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VOLUME II: TECHNICAL REPORT

FOR THE NATIONAL SCIENCE FOUNDATION/
RESEARCH APPLIED TO NATIONAL NEEDS

THE AEROSPACE CORPORATION

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MISSION ANALYSIS OF PHOTOVOLTAIC SOLAR ENERGY SYSTEMS, ###

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TECHNICAL REPORT

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FOREWORD

This report presents the technical results that were achieved under Grant No. GI-44099, "Mission Analysis of Photovoltaic Solar Energy Systems", issued by the National Science Foundation/Research Applied to National Needs (NSF/RANN). The report is the second of three volumes; the others are: Volume I, Summary, and Volume III, Appendices.

The study was conducted by the Energy Programs Group of the Energy and Transportation Division of The Aerospace Corporation. Dr. Tapan Mukherjee has been the NSF Program Manager for this grant; the principal active supervision has been provided by Dr. Morton Prince (Chief, Photovoltaic Branch) and Dr. Leonard Magid of the Solar Energy Division of the Energy Research and Development Administration (ERDA). Dr. A. B. Greenberg, General Manager of the Energy and Transportation Division was the Principal Investigator. Dr. M. B. Watson is Associate Group Director of the Energy Programs Group. Dr. S. L. Leonard, Associate Director, Photovoltaic Projects, provided the program management.

This report was prepared by Dr. S. L. Leonard, with contributions from Mr. E. Blond, Dr. R. T. Hall, Dr. P. J. Peters, and Dr. C. M. Randall.

The author of this report wishes to express appreciation for the support of the project by a number of other personnel of The Aerospace Corporation. These include Mr. A. Forster, Mr. W. A. Kammer, Mr. J. R. Kettler, Mr. H. J. Killian, Mr. D. E. Kind, Mr. R. B. Laube, Mr. O. J. Mead, Mrs. P. L. Merryman, Mr. J. A. Neiss, Mr. S. Sugihara, and Ms. H. Wong. The help of Mr. Fred Eggers in overseeing the production of the report, of Mrs. J. Rausch in typing the bulk of the text, and of Mrs. M. Bythway and Mrs. A. Wagner in assisting with the typing is also gratefully acknowledged.

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SUMMARY

The overall objective of the Photovoltaic Mission Analysis Program discussed in this report has been to provide a basis for assessing the size and nature of the potential role of photovoltaic solar energy conversion in the energy economy of the future, and thereby to support the development and management of an effective federal program directed at the production and utilization of the technology. The accomplishment of this objective has required the formulation of procedures for evaluating the various conceivable missions (applications) for photovoltaic systems with respect to satisfaction of mission performance requirements and economic competitiveness with alternative methods for carrying out the mission. Methods for determining the requirements that must be satisfied by components and subsystems in order to meet the technical and economic objectives of the mission were also needed. In order to keep the scope of the study within manageable size, it was restricted in geographical coverage to the southwestern United States and, in time, to the 1980 to 2000 period. A secondary objective was to apply the methodology, when developed, to the evaluation of a number of illustrative examples of candidate missions in order to obtain at least a preliminary indication of the competitive position of the photovoltaic technology in the future energy economy of the Southwest.

The general approach that was adopted was a conservative one in which photovoltaic solar energy conversion is treated, without favoritism, as just one more competitor in an energy marketplace that is characterized by high standards of service reliability and by various types of built-in subsidies (overt and hidden) for more conventional power generation methods. This approach therefore represents a "worst case" analysis in the sense that most of the reasonable modifications that might be made in the assumptions or methodology would probably be more favorable to photovoltaic technology. The results that were obtained when this methodology was

applied to various illustrative examples (indicating that, for array prices in the \$100-200/kWpk range, solar energy conversion can be competitive in at least two major classes of applications) are therefore conservative.

Of the many possible missions for photovoltaic solar energy conversion, two general classes of applications were selected for early consideration because of their potential economic significance: on-site missions and central station power production missions. An on-site mission, in this terminology, is one in which the photovoltaic system is dedicated to serving the electric power demand associated with a load point that is co-located with the system, e. g., a rooftop photovoltaic array providing power for a single-family residence. Central station power production missions, as the name implies, are those in which the photovoltaic system functions as an electric generating plant feeding power into the transmission/distribution grid of a utility system. The program reported here has concentrated largely on these two classes of missions, although a smaller amount of attention has also been given to fuel production missions (in which the output of the photovoltaic system is dedicated to the electrolytic production of hydrogen).

A major part of the effort was devoted to the formulation and implementation of analytical procedures for the technical and economic evaluation of on-site and central station missions. The central element of the methodology that was developed is computer simulation of the performance of the photovoltaic system within mission constraints. The mathematical models and computer programs required for these simulations were constructed, and appropriate representations were formulated for the solar energy input and the electric power demand to be met. Also incorporated in the methodology was a reliability analysis procedure for calculating the amount of conventional capacity that must be provided as backup to the photovoltaic systems because of the inherently variable character of solar energy.

In the next step in the methodology, the results of the performance evaluation computations (including backup capacity requirements) are used as inputs for economic analyses. In the on-site case, an economic evaluation procedure was developed that is based on a determination of the present value cost (as of the year of initial operation) of meeting the full load point demand over the lifetime of the photovoltaic system. This cost is then compared with the corresponding present value cost of meeting the same demand by conventional means. In the central station power plant case, the economic evaluation procedure that was chosen involves a complete discounted cash flow analysis of the operation of the plant over its lifetime. To carry out this analysis, a computer program developed in the companion Aerospace Corporation Solar Thermal Mission Analysis Program was adapted to the photovoltaic case. The result is expressed in terms of the busbar cost of energy (in mills/kWh) in any year that is of interest. In both of these economic evaluation procedures, the capital cost of the required conventional backup capacity is included in the cost of the photovoltaic system.

The procedure that was adopted for use in evaluating fuel production (i. e., electrolytic production of hydrogen with photovoltaic power) missions is a simplified version of the methodology described above. While computer simulation is used to determine the performance characteristics of the system, the economic analysis is based on a levelized fixed charge calculation. This simplification was justified on the basis that, although the result is a fairly rough approximation, it is accurate enough to show that costs of photovoltaic hydrogen are not likely to be competitive with costs for alternative fuels, including hydrogen produced in other ways, at least until after the year 2000; a more sophisticated analysis was not needed.

When the development phase was complete and these analytical procedures became operational, the principal focus of the study shifted to application of the methodology to a number of illustrative examples of candidate on-site and central station missions.

In the case of on-site missions, a fairly detailed technical and economic analysis was made of a baseline mission in which flat plate photovoltaic arrays were presumed to be deployed on single-family residences in Phoenix, Arizona. The effect on system performance of varying collector area, electric storage capacity, and collector orientation was studied in a systematic fashion. A number of sensitivity studies were made, with the baseline mission as reference. These included studies of the effects of a) changing the geographical location (within the southwestern U. S.), b) varying the degree of solar penetration (the ratio of the average output of the solar arrays to the average demand in the local utility systems), c) using Winston concentrators, and d) substituting commercial or industrial demand profiles for the residential profiles. The sensitivity of mission economics to such factors as fuel costs of competitive systems, array efficiency, subsystem costs, and the possible use of insolation forecasting was also investigated. (Reliable forecasts of insolation can permit management of the electric storage capacity in such a way as to minimize the impact of backup energy requirements on the peak demand in the utility system, and thereby minimize the amount of supplementary backup capacity that must be provided.)

The central station power plant analyses that were carried out considered 100 MW plants of a single basic design that utilizes flat plate collectors whose tilt angle (about an east-west axis) is adjusted monthly for optimum energy collection. The fundamental system parameters, array area and storage capacity, were varied systematically in studies of the effects of these parameters on system performance. For different ranges of these variables the plant operation can be characterized as baseload, intermediate, or peaking.

The analyses of the on-site, electric-only, and central station missions support the tentative conclusion that, with presently achievable efficiencies and with array prices in the \$100-200/kWpk range, photovoltaic solar energy conversion would indeed be competitive with alternative sources of energy. The analyses leading to this conclusion, furthermore,

did not take into account a number of factors that might improve the competitive position of the photovoltaic technology, such as: a) the productive utilization of the thermal energy removed in cooling the cells, b) the use of concentrators, c) relaxation of the current rigid standards for reliability of service, or d) introduction of government incentives to encourage the use of solar energy or to compensate for noninternalized societal costs of conventional power production.

Complete discussions of these analyses are presented in the body of this report. For illustrative purposes, representative results are included here:

Example 1. On-site Residential System: Phoenix, Arizona, 1990

Specifications

Peak demand	8.2 kW
Average demand	3.5 kW
Array area (cell packing factor = 0.9)	114.0 m ²
Electric storage capacity	28.5 kWh
Collector type	flat plate, fixed tilt (24°)

Results of Analysis

Energy displacement	60.7%
Conventional backup capacity needed	2.09 kW
Breakeven photovoltaic array price	\$135/kWpk (1975 dollars)

Example 2. Central Station Power Plant (Intermediate Mode):
Inyokern, California, 1990 (year of first commercial operation)

Specifications

Rated output	100 MW
Array area (cell packing factor = 0.9)	2(10 ⁶) m ²
Electric storage capacity	5(10 ⁵) kWh
Collector type	flat plate, tilt adjusted monthly

Results of Analysis

Plant capacity factor	0.41	
Required backup capacity	26.0 MW	
Photovoltaic array price	\$100/kWpk	} 1975 dollars
Solar plant investment cost, 1990*	\$1126/kW	
Busbar energy cost, 1991	40 mills/kWh	

Example 3. Central Station Power Plant (Baseload)
Inyokern, California, 1990 (year of first commercial operation)

Specifications

Rated output	100 MW
Array area (cell packing factor = 0.9)	$5(10^6) \text{ m}^2$
Electric storage capacity	$1.5(10^6) \text{ kWh}$
Collector type	flat plate, tilt adjusted monthly

Results of Analysis

Plant capacity factor	0.81	
Required backup capacity	3.0 MW	
Photovoltaic array price	\$100/kWpk	} 1975 dollars
Solar plant investment cost, 1990*	\$2772/kW	
Busbar energy cost, 1991	46 mills/kWh	

It should be reiterated that these analyses were intended primarily as illustrative examples of the application of the methodology. Even for the specific missions studied, they provide only a preliminary indication of merit and economic viability. The cost levels where photovoltaic arrays are economically competitive can be expected to increase when the constraints imposed in these illustrative calculations are realistically relaxed. For

* For a breakdown of this investment cost, see Table 31, page 193.

example, in the comparison between photovoltaic and conventional systems, the fundamental assumption was made that the current economic, institutional, and legal constraints on electric power production and distribution would continue in force. No consideration was given to possible changes in these conditions even though such changes can be projected independent of photovoltaic system considerations. The analyses have served primarily a) to demonstrate the capabilities of the methodology, and b) to point the way for the further investigations that will be needed to make a complete assessment of the potential contribution that photovoltaic conversion of solar energy can make toward meeting the nation's energy needs.

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SECTION 1

INTRODUCTION

In the more than twenty years that have elapsed since the first rudimentary solar cell was fabricated, the principal use that has been found for the photovoltaic conversion of solar energy has been in providing electric power for a variety of space systems. Enough experience has been accumulated with terrestrial applications, however, to demonstrate that there are no fundamental technical barriers to the large-scale use of the technology on the surface of the earth also. The main obstacles are economic, the dominant one being the high cost of the solar cells themselves. It is for this reason that much of the federally-sponsored research on terrestrial photovoltaic applications has been directed toward reducing the cost of the basic photovoltaic materials and devices by up to two orders of magnitude.

In order to justify the current and projected government investment in reducing solar array costs, it is necessary to demonstrate that, when the array cost goals are reached, photovoltaic solar energy systems will have a good chance of competing successfully for a significant place in the nation's energy market. The most promising future missions (applications) for the technology must be identified, and an assessment must be made of its potential competitive position with respect to these missions, within the projected technical, economic, environmental and institutional constraints. It is the function of mission analysis to carry out these tasks. This function, it should be noted, is quite different from that of systems analysis programs, where the goal is to optimize the internal structure of the system, to adjust the system design for maximum performance, minimum cost, or both (i. e., for maximum cost effectiveness). The two types of study are complementary in that systems analysis produces more sharply defined system characterizations which lead to greater precision in mission analysis, while the identification of appropriate applications through mission analysis leads to the recognition of additional factors affecting system design.

In this volume an account is given of one such mission analysis program. The specific objectives and the scope of the study are described below in this section (Section 1) of the document. In the following section (Section 2), a description is given of the basic approach that has been taken in the study, while the next five sections (Sections 3-7) contain discussions of the principal elements of the methodology that was developed. These are followed by three sections (Sections 8-10) in which a number of illustrative examples of the application of the methodology are discussed. The volume then concludes with a brief summary of the conclusions that were reached (Section 11) and a report on research utilization activities (Section 12).

1.1 OBJECTIVES

The primary objective of this project has been to provide a basis for the selection of preferred applications or missions for photovoltaic conversion systems and thereby support the management of an effective research program directed at the production and utilization of photovoltaic technology. To narrow the geographic coverage of the study and permit analysis of specific regional problems, the study has initially examined the southwestern region of the United States and considered the time period from 1980 - 2000.

Secondary objectives of the effort have been to:

- a. Augment and extend the analytical methodology for conducting mission analyses developed for solar thermal conversion systems to photovoltaic conversion systems.
- b. Provide standardized and detailed insolation and demand projections both for the current mission analysis program and for use in other NSF or ERDA-contracted studies.
- c. Determine the technical and economic system/subsystem requirements for the preferred photovoltaic mission(s)/system(s).
- d. Provide a basis for focusing photovoltaic conversion technology research efforts which are being or are planned to be sponsored by NSF/RANN and ERDA.

e. Support the formulation and justification of demonstration projects appropriate for photovoltaic conversion systems.

1.2 SCOPE

The scope of the study was somewhat more sharply defined than is indicated by the rather general statement of objectives in the preceding section. The principal assigned task was to develop methods for evaluating three main classes of terrestrial missions for the photovoltaic conversion of solar energy: on-site power generation, central station power generation, and fuel/feedstock production. For the purposes of the study an on-site mission was defined as an application in which the photovoltaic system is dedicated to serving all or part of the electric power demand at a load point that is colocated with the system. An example of such an application would be the use of a rooftop array to provide power to a single-family residence. In central station power generation missions, a very large photovoltaic conversion plant generates power that is dispatched into the transmission/distribution grid of an electric utility system. A fuel/feedstock production mission is one in which photovoltaic electricity is used in the direct production of a material that can either be used directly as a fuel or can serve as the basis for production of a valuable manufacturing feedstock. The most obvious example is the electrolytic production of hydrogen.

A second major task was to apply the evaluation methodology, when it should become ready for operation, in preliminary assessments of a number of illustrative examples of each of the three mission classes. The objective of these analyses was to be the validation and demonstration of the methodology and the tentative identification of those applications in which photovoltaic technology has the highest probability of making a significant contribution toward meeting national energy needs. This assessment task included the assignment of technical and economic goals to be met by photovoltaic systems, subsystems, and components in order that the photovoltaic technology can compete effectively with alternative sources of energy.

As will become clear in the later sections of this report, most of the effort in the program was, in fact, devoted to the first two classes of missions: on-site and central station applications. A preliminary analysis indicated that fuel/feedstock production was a considerably less attractive possibility than were the other two missions, and it was early decided that the most productive use of the available resources would be achieved by concentrating on the two more promising mission classes.

SECTION 2

APPROACH

The focus of this study has been on the development and application, in a number of illustrative examples, of analytical procedures for the evaluation of several specific classes of missions (applications) for photovoltaic solar energy conversion. Although the sets of procedures that have been developed for evaluating each of these mission classes differ from each other in a number of particulars, they are all based on the same general approach. This approach, illustrated schematically in Figure 1, contains three basic elements: a) computer simulation to evaluate the technical performance of the photovoltaic system within the constraints that characterize the mission, b) reliability analysis to determine the amount of backup generation capacity (if any) that must be provided in order to ensure that the overall reliability of electric power service meets mission requirements, and c) economic analysis to determine the cost of providing the required electric power by photovoltaic means. This cost must then be compared with the cost of generating the power by more conventional methods.

The computations of system performance are carried out with the aid of a suitable mathematical model for the photovoltaic system, along with representations for the solar energy input (characteristic of the presumed location of the system) and for the electric power demand that characterizes the mission being studied. In order that the effects of the diurnal and seasonal variations in both insolation (incident solar energy) and demand may be taken into account, the computations are typically carried out on an hour-by-hour basis for a full year of simulated operation. The objective of the simulation is to evaluate the effects of the complex interaction between time-varying insolation input, general system performance characteristics, and time-varying demand rather than to optimize system design. It is therefore appropriate to use a fairly general system model, although key parameters and critical interfaces must be included. The same basic

Figure 1

FLOW DIAGRAM OF STUDY APPROACH

system model, with suitable modifications, has been used in the evaluation of the different classes of missions investigated in this study.

As is indicated in Figure 1, the results of the performance analysis computations serve as inputs both to the economic analysis and to the reliability analysis.

