest that it will be difficult for concentrating systems to produce photovoltaic power at a competitive price unless profitable use can be made of the thermal energy that is also collected. A preliminary study was also made, therefore, of high-concentration systems in which the thermal energy is either sold or used in the generation of additional electricity.

---

*"Allowable" within the constraint that the busbar cost of the output energy is required to be competitive with that produced by a conventional intermediate-load plant.

3.1 PERFORMANCE EVALUATIONS: THE EFFECT OF GEOGRAPHIC LOCATION AND COLLECTOR/ CONCENTRATOR TYPE

Simulation computations were made of the performance of 100 MW photovoltaic central station power plants at five locations: Inyokern, California; Miami, Florida; Sterling, Virginia; Cleveland, Ohio; and Seattle, Washington. At each location, simulations were carried out for three different collector/concentrator configurations: flat plate, north-south parabolic trough (concentration ratio = 20), and central receiver (concentration ratio = 600). In the flat plate case, rectangular arrays were assumed to be tilted about an east-west axis to an angle, with respect to the horizontal, that was equal to the local latitude. In the trough case, parabolic cylinders with axis horizontal and aligned in the north-south direction were assumed to track the sun through rotation about the north-south axis. In the central receiver configuration, illustrated in Figure 7, large numbers of steerable flat mirrors (heliostats) are used to reflect sunlight onto photovoltaic arrays attached to the exterior surface of a tower-mounted central receiver.

In the flat plate and parabolic trough simulations, it was assumed that the arrays were comprised of silicon solar cells and were passively cooled. In the trough case, cooling fins having a total area ten times greater than that of the arrays themselves were assumed to be mounted on the rear surface of the arrays. The central receiver calculations, on the other hand, were based on the use of AlGaAs/GaAs arrays served by a water cooling system that kept the average array temperature at a constant 80°C.

For each location and collector/concentrator type, simulation runs were made for a range of values of the total collector area (keeping the rated plant capacity fixed at 100 MW). In order to keep the total amount of computation within reasonable limits, the assumed amount of electric storage capacity was not, in general, varied but was kept fixed at $5(10^5)$ kWh. This value was selected because the earlier study (Ref. 1) had shown that 5 hours of storage was sufficient to permit a photovoltaic plant to serve intermediate

Figure 7
CENTRAL RECEIVER CONFIGURATION

loads (plant capacity factor $PCF \geq 0.4$) and that this amount of storage was roughly optimum in terms of minimum energy cost for intermediate-load operation when the total present-value cost of storage is $\sim \$20/\text{kWh}$. For one of the locations (Sterling), however, an additional set of runs was made, for each collector/concentrator configuration, with the storage capacity set at 0.

For each of these simulation runs, reliability analyses were also carried out and determinations were made of the amount of conventional backup capacity that would be required in order to maintain overall utility system reliability. The utility system model used in each case was the one that was designed to be representative of the region in which the photovoltaic plant was presumed to be located: Inyokern - Southwest model; Miami - Southeast/

South Central model; Sterling - East Central model; Cleveland - Northeast/
North Central model; Seattle - Northwest model.

The amount of backup capacity required, of course, depends significantly on the fraction of the total utility system load that is carried by photovoltaic plants. In order that reasonably valid comparisons might be made between backup requirements for solar plants operating as parts of different utility systems, therefore, all the reliability analyses were carried out for approximately the same degree of solar penetration, i.e., solar capacity equal to $\sim 5\%$ of maximum utility system demand. (To accomplish this, the hour-by-hour record of solar plant output was simply multiplied by the appropriate integral factor before being fed into the reliability analysis, corresponding to an increase in the number of 100 MW photovoltaic plants. This procedure can be justified on the grounds that identical photovoltaic power plants should display essentially identical performance when they receive the same insolation input, and the insolation input should be fairly similar for photovoltaic plants in a single utility system.)

The results of these simulations are displayed in Tables 6 and 7 and in Figures 8, 9, and 10. The computational results do not actually depend separately on the baseline ($T = 70^\circ\text{C}$) array efficiency or the total collector area but rather on their product. One can therefore interpret the results of any given computational run as representing any of a wide range of different combinations of values for efficiency and collector area that have the same product. The collector-area values shown in these tables and graphs are those that result when the assumption is made that at 70°C the silicon cell efficiency is 12% and that of AlGaAs/GaAs cells (under high-concentration illumination) is 22% ; the corresponding figures at room temperature (20°C) are 15% and 24.5% , respectively. Since a 90% packing factor is assumed, these values yield array efficiencies of 10.8% and 19.8% , at 70°C , and 13.5% and 22.1% at 20°C . Recent results in the ERDA National Photovoltaic Program indicate that it is not unreasonable to expect such efficiencies to be achieved in large-scale array production in the mid-1980's, although they are higher than the values currently being achieved in quantity production.

Table 6

PERFORMANCE OF PHOTOVOLTAIC POWER PLANT WITH STORAGE CAPACITY

Rated Plant Capacity: 100 MW

Electric Storage Capacity: 500 MWh

Cell Type → Array Efficiency → (70°C)	Flat Plate			N-S Parabolic Trough			Central Receiver		
	Si 0.12(.9) = 0.108			Si 0.12(.9) = 0.108			Al(GaAs/GaAs) 0.22(.9) = 0.198		
	Collector Area 10^6 m^2	PCF*	Backup Capacity, MW	Collector Area 10^6 m^2	PCF*	Backup Capacity, MW	Collector Area 10^6 m^2	PCF*	Backup Capacity, MW
Inyokern	0.746	.215	80.6	0.721	.157	85.6	0.712	.248	77.5
	1.49	.400	51.3	1.44	.311	75.0	1.42	.463	41.6
	2.24	.513	11.9	2.16	.437	40.9	2.14	.566	14.1
	2.98	.532	8.4	2.88	.532	15.6	2.85	.584	12.5
	3.73	.544	6.9	3.61	.555	12.8	3.56	.590	11.3
Sterling	0.746	.169	72.3	-	-	-	0.712	.179	72.8
	1.49	.319	53.8	1.44	.234	67.8	1.42	.338	57.5
	2.24	.422	40.0	2.16	.332	57.3	2.14	.438	49.5
	2.98	.461	35.3	2.88	.409	51.5	2.85	.472	45.9
	3.73	.480	30.8	3.61	.445	48.8	3.56	.488	42.3
Miami	-	-	-	4.33	.462	46.3	-	-	-
	0.746	.179	74.1	-	-	-	0.712	.193	72.3
	1.49	.339	42.3	1.44	.243	69.6	1.42	.365	43.2
	2.24	.456	17.7	2.16	.346	46.8	2.14	.478	22.7
	2.98	.500	10.5	2.88	.435	27.7	2.85	.516	16.4
Cleveland	3.73	.521	8.6	3.61	.479	20.5	3.56	.534	15.5
	-	-	-	4.33	.502	18.2	-	-	-
	1.49	.262	60.0	-	-	-	1.42	.268	63.6
	2.24	.368	42.9	2.16	.274	61.4	2.14	.367	50.0
	2.98	.424	32.1	2.88	.349	50.0	2.85	.418	40.7
Seattle	3.73	.453	27.1	3.61	.399	42.1	3.56	.445	36.4
	4.47	.478	22.9	4.33	.425	37.9	4.27	.460	34.3
	1.49	.244	80.0	-	-	-	1.42	.248	80.0
	2.24	.335	68.3	2.16	.252	80.0	2.14	.331	71.7
	2.98	.384	61.7	2.88	.316	73.3	2.85	.374	66.7
Seattle	3.73	.414	56.7	3.61	.354	70.0	3.56	.398	65.0
	4.47	.436	53.3	4.33	.377	68.3	4.27	.414	63.3

* PCF = Plant Capacity Factor (defined on page 24).

Table 7

PERFORMANCE OF PHOTOVOLTAIC POWER PLANT WITH NO STORAGE

Location: Sterling, Virginia
 Rated Plant Capacity: 100 MW

Cell Type →
 Array Efficiency →
 (70°C)

Flat Plate			N-S Parabolic Trough			Central Receiver		
Si 0.12(.9) = 0.108			Si 0.12(.9) = 0.108			AlGaAs/GaAs 0.22(.9) = 0.198		
Collector Area 10^6 m^2	PCF	Backup Capacity, MW	Collector Area 10^6 m^2	PCF	Backup Capacity, MW	Collector Area 10^6 m^2	PCF	Backup Capacity, MW
0.746	.169	72.3	-	-	-	0.712	.179	72.8
1.49	.272	60.0	.144	.229	67.9	1.42	.294	63.0
2.24	.308	57.0	2.16	.279	63.8	2.14	.327	61.3
2.98	.329	55.0	2.88	.303	62.5	2.85	.343	60.8
3.73	.343	53.8	3.61	.319	62.0	3.56	.352	60.6
-	-	-	4.33	.329	61.5	-	-	-

Figure 8
PHOTOVOLTAIC POWER PLANT PERFORMANCE:
FLAT PLATE COLLECTORS

Figure 9
 PHOTOVOLTAIC POWER PLANT PERFORMANCE:
 NORTH-SOUTH PARABOLIC TROUGH COLLECTORS

Figure 10
 PHOTOVOLTAIC POWER PLANT PERFORMANCE:
 CENTRAL RECEIVER CONFIGURATION

3.2 ECONOMIC EVALUATIONS

3.2.1 System Cost Assumptions

The first step in the economic evaluation of photovoltaic central station power plants is to make as accurate an estimate as possible of the total capital investment required to construct the plant and put it into operation. In addition to the basic plant costs, this quantity must include allowances for spares and contingencies, for indirect costs (construction facilities, engineering and construction management, taxes and insurance during construction, etc.), and for interest during construction. The estimates and assumptions used in this study as the basis of the economic evaluations of photovoltaic central station power plants are presented in this section. The investment costs were segregated into a number of different investment accounts representing different subsystems or investment categories. These accounts are, in general, the same as the two-digit accounts used for similar purposes by the Federal Power Commission, but special accounts have been added to represent those elements that are peculiar to solar plants.

In general, the cost figures are expressed in 1975 dollars but represent expected costs in the 1990-2000 period. For the conventional portions of the plant, the figures are based on current costs and it is assumed that any escalation in price will take place at the rate of general inflation (in other words, that these figures will remain unchanged when expressed in terms of constant dollars).

3.2.1.1 Collector/Concentrator Structures

In order to make even roughly valid economic comparisons between photovoltaic power plants using different types of collector/concentrator assembly, it is essential that the capital cost of these assemblies be estimated on a common technical and economic basis. An attempt has therefore been made to develop such a mutually consistent set of cost estimates for several types of collectors.

The starting points were engineering designs and cost estimates, made by Honeywell, Inc., in collaboration with Black and Veatch (Refs. 7 and 8), for three types of concentrator systems to be used in solar thermal power plants: parabolic dish, parabolic trough, and the central receiver configuration. (The element of a central receiver system that would be considered under this collector/concentrator investment account is the two-axis tracking reflector structure, or "heliostat".) Adjustments were made in the system designs to adapt them to the photovoltaic case (e.g., to remove the thermal transfer elements in the parabolic trough case, since it is expected the arrays in this case will be passively cooled) and to bring the designs into conformity with a common structural loading standard. The critical loading for the purpose of sizing structural members and foundations was assumed to be that associated with a 108-mph wind (30 lb/ft^2 stagnation pressure), and a safety factor of approximately 3 was applied. A design was also prepared on the basis of the same engineering standards and assumptions for a fixed-tilt, non-concentrating support structure for use with flat-plate arrays.

Collector/concentrator units for a solar photovoltaic power plant would be made and installed in large quantities. For example, a collector field for a 100 MW plant would require more than $1 \times 10^6 \text{ m}^2$ (approximately $11 \times 10^6 \text{ ft}^2$) of aperture area. More than 20,000 parabolic collectors, 420 ft^2 each, would be required, or 110,000 flat plate units (76 ft^2). If photovoltaic plants are to be deployed in significant numbers, production quantities at least an order of magnitude greater than these would be required. Such large quantities would justify considerable investment in planning efforts and production facilities to utilize mass production techniques to reduce costs in all phases of fabrication, installation, and on-site checkout. Costs for producing and installing structures analogous to collector/concentrators in these quantities are not readily available. Thus, materials costs were estimated from estimated weights and wholesale costs per pound for materials (Ref. 9), and fabrication and installation costs were estimated as a fraction of the cost of materials.

The relationship between fabrication/installation and material costs was based on data on field construction costs in small quantities. Materials costs per pound were estimated for a number of such cases, and the residual costs, for fabrication and installation, were adjusted using an 85 percent "learning," or "cost-quantity" curve to obtain fabrication and installation costs as a percentage of material costs for large production quantities. The resulting fabrication/installation percentage of material cost for large quantity production varied from roughly 50 to 75 percent for simple structures to 150 to 200 percent for complex structures. For this study, accordingly, fabrication/installation costs per pound were estimated to be 100 percent of material costs for steel structures.

Costs for aluminum fabrication/installation were assumed to be the same as those for steel parts which would perform the same function. These costs, as a percentage of material costs, would be less than for steel because the increase in material cost per pound more than offsets the reduction in weight. For the purpose of calculating fabrication/installation costs as a percentage of material costs for the aluminum reflector structures, it was assumed that deflection limits under bending loads would determine the selection of structural sections. Beam deflections under bending loads are proportional to I/EI , where E is Young's modulus and I is the moment of inertia. For the same deflection, EI must be the same for aluminum and steel members. Since E for aluminum is one-third of E for steel, the I for the aluminum beam must be three times the I for steel. The weight of standard I-beam sections varies as $(I)^{0.367}$. The ratio of weights of the aluminum and steel beams is $(3)^{0.367}$ times the ratio of densities, $(0.0975/0.284)$, or 0.51. Thus, where fabrication/installation costs are \$0.15 per pound of steel parts the same costs for equivalent aluminum parts would be \$0.15 per 0.51 pound or \$0.29 per pound.

Higher fabrication/installation costs (\$0.45/lb) were used for the parabolic dish aluminum dish structure to allow for costs of maintaining the closer tolerances required with the 200:1 concentration ratio.

Estimates for the mechanical drive systems for the tracking configurations were based on the Honeywell, Black & Veatch estimates, adjusted for 1974 to 1975 inflation.

The resulting figures, expressed in 1975 dollars, that were developed in this study for the capital cost of collector/concentrator structures, installed, are displayed in Table 8. Two different parabolic trough structures are included, polar and horizontal. The polar trough is one that employs single-axis tracking about an axis that is oriented in the north-south direction and tilted at an angle, above the horizontal, equal to the local latitude. The particular heliostat design represented in this table is the so-called tilt-tilt design. The basis elements are an outer gimbal frame that rotates about one axis and a number of individual flat mirrors which rotate about axes that lie in the plane of the outer gimbal frame but are perpendicular to the first axis.

Table 8
COLLECTOR/CONCENTRATOR COST FIGURES
(in 1975 dollars/m²)

	Flat Plate	Parabolic Trough		Parabolic Dish	Heliostat
		Horizontal	Polar		
Reflector, cell mounting structure	8.90	30.20	30.20	39.40	14.0
Frame and Foundation	6.30	5.30	16.70	26.80	11.60
Mechanical Drive	-	28.20	28.20	59.70	34.20
Cooling Provisions	-	0.20*	0.20*	2.40**	-
Total	15.20	63.90	75.30	128.30	59.80

*Passive cooling fins

**Water cooling fixtures, not including any external water supply, cooling tower, or other elements not mounted on the collector structure.

3.2.1.2 Photovoltaic Arrays

This account includes the assembled photovoltaic array modules, encapsulated and supported on suitable substrates. In the economic evaluation of photovoltaic power plants using flat-plate collectors or concentrators of low-to-moderate concentration ratio ($X \lesssim 30$), it has been assumed that these modules are fabricated from silicon solar cells and that the cost, in 1975 dollars, is $\$100/\text{kW}_{\text{pk}}$. The cost per unit area is thus $\$100 \eta_a / \text{m}^2$, where η_a is the nominal array efficiency at a temperature of 20°C .

In the case of plants using high-concentration collectors ($X \gtrsim 200$), it has been assumed that the arrays consist of AlGaAs/GaAs cells, and that the array price is $\$10,000/\text{m}^2$. This figure is intended to include the receiver structure, which is envisioned as consisting primarily of a cylindrical surface to which the solar cells are attached. The cost of plumbing, fittings, and additional structure needed in order to provide water cooling for the cells is not included here but is accounted for in a separate investment account, "Allowance for Cooling" (Section 3.2.1.11).

3.2.1.3 DC Wiring

The cost of the heavy DC wiring heading from array modules to the storage and power conditioning systems depends, of course, on the total collector area and is significant enough to be considered in a separate investment account. The values used in this study are based on the assumption that the average DC voltage is about 1000 V and that wire size is selected on the basis of a cost trade-off between increasing wire size to reduce ohmic losses and increasing collector and array area to compensate for the losses.

3.2.1.4 Tower

This account includes the total cost of fabricating and erecting the tower structure that supports the receiver in the central receiver configuration. The cost figures utilized were abstracted from those developed for the same type of structure for use in solar thermal power plants. In the companion Aerospace Corporation Solar Thermal Mission Analysis program

(Refs. 3, 4), costing data developed by the McDonnell Douglas Aircraft Corporation for steel towers (Ref. 10) were used as a basis for constructing the appropriate scaling relationships:

$$\begin{aligned} \text{Tower Cost (1975\$)} &= 1.87(10^3 h) & h < 90 \text{ m} \\ &= 20.5 h^2 & h > 90 \text{ m} \end{aligned}$$

where h is tower height in meters. The relationship between tower height and the total collector area, A_c , that was used was

$$h = 0.368 (A_c)^{1/2} \text{ meters } (A_c \text{ in } m^2).$$

This result was also obtained in the companion Solar Thermal Mission Analysis project, on the basis of an optimized collector field model constructed by the University of Houston.

3.2.1.5 Land

This account includes, in addition to the cost of the raw land, the cost of clearing, grading, and relocating utilities and buildings. The assumed total price of \$500/acre (1975 dollars) is considered reasonable for rural land (especially desert land) that is not suitable for agriculture. It was assumed, in the cases of flat plate and parabolic trough collectors (5 m by 2 m collectors, spaced 6 m apart, center to center, in the width direction and 7 m apart in the length direction), that the area of the collector field will be ~4.2 times the total collector aperture area, and that the collector field will occupy 95% of the total site area. In the central receiver case, the assumptions used were the same as those used in The Aerospace Corporation analyses of solar thermal power plants, namely that the collector field is 40% dense and occupies 75% of the total site area.

3.2.1.6 Structures and Facilities

This account includes all structures and facilities required for the conventional portion of the solar plant (administration building, control room, auxiliary structures) and for housing the power conditioning and electric

storage subsystems. The cost in 1975 dollars was estimated at \$10.85/kW on the basis of figures in the Westinghouse Data Book (Ref. 11).

3.2.1.7 Power Conditioning Equipment

This account includes all the equipment needed to convert the DC output of the photovoltaic array into 60 Hz AC power, acceptably free from harmonics. Inverters, filters, control circuitry, and output transformers are included and the cost in 1975 dollars has been taken to be \$70/kW for the large-scale equipment that would be used in central station power plants.

3.2.1.8 Electric Storage

This account includes batteries, interconnections, and control circuitry. The value used in this study, \$40/kWh, is based on the usable storage capacity (at ~80% maximum depth of discharge) and represents the total present value cost of storage for 30 years of service, including replacement batteries at the end of 15 years. This value corresponds to a battery purchase price, also based on the usable capacity, of ~\$24/kWh, or ~\$19 per kWh at 100% discharge. These values are believed to be reasonable for the advanced high-temperature battery systems that are expected to be available in the post-1985 period.

3.2.1.9 Electric Plant Equipment

This account includes the switch-gear, switchboards, wiring containers, control wiring, etc., that are associated with the conventional portion of the plant. The costs were estimated at \$16.30/kW in 1975 dollars on the basis of numbers in Ref. 11.

3.2.1.10 Miscellaneous Plant Equipment

This account includes transportation, communications, and lifting equipment; air and water systems; furnishings and fixtures. The cost in 1975 dollars, estimated on the basis of figures in Ref. 11, was taken to be \$5.97/kW.

3.2.1.11 Allowance for Cooling

This account represents the costs associated with forced cooling. Since it was assumed in this study that arrays used with flat-plate or low concentration ($X \lesssim 30$) collectors would be passively cooled, this account is used only in the case of plants using high-concentration collectors, especially those in the central receiver configuration. It has been assumed, on the basis of very approximate estimates of plumbing requirements, cooling tower costs, etc., that these costs will amount to roughly \$10/kW, when expressed in terms of rated plant capacity.

3.2.1.12 Spares and Contingencies

This account is made up of allocations for equipment spare parts and for construction cost contingencies, e.g., design changes, construction scheduling delays, licensing delays, additional equipment and labor requirements. The spare parts allocation was taken to be equal to 1% of the cost of the basic plant (the sum of items 3.2.1.1 through 3.2.1.11 above), while the contingency allowance was set at 7%, so that the combined figure used was 8% of the basic plant cost.

3.2.1.13 Indirect Costs

This account represents the costs of construction facilities, construction equipment, construction services, architectural and engineering services, engineering and construction management, training and startup. For the non-solar portions of the plant, these costs were estimated by means of scaling relationships developed in the Aerospace Solar Thermal Mission Analysis effort on the basis of AEC figures for large conventional plants. This scaling relationship suggests that for 100 MW plants, the indirect costs would amount to ~52% of the basic plant cost. Solar plants differ from conventional ones, however, in that the solar elements (items 3.2.1.1 through 3.2.1.4) are much more modular, so that construction of these portions of the plant is more a repetitive assembly process than a construction process. For these reasons, the indirect costs were estimated at

10% of the cost of the solar elements (items 3.2.1.1 through 3.2.1.4) plus 52% of the cost of the conventional elements (items 3.2.1.5 through 3.2.1.11).

3.2.1.14 Interest During Construction

In computing these costs, it was assumed that plant construction is financed by borrowed capital, at an interest rate of 8%. Plant construction was assumed to take 4 years, with cash flows allocated as follows, in terms of the total capital cost of the plant (the sum of items 3.2.1.1 through 3.2.1.13): 5% expended during the first year, 15% in the second, 65% in the third, and 15% in the fourth. The total amount is equivalent to 12.8% of the capital cost figure, since

$$[0.05(3.5) + 0.15(2.5) + 0.65(1.5) + 0.15(0.5)] (0.08) = 0.128.$$

3.2.2 Economic Results

On the basis of the system cost assumptions detailed in the preceding section, the total plant investment cost, as of the first year of commercial operation, was determined for each of the photovoltaic power plants for which simulation computations had been made. Breakdowns of these costs for three examples (one for each type of collector/concentrator) are presented in Table 9. These figures are expressed in 1975 dollars but are intended to represent plant costs in the 1990-2000 period.