The philosophical basis of the reliability analysis has been the fundamental assumption that the ultimate consumer of electric power in any of the missions considered in this study will demand the same high degree of reliability in electric service that he receives from conventional power sources. Because of the inherently variable nature of the solar energy input, a photovoltaic system can match the reliability of conventional sources only if the system includes both a very large amount of storage capacity for electric energy and a photovoltaic array that is large enough to fill the storage in addition to meeting current demand. Since both storage capacity and the additional array area needed to fill it are very expensive, the result of the imposition of the reliability requirement is that, in most cases, photovoltaic on-site or central station systems must be operated in conjunction with conventional energy sources.

The nature of the interface between photovoltaic system and non-solar generation capacity depends on the type of mission under study. If the photovoltaic systems are used as central station power plants, they become units in a utility generation system containing, in general, many individual power plants whose combined output is used to meet the system demand. In an on-site application, the photovoltaic system is dedicated to serving a particular local demand, with backup power from conventional sources as required. In either case, the fact that a photovoltaic solar energy system experiences weather-related outages that are not experienced by fossil-fuel or nuclear systems means that conventional generation capacity cannot simply be replaced, on a kW-for-kW basis, by photovoltaic capacity without reducing overall utility system reliability. To maintain that reliability,

therefore, a certain amount of additional conventional capacity must be provided to compensate for the effect of the photovoltaic system's insolation outages. For this reason, the mission evaluation methodology used in this study includes a reliability analysis procedure for calculating how much backup capacity is needed. The principal inputs that are required are the results of the simulation computations and a mathematical model for the utility system that provides the backup power. This model includes representations for the total system demand, on an hourly basis, and for the total generation capacity of the system.

The output of the reliability analysis (in the form of a value for the required backup capacity) then serves as an input to the economic analysis, along with the results of the simulation computations and estimates for the capital costs of the various elements of the photovoltaic system. Somewhat different approaches have been used in carrying out the economic analyses for the three main classes of missions investigated in this study. For on-site missions, the economic evaluation is based on a determination of the present value cost (as of the year of initial operation) of meeting the full load point demand over the lifetime of the photovoltaic system. This cost is then compared with the corresponding present value cost of meeting the same demand by conventional means. In the central station power plant case, the economic evaluation is based on a complete discounted cash flow analysis of the operation of the plant over its lifetime. This analysis is accomplished with the aid of a computerized Power Plant Economic Model developed for the successive Aerospace Corporation Solar Thermal Mission Analysis studies. The result is expressed in terms of the cost of energy (in mills/kWh) in the year of interest. In both of these economic evaluation procedures, the capital cost of the required conventional backup capacity is included in the cost of the photovoltaic system.

The procedure that has been used in evaluating the fuel production (i. e., electrolytic production of hydrogen with photovoltaic power) mission is a simplified version of the methodology described above. While computer

simulation is used to determine the performance characteristics of the system, the economic analysis is based on a levelized fixed-charge calculation. This simplification has been justified on the basis that, although the result is a fairly rough approximation, it is accurate enough to show that costs of photovoltaic hydrogen will not be competitive with costs for hydrogen produced by other methods in the foreseeable future; a more sophisticated analysis is not needed.

There are a number of other respects in which the implementation of the general analytical approach outlined in this section has differed for the three different mission classes. The body of this report contains more detailed descriptions of the specific methodologies employed in the three cases, along with presentations of the results of application of the methodologies to a number of illustrative examples.

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SECTION 3

INSOLATION

One essential element of every system simulation computation carried out in the course of this study is a suitable representation for the incident solar radiation (insolation) at the site where the system is presumed to be located. Because the variability of the input energy flow is one of the most significant characteristics of any solar energy conversion system, it is essential that this input energy be represented in a realistic fashion. The random weather-related variations in insolation must be included in the model along with the regular diurnal and seasonal patterns. The most satisfactory way to prepare such a model is to use actual historical records of insolation at the location in question, on the hypothesis that the weather patterns of the past are the best available indicators of future patterns. At locations for which insolation records are not available, records of other weather variables (e. g., cloud cover) that are correlated with sunshine may be used as indicators of insolation levels.

The insolation representations that were used in this study are a part of a much larger insolation data base that has been prepared at The Aerospace Corporation for general use in evaluating solar energy conversion systems. The basic characteristics of the data base -- format, content, procedures for estimating missing data -- were developed in the course of a study of possible Southern California applications (missions) for solar thermal systems (Reference 1). The data base has since been extended several times (References 2 and 3) and now provides coverage for the 48 contiguous states of the U. S. Data for three sites (Charleston, S. C., Great Falls, Montana, and Cleveland, Ohio) were added to the data base as part of the effort in the Photovoltaic Mission Analysis study reported here.

The requirements that the Aerospace insolation data base was designed to satisfy are discussed briefly below (in Section 3.1). The

available historical records of insolation measurements are described in Section 3.2, while Section 3.3 contains a discussion of the correlations that were used in estimating missing insolation values. This is followed, in Section 3.4, by descriptions of the procedures used in constructing the data base, its content, and its limitations. The final two sections of the chapter contain accounts of two special studies that were carried out as part of the current Photovoltaic Mission Analysis. The first of these was an investigation of the importance to photovoltaic system simulation studies of typical variations in the spectral content of insolation. The second study was a preliminary investigation of the accuracy with which insolation can be forecast on the basis of current weather-prediction techniques. This latter study was also supported in part by the current Solar Thermal Mission Analysis Program at The Aerospace Corporation (Reference 3).

3.1 DATA REQUIREMENTS

The insolation data base used in these studies was designed to satisfy a number of general requirements:

- a. In order to permit evaluation of solar energy conversion systems employing concentrating collectors as well as those using flat plate collectors, the data base must include values for both direct, unscattered radiation and total insolation (including both the direct and the diffuse, or scattered, components).
- b. Separate representation for each major climatic region is needed.
- c. The time interval between recorded values must be small enough to reflect diurnal variations.
- d. All sets of data should cover the same time period, and this period should be at least one year in length and should be a period in which the insolation record was reasonably "typical".
- e. Measured values for other weather variables likely to be important to the operation of solar energy conversion systems should be included.

After a study of the availability of insolation data (see Section 3.2, below), it was decided that the data base would meet these general requirements to an acceptable degree if it contained a two-year record of hourly values for the readings of a normal-incidence pyrliometer and a hemispherical pyranometer, along with hourly values for the other weather parameters that are routinely measured. (A pyrliometer records the radiation from a small field of view, typically 5.7° in diameter, centered on the sun; the output thus represents the direct radiation plus only a small amount of scattered light. A pyranometer records all the solar radiation, direct plus diffuse, that falls on a horizontal surface.) Because of the rapidly increasing volume of data involved, the requirement for representation of climatic regions was relaxed in stages as the focus of the studies widened from Southern California (Reference 1) to the southwestern U.S. (Reference 2) and eventually to the contiguous 48 states (Reference 3). As a result, Southern California and the Southwest are considerably more heavily represented in the data base than are other areas of the country.

3.2 DATA AVAILABILITY

The only possible source for the immense numbers of measured values needed in order to construct the desired data base was the body of data routinely gathered by the National Weather Service (NWS) and by independent weather stations cooperating with the NWS. Only three kinds of instruments have been used to make routine measurements of solar radiation at any of these stations: normal-incidence pyrliometers, hemispherical pyranometers, and sunshine switches. The first two types of instruments have been discussed above. Sunshine switches simply record the fraction of the time when sunshine, sufficiently collimated to be focused with a lens, exceeds some minimum value; the output is expressed as total minutes per day or total hours per day of sunshine or as a percentage of possible sunshine duration. All of these data are archived, in one form or another, at the National Climatic Center in Asheville, N. C.

From the point of view of those interested in solar energy conversion, this store of historical insolation records suffers from a number of serious deficiencies. The most important shortcoming is the relative scarcity of the data. Routine pyrheliometer measurements have been made at only a handful (typically four or five during any given year) of sites in the U.S. The pyranometer network includes many more stations than this, but still relatively few in comparison to the total number of weather stations in the U.S. In 1951, the number of pyranometer stations was increased from 35 to 83 (58 operated by the NWS and 25 by cooperators). This number increased gradually to 90 in 1963 (60 NWS and 30 cooperating stations), of which four were in Alaska and one in Hawaii. Although the number of stations equipped with sunshine switches is larger (160 in 1973), the output data represent only total daily sunshine duration and provide no hourly information at all.

The available store of data is even more limited than is indicated by the above numbers. The normal incidence pyrheliometer measurements were not made at hourly intervals but rather at times corresponding to certain standard air mass ratios (i.e., to certain standard values of the angular distance of the sun from the zenith). Values were not always recorded even for these times, moreover; apparently measurements were frequently omitted when the sun was even partially obscured. For several of the stations, the missing data far outnumber those that were recorded, at least insofar as tabulated values (as reported in the NWS publication, Climatological Data, National Summary) are concerned. (In some cases, the raw data, in the form of strip-chart records, have been archived at Asheville and could, albeit at considerable expense, be reduced to digital form.)

The situation with respect to total insolation data is somewhat better; hourly data for 44 stations have been stored on magnetic tape in a format ("Card Deck 280") that also includes values for a number of other surface weather variables. To be sure, for a significant fraction of these stations the period of record, in this format, is very short; and, furthermore,

six of the 44 sets of records simply represent continuations of earlier records of data obtained at nearby sites. In addition to the Card Deck 280 records, manuscript records of hourly total insolation values are available for several of the other sites in the pyranometer network. For a number of the stations, however, no hourly data appear to be available in any form, although values for daily totals have been archived.

Another deficiency of the historical insolation records is that the quality of the data is subject to considerable question. Because of the relatively low priority of the insolation measurement program within NWS, only very limited resources have been allocated to the program for a number of years. As a result, there was inadequate routine maintenance and station inspection and only limited data monitoring and quality control. These deficiencies led, in turn, to undetected instrument deterioration and unreliable data. This process culminated in a decision by the NWS, in 1972, to cease publication of the data. As a result of the current resurgence of interest in solar energy, steps are being taken to upgrade the network and to devise means for validating or rehabilitating at least a part of the historical data. In the meantime, however, the only available NWS data are those published before September 1972, and any insolation representation must be based on these values.

3.3 CORRELATIONS

Because of the relative scarcity of hourly historical data, particularly values for direct insolation, a search was made for ways to estimate the required data from measured values of other weather variables on the basis of observed correlations. Of the various possible correlations that were investigated, only two proved close enough to be used with any degree of reliability in such estimation procedures. These are the correlation between direct insolation and the percent of possible total insolation, P , (the ratio of ground-level total insolation to the corresponding value at the top of the atmosphere) and the correlation between P and opaque sky cover, S , (the fraction of the sky, in tenths, that is covered by clouds

thick enough to obscure the image of the sun or moon, as estimated by a NWS observer). In studying these correlations, values for P were obtained by dividing each measured value for total insolation by a calculated value for the intensity of the extraterrestrial radiation at the same hour.

The correlation between direct (normal incidence) insolation, N, and the percent of possible total insolation, P, was studied on the basis of measured values for these two parameters that were obtained at Albuquerque, New Mexico, and Blue Hill, Massachusetts. Data from these sites were used because the number of measured values for N was much higher for these two sites than for the other pyrheliometer stations. As was mentioned in Section 3.2, values for N were only recorded at times corresponding to certain standard air mass ratios; hourly values were obtained from these records by interpolation.

Figure 2 is a scatter plot of the Albuquerque data for the years 1962 and 1963, each point representing the value of N and P for a given hour. (The years 1962 and 1963 were chosen because these are the base years selected for the entire insolation data base, as discussed in Section 3.4, below.) The plot indicates that there is a roughly linear relationship between the two variables; the least-squares best-fit regression line obtained on the basis of these data is included in the figure (labeled "Albuquerque"). Also included in the figure is the linear regression line obtained on the basis of a separate analysis of the Blue Hill data for the same years. Since these lines nearly coincide in the region where there are data points, an estimation procedure was adopted that is based on an average of the two lines, weighted in accordance to the relative numbers of observations represented by each. In addition, it was assumed (somewhat arbitrarily) that for values of P below 25%, there is no direct radiation. The result is an estimation procedure that can be described by the equation:

$$N = \begin{cases} b_1 + b_2 P & P \geq 25\% \\ 0 & P < 25\% \end{cases} \quad (1)$$

where $b_1 = -117.1 \text{ W/m}^2$ and $b_2 = 12.28 \text{ W/m}^2$.

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where $b_1 = -117.1 \text{ W/m}^2$ and $b_2 = 12.28 \text{ W/m}^2$.

Figure 2

CORRELATION OF NORMAL-INCIDENCE INSOLATION WITH
PERCENT OF POSSIBLE TOTAL INSOLATION, ALBUQUERQUE, NM, 1962-3

(The units have been converted to correspond to those chosen for the insolation data base.)

The correlation between percent of possible total insolation, P, and cloud cover proved to be, in general, somewhat poorer than that between N and P. The NWS records include two measures of overall cloud cover; total sky cover, R, and opaque sky cover, S. Since the correlation between R and P was found to be somewhat poorer than that between S and P, it was the latter correlation that was selected for further investigation. It was expected that P would depend not only on cloud cover but also (because of absorption and scattering) on the path length of the incident radiation through the atmosphere, as measured by the air-mass ratio, A (the ratio of the actual path through the atmosphere to the vertical thickness of the atmosphere). For this reason, the correlation between S and P was studied on the basis of data taken under conditions when A fell within a restricted range.

Figure 3 is a scatter plot of pairs of P and S values measured at Riverside, California, in 1962 when A lay between 1 and 2. Inspection of plots like that in Figure 3 immediately indicated that the relationship between P and S is not linear. Least-squares best-fits of these data with polynomials of increasing degree were attempted and it was found to be unnecessary to use polynomials of degree higher than three. Accordingly, an estimating relationship for P was developed in the form:

$$P = a_1 + a_2 A + a_3 S + a_4 S^2 + a_5 S^3 \quad (2)$$

Although data from a given station led at a_i values at least slightly different from those for any other station, it was found that the a_i values for stations in the southwestern U. S. fall into two large groups. The average a_i values for these groups are listed in Table 1, along with the a_i values for each of the other stations where hourly P values were available. (Where measured insolation data were not available, the a_i values shown in Table 1 are the values adopted for use in estimating P.)

Figure 3

CORRELATION OF PERCENT OF POSSIBLE TOTAL INSOLATION WITH
OPAQUE SKY COVER, RIVERSIDE, CA, 1962: AIR MASS 1-2

Table 1

DATA SOURCES, INSOLATION DATA BASE

Station	Station Number	Latitude	Longitude	Weather Data Source	Total Insolation Data Source*	Direct Insolation Data Source*	Estimation Parameters (Eq. 2)				
							a ₁	a ₂	a ₃	a ₄	a ₅
Albuquerque, NM	23050	35.05	106.62	144	280	CDNS + Est	83.018	-3.847	-4.4074	1.10129	-0.110903
Cleveland, OH	14820	41.40	81.85	144	Est	Est	↓	↓	↓	↓	↓
Edwards AFB, CA	23114	34.90	117.90	144	Est	Est					
El Paso, TX	23044	31.80	106.40	280	280	Est					
Ely, NV	23154	39.28	114.85	280	280	Est					
Grand Junction, CO	23066	39.12	108.53	144	Est	Est					
Inyokern, CA	93104	35.68	117.68	144	MANS	Est					
Los Angeles Airport, CA	23174	33.93	118.38	280	280	Est					
L. A. Civic Center, CA	93134	34.05	118.23	APCD	APCD	Est					
Midland, TX	23023	31.93	102.20	144	Est	Est					
Omaha, NE	94918	41.37	96.02	144	280	CDNS + Est					
Riverside, CA	23119	33.95	117.45	144	MANS	Est	↓	↓	↓	↓	↓
Salt Lake City, UT	24127	40.78	111.92	144	MANS	Est					
San Diego, CA	23188	32.73	117.18	144	Est	Est					
Santa Maria, CA	23273	34.90	120.45	280	280	Est					
Yuma, AZ	23195	32.65	114.62	144	Est	Est					
Dodge City, KS	13985	37.77	97.97	280	280	Est					
Fort Worth, TX	03927	32.83	97.05	280	280	Est					
Phoenix, AZ	23183	33.43	112.02	144	280	Est					
Tucson, AZ	23160	32.23	110.95	144	MANS	CDNS + Est					
Bismarck, ND	24011	46.77	100.75	280	280	Est					
Blue Hill, MA	14753	42.22	71.02	144	280	CDNS + Est	77.80	-0.7682	-3.5115	0.75070	-0.08906
Boise, ID	24131	43.57	116.22	144	Est	Est	81.90	-3.7107	-7.4073	1.4535	-0.12449
Charleston, SC	13880	32.54	80.02	280	280	Est	83.02	-3.847	-4.4074	1.10129	-0.11090
Fresno, CA	93193	36.77	119.72	280	280	Est	76.11	-1.0357	-3.7028	0.86979	-0.10291
Great Falls, MT	24143	47.29	111.21	280	280	Est	78.335	-2.817	-6.2334	1.41585	-0.12854
Lake Charles, LA	03937	30.12	93.22	280	280	Est	72.62	-0.6357	-2.6434	0.23783	-0.043214
Madison WI	14837	43.13	89.33	280	280	Est	71.34	-0.9497	-4.6256	1.1703	-0.11779
Medford, OR	24225	42.37	122.87	280	280	Est	72.41	-0.6481	-4.7503	1.1271	-0.11268
Miami, FL	12839	25.80	80.27	144	280	Est	72.24	-0.7993	-2.5297	0.64791	-0.084989
Nashville, TN	13897	36.12	86.68	280	280	Est	71.81	-2.8132	-4.4017	1.1349	-0.11834
Seattle, WA	24233	47.45	122.30	280	280	Est	75.94	-0.7863	-4.1720	1.1144	-0.11947
Sterling, VA	93734	38.98	77.47	144	280	Est	74.39	-0.7155	-3.9603	1.0734	-0.11803

* "280" indicates National Climatic Center (NCC) Card Deck 280. "144" indicates NCC Card Deck 144. "CDNS" indicates the publication, Climatological Data, National Summary. "APCD" indicates that the data were obtained from the Los Angeles Air Pollution Control District. "MANS" indicates that hourly insolation data were obtained in manuscript form from the NCC. "Est" indicates that values were estimated.

The studies leading to the development of the estimating relationships represented by Equations 1 and 2 are described in greater detail in Volume III of Reference 1.

3.4 INSOLATION DATA BASE

The insolation data base that has gradually evolved now includes representation for 33 different locations; these are located on the map in Figure 4 and listed in Table 1. As is indicated in the table, the basic data have come, in general, from several different sources within the archives at the National Climatic Center (NCC), in Asheville, N. C. The only exception is the body of data gathered at the Los Angeles Civic Center by the Los Angeles Air Pollution Control District. In the great majority of cases, the data were obtained from the NCC in Card Deck 280 format. This format includes, in addition to hourly insolation values, data on a variety of other weather variables. Values are given, however, only for daylight hours and the surface weather data do not include any information on winds.

For all locations for which Card Deck 280 data were not available (except for the Los Angeles Civic Center) weather data were obtained from the NCC in Card Deck 144 format. This format includes hourly (at least for years prior to 1965) data, covering the full 24 hours of each day, on all the surface weather variables that are included in Card Deck 280 and, in addition, on wind velocity and direction. For four stations (Inyokern, Riverside, Tucson, and Salt Lake City) out of this latter group, manuscript records of hourly values of total insolation were obtained from the NCC. For the remaining stations, hourly values of total insolation were obtained through the use of the estimation procedure represented by Equation 2 in Section 3.3. In at least two of these cases (Boise and Cleveland), measured values for the daily insolation totals were available; the estimated hourly values were therefore normalized to yield daily total values equal to the measured values.

Figure 4
SITES REPRESENTED IN INSOLATION DATA BASE

In the applications for which the insolation data base was first designed, the absence of wind data and of nighttime values for other surface weather data in the Card Deck 280 records was not considered to be a significant deficiency. More recently, however, this data base has come to be used in studies for which the thermal energy balance is important. For this reason, Card Deck 144 (24-hour surface weather data) records were obtained for six sites (Albuquerque, Phoenix, Omaha, Blue Hill, Sterling, and Miami) and incorporated into the data base records for these sites. Wind data and 24-hour surface weather data are therefore included in the records for a total of 17 sites (the six listed above and the 11 others for which Card Deck 144 data were obtained in the first place).

As has been indicated in Section 3.3, data on direct insolation are available only for a handful of locations and have been recorded only for hours corresponding to certain air-mass ratios. These data are published in tabular form in the monthly U.S. Dept. of Commerce publication, Climatological Data, National Summary. For two of the sites (Albuquerque and Blue Hill) the data records are fairly complete, but for the others the recorded values are fairly sparse. For those locations and times for which these data were available, hourly values for direct insolation were obtained by interpolation. In all other cases, the hourly direct insolation data were estimated, on the basis of the corresponding values for total insolation, by means of the relationship expressed in Equation 1 of Section 3.3.

Data for two full years, 1962 and 1963, are included in the data base. The choice of these particular years was based on several considerations. The first of these was that in 1965 the NWS switched from reporting surface weather data on an hourly basis to reporting them at three-hour intervals. At the same time certain types of data (e.g., opaque sky cover) were omitted from the Card Deck 280 records. Only years prior to 1965 were therefore considered. Inspection of records at the NCC indicated that the amount of available insolation data was greater for the period of the late 1950's and early 1960's than for earlier years. Since the average values for the relevant weather and insolation variables for the years 1962

and 1963 (at least in the Southwest) fairly closely approximated the long-term averages, these two years were selected. Subsequent, more detailed comparisons (References 1 and 2) revealed that the insolation in these two years was, indeed, fairly "typical", i. e., not sharply divergent from long-term trends.

The contents of the resulting data base are summarized in Table 2. As has been indicated in the preceding paragraphs, not all of these data are available for every hour at every station. In every case, however, the records of hourly values for direct and total insolation are complete; where data were missing in the original records, estimated values have been inserted. The hierarchy of procedures used in estimating these missing data is described in References 1 and 2. The format that has been used in The Aerospace Corporation insolation data base is based on that of the NCC Card Deck 280 records. It has, however, been expanded to permit inclusion of values for direct insolation and for wind direction and velocity. The format also provides sufficient space for incorporating still more data at some later time.

3.5 EFFECTS OF SPECTRAL VARIATIONS

The data base that has been described in the preceding sections was designed for use in simulations of a wide variety of solar energy conversion systems. In one important particular, its use in evaluating photovoltaic systems can be questioned: it contains no spectral information. The basic insolation measurements represented in the base were made with pyranometers or pyrhemimeters that have essentially flat spectral response characteristics over the full solar spectrum. The responses of photovoltaic devices, however, exhibit marked dependence on the spectral content of the incident light, and it is well known that the spectrum of the insolation arriving at the surface of the earth is not constant. It varies with time of day and with changing meteorological conditions, principally as a result of scattering from aerosol particles and absorption by water vapor.

Table 2

CONTENTS OF THE INSOLATION CLIMATOLOGY DATA BASE

1. Identifying Information

Station Number
Date as Year, Month, Day
Hour of Local Standard Time
Date as Modified Julian Day Number
Hour of Solar Time
Solar Elevation Angle
Solar Azimuth Angle
Solar Declination
Solar Week

2. Insolation Data

Extraterrestrial Solar Radiation on horizontal flat plate
Observed Total Solar Radiation on a horizontal flat plate for one hour
Flags to indicate when Total and Normal-Incidence Insolation have
 been estimated
Normal-Incidence Solar Radiation
Percent of Possible Total Insolation on a flat horizontal plate

3. Weather Data

Snow Cover
Opaque Sky Cover
Visibility
Weather and Obstructions to Vision (Precipitation, Haze, etc.)
Dry Bulb Temperature
Dew Point Temperature
Clouds and Obscuring Phenomena (see Appendix B for details)
Total Sky Cover
Wind Direction
Wind Speed
Station Pressure

An assessment of the magnitude of the error that might be introduced by ignoring these spectral variations has been carried out with the aid of a computer program for determining atmospheric transmittance as a function of wavelength and of the zenith angle of the source. When the spectrum of the extraterrestrial radiation is used as an input to this program, the output is the insolation spectrum at the surface of the earth. The program permits the use of one of five different standard models (Reference 4) of the atmosphere: a tropical model and models representing mid-latitude summer, mid-latitude winter, subarctic summer, and subarctic winter. All of these models incorporate the same size distribution for aerosol particles and yield the same sea level visibility, 23 km. Also available for use with the program are alternative versions of each atmospheric model in which the aerosol concentration near the surface is increased in such a way as to reduce sea level visibility to 5 km. The total amounts of precipitable water vapor that are included in the first three atmospheric models are: tropical, 5.15 cm; mid-latitude summer, 3.68 cm; and mid-latitude winter, 1.05 cm. Figure 5 indicates that these values bracket reasonably well those to be expected in the southwestern U.S.

Calculations were made of the ground-level solar spectrum under a variety of conditions. The first three atmospheric models (tropical, mid-latitude summer, and mid-latitude winter) were used in both the high-visibility (23 km) and low-visibility (5 km) versions, and for each of these six models six different solar zenith angles (0° , 15° , 30° , 45° , 60° , and 70°) were assumed. The calculated ground-level spectra were then convolved with the transmission spectrum for a 1 mm thick layer of Pyrex. The integral of one of these convolution spectra with respect to wavelength is then proportional to the output of a pyranometer under the associated atmospheric conditions (since the radiation-absorbing element in a pyranometer is covered by a thin glass hemisphere).

Each of these ground-level insolation spectra was also convolved with a standard spectral response curve for a silicon solar cell. The integral of such a convolution spectrum is proportional to the electric

Figure 5

AVERAGE PRECIPITABLE WATER VAPOR
IN THE UNITED STATES (gm/cm^3)

power output to be expected from the cell. Figure 6 illustrates some of the results of these calculations and calls attention to the fact that it is atmospheric water vapor that plays the largest role in shifting the ground-level insolation spectrum. The figure includes the insolation spectrum obtained if the high-visibility version of the tropical atmospheric model is used, the silicon spectral response curve, and the calculated solar cell output as a function of wavelength. Also shown are the corresponding curves that are obtained when the tropical model is altered by arbitrarily setting the precipitable water vapor to zero. The corresponding curves that are obtained if the low-visibility (5 km) version of the tropical model is used are shown in Figure 7.

The way in which the results of these calculations were used to assess the error incurred by ignoring the effect of variations in the insolation spectrum is indicated in Table 3. The numbers in the lines labeled "spectral effect included" are those obtained by integrating the convolutions of the ground-level insolation spectra with the silicon spectral response curve. These values were then arbitrarily normalized with respect to the result obtained at $\theta = 15^\circ$ with the high-visibility mid-latitude summer atmosphere. The numbers in the lines labeled "spectral effect neglected" were obtained by multiplying the integrals of the convolutions of the insolation spectra with the transmission spectrum for 1 mm of Pyrex (i. e., the calculated pyranometer readings) by the same constant factor. (In effect a constant "efficiency" relating solar cell output and pyranometer reading, independent of variations in insolation spectrum, is being assumed.) The constant factor used in calculating the values in Table 3 is the ratio of the calculated solar cell output to the integral of the solar insolation spectrum (the calculated pyranometer reading) for the $\theta = 15^\circ$, 23 km visibility, mid-latitude summer case. The computational procedure corresponds to an observational one in which the output of a solar cell is compared to the reading of a pyranometer on a clear summer day and then the observed efficiency factor is used to predict solar cell output values from pyranometer readings made at other times. The results of the calculations for the tropical atmosphere case (lower third of Table 3) are also displayed in graphical form in Figure 8.

Figure 6

CALCULATED INSOLATION SPECTRUM AND SILICON
SOLAR CELL OUTPUT - CLEAR DAY

VISIBILITY 5 km

Figure 7

CALCULATED INSOLATION SPECTRUM AND SILICON
SOLAR CELL OUTPUT - HAZY DAY

Table 3

EFFECT OF AIR MASS ON SILICON SOLAR CELL OUTPUT

ATMOSPHERE	VISIBILITY	SPECTRAL EFFECT	ZENITH ANGLE					
			0	15°	30°	45°	60°	70°
MID-LATITUDE SUMMER	23 km	INCLUDED	1.0108	1.0	0.9642	0.8919	0.7511	0.5797
		NEGLECTED	1.0116	1.0	0.9626	0.8881	0.7477	0.5828
		DIFFERENCE	0.0008	0	-0.0016	-0.0038	-0.0034	0.0031
	5 km	INCLUDED	0.6174	0.6004	0.5469	0.4476	0.2878	0.1471
		NEGLECTED	0.6390	0.6222	0.5697	0.4728	0.3181	0.1793
		DIFFERENCE	0.0216	0.0218	0.0228	0.0252	0.0303	0.0322
MID-LATITUDE WINTER	23 km	INCLUDED	1.0339	1.0230	0.9873	0.9149	0.7733	0.5997
		NEGLECTED	1.0501	1.0387	1.0006	0.9255	0.7836	0.6153
		DIFFERENCE	0.0162	0.0157	0.0133	0.0106	0.0103	0.0156
	5 km	INCLUDED	0.6334	0.6163	0.5622	0.4612	0.2982	0.1540
		NEGLECTED	0.6678	0.6509	0.5971	0.4977	0.3379	0.1934
		DIFFERENCE	0.0344	0.0346	0.0349	0.0365	0.0397	0.0394
TROPICAL	23 km	INCLUDED	1.0041	0.9930	0.9575	0.8854	0.7458	0.5756
		NEGLECTED	1.0006	0.9892	0.9520	0.8776	0.7387	0.5751
		DIFFERENCE	-0.0035	-0.0038	-0.0055	-0.0078	-0.0071	-0.0005
	5 km	INCLUDED	0.6127	0.5957	0.5424	0.4436	0.2848	0.1454
		NEGLECTED	0.6304	0.6139	0.5619	0.4658	0.3124	0.1755
		DIFFERENCE	0.0177	0.0182	0.0195	0.0222	0.0276	0.0301

Figure 8

EFFECT OF AIR MASS ON SILICON SOLAR CELL OUTPUT

The absolute differences between the "spectral effect included" and the "spectral effect neglected" numbers in Table 3 and in Figure 8 are clearly small, although the percentage differences are substantial for hazy atmospheres at large zenith angles. The conclusion that has been drawn from these results is that the errors incurred through neglecting the effect of variations in the insolation spectrum would not have a substantial effect on the system simulation calculations planned in this program. No attempt was made, therefore, to develop methods for estimating the spectral distribution of the insolation on the basis of time of day or measured meteorological parameters. The insolation data base described in Section 3.4 was used without change.

Similar calculations to those described above were carried out for CdS/Cu₂S solar cells, utilizing a spectral response curve reported by Palz and his colleagues (Reference 5). The results of these calculations were very similar to those obtained for silicon cells and supported the same conclusion, namely, that it would be unjustifiable, in the context of this mission analysis program, to allocate any substantial effort to the task of modeling the effect of air mass variations on the ground-level insolation spectrum.

3.6 INSOLATION FORECASTING

It became apparent fairly early in this investigation that there was a distinct possibility that significant economic benefits might be derivable from the availability to operators of photovoltaic systems of accurate 12-24 hour forecasts of insolation. In the case of on-site photovoltaic applications, in particular, such forecasts would provide advance warning of an impending insolation short-fall and of the corresponding requirement for backup energy during the following day. The photovoltaic system operator could then extract the required backup energy from the utility grid during off-peak hours and store it in his electric storage subsystem for later

use. The widespread use of such a storage management strategy with on-site photovoltaic systems could minimize the impact of backup energy requirements on the peak demand in the utility system and, therefore, on the amount of supplementary generation capacity that would be needed. Since the capital cost of this supplemental generation capacity is a cost that properly should be included in the capital costs of photovoltaic power generation, the use of forecasting and optimal storage management could conceivably reduce overall system costs appreciably.

In order to assess the potential value of insolation forecasts in the management of photovoltaic energy systems, it is necessary to determine a) how much economic advantage could be realized if highly accurate forecasts were available, b) how this result varies with forecast reliability, and c) how accurately insolation can, in fact, be forecasted. The first two of these questions were addressed, to a limited extent, in the technical and economic analyses of on-site applications that are described later in this report. The last question was the subject of a short special study that is reported in this section.

As far as can be determined, there have not been any attempts by weather forecasters to forecast insolation directly. Cloud cover, however, is routinely forecasted in most parts of the world, and the U.S. National Weather Service provides quite detailed cloud forecasts at a number of locations in the U.S. Furthermore, the correlation studies discussed earlier in this chapter (Section 3.3) have shown that it is possible to estimate total insolation on the basis of values for opaque cloud cover. One can therefore get a fairly good indication of the insolation forecasting accuracy that is permitted by the present state of meteorological science by comparing measured values of insolation with values derived from forecasted cloud cover. Such a comparison has been carried out on the basis of data obtained at two widely separated locations: Madison, Wisconsin and Albuquerque, New Mexico.

3.6.1 Methodology

The basic data used in this study were cloud cover forecasts and observations of daily total insolation. The National Weather Service provides aviation weather forecasts for the next 12- or 24-hour period four times a day at 0500, 1100, 1700, and 2300 GMT.* These forecasts include cloud cover predictions for each hour over the entire forecast period. The cloud cover is forecast in one of four groups: clear (less than 0.1 sky cover), scattered (0.1 to less than 0.6 sky cover), broken (0.6 to 0.9 sky cover), and overcast (more than 0.9 sky cover). Also available from the Climatological Data National Summary published by the National Weather Service are measurements of the daily amounts of total hemispheric insolation.