The total capital investment needed in each case was then obtained by adding the cost of the required conventional backup capacity (in the form of gas turbine generating plants at \$140/kW) to the photovoltaic plant investment cost. The final step in the economic evaluation was a determination of levelized busbar energy cost ($\overline{BBEC}$) figures on the basis of these total capital costs. The levelized fixed charge methodology discussed in Section 2.4.1 was used, with the fixed charge rate set at 15% (corresponding to an after-tax discount rate of about 8%) and the levelized operation and maintenance cost assumed to be 3 mills/kWh.

Table 9
INVESTMENT COST BREAKDOWN FOR PHOTOVOLTAIC
CENTRAL STATION POWER PLANTS
(1975 Dollars per Rated Kilowatt)

	Collector Type		
	Flat Plate	NS Parabolic Trough	Central Receiver
Collector Aperture (10^6 m^2)	2.24	2.16	2.14
Cell Type	Si	Si	AlGaAs/GaAs
Capital Costs			
Collector Structure	341	1382	1284
Arrays	302	15	357
DC Wiring	27	35	53
Tower	-	-	59
Land	12	12	9
Structures/Facilities	11	11	11
Power Conditioning	70	70	70
Electric Storage	200	200	200
Electric Plant Equip.	16	16	16
Misc. Plant Equip.	6	6	6
Allowance for Cooling	-	-	10
Total Basic Plant	985	1747	2075
Spares/Contingencies	79	140	166
Indirect Costs	231	307	343
Interest During Constr.	165	281	331
Plant Investment Cost	1460	2475	2915

The results of these calculations are presented in some detail in Tables 10-13. The first three of these tables contain $\overline{\text{BBEC}}$ values for photovoltaic plants having 5 kWh/kW of electric storage capacity, while the plants represented in Table 13 have no electric storage. Some of these same results are also presented in graphical form in Figure 11 (plants with flat-plate collectors at five different locations) and Figure 12 (plants with three different collector/concentrator configurations at Inyokern, California). In these two figures, the $\overline{\text{BBEC}}$ values for a coal-fired intermediate load ($\text{PCF} = 0.4$) generating plant are represented by three horizontal lines, one for each of the three fuel-price scenarios discussed in Section 2.4.3. The minima in the curves representing the dependence of $\overline{\text{BBEC}}$ on collector/concentrator aperture area are a result of the fact that all points on each curve represent plants with the same "name-plate" rating, i. e., the capacity of the power conditioning system is the same (100 MW output) for each plant. When the collector area is small, the power conditioning system is seldom driven to its limiting capacity and the overall plant capacity factor is small and the busbar energy cost is correspondingly high. As the collector aperture is increased, the limiting power conditioning capacity is reached more frequently. The excess array output energy in these instances is dispatched to storage for use when array output falls. The effect is to extend the period of the plant operation at high output levels and thus to increase the plant capacity factor and decrease the busbar energy cost. If the storage system is fully charged, however, any excess energy (above the power conditioning handling capability) must be wasted. As collector aperture becomes large, the amount of wasted energy increases rapidly and the overall busbar cost of energy also rises.

The figures presented in Table 13 indicate that the busbar cost of energy produced by photovoltaic plants without electric storage is lower than that of energy produced by plants with storage. Although the plants with storage have considerably greater plant capacity factors and require less conventional backup (or, in other words, provide greater capacity displacement),

Table 10

LEVELIZED BUSBAR ENERGY COSTS FOR 100 MW PHOTOVOLTAIC
POWER PLANTS WITH FLAT PLATE COLLECTORS
(Electric Storage Capacity = 5 kWh/kW)

Location	Array Area, 10^2 m^2	PCF*	Backup Capacity, MW	Plant Investment Cost, \$/kW	Backup Capacity Cost, \$/kW	Total Capital Cost, \$/kW	BBEC Mills/ kWh
Inyokern	0.75	.215	80.6	846	113	959	79
	1.49	.400	51.3	1151	72	1223	55
	2.24	.513	11.9	1460	17	1477	52
	2.98	.532	8.4	1771	12	1783	60
	3.73	.544	6.9	2086	10	2096	69
Sterling	0.75	.169	72.3	846	101	947	99
	1.49	.319	53.8	1151	75	1226	69
	2.24	.422	40.0	1460	56	1516	65
	2.98	.461	35.3	1771	49	1820	71
	3.73	.480	30.8	2086	43	2129	79
Miami	0.75	.179	74.1	846	104	950	94
	1.49	.339	42.3	1151	59	1210	64
	2.24	.456	17.7	1460	25	1485	59
	2.98	.500	10.5	1771	15	1786	64
	3.73	.521	8.6	2086	12	2098	72
Cleveland	1.49	.262	60.0	1151	84	1235	84
	2.24	.368	42.9	1460	60	1520	74
	2.98	.424	32.1	1771	45	1816	76
	3.73	.453	27.1	2086	38	2124	83
	4.47	.473	22.9	2402	32	2434	90
Seattle	1.49	.244	80.0	1151	112	1263	92
	2.24	.335	68.3	1460	96	1556	83
	2.98	.384	61.7	1771	86	1857	86
	3.73	.414	56.7	2086	79	2165	93
	4.47	.436	53.3	2402	75	2477	100

*Plant Capacity Factor

Table 11

LEVELIZED BUSBAR ENERGY COSTS FOR 100 MW PHOTOVOLTAIC
POWER PLANTS WITH NORTH-SOUTH PARABOLIC
TROUGH CONCENTRATORS
(Electric Storage Capacity = 5 kWh/kW)

Location	Array Area, 10^6 m^2	PCF*	Backup Capacity, MW	Plant Investment Cost, \$/kW	Backup Capacity Cost, \$/kW	Total Capital Cost, \$/kW	BEEC Mills/ kWh
Inyokern	0.72	.157	85.6	1184	120	1304	145
	1.44	.311	75.0	1826	105	1931	109
	2.16	.437	40.9	2475	57	2532	102
	2.88	.532	15.6	3127	22	3149	104
	3.61	.555	12.8	3792	18	3810	121
Sterling	1.44	.234	67.8	1826	95	2021	151
	2.16	.332	57.3	2475	80	2555	135
	2.88	.409	51.5	3127	72	3199	137
	3.61	.445	48.8	3792	68	3860	152
	4.33	.462	46.3	4451	65	4516	170
Miami	1.44	.243	69.6	1826	97	1923	139
	2.16	.346	46.8	2475	66	2541	129
	2.88	.435	27.7	3127	39	3166	128
	3.61	.479	20.5	3792	29	3821	140
	4.33	.502	18.2	4451	25	4476	156
Cleveland	2.16	.274	61.4	2475	86	2561	163
	2.88	.349	50.0	3127	70	3197	160
	3.61	.399	42.1	3792	59	3851	168
	4.33	.425	37.9	4451	53	4504	184
Seattle	2.16	.252	80.0	2475	112	2587	179
	2.88	.316	73.3	3127	103	3230	178
	3.61	.354	70.0	3792	98	3890	191
	4.33	.377	68.3	4451	96	4547	210

* Plant Capacity Factor

Table 12

**LEVELIZED BUSBAR ENERGY COSTS FOR 100 MW PHOTOVOLTAIC
POWER PLANTS IN CENTRAL RECEIVER CONFIGURATION**
(Electric Storage Capacity = 5 kWh/kW)

Location	Array Area, 10^6 m^2	PCF*	Backup Capacity, MW	Plant Investment Cost, \$/kW	Backup Capacity Cost, \$/kW	Total Capital Cost, \$/kW	BBEC, Mills/ kWh
Inyokern	0.71	.248	77.5	1347	109	1456	104
	1.42	.463	41.6	2124	58	2182	84
	2.14	.566	14.1	2915	20	2935	92
	2.85	.584	12.5	3694	18	3712	112
	3.56	.590	11.3	4474	16	4490	133
Sterling	0.71	.179	72.8	1347	102	1449	142
	1.42	.338	57.5	2124	81	2205	115
	2.14	.438	49.5	2915	69	2984	120
	2.85	.472	45.9	3674	64	3758	139
	3.56	.488	42.3	4474	59	4533	162
Miami	0.71	.193	72.3	1347	101	1448	131
	1.42	.365	43.2	2124	60	2184	105
	2.14	.478	22.7	2915	32	2947	109
	2.85	.516	16.4	3694	23	3717	126
	3.56	.534	15.5	4474	22	4496	147
Cleveland	1.42	.268	63.6	2124	89	2213	144
	2.14	.367	50.0	2915	70	2985	142
	2.85	.418	40.7	3694	57	3751	157
	3.56	.445	36.4	4474	51	4525	177
	4.27	.460	34.3	5253	48	5301	200
Seattle	1.42	.248	80.0	2124	112	2236	157
	2.14	.331	71.7	2915	100	3015	159
	2.85	.374	66.7	3694	93	3787	176
	3.56	.398	65.0	4474	91	4565	199
	4.27	.414	63.3	5253	89	5342	224

* Plant Capacity Factor

Table 13

**LEVELIZED BUSBAR ENERGY COSTS FOR 100 MW PHOTOVOLTAIC
POWER PLANTS IN STERLING, VIRGINIA
(Various Collector/Concentrator Types - No Storage)**

Collector/ Concen- trator	Array Area, 10^6 m^2	PCF*	Backup Capacity, MW	Plant Investment Cost, \$/kW	Backup Capacity Cost, \$/kW	Total Capital Cost, \$/kW	<u>BEEC</u> , Mills/ kWh
Flat Plate	0.75	.169	72.3	485	101	586	62
	1.49	.272	60.0	790	84	874	58
	2.24	.308	57.0	1099	80	1179	69
	2.98	.329	55.0	1410	77	1487	80
	3.73	.343	53.8	1725	75	1800	93
N-S Parabolic Trough	1.44	.229	67.9	1466	95	1561	120
	2.16	.279	63.8	2114	89	2203	138
	2.88	.303	62.5	2766	88	2854	164
	3.61	.319	62.0	3431	87	3518	192
	4.33	.329	61.5	4090	86	4176	220
Central Receiver	0.71	.179	72.8	986	102	1088	107
	1.42	.294	63.0	1763	88	1851	111
	2.14	.327	61.3	2554	86	2640	141
	2.85	.343	60.8	3333	85	3418	174
	3.56	.352	60.6	4113	85	4198	207

* Plant Capacity Factor

ELECTRIC STORAGE CAPACITY
= 5 kWh/kW_{rated}
FIXED CHARGE RATE = 0.15
LEVELIZED O&M COST = 3 mills/kWh

ARRAY PRICE = \$100/kW_{pk}
ARRAY EFFICIENCY (20°C) = 0.135

FUEL PRICE CASES

	FL ₀ (\$/10 ⁶ Btu)	g
A	0.75	0.05
B	1.25	0.06
C	1.75	0.07

Figure 11

LEVELIZED BUSBAR ENERGY COST: PHOTOVOLTAIC PLANTS
WITH FLAT PLATE COLLECTORS

ELECTRIC STORAGE CAPACITY
= 5 kWh/kW_{rated}
FIXED CHARGE RATE = 0.15
LEVELIZED O&M COST = 3 mills/kWh
FLAT PLATE ARRAY PRICE = \$100/kW_{pk}

FUEL PRICE CASES

	FL_0 (\$/10 ⁶ Btu) g	
A	0.75	0.05
B	1.25	0.06
C	1.75	0.07

Figure 12

LEVELIZED BUSBAR ENERGY COST: PHOTOVOLTAIC POWER PLANTS AT
INYOKERN, VARIOUS COLLECTOR CONFIGURATIONS

these advantages are outweighed by the effect of the capital cost of the storage system. This result is in disagreement with one of the general conclusions reached in the earlier Photovoltaic Mission Analysis study (Ref. 1). The difference is a direct result of differences in the assumed cost of battery storage in the post-1985 period. The number used in the earlier study was \$20/kWh (present value of the cost of storage, including battery replacements if needed, for the 30-year life of the photovoltaic plant), while that used in the present study is \$40/kWh. The higher figure is based on more recent information and projections and is believed to be considerably more realistic.

3.2.3 Allowable Area-Related Costs: Photovoltaic Plants with Storage

The results of the performance and reliability analyses discussed in Section 3.1 and the economic analyses described in Sections 3.2.1 and 3.2.2 have been used as starting points in the formulation of a more generalized and readily applicable procedure for the approximate economic evaluation of photovoltaic central station power plants. This procedure leads to a set of graphs, in which the maximum allowable area-related cost of a photovoltaic plant (in $\$/m^2$) is plotted against array efficiency and average collected insolation (which depends on plant location and overall collector efficiency). Such costs are considered to be "allowable" if they are low enough to permit the photovoltaic plant to compete economically with a conventional coal-fired intermediate load plant of the type discussed in Section 2.4.3.

This mode of presentation of photovoltaic power plant economics was invented by Mr. P. Bos of the Electric Power Research Institute.

3.2.3.1 Allowable Capital Cost of a Photovoltaic Plant with Storage

The first step in the creation of the summary graphs mentioned above is to determine the maximum total investment cost (including the capital cost of conventional backup) that would permit a photovoltaic power

plant to compete economically with an alternative conventional plant with equivalent performance, i. e., with the same plant capacity factor. The photovoltaic plants considered in this section incorporate enough electric storage capacity ($5 \text{ kWh/kW}_{\text{rated}}$) so that plant capacity factors typical of intermediate load plants are achievable in nearly any U.S. location. The comparison with the conventional alternative is based on plants with identical plant capacity factors, $\text{PCF} = 0.4$, and the plants are considered to be economically competitive when the levelized busbar energy cost figures, calculated as described in Section 2.4, are the same.

On this basis, the maximum allowable capital cost of an intermediate load photovoltaic plant (including spares, contingencies, indirect costs, interest during construction, and the capital cost of backup capacity) is given, in terms of 1975 dollars per rated kW, by the equation

$$C_t = 550 + \frac{8.76 \text{ PCF}}{\text{FCR}} G(k, g) \cdot \text{FL}_o (10^{-3}) \cdot \text{HR} \cdot \text{CRF}_{k, N} \quad (5)$$

The notation is that of Section 2.4.1 and the capital cost of the conventional alternative has been set equal to $\$550/\text{kW}_{\text{rated}}$, as discussed in Section 2.4.3. If, as mentioned above, the value of PCF is set equal to 0.4 and FCR, HR, and $\text{CRF}_{k, N}$ are assigned the standard values discussed in Section 2.4.3 (namely, $\text{FCR} = 0.15$, $\text{HR} = 9200 \text{ Btu/kWh}$, $\text{CRF}_{k, N} = 0.0888$), the equation becomes

$$C_t = 550 + 19.1 G(k, g) \cdot \text{FL}_o \quad \$/\text{kW}_{\text{rated}} \quad (6)$$

For the three different fuel price scenarios displayed in Table 5, the corresponding C_t values are: Case A, $\$836/\text{kW}_{\text{rated}}$; Case B, $\$1093/\text{kW}_{\text{rated}}$; Case C, $\$1421/\text{kW}_{\text{rated}}$. (Note: in this general analysis, it has been assumed that the O&M costs, excluding fuel, for conventional and solar plants are identical.)

3.2.3.2 Allowable Area-Related Costs

The relationship between total investment cost and the area-related fraction can be expressed in the relatively simple form

$$C_t = (C_a \cdot A + C_{bp}) \cdot F + C_{cb} \quad (7)$$

where

- C_a = area-related cost (collector/concentration structures, photovoltaic arrays, DC wiring, land, and land preparation costs), in 1975 dollars per m^2 of collector aperture.
- A = total collector aperture, in m^2 per rated kW of plant capacity.
- C_{bp} = basic cost of the balance of the plant, including storage, in 1975 dollars per rated kW of plant capacity.
- F = dimensionless multiplicative factor to adjust basic plant cost figures for the effects of the cost of spares, of contingencies, of indirect costs, and of interest during construction.
- C_{cb} = total capital cost of backup capacity expressed in 1975 dollars per rated kW of photovoltaic plant capacity.

The value of the factor A can be related to other, more directly significant, variables through the relationship

$$0.9 \eta_a (\eta_{co} I_{av}) \eta_{bp} A = kW_{av} / kW_{rated} = PCF \quad (8)$$

where the factor 0.9 represents a correction for an assumed 10% scheduled outage for regular maintenance. The other variables are defined:

- η_a = nominal array efficiency (efficiency at average operating temperature).

$\eta_{co} I_{av}$ = annual average collected insolation, in kW/m², expressed as the product of a collector efficiency, η_{co} , and the annual average insolation at the site of the plant.

η_{bp} = effective balance-of-plant efficiency, defined as the ratio of the computed average value of the power output of the plant, in kW/m², to the product of η_a and $\eta_{co} I_{av}$. This factor thus includes the effect of deviations of array efficiency from η_a as a result of temperature variations.

In these definitions the term "average power" (whether referring to electrical or radiative power) is intended to represent the annual total amount of energy transferred divided by 8760, the number of hours in a year.

The utility of this expression for A (Equation 8) arises largely from the fact that the simulation computations described in Section 3.1 yield roughly the same value of η_{bp} (≈ 0.8) when PCF ≈ 0.4 , independent (more-or-less) of location and of the type of collector/concentrator involved. In the analysis that follows, therefore, η_{bp} is set equal to 0.8.

Values for the other variables in Equation 7 can also be obtained from the more detailed analyses discussed in Sections 3.2.1 and 3.2.2:

$C_{bp} \approx \$305/\text{kW}_{\text{rated}}$. This figure includes an allocation of \$200/kW for 5 kWh/kW of storage. In the case of central receiver collectors, it should be increased somewhat to take into account the cost of the tower and the allowance for cooling, but these contributions are relatively small and it is therefore roughly correct to use this figure for a photovoltaic plant with any type of collector/concentrator.

$C_{cb} \approx \$60/\text{kW}_{\text{rated}}$. The average amount of backup capacity required, at PCF = 0.4, for the various plants discussed in Sections 3.2.1 and 3.2.2 was in the neighborhood of 40 MW or a little more. At \$140/MW, this amounts roughly to \$60 per kW of rated photovoltaic plant capacity.

$F \approx (1.28)(1.128) = 1.44$. This value is based on the assumption that spares and contingencies will add 8% to the basic plant cost, that indirect costs will amount to about 20% more (a rough weighted average of the 52% figure used for conventional components in the more detailed analysis and the 10% figure used for solar elements), and that interest during construction will add 12.8% to the total capital cost (as discussed in Section 3.2.1.14).

When all of these numerical values, along with the value for A from Equation 8, are substituted into Equation 7, the result is

$$C_t = 1.44 \left[\frac{0.4 C_a}{0.9 \eta_a (0.8) \eta_{co} I_{av}} + 305 \right] + 60 \quad (9)$$

Equation (9) can then be solved for C_a , to yield

$$C_a = \left[0.693 (C_t - 60) - 305 \right] (1.8) \eta_a (\eta_{co} I_{av}) \quad (10)$$

If the three C_t values from Section 3.2.3.1, corresponding to the three standard fuel-price scenarios, are substituted into this equation, the results are:

$$\text{Case A: } C_a = 424 \eta_a (\eta_{co} I_{av}) \quad \$/m^2 \quad (11a)$$

$$\text{Case B: } C_a = 736 \eta_a (\eta_{co} I_{av}) \quad \$/m^2 \quad (11b)$$

$$\text{Case C: } C_a = 1147 \eta_a (\eta_{co} I_{av}) \quad \$/m^2 \quad (11c)$$

Figures 13-15 graphically display the relationship expressed in these equations. The format for these figures is the "carpet-plot" format in which the abscissa does not represent a specific variable but serves as a linear horizontal scale for interpolating between lines of constant η_a (nominal array efficiency) or between lines of constant $\eta_{co} I_{av}$ (average collected insolation). Superimposed on the basic chart in each case are four additional lines of constant $\eta_{co} I_{av}$. These correspond to the $\eta_{co} I_{av}$ values, derived from the simulation computations discussed in Section 3.1, for flat plate collectors and for N-S parabolic trough and central receiver concentrators (the $\eta_{co} I_{av}$ figure for these two cases being virtually identical) at Inyokern, California, and Sterling, Virginia. In order to use the charts for other locations or for

other types of collectors one must be able to estimate the corresponding value of $\eta_{co} I_{av}$. Since the effective value of η_{co} for a given type of collector does not, in general, depend strongly on location, it is often possible to approximate $\eta_{co} I_{av}$ by simply multiplying an effective η_{co} value generated for one site by the value of I_{av} for another site. In general, although a number of approximations were used in their formulation (as detailed in this section), these charts provide reasonably accurate representations of the economics of a photovoltaic power plant (incorporating 5 kWh/kW of storage) with arbitrary collector configuration and at an arbitrary site.

As an example of the utility of these charts, consider the case of a plant with flat-plate collector located at Inyokern. If the prevailing fuel price and escalation rate correspond to Case B, then one can use Figure 14. The dependence of allowable area-related cost on array efficiency is then represented by the heavy unbroken line corresponding to the $\eta_{co} I_{av}$ value for a flat plate collector at Inyokern. If $\eta_a = 0.14$, the allowable area-related cost is just over $\$28/m^2$. If the subsystem cost figures given in Section 3.2.1 are accepted, support structure costs in this case will amount to about $\$15/m^2$ and land and wiring costs will be about $\$1.70/m^2$ more; the maximum amount that can be spent for arrays would then be $\sim \$11 - \$12/m^2$ (or just under $\$100/kW_{pk}$). If the array efficiency is increased to 0.20, the allowable area-related cost rises to $\sim \$41/m^2$ so that $\sim \$24-25/m^2$ can be spent on arrays (or $\sim \$120-125/kW_{pk}$). For a central receiver plant at the same location, the dependence of allowable area-related cost on array efficiency is represented by the heavy dashed line corresponding to the $\eta_{co} I_{av}$ value for trough or central receiver collectors at Inyokern. In this case, even at $\eta_a = 0.22$, the allowable area-related cost is $\sim \$37/m^2$. Since the cost of the heliostats alone in a central receiver system is projected to be no less than $\$60/m^2$, the chart indicates that such a system will not be competitive.

In order to use Figures 13-15 for other locations or for other types of collector/concentrator, as mentioned briefly above, one must either be able to estimate the product $\eta_{co} I_{av}$ or have separate values for the effective

collector efficiency, η_{co} , and for the array insolation at the site, I_{av} . The simulation computations carried out in this study indicate that for systems with flat plate collectors, one may use an I_{av} value obtained by dividing the total annual hemispheric insolation (as measured by a standard pyronometer) by 8760, the number of hours in a year. The appropriate value for η_{co} at any site in the U.S. would be roughly 1.10 for a flat plate collector tilted about an east-west axis at an angle equal to the local latitude. The η_{co} values deduced from the simulation runs for the five widely separated sites considered in this study did not differ from this figure (1.10) by more than 5%. (This "effective" efficiency is greater than 1 because a tilted flat plate collector collects more radiation than a horizontal one, while a pyronometer measures essentially the radiation on a horizontal surface.)