The analysis begins with the assignment of a single sky cover value and an associated range to each descriptive sky cover category. By use of the previously derived relationship (Equation 2, Section 3.3) between opaque sky cover, S , air-mass ratio, A , and percent of possible total hemispheric insolation, P , a forecast value and range for P can be calculated from the forecast hourly cloud amount. The calculated value of P can then be converted into a calculated value for the total hemispheric insolation, on the basis of the known magnitude of the extraterrestrial insolation for that hour. By summing these calculated hourly total hemispheric insolation values for a day, a calculated daily total can be derived against which the observed daily total insolation can be compared. This comparison will result in one of three possibilities: the observed insolation was within the range predicted; the observed insolation was greater than the upper limit of the predicted range; or the observed insolation was less than the lower limit of the predicted range. Performing this comparison for a full year of data and forecasts will provide a statistical estimate of the accuracy of cloud-cover-derived insolation forecasts.

The National Weather Service forecasts are issued from a central forecasting office in each area. For example, the Chicago office issues

* Greenwich Mean Time

forecasts for 20 airports in portions of Illinois, Indiana, and Wisconsin. The aviation weather forecasts are archived for a five-year period. Thus, forecasts back to 1971 are still available in 1975. The year 1971 also is the last full year in which the National Weather Service reported the daily total insolation. Thus, 1971 is the only year for which comparisons between forecast and published observed insolation can be made. The forecasts are archived only in the form of teletype records. Figure 9 is an example of a portion of one of the Chicago area aviation weather forecasts from which the cloud cover forecasts had to be manually extracted.

The forecast shown in Figure 9 is for 0500-1700 GMT (2300-1100 CST) for 14-15 September 1971. The Madison forecast is indicated by the arrow next to the symbol, MSN. That forecast reads: "A ceiling of broken clouds at 1000 feet with an overcast layer at 4000 feet, three-mile visibility with thunderstorms and rain showers, gusty winds to 30 knots, occasionally one-mile visibility with thunderstorms and rain showers; at 0700 GMT (0100 CST) scattered clouds at 1000 feet and 4000 feet with a ceiling of broken clouds at 10,000 feet, 12 knot winds from 180° (south) with gusts, the cloud layers are variable between scattered and broken, occasional two-mile visibility in thunderstorms and light rain showers or light rain showers alone, with a chance for an overcast ceiling at 500 feet, one-mile visibility in a thunderstorm with rain showers and fog; at 1600 GMT (1000 CST) a ceiling of scattered clouds at 2500 feet with an overcast layer at 8000 feet, 15 knot winds from 170° (SSE) with gusts, occasionally an overcast ceiling at 1200 feet with one-mile visibility in a thunderstorm with rain showers, gusts to 35 knots".

In transcribing the cloud cover forecast from these weather forecasts, only the layer of greatest coverage was transcribed. It was found that 13 cases of cloud cover are generally given in an aviation weather forecast. These are given in Table 4, together with the adopted numerical cloud cover and cloud-cover range associated with each case. The forecast in Figure 9 would be transcribed:

MLI C400 0V0 OCNL 3H CHC C15011/2RW- OR TRW G35. 16Z C250800 1715G
 OCNL C1201TRW G35..
 PIA C400 0V0 OCNL 3H CHC C15011/2RW- OR TRW G35. 16Z C250800 1715G
 OCNL C1202TRW G35..
 CMI 10006H OCNL C1503TRW. 07Z 1503FH 0V0 OCNL C1503TRW CHC
 C701F AFT 09Z. 14Z C3001000 2012G OCNL C1503TRW G35..

WBC

GDW

UIN C400 0V0 OCNL 3H CHC C15011/2RW- OR TRW G35. 16Z C250800 1715G
 OCNL C1201TRW G35..

WBC

130

075

SPI C400 0V0 OCNL 3H CHC C15011/2RW- OR TRW G35. 16Z C250800 1715G
 OCNL C1201TRW G35..

WBC

YUR

EAU 100500C1000 1812G LYRS 0V0 OCNL 2TRW- OR RW- CHC C501TRWF.

16Z C250800 1715G OCNL C1201TRW G35..

GRB 100500C1000 1812G LYRS 0V0 OCNL 2TRW- OR RW- CHC C501TRWF.

16Z C250800 1715G OCNL C1201TRW G35..

LSE 100500C1000 1812G LYRS 0V0 OCNL 2TRW- OR RW- CHC C501TRWF.

16Z C250800 1715G OCNL C1201TRW G35..

→ MSN C100403TRW G30 OCNL 1TRW. 07Z 100400C1000 1812G LYRS 0V0 OCNL
 2TRW- OR RW- CHC C501TRWF. 16Z C250800 1715G OCNL C1201TRW G35..

MKE 100500C1000 1812G LYRS 0V0 OCNL 2TRW- OR RW- CHC C501TRWF.

16Z C250800 1715G OCNL C1201TRW G35..

RFD 100500C1000 1812G LYRS 0V0 OCNL 2TRW- OR RW- CHC C501TRWF.

16Z C250800 1715G OCNL C1201TRW G35..

WBC

SYM

AUW 100500C1000 1812G LYRS 0V0 OCNL 2TRW- OR RW- CHC C501TRWF.

16Z C250800 1715G OCNL C1201TRW G35..

WBC

EVE

ORD 400C1000 1810G 0V0 OCNL TRW CHC C801TRW. 08Z 150330010004H 1812

0V0 OCNL TRW CHC 1TRW. 16Z C3001000 2015G OCNL C1502TRW G35..

MDW 400C1000 1810G 0V0 OCNL TRW CHC C801TRW. 08Z 150330010004H 1812

0V0 OCNL TRW CHC 1TRW. 16Z C3001000 2015G OCNL C1502TRW G35..

WBC

145

CGN

SBN 10004H 0V0. 07Z 1503FH 0V0 CHC C701F AFT 09Z. 14Z C3001000

2012G CHC C1503TRW G35..

FWA 10004H 0V0. 07Z 1503FH 0V0 CHC C701F AFT 09Z. 14Z C3001000 2012G

CHC C1503TRW G35..

WBC

HEM

LAF 04H. 08Z 1503FH 0V0 CHC C701F AFT 10Z. 14Z C3001000 2012G OCNL

C1503TRW G35..

HUF 10004H 0V0. 07Z 1503FH 0V0 CHC C701F AFT 09Z. 14Z C3001000 2012G

OCNL C1503TRW G35..

IND 10004H 0V0. 07Z 1503FH 0V0 CHC C701F AFT 09Z. 14Z C3001000 2012G

CHC C1503TRW G35..

EVV 05H. 09Z 1503FH 0V0 CHC C802F. 14Z C3001000 1612G OCNL

C2003144 G35..

Figure 9

TELETYPE RECORD OF AVIATION WEATHER FORECAST

Table 4

FORECAST CLOUD COVER CATEGORIES

<u>Category Number</u>	<u>Description</u>	<u>Assigned Numerical Sky Cover Values</u>	
		<u>Coverage</u>	<u>Range</u>
1	Clear	0/10	0.5/10
2	Scattered	3/10	2.0/10
3	Broken	7.5/10	1.5/10
4	Overcast	10/10	0.5/10
5	Two scattered layers	5/10	3/10
6	Two scattered layers, one high (cirrus)	4/10	3/10
7	Two scattered layers, one high and thin (cirrus)	3/10	2.5/10
8	Scattered high (cirrus) clouds	2/10	1.5/10
9	Broken high (cirrus) clouds [not opaque enough to be a ceiling]	3.3/10	1.1/10
10	Overcast high (cirrus) clouds [not opaque enough to be a ceiling]	5.0/10	0.3/10
11	Scattered high, thin (cirrus) clouds	1.0/10	0.8/10
12	Broken high, thin (cirrus) clouds [not opaque enough to be a ceiling]	1.6/10	0.6/10
13	Overcast high, thin (cirrus) clouds [not opaque enough to be a ceiling]	2.5/10	0.2/10

2300 - 0000 CST	Category 4,
0100 - 1000 CST	Category 3,
1000 CST	Category 4.

Since 24-hour forecasts are not made for Madison and the timing of the forecasts is such that no one 12-hour forecast covers a whole day over the entire year, a day's forecast was synthesized from 12-hour forecasts. Only the last half of a 12-hour forecast was used so that the minimum forecast period was six hours and ranged up to 11 hours. The eleventh hour of the 5 pm forecast was used for the forecast of the 4 am cloud cover; the sixth through eleventh hours of the 11 pm forecast were used for the forecasts of the 5 am through 10 am cloud covers; the same hours of the 5 am forecasts were used for the forecast of the 11 am through 4 pm cloud covers; and the sixth through eighth hours of the 11 am forecast were used for the forecast of the 5 pm through 7 pm cloud covers.

For Albuquerque, 24-hour forecasts were available and thus the forecast of a day's cloud cover could be obtained in several ways. Two alternative means were included in the study. The first method uses the 10 pm forecast for the entire daylight period of the following day. This resulted in a minimum forecast period of six hours up to a maximum 21 hours. The second method uses 12-hour portions of several 24-hour forecasts to synthesize a forecast for the subsequent daylight period in a manner similar to that used for the Madison forecasts. This resulted in a minimum forecast period of six hours and a maximum of 11 hours.

The cloud forecasts for the daytime hours were coded onto computer cards together with the observed daily total insolation and the date. A computer program was written which takes these data cards and computes, for each hour of each day, the extraterrestrial insolation and the percent of possible insolation, P , for the forecast cloud cover plus similar values for each extreme of the range of cloud cover. The coefficients, a_1 , used in Equation 1 to estimate the value of P , are averages derived from data from widely diverse climatic regions and are $a_1 = 83.02$, $a_2 = -3.847$,

$a_3 = -4.4074$, $a_4 = 1.10129$, $a_5 = -0.11090$. The values of P are then converted into total hemispheric insolation. The process is repeated for each hour of the day, with the average values summed and the ranges summed in a root mean square manner. Thus, for each day there is a calculated total hemispheric insolation plus a calculated range about this value. The range determined in this way is dependent on the rather arbitrary assignment of ranges for each cloud cover category presented in Table 4. To explore the effect of varying the range on the forecast success rate, the analysis program permits increasing the root-mean-square estimated range to a range defined as a fixed percent of the total estimated insolation for the day. In addition to analyses of the data for the root-mean-square range, analyses were carried out for bounds of plus and minus 10 percent, 15 percent, 20 percent, and 25 percent of the estimated total insolation for the day. It should be noted that a bound of plus or minus 10 percent means the estimated value plus 10 percent and the estimated value minus 10 percent, giving a total width of 20 percent of the estimated value. The observed insolation was then compared with the ranges of estimated values. Three results are possible: the observed was less than the lower bound estimated; the observed was between the lower and upper bounds estimated; or the observed was above the upper estimated bound. The frequency of occurrence of each of these three cases was summarized by month and year.

3.6.2 Results

The results of the calculations for Madison are tabulated in Table 5 and for Albuquerque in Tables 6 and 7. The Table 6 data are the results from the 24-hour forecast data; those in Table 7 are from the 12-hour synthesized forecast data. Results are shown for five different ranges extending from the range calculated from the root-mean-square of the individual ranges to plus or minus 25 percent of the daily estimated insolation. The results for Madison and Albuquerque with ± 10 percent ranges are shown graphically in Figures 10 and 11, respectively. These bar graphs show the fraction of the observations which, reading up a bar,

Table 5

Comparison of Observed, m, with Estimated, e, Daily Total Insolation
for Various Ranges, r

Madison, Wisconsin 1971
12-hour Forecasts
Percent of Days

	<u>r = RMS Value</u>			<u>r ≥ 10 Percent</u>			<u>r ≥ 15 Percent</u>			<u>r ≥ 20 Percent</u>			<u>r ≥ 25 Percent</u>		
	<u>m < e - r</u>	<u>e - r < m</u> <u>< e + r</u>	<u>e + r < m</u>	<u>m < e - r</u>	<u>e - r < m</u> <u>< e + r</u>	<u>e + r < m</u>	<u>m < e - r</u>	<u>e - r < m</u> <u>< e + r</u>	<u>e + r < m</u>	<u>m < e - r</u>	<u>e - r < m</u> <u>< e + r</u>	<u>e + r < m</u>	<u>m < e - r</u>	<u>e - r < m</u> <u>< e + r</u>	<u>e + r < m</u>
Jan	20.0	6.7	73.3	16.7	20.0	63.3	16.7	30.0	53.3	13.3	43.3	43.3	3.3	63.3	33.3
Feb	29.2	4.2	66.7	25.0	16.7	58.3	25.0	25.0	50.0	20.8	41.7	37.5	20.8	45.8	33.3
Mar	30.0	3.3	66.7	23.3	13.3	63.3	20.0	20.0	60.0	20.0	30.0	50.0	16.7	46.7	36.7
Apr	50.0	0.0	50.0	40.9	36.4	22.7	40.9	40.9	18.2	40.9	54.5	4.5	31.8	63.6	31.8
May	44.8	3.4	51.7	37.9	37.9	24.1	31.0	55.2	13.8	27.6	65.5	6.9	20.7	72.4	6.9
June	60.9	13.0	26.1	34.8	47.8	17.4	30.4	56.5	13.0	17.4	69.6	13.0	8.7	87.0	4.3
July	60.9	4.3	34.8	52.2	30.4	17.4	47.8	43.5	8.7	43.5	47.8	8.7	30.4	60.9	8.7
Aug	63.3	16.7	20.0	33.3	53.3	13.3	26.7	66.7	6.7	20.0	73.3	6.7	16.7	83.3	0.0
Sep	53.6	10.7	35.7	35.7	42.9	21.4	32.1	53.6	32.1	21.4	67.9	10.7	21.4	75.0	3.6
Oct	46.4	0.0	53.6	39.3	21.4	39.3	32.1	39.3	28.6	28.6	53.6	17.9	25.0	57.1	17.9
Nov	51.7	10.3	37.9	37.9	27.6	34.5	34.5	37.9	27.6	27.6	48.3	24.1	27.6	48.3	24.1
Dec	43.3	10.0	46.7	40.0	13.3	46.7	36.7	16.7	46.7	36.7	20.0	43.3	36.7	26.7	36.7
Ann.	45.7	7.1	47.2	34.4	29.8	35.9	30.7	40.2	29.1	26.1	50.9	23.0	21.5	60.4	18.1

Table 6

Comparison of Observed, m, with Estimated, e, Daily Total Insolation
for Various Ranges, r

Albuquerque, New Mexico 1971
24-hour Forecasts
Percent of Days

	<u>r = RMS Value</u>			<u>r ≥ 10 Percent</u>			<u>r ≥ 15 Percent</u>			<u>r ≥ 20 Percent</u>			<u>r ≥ 25 Percent</u>		
	<u>m<e-r</u>	<u>e-r<m</u> <u><e+r</u>	<u>e+r<m</u>	<u>m<e-r</u>	<u>e-r<m</u> <u><e+r</u>	<u>e+r<m</u>	<u>m<e-r</u>	<u>e-r<m</u> <u><e+r</u>	<u>e+r<m</u>	<u>m<e-r</u>	<u>e-r<m</u> <u><e+r</u>	<u>e+r<m</u>	<u>m<e-r</u>	<u>e-r<m</u> <u><e+r</u>	<u>e+r<m</u>
Jan	16.7	3.3	80.0	6.7	30.0	63.3	6.7	60.0	33.3	3.3	76.7	20.0	3.3	80.0	16.7
Feb	15.4	0.0	84.6	11.5	23.1	65.4	11.5	46.2	42.3	7.7	69.2	23.1	7.7	73.1	19.2
Mar	12.9	3.2	83.9	6.5	38.7	54.8	3.2	74.2	22.6	3.2	80.6	16.1	0.0	87.1	12.9
Apr	30.0	3.3	66.7	20.0	50.0	30.0	16.7	60.0	23.3	6.7	83.3	10.0	3.3	86.7	10.0
May	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
June	17.2	6.9	75.9	6.9	41.4	51.7	6.9	79.3	13.8	3.4	86.2	10.3	3.4	86.2	10.3
July	16.7	10.0	73.3	10.0	53.3	36.7	10.0	66.7	23.3	3.3	86.7	10.0	3.3	96.7	0.0
Aug	29.0	19.4	51.6	25.8	48.4	25.8	12.9	67.7	19.4	9.7	83.9	6.5	9.7	87.1	3.2
Sept	33.3	6.7	60.0	23.3	60.0	16.7	13.3	73.3	13.3	13.3	73.3	13.3	13.3	76.7	10.0
Oct	41.9	16.1	41.9	25.8	67.7	6.5	22.6	74.2	3.2	16.1	80.6	3.2	16.1	80.6	3.2
Nov	33.3	16.7	50.0	20.0	60.0	20.0	10.0	73.3	16.7	6.7	83.3	10.0	6.7	83.3	10.0
Dec	43.3	3.3	53.3	40.0	13.3	46.7	36.7	43.3	20.0	30.0	53.3	16.7	30.0	56.7	13.3
Ann.	26.4	8.2	65.3	17.9	44.4	37.7	13.7	65.3	21.0	9.4	78.1	12.5	8.8	81.5	9.7

Table 7

Comparison of Observed, m, with Estimated, e, Daily Total Insolation
for Various Ranges, r

Albuquerque, New Mexico 1971
12-hour Forecasts
Percent of Days

	<u>r = RMS Value</u>			<u>r ≥ 10 Percent</u>			<u>r ≥ 15 Percent</u>			<u>r ≥ 20 Percent</u>			<u>r ≥ 25 Percent</u>		
	<u>m<e-r</u>	<u>e-r<m</u>	<u>e+r<m</u>	<u>m<e-r</u>	<u>e-r<m</u>	<u>e+r<m</u>	<u>m<e-r</u>	<u>e-r<m</u>	<u>e+r<m</u>	<u>m<e-r</u>	<u>e-r<m</u>	<u>e+r<m</u>	<u>m<e-r</u>	<u>e-r<m</u>	<u>e+r<m</u>
Jan	10.0	0.0	90.0	10.0	26.7	63.3	10.0	56.7	33.3	6.7	80.0	13.3	3.3	70.0	6.7
Feb	11.5	3.8	84.6	11.5	11.5	76.9	7.7	46.2	46.2	7.7	69.2	23.1	7.7	73.1	19.2
Mar	9.7	9.7	80.6	3.2	48.4	48.4	3.2	80.6	16.1	3.2	80.6	16.1	0.0	87.1	12.9
Apr	33.3	10.0	56.7	20.0	53.3	26.7	6.7	83.3	10.0	3.3	93.3	3.3	3.3	93.3	3.3
May	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
June	13.8	3.4	82.8	6.9	41.4	51.7	3.4	79.3	17.2	3.4	89.7	6.9	3.4	96.6	0.0
Jul	16.7	13.3	70.0	13.3	40.0	46.7	6.7	73.3	20.0	3.3	86.7	10.0	3.3	96.7	0.0
Aug	35.5	12.9	51.6	29.0	38.7	32.3	9.7	80.6	9.7	9.7	37.1	3.2	9.7	90.3	0.0
Sep	33.3	6.7	60.0	20.0	66.7	13.3	13.3	76.7	10.0	10.0	83.3	6.7	10.0	83.3	6.7
Oct	35.5	19.4	45.2	25.8	64.5	9.7	22.6	71.0	6.5	16.1	80.6	3.2	12.9	83.9	3.2
Nov	36.7	20.0	43.3	23.3	63.3	13.3	13.3	83.3	3.3	10.0	86.7	3.3	10.0	86.7	3.3
Dec	46.7	3.3	50.0	43.3	16.7	40.0	40.0	36.7	23.3	36.7	46.7	16.7	30.0	60.0	10.0
Ann.	25.9	9.5	64.6	18.9	43.3	37.8	12.5	70.1	17.4	10.1	80.5	9.5	8.5	85.7	5.8

Figure 10

INFERRED INSOLATION FORECAST ACCURACY, MADISON

Figure 11

INFERRED INSOLATION FORECAST ACCURACY, ALBUQUERQUE

were less than the lower limit of the calculated insolation, within the limits of the calculated range, and greater than the upper limit of the calculated range. The graph for Madison, Figure 10, shows that on an annual basis the observed insolation fell within the estimated range of ± 10 percent about 30 percent of the time and that there was about an equal tendency to overestimate insolation as to underestimate it. Taken on a monthly basis, the fraction estimated within range varied between 13.3 percent (December) and 53.3 percent (August) with a tendency to underestimate insolation in January, February, and March, and to overestimate it in the late spring and early summer.

The graph for Albuquerque, Figure 11, shows that on an annual basis for both the 12- and 24-hour forecasts, the observed insolation fell within the estimated range of ± 10 percent about 45 percent of the time but that there was a tendency to underestimate the insolation. Taken on a monthly basis, the fraction estimated within range varied between 11.5 percent (February 12-hour) and 67.7 percent (October 24-hour) with a greater tendency to underestimate insolation in January, February, March, and June. The months for overestimation are August through December. The difference in accuracy between the 12- and 24-hour forecasts is most marked in February. On an annual basis, the difference is insignificant. One possible reason for the overall tendency to underestimate insolation at Albuquerque has been suggested by observers familiar with cloud patterns at that city. It is a fairly common occurrence for clouds to build up in the northern sky, about the crests of nearby mountains, thereby producing a reportable amount of sky cover but without reducing insolation. Specific forecasts of insolation by local weather forecasters would, of course, take such effects into account and would therefore probably be somewhat more accurate than is indicated by this study.

3.6.3 Discussion

The fraction of the time the observed insolation is within the calculated range of insolation is naturally a function of the range. The

actual cut-off range should be chosen by the systems engineer on the basis of various design criteria for the solar energy facility. However, even for a 25-percent range (50-percent width) the forecast accuracy is only 60 percent at Madison and 81 percent (24-hour) or 86 percent (12-hour) at Albuquerque. There are several possible reasons why the results are this poor. First the cloud-cover forecasts could actually be that bad. It should be remembered that, particularly for Madison, the available timing of the forecasts was not optimum for the purposes of this study. Had one consistent forecast been available for the entire day, the results might have been different, although the results of the 12-hour forecast study at Albuquerque do not tend to support this hypothesis. The second reason is that the translation from cloud cover to insolation may be inadequate. This second possibility is explored in detail in the next several paragraphs, leading to the conclusion that, although exact numerical values are dependent on the insolation modeling from cloud cover, the basic qualitative features of the results summarized above are not.

There are several ways in which the computations of insolation from cloud cover could introduce errors into the calculations to bias the study results. A bias could be introduced by the assignment of sky-cover values chosen for each of the 13 cloud categories. A bias might be introduced by the use in Equation 2 of parameters that were based on annual data when seasonal variations are being calculated. A bias might be introduced by the use of average estimated parameters rather than site-specific parameters. Errors might be introduced by an oversimplification of the forecast cloud categories. Each of these potential problems is discussed in turn below.

The question of misassignment of sky cover to each of the 13 categories was tested by varying the sky coverage for the most arbitrarily assigned categories, eight to 13. These categories consist of overcast layers of thin cirrus clouds sufficiently transparent not be a ceiling for a pilot. The assignment of an effective opaque sky cover in these categories is rather arbitrary. The effective sky cover for each of the six categories

of cirrus clouds was reduced by up to a factor of four with no significant change in the results, indicating the insensitiveness of the model to these most arbitrary cloud cover assignments.

The seasonal variation of the estimating parameters (a_i in Equation 2) was checked by analysis of data from an independent location -- Bismarck, North Dakota. The hourly insolation data tapes for Bismarck were analyzed for each quarter of each of the two years to see how the estimating parameters changed. The variation between years was as great as the variation between quarters and in no case was the variation more than 15 percent. In addition, the quarterly pattern was inconsistent with the apparent seasonal pattern on the estimated values. Therefore, the seasonal effect in the forecast accuracy does not appear to be due to an unrecognized seasonal modeling factor.

The use of average estimating parameters rather than site-specific parameters was checked by computing the estimating parameters from the Albuquerque hourly data base. The values obtained were different from the average a_i in a way which would have lowered even further the estimated values and thus increased the fraction of cases for which the observed was greater than the estimated.

The question of the oversimplification of cloud categories cannot be easily answered without returning to the original data and trying a more detailed breakdown of cloud categories.

3.6.4 Conclusions

On the basis of the study summarized here, it appears that ability to forecast insolation from present forecasts of cloud cover is limited. Even if a ± 10 percent variation is acceptable, the observed insolation will be within the forecast range less than half the time. There appears to be a seasonal dependence of the ability to forecast the insolation that does not appear to be dependent on the model employed to derive insolation from the cloud cover.

The accuracy estimates presented here probably represent a worst case in the sense that the accuracy assessments were not obtained from forecasts designed for the estimation of insolation, but rather from forecasts oriented toward the needs of pilots. Future studies in this area should include the preparation of insolation forecasts per se by the Weather Service. They should also include an analysis of the best way to estimate insolation from cloud cover on a quantitative basis. Finally, the timing of present forecasts may not be optimum for solar energy purposes. The accuracy of forecasts made at the time required for solar energy system operational decisions should be assessed.

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SECTION 4

ELECTRIC POWER DEMAND

In simulation computations designed to evaluate the performance of a photovoltaic system in a specific mission or application, the characteristics of the mission are reflected principally in the representation for electric power demand that is used in the computations. Realistic representations for the time-varying properties of the demand associated with the particular missions under investigation in this study were therefore essential. The minimum requirements to be satisfied by the demand representations were judged to be:

- a. the demand should be expressed on a time scale at least as short as that used in the insolation representation (i. e. , hourly),
- b. the demand representation should exhibit the diurnal and seasonal variations that are characteristic of the mission in the region where the photovoltaic system is presumed to be located, and
- c. the representation should be characteristic of future (1980-2000) patterns rather than present ones, if changes are expected.

In order to generate demand representations meeting these criteria, it has been necessary to seek out a variety of different sorts of basic information. The types of data needed for this purpose are summarized in Table 8. The information that has been uncovered and the demand representations that have been synthesized on the basis of this information are described in the following two sections.

4.1 DEMAND REPRESENTATIONS FOR ON-SITE APPLICATIONS

The development of suitable representations for the demand at residential, commercial, and industrial load points proved to be a challenging task. In the first place, it was unreasonable to attempt to use selected

Table 8

DEMAND DATA REQUIREMENTS

- On-site applications (residential/commercial/industrial)
 - Daily load profiles
 - Hourly
 - Seasonal
 - Seasonal energy-demand variations
 - Projections to 1980-2000
 - Load profile changes
 - Average energy demand
 - Changes in seasonal pattern
 - Energy demand per unit land area
- Central station plants
 - Long-term historical records (hourly) of system demand
 - System demand forecasts, 1980-2000

historical records in imitation of the procedure used with respect to insolation. Because of the large variations in the type, size, and temporal pattern of the demand associated with consumers in these broad general categories, the selection of a demand record for any particular load point as "typical" would justifiably be open to question. The question is academic, moreover, because no long-term hourly records of demand at single load points, or of aggregate demand associated with a group of similar load points, have been found. The closest approximation to this type of data that has been located is a set of long-term records of demand on a feeder line serving a predominantly residential area of Edwards Air Force Base in Southern California. These data are discussed in Section 4.1.5, below; they were used in some early simulation computations, but they cannot be considered a suitable representation for residential demand.

For the purposes of this study, the most satisfactory method of representing on-site demand has proved to be the use of artificial demand "records", synthesized on the basis of information obtained from a variety of different sources. The types of information used in these syntheses are discussed in Sections 4.1.1 to 4.1.3, below, while the procedure used to carry them out is described in Section 4.1.4. The Edwards AFB data are discussed in Section 4.1.5, while Section 4.1.6 contains information on the density of energy demand per unit land area as projected for one urban region in the Southwest (specifically, Southern California). Projections of this type are important, of course, in relating local demand to the total available local supply of solar energy.

4.1.1 Diurnal Profiles

As was pointed out above, one of the more difficult tasks associated with the preparation of load point demand representations was that involved in acquiring a sufficiently representative body of information about daily demand profiles and about seasonal variations and long-term trends in these daily patterns. There has apparently never been a comprehensive program to gather this type of information. The data that exist were generated in the course of widely scattered (in both time and space) measurement

programs that were carried out for a variety of different purposes -- for example, for use in connection with rate increase applications by utility companies or with energy conservation programs. The raw data are often destroyed when their original purpose has been served, and even when they have been preserved, their release is often hampered by questions of confidentiality or by proprietary considerations.

The approach that was used in this program was simply to gather up as much of the fragmentary information on residential, commercial, and industrial daily demand profiles as was possible within the constraints of the resources allocated to the task. These data were then examined in an attempt to identify common characteristics within each of the categories, with the goal of selecting or synthesizing a small group of profiles that could reasonably be considered representative.

4.1.1.1 Residential Profiles

Some examples of the daily demand profiles that have been obtained from various sources are shown in Figures 12 through 14. The curves shown in Figure 12 were extracted from a load study carried out in 1971 by the Southern California Edison Company (Reference 6). Each curve represents the average per-customer demand from a selected group of residential customers on a winter weekday (day of the Edison Co. system-wide winter demand peak). For the purposes of this load study, the residential customers of the Edison Co. were divided into five groups of roughly equal population on the basis of average power consumption. A small number of individual residences were chosen to represent each of the groups, and demand meters were placed in the selected homes. The demand profiles shown in Figure 12 illustrate the points that the per-customer residential demand covers a wide range and that there is substantial variation in demand over the hours of the day, with a peak (in winter) in the early evening hours.

The seasonal variations in the shape of residential daily demand profiles in two different regions of the Southwest are illustrated in

Figure 12

DAILY DEMAND PROFILES - SOUTHERN CALIFORNIA RESIDENCES

Figure 13

SOUTHERN CALIFORNIA RESIDENTIAL DEMAND
PROFILES - SEASONAL DIFFERENCES

Figure 14

CENTRAL ARIZONA RESIDENTIAL DEMAND
PROFILES - SEASONAL DIFFERENCES

Figures 13 and 14. The curves in Figure 13 were taken from the same Southern California load study (Reference 6) that was mentioned in the preceding paragraph and represent summer and winter profiles for homes in Group 5, the group with the highest electric energy consumption (8880 - 30,000 kWh/year). Those in Figure 14 represent average daily profiles for a sample group of 22 high-demand (~30,000 kWh/year) homes in Phoenix, Arizona, during representative summer and winter weekdays. The homes in this sample included 11 all-electric residences (with electric water heaters and either heat pumps or separate electric heating and refrigeration air-conditioning units) and 11 dual-energy homes (with refrigeration air-conditioning but with gas-fueled water heaters and space-heating systems). The marked seasonal variation in the shape of the Phoenix profile is presumed to be a result of the summer air-conditioning load. The absence of a corresponding variation in the Los Angeles profiles reflects the more moderate character of the Southern California climate; fewer homes (even expensive ones) are equipped with air-conditioners and those that are so equipped consume less energy.

In spite of their obvious differences, however, these daily profiles have much in common with each other and with profiles for residential customers in other parts of the country. There is in nearly every case a late afternoon or early evening peak. The daily load factors (ratios of average to peak demand) generally fall in the range between 0.6 and 0.7. (One exception is the winter Phoenix profile of Figure 14, where the load factor is 0.78.)

4.1.1.2 Commercial Profiles

Although the commercial establishments that play significant roles in the U.S. economy are of enormous variety, their daily electric power demand profiles are expected to display a number of common features. Utility company representatives have asserted that, because of the nature of electric loads in nearly all commercial buildings (lighting, heating, air-conditioning, typewriters, etc.), the demand during business

hours is generally fairly constant, dropping off sharply to another constant value during non-business hours. This off-hour load level tends to be very small; notable exceptions are markets and restaurants, where refrigeration for food storage is important, and commercial establishments with substantial computer facilities requiring 24-hour air-conditioning. Since much of the heat input to such buildings is actually generated internally by various types of equipment, the seasonal variation in air-conditioning load is much smaller than it is in residences; the result is that the seasonal variation in overall electric power demand is also much smaller.

These general characteristics are illustrated by the graphs in Figures 15 and 16, representing summer and winter daily demand profiles for two important types of commercial establishments: department stores and supermarkets. Both types of store display the expected flat profile during business hours, dropping off to a lower value after closing time. The heavy refrigeration load in a supermarket prevents the off-hour load from falling below about 50% of the daytime level. Another striking characteristic of both pairs of graphs is the relatively small difference between summer and winter profiles. These data were taken in stores in Southern California. In other parts of the Southwest, where temperature extremes are more pronounced, substantially greater seasonal demand variation might be expected. As will be shown in the next section, however, average values for Arizona and Texas indicate summer/winter demand ratios for commercial loads that are only ~15% higher than the corresponding value for the entire state of California. By contrast, the summer/winter ratio for residential demand is 45% higher in Texas and Arizona than in California.

4.1.1.3 Industrial Demand

The daily demand profiles for industrial concerns undoubtedly are substantially different for different industries and for different modes of operation. For many important industries, however, especially those

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Figure 16
DAILY DEMAND PROFILES - SOUTHERN CALIFORNIA SUPERMARKET

that operate on a three-shift 24-hour basis, the demand profile can be expected to be fairly constant over the full daily cycle, at least on the average. An example of a demand profile for one such industry, an electric-arc steel plant, is shown in Figure 17. It is clear that there are marked fluctuations in demand as one or another of the furnaces is fired up or shut down, but there is no regular daily pattern and no seasonal variation in pattern. Other curves for this same plant show that there is only a slight difference between weekday and weekend operations; a certain amount of associated plant equipment is shut down on weekends. The load factor typically varies between 0.65 and 0.70, limited in part by the fact that the peak power demand is arbitrarily set at a predetermined value, with computer control to ensure that the preset value is not exceeded. (One of the reasons for utilizing such a control procedure is that the electric utility bills for industrial concerns are based on two factors: the total energy consumed, in kWh, and the peak demand, in kW.)

4.1.2 Seasonal Demand Variations

Seasonal variations in electric energy consumption in the four southwestern states of California, Arizona, New Mexico, and Texas are shown in Figures 18 through 21. In each figure are plotted separate graphs of the energy consumption, by month, in the residential, commercial, and industrial sectors. The data represented by these graphs were extracted from the Federal Power Commission publication, "Electric Power Statistics", and cover a period of slightly more than two years. In each case, the long-term growth trend was removed by a somewhat arbitrary procedure based on the assumption that the trend is exponential, with a different exponential coefficient for each state and each type of demand.