In the cases of systems with concentrators of reasonably high concentration ratio ($X \geq 10$), the appropriate value for I_{av} is the annual average value of the direct normal insolation, as measured by a pyrhelimeter, in kW/m^2 . For either type of concentrator considered in this study (N-S parabolic troughs or central receiver assemblies) the effective collector efficiency, η_{co} , is about 0.62 (and, again, deviations from this figure for the five sites considered in this study were 5% or less). For other types of collectors, of course, appropriate values of η_{co} must be determined independently. For low concentration ratios ($X = 3 - 10$), it may not be possible to use separate values for η_{co} and I_{av} , since direct and diffuse insolation would be collected in proportions that would depend on the details of collector design and on the exact value of the concentration ratio. In these cases, one would probably need to make a separate determination of the product, $\eta_{co} I_{av}$, for each location.

3.2.3.3 Allowable Array Price as a Function of Efficiency: Flat Plate Collectors

The generalized analysis used in the construction of Figures 13-15 can also be used to elucidate the relationship between array efficiency and

Figure 13

ALLOWABLE AREA-RELATED COST FOR PHOTOVOLTAIC POWER PLANT
WITH STORAGE: FUEL PRICE CASE A

ELECTRIC STORAGE CAPACITY
= 5 kWh/kW_{rated}

ALTERNATIVE: COAL-FIRED INTERMEDIATE-LOAD PLANT
FIXED CHARGE RATE = 0.15
AFTER-TAX DISCOUNT RATE = 0.08

Figure 14

ALLOWABLE AREA-RELATED COST FOR PHOTOVOLTAIC POWER PLANT
WITH STORAGE: FUEL PRICE CASE B

ELECTRIC STORAGE CAPACITY
= 5 kWh/kW_{rated}

ALTERNATIVE: COAL-FIRED INTERMEDIATE-LOAD PLANT
FIXED CHARGE RATE = 0.15
AFTER-TAX DISCOUNT RATE = 0.08

Figure 15

ALLOWABLE AREA-RELATED COST FOR PHOTOVOLTAIC POWER PLANT
WITH STORAGE: FUEL PRICE CASE C

allowable array price for a given type of collector/concentrator at any desired location. In the particular case of flat plate collectors, if the cost figures of Section 3.2.1 are accepted for all area-related system elements except for arrays, then the relation between array price and efficiency is obtained from Equations (11a, b, c) simply by subtracting $\$16.90/\text{m}^2$ ($\$15.20/\text{m}^2$ for support structure, $\$1.70/\text{m}^2$ for land, land preparation, and wiring). If the effective $\eta_{\text{coI}_{\text{av}}}$ values for Inyokern ($0.279 \text{ kW}/\text{m}^2$) and Sterling ($0.213 \text{ kW}/\text{m}^2$) are substituted into the resulting equations, one obtains the following expressions for C_{ar} , the maximum allowable array price, in 1975 dollars per m^2 :

	Inyokern	Sterling
Case A:	$C_{\text{ar}} = 118 \eta_a - 16.9$	$C_{\text{ar}} = 90 \eta_a - 16.9$
Case B:	$C_{\text{ar}} = 205 \eta_a - 16.9$	$C_{\text{ar}} = 157 \eta_a - 16.9$
Case C:	$C_{\text{ar}} = 320 \eta_a - 16.9$	$C_{\text{ar}} = 244 \eta_a - 16.9$

In order to express these allowable array prices in the customary units of dollars per kW_{pk} , it is only necessary to divide by η_a . (It is recognized that there is a degree of ambiguity in this procedure. The η_a values in this analysis represent array efficiencies at the expected average operating temperature, while the standard kW_{pk} rating of an array is usually based on performance at 28°C . The differences should, in general, be small enough to be negligible in the context of this generalized analysis.)

These relationships between allowable array price and array efficiency are also displayed graphically in Figure 16 (array price in 1975 dollars per m^2) and Figure 17 (array price in dollars per kW_{pk}). This method of graphical display, particularly that in Figure 16, was suggested in part by somewhat similar displays in a report on a study by E. A. DeMeo (Ref. 12) of the use of CdS arrays in photovoltaic power plants. The principal message of these two charts is that there is a minimum allowable array efficiency associated with each location and fuel-price scenario. They indicate, for example, that if fuel prices and escalation rates follow the

Figure 16
 ALLOWABLE ARRAY PRICE (\$/m²) VS ARRAY EFFICIENCY: PHOTOVOLTAIC
 PLANT WITH STORAGE -- FLAT PLATE COLLECTORS

Figure 17
 ALLOWABLE ARRAY PRICE (\$/kW_{pk}) VS ARRAY EFFICIENCY: PHOTOVOLTAIC
 PLANT WITH STORAGE - FLAT PLATE COLLECTORS

Case B scenario, the arrays for a flat-plate photovoltaic power plant at Inyokern would have to have an efficiency of greater than 8% in order for the plant to be economically competitive, even if the array price were zero. If the array price in this case were \$100/kW_{pk}, then an array efficiency of about 16% would be required. If fuel prices follow the Case C scenario, these minima are considerably relaxed (to ~6% for the case where the array price is zero and ~7.5% when the array price is \$100/kW_{pk}).

3.2.3.4 Allowable Array Price as a Function of Efficiency:

Central Receiver Configuration

One theme that pervades all of these analyses is the strong sensitivity of photovoltaic plant economics to array efficiency. Although the ultimate efficiency of single structure photovoltaic cells appears to be limited to no more than about 25%, a number of multiple-structure concepts have been suggested that might have appreciably higher overall efficiencies. One suggestion, for example, is the use of spectrally selective optics to direct different portions of the solar spectrum to separate photovoltaic devices with high response in the selected wavelength regions. Such complicated structures would clearly be more expensive to produce than the more conventional cells, and it is of interest to ask how much of an increase in array price can be tolerated (particularly in high-concentration systems) in return for very high array efficiency.

The generalized analytical approach discussed in Section 3.2.3.2 has been used to provide some insight into this question, in the special case of concentrators in the central receiver configuration. For this purpose, Equations (9) and (10) were corrected slightly to take into account the small differences in balance-of-plant cost (mainly the cost of water cooling) and in backup capacity requirements, which were neglected in the earlier analysis in the interests of generality. The resulting equation for the area-related cost in the special case of central receiver concentration systems, is then

$$C_a = [0.693 (C_t - 70) - 315] (1.8) \eta_a (\eta_{co} I_{av}) \quad (12)$$

To obtain the corresponding equation for array cost alone, one must only deduct the costs associated with the other area-related elements: collectors (heliostats), land, DC wiring, and, in this case, the central tower. The total of these costs is, for a plant with PCF = 0.4, approximately \$66/m², on the basis of the assumptions discussed in Section 3.2.1. If this figure is subtracted from C_a, the remainder represents the array cost in dollars per m² of collector area and can be expressed as C_{ar}/X, where C_{ar} is array cost in dollars per m² of array and X is the geometric concentration ratio. When the C_t values for these standard fuel price scenarios are substituted into the resulting equation, it takes the forms

$$\text{Case A: } C_{ar}/X = 395 \eta_a \eta_{co} I_{av} - 66$$

$$\text{Case B: } C_{ar}/X = 705 \eta_a \eta_{co} I_{av} - 66$$

$$\text{Case C: } C_{ar}/X = 1120 \eta_a \eta_{co} I_{av} - 66$$

The relationship between C_{ar}/X and η_a for the Case C fuel price scenario is also shown in carpet-plot format in Figure 18. The heavy dashed line represents the dependence of C_{ar}/X on η_a for the particular $\eta_{co} I_{av}$ value that is appropriate for a central receiver collector at Inyokern. This figure indicates, for example, that if array efficiencies as high as 36% could be reached, the allowable value for C_{ar}/X for a plant at Inyokern would be \$25/m². If the geometric concentration ratio were 600, then one could afford to pay \$15,000/m² for the arrays themselves. Graphs representing the C_{ar}/X vs η_a relationship for fuel price cases A and B are not presented here because, even at the Inyokern value of $\eta_{co} I_{av}$ (0.227 kW/m²), C_{ar}/X is positive only for η_a values greater than 40%.

3.2.4 Allowable Area-Related Costs: Photovoltaic Plants with No Storage

A generalized analytical procedure similar to that described in Section 3.2.3 has also been formulated for evaluating photovoltaic power plants without electric storage capacity. In the absence of the smoothing effect of

NO UTILIZATION OF THERMAL ENERGY
ELECTRIC STORAGE CAPACITY = 5 kWh/kW_{rated}

Figure 18

MAXIMUM ALLOWABLE ARRAY PRICE: PHOTOVOLTAIC CENTRAL RECEIVER POWER PLANT WITH STORAGE, FUEL PRICE CASE C

storage on plant output, it is less meaningful to assign such plants a "rated" output or to express plant performance in terms of a plant capacity factor. In these cases, therefore, it was decided to use the annual average plant output (total annual production, in kWh, divided by 8760) as the measurement of plant performance. Elements of the capital cost of the plant, therefore, are expressed in terms of dollars per average kW rather than dollars per rated kW.

3.2.4.1 Allowable Capital Cost of a Photovoltaic Plant Without Storage

As was true in the case of the plants with storage, the first step in the generalized analysis procedure is to determine the maximum total investment cost (including the capital cost of conventional backup) that would permit a photovoltaic plant without storage to compete economically with an alternative conventional plant with equivalent performance (i.e., in this case, with the same average power output). It was assumed that the photovoltaic plants under consideration here were essentially the same in design as plants with storage except for (a) the absence of the storage system and (b) the incorporation of a power conditioning system with significantly higher rated capacity (to handle the peak midday output of the array). The conventional alternative was assumed to be the same as before, namely, a coal-fired intermediate load (PCF ≈ 0.4) plant costing about $\$550/\text{kW}_{\text{rated}}$. In terms of average power output, this cost would then be $\approx \$1375/\text{kW}_{\text{av}}$. (Note that in this case we are assuming a somewhat more likely mode of operation for a no-storage plant than was implicit in the no-storage cases discussed in Sections 3.1 and 3.2.2. In those computations, the no-storage plant was assumed to have the same rated output, i.e., the same power conditioning system capacity, as did the plants with storage. As a result, when array output exceeded the rating of the power conditioning system, the excess was wasted. In the present case we assume that the power conditioning system is sized to handle maximum array output, regardless of array size.)

The maximum allowable capital cost (including spares, contingencies, indirect costs, interest during construction, and the capital cost of backup capacity) of a photovoltaic power plant with storage can then be written in the form

$$C'_t = 1375 + \frac{8.76}{FCR} G(k, g) \cdot FL_o (10^{-3}) HR \cdot CRF_{k, N} \quad (13)$$

where the prime is used in C'_t to indicate that a value in \$ per average kW is meant. If the same values as before are assumed for the standard variables (i.e., $FCR = 0.15$, $HF = 9200$ Btu/kWh, $CRF_{k, N} = 0.0888$) this becomes

$$C'_t = 1375 + 47.7 G(k, g) \cdot FL_o \quad (14)$$

For the three different standard fuel-price scenarios displayed in Table 5 the corresponding C'_t values are: Case A, \$2090/kW_{av}; Case B, \$2730/kW_{av}; Case C, \$3550/kW_{av}.

3.2.4.2 Allowable Area-Related Costs

The relationship between the total investment cost of a no-storage plant and the area-related portion of that cost can be expressed, in a manner completely analogous to that used before, as

$$C'_t = (C_a \cdot A' + C'_{bp}) \cdot F + C'_{cb} \quad (15)$$

where

C_a = area-related cost in 1975 dollars per m² of collector/
concentration aperture

A' = total collector aperture, in m² per average kW of plant
output

C'_{bp} = basic cost of the balance of the plant (not area-related)
in 1975 dollars per average kW

F = dimensionless multiplicative factor to adjust basic plant cost figures for the effects of the cost of spares, contingencies, indirect costs, and interest during construction

C'_{cb} = total capital cost of backup capacity in 1975 dollars per average kW of photovoltaic plant output

The relationship of the factor A' to more directly significant variables is given by the equation, analogous to Equation (8)

$$0.9 \eta_a \eta_{bp} \eta_{co} I_{av} A' = 1 \quad (16)$$

where all of the variables except for A' have exactly the same significance as in Section 3.2.3.2. The value of η_{bp} in the present case is somewhat higher, however, since there are no storage losses. The value used in this generalized analysis was $\eta_{bp} = 0.9$ (corresponding to a power conditioning system efficiency of 0.95, with about 5% ohmic losses in plant conductors).

The values used for the other variables in Equation (15) were:

$C'_{bp} \approx \$416/\text{kW}_{av}$. The major element of this cost is the power conditioning system, at \$70 per kW. Since this system must handle the maximum power output of the array, which is roughly 4.7 times the average output (for flat-plate collectors), it contributes $\sim \$329/\text{kW}_{av}$ to C'_{bp} . If it is assumed that the remainder of the non-area-related costs are essentially the same as in the plants with storage, they contribute $\sim 35/0.4 = \$87.50/\text{kW}_{av}$.

$C'_{cb} \approx \$210/\text{kW}_{av}$. On the basis of the simulation computations, it was estimated that the amount of backup capacity for a no-storage plant of roughly the same size as an intermediate load plant with storage would be ≈ 60 MW and would cost, at \$140/kW, \$8.4 (10^6). If the average plant output is also about the same, namely ~ 40 MW, the value of C'_{cb} would be approximately \$210/kW_{av}.

$F = 1.44$. This figure is the same as that used in Section 3.2.3.2, for the same reasons.

When these numerical values, along with the value for A' from Equation (16), are substituted into Equation (15) the result is

$$C'_t = 1.44 \left[\frac{C_a}{0.9 \eta_a (0.9) \eta_{co} I_{av}} + 416 \right] + 210 \quad (17)$$

The value for C_a is then given by

$$C_a = [0.693 (C'_t - 210) - 416] (0.81) \eta_a (\eta_{co} I_{av}) \quad (18)$$

Then, if the three C'_t values from Section 3.2.4.1 (based on the three standard fuel price and escalation scenarios) are used, the value of C_a can be expressed in the form:

$$\text{Case A: } C_a = 718 \eta_a (\eta_{co} I_{av})$$

$$\text{Case B: } C_a = 1078 \eta_a (\eta_{co} I_{av})$$

$$\text{Case C: } C_a = 1538 \eta_a (\eta_{co} I_{av})$$

These relationships are displayed in Figures 19-21 in the same carpet plot format as was used in the case of plants with storage (Figures 13-15). These figures convey the same general message that was mentioned at the end of Section 3.2.2, namely, that no-storage systems have an economic advantage where storage costs are no smaller than the \$40/kWh figure that has been used in this study. For the Case B fuel price scenarios, for example, Figure 20 reveals that the allowable area-related cost for a flat-plate photovoltaic plant at Inyokern, for $\eta_a = 0.14$, is $\sim \$42/\text{m}^2$ (as compared to a figure of $\$28/\text{m}^2$ in the corresponding case for a system with storage). If the total cost of support structure, DC wiring, and land is taken to be $\sim \$17/\text{m}^2$ (as before), the array price can be $\sim \$25/\text{m}^2$, or $\sim \$180/\text{kW}_{pk}$. For a no-storage central receiver plant at Inyokern, however, even at $\eta_a = 0.22$, the allowable area-related cost is still only about $\$53/\text{m}^2$, less than the projected cost of the heliostats alone.

If fuel prices follow the high-cost Case C scenario (Figure 21), the corresponding allowable area-related costs are: (a) for the flat plate case at

Figure 19

ALLOWABLE AREA-RELATED COST FOR PHOTOVOLTAIC PLANT
 WITHOUT STORAGE: FUEL PRICE CASE A

NO ELECTRIC STORAGE

ALTERNATIVE: COAL-FIRED INTERMEDIATE-LOAD PLANT
FIXED CHARGE RATE = 0.15
AFTER TAX DISCOUNT RATE = 0.08

Figure 20

ALLOWABLE AREA-RELATED COST FOR PHOTOVOLTAIC PLANT
WITHOUT STORAGE: FUEL PRICE CASE B

Figure 21

ALLOWABLE AREA-RELATED COST FOR PHOTOVOLTAIC PLANT
 WITHOUT STORAGE: FUEL PRICE CASE C

$\eta_a = 0.14$, $\$60/\text{m}^2$ corresponding to an array price of $\$43/\text{m}^2$ or $\$307/\text{kW}_{\text{pk}}$ and (b) for the central receiver case at $\eta_a = 0.22$, $\$77/\text{m}^2$. In this latter case, the total estimated cost of heliostats, land, tower and DC wiring is $\sim \$66/\text{m}^2$, leaving $\$11$ per m^2 of concentration aperture available to pay for the arrays. If $X = 600$, this amounts to $\$6600$ per m^2 of array.

3.2.4.3 Allowable Array Price as a Function of Efficiency: Flat Plate Collectors

The relationship between allowable array price and nominal array efficiency can be illustrated in the no-storage case in a manner exactly parallel to that used in the case of plants with storage, as discussed in Sections 3.2.3.3 and 3.2.3.4. To accomplish this, it is only necessary to subtract from C_a the estimated values (in $\$/\text{m}^2$) of all the area-related costs other than the array itself. In the flat plate case, these costs amount to $\$16.90/\text{m}^2$, so that, in the notation of Section 3.2.3.3

Inyokern	Sterling
Case A: $C_{\text{ar}} = 200 \eta_a - 16.9$	$C_{\text{ar}} = 153 \eta_a - 16.9$
Case B: $C_{\text{ar}} = 301 \eta_a - 16.9$	$C_{\text{ar}} = 229 \eta_a - 16.9$
Case C: $C_{\text{ar}} = 429 \eta_a - 16.9$	$C_{\text{ar}} = 327 \eta_a - 16.9$

where C_{ar} is given in 1975 dollars per m^2 . As before, in order to convert to array price in $\$/\text{kW}_{\text{pk}}$, one only needs to divide by η_a .

These relationships are displayed graphically in Figures 22 and 23, which show, for example, that if fuel prices follow the Case B scenario, the minimum allowable array efficiency for a flat plate photovoltaic plant at Inyokern is $\sim 5.6\%$, even if the array price is zero. For arrays costing $\$100/\text{kW}_{\text{pk}}$, the array efficiency must be greater than 8% . These minimum efficiency values are somewhat lower than those obtained in the case of plants with storage, again reflecting the negative overall economic effect of storage when the effective storage cost is $\$40/\text{kWh}$ or more.

Figure 22
ALLOWABLE ARRAY PRICE (\$/m²) VS ARRAY EFFICIENCY:
PHOTOVOLTAIC PLANT WITHOUT STORAGE--
FLAT PLATE COLLECTORS

Figure 23
 ALLOWABLE ARRAY PRICE ($\$/kW_{pk}$) VS ARRAY EFFICIENCY:
 PHOTOVOLTAIC PLANT WITHOUT STORAGE--
 FLAT PLATE COLLECTORS

3.2.4.4 Allowable Array Price as a Function of Efficiency: Central Receiver Configuration

As was true in the case of plants with storage, it is instructive in the no-storage case to determine how large an array price can be tolerated in return for very high array efficiency. The approach used was essentially identical to that taken in Section 3.2.3.4 except that total system costs were expressed in dollars per average kW rather than in dollars per rated kW. As in that earlier calculation, the generalized expressions (Equations 17 and 18) for allowable area-related costs were adjusted slightly to take into account the small difference in balance-of-plant costs between the generalized figure used earlier and the value that is specific to central receiver systems. (No adjustment was made in this case, however, of the assumed value for backup capacity.) The adjusted version of Equation (18) is then

$$C_a = [0.693 (C'_t - 210) - 440] (0.81) \eta_a (\eta_{co} I_{av}) \quad (19)$$

Then, subtracting the costs of the other area-related elements (land, heliostats, DC wiring, towers) — a total of \$66/m², as in Section 3.2.3.4 — and inserting the values of C'_t for the three standard fuel price scenarios, one obtains expressions for the ratio, C_{ar}/X , of the allowable array price (in dollars per m² of array) to the geometric concentration ratio:

$$\text{Case A: } C_{ar}/X = 699 \eta_a \eta_{co} I_{av} - 66$$

$$\text{Case B: } C_{ar}/X = 1058 \eta_a \eta_{co} I_{av} - 66$$

$$\text{Case C: } C_{ar}/X = 1518 \eta_a \eta_{co} I_{av} - 66$$

The relationships for the Case B and C fuel price scenarios are displayed graphically, in the usual carpet plot format, in Figures 24 and 25. The dashed lines on the plot represent the relationships between C_a/X and η_a for the particular $\eta_{co} I_{av}$ values that are appropriate for central receiver concentrator systems at Inyokern and Sterling. For such a system at

Figure 24

MAXIMUM ALLOWABLE ARRAY PRICE: PHOTOVOLTAIC CENTRAL
 RECEIVER PLANT WITHOUT STORAGE, FUEL PRICE CASE B

Figure 25

MAXIMUM ALLOWABLE ARRAY PRICE: PHOTOVOLTAIC CENTRAL
 RECEIVER PLANT WITHOUT STORAGE, FUEL PRICE CASE C

Inyokern, for example, in the Case C fuel scenario (Figure 25) the value of C_a/X for $\eta_a = 0.36$ is about $\$58/\text{m}^2$, so that if $X = 600$, the allowable array price is $\$34,800/\text{m}^2$. When these values are compared to the corresponding ones for a system with storage ($C_a/X = \$25/\text{m}^2$) as discussed in Section 3.2.3.4, the economic disadvantage of the use of storage is again apparent.

3.3 CENTRAL RECEIVER PHOTOVOLTAIC POWER PLANTS INCORPORATING PRODUCTIVE USE OF THERMAL ENERGY

3.3.1 Introduction

The results of the analyses discussed in the preceding sections strongly suggest that photovoltaic power plants employing concentrating collectors are unlikely to be competitive with coal-fired plants unless some profitable use can be made of the large amounts of thermal energy that are also collected. It was therefore decided, as part of the photovoltaic mission analysis effort, to make a preliminary investigation of the design characteristics and economics of photovoltaic plants in which the thermal energy is either sold as heat or used to generate additional electricity in a low-temperature "bottoming-cycle" turbine.

Since the value of thermal energy for either of the above uses increases with temperature, the most promising photovoltaic systems for this sort of combined operation are those using high-concentration collectors. The investigation therefore centered on systems using collectors in the central receiver configuration, as discussed in Sections 3.1 to 3.3 and illustrated in Figure 7, in which a field of flat steerable mirrors (heliostats) reflect the direct radiation from the sun onto the surface of a cylindrical receiver mounted on a central tower. It was assumed that the exterior surface of the receiver is covered by AlGaAs/GaAs solar cells that are cooled by a flow of water in an annular channel on the inner side of the receiver surface. In this case some of the solar energy that is concentrated on the

receiver is reflected, some of it is converted directly to DC electricity by the solar cells, but most of it is absorbed as heat and transferred to the cooling water by conduction and convection. (Convective and radiative heat losses to the atmosphere can be shown to be negligible for high concentration systems in which array temperatures are restricted to a few hundred degrees (C) or less.)

In the investigation, three different modes of operation were considered:

a. Photovoltaic-Only

In this option, illustrated in Figure 26, no use is made of the coolant heat; it is simply rejected to the atmosphere. The system is designed to provide maximum net electric power per unit array area, where net electric power is defined as the array output minus the power required to pump the coolant. This option is essentially identical to that considered in earlier sections of this report, the principal difference being that here explicit attention is paid to the cooling system tradeoffs. (It will be shown that the pump power is negligible when the average array temperature is greater than 80°C , the value assumed in the earlier analyses.)

b. Photovoltaic/Thermal

In this option, illustrated in Figure 27, all or part of the thermal energy carried away by the coolant is sold directly as heat. The system is designed to provide maximum net electric power at a specified value of the maximum (outlet) water temperature. It will be shown that, over a wide range of outlet water temperatures (70°C - 150°C), the maximum net electric power will not be greatly different than that obtained under option (a).

c. Photovoltaic/Thermal-Electric

In this option, illustrated in Figure 28, the coolant heat is transferred to a working fluid that is then expanded through a low-temperature turbine to generate electricity. The system is designed to provide maximum net electric power per unit area; in this case, net electric power is defined as the sum of the power generated in the array and the power generated by the turbine minus the power expended in pumping the coolant.

Figure 26
PHOTOVOLTAIC-ONLY SYSTEM

Figure 27
PHOTOVOLTAIC/THERMAL SYSTEM

Figure 28
PHOTOVOLTAIC/THERMAL-ELECTRIC SYSTEM

In the following sections, the basic electrical and thermal parameters and their relationships are defined and each of the three modes of operation is discussed in greater detail. The conditions for maximum electrical efficiency (i.e., maximum net power output per unit of insolation power input) are defined for each mode of operation at an input insolation level of 1 MW/m^2 . (This level would correspond to an actual concentration ratio, as opposed to a geometric concentration ratio, of 1000 to 1). The assumed cell efficiency at $T = 70^\circ\text{C}$ was 17.5%, which was consistent with experimentally demonstrated values as of mid-1976. The results of these analyses were then used in making a rough comparison of the total system costs and busbar (electric) energy costs associated with photovoltaic plants using flat plate collectors and plants in the central receiver configuration operating in each of the three modes. In making this comparison, however, the results of the system trade-off analyses were adjusted to reflect a somewhat higher cell efficiency, $\eta(70^\circ\text{C}) = 22\%$, in accordance with more recent estimates of achievable efficiency values, and a somewhat lower maximum insolation input, corresponding to a geometric concentration ratio of $X = 600$. (This degree of concentration appears to be about the maximum achievable with reasonably inexpensive heliostats.)

3.3.2 Basic Analytic Considerations

The fundamental relationships that were used in the trade-off analyses discussed in later sections are listed below.

The DC electricity produced by the array is

$$P_G = E_g \eta_c \cdot PF \cdot A_A \quad (20)$$

where

E_g = insolation on the array

PF = fraction of array surface area covered by GaAs cells
(packing fraction)

A_A = array surface area

η_c = the GaAs cell conversion efficiency

and for GaAs cells

$$\eta_c = 0.175[1 - 0.0024(T_A - 70)] \quad (21)$$

where T_A is the average solar cell temperature in °C (assumed equal to the average array temperature). The heat absorbed by the array and receiver is

$$Q_A = E_g(\alpha - \eta_c PF) \quad (22)$$

where α is the fraction of the total insolation absorbed by the array. The heat transferred to the water is

$$Q_T = (T_A - \bar{T}_W)/R_{total} \quad (23)$$

where $\bar{T}_W$ is the average water temperature, and R_{total} is the total heat transfer resistance between the solar cell and the water. The total heat transfer resistance is

$$R_{total} = R_{conduction} + \frac{1}{h A_{HT}} \quad (24)$$

where

$R_{conduction}$ = conduction heat transfer resistance between the solar cell and the flow channel wall

h = convective heat transfer coefficient between the flow channel wall and the water

A_{HT} = heat transfer surface area (essentially the inner surface of the array)

and for water cooling (Ref. 13)

$$h = 0.01021(1 + 0.011 \bar{T}_w) V^{0.8} / D_e^{0.2} \quad (25)$$

where

h = heat transfer coefficient, in watts/cm² - °C

V = flow velocity, in cm/sec

D_e = annular channel width, in cm

The heat carried away by the water is

$$Q_w = C_p \dot{W}(T_o - T_i) \quad (26)$$

where

C_p = specific heat of water

$\dot{W}$ = mass flow (ρAV)

T_o = outlet water temperature

T_i = inlet water temperature

ρ = water density

A = flow cross sectional area, which equals $\pi D_e D_1$ for small D_e

D_1 = outer diameter of cylindrical receiver

The electrical power required to pump the water through the array is

$$P_p = f \frac{L}{D_e} \frac{V^2}{2g} \dot{W} \quad (27)$$

where

f = the friction factor

L = array length

g = acceleration of gravity

If it is assumed that the array illumination is uniform and that all of the absorbed heat is carried away by the water (i.e., $Q_A = Q_T = Q_W$), Equations (20)-(27) may be solved at specified values of input insolation, E_g , and inlet water temperature, T_i , for a given array geometry. The analyses reported below were made on the basis of the array geometry that is illustrated in Figure 29. As indicated there, the heat transfer analysis treated the cells as if they were 20- μ -thick GaAs wafers backed by a 100- μ tin backing. These cells were assumed to be attached to the 1-mm-thick aluminum receiver wall by a thin layer of adhesive. The indicated thermal conductance figures are, in general, based on the bulk properties of the materials involved; in the case of the adhesive, the conductance value is one obtained experimentally by investigators at Arizona State University (Ref. 14). The resulting thermal conductance, $R_{\text{conduction}} = 3.41 \text{ cm}^2 \text{ }^\circ\text{C/W}$, is, in general, small compared with that associated with the heat transfer into the water. The following other specific assumptions were used in the analysis:

$$E_g = 1 \text{ MW/m}^2$$

$$\alpha = 0.77$$

$$\text{PF} = 0.9$$

$$T_i = 70^\circ\text{F} (21^\circ\text{C})$$

$$L = 8.92 \text{ meters}$$

$$D_1 = 17.84 \text{ meters}$$

$$70\% \text{ pump efficiency}$$

3.3.3 Photovoltaic-Only Mode

In the Photovoltaic-Only mode of operation, as illustrated in Figure 26, the DC electricity generated in the array is either stored in a battery or sent to a power conditioning unit, converted to AC electricity, and supplied to the electrical load. It is assumed that any required backup electrical power is provided by the utility grid. The thermal energy absorbed is carried away by the water and is eventually dumped to the atmosphere through a cooling tower.

Figure 29
RECEIVER/ARRAY GEOMETRY: PHOTOVOLTAIC CENTRAL
RECEIVER PLANT

In this option the photovoltaic power and the required water pumping power are the key parameters involved in system optimization. On the basis of the assumptions listed in the preceding section, the net array efficiency (array output minus pumping power per unit of array area) was calculated as a function of water flow rate per unit array area for several different channel widths. The results, presented in Figure 30, lead to several interesting conclusions:

- a. There is an optimum flow rate for a given channel width. This occurs because as the flow rate is decreased from the optimum, the average cell temperature increases, reducing cell efficiency, while increasing the flow rate beyond the optimum causes an increase in the required pumping power that more than compensates for the improvement in cell efficiency caused by the decrease in cell temperature.
- b. As the channel width increases, the optimum flow rate also increases. Since the flow rate (W) is proportional to the product of the channel width (D_c) and the flow velocity (V), as the channel width is increased at a given flow rate, the flow velocity must decrease. The result is to reduce the pump power at a given flow rate [Equation (27)], or allow higher flow rates for the same pump power. (For the configuration shown in Figure 29, it can be shown that the pump power is inversely proportional to the cube of the channel width for a given flow rate.) However, these higher flow rates do not greatly increase maximum net power because the heat transfer coefficient, h , is also reduced by an increase in the channel width [Equation (25)] which results in higher cell temperatures and lower cell efficiency at a given flow rate.
- c. At low flow rates, higher net power is achieved by reducing the channel width, while at high flow rates, higher net power is achieved by increasing the channel width. At low flow rates net power is limited by high solar cell temperatures and corresponding low cell efficiencies. Reducing the channel width increases the heat transfer coefficient, h , [Equation (25)] and reduces the cell temperature at a given flow rate [Equations (23) and (24)]. At high flow rates, net power is limited by the pump power. Increasing the channel width in this region reduces the pump power [Equation (27)] and provides higher net power.

The maximum water temperature, T_o (water temperature at the top of the array), is shown as a function of flow rate in Figure 31, where the

Figure 30
NET ARRAY EFFICIENCY VS COOLANT FLOW RATE

Figure 31
WATER EXIT TEMPERATURE VS COOLANT FLOW RATE

Figure 32
NET ARRAY EFFICIENCY VS AVERAGE
ARRAY TEMPERATURE

inlet water temperature, T_i , was set at 21°C . It is to be noted that the maximum water temperature is not greatly affected by channel width and is virtually constant at the higher flow rates, approaching the inlet water temperature as the flow rate becomes very large. However, at the lower flow rates, small changes in flow rate greatly affect the maximum water temperature.

Net array efficiency is shown as a function of average cell temperature in Figure 32. Each point on the curve presented corresponds to a specific combination of flow channel width and optimum flow rate (from Figure 30). The maximum value of overall efficiency, about 15%, is achieved at an average array temperature of 70°C . Going to lower array temperatures requires excessive pump power, while going to higher array temperatures reduces cell efficiency. At the optimum point, the maximum water temperature is 41°C , the water flow rate is 120 gallons per minute per square meter of array, and the flow channel width is 5 cm.

In the above calculations the insolation incident on the array was assumed to be 1 MW/m^2 . This is a maximum figure, reached only at mid-day. For other hours, when the insolation is reduced, two system options are possible:

- a. Operate at constant pump power and coolant flow rate. This procedure will reduce average array temperature and maximum water temperature and increase array electrical efficiency. For example, if the insolation is reduced by 50%, the average array temperature is reduced to 41°C and the array efficiency is increased to almost 17%.
- b. Operate at constant average array temperature by reducing the flow rate and pumping power. Since the pumping power is proportional to the cube of the insolation for a fixed channel width [this can be shown by substituting $V = \dot{W}/(\rho(\pi/2) D_e D_1)$ in Equation (27) and noting that $\dot{W}$ is related to the insolation by Equation (26)], the pumping power becomes negligible at lower insolation.

Preliminary calculations indicate that the first of these options is the more desirable, but a more detailed analysis (probably involving computer simulation runs) would be required in order to confirm this judgement.

The operational conditions that lead to maximum electrical efficiency in the Photovoltaic Only mode of operation, for the case where 1 MW/m^2 of insolation is incident, are displayed in the left-hand column of Table 14.

Table 14
COMPARISON OF OPTIMUM CONDITIONS FOR CENTRAL
RECEIVER PHOTOVOLTAIC OPTIONS
 1 MW/m^2 INSOLATION ON ARRAY

	Photovoltaic Only	Photovoltaic/ Thermal (District Heating)	Photovoltaic/ Thermal- Electric
Maximum Array Temperature, °C	81	140	200 (Assumed Limit)
Average Array Temperature, °C	70	100	126
Maximum Water Temperature, °C	41	100	167
Channel Width, cm	5.0	1.0	0.6
Flow Rate, gpm/m^2	120	34	16.5
Electrical Conver- sion Efficiency	15.5	14.6	24.0

3.3.4 Photovoltaic/Thermal Mode

In a Photovoltaic/Thermal system, the electrical energy generated by the array is handled in exactly the same manner as in the Photovoltaic Only system, except that the thermal energy in the cooling water is used to satisfy thermal load requirements, either directly or through a heat exchange with a working fluid (see Figure 27). Thermal energy is either

delivered directly to the thermal load or sent to storage. It is assumed that any required thermal energy backup is provided by the utility grid if electrical heating is used, or by fossil fuel systems located at the load points.

The heat energy available in the coolant of a GaAs array is typically 3 to 6 times greater than the photovoltaic electrical energy and could potentially be sold to generate revenue. For example, at the optimum average array temperature in the Photovoltaic Only system (70°C), approximately 61% of the insolation is converted to heat, while only about 15% is converted to electrical energy. In addition, it can be shown that by selecting small channel widths and reducing the flow rate, relatively high exit water temperatures can be achieved without significantly reducing electrical output. This can be illustrated with the aid of Figure 33 (a combination of Figures 30 and 31), which shows, for example, that if a 1 cm channel is selected, the maximum array efficiency is reduced about 5%. With a 1-cm channel, reducing the flow rate from 50 gpm/m^2 (Point A on Figure 33) to 25 gpm/m^2 (Point B on Figure 33) increases the exit water temperature from 70° to 150°C while changing the array electrical output only by about 8%. This outcome is a result of the fact that, as the flow rate is reduced over the range suggested, the decrease in pumping power is almost compensated by a decrease in array efficiency resulting from the higher array temperatures at lower flow rates. It therefore appears that a photovoltaic central receiver system concept can be defined in which the channel width is selected in such a way as to provide thermal energy at customer specified temperatures without significantly affecting system electrical output. If the maximum array temperature is set at 200°C (on the basis of manufacturers' estimates that higher temperatures could reduce array lifetime), exit water temperatures of up to 175°C can be provided.

Heat energy at the temperatures available from such a Photovoltaic/Thermal central receiver could potentially be used for space heating, domestic hot water, air conditioning, and in many industrial processes (see the discussion on total energy applications in Section 5 of this volume). The economic desirability of such uses is obviously a function of the cost of thermal

Figure 33
NET ARRAY EFFICIENCY AND WATER EXIT TEMPERATURE
VS COOLANT FLOW RATE

energy distribution and storage. Since photovoltaic systems require large amounts of land, they are likely to be located in rural areas, at some distance from thermal load points. Two recent studies (Refs. 15 and 16) indicate that thermal energy may be economically delivered as steam for district heating over distances of 10-15 miles. In another recent and very interesting investigation (Refs. 17 and 18), the use of hot water for delivery of thermal energy for district heating was examined. This report stated that such a method of thermal energy delivery is presently in use in a number of European countries, particularly Sweden and Poland. The authors estimated the total cost of a system of polymer-lined concrete pipes capable of delivering 100°C water (for space heating and domestic hot water) to several large urban areas in the United States from plants located at significant distances from these areas. Figure 34, which is taken from Ref. 18, indicates that the estimated capital cost of such a system (including all piping up to the individual load hookup) for the colder areas of the country is slightly greater than \$1 per million Btu delivered over distances as large as 50 miles. Since the costs of space heating in many areas of the country (particularly the Northeast) is well over \$3 per million Btu (Refs. 18 and 19), net income from the sale of thermal energy using this distribution concept could be as much as \$2 per million Btu.

These results and the fact that central receiver photovoltaic systems can be designed to provide large amounts of thermal energy in the temperature range of interest without seriously affecting electrical output indicates that a system providing both electricity and thermal energy to a small city or part of an urban area may be a highly attractive application.

The operational conditions that lead to maximum electrical efficiency for the Photovoltaic/Thermal mode of operation, when the desired coolant output temperature is set at 100°C, are displayed in the central column of Table 14.

Figure 34

CAPITAL COST OF TRANSMITTING THERMAL ENERGY

3.3.5 Photovoltaic/Thermal-Electric Mode

The elements of a Photovoltaic/Thermal-Electric system are shown in block diagram form in Figure 28. In this option, the electrical energy generated in the photovoltaic array is handled in the same manner as in the previous concepts. The thermal energy, however, is transferred in a heat exchanger from the array coolant to a working fluid that flows in a secondary loop. The working fluid is vaporized, raised to a temperature that is lower than the maximum (outlet) temperature of the array coolant by an amount ΔT , and used to drive a turbine-generator that produces AC electric power. After passing through the turbine, the vapor is condensed and pumped back to the heat exchanger for reheating. As indicated in Figure 28,

thermal storage may or may not be included; the choice will depend on the relationships between insolation, turbine operating conditions, and the electrical load. If provided, it would most likely, for the temperature range involved, take the form of an insulated tank of hot water. In the following analysis it is assumed that water is used both to cool the array and as the working fluid and that ΔT is 25°F (14°C).

Analysis of a combined Photovoltaic/Thermal-Electric system involves defining a combined optimum of several variables. The design objective is to maximize the net electric power, i. e., the sum of the photovoltaic and thermal-electric power minus the pumping power. Since photovoltaic power increases with decreasing average array temperature [Equation (21)], and since array temperature decreases with decreasing coolant temperature, low values of coolant maximum temperature or high flow rates (see Figures 31 or 33) are needed in order to maximize photovoltaic power. For example, in the Photovoltaic Only system, the maximum water temperature was only 41°C at the maximum efficiency point. On the other hand, the fraction of thermal energy that can be converted to electricity in a turbine increases with increasing turbine inlet temperature. Figure 35 shows the efficiency of a steam turbine, over the inlet temperature range of interest, when the condenser temperature is 38°C (100°F) and only 10% of the steam condenses in the turbine (90% steam quality). Since the maximum inlet temperature is the maximum array coolant temperature minus ΔT , high turbine efficiency, and hence high thermal-electric efficiency is achieved at high maximum coolant temperatures and low flow rates (and, therefore, low pump power).

If it is assumed that water is used as the turbine working fluid, it can be shown by comparing Figure 31 or 33 with Figure 35 that significant thermal-electrical power can be generated only at the lower flow rates. Since, as the flow rate is reduced, higher net photovoltaic efficiency can be achieved by going to smaller flow channel widths (see also Figures 30 or 33), the net electrical efficiency of this combined system can be improved

Figure 35
TURBINE GENERATOR EFFICIENCY AS A FUNCTION
OF INLET TEMPERATURE OF WORKING FLUID

by reducing both flow rate and channel width. This improvement is limited by two factors:

- a. The pump power decreases proportionally with flow rate [Equation (27)] but, as noted previously, is inversely proportional to the cube of the channel width. Therefore, as the channel becomes very small, the pump power becomes very large.
- b. The maximum water temperature cannot continue to increase without limit because this implies that the maximum array temperature may also so increase. In these analyses it has been assumed that the maximum array temperature cannot be permitted to exceed 200°C, on the basis of information from manufacturers that higher temperatures might adversely affect array lifetime.

Within these constraints, computations were made of the overall system efficiency (including both photovoltaic and thermal-electric power output) as a function of channel width, for an incident insolation intensity of 1 MW/m^2 . The results are displayed in Figure 36; also shown is flow rate as a function of channel width. The maximum overall conversion efficiency shown in the figure, $\sim 24\%$, is achieved when the channel is 0.6 cm wide, the flow rate is 16.5 gpm per m^2 of array area, and the average array temperature is 126°C . The overall system efficiency as a function of average array temperature is displayed in Figure 37, which indicates that, at the optimum point, approximately 60% of the electrical energy output is photovoltaic and 40% is thermal-electric. Each point on the curves of Figure 37 corresponds to a different combination of flow rate and channel width; as the average temperature decreases, both the channel width and flow rate decrease.

The effect of reduced insolation on the operation and performance of a combined Photovoltaic/Thermal-Electric system is more complex than in the Photovoltaic-Only or Photovoltaic/Thermal concepts discussed previously. At least three operating strategies can be defined:

- a. Maintain constant flow rate (16.5 gpm/m^2) and pump power and allow both the average array and maximum water temperatures to decrease.
- b. Maintain constant maximum water temperature (167°C) by reducing the flow rate and pump power to compensate for reduced insolation. The turbine inlet pressure is also reduced to maintain constant volume flow rate in the secondary loop of the heat exchanger.
- c. Maintain constant maximum array temperature (200°C) by reducing the flow rate and pump power to compensate for reduced insolation. The required reduction in turbine inlet pressure is significantly greater in this case than in case (b) above.

The results of preliminary calculations for each of these strategies are shown in Figure 38. Of the three approaches, operation at constant coolant maximum temperature (center graph) appears to be the most desirable and results in essentially constant efficiency down to an array insolation of 0.4 MW/m^2 . This occurs primarily because photovoltaic efficiency improves slightly at lower insolation (lower average array temperature)

MAXIMUM ARRAY TEMPERATURE = 200°C

INCIDENT INSOLATION = 1 MW/m²

WATER INLET TEMPERATURE = 21°C

CONDENSER TEMPERATURE = 38°C

STEAM QUALITY = 90%

Figure 36

OVERALL NET SYSTEM EFFICIENCY AND WATER FLOW
RATE PER UNIT AREA VS FLOW CHANNEL WIDTH IN
PHOTOVOLTAIC/THERMAL-ELECTRIC SYSTEM

Figure 37
NET EFFICIENCY OF PHOTOVOLTAIC/THERMAL-ELECTRIC
SYSTEM VS AVERAGE ARRAY TEMPERATURE

Figure 38

NET EFFICIENCY OF PHOTOVOLTAIC/THERMAL-ELECTRIC SYSTEMS FOR ALTERNATIVE OPERATIONAL STRATEGIES

while the thermal-electric efficiency remains essentially constant (constant turbine inlet temperature and only moderate reduction in inlet pressure). In the constant flow rate case (left-hand chart), the rapid drop in system efficiency is due primarily to the decrease in thermal-electric output resulting from reductions in maximum coolant temperature. This decrease far outweighs the improvement in photovoltaic efficiency that occurs because of reductions in average array temperature. When the system is operated at constant maximum array temperature (right-hand graph), the reduction in turbine efficiency as a result of reduced pressure more than compensates for the slight increase in turbine inlet temperature which occurs. This net reduction in turbine efficiency, in turn, more than compensates for the slight increase in array efficiency caused by the drop in average temperature with decreasing insolation.

This combined Photovoltaic/Thermal-Electric system requires further investigation in at least two areas:

- a. System performance and economics are greatly affected by the design, efficiency, and cost of the low temperature turbine system in converting coolant thermal energy to electric power. Such factors as the appropriate turbine size, outlet conditions, and variation in efficiency with insolation, inlet temperature, and flow rate need to be examined in greater detail. Consideration should also be given to the desirability of using a low boiling point secondary fluid to drive the turbine, rather than water. In addition, better information is needed about turbine development and capital costs and on the costs of operation and maintenance.
- b. Computer simulation of system operation is needed in order to provide information on the appropriate mix of electrical and thermal storage and to define operational strategies for maximizing net electrical output over a significant period (e.g., one year of operation).