The very large seasonal variation in residential demand in Arizona and Texas contrasts markedly with the corresponding variations

Figure 17
DAILY DEMAND PROFILE - ELECTRIC-ARC STEEL PLANT

Figure 18
CALIFORNIA ELECTRIC ENERGY CONSUMPTION
BY MONTH - TREND REMOVED

Figure 19
ARIZONA ELECTRIC ENERGY CONSUMPTION
BY MONTH - TREND REMOVED

Figure 20
NEW MEXICO ELECTRIC ENERGY CONSUMPTION
BY MONTH - TREND REMOVED

Figure 21
TEXAS ELECTRIC ENERGY CONSUMPTION
BY MONTH - TREND REMOVED

in residential demand in California and New Mexico and with the variations in commercial and industrial demand in all four states. Residential air-conditioning is clearly responsible for much of the difference. In California, the dominant demand centers, Los Angeles and the San Francisco Bay area, have climates that are moderated by the proximity of the ocean, leading to a smaller requirement for air-conditioning. In New Mexico, the high elevation above sea level of the principal load center, Albuquerque, has a similar effect.

4.1.3 Projections

The focus of the photovoltaic mission analysis study reported here has been on future applications, with particular attention to the period 1980-2000. The demand representations used in the system simulation calculations, accordingly, are intended to represent future rather than current demand patterns and magnitudes. In order to develop appropriate models for use in calculations of the performance of on-site photovoltaic systems, it was therefore necessary to seek out authoritative projections of the characteristics of demand associated with residential, commercial, and industrial load points. In the case of residential demand, the most useful single parameter is the projected annual demand per residential customer; a number of such projections have been made. In the cases of commercial and industrial demand, the most valuable parameter would be projected values for the total annual energy consumption per m^2 of total site area; no studies leading to projections of this type were found.

The most authoritative projections of the annual average residential energy consumption per customer appear to be those contained in the successive versions of the Annual Electrical Industry Forecast published in the journal, Electrical World. In Figure 22 are plotted the values of this parameter that are contained in the 1974 forecast (Reference 7); the values shown for 1965-1973 are, of course, based on actual measurements. Also shown in Figure 22 is a plot of the most recent (March 1974) projection by the Southern California Edison Company of the average per-customer residential energy consumption in that utility system. For

Figure 22

PROJECTED ANNUAL AVERAGE ELECTRIC ENERGY
PER RESIDENTIAL CUSTOMER

comparison, historical values for the 1962-1972 period for a number of southwestern utility companies are shown in Figure 23.

Another view of future electric energy consumption that is of particular interest to this study can be found in the reports of the Rand Corporation's study of the future electric power demand in California (References 8, 9, and 10). In Figure 24 (taken from Reference 8) are shown projected values for energy consumption per residential customer for a group of California utilities. The Rand projections of the intensiveness of commercial and manufacturing demand (References 9 and 10) are expressed in terms of kWh/GSP (GSP = Gross State Product) and kWh/\$VA (\$VA = Value Added, Dollars), respectively, and thus could not be used directly in the current study.

4.1.4 Demand Models

On the basis of the information discussed in the preceding three sections, five different demand representations were prepared for use in simulation computations of the performance of on-site photovoltaic systems. These four included two different models for residential demand, two for commercial demand, and one for industrial demand.

The two residential models were based on the daily profiles shown in Figures 13 and 14. These profiles were simply multiplied by different factors for each month of the year in accordance with the prescription summarized in Table 9. The multiplying factors shown in the table were chosen in such a way as to yield monthly totals whose seasonal variations exactly match those shown in the residential sector graphs of Figures 18 and 19. The results of this procedure are demand representations in which each month contains a series of identical days but the days of one month differ from those of adjoining months in a manner consistent with observed seasonal variations in residential demand. The daily profile for each day follows either a "winter" or a "summer" pattern.

Figure 23

AVERAGE ANNUAL ELECTRIC ENERGY USAGE
PER RESIDENTIAL CUSTOMER: HISTORICAL RECORDS

Figure 24

RAND CORPORATION PROJECTIONS OF ANNUAL AVERAGE
 ELECTRIC ENERGY USAGE PER RESIDENTIAL CUSTOMER:
 CALIFORNIA UTILITIES

Table 9

DEMAND PROFILE MULTIPLYING FACTORS

	Residential		Supermarket Arizona	Dept. Store Arizona	Industrial Arizona
	California	Arizona			
January	1.000 C _W	1.028 A _W	0.852 S _W	0.876 D _W	0.881 I
February	0.916 C _W	0.854 A _W	0.795 S _W	0.818 D _W	0.922 I
March	0.822 C _W	0.756 A _W	0.805 S _W	0.828 D _W	0.921 I
April	0.756 C _W	0.431 A _S	0.828 S _W	0.852 D _W	0.964 I
May	0.800 C _S	0.480 A _S	0.803 S _S	0.803 D _S	1.000 I
June	0.824 C _S	0.680 A _S	0.890 S _S	0.890 D _S	0.955 I
July	0.877 C _S	0.880 A _S	0.967 S _S	0.967 D _S	0.957 I
August	0.911 C _S	1.000 A _S	0.990 S _S	0.990 D _S	0.926 I
September	0.909 C _S	0.858 A _S	1.000 S _S	1.000 D _S	0.926 I
October	0.869 C _S	0.609 A _S	0.852 S _S	0.852 D _S	0.841 I
November	0.824 C _W	0.778 A _W	0.810 S _W	0.833 D _W	0.841 I
December	0.909 C _W	0.826 A _W	0.753 S _W	0.774 D _W	0.790 I

C_W = California winter
residential profile } Figure 13

C_S = California summer
residential profile

A_W = Arizona winter
residential profile } Figure 14

A_S = Arizona summer
residential profile

S_W = Supermarket winter
profile } Figure 16

S_S = Supermarket summer
profile

D_W = Department store
winter profile } Figure 15

D_S = Department store
summer profile

I = Constant Profile

Although these residential demand models are quite simple, there does not appear to be any need for significantly greater complexity. Attempts to provide a more realistic simulation of day-to-day fluctuations in demand would have merit only if the correlations between these fluctuations and weather parameters could be incorporated. To include these correlations would require either a) the use of historical demand records and historical weather records for the same location and the same period or b) the development of a detailed model including cause-and-effect relationships between weather variables and components of demand. Neither of these alternatives could be included within the scope of the study reported here.

The use of current daily profiles to simulate the profiles of the future can be justified on the basis that the particular current profiles that were selected for use represent energy-consumption patterns that are expected to be common in future years. The residences whose demand profiles are shown in Figures 13 and 14 are those with unusually high (by current standards) levels of consumption, presumably because they are equipped with appliances (e. g., central air-conditioning) that will be found to an increasing extent in the average home of the future. The per-customer demand totals represented by the profiles are ~16,000 kWh/year in the California case and ~30,000 kWh/year in the Arizona case. The first figure corresponds roughly to the projected average consumption in the U. S. in 1995 (as illustrated in Figure 22). The average future consumption in the Southwest should be substantially greater than that in the U. S. as a whole, i. e., nearer to the 30,000 kWh/year figure represented by the Arizona demand model. These annual totals are important mainly as indicators that the "typical" home of the future will have an appliance complement similar to that in the reference homes and, therefore, a similar daily profile. The assumed trend toward greater per capita consumption of energy in the home may well, of course, be moderated by conservation programs, but it is unlikely to be changed drastically.

The representations for commercial and industrial demand were prepared in essentially the same way as were the residential models. The two commercial models represent, respectively, a central Arizona supermarket and a central Arizona department store and are based on the summer and winter diurnal profiles shown in Figures 15 and 16. The basic diurnal profile in the industrial model was a completely flat one, constant over the 24-hour period. This is essentially equivalent to the profile shown in Figure 17, averaged over the random fluctuations shown in that figure. These commercial and industrial profiles were multiplied by different factors for each month, as shown in Table 9.

As will be discussed in greater detail in later sections of this report, the absolute magnitude of the demand values in these models is of little consequence in the simulation computations. The computational results are independent of the magnitude of the demand so long as the ratios of important system parameters (collector/array area, electric storage capacity, power conditioner rating) to demand are kept constant. The important demand parameters are the daily and seasonal profiles. In order to facilitate comparisons, therefore, the magnitudes of the demand representations were all normalized to yield the same annual average. (This average value, chosen early in the study, was set at 100 times the average demand on Feeder 3A at Edwards Air Force Base, or 121.8 MW. Each of the demand representations described above was multiplied by the appropriate factor before being used as an input for simulation computations.)

4.1.5 Residential Demand: Edwards Air Force Base

At Edwards Air Force Base in the Mojave Desert region of Southern California, the electric power demand on several of the feeder lines serving the base, as measured with 15-minute demand meters, has been recorded routinely for a number of years. Through the cooperation of base engineering personnel, access was obtained to these records. The record for Feeder 3A was of particular interest because the bulk of the load served by this feeder was residential, derived largely from

single-family residences not very different from those in many other southwestern suburban areas. Of the large volume of available strip-chart data for this feeder line, one-hour demand records for the entire year 1971 were digitized and recorded on magnetic tape. This tape record contains substantial information about daily profiles, weekday/weekend and seasonal profile variations, and seasonal variations in total electric energy consumption for this largely residential load. The records for the first weeks of April, August, and September 1971, are shown in Figure 25.

The dominant element in the load on Feeder 3A is that associated with service to 100 all-electric homes (no gas service). All of the homes are constructed of concrete and have a net floor area of 1344 square feet, with two bedrooms and one bath. They are cooled by evaporative coolers and heated by electric resistance heaters.

The record of demand on Feeder 3A has one important advantage over the synthetic demand representations discussed in the preceding section: it contains all the weekday/weekend variations and the random daily fluctuations that occur in actual service. It has the disadvantage that the characteristics of the load in the houses connected to Feeder 3A cannot be considered representative of the future or even of the present in most areas of the Southwest. The combination of resistive heating and evaporative cooling leads to a pronounced winter peak in demand. The records of seasonal variations in residential demand in the Southwest, as displayed in Figures 18 through 21, indicate that such a winter peak is quite atypical, at least of the populous regions of the Southwest. Because this disadvantage appears to outweigh the advantages of using an actual year-long historical demand record, the Edwards demand record has not been used extensively in system simulation computations in the course of this study.

4.1.6 Average Demand Per Unit Land Area

In any assessment of the utility of photovoltaic solar energy conversion for on-site applications, it is important to know whether or not there will be sufficient solar energy falling on the site to permit

Figure 25
RESIDENTIAL DEMAND PROFILES: EDWARDS AIR FORCE BASE

meeting the expected demand for electric energy. In order to address this question it is necessary to have information about the projected magnitude of the demand per unit area of the site, since the solar energy supply will depend on the total area on which collectors can be deployed.

An indication of the demand per unit site area for different classes of consumers in one location in the Southwest is given by the numbers in Table 10. The figures in the table actually represent demand per unit total land area (including public streets) rather than per unit site area, but the difference should not be important. The data on peak loading represent projected values for the highest density of power demand (in kW/mi^2) at any time during the year for the years 1980 and 2000. These estimates were made by a Southern California utility company as part of a study designed to forecast feeder-line requirements. The numbers shown in the columns labeled "Average Demand (kW/mi^2)" were derived from the utility peak-demand projections on the basis of conservative assumptions about load factors and coincidence factors (the degree of coincidence between demand peaks for consumers of the same type). In the utility study, consumers in each class were divided into "light", "medium", or "heavy" subclasses in accordance with their electric-power demand; only the numbers for the light users (L) and the heavy users (H) are included in the table.

For comparison purposes, the average insolation per unit area and the average amount of power that could be produced by photovoltaic means are also shown in the table. The insolation value -- $650,000 \text{ kW}/\text{mi}^2$ -- corresponds to approximately $6 \text{ kWh}/\text{m}^2$ -day, roughly equal to the annual average of insolation (on a horizontal surface) in favored locations in the southwestern United States. The value given for average photovoltaic power production is clearly based on rather optimistic assumptions: an overall system efficiency of 12% and collector area equal to one-fourth of the total land area.

Table 10

POWER DENSITY - SOUTHERN CALIFORNIA URBAN AVERAGE

<u>Class</u>	<u>Density</u>	<u>Peak Loading (kW/mi²)</u>		<u>Average Demand (kW/mi²)</u>	
		<u>1980</u>	<u>2000</u>	<u>1980</u>	<u>2000</u>
Single Family	L	6,000	7,500	1,800	2,250
Dwellings	H	8,000	20,000	2,400	6,000
Small Apartment	L	30,000	45,000	9,000	13,500
Buildings	H	60,000	90,000	18,000	27,000
Large Apartment	L	75,000	90,000	22,500	27,000
Buildings	H	115,000	180,000	34,500	54,000
Light Commercial	L	15,000	25,000	7,500	12,500
Areas	H	35,000	90,000	17,500	45,000
Heavy Commercial	L	40,000	75,000	20,000	37,500
Areas	H	100,000	300,000	50,000	150,000
Light Industries		30,000	70,000	13,500	31,500
Heavy Industries		100,000	250,000	65,000	162,500
Average Insolation - Southwestern U.S.		650,000 kW/mi ²			
Corresponding Average Photovoltaic Power (Land use factor = 0.25, η = 0.12)		20,000 kW/mi ²			

The values given in Table 10 are consistent with numbers obtained from other sources. One projected value for the average annual consumption of electric energy per residential customer in 1995 is approximately 18,000 kWh (Figure 22). The corresponding annual average power is 2.06 kW ($18,000 \text{ kWh/yr} \div 8760 \text{ hr/yr}$). If there are 1830 residences per mi^2 (the density assumed for high-demand homes in the utility study represented in Table 10), then the average power density is approximately 3800 kW/mi^2 , not very different from the average of the light and heavy users of the year 2000, as shown in the table.

The reasonableness of these projected values can also be assessed by comparing them with current values of demand per unit site area for selected commercial and industrial examples. In Table 11 are shown some 1973-74 values for this ratio, as measured at three Southern California shopping centers. All three of these shopping centers are located well inland from the coast in regions characterized by mild winters and hot summers. They may, therefore, be considered reasonably representative of the southwestern states as a whole. As is indicated in Table 11, the average demand per unit area of the entire shopping center site (including parking lots and internal roadways) for these three shopping centers is roughly 30 MW/mi^2 . This value falls in the middle of the range of projected 1980 values for "heavy" commercial areas. Also shown in the table are values for the average demand per unit floor area. Since some of the buildings on the shopping center sites have more than one story, these values are somewhat lower than the corresponding values of average demand per unit roof area.

The industrial power density values shown in Table 10 can be compared with figures for the electric-arc steel plant whose demand profile was shown in Figure 17. For this admittedly very heavy user of electric power, the average power density, calculated in terms of the total land area at the site (including parking lots), is 300 MW/mi^2 .

Table 11

AREAL DENSITY OF AVERAGE ELECTRIC DEMAND IN 1973-74
FOR THREE SOUTHERN CALIFORNIA SHOPPING CENTERS

Shopping Center	Total Site Area		Floor Area m^2	Annual Average Demand kW	Average Demand Per Unit Site Area		Average Demand Per Unit Floor Area kW/ m^2
	mi^2	m^2			kW/mi^2	kW/m^2	
1	.0984	$2.55(10^5)$	$8.28(10^4)$	3,196	$32.5(10^3)$	.0125	.0386
2	.102	$2.64(10^5)$	$8.22(10^4)$	2,743	$26.9(10^3)$	.0104	.0334
3	.148	$3.84(10^5)$	$1.24(10^5)$	5,090	$34.4(10^3)$	.0133	.0410

Typical Insolation, Annual Average - Southwestern U.S.: $650,000 \text{ kW}/mi^2$
 $.25 \text{ kW}/m^2$

The implications of these numbers are fairly clear. In general, photovoltaic solar energy conversion systems should be able to meet the full demand associated with single-family residences, small apartment buildings, and light commercial areas. On-site systems serving large apartment buildings, heavy commercial areas, or any but the lightest of industrial loads will probably have to be viewed as strictly supplementary sources, serving only a fraction of the full demand, even in favorable areas of the Southwest. For example, the average electric demand for the three shopping centers listed in Table 11 is roughly equal to the power that could be generated if the average solar energy falling on the entire site were converted to electricity with an overall efficiency of ~5%. In a real situation, of course, the mismatch between periods of high demand and high insolation would raise the required overall conversion efficiency substantially. To serve the full demand, therefore, it is clear that virtually the entire site, including parking lots, would have to be covered with a roof of solar arrays.

4.2 DEMAND REPRESENTATIONS FOR CENTRAL STATION APPLICATIONS

The mission assigned to a photovoltaic central station power plant is quite different from that of an on-site system. When such plants go into service, they will almost certainly do so as individual elements of the total generation capacity of an electric utility system that also includes a large number of conventional nuclear and fossil-fuel plants. All of the plants will be interconnected by the transmission grid of the system, and the electric energy generated in the different plants will be, in effect, "pooled" before distribution to consumers. The central dispatcher of the utility system will control the output of the individual plants in such a way that their combined energy production will meet the total system demand in the most economical fashion.