The operational conditions leading to maximum overall system efficiency in the Photovoltaic/Thermal-Electric mode of operation, for an incident insolation intensity of 1 MW/m^2 , are displayed in the right-hand column of Table 14.

3.3.6 Cost Comparison: Intermediate Load Photovoltaic Plants

The results of the analyses reported in the preceding sections (Sections 3.3.2-3.3.5) and of the computer simulations discussed in Section 3.1 have been used as the basis for a rough economic comparison of photovoltaic power plants in the central receiver configuration, operating in the three different modes discussed. Also included in the comparison were plants using flat plate collectors, for two different array prices, $\$100/\text{kW}_{\text{pk}}$ and $\$500/\text{kW}_{\text{pk}}$. To facilitate direct comparison, each of the plants evaluated was assumed to have a rated capacity of 100 MW, to be located at Inyokern, California, and to go on line in 1990. The design parameters of the plants were adjusted to yield essentially identical electrical performance characteristics, with all plants having the same plant

capacity factor, 0.4, when operated at Inyokern. The plants with flat plate collectors were assumed to utilize silicon solar arrays, with an overall array efficiency (including the effect of a 0.9 packing factor) of $0.12 (0.9) = 0.108$ at 70°C (0.135 at 20°C). The arrays in the central receiver plants, on the other hand, were assumed to be made up of AlGaAs/GaAs cells and to have an array efficiency of $0.22 (0.9) = 0.198$ at 70°C . In all cases, it was assumed that the plant incorporated 5 hours of electric storage. In the Photovoltaic/Thermal-Electric case, since no allowance was made for thermal storage, the assumed mode of operation was one in which the turbine system continually generates all the electric energy it can produce and dispatches it into the grid. Photovoltaic output, on the other hand, is used to bring the total plant output up to 100 MW, with the excess stored for later use. (This may not be the appropriate storage configuration for this system; simulation computations would be needed in order to determine the optimum combination of electrical and thermal storage.)

The first step in carrying out the comparison was to determine the total collector aperture area, for each type of plant and each mode of operation, that would result in the prescribed overall performance ($\text{PCF} = 0.4$). In the flat plate case, the system simulation computations indicated (Table 6) that a collector (array) area of $1.49 (10^6) \text{ m}^2$ would be needed. The system simulation computations were also used to determine, by interpolation, the collector aperture area that would be required in a central receiver plant operated in the Photovoltaic-Only mode. In the simulations for this latter case, the average array temperature was set at 80°C so that pumping power losses were negligible, as shown in Figure 32. As indicated in that figure, a slight increase in overall efficiency (and a corresponding slight reduction in required collector area) could have been achieved by operating at a slightly lower temperature, perhaps 70°C ; this potential improvement in performance was neglected in the rough comparison discussed here. As for the Photovoltaic/Thermal mode of operation, it was only necessary to adjust the Photovoltaic-Only aperture requirement upward to take into account the reduction in array

efficiency that results from operation at an average array temperature of 100°C instead of 80°C.

The determination of the collector area needed in order to achieve the desired performance in the Photovoltaic/Thermal-Electric mode of operation required a little more computation. It was necessary to determine the total AC electric output of the combined system, per unit collector area, taking into account the balance-of-plant efficiency, including power conditioning, in converting DC array output to plant AC output. The average array temperature was taken to be 126°C and the maximum (outlet) water temperature to be 167°C, so that the turbine inlet temperature was ~153°C; these are the parameters leading to maximum overall efficiency, as discussed in Section 3.3.5. The required collector area was then determined by using the ratio of this AC electric output per unit area to the AC output per unit area in the Photovoltaic-Only case as a scaling parameter. (The collector area for the Photovoltaic-Only case was divided by this scaling parameter to yield the required area in the Photovoltaic/Thermal-Electric case).

Once the required collector aperture areas were determined, it was a straightforward process to estimate the total plant cost for each type of plant and each mode of operation. The system cost assumptions discussed in Section 3.2.1, supplemented by estimates of the cost of such additional elements as the low-pressure turbine for the Photovoltaic/Thermal-Electric system, were used in arriving at figures for the total investment cost for each system, including the cost of conventional backup capacity. Levelized figures for the busbar cost of the output electric energy were then developed by the levelized fixed charge methodology described in Section 2.4.1. In the Photovoltaic/Thermal case, separate estimates were made of the revenue that would be generated if either 50% or 100% of the available thermal energy were sold (e.g., for district heating) at a net price of $\$2/10^6$ Btu (after subtracting the costs of transmission and distribution). The levelized value of this thermal energy revenue was then deducted from the calculated

busbar cost of electric energy to yield a net busbar charge that would have to be made for the electric energy. It is this net figure that is shown, along with the results of the other calculations, in Table 15.

Although the preliminary and approximate nature of these cost evaluations precludes any final judgments, the results shown in Table 15 indicate that the profitable utilization of the thermal energy, in either of the two ways that were considered, would result in very significant reductions in the cost of energy from a central receiver photovoltaic plant. The reductions, in fact, appear to bring these energy costs into or near the competitive range.

In order to draw any more definitive conclusions, however, much more refined analyses are clearly in order. It would be particularly useful to investigate the cost and performance of the bottoming-cycle turbine, the cost of storage and distribution of thermal energy, the appropriate mixes of electric and thermal storage, and the existence and nature of potential markets for the thermal energy.

Table 15
COST COMPARISON OF INTERMEDIATE LOAD PHOTOVOLTAIC POWER PLANTS

	Photovoltaic Flat Plate		Central Receiver Systems			
			Photovoltaic Alone	Photovoltaic Thermal Electric	Photovoltaic Plus Thermal 50%*	Photovoltaic Plus Thermal 100%*
Collector Area (m ²)	1.49 (10 ⁶)	1.49 (10 ⁶)	1.20 (10 ⁶)	0.81 (10 ⁶)	1.26 (10 ⁶)	1.26 (10 ⁶)
Concentration Ratio	1	1	600	600	600	600
Cell Material	Si	Si	GaAs	GaAs	GaAs	GaAs
Storage Capacity (kWh/kW _{rated})	5	5	5	5	5	5
1990 Capital Costs (\$/kW _{rated})						
Collector	226	226	720	486	756	756
Array	201 [†]	1006 ^{††}	200	135	210	210
Storage	200	200	200	200	200	200
Power Conditioning	70	70	70	70	70	70
Balance of Plant	56	56	111	109	114	114
Total Basic Plant	753	1558	1301	1000	1350	1350
Total Plant (including spares, contingencies, interest during construction)	1149	2221	1883	1490	1948	1948
Capital Cost of Backup Capacity	60	60	60	60	60	60
Busbar Energy Costs (mills/kWh)						
Electric	55	101	86	69	66	43
Thermal	--	--	--	--	23**	46**
Plant Capacity Factor = 0.4 GaAs Array Price: \$10,000/m ² All Costs in 1975 Dollars						

* Fraction of heat sold at a net price (after distribution/storage cost) of \$2/10⁶ Btu

** Value of thermal energy assumed to escalate at 5% after 1990

[†] Array price = \$100/kW_{pk}

^{††} Array price = \$500/kW_{pk}

THIS PAGE
WAS INTENTIONALLY
LEFT BLANK

SECTION 4

RESIDENTIAL ON-SITE APPLICATIONS

Although the principal emphasis of the Task 2 efforts in this project was on the central station power plant missions (Section 3) and, to a lesser extent, on total energy applications (Section 5), some consideration was also given to residential on-site applications for photovoltaic electricity. These are applications in which photovoltaic arrays mounted on the roofs of individual single-family residences are used to serve the electric energy demands of the residence. No new detailed performance analyses (computer simulations) were carried out for the current study, but performance results obtained in the earlier Aerospace Corporation photovoltaic mission analysis project (Ref. 1) were used as inputs to a revised and extended economic analysis.

In the earlier study (Ref. 1), the economic analysis consisted essentially of determinations of the total incremental present-value cost of providing electric service to a large number of single-family homes either (a) by means of on-site photovoltaic systems, backed up by the utility grid, or (b) directly from the grid. In either case, the capital cost of the required additional conventional generation capacity was included in the accounting. On the basis of a comparison of these costs, a determination was then made of the break-even array price, the array price at which the total cost of the photovoltaic option is equal to that of the conventional alternative.

This procedure had the advantage that it avoided all questions about who owned and operated the photovoltaic system or, indeed, about who would pay for any of the various elements of the total cost of service. It had the corresponding disadvantage that it did not include in the accounting the effect of the cost of money on the annual cost of service or, more importantly, the effect of differences in the cost of the money used to defray different parts

of the cost of service. In the current study, this economic methodology was revised to take into account some of these differences so that differences in the break-even array price associated with different ownership options could be examined. The revised methodology is described in Section 4.1, while some of the results of the application of the procedure in conjunction with previously calculated system performance characteristics are described in Section 4.2. This is followed by a brief discussion of tentative conclusions that can be drawn from these results (Section 4.3).

4.1 PROCEDURE

The procedure used in this study for the economic evaluation of residential on-site applications for photovoltaic systems is illustrated schematically in Figure 39. As mentioned above, it is a refined version of the procedure used in the earlier Aerospace study (Ref. 1) and retains all of the basic features of the earlier method.

The methodology addresses the somewhat hypothetical situation in which a large number of new residential load points are introduced into the service area of an existing utility grid. The crux of the analysis lies in a comparison of the total annual cost of meeting this new demand by means of on-site photovoltaic systems (backed up by the utility grid) with the cost of meeting it directly from the grid. From this comparison the break-even array price is determined.

The methodology for computing the total annual cost of service when photovoltaic systems are used is illustrated in the upper portion of Figure 39. The starting point is a set of simulation computations of hourly photovoltaic system performance over a period of at least a year. As mentioned earlier, no new simulation computations were carried out for the study reported here; instead, simulation results obtained in the earlier study (Ref. 1) were used as inputs to the revised economic methodology. These earlier simulation computations used the system model illustrated in Figure 2, in conjunction with inputs representing the hourly insolation and the hourly demand at the residential load points. The outputs included an hourly

Figure 39

METHODOLOGY FOR DETERMINING BREAK-EVEN ARRAY PRICE
IN ON-SITE PHOTOVOLTAIC APPLICATIONS

record of the amount of photovoltaic energy delivered to the residential load, D_P . This was subtracted on an hour-by-hour basis from the hourly residential demand, D_R , to yield hourly values for the amount of backup energy to be provided by the utility. The yearly totals of the hourly D_P and $D_R - D_P$ values were used in developing estimates of (a) the total cost of operation and maintenance of the photovoltaic system (assumed to be proportional to photovoltaic energy production) and (b) the operation, maintenance, and fuel costs associated with the production of the backup energy.

The only impact of the addition of the new residential demand on the existing utility system, in this case, is the requirement to provide the backup energy. In the analysis, therefore, the $D_B = D_R - D_P$ values are added, on an hour-by-hour basis, to the original system demand to yield a new set of hourly demand values, $D_O + D_B$. This new total demand record then serves as an input, along with the utility system generation model, to the margin analysis procedure that is described in Section 2.3.2. The output of the margin analysis is a value for the amount of conventional capacity that must be added to the utility system in order to prevent any decrease in the overall reliability with which utility generation capacity is available to meet demand.

The total cost of electric service to the residences involved, over the assumed 30-year life of the photovoltaic systems, then consists of:

- a. The initial capital outlays for the photovoltaic systems themselves, C_P , and for the required additional conventional capacity, C_B .
- b. The recurring costs associated with operation and maintenance of the photovoltaic systems, $O\&M_P$.
- c. The recurring operation and maintenance, $O\&M_B$, and fuel, FL_B , costs incurred in generating the backup energy.

In order to put these costs on a common basis, the present values (as of the beginning of system operation) of the recurring cost streams over the life of the system are computed. The present value of a stream of recurring costs

is that lump sum principal amount which would, if invested at a prescribed interest rate, generate exactly enough income to permit payment of the recurring costs over a specified period of time by expending both principal and interest. The sum of the capital costs and the present values of the recurring cost streams is the total present-value cost of service and represents the single lump sum amount which would, if paid down at the time of installation, fully pay for 30 years of electric service to the residences under consideration.

In the discussion in the preceding paragraph no consideration was given to the capital and recurring costs associated with transmission and distribution of the backup energy. Since the backup system must be capable of carrying the full demand of the residential systems during extended (several-day) periods of insolation outage, the power ratings of the distribution and transmission lines and transformers must be as great as they would be if the new residential demand were met entirely from the grid. The costs, therefore, are also essentially the same. It can thus be argued that, when the comparison is made of the costs of meeting the new residential demand by photovoltaic systems with the costs of meeting the demand by conventional means, the transmission and distribution costs are the same for both and thus cancel. These latter costs therefore have not been considered in the economic analysis reported here.

The total present value cost of meeting the new residential demand entirely from the utility grid is determined in an exactly parallel way, as indicated in the lower part of Figure 39. In this case the utility system is called upon to meet the entire new demand, D_R . The hourly D_R values are added, on an hour-by-hour basis, to the pre-existing utility system demand, D_O , to generate a new total demand record. These values, along with the utility system generation model, are used as inputs to the margin analysis procedure, which computes the amount of new conventional generation capacity that must be added to the utility system in order to meet the increased demand without compromising overall generation reliability. The total present value cost of satisfying the new residential demand (again

neglecting transmission and distribution costs) is then made up of the capital cost, C_C , of this new generation capacity, and the recurring operation and maintenance ($O\&M_C$) and fuel (FL_C) costs associated with providing the electric energy required to meet the new residential demand.

Up to this point in the discussion, the economic evaluation procedure is essentially identical to that used in the earlier study (Ref. 1). In the current project, the economic assessment is carried one step further: each of the elements of the total present-value cost of service is expressed in terms of an equivalent levelized stream of annual costs, calculated in a manner that is completely analogous to that discussed in Section 2.4.1 and in Ref. 5. The sum of these levelized streams is then the levelized annual cost of service, the constant annual amount that would pay all of the costs of meeting the postulated new residential demand for 30 years. The calculation of the levelized annual value of each cost element is based on the cost of money to the payer responsible for that cost element and will depend, for example, on who is considered to be the owner of the physical property involved.

In this study, two different ownership options have been considered in the case where on-site photovoltaic systems are used to meet the new residential demand: (a) the utility company owns everything, the on-site photovoltaic systems as well as the backup conventional capacity, and (b) the photovoltaic system is owned by the homeowner, but the backup energy is supplied by an investor-owned utility which therefore must pay for any additional backup capacity that may be required. The levelized annual cost of service, $\overline{CS}_P$, in the first case can be expressed in the form

$$\overline{CS}_P = (C_P + C_B) \cdot FCR + (O\&M_P + O\&M_B + FL_B)_{pv} \cdot CRF_U \quad (28)$$

where

FCR = levelized fixed charge rate appropriate for the utility system, including the effects of corporate taxes and depreciation

CRF_U = capital recovery factor (defined in Section 2.4.1) corresponding to the utility system's after-tax discount rate, k , and the presumed 30-year duration of service

and the subscript pv indicates that the term in parentheses represents the present value of the included elements.

The value of $\overline{CS}_P$ when the photovoltaic system is owned by the homeowner (Case b above) is given by

$$\overline{CS}_P = [C_P + (O\&M_P)_{pv}] \cdot CRF_H + C_B \cdot FCR + (O\&M_B + FL_B)_{pv} \cdot CRF_U \quad (29)$$

where CRF_H is the capital recovery factor corresponding to the homeowner's effective discount rate (mortgage interest rate) and the 30-year duration of service. This determination of the cost of service neglects the effects of (a) property taxes on the photovoltaic system and (b) reductions in personal income taxes as a result of deductions for interest and property taxes. The magnitudes of these effects are highly dependent on the exact location of the system and on the particular income-tax status of the homeowner. Since the effects are opposite in direction and would, in most cases, be comparable in magnitude, neglecting them is not considered likely to distort the results of the evaluation to any significant extent.

The final step in the economic analysis is the determination of the break-even array price. This is accomplished simply by comparing the value of $\overline{CS}_P$ with that of $\overline{CS}_C$, the levelized annual cost of providing service to the postulated new residential demand directly from the grid, where

$$\overline{CS}_C = C_C \cdot FCR + (O\&M_C + FL_C)_{pv} \cdot CRF_U \quad (30)$$

The break-even array price is the array price at which $\overline{CS}_P = \overline{CS}_C$.

The methodology outlined above does not address a number of questions that would face a homeowner attempting to decide whether or not to install a photovoltaic system on his home. The break-even array price

determination is based simply on an assessment of the total cost of providing the required service. If the photovoltaic system is owned by the homeowner, some of these costs (the photovoltaic system capital cost and the associated O&M costs) are borne by him, but others (the capital cost of backup capacity and the O&M and fuel costs associated with backup energy) are borne by the utility. The question of payment by the homeowner to the utility for this backup service is not addressed; only the incremental cost to the utility is considered. In order to establish the magnitude of the appropriate charge for such backup service, it would be necessary to make a detailed analysis of the many interrelated factors (including regulatory practices and the rate structure of the utility) that would be involved in each case; there are virtually no relevant precedents that can be used as a guide. The procedure used in this study was adopted in the belief that it provides as realistic an approach to the calculation of the break-even array price as can be formulated, in the absence of a method for determining the charge to the customer for backup energy and capacity.

4.2 BREAK-EVEN ARRAY PRICE DETERMINATIONS

4.2.1 Economic Assumptions

The assumptions that were made in this study about the economic parameters and the capital and recurring cost figures needed in order to evaluate Equations (28) - (30) (with the exception of the photovoltaic system capital costs which are discussed at the end of this section) are summarized below:

$C_B = 550 K_B$, where K_B is the amount of backup capacity required (in kW), and the total investment cost of a coal-fired intermediate load power plant, as discussed in Section 2.4.3, has been assumed to be \$550/kW.

FCR = 0.15. This number corresponds to an ~0.08 after-tax discount rate and a 30-year power plant service life.

$(O\&M_P)_{pv} = 0.0034 (19.97) E_P$, where E_P is the total annual number of kWh delivered by the photovoltaic system to the load and 19.97 is the magnitude of the present value factor [G in Equation (2), Section 2.4.1] when $k = 0.08$ and the escalation rate (mainly for labor charges) is taken to be 0.05. This O&M allowance corresponds to a levelized charge of ~6 mills/kWh and is twice as large as the O&M figure used for conventional power, reflecting the expected greater cost of servicing dispersed systems.

$(O\&M_B)_{pv} = 0.0017 (19.97) E_B$, where E_B is the total annual number of kWh required as backup to the photovoltaic system; the remainder of the relationship is discussed above, in connection with $(O\&M_P)_P$.

$(FL_B)_{pv} = FL_O (10^{-6}) \cdot G \cdot 9200 \cdot E_B$, where FL_O is the fuel price (in $\$/10^6$ Btu), G is the present value factor (left unspecified, since the fuel escalation rates will be varied parametrically in the analysis), 9200 is the assumed heat rate (in Btu/kWh), and E_B is again the annual amount of backup energy.

$CRF_U = 0.0888$, corresponding to an after-tax discount rate of 0.08.

$CRF_H = 0.0973$, corresponding to an effective discount rate (mortgage interest rate) of 0.09.

$C_C = 550 K_C$, where K_C is the incremental amount of new conventional generation capacity required when the new residential demand is met directly by the grid.

$(O\&M_C)_{pv} = 0.0017 (19.97) E_C$, where E_C is the total annual amount of energy (kWh) required by the new residential demand.

$(FL_C)_{pv} = FL_O (10^{-6}) \cdot G \cdot 9200 \cdot E_C$, where E_C has been defined above, in the discussion of $O\&M_C$, and the meanings of the other terms were discussed in connection with $(FL_B)_{pv}$.

The only remaining term in Equations (28) and (29) is C_P , the capital cost of the photovoltaic system. The different elements of this cost were allocated among the same five accounts that were used in the earlier study: arrays, array support structure, storage, power conditioning, and

installation/wiring. The estimates of the costs associated with each of these accounts, however, have been updated in the light of more recent information and are based on the following unit costs:

- a. Arrays. The array price has been left as a variable, to be determined with $\overline{CS}_P$ is set equal to $\overline{CS}_C$.
- b. Array Support Structure, \$10/m². This is intended to represent the incremental cost of mounting the arrays slightly above (i.e., with a space beneath, for air flow) an existing sealed roof that has the desired orientation.
- c. Storage, \$40/kWh. This figure represents the total present-value capital cost of storage (installed) for 30 years of electric service. It therefore includes the properly discounted cost of battery replacement as required.
- d. Power Conditioning, \$100/kW. This value is somewhat larger than the figure (\$70/kW) used in Section 3.2.1.7 for power conditioning systems for central station power plants. The difference reflects expected economies of scale.
- e. Installation/Wiring, \$1.00/m² plus 10% of the storage and power conditioning costs. This amount is intended to include the cost (materials and labor) of electrical assembly of the system, including conductors, switches, relays, etc.

4.2.2 Results

The methodology described in Section 4.1 and the economic assumptions outlined in Section 4.2.1 have been applied in a reevaluation of a set of examples of on-site residential applications that were examined before (Ref. 1). The particular set of examples chosen for reconsideration represent a hypothetical situation in which a large number (35,060) of new homes are constructed in the Phoenix, Arizona, area and equipped with roof-mounted photovoltaic arrays. In each case the arrays are south-facing, with a tilt angle of 24° with respect to the horizontal. The peak electric power demand associated with this aggregation of homes is 287.1 MW (8.19 kW/home, on the average) and the average aggregate demand is

121.8 MW (3.47 kW/home). The homes are assumed to be within the service area of a utility system that can be adequately represented by the Central Arizona System Model described in Vol. II of the report of the earlier study (Ref. 1).

In the examination that was made in the earlier study of this hypothetical situation, system simulation computations and reliability analyses (backup capacity determinations) were carried out for photovoltaic systems characterized by a range of array sizes and storage capacities. In addition, a determination was made of the amount of additional conventional generation capacity that would be needed in order to meet the new aggregate residential demand if no photovoltaic systems are installed; the required amount was found to be 267 MW. The details of these analyses (including the characteristics of the Central Arizona utility system model) were presented in Vol. II of Ref. 1 and will not be repeated here. For use in the current study, the results of these earlier calculations were adjusted to reflect the higher array efficiency ($\eta_a = 0.135$, at 20°C , instead of 0.1125) and higher power conditioning efficiency ($\eta_{pc} = 0.9$ instead of 0.85) that appear reasonable in the light of more recent developments, but were otherwise used unchanged. (The adjustment consisted simply of reducing the total amount of array area needed in order to achieve a given level of performance).

The break-even array price figures that are obtained when the revised economic evaluation procedures (Section 4.1) are used in conjunction with the (adjusted) results of these performance and reliability computations are presented in Table 16. Although the computations were based on the total impact of an aggregation of 35,060 homes in the utility system service area (generating a peak demand equal to about 3% of the pre-existing peak demand), the figures for array area, storage capacity, and backup capacity in the table represent the per-residence values. Results are presented for both the utility ownership and homeowner-ownership options and for all three of the fuel price/escalation scenarios discussed in Section 2.4.3. The break-even array price figures shown in Table 16 indicate that a substantial

Table 16

**BREAK-EVEN-ARRAY PRICES FOR ON-SITE RESIDENTIAL
SYSTEMS AT PHOENIX**

Array Area, m ² Storage Capacity, kWh Energy Displacement Backup Capacity, kW				Break-even Array Price, \$/kW _{pk}					
				Utility-Owned			Homeowner-Owned		
				Fuel Price Case					
				A	B	C	A	B	C
45	0	0.306	5.03	89	195	329	252	414	621
	28.5	0.340	4.82	-	30	181	90	273	504
90	0	0.420	3.06	110	184	279	247	362	508
	28.5	0.605	2.09	80	189	328	254	422	637
	42.8	0.619	2.09	30	142	285	206	378	598
135	0	0.457	2.26	74	129	198	181	264	371
	28.5	0.714	0.84	76	162	273	218	351	521
	42.8	0.791	0.83	49	146	269	195	344	533
180	28.5	0.741	0.43	48	115	201	160	264	397
	42.8	0.847	0.43	30	108	207	147	266	419

economic advantage is realized when the photovoltaic system is owned by the homeowner. This result is a consequence, principally, of the fact that a utility must pay (a) dividends on equity capital and (b) income taxes on the revenues generated in order to pay the dividends.

The effect on these results of variations in the nominal array efficiency are presented, for one case (array area = 90 m^2 /residence, storage capacity = 28.5 kWh/residence), in Figure 40. Again, both ownership options and all three fuel price scenarios are represented.

4.3 CONCLUSIONS

It is instructive to compare the Phoenix break-even array prices reported in the preceding section to the corresponding values (there reported as "maximum allowable array price") for central station power plants at Inyokern (Figures 17 and 23). The differences between the acceptable array price figures in the two cases are small when only utility ownership is considered. When the homeowner-ownership option in the on-site case is considered, however, it appears that such on-site applications may reach economic viability, as a result of reductions in array price, considerably earlier than central station power plant applications. From another viewpoint, these results indicate that the homeowner-owned on-site application, for a given array price, can tolerate lower efficiencies or poorer average insolation than can the central power application.

- ELECTRIC STORAGE: 3.2 hr AT AVERAGE POWER

		FL_0 (\$ / 10^6 Btu)	g
FUEL	CASE A	0.75	0.05
PRICE	CASE B	1.25	0.06
SCENARIOS	CASE C	1.75	0.07

- AEROSPACE SUBSYSTEM COST ESTIMATES
- BATTERIES AT \$40/kWh; POWER CONDITIONING AT \$100/kW

Figure 40

BREAK-EVEN ARRAY PRICE: ON-SITE RESIDENTIAL
PHOTOVOLTAIC SYSTEMS IN PHOENIX

SECTION 5

PHOTOVOLTAIC TOTAL ENERGY SYSTEMS

5.1 INTRODUCTION

At best only about 20% of the solar radiation that falls on a photovoltaic array is converted directly to electricity. Much of the remainder is absorbed as thermal energy that, in general, must be removed in order to keep array temperatures low enough to maintain photovoltaic conversion efficiency. If this thermal energy could be put to some productive use, it seems likely that its economic value would enhance the overall economic attractiveness of the use of photovoltaic arrays. An example of a system in which the thermal energy might be used to considerable economic advantage has, in fact, been discussed earlier in this report (Section 3.3).

In this section, a description is given of the initial phases of an investigation of a major class of applications in which the economic value of the thermal energy collected by a photovoltaic array is exploited: photovoltaic total energy systems (PTES). These are systems in which both photovoltaic electricity and the solar thermal energy collected by the array are used to meet all or part of the total thermal and electric load at a single load point or at a group of related load points. The economic saving realized as a result of the reduction in purchases of thermal energy can be credited against the cost of photovoltaic electric power, thereby increasing the effective break-even price for arrays.

The principal objective of this investigation is the identification of the most promising PTES applications, both technically and economically, for the post-1985 period. Applications likely to be economically viable before 1985 (as ERDA array-price goals are reached) are not excluded from the study, however. Other objectives include the determination of the conditions (insolation level, prices of alternative fuels, subsystem cost and performance) under which such systems will be cost-competitive in each of the promising applications and of the potential size of the market in each case.

At the close of the period of performance that is described in this report, this study of photovoltaic total energy applications was still at an early stage. The discussion presented here is therefore an initial report of progress to date and, to some extent, of plans, rather than an account of a completed study. In Section 5.2, an account is given of the approach that has been adopted. Following that, in Section 5.3, is a discussion of the results that have been obtained so far in a comprehensive search for relevant data about potential applications. A brief account is then given in Section 5.4 of the methodology that has been developed for computer simulation of PTES operation and of the results of some preliminary computations of PTES performance in a single-family residential application.

5.2 APPROACH

A mission analysis of photovoltaic total energy systems presents a more complex problem than does, for example, the analysis of central station power generation. On-site generation of electrical and thermal energy can be considered for a variety of application types and sites, and for many end uses for both the electrical and thermal energy to be produced. Superimposed over this applications matrix is another composed of a number of component design, system design, and operational concepts which have to be evaluated interactively with the applications matrix to determine photovoltaic feasibility and economic potential.

In Figure 41 an attempt has been made to illustrate the many dimensions of a total energy mission analysis. Additional trade-offs which need to be performed can easily be visualized, such as, for example, that between electric storage and thermal storage. The methodology of the mission analysis must be designed to reduce the required number of individual trade-offs and the need for quantitative definition of the many factors involved in these trade-offs, if the mission analysis task is to be accomplished in a timely manner. Figure 42 shows the major phases of this analysis methodology, in chronological order, and indicates that the screening activity, designed to rapidly focus the analysis on applications with high potential for photovoltaic total energy systems, occurs early in the study. Screening is preceded

Figure 41

MISSION ANALYSIS OF PHOTOVOLTAIC TOTAL ENERGY SYSTEMS: DIMENSIONS

- RATIONALE: UTILIZATION OF WASTE HEAT MAY MAKE PHOTOVOLTAIC POWER COMPETITIVE AT HIGHER ARRAY COST

- APPROACH:

Figure 42

MISSION ANALYSIS OF PHOTOVOLTAIC TOTAL ENERGY SYSTEMS: APPROACH

only by the development of a data base which, in part, is needed for the design of the analytical tools to be employed in the screening process. Both economic and technical screening are required in order to accomplish the desired focus for subsequent analyses. Although only a few of the criteria to be used in screening have been defined at this time, a brief discussion of some of these will assist in the visualization of the approach.

a. Economic Screening Criteria

1. Potential market size. The number of individual load points associated with an applications class, and the potential growth in this number, will determine the extent to which fossil fuel displacement can be accomplished.
2. Geographic distribution. The geographic distribution of the load points should be as wide as possible, both to increase potential fossil fuel displacement and also to contribute to diffusion of this new technology to other application classes.
3. Relative economic benefit of land use. It is likely that more photovoltaic array area will be required than can be deployed on the available roof area, except for a few applications, such as for single-family home use. Thus, a factor relating the dollar benefit of energy savings accomplished by the photovoltaic total energy system to the potential revenue loss resulting from the use of additional land for solar collectors would be a useful criterion.
4. Array break-even price. Knowledge of the price at which a photovoltaic system is cost-competitive with alternative energy generation systems would permit an ordering of applications for detailed analysis, with higher break-even prices receiving earlier and more concentrated attention.

b. Technical Screening Criteria

1. The ratio of thermal to electrical demand. This ratio is the principal criterion which determines match between photovoltaic system capacity and load demand. A mismatch indicates need to purchase additional energy and a probable reduction in photovoltaic total energy system cost-effectiveness. Since the ratio of thermal energy to electrical energy delivered by a photovoltaic

array ranges upward from 3:1, depending on array temperature and cell material, optimum matches will be with applications in which the thermal/electrical demand ratio is also greater than 3.

2. Building aspect ratio (ratio of floor area to site area). Since the solar energy supply is proportional to the total site area and the load is, in most instances, proportional to the building floor area, a ratio of these areas would offer another measure of the probable energy supply/demand match. Off-match applications are likely to be less cost effective candidates for photovoltaic total energy.
3. Storage requirements. The amount of electrical and/or thermal storage needed in a given PTES application will depend on the daily electrical and thermal load profiles. Storage requirements will be smallest in those cases where the demand profile most nearly matches the insolation profile.
4. Uniformity. Uniformity in the design requirements on photovoltaic total energy systems for a particular application would be highly beneficial. Architectural and engineering costs could be substantially reduced if many identical, or nearly identical, systems were required (e.g., in supplying energy to the individual members of a chain of restaurants).

The next step in the process, and the one on which by far the greater part of the effort will be spent, will be detailed analyses of the leading candidates among the applications that survive the initial screening. Computer simulation procedures will be used to evaluate the performance of the PTES systems in the application, as a function of system parameters, and these results will serve as inputs, along with system cost estimates, to an economic analysis that will determine the economic viability of the use of PTES in the application. Conversely, these economic analyses will also determine subsystem cost/performance goals that must be met if economic viability is to be achieved.

Although probable market size will have been one of the screening criteria employed early in the methodology, additional market size determinations will be performed for those applications which survive the detailed

analysis phase in order to provide information on total potential fossil fuel displacement and to assist in the planning of suitable test and demonstration programs.

5.3 DATA SEARCH

5.3.1 General

The concept of total energy utilization applied to power generation is not new. It has been used in central station applications for many years in the form of district heating, i. e., the sale of waste heat for water and space heating in surrounding urban areas. In the years immediately following World War II, a number of on-site power generation installations were made, using either internal combustion engines or gas turbines for generator drive systems, in which the waste heat in the engine or turbine exhaust gases was utilized for a variety of purposes ranging from space heating to industrial process applications. The extraction and use of this waste thermal energy made it possible for such installations to produce electric power at costs comparing favorably with utility rates, while at the same time offering energy independence at sites where that characteristic was important. During the 1950s and 1960s, when natural gas was both plentiful and relatively cheap, the gas utilities developed the total energy market as a means of increasing gas sales. Not all installations were successful, and the market has not grown because some of the assumptions under which gas total energy systems were promoted have proved incorrect. A primary source of difficulty was the fact that the on-site generating systems were owned by the end users, rather than by the utility company. One result of this ownership pattern was generally higher maintenance costs and reduced economic benefit.

In recent years, interest in energy conservation has rejuvenated the concept of total energy for fossil-fueled on-site generation plants and has amplified the concept by introducing the supplemental combustion of local site waste materials to increase the availability of thermal energy and to

reduce the waste disposal problem. This amplified total energy concept has been designated the Modular Integrated Utility System (MIUS) concept and is under active development by the Department of Housing and Urban Development (HUD).

Because of the obvious similarities between the characteristics and capabilities of these fossil-fueled total energy and MIUS systems and those of photovoltaic total energy systems, an early focus of the data search was on information about applications of the former system types. In search of such data, contacts were made with the ERDA and HUD offices concerned with development programs in these fields and with the National Bureau of Standards offices responsible for the MIUS field test program. Other contacts were also made with ERDA-sponsored contractors working in the fields of solar thermal total energy applications. In addition, an extensive literature search was initiated to identify additional sources of information on total energy and MIUS systems and applications. This search included computer searches of the data bases available at the NASA Scientific and Technical Information Facility, ERDA, the Battelle Memorial Institute, and the Smithsonian Science Information Exchange. Hand searches were performed of bibliographies on total energy and on MIUS published by the National Technical Information Service and by HUD. Other searches covered reports and technical indices available at the Aerospace Corporate Library.

The objectives of all of these searches included the identification of existing and potential applications for conventional total energy and MIUS systems, data concerning operational experience with existing systems, and the current and forecast market for such applications. Information was also sought concerning conceptual and design studies relating to solar energy utilization in total energy and MIUS systems. An additional and major objective was the development of data on thermal and electrical energy demand profiles as a function of application, geographic location, time of day, and season of the year.

Although the data search was still under way at the time this report was prepared, a substantial amount of information has been collected on such

topics as (a) the characteristics of conventional total energy and MIUS systems, (b) thermal energy requirements for water heating and heating and cooling of buildings, (c) electrical loads and load profiles for some selected residential applications, and (d) process heat requirements for a variety of industrial processes. A number of gaps in the available data have also been recognized. For example, very little building-specific data and few load profiles have yet been located for commercial and institutional applications. In particular, information on correlations between energy demand and building aspect ratios (the ratio of floor area to site area) appears to be lacking. Data on the electrical loads that are associated with industrial process heat usage and on the diurnal and seasonal variations in the process heat requirements have also proven to be hard to find.

A bibliography of selected reports that were found to contain useful data is appended to this volume.

5.3.2 Industrial Process Heat Requirements

A surprisingly large fraction of the industrial process heat used in the United States is used at temperatures below 250°C, i.e., at temperatures that may be compatible with the operation of GaAs solar cells. (GaAs cells have been operated at 300°C, and it is expected that arrays will be developed that are capable of prolonged operation, without appreciable reduction in usable life, at temperatures in the 200-250°C range). In this section, a summary is presented of U.S. industrial process heat requirements, with emphasis on these lower-temperature applications.

The total annual amount of industrial process heat utilized in the United States in the 1968-1970 period was about 15 quads/year, where 1 quad = 10^{15} Btu (Refs. 20-22). Of this total, approximately 10 quads were used in the form of steam or hot water, and this steam requirement is expected to more than double by the year 2000.

The largest industrial consumers of process heat are the primary metals producers, the chemical and allied products sector, the petroleum

industry, the food and kindred products industry, and the paper and allied products industry. Of these, the primary metals industry group offers little opportunity for photovoltaic total energy because of the high process temperatures generally required.

The chemical and allied products group is the largest energy consumer among the five industrial groups mentioned above. Since there are thousands of chemical products with individual process heat requirements, as well as different processes to arrive at the same product, however, the identification of potential photovoltaic total energy applications will require considerable effort. Figure 43 shows the cumulative distribution of process steam requirements for this industry group as a function of desired steam temperature, between the limits of 125°C and 250°C. The limited data available at this time also indicate that the ratio of thermal to electrical energy required for most of the processes in this industry group will lie above 3 to 1, thus making this industry an interesting candidate for photovoltaic total energy.

The petroleum industry consumes most of its process heat at temperatures above 375°C but still requires about 1 quad at temperatures below 250°C. The lower cost of fossil fuel to this industry, the very high ratio of thermal energy to electrical energy, and the availability of refinery wastes for combustion in steam generating plants make this industry a less likely prospect for photovoltaic total energy. Available data concerning steam requirements of this industry at temperatures below 250°C are presented in Figure 44.

The food and kindred products industry has most of its thermal energy requirements within a temperature regime accessible to photovoltaic total energy system penetration, as shown in Figure 45. However, since the electrical energy requirements are nearly 30% of its total energy needs, supplemental electrical power might have to be purchased. A review of the individual components of this industry may develop many interesting and viable photovoltaic total energy applications.

Figure 43.

CUMULATIVE DISTRIBUTION OF PROCESS STEAM REQUIREMENTS: CHEMICAL AND ALLIED PRODUCTS INDUSTRY

Figure 44
 CUMULATIVE DISTRIBUTION OF PROCESS STEAM REQUIREMENTS: PETROLEUM
 INDUSTRY

Figure 45
 CUMULATIVE DISTRIBUTION OF PROCESS STEAM REQUIREMENTS: FOOD AND
 KINDRED PRODUCTS INDUSTRY

The paper and allied products industry is a large user of thermal energy but is about 40% self-sufficient through use of waste products in energy generation. The ratio of thermal to electrical energy required is about 9:1, indicating that at least some of the components of the industry may find that a photovoltaic total energy system could provide all of the required electrical energy and most of the thermal energy, if a satisfactory method of energy storage can be found. Paper mills are three shift operations and are individually large users of energy; the power requirement of a typical integrated mill is between 20 and 30 MW. They are usually located in rural areas, so that land area may not be a limiting factor. Figure 46 provides data on process steam requirements for this industry group.

Other industrial applications would include the textile, rubber, and plastics industries, all of which require large quantities of steam and hot water for process applications. Since it has been difficult to separate out space heating needs from the other thermal energy requirements of these industries, Figure 47 includes this requirement and consequently reaches to lower temperatures. Since a photovoltaic total energy system could satisfy space heating requirements, as well as cooling needs (through an absorption refrigeration system), this figure still accurately represents the total thermal energy requirements of the industry groupings in this classification, at temperatures below 250°C.

Figure 48 summarizes the cumulative process heat requirements of the industries surveyed to date. It is of interest to note that the ability to provide higher array temperatures, and thus coolant exit temperatures, can have a very important impact on the total industrial thermal energy requirements which photovoltaic total energy systems could supply. Over 2 quads of thermal energy are represented by each of the temperature regimes from 125° to 150°C, 150° to 180°C, and 180° to 200°C. Since 1 quad represents about 10% of the total industrial process steam requirements of the United States, there would appear to be strong incentive for the development of photovoltaic systems capable of operating at higher array temperatures, at least for industrial applications.

Figure 46
 CUMULATIVE DISTRIBUTION OF PROCESS STEAM REQUIREMENTS: PAPER AND
 ALLIED PRODUCTS INDUSTRY

Figure 47
 CUMULATIVE DISTRIBUTION OF PROCESS STEAM AND HOT WATER REQUIREMENTS:
 OTHER INDUSTRIES

Figure 48
CUMULATIVE DISTRIBUTION OF INDUSTRIAL PROCESS STEAM AND HOT WATER REQUIREMENTS

Figure 49 provides another view of the distribution of process heat requirements by temperature range and, perhaps more graphically, portrays the fractions of the total thermal energy requirements which offer opportunities for major displacement of fossil fuels through appropriate design of photovoltaic total energy systems.

The results achieved so far in this review of industrial energy requirements data available in the literature indicate a need for considerable on-site investigation of actual electrical load requirements, both integrated and time-related profiles, of promising industrial PTES applications. Similarly, no thermal load profiles for industrial processes have been located to date. Except for batch processes, however, such profiles may be relatively easy to synthesize; in most continuous industrial processes, thermal energy requirements as well as electric power needs are relatively constant during operational periods.

5.3.3 Residential and Commercial Energy Requirements

As stated earlier, much information on heating and cooling requirements for a variety of building types can be found in the literature, both in terms of integrated energy requirements and of hourly, daily, and seasonal load profiles. Somewhat less but still sufficient data are available on general electrical load profiles. However, very little information about correlated thermal and electrical load profiles for the same building or total site has been located so far, although a considerable amount of integrated energy requirements data is available, and synthesized load profiles for MIUS systems at a few specific geographic locations and for specific applications have been reported. The data search in this area is not complete but, at this point in the study, it now seems probable that photovoltaic total energy systems analysis will have to be based to a large extent on load profiles specifically synthesized for this purpose.

Figure 49
DISTRIBUTION OF INDUSTRIAL PROCESS HEAT USAGE, BY TEMPERATURE

5.4 RESIDENTIAL PHOTOVOLTAIC TOTAL ENERGY APPLICATIONS

5.4.1 Introduction

It was decided at the outset of the investigation of PTES applications to conduct a preliminary examination of a selected application in parallel with the orderly study procedure that was discussed in Section 5.2 and illustrated in Figure 42. The intended functions of this preliminary investigation are multiple. For one thing, it provides a focus (and test example) for the development of computer simulation procedures that will be needed for the analysis of PTES performance in the candidate applications passed by the screening procedure. It also is expected to expose previously unrecognized technical and economic issues that must be considered in the screening procedure and in the detailed evaluation of the candidate applications that survive the screening. In addition, such a preliminary study should provide an early indication of the degree to which the delivery of thermal energy by a photovoltaic total energy system can increase the break-even price of photovoltaic arrays and thereby speed the day when this technology will be cost-competitive.

Selected as the subject for this preliminary examination was the application of photovoltaic total energy systems to serving the electrical and thermal demands of a single-family residence. This application was chosen largely because it appeared sufficiently promising to survive any likely screening procedure. The potential market clearly is enormous (Ref. 23), and the match between the thermal/electrical demand and the thermal/electrical output of a PTES is fairly good and could be improved by judicious load management.

This section of the report describes the simulation and economic analysis procedures developed to investigate the performance of such systems, and some preliminary results for a single-family residence located in Phoenix, Arizona.

It is assumed that the residence in question uses electricity for air conditioning and basic electrical loads (lights, appliances, dryer, range) and

thermal energy for domestic hot water and space heating. It is also assumed that backup thermal energy can be provided electrically by conventional generating systems and that all backup electrical energy is provided by the utility grid.

A schematic of the photovoltaic total energy system considered in the analysis is shown in Figure 50. The photovoltaic array consists of a water-cooled panel which converts solar insolation to DC electricity and thermal energy and a separate air-cooled panel which provides only DC electricity. The electricity generated is either converted to AC and delivered directly to the electrical load, used to charge a storage battery, or dumped if the battery is fully charged. Thermal energy carried by the water is, in order of priority, used for space heating through a water-to-air heat exchange, used for domestic hot water heating through a water-to-water heat exchange, stored in a hot water tank, or dumped to the atmosphere if the water in the tank is already at a specified maximum temperature. When solar insolation is not capable of maintaining the temperature of the water in the thermal storage tank at or above a prescribed minimum level, electrical resistance heating of the water is provided by backup power. Photovoltaic total energy system performance and costs are compared to the conventional alternative, which is assumed to be an all-electric home powered by the local utility. In computing the cost of service, it is assumed that the photovoltaic system is owned by the homeowner and financed under his mortgage.

The total energy system configuration selected for analysis is one of a number of possible technical and economic options which include:

- a. Integrated photovoltaic/thermal panels or separate photovoltaic and solar thermal systems
- b. Various combinations of electrical and thermal storage
- c. Different combinations of on-site fossil fuel and electrical systems for cooking, hot water, space heating and cooling (e.g., heat pump, resistance heating, absorption air conditioning, etc.)

Figure 50

SCHEMATIC OF RESIDENTIAL PHOTOVOLTAIC TOTAL ENERGY SYSTEM

- d. The potential for feeding back and storing excess electrical energy in the utility grid system
- e. Backup power by on-site systems or the utility grid
- f. System ownership by the homeowner or the utility
- g. Provision of energy by individual systems mounted on homes or through a central system providing energy to many homes

It is planned that at least some of these options will be considered in future studies and that analyses will be made of PTES performance in homes in locations other than Phoenix so that a more complete understanding of the performance of residential photovoltaic total energy systems can be developed.