Simulations of the operation of a photovoltaic central station power plant must, therefore, be carried out in a context that reflects

the plant's role as part of the total generation capacity of a utility system. The role of the dispatcher in regulating the output of the various plants in the system, including solar plants, must be reflected in some way in the methodology. (The details of the simulation procedure, including dispatching logic, used in this study are discussed later in this report, in Section 5.3.) It is clear, moreover, that the only type of demand representation that has meaning in this context is the total demand of the entire utility system. Since the simulations are to represent plant operation at periods some time in the future, the demand models cannot consist simply of reproductions of either current or historical demand records of actual utility systems. Some procedure to make projections to future years must be utilized. The methods that were employed to develop the models of projected demand for use in the current study are discussed in Section 4.2.1, below, and in Volume III, Appendix A. The characteristics of the specific demand models that were constructed in this way are described in Section 4.2.2. Following this, in Section 4.2.3, there is a description of an improved projection methodology. Although the new procedure became available too late for extensive use in the current study, it has been used to prepare models of projected demand for the same cases for which the older method was used. These are available for use in subsequent studies.

4.2.1 Projection Methodology for System Demand

The system demand models that were used in the central station power plant simulations in this study were developed by projecting into the future historical demand records for actual utility systems located in the geographical regions of interest. The basic input data for the projection methodology were long-term (up to 10 years) hourly records of total system demand.

The demand forecasting procedure that was used is based on the assumption that a time series of values for electric power demand is a composite of several factors: a growth trend, variations induced by

weather conditions, weekly and seasonal influences, and hourly cyclic variations. It has been assumed that the growth trend is exponential, that the seasonal and hourly variations are repeated from year to year, and that the effect of weather is random in the short run and follows some long-term cyclic pattern that cannot be quantized from available data without a high degree of uncertainty. The forecasting procedure (illustrated in Figure 26) utilizes a decomposition methodology that attempts to separate these elemental factors from the historical demand record by the successive application of mathematical filters, each designed to extract specific demand components. The seasonal, weekly, and hourly factors isolated in this way are then combined with a forecasted value for peak demand to generate a demand record for a specific future year. In the decomposition/recomposition actually used in this program, no attempt was made to include the effects of the more or less random variations in local weather.

Given a sufficiently extensive history of demand data amenable to computer analysis, the first decomposition step is to remove the influence of the historical growth trend by treating the data with a least-squares filter which assumes a linear exponential form. This is accomplished by fitting an exponential to the data and subsequently dividing each observation by the exponential function, evaluated at the proper time point. The cyclical components are then extracted by the application of a moving average filter to isolate the slower responding seasonal (or weekly) variations, while a corresponding point averaging technique is used to represent year-to-year hourly variation. These cyclic factors are removed by division, leaving the residual. If the assumed structure of the historical demand records is correct and if all the significant factors are taken into account in the decomposition process, the residual variations should be negligible. It is a measure of the validity of the procedure that its application to the records used in this study resulted in residuals whose variations were indeed insignificant ($\leq \pm 5\%$). These small remaining fluctuations are presumably caused primarily by short-term and long-term weather variations.

TIME SERIES DECOMPOSITION AND RECOMPOSITION

SYMBOLS

TR - TREND

C - CYCLICAL (Seasonal * Hourly)

I - IRREGULARITIES

Figure 26

DEMAND FORECASTING MODEL

The recomposition methodology generates an hourly demand forecast projection at some future time. Given cyclic phenomena representing hourly and seasonal variations and a projected demand trend, the methodology combines these factors in a form prescribed by the model and generates a time series proportional to its components, thereby defining the varying hourly electric power demand over the time period of interest. This time series may then be used as input to system simulation computations. A more detailed description of the computer programs that affect these decomposition and recomposition procedures can be found in Volume III, Appendix A.

As originally formulated, the decomposition portion of this forecasting methodology utilized up to 10 years of historical data and, in averaging over the full period, treated all years with equal weight. This procedure is a reasonable one so long as there are no pronounced internal trends in the data, i. e., trends in the seasonal, weekly, or hourly component factors. When such trends are present, the procedure can lead to unreasonable results.

An example of this type of problem arose during initial applications of the forecasting methodology and led to a slight modification. The first forecasts of 1990 demand for the Southern California Edison Company showed an annual profile with a winter peak. Since the Edison Co. profile currently peaks in the summer, the result was questioned. A review of the historical data showed that the summer-peaking trend had been gradually building up over a period of years and had produced a summer peak during the last four years of the record. When averaged over a full 10 years, however, the original winter-peaking profile had been retained.

In order to correct this situation, a system of geometric weighting was adopted that gave greater emphasis to the latter years of the historical record in calculations of the weekly and hourly indices (factors). It was this revised demand forecasting methodology (including

the weighting system) that was used in developing the demand forecasts used in the current study. An alternative method for dealing with internal trends in a more systematic manner has recently been developed and is described in Section 4.2.3.

4.2.2 Characteristics of System Demand Representations

Two different system demand representations, prepared by the revised forecasting methodology (with geometric weighting) described above, were used in this study. The first of these, which is considered to represent the Southern California region, is based on projections to the year 1990 of historical demand records for the Southern California Edison Company. The daily demand profiles for the first weeks of April, August, and December of 1990 in this representation are shown in Figure 27. Also shown in the figure is the load duration curve for this demand representation, a plot of the total demand (load) versus the fraction of the time when the indicated load is experienced. The maximum demand in this representation is 32,000 MW (occurring on 30 July 1990) and the minimum is 13,337 MW (occurring on 1 April 1990). The load factor (ratio of average demand to peak demand) is 0.654.

The second system demand representation used in this study is based on projections to 1990 of demand records of the Arizona Public Service Company and is considered generally representative of central Arizona. Figure 28 contains a plot of the daily profiles for the last weeks of April, July, and December of 1990. (These particular weeks are not the standard FPC weeks, of course, but were chosen in this case in order to include the annual demand peak.) The load duration curve for this demand representation is also included in the figure. The annual peak demand in this case is 7109 MW (occurring on 26 July 1990) and the minimum demand is 2227 (on 4 January 1990). The load factor, 0.557, is very similar to that experienced in the Arizona Public Service Company system in recent years.

Figure 27

SOUTHERN CALIFORNIA UTILITY SYSTEM
DEMAND REPRESENTATION, 1990

Figure 28

CENTRAL ARIZONA UTILITY SYSTEM
DEMAND REPRESENTATION, 1990

4.2.3 An Alternative Projection Methodology

The demand forecast model that is described in Section 4.2.1 (and in Volume III, Appendix A) utilizes only a single trend in predicting future electric demand for a given utility. This trend corresponds to the yearly average growth that has been forecasted for that utility. Consequently, the forecasted variation in demand within a year (yearly demand distribution) is independent of the forecast year. This distribution is essentially assumed to be the same as the average of the last few years in the demand data base (geometric weighting) or the average of all years in the data base (no weighting).

This characteristic of the earlier model is not a serious limitation if the utility in question has a history of reasonably stable yearly distributions. However, if major redistributions of demand have occurred (such as a shift from winter to summer peaking or a shift from morning to evening peaking) the projected demand will not properly reflect these redistributions. It is for this reason that a new, more flexible model was developed.

The new procedure, like the old, begins with the decomposition of the historical demand record into a number of component factors. In this case, however, there are, in general, six 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 future year can then be 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. There is no necessity to resort to such arbitrary procedures as the geometrical weighting that was required when the earlier projection methodology was applied to the Southern California Edison data (as discussed in the preceding section).

A more detailed discussion of the new forecasting methodology, along with a description of 1990 forecasts for two different utilities (Southern California Edison Co. and Arizona Public Service Co.) is presented in Volume III, Appendix B.

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SECTION 5

SYSTEM SIMULATION

In addition to representations for the insolation input and for energy demand (as discussed in Sections 3 and 4), simulation computations of photovoltaic system performance require the development of a suitable mathematical model for the system itself. In this study, the main function of these computations is to determine how well the system accomplishes the primary task of satisfying a time-varying demand for electric power through the conversion of a highly variable solar energy input over an extended period of time. The model representing the system, therefore, does not need to reflect the finer details of system design, although all significant losses and the principal subsystem interfaces should be included.

The system models used in investigating different classes of missions must necessarily differ from each other in some particulars, but they also clearly have a great many features in common. In this study, accordingly, a basic model was developed that could then be adapted to meet the requirements of each of the three mission classes that were considered. This basic model is described in Section 5.1 below; details of the algorithms on which the computer subroutines are based are reserved for Volume III, Appendix C. The modifications that were made to adapt this basic model for evaluating on-site missions are discussed in Section 5.2, while those required for central station and fuel production missions are described in Sections 5.3 and 5.4.

5.1 BASIC SIMULATION MODEL

In developing a basic simulation model to meet the needs of this program, it was decided at the outset a) to construct the computer routines in modular form, with careful attention to interfaces in order to permit ready substitution of one module (subroutine) for another serving the same purpose; b) to start with relatively simple subroutines so that

computations could begin without unnecessary delay; and c) to increase the complexity of the model in an evolutionary manner through the replacement of the initial subroutines by subroutines that are more sophisticated, that reflect new information, or that fulfill requirements made apparent by the initial computations. In addition to facilitating the evolutionary development of the simulation model, the modular feature also makes it simple to study the effects of configuration changes (e. g., changes in concentrator type) on system performance or to alter the configuration to suit the special requirements of a mission.

The modules that comprise the basic system model that was constructed are shown in block diagram form in Figure 29. The blocks and flow paths indicated by solid lines represent the basic system elements of the power-production system, including backup power from the conventional utility grid. The dashed lines represent the power flow that would take place if the backup power from the utility were obtained during off-peak hours (late night and early morning, typically) and stored for later use. This procedure, which presupposes at least a limited capability to forecast periods of poor insolation (cloudy days), would minimize the impact of the backup power requirement on the required generation capacity of the utility system. The dotted lines represent the power flow, if any, required for collector tracking and solar cell cooling.

The subsystem routines, as represented by the blocks on Figure 29, compute the various system energy losses between the incident insolation and the delivery of electrical energy to meet the demand. Subsystem design characteristics based on typical existing components were used in modeling these subsystem losses.

The block labeled "insolation" represents a magnetic tape containing an hour-by-hour record of direct (unscattered) insolation, total insolation, and various other weather information (including ambient temperature) at a particular site.

The tracking routine applies the appropriate geometrical and tracking corrections for the alternative collector configurations analyzed, and, therefore, computes the insolation energy which can potentially be collected.

The collector routine defines the total collector area and the losses associated with its design configuration (e.g., reflectivity, aiming losses, shading).

The photovoltaic conversion routine represents the efficiency of the solar cells (i.e., receiver) as a function of their temperature. A subroutine is incorporated to compute the solar cell temperature as a function of incident insolation and ambient temperature.

The d.c. losses routine represents the internal resistive losses in the solar array and the direct current line losses between the array and the power conditioning or electrical storage (i.e., battery) subsystems.

The power conditioning routine represents the conversion of d.c. to a.c. power and any required a.c. voltage transformation (e.g., 220 to 110V) needed to meet load requirements. The dashed power conditioning subsystem represents a rectifier for converting a.c. to d.c. at the desired storage voltage, when conventional power is input into storage for later use.

The electrical storage routine represents the performance of an electric battery with a maximum storage capability and an overflow (surplus) provision. Representative power losses are incorporated in the routine.

The power requirements routine defines the electrical power required to meet the solar cell cooling and collector tracking needs.

The transmission losses routine represents the alternating current line losses between the power conditioning unit and the demand point.

The computed hourly amount of electrical energy generated by the photovoltaic system, after all the above losses are deducted, is then multiplied by yet another factor smaller than 1.0 to correct for an assumed probability of unscheduled outage resulting from subsystem or component failure. The use of a constant factor in making this correction has been justified on the grounds that photovoltaic systems are inherently modular. Component or subsystem failures are likely to result in many small partial outages rather than in a few complete outages; the overall effect will more closely resemble a constant system degradation than a probabilistic sequence of major problems. The unscheduled outage factor that has been used in this study is 0.96, corresponding to an outage rate of 4%.

The resulting hourly values for generated electrical energy, supplemented with backup conventional power as required, are then matched to the electrical demand, hour-by-hour, for a full year of simulated operation.

A description of the mathematical content of each of the individual subsystem routines and a listing of program inputs and outputs are presented in Volume III, Appendix C. The numerical values (or ranges of values) that were used for these inputs are also discussed there.

5.2 ADAPTATIONS FOR SPECIFIC MISSION CLASSES

5.2.1 On-Site Missions

In carrying out performance evaluations for on-site missions, the basic simulation model was used essentially as was described in the preceding section, except when the possible advantages of insolation forecasting were being explored. A very simple dispatching logic was used that dispatched incoming power from the solar array (minus losses) to meet current demand, with any excess sent to storage. When the solar power was insufficient to meet demand, the required energy was extracted from the storage system. When the storage was exhausted, backup power was obtained from the conventional utility grid.

The dispatching logic described above presupposes the availability of backup power from the utility grid whenever solar energy (from the array or from storage) is insufficient to meet the demand. If the amount of photovoltaic generation capacity within a given utility service area is large, the sudden requirement for backup power for all of these photovoltaic systems during a succession of cloudy days might well cause a substantial increase in the peak demand within the utility system. This would mean that, in order to be sure of providing service with acceptable reliability, the utility system would require additional conventional generation capacity. As was pointed out earlier in this report (Section 3.6), the impact of the requirement for backup power for the photovoltaic systems could be reduced if reasonably accurate insolation forecasts were possible. For example, if a period of cloudy weather were forecasted, power could be withdrawn from the utility grid during off-peak hours of the night and early morning preceding the cloudy day. The effect on the peak demand in the utility system would, therefore, be minimized, as would the requirement for supplementary conventional generation capacity.

In an attempt to get at least a rough indication of the real usefulness of accurate insolation forecasting and the associated storage management possibilities, provisions have been made in the model to simulate two extreme cases. The first option, the case where no forecasting (and thus no storage management) is possible, is simply the standard model, without modification. The second option represents the case when perfect forecasting of both insolation and demand over a 24-hour period is possible.

In the perfect forecasting option, the computer routine carries out two simulation computations for each 24-hour period. The first computation obtains the information about insolation and demand during the succeeding 24 hours, computes the total required backup power, and makes this information available (as if forecasted) for the second computation. During the second simulation computation, this total amount of

backup power (plus projected storage losses) is obtained from the grid during a preselected off-peak period (typically between 12 midnight and 7 am) and dispatched either to meet current demand or to storage, or both.

The decision to use the basic simulation model for evaluating on-site residential applications implies the assumption that the residential loads will be conventional 60 Hz a.c. loads. If these loads could instead accept direct current power, the substantial costs and energy losses associated with d.c./a.c. inversion could be avoided. For this reason, a preliminary investigation was made of the problems associated with operating a typical residence on d.c. power. The results of this investigation are discussed in Volume III, Appendix D. The study revealed, in general, that the obstacles to d.c. residential usage are formidable and that overcoming them would involve a variety of costs that are difficult even to estimate. Accordingly, no attempt has been made in the present study to evaluate the d.c.-house alternative.

5.2.2 Central Station Missions

The principal adaptations that were required in order to use the basic simulation model for evaluating central station missions were two: introduction of a limit on the output of the power conditioning system and formulation of a different dispatching logic. The power conditioning limit has the effect of defining the "name-plate" rating of the solar energy plant in the same way that the turbo-generation rating defines that of a conventional or solar thermal plant.

The dispatching logic that was used in nearly all of the central station evaluation computations carried out in this study was designed to permit investigation of the effects of a range of operating strategies. The operation of the logic is controlled by the values of two input parameters: PMULT, a number between 0 and 1 that represents a prescribed fraction of the daily demand peak, and STBASE, a number between 0 and 1 that represents a prescribed fraction of the system storage capacity. The logic is arranged so that, on a given day, solar power is dispatched

into the utility system transmission/distribution grid when either a) the total system demand is greater than the product of PMULT and the peak system demand for that day, or b) the amount of solar energy stored in the electric storage subsystem is greater than the product of STBASE and the total storage capacity. When the sun rises in the morning, photovoltaic power from the array is dispatched into storage until either system demand reaches the preselected magnitude or the storage capacity has been filled to the predetermined level. When either of these two lower limits is reached, solar power is dispatched into the utility grid. Delivery of solar power to the grid then continues until both system demand and stored energy have again fallen to the prescribed lower limits.

The effect of the operation of this logic is that the solar plant preferentially dispatches power to meet a preselected "band" of the total utility system demand, as indicated in Figure 30. The value for PMULT is, in general, chosen so that the annual amount of energy in the associated energy band represents a predetermined fraction, f , of the nominal maximum annual energy output of the solar plant (i.e., the product of 8760 -- the number of hours in a year -- and the rated plant output). A plant that provided all of this in-band energy, and no more, would then be operating at a plant capacity factor, PCF, equal to f . The logic therefore simulates an operational strategy in which the solar plant is constrained, to a degree, to operate as a baseload plant ($PCF \sim 1.0$), an intermediate plant ($PCF \sim 0.5$), or a peaking plant ($PCF \sim 0.1$).