The following sections describe the assumed electrical and thermal load profiles, the system simulation approach, the economic analysis procedure, and the results obtained.

5.4.2 Electrical and Thermal Loads

The hourly electrical demand representations used in the simulation computations of PTES performance in a single-family residence were synthesized by adding together a standard baseload profile and a temperature-dependent air conditioning load. Similarly, the thermal demand representations were synthesized by adding a temperature-dependent space heating load to a standard profile corresponding to the thermal demand for domestic hot water. The thermal and electrical baseload profiles and the functional relationships between the temperature-dependent loads and the ambient temperature were all based on measurements representing average values for a number of homes. Because of the diversity factor in such measurements, the resulting demand representations (especially the electric demand) are undoubtedly considerably smoother than would be actual measured profiles for a single residence. The loss of realism in the simulation as a result of this smoothing effect is believed to be small, however. The principal difference is the absence of the large "spikes" in electric demand that occasionally occur in real demand profiles. It is probably not unreasonable to

postulate that such spikes are accommodated by backup power from the utility grid and that they represent a negligible fraction of the annual average amount of energy consumed.

The proposed load profile for baseload electric power (lights, appliances, dryer, range) is shown in Figure 51 and is based on national averages for new construction (Ref. 24). The home is assumed to have 1600 ft² of floor space so that the total daily baseload is about 27 kWh.

The required electric power for air conditioning as a function of ambient temperature is shown in Figure 52. This curve is based on information collected on a number of homes in the Phoenix area during a summer day in 1973 (Ref. 25).

The proposed load profile for domestic hot water heating is shown in Figure 53. The load profile and maximum values are based on national averages (Ref. 26) and correspond to the requirements for a family of four.

The required thermal power for space heating as a function of ambient temperature is shown in Figure 54. The information in this figure is based on a survey of homes in the Philadelphia area using resistance heating (Ref. 27).

The total annual thermal and electric requirements for a typical home in the Phoenix area, as estimated on the basis of the above load profiles, are shown in Table 17. For comparison, estimates made in other studies (Refs. 1, 23, 28, and 29) are also shown in Table 17. It appears that the estimated annual loads are not greatly different from those of other analyses when allowances are made for the differences in supporting equipment, such as the heat pump whose presence was assumed in the G.E. study (Ref. 23).

5.4.3 Simulation Methodology

5.4.3.1 Approach

It is assumed that the collector in the photovoltaic total energy system is composed of a water-cooled section that generates both DC electricity and thermal energy (photovoltaic/thermal panel) and an air-cooled section

Figure 51
BASELOAD ELECTRIC POWER REQUIREMENTS: 1600 ft² RESIDENCE

Figure 52
POWER REQUIREMENT FOR RESIDENTIAL AIR CONDITIONING

Figure 53
THERMAL ENERGY REQUIREMENTS FOR DOMESTIC HOT WATER:
SINGLE-FAMILY RESIDENCE, FOUR PERSONS

Figure 54
POWER REQUIREMENT FOR RESIDENTIAL SPACE HEATING

Table 17
ESTIMATED ANNUAL ELECTRIC AND THERMAL DEMAND – 1600 FT²
SINGLE-FAMILY RESIDENCE IN PHOENIX

Source	Electrical Load (kWh)		Thermal Load (kWh)		Total (kWh)	Remarks
	Base	A/C	Domestic Hot Water	Space Heating		
This Study	9745	7686	5585	4790	27,806	
Aerospace (Ref. 1)					30,000	All Electrical
Westinghouse (Refs. 28, 29)	7227	7070	12,891		27,188	
GE (Ref. 23)	7665	NA*	5110	NA*	20,696	Heat Pump

* Not Available

that generates only DC electricity (photovoltaic panel). It is also assumed that the entire array is mounted on the roof of the residence.

The photovoltaic/thermal panel is assumed to operate at a constant average temperature that is defined by thermal requirements. This means that both the thermal and electrical conversion efficiencies of the panel are constant, and permits separate simulations of the thermal and electrical portions of the photovoltaic total energy system. (It can be shown, however, that separate simulations would result in only small errors even if relatively large variations in panel temperature were permitted.)

The overall simulation approach is illustrated in Figure 55. The thermal simulation is conducted first. Computations are carried out on an hour-by-hour basis in a manner essentially identical to that described in Section 2.2. (The computer program used in these PTES studies is basically the same program discussed in the earlier section, with minor modifications). The controlling input data are obtained from a tape-recorded insolation/weather data record (as described in Section 2.2.2). In the PTES simulation, hourly ambient temperature data from the insolation tape are combined with space heating requirements which are provided as a function of ambient temperature (Figure 54) to develop the space heating thermal load profile. The space heating load combined with the domestic hot water demand (Figure 53) is defined as the total thermal load. With this load and the insolation data as inputs, an hour-by-hour simulation of the thermal portion of the photovoltaic total energy system is conducted for various input values of thermal collector area and thermal storage. The results of the simulation are used in an economic analysis to define the collector area and thermal storage level that result in satisfaction of the thermal demand at minimum annual cost. This optimum collector area is then also the area of the water-cooled portion of the photovoltaic array.

Simulation of the electrical portion of the system is conducted in a similar manner. Hour-by-hour temperature information on the insolation tape is merged with air conditioning requirements (Figure 52) to develop the

Figure 55
RESIDENTIAL PTES: SIMULATION/ANALYSIS APPROACH

air conditioning demand. The total residential electrical demand is the sum of the basic residential electrical load (Figure 51) and the air conditioning demand. The electrical load and insolation data are used in an hour-by-hour simulation of the electrical portion of the photovoltaic total energy system for various input values of storage capacity and photovoltaic array area. The photovoltaic array consists of a water-cooled, fixed efficiency, photovoltaic/thermal panel, with area defined by the thermal simulation, and an air-cooled panel. The results of the simulation are used in an economic analysis to define the combination of electrical storage and air-cooled panel area that minimizes the annual cost of satisfying the electrical demand.

The results of the separate thermal and electrical simulations are then combined and used in a determination of the total annual cost of meeting the combined demand.

5.4.3.2 Simulation Procedure

The DC electric power generated by a photovoltaic flat plate array can be expressed in the form

$$P_G = E_g \cdot \eta_c \cdot PF \cdot A_A \quad (31)$$

where

E_g = insolation reaching the array (taking into account collection efficiency)

η_c = solar cell conversion efficiency (which depends on array temperature)

PF = array packing factor

A_A = array area

In a system using both a photovoltaic/thermal panel and an air-cooled photovoltaic panel, the equation becomes

$$P_G = E_g \cdot PF \cdot [(\eta_c A)_e + (\eta_c A)_{th}] \quad (32)$$

where the subscripts e and th refer, respectively, to the air-cooled panel and the photovoltaic/thermal panel. In this analysis, furthermore, it has been assumed that the arrays are comprised of silicon cells whose efficiency is given by the relation

$$\eta_c = 0.12 [1 - 0.005(T_c - 70)] \quad (33)$$

where T_c is the cell temperature.

In the air-cooled part of the array, the average array temperature, T_A , and, therefore, the cell efficiency vary with incident insolation, E_g , and with ambient air temperature, T_{amb} . For passive, free convection cooling, the average array temperature can be determined from the relation

$$T_A = T_{amb} + \frac{E_g (\alpha - \eta_c PF)}{h_c (1 + F) + 2 h_r} \quad (34)$$

where

α = absorbtivity

h_c = convective-film heat transfer coefficient

h_r = radiative-film heat transfer coefficient

F = ratio of cooling area to the array area

For the water-cooled photovoltaic/thermal part of the array, as noted previously, the average array temperature is assumed to be constant and is selected on the basis of the thermal requirements. The maximum water temperature required for space heating and domestic hot water was assumed to be 140°F (60°C) (Ref. 28) and, accordingly, a slightly higher average array temperature of 70°C was selected. The average electrical efficiency of the cells in the photovoltaic/thermal part of the array is therefore 0.12, as is indicated by Equation (33) if T_c is set equal to T_A .

For the photovoltaic/thermal panel, the thermal power that can be transmitted to the coolant (i. e., useable thermal power) is

$$P_{th} = [E_g (\alpha - \eta_c PF) - \mu_L (T_A - T_{amb})] A_{th} \quad (35)$$

where μ_L is the convective heat transfer coefficient between the photovoltaic/thermal panel and the air. The thermal system simulation procedure is illustrated in Figure 56. It is assumed that the flat plate array is non-tracking, south-facing, and tilted at an angle (with respect to the horizontal) that is equal to the local latitude. The cell packing factor is assumed to be 0.9 and the absorptivity, 0.77.

It is further assumed that:

- a. No thermal energy is available until the heat absorbed, $[E_g (\alpha - \eta_c PF)]$ is greater than the convective heat loss with $T_A = 70^\circ\text{C}$ [see Equation (35)]. A value of $0.007 \text{ kW/m}^2\text{-}^\circ\text{C}$ has been assumed for μ_L (Ref. 30) and the hourly ambient temperature is provided on the insolation tape.
- b. Thermal losses between the array and the load are zero. In an actual system there will be thermal losses from distribution pipes and in heat exchangers.
- c. The thermal storage efficiency is 80%.
- d. Backup thermal energy is provided by electrical heating of water in storage, rather than being provided directly to the load.

On the basis of simulation calculations for several values of photovoltaic/thermal panel area and for several thermal storage capacities, the fraction of the thermal demand that is satisfied by the PTES system can be defined as a function of these two parameters. This result, combined with figures for system cost and the cost of backup energy, can then be used in an economic analysis leading to a determination of the system parameters that minimize the total annual cost of meeting the thermal demand. The area of the panel in this optimum configuration then defines that portion of the total array that is contained in a combined photovoltaic/thermal panel.

Figure 56
RESIDENTIAL PTES: THERMAL SIMULATION

Figure 57
RESIDENTIAL PTES: ELECTRICAL SIMULATION

The electrical simulation is then carried out as indicated in Figure 57. As was mentioned previously, it is assumed that the photovoltaic array consists of two parts, a photovoltaic/thermal portion, whose area is determined in the thermal analysis, and an air-cooled portion. Simulation computations are carried out for a range of values of the area of the air-cooled portion of the array and for several values of the electrical storage capacity. The fraction of the electrical demand that is provided by the total array can then be determined as a function of these parameters. These results are then used as inputs to the economic analysis, along with estimates of system cost and the cost of backup electricity. The economic analysis leads to a determination of the annual cost of meeting the total electric demand, as a function of air-cooled array area and of electric storage capacity. The optimum PTES system is then defined as the system which leads to minimum overall cost of satisfying both the thermal and electric demand.

5.4.3.3 Economic Analysis Methodology

In view of the preliminary and exploratory character of this residential PTES analysis, the procedures chosen for use in the economic evaluations have been simplified versions of the methods described in other sections of this report. The main simplifications have been in the computation of the costs associated with backup power from the utility grid and in the treatment of the cost of conventional power (as an alternative). In both of these cases, the cost of utility power has been expressed as a single parameter, a levelized cost for delivered electricity, expressed in mills/kWh (1975 dollars). (It will be recalled that backup thermal energy is provided in the form of electricity through a resistive heating element in the thermal storage tank.) Thus the complexities associated with margin analysis and the determination of precise backup capacity requirements and with calculations of the costs (fuel and O&M) of generating backup energy have been ignored here. The difference between what a utility might charge for backup energy (coupling a requirement for maintaining standby energy-delivery capability with relatively small energy sales) and what it might charge for regular service is only dealt with in parametric fashion.

The relatively simple methodology used here is considered to be adequate for the purposes of this preliminary study. It permits a comparative evaluation of the effects of variations in water-cooled panel area, in air-cooled panel area, in electric and thermal storage capacity, in photovoltaic array price, in the cost of backup energy and alternative conventional energy (treated parametrically), in system and subsystem costs, and in the effective cost of money. It also permits a determination of the relative advantages of the PTES concept with respect to conventional photovoltaic systems. In short, although the simplification introduced here prevents a direct comparison of the numerical values obtained in this section with corresponding values reported in other parts of this report, it is accurate enough for the parametric comparisons presented here. The added complications of a more detailed treatment of backup energy or of the conventional alternative were not considered to be justified.

Apart from the differences discussed above, the economic evaluations were carried out by essentially the methods that were used in other parts of the study (see Section 4). The annual levelized cost of the thermal energy delivered by the thermal portion of the system, $\overline{CS}_{th}$, can be expressed in the form

$$\overline{CS}_{th} = C_{th} \cdot CRF_H + \overline{O\&M}_{th} \quad (36)$$

where

- C_{th} = capital cost of the thermal part of the system
- CRF_H = capital recovery factor corresponding to the homeowner's effective discount rate (mortgage interest rate) and the presumed service life of the system
- $\overline{O\&M}_{th}$ = levelized operation and maintenance cost of the thermal part of the system, expressed in dollars/year.

Similarly, the annual levelized cost of the electrical energy from the photovoltaic array, $\overline{CS}_e$, is

$$\overline{CS}_e = C_e \cdot CRF_H + \overline{O\&M}_e \quad (37)$$

where

C_e = capital cost of the electric part of the system (including the portion of the array that is mounted on the photovoltaic/thermal panel)

$\overline{O\&M}_e$ = levelized operation and maintenance cost of the electric part of the system, in dollars/year.

When the total annual cost of service to these thermal and electrical loads is to be calculated, it is only necessary to add in the cost of the backup energy, which is here taken to be the product of the annual quantity of backup energy required (kWh/year) by the unit price charged by the utility for this energy (\$/kWh).

The annual cost of meeting the thermal or electric demand with conventional power is calculated in exactly the same way, as the product of the utility rate (\$/kWh) by the annual demand.

In this analysis, all costs are expressed in 1975 dollars, and the baseline utility rate (for either backup or alternative power) is assumed to be \$0.05/kWh (50 mills/kWh). The levelized annual O&M cost for the thermal system is assumed to amount to 1.5% of the capital cost of the thermal part of the system (Ref. 31). For the electrical system, the levelized O&M cost has been taken to be 6 mills/kWh, the same figure that was used in Section 4.

5.4.3.4 System Capital Cost Assumptions

The capital cost of the thermal part of the system, C_{th} , can be divided into three accounts.

- a. The installed cost of the photovoltaic/thermal panel, including glass cover, backplate, tubing, and heat transfer fluid, but not including the photovoltaic elements. (The cost of the photovoltaic material in the panel is included as part of the cost of the electric part of the system.) The present and expected future costs of such panels have been estimated in a number of studies (Refs. 28, 29, 32-34); projected cost figures have

ranged from $\$4.7/\text{ft}^2$ to $\$9/\text{ft}^2$. For the purposes of this preliminary analysis, the installed cost of the photovoltaic/thermal panel has, in general, been assumed to be $\$50/\text{m}^2$ ($\$4.7/\text{ft}^2$).

- b. Thermal storage. In this study it is assumed that the thermal storage medium is hot water in a suitably insulated tank. In earlier studies (Refs. 28, 29, 32-36) various methods have been used for estimating the amount of thermal storage required and the cost of such storage. In one case (Ref. 35), the total storage cost has been estimated to vary from $\$2/\text{gallon}$ down to $\$0.50/\text{gallon}$, as tank capacity is increased from 500 to 5000 gallons. For the purposes of this investigation, a value of $\$2/\text{gallon}$ has been assumed, corresponding to $\$10.66$ per kWh (i. e., per 3413 Btu) of thermal energy stored if it is assumed that the water temperature is increased from 16°C (60°F) to 60°C (140°F).
- c. The balance of plant (BOP). This account includes the costs of all the additional solar-peculiar equipment, such as special pumps or fans, heat exchangers, etc. According to Reference 32, the balance-of-plant cost typically amounts to about 30% of the total system cost. On this basis, taking into account the collector panel and storage costs discussed above, the BOP cost has been assumed to be approximately $\$1000$ for the single-family residence considered in this study.

The capital cost of the electric part of the system has been treated in a manner virtually identical to that described in Section 4, and most of the cost figures are the same as those cited there. The total cost is divided among five accounts:

- a. Arrays. For this part of the study, the array cost has been treated parametrically but, for the baseline case discussed below, was set at $\$13.50/\text{m}^2$. This array price is equivalent to $\$100/\text{kW}_{\text{pk}}$, since the array efficiency at 20°C is $0.15 (0.9) = 0.135$ if the cell efficiency is defined by Equation (33) and the array packing factor is taken to be 0.9. This array price is assumed to apply both to the air-cooled portion of the array and to the water-cooled photovoltaic/thermal portion.
- b. Support Structure. As in Section 4, the assumed cost of this structure is $\$10/\text{m}^2$. This cost, however, is only incurred for the air-cooled portion of the array. The cost of the supporting structure for the photovoltaic/thermal panel is included in the cost of the thermal part of the system.

- c. Electric Storage. As in the earlier section, the assumed cost for the electric storage system (batteries) is \$40/kWh and represents the total present value cost of the battery system (including replacements, if any) over the assumed 30-year life of the photovoltaic total energy system.
- d. Power Conditioning. The assumed figure, as in Section 4, is \$100/kW. Since the peak electrical loads used in the PTES simulation are somewhat above 6 kW, the required rating for the power conditioning system was set at 8 kW in order to provide a small amount of margin. The total power conditioning cost has therefore been set at \$800 in this preliminary PTES study.
- e. Installation/Wiring. As in Section 4, an allowance of \$1 per m² of array plus 10% of the storage and power conditioning cost has been made to account for the cost (materials and labor) of electrical assembly of the system (including conductors, switches, relays, etc.).

5.4.3.5 Thermal Simulation Results

The results of the simulation computations of the performance of the thermal part of the PTES are shown in Figure 58. The graph represents the fraction of the annual residential thermal demand (space heating plus domestic hot water) that is provided by the photovoltaic/thermal panel (in Phoenix, Arizona) as a function of panel area, for several values of thermal storage capacity. (This total annual demand amounts in these examples to 10,370 kWh/year, expressed in terms of the electric energy that must be provided to heat the house electrically. The efficiency of converting 1 kWh of electricity into 1 kWh of thermal energy, or 3413 Btu, has been assumed to be 100%). For panel areas greater than 25-35 m², large increases in panel area are required to significantly increase the fraction of thermal demand provided by solar energy. In addition, while small levels of thermal storage greatly improve system performance, large storage capacities provide only slight improvements (compare the curves for 25 kWh and 50 kWh storage at a panel area of 30 m² in Figure 58). It is assumed that thermal demand that cannot be satisfied by the photovoltaic/thermal panel is provided by electric heating of the circulating thermal fluid (water) and that this backup electrical power is provided by the local utility grid.

Figure 58
THERMAL SYSTEM SIMULATION RESULTS, PHOENIX

When the PTES systems represented by these performance computations are subjected to the simplified economic analysis discussed in Section 5.4.3.3, the curves displayed in Figure 59 are obtained. The vertical axis represents the total levelized annual cost of meeting the full thermal demand of the residence; it therefore includes the cost of backup energy. The levelized annual cost of meeting this demand with utility power is represented by the horizontal line at \$520/year, corresponding to the cost of 10,370 kWh at an assumed unit cost to the homeowner of \$0.05/kWh. The various curves in Figure 59 illustrate the dependence of the total levelized annual cost of service on the area of the photovoltaic/thermal panel, for several different thermal storage capacities and for various choices of the relevant economic parameters.

The most striking features of the curves in Figure 59 are the pronounced minima that are obtained in every case. These occur because, at small values of panel area, the incremental cost of increasing the panel area is smaller than the cost of backup energy. As the panel area becomes large, however, the incremental useful thermal energy provided becomes smaller (i.e., more is wasted) and eventually it becomes less expensive to purchase backup energy than to add panel area. The baseline case, represented by curve (1) in Figure 59 corresponds to a case where 50 kWh of thermal storage is provided, the capital recovery factor is 0.09 (corresponding to a mortgage interest rate of slightly more than 8%), the panel cost is \$50/m², and backup energy can be obtained at a unit price of \$0.05/kWh. For this case, the optimum photovoltaic/thermal panel area is about 30 m² and the annual cost of thermal service is \$440, about \$80 less than the cost of meeting the entire demand with utility power at \$0.05/kWh.

The other curves in Figure 59 display the effects of several types of variations from the baseline case:

- a. The effect of thermal storage level [compare curves labeled (2) and (3) with (1)]. Reducing thermal storage from 50 kWh to 25 kWh makes virtually no change in levelized annual cost.

Figure 59

LEVELIZED ANNUAL COST OF THERMAL ENERGY, RESIDENTIAL PTES IN PHOENIX

NOTES

LOCATION: PHOENIX
 ANNUAL THERMAL DEMAND:
 10,370 kWh
 PRICE OF CONVENTIONAL
 ELECTRICITY = \$0.05/kWh

- (1) BASELINE CASE:
 COLLECTOR PANEL COST = \$50/ m^2
 STORAGE CAPACITY = 50 kWh
 CRF = 0.09
 BACKUP ENERGY COST = \$0.05/kWh
- (2) BASELINE CASE EXCEPT
 STORAGE = 25 kWh
- (3) BASELINE CASE EXCEPT
 STORAGE = 0 kWh
- (4) BASELINE CASE EXCEPT BACKUP
 ENERGY COST = \$0.06/kWh
- (5) BASELINE CASE EXCEPT CRF = 0.10
- (6) BASELINE CASE EXCEPT PANEL
 COST = \$100/ m^2

However, with no storage, the nominal system is no longer competitive with conventional power, if both backup and alternative power can be obtained at \$0.05/kWh, and the optimum panel area drops to about 10 m².

- b. The effect of different rates for backup and conventional power. A utility may charge customers with photovoltaic/thermal systems a higher rate for backup power (to cover the costs of decreased utilization of existing generation, transmission, and distribution systems or for new capacity required for solar backup) than is charged customers who use only conventional power. Curve (4) in Figure 59 shows the levelized annual costs that result when the rate charged for backup power is increased to \$0.06/kWh (a 20% increase over the assumed nominal cost of \$0.05/kWh). As Figure 59 shows, such an increase does not lead to results that are very different from those of the nominal case. As expected, the increase in backup costs makes a panel area slightly larger than the nominal more desirable and raises the minimum levelized annual cost. In practice, the levelized cost per kWh of backup power would likely be a function of the amount of backup power required.

At present, utilities charge large users lower rates than small users. Since more backup power is used at small panel areas than at large ones, present utility policy would move the optimum panel area to slightly smaller values than those shown in Figure 59. Preliminary calculations show that for the utility rate differentials currently in use in the Phoenix area (a decrease of from \$0.01/kWh to \$0.02/kWh in the rate when usage is increased from 100 kWh/month to 1000 kWh/month) (Ref. 37), the results shown in Figure 59 are not significantly altered.

- c. The effect of a higher CRF value. Curve (5) on Figure 59 shows levelized annual cost, as a function of panel area, for a CRF value of 0.10, a figure that is close to what a homeowner would pay with present mortgage rates since it corresponds to a mortgage rate of just over 9%. Again very little change from the nominal case is seen.
- d. The effect of increased panel costs. Curve (6) shows thermal system levelized annual costs for a system where the panel is assumed to cost \$100/m². This cost is approximately the present installed cost for thermal panels. The curve indicates that such a system would be not quite competitive with conventional power at \$0.05/kWh.

Figure 59 shows that photovoltaic/thermal panel areas in the vicinity of 30 m^2 are optimum for many of the cases considered in this analysis. It should be noted, also, that the minimum annual cost for the nominal case is only \$80 less than the cost of conventional power. Such a system would not be competitive at present in the Phoenix area, where large users (1000 kWh/month) pay \$0.0354/kWh (Ref. 37).

Figure 58 also shows that for the nominal system, at the optimum panel area (30 m^2), approximately 75% of the thermal demand is provided by the solar thermal system, with the remainder provided by conventional power. A larger fraction of the thermal demand can be provided by the photovoltaic/thermal system, at increased annual cost, by going to larger panel areas. For example, Figure 59 shows that the cost of meeting the thermal demand, in the baseline case, with the photovoltaic/thermal system becomes equal to the conventional cost when the panel area is approximately 55 m^2 . Figure 58 shows that for this panel area, the photovoltaic/thermal system would meet about 83% of the thermal demand. In general, Figures 58 and 59 indicate that achieving minimum annual cost of service with photovoltaic/thermal systems requires significant conventional power backup and that efforts to reduce the backup power to small values (e.g., "all" solar homes) may be uneconomic.

The elements of the capital cost of the thermal portion of the residential photovoltaic total energy system, for a case where the panel area is 30 m^2 , are summarized in Table 18.

Table 18
CAPITAL COST OF THERMAL PORTION OF RESIDENTIAL PTES

<u>Item</u>	<u>Size</u>	<u>Unit Cost</u>	<u>Cost (\$)</u>
Collector/Panel	30 m^2	$\$50/\text{m}^2$	1500
Thermal Storage	50 kWh	$\$10.66/\text{kWh}$	533
Balance of Plant	-	-	1000
Total Capital Cost			<u>\$3033</u>

The estimated system capital cost is about $\$100/\text{m}^2$ (or $\$9.4/\text{ft}^2$), which is approximately the expected installed cost of solar thermal residential systems in the late 1980s (Ref. 33). Present system installed costs are in the $\$15\text{-}20/\text{ft}^2$ range.

5.4.3.6 Electrical Simulation Results

The fraction of the annual electrical demand that is provided by the solar electric part of the PTES in the same single-family home in Phoenix is shown in Figure 60 as a function of the photovoltaic panel area and electric storage capacity. The photovoltaic power provided includes both the power generated by the air-cooled photovoltaic panel (A_e) and by the water-cooled photovoltaic/thermal panel (A_{th}). The results shown in Figure 60 are based on the assumptions that (a) the photovoltaic/thermal panel has an area of 30 m^2 (the panel area leading to minimum annual cost of meeting the thermal demand) and (b) this panel has an average temperature of 70°C . The photovoltaic power is therefore being provided by an air-cooled photovoltaic panel of area A_e and varying conversion efficiency and by a 30 m^2 water-cooled photovoltaic thermal panel with a cell efficiency of 0.12 (silicon cells at 70°C). Figure 60 shows that for air-cooled panel areas greater than about 50 m^2 , large increases in this area are required in order to increase the fraction of electrical demand provided by the photovoltaic array. Similarly, beyond an electrical storage level of 25 kWh, large increases in storage have only a small effect. Any electrical demand that cannot be provided by the photovoltaic array is assumed to be supplied by the local utility.

Figure 61 shows the total levelized annual cost of meeting the full electrical demand (17,440 kWh) as a function of the air-cooled photovoltaic panel area A_e for three levels of electrical storage. The annual cost of meeting this demand with utility power is represented by the horizontal line at $\$872/\text{year}$, corresponding to the cost of providing 17,440 kWh at an assumed unit cost of $\$0.05/\text{kWh}$.

LOCATION: PHOENIX
ANNUAL ELECTRICAL DEMAND: 17,440 kWh
PHOTOVOLTAIC/THERMAL PANEL AREA: 30 m²

Figure 60
ELECTRICAL SYSTEM SIMULATION RESULTS, PHOENIX

Figure 61
LEVELIZED ANNUAL COST OF ELECTRIC ENERGY, RESIDENTIAL
PTES IN PHOENIX

Figure 61 shows that for a given set of assumptions, there is an optimum air-cooled photovoltaic panel area that corresponds to the minimum levelized annual cost to satisfy the electrical demand. At small panel areas, the incremental cost of adding panel area is less than the cost of backup power saved, while at large panel areas the converse is true. Note that, in general, the system with minimum levelized annual cost requires significant levels of backup power and that the amount of backup power required decreases with increasing levels of storage. For example, referring to Figures 60 and 61, with no storage, the minimum cost system (30 m^2 photovoltaic panel) provides only 40% of the annual electrical demand, while with 50 kWh storage, the minimum cost system (80 m^2 photovoltaic panel) provides over 87% of the annual demand.

For the storage levels shown in Figure 61, 25 kWh provides the lowest cost electrical system. This occurs at a panel area of approximately 75 m^2 . This system will be used as the baseline electrical system for discussing the effects of changes in system assumptions on annual cost and optimum air-cooled photovoltaic panel area. Characteristics and costs of the baseline system are listed in Table 19.

The effect of photovoltaic array cost is shown in Figure 62, for systems with 25 kWh electrical storage, for array costs of \$100 and \$300/kW_{pk}. Note that for \$300/kW_{pk} arrays, the annual cost of satisfying the electrical demand by photovoltaic or utility power is approximately equal for photovoltaic panel areas between about 5 m^2 and 75 m^2 . As the array cost increases, the optimum photovoltaic area and the fraction of annual demand provided both decrease. For example, at \$100/kW_{pk} array cost, Figure 62 shows an optimum photovoltaic panel area of 75 m^2 and Figure 60 indicates that 83% of the electrical demand can be provided by photovoltaic power. For a \$300/kW_{pk} array cost, Figure 62 shows an optimum photovoltaic panel area of 20-40 m^2 , which would provide 50-70% of the electrical demand. This suggests an approach where initially small, expensive, photovoltaic panels are installed and then, as the cost of panels is reduced, more panel area is added.

Table 19
BASELINE ELECTRICAL SYSTEM CHARACTERISTICS AND COST

	Size	Cost (\$)
Optimum Photovoltaic Panel Area	75 m^2	
Total Photovoltaic Array Area ($A_e + A_{th}$)	105 m^2	
Photovoltaic Array (\$100/kW _{pk})		1418
Array Supporting Structure		750
Electrical Storage (\$40/kWh)		1000
Power Conditioning (\$100/kW _{pk})		800
Wiring/Miscellaneous		285
Total Capital Cost		4253
Fraction of demand provided by photovoltaic array: 83%		
Levelized annual cost to homeowner (CRF = 0.09; levelized operations and maintenance cost = 6 mills/ kWh; backup power cost = \$0.05 kWh)		610
Annual savings to homeowner if conventional power costs \$0.05/kWh		262

The effect of increasing the backup power cost 20% to \$0.06/kWh and 40% to \$0.07/kWh is shown in Figure 63 for 25 kWh storage and \$100/kW_{pk} arrays. The effect is to slightly increase both the annual cost and the optimum photovoltaic panel area.

Figure 62
EFFECT OF ARRAY PRICE ON LEVELIZED ANNUAL COST OF
ELECTRIC SERVICE

Figure 63
EFFECT OF BACKUP ENERGY COST OF LEVELIZED ANNUAL COST
OF ELECTRIC SERVICE

5.4.3.7 Photovoltaic Total Energy System (PTES)

The PTES that provides electrical and thermal service at minimum total annual cost can be, at least roughly, defined by combining the optimum solar thermal and solar electric systems. The characteristics of such a combined system are summarized in Table 20.

This table shows that the residential PTES providing service at minimum total annual cost requires about 5500 kWh of conventional backup power, which is about 20% of the combined thermal and electrical demand. If the cost of conventional power were higher than assumed here (\$0.05/kWh), the amount of conventional power required would be reduced, while the opposite would occur if the cost of conventional power were lower than assumed. In addition, although relatively optimistic assumptions were made with regard to the installed future costs of photovoltaic total energy systems (\$100/m² for the installed cost of the solar thermal system and \$100/kW_{pk} photovoltaic arrays), the resulting first cost of such systems is not small (almost \$7300 in 1975 dollars), nor are the levelized annual savings over conventional power at \$0.05/kWh large (\$340 savings per year or 20% of the annual cost of conventional power).

5.4.4 Conclusions and Status

This preliminary analysis of PTES use in single-family residences has developed procedures and information for estimating thermal and electrical loads and for analyzing some of the many parameters involved. These procedures and the existing simulation program will be used in future studies of residential PTES applications in locations other than Phoenix and to define the conditions under which such systems become attractive in comparison with conventional and pure photovoltaic systems. The analysis to date indicates that for single-family residential applications:

- a. Minimum annual cost photovoltaic total energy systems can be defined as a function of system capital costs and backup power costs.

Table 20
CHARACTERISTICS OF EXAMPLE OF RESIDENTIAL PTES IN
1990-2000 PERIOD

(Single-Family Phoenix Residence; Total Demand,
Thermal plus Electrical = 27,810 kWh)

	Size	Cost (\$)
<u>Solar Thermal System</u>		
Photovoltaic/Thermal Panel	30 m ²	1500
Thermal Storage	50 kWh	533
Balance of Plant		1000
Capital Cost		\$3033
Fraction of Thermal Demand Provided, 75%		
Backup Electrical Power Required, 2592 kWh		
Annual Cost (CRF = 0.09, Backup Power at \$0.05/kWh, O&M = 1.5% of Capital Cost)		440
<u>Solar Electric System</u>		
Photovoltaic Panel (Air-Cooled)	75 m ²	1418
Photovoltaic/Thermal Panel	30 m ²	
Array Structure	75 m ²	750
Electrical Storage	25 kWh	1000
Power Conditioning	8 kW _{pk}	800
Wiring/Miscellaneous		285
Capital Cost		\$4253
Fraction of Electrical Demand Provided, 83%		
Backup Electrical Power Required, 2964 kWh		
Annual Cost (CRF = 0.09, Backup Power at \$0.05/kWh, O&M = 6 mills/kWh)		610
Total incremental capital cost for photovoltaic total energy system		7286
Total annual cost to homeowner with photovoltaic total energy system		1050
Total annual cost to homeowner with conventional power (\$0.05/kWh)		1392
Total annual savings to homeowner with photovoltaic total energy system		342

- b. Minimum annual cost systems usually require significant levels of backup power. It may be uneconomic to provide 100% of the residential thermal and/or electrical demand with photovoltaic total energy systems.
- c. Except for small panel areas, systems with thermal and electrical storage have lower annual costs than systems without storage.
- d. It may be desirable to initially install small photovoltaic arrays and add array area as the cost of such arrays is reduced.

SECTION 6

CONCLUSIONS AND RECOMMENDATIONS

On the basis of analyses that have been described in the preceding sections of this volume, several tentative conclusions can be drawn:

- a. Photovoltaic central station power plants with flat plate collectors are likely to be cost-competitive at a number of sites in the U.S. sunbelt (possibly as far north as Washington, D.C.) when array prices have been reduced to the \$100-200/kW_{pk} range (perhaps by 1990).
- b. Photovoltaic power plants with concentrating collectors are also likely to be economically competitive, at least in the Southwest, if the thermal energy that is also collected can be put to profitable use.
- c. Photovoltaic power plants without electric storage can provide electricity at lower cost than can plants with storage when the total present value capital cost of storage (including replacements) is \$40/kWh or greater.
- d. The economic competitiveness of photovoltaic power plants depends strongly on the future price of competitive fuels, especially coal, and on the associated price escalation rates.
- e. On-site residential systems are likely to be cost-competitive in the Southwest at array prices in the \$300-600/kW_{pk} range if the system is owned by the homeowner. If the system is owned by the utility, the array price would have to be in the \$100-300/kW_{pk} range.
- f. It is probably not economically reasonable to attempt to provide the full electric and thermal requirements of a single-family residence with a photovoltaic total energy system. The minimum total cost of service is achieved when the backup energy requirement is still significant (20% or more of the total).

When the results of this study are considered as a whole, a number of areas requiring further examinations become apparent. Some specific recommendations for future investigations are listed below:

- a. The study of applications for photovoltaic total energy systems should be continued and extended to cover the full range of potentially attractive applications in the residential, commercial, industrial, and institutional sectors.
- b. An intensive effort should be made to identify and evaluate potential load-point applications for photovoltaic electricity in the intermediate-to-large size range, i.e., greater than $\sim 100 \text{ kW}_{pk}$. No really attractive applications appear yet to have been identified for systems larger than residential systems and smaller than full-scale central power plants.
- c. Additional studies are needed of the design characteristics and economics of photovoltaic thermal-electric systems incorporating low-pressure bottoming cycle turbines.

REFERENCES

1. Mission Analysis of Photovoltaic Solar Energy Systems, Vols. I-III, ATR-76(7476-01)-1, Energy and Transportation Division, The Aerospace Corporation (1 December 1975).
2. Solar Thermal Conversion Mission Analysis, ATR-74(7417-05)-1, Vols. I-V, Civil Programs Division, The Aerospace Corporation (15 January 1974).
3. Solar Thermal Conversion Mission Analysis, Vols. I-V, ATR-74(7417-16)-2, Energy and Resources Division, The Aerospace Corporation (15 November 1974).
4. Solar Thermal Conversion Mission Analysis--Midterm Report, ATR-75(7506-05)-1, Energy and Transportation Division, The Aerospace Corporation (1 September 1975).
5. J. W. Doane, R. P. O'Toole, R. G. Chamberlain, P. B. Bos, and P. D. Maycock, The Cost of Energy from Utility-Owned Solar Electric Systems: A Required Revenue Methodology for ERDA/EPRI Evaluations, JPL 5040-29, ERDA/JPL-1012-76/3, Jet Propulsion Laboratory, California Institute of Technology (June 1976).
6. FPC News, Vol. 9, No. 12, Federal Power Commission, March 19, 1976.
7. Honeywell, Inc., and Black and Veatch, Dynamic Conversion of Solar Generated Heat to Electricity, NASA CR-134724 (August 1974).
8. Honeywell, Inc., and Black and Veatch, Solar Pilot Plant, Phase 1: Collector Subsystem Research Experiment Conceptual Design Report (Final), CDRL Item No. 3 (30 January 1976).
9. Wholesale Prices and Price Indexes, U.S. Department of Labor, Bureau of Labor Statistics (monthly publication).
10. Central Receiver Solar Thermal Power, Phase I Final Report, Book 1, Report MDC 66040, McDonnell-Douglas Aircraft Corporation (January 1976).
11. Power Generation Systems, Westinghouse Power Generation Databook, Westinghouse Electric Corporation (1973).

12. E. A. DeMeo, Assessment of Cadmium Sulfide Photovoltaic Arrays for Large Scale Electric Utility Applications, Report No. ER-188, Brown University (February 1976). (Prepared for the Electric Power Research Institute, Palo Alto, Calif.).
13. W. H. McAdams, Heat Transmission, 3rd ed., McGraw-Hill Book Co. (1954).
14. Terrestrial Photovoltaic Power Systems with Sunlight Concentration, NSF/RANN/SE/GI-41894/PR/74/4, College of Engineering Sciences, Arizona State University, and Spectrolab Division of Textron, Inc. (December 1974).
15. S. E. Beale and A. J. Miller, Urban Utilization of Extracted Heat and Waste Heat from Central Station Power Plants, Oak Ridge National Laboratory (1971).
16. A. Ileri, G. M. Reistad, and W. E. Schmisser, "Urban Utilization of Waste Energy from Thermal Electric Power Plants," Oregon State University, Journal of Engineering for Power (July 1976).
17. J. Karkheck, E. Beardsworth, and J. R. Powell, "Technical and Economic Aspects of Potential U.S. District Heating Systems," 11th Inter-society Energy Conversion Engineering Conference Proceedings, Vol. II (1976).
18. J. Karkheck, E. Beardsworth, and J. R. Powell, The Technical and Economic Feasibility of U.S. District Heating Systems Using Waste Heat from Fusion Reactors, DNL 50516, Brookhaven National Laboratories, February 1976.
19. Solar Heating and Cooling of Buildings (Phase 0), Vol. III, Appendices, NSF/RA/N-74-0226, TRW Systems (May 1974).
20. Gordon M. Reistadl, Analysis of Potential Nonelectrical Applications of Geothermal Energy and their Place in the National Economy, UCRL 51747, Lawrence Livermore Laboratory (February 1975).
21. J. F. Kunze and A. S. Richardson, National Program Definition Study for the Non-Electrical Utilization of Geothermal Energy, ANCR-1214, Idaho National Engineering Laboratory (June 1975).
22. B. Lindal, "Industrial and Other Applications of Geothermal Energy," UNESCO 1973, Geothermal Energy (Earth Sciences, 12).
23. Conceptual Design and System Analysis of Photovoltaic Power Systems, "Final Report, Vol. II, On-Site Residence System, General Electric (June 15, 1976).

24. AXCESS Computer Code, Edison Electric Institute.
25. Report on Residential Load Research Study (1972-1974), Arizona Public Service Company (March 1974).
26. ASHRAE Handbook: Systems 1976.
27. 1969-70 Residential Electric Resistance Heating Load Study, Philadelphia Electric Company (July 1971).
28. P. F. Pittman, Conceptual Design and Systems Analysis of Photovoltaic Power Systems, Westinghouse Corporation, Draft (June 1976).
29. P. F. Pittman, Conceptual Design and Systems Analysis of Photovoltaic Power Systems, Vols. III (1) and III (2), Westinghouse Corporation, Draft (September 1976).
30. Northrup Collector is Efficient, Northrup Inc.
31. Solar Heating and Cooling of Buildings, Phase 0, Final Report, Vol. II, Technical Report, NSF/AA/-N-74-021B, General Electric Company.
32. Solar Heating and Cooling of Buildings (Phase 0), Vol. II, Final Report, NSF/RA/N-74-022C, TRW, Inc. (May 31, 1974).
33. J. F. Kreider and F. Keith, Solar Heating and Cooling, Scripta Book Company (1975).
34. Solar Energy Intelligence Report (January 3, 1977).
35. E. E. Pickering, "Residential Hot Water Solar Energy Storage," Proceedings - Solar Energy Storage Subsystems for the Heating and Cooling of Buildings, Charlottesville, VA (April 16-18 1975).
36. M. Wolf, "Performance Analysis of Combined Heating and Photovoltaic Power Systems for Residences," Energy Conversion 16, Pergamon Press (1976).
37. Typical Electric Bills, 1975, Federal Power Commission.

THIS PAGE
WAS INTENTIONALLY
LEFT BLANK

BIBLIOGRAPHY: TOTAL ENERGY SYSTEMS

A Market Study of Energy-Related Equipments for the Commercial Buildings Sector, FEA Contract CO-04-50202-00, FEA/D-76/010, Ultrasystems, Inc. (Sept. 1975).

Assessment of Total Energy Systems for the Department of Defense, Vols. I & II, DACA 23-73-C-0014, AD 781-817, A. D. Little (Nov. 1973).

Commercial Applications of Solar Energy Systems, Contract No. E(04-3)-1210, Current, Progress Reports, Rockwell International (AID).

Cost/Benefit Analysis Report and Supporting Opinion Survey, Commercial Buildings, ITC Report 011976, COO/2688-76/1, Inter-Technology Corporation.

Crawford, J. J., "Total Energy and District Heating," Electronics & Power, 621-624 (29 May 1975).

Economic Evaluation of Total Energy Guidelines, HUD-DSC-2, Decision Sciences Corporation (July 1973).

Evaluation of New Energy Sources for Process Heat, PB-245-604, NSF-OEP74-18055-1, Dow Chemical Company (Sept. 1975).

Feasibility Study of Solar Energy Utilization in Modular Integrated Utility Systems, DRD No. MA-542-T, ADL Report No. 78036, A. D. Little, Inc. (30 June 1975).

Funnel, J. E. and Wolfe, E. J., "Utilization of Power-Plant Heat," Combustion, 4-10 (May 1974).

Future Developments in Waste Heat Utilization, Circular No. 49, Oregon State University (Sept. 1975).

Housing Data for Modular Integrated Utility System Economic Analysis, HUD-DSC-3, Vol. I PB 242 392, Vol. II PB 242 393, Decision Sciences Corporation (May 1974).

Initial Comparisons of Modular-Sized, Integrated Utility Systems and Conventional Systems for Several Building Types, JSC-09076, TMX 58140, L. B. Johnson Space Center, NASA (Apr. 1976).

- Industrial Applications of Solar Energy, Contract E(04-3)-1132,
Current, Progress Reports, McDonnell Douglas Astronautics
Company.
- MIUS Community Conceptual Design Study, L. B. Johnson Space Center,
NASA (Feb. 1974).
- MIUS Systems Analysis - The Effects of Thermal Energy Storage and
Solid Waste Incineration Options on MIUS Cost and Fuel Consumption,
ORNL-HUD-MIUS-26, Oak Ridge National Laboratory, July 1976.
- MIUS Technology Evaluation - Thermal Energy Storage Materials and
Devices, ORNL-HUD-MIUS 23, Oak Ridge National Laboratory
(Nov. 1975).
- Northview Junior High Solar Energy Demonstration Project, ERDA
Contract E(11-1)2624, COO/2624-1, Honeywell Systems and Research
Center (May 1975).
- Parisian, R. W., "How Reliable are Today's Prime Movers?" Power, 45-47
(Jan. 1970).
- Proposed Systems Level Plan for Solar Heating and Cooling Commercial
Buildings, Vols. I, II, III, COO/2688-76/6, Inter Technology
Corp. (May 1976).
- Social Cost Considerations and Legal Constraints in Implementing
Modular Integrated Utility Systems, NASA CR-140894, N 75-15503,
Texas Southern University (Dec. 1974).
- Solar Energy for Process Steam Generation, TE 5392-34-75, PB 238-109,
Thermo-Electron Corporation, Waltham, Mass. (Nov. 1974).
- Survey of the Applications of Solar Thermal Energy Systems to Industrial
Process Heat, Vols. I, II, III, Battelle Columbus Laboratories
(Jan. 1977).
- Technical and Economic Feasibility of Thermal Energy Storage, ERDA
Contract E(11-1)-2558, COO-2558-1, Document No. 76SD 4208,
General Electric Corporation (Space Division) (Feb. 1976).
- Technology Evaluation Report, Commercial Buildings, COO/2683-76/1,
General Electric Company (Space Division) (Apr. 1976).