The choice of STBASE modifies the above operational strategy. When this input is set high (~ 1), the system operates as described above, except that after the storage capacity has been filled, any additional solar power that is available will be dispatched into the grid, regardless of whether or not this power would go into the prescribed band. When the selected value of STBASE is small, more of the solar output will be dispatched outside the assigned band. When STBASE is 0, solar power is dispatched into the grid whenever it is available (either directly from the array or from storage). The only times when solar power is actually

Figure 30

SOLAR PLANT DISPATCH LOGIC: ASSIGNED BANDS

wasted are those occasions on which the storage is full and the incoming solar power is greater than the rated maximum power-handling capability of the power conditioning system (i. e., greater than the name-plate rated output of the solar plant). The computer program keeps separate records of the amounts of energy delivered by the solar plant into and outside of the prescribed solar band, as well as of power wasted.

The objective of the dispatch logic design, as was noted earlier, was to permit investigation of alternative dispatch strategies. Although the range of possibilities has not been thoroughly explored to date, several different strategies have been evaluated. These investigations and their results are reported in Section 9.

5.2.3 Fuel Production Missions

In performance evaluations of fuel production (i. e., electrolytic hydrogen generation) missions, the system simulation model was truncated at the branch point in Figure 29, on the output side of the "DC Losses" block. The conversion of the d. c. electric power that arrives at this point in the system into a corresponding amount of hydrogen is simulated by a single efficiency factor (kg of H_2 per kWh of d. c. electric energy).

No electric storage is included in the model in this case, because the use of such storage does not appear to be justifiable on economic grounds. This conclusion was reached on the basis of some comparisons of approximate capital costs. A simple example is presented in Table 12, where a comparison is made of the total capital costs for two hypothetical electrolytic plants, one with electric storage and one without, but both supplied with power by identical photovoltaic systems. In the first plant, the electrolytic cells are sized to handle the peak output of the array while in the second they are rated at the average output of the array. (The ratio of the annual average amount of insolation that can be collected in the southwestern U.S. by flat plate arrays, whose tilt angle is adjusted monthly, to the peak amount that can be collected is about 0.25.) The

Table 12

CAPITAL COSTS OF ELECTROLYTIC PLANTS
FOR USE WITH PHOTOVOLTAIC SYSTEMS
(MILLIONS OF 1975 DOLLARS)

	Case I	Case II
	Maximum Electric Power Input: 1000 MWe Storage Capacity: 0	Maximum Electric Power Input: 250 MWe Storage Capacity: 3600 kWh
Electrolytic Plant	30.0	7.5
Hydrogen Storage	1.2	--
Electric Storage (\$20/kWh)	--	72.0
TOTAL	31.2	79.5

capital cost figures for electrolytic plants are those given for "advanced plants" in Reference 11 (adjusted to remove cost of the "power supply"), while hydrogen storage costs were estimated on the basis of figures in Reference 12. (It is assumed that the use of electric storage permits fairly constant flow of output hydrogen into a pipeline, thereby minimizing storage requirements for hydrogen gas in this case.) The value used for battery storage (\$20/kWh in 1975 dollars) is consistent with recent optimistic projections for future advanced systems (e. g., Reference 13) rather than with current (higher) prices.

In the simulation model, as adapted for the fuel production case, a provision is included for setting the maximum capacity of the electrolytic system at a selected fraction of the maximum expected power output of the photovoltaic array. The value of this preset fraction can then be varied parametrically in order to investigate the effect of electrolytic plant capacity on overall hydrogen production costs. (The tradeoff involved is the one between wasting a certain fraction of the available solar energy and paying for seldom used electrolytic plant capacity.)

SECTION 6

RELIABILITY ANALYSIS

The output of a photovoltaic solar energy conversion system is an inherently variable quantity. Since proven methods of storing electrical energy are costly, it is economically unattractive to provide sufficient electric storage capacity to isolate such a system from the effects of the diurnal, seasonal, and weather-related variations in the solar energy falling on the photovoltaic arrays. Therefore, if reliable electric service is to be provided, a backup source of electric power is required. Any assessment of the economics of photovoltaic solar energy conversion must take into account the costs of providing the backup power. It has been assumed in this study that the source of backup energy is the conventional generation capacity associated with a utility grid. In this case, the backup energy costs include: a) the cost of fuel consumed in generating the backup energy, b) the associated costs of plant operation and maintenance, c) the cost of transmission and distribution of the backup energy, and d) the cost of any additional generation capacity that may be required in order to ensure that the utility can meet the electric power demand of all its customers with sufficiently high reliability. It is the last of these costs, the backup capacity requirement, that is addressed in this section.

The methodology that has been used in this study for the calculation of backup capacity requirements is an adaptation of one that was developed in the earlier Aerospace Corporation Solar Thermal Mission Analysis studies (References 1 and 2). The principal element of this methodology is a procedure, called margin analysis, for calculating the statistical probability of loss of load (failure of the system to meet overall system demand) as a result of unscheduled outages of generation plants. The usual function of margin analysis is to determine how large a margin (excess of total generation capacity over projected peak demand) a utility

system must maintain in order to ensure that the probability of loss of load is acceptably small. The current generally accepted reliability criterion is that there should not be more than one day of loss of load in 10 years of service, and it is this criterion that has been adopted in this study.

The other main ingredient in the backup capacity methodology is a baseline model for the utility system that is considered to be the source of the backup power. This baseline model must include both a representation for the total system demand and a model (generation model) for the system's conventional generation capacity, including the individual capacity and probability of unscheduled outage for each plant. The generation model is adjusted, with the aid of the margin analysis procedure, to bring the calculated loss of load to the required level (one day in 10 years or 2.4 hours per year).

Although the details of the calculation are different for different mission classes, the same general approach has been used in applying the methodology in each case. The baseline generation model is perturbed by the introduction of photovoltaic generation capacity, thereby changing the loss-of-load probability. Incremental additions of conventional capacity are then made to the generation model until the loss of load probability is restored to the original level. The amount of conventional capacity so introduced is taken to be the required amount of backup capacity.

In the sections that follow, the utility system models and the margin analysis procedure that constitute the backup capacity methodology are discussed and the specific procedures used for on-site and central station missions are described.

6.1 UTILITY SYSTEM MODELS

Baseline utility system models for the year 1990 have been prepared for two specific regions of the United States, Southern California

and Central Arizona (Phoenix area). Others are in preparation, including one for the Cleveland, Ohio area. The demand representations used in these models are identical to representations for the same year and location that were prepared for use in system simulation computations for central station missions, as described in Section 4.2. They consist of projections to 1990 of long-term historical records of hourly demand in utility systems actually operating in the areas in question.

The generation capacity representations used in the utility system models are generalizations based on the current and projected capacity for actual utility systems in the regions under study, as revealed in annual reports or other public documents or as reported directly by utility representatives. The actual wide variety of plant sizes and types in the capacity projections for a real utility are replaced in the model by a much more limited distribution that has the same total capacity and the same general characteristics as are displayed in the original utility projections. Included in the model are representative figures for the duration of scheduled maintenance shut-downs and for unscheduled outages caused by equipment failure. The resulting generation model can then be considered to be reasonably representative of the capacity serving a region, but it is not, of course, a valid representation of the future capacity of any specific utility system. In each case, the generation model has been adjusted, by means of the margin analysis procedure, so that it is capable of meeting the system demand projected for the same region with an expected annual loss of load (outage) figure of 2.4 hours, corresponding to one day of loss of load in 10 years.

The contents of the Southern California and Central Arizona generation models used in this study are summarized in Table 13. In addition to the unscheduled outage probabilities listed in the table, each plant is assumed to be "down" for scheduled maintenance about 10% of the time. These maintenance outages, of course, are scheduled so as to minimize the probability of system loss of load.

Table 13

CONTENTS OF UTILITY SYSTEM GENERATION MODELS

Southern California Model
Total Capacity - 35,800 MW

<u>Plant Size (MW)</u>	<u>Number of Units</u>	<u>Capacity</u>	<u>Unscheduled Outage Probability</u>
1000	18	18,000	.04
500	20	10,000	.04
200	39	7,800	.04

Central Arizona Model
Total Capacity - 8210 MW

500	4	2,000	.036
400	3	1,200	.067
250	3	750	.045
160	11	1,760	.062
100	25	2,500	.036

6.2 MARGIN ANALYSIS PROCEDURES

The basic element of the margin analysis procedure is a set of graphs, one for each month of the year, representing the (cumulative) probability that the total available generation capacity of the utility system is smaller than a given value x , expressed as a function of x . The procedure used to develop these graphs is as follows. For a given month, those plants "down" for scheduled maintenance are excluded from consideration. 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 (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 of the system is exactly x . From such numbers, in turn, the graphs for cumulative probability are generated. An example of one such cumulative probability function is shown in a linear plot in Figure 31. The discontinuities in slope result, of course, from the fact that the generation model contains a finite number of plants. The full range of variation of the cumulative probability is illustrated more clearly in the smoothed semilog plot of Figure 32.

The margin analysis procedure that is based on these cumulative probability graphs is, in principle, quite straightforward. The individual loss of load rate for each hour of the year is simply determined by noting the total system demand for that hour and then using the cumulative probability graphs to find the probability that this demand is greater than the available system capacity (or conversely, that the available capacity is smaller than the demand). This probability multiplied by the time interval (i. e., one hour) represents the loss of load for that particular

Figure 31

MARGIN ANALYSIS CUMULATIVE PROBABILITY
FUNCTION - LINEAR PLOT

Figure 32

MARGIN ANALYSIS CUMULATIVE PROBABILITY
FUNCTION - SEMILOG PLOT

hour of the year, and the total number of loss-of-load hours for the year is the sum of these hourly values over the 8760 hours of the year. If the total is more than 2.4 hours, the conclusion is drawn that the total system generation capacity is too small to meet the system demand with the required reliability.

If the reliability criterion is not met, it is a relatively straightforward matter to determine how much additional capacity is needed. The total capacity in the generation model is 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 dependence of loss of load on incremental capacity. The amount of backup capacity required in order to reduce the loss of load to 2.4 hours per year is then determined by interpolation.

6.3 APPLICATION TO ON-SITE AND CENTRAL STATION MISSIONS

Although the same general approach has been used in calculating the required amount of backup capacity in on-site and central station missions, the methods of implementing the approach are somewhat different in the two cases.

In the case of on-site missions, the analysis addresses a hypothetical situation in which a substantial aggregation of new load points, all served by similar on-site photovoltaic systems, are simultaneously introduced into the service area of the baseline utility system. The only impact on the utility demand profile and capacity requirements is that produced by the necessity to provide backup power to these photovoltaic systems. In the analysis, the required backup power is added on an hour-by-hour basis to the baseline utility system demand. The margin analysis procedure

is then used to determine the loss of load under the new conditions, and the baseline generation model is augmented incrementally with new conventional generation capacity until the reliability criterion is again satisfied.

In the case of central station power plants, the procedure treats a postulated situation in which a solar power plant is constructed instead of a conventional power plant of the same rated (name-plate) output. In the analysis, the output of the solar plant is subtracted on an hour-by-hour basis from the utility system demand. The margin analysis procedure is then used to compute the annual loss of load associated with meeting this reduced demand with power from conventional plants as represented by the baseline generation model minus the plant that has been replaced by the solar plant. This modified model for conventional capacity is then incrementally augmented until the loss of load again satisfies the reliability criterion. The effective amount of conventional generation capacity that is displaced by a solar power plant is then obtained by subtracting this incremental amount of conventional capacity from the name-plate rating of the solar plant.

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SECTION 7.

ECONOMIC EVALUATION PROCEDURES

The fundamental objective of an economic analysis of a particular photovoltaic mission is to determine the relative cost of meeting mission objectives (e.g., providing the required electric energy with the required reliability) as compared with the cost of meeting these objectives by alternative means. The most straightforward way, in general, to express the result is in terms of the relative unit cost of the desired end product, e.g., in mills/kWh if the product is electric energy or in dollars/ 10^6 Btu if the product is a fuel such as hydrogen. The procedures that have been used in this study for the economic evaluation of central station and hydrogen production missions lead to results expressed in these terms.

The situation with respect to on-site missions is somewhat more complex, however. In assessing the economics of such systems, it is often assumed a) that they are owned by the consumer of the electric power produced, and b) that the cost of this power can be determined simply in terms of the costs of amortizing the purchase price and of maintaining the system. Such analyses often either neglect the cost of the backup energy needed to ensure reliable service or make the explicit or implicit assumption that the backup power will be provided by a utility company at the standard retail price.

This latter assumption is an exceedingly questionable one. To begin with, it should be noted that the distribution system required to bring backup power to a load point served by an on-site photovoltaic system is essentially identical to the system that would be required for serving the entire load-point demand, since it must be able to provide the same peak power. (As will be shown in Section 8.2, this statement is true even if the system storage is managed in such a way as to extract the necessary backup power during off-peak, early-morning hours and store it for use during high-demand periods.) Use of on-site photovoltaic

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systems thus does not produce any savings in the capital costs of distribution lines but does sharply reduce the amount of delivered energy from the grid. From the utility company point of view, therefore, the cost of the distribution system must be repaid through revenues from the sale of a much smaller amount of energy. The unit price of this backup energy should, accordingly, be substantially higher than the average rate.

Because of the uncertainties associated with estimating a reasonable price for the backup energy (or of synthesizing a reasonable alternative way to defray the costs of providing backup power), it was decided in this study not to treat the economics of on-site photovoltaic systems from the point of view of a consumer-owner. Instead, an approach was adopted that is consistent with utility company ownership of the on-site photovoltaic systems and, furthermore, retains a degree of validity even if the question of ownership is completely unsettled. In this approach, the present value (in some designated year) of the overall incremental cost of meeting the demand of a group of load points for a specified number of years by means of on-site photovoltaic systems (with utility backup) is determined. This cost is then compared with the present value cost (in the same year) of meeting the same demand directly from the utility grid. In effect, what are being compared are two cash prices for a specified amount of service for a specified period of time, and the comparison should be valid independently of who pays what part of the cash price. If the price is not paid in cash, of course, then the different costs of money to different payers would distort the result.

It should be noted that it is the incremental cost of meeting the load-point demand that is calculated in the above procedure. From this value, an incremental cost of energy (in mills/kWh) could be deduced, but this would not represent a realistic value for either the busbar or the delivered cost of the energy. Rather than attempt to express the results in terms of unit energy cost, therefore, it was decided to make the evaluation in terms of the total present value costs of meeting the full demand. (It was assumed, explicitly, that the service lifetimes

of the photovoltaic systems and of the incremental conventional capacity involved in the comparison are the same.)

More complete descriptions of the economic evaluation procedures used for the three different classes of missions are given in Sections 7.1, 7.2, and 7.3. The procedures used for the economic evaluation of conventional power plants (needed for comparison purposes and to determine the cost of backup power) are described in Section 7.4

7.1 ON-SITE MISSIONS

The procedure used in the economic evaluation of on-site missions addresses a hypothetical situation in which a substantial aggregation of new load points, all served by photovoltaic energy conversion systems, are introduced into the service area of an existing utility. This additional demand can take any of a variety of forms: residential, commercial, industrial, or some combination. The only resulting impact on the demand profile or capacity requirements of the utility company is that produced by the necessity to provide backup power to these photovoltaic systems.

The structure of the procedure is illustrated in Figures 33 and 34. In the computations, the "existing utility grid" shown in Figure 33 is represented by one of the available utility system models (described in Section 6.1) in which the generation capacity has been adjusted (via margin analysis) so that the system demand, D_0 , is satisfied with acceptable reliability (one day of loss of load in 10 years). Through system simulation computations, as described in Section 5, hour-by-hour records of the required backup energy are obtained. These can be summed, as appropriate, to give an hour-by-hour record of the total backup energy, D_B , required by the entire aggregation of on-site systems.

Then, as is indicated in Figure 34, two situations are compared. The first is the one just described. The required backup energy, D_B , is added on an hour-by-hour basis to the baseline system demand, D_0 , to yield a new hourly record of total demand, $D_B + D_0$. Margin analysis

Figure 33
PERFORMANCE EVALUATION RATIONALE: ON-SITE MISSIONS

Figure 34

ECONOMIC EVALUATION RATIONALE: ON-SITE MISSIONS

procedures, as described in Section 6.2, are then used to determine how much additional generation capacity must be incorporated in the generation model in order to restore the loss of load value to the required 2.4 hours per year. The capital cost of the additional capacity required to satisfy the reliability criterion must then be included, along with the capital cost of the photovoltaic systems, in computing the total capital cost of meeting the new load point demand. The capital cost figures for the additional conventional capacity must include interest charges during the construction period and must take into account escalation of costs during construction. It has been assumed in the analysis that the date of initial operation of the new backup capacity is the same as the date of the introduction of the on-site photovoltaic systems. These latter are considered to be manufactured products whose installation takes only a short time; for simplicity, it is assumed that all of the on-site systems involved were installed during the same year, and any interest charges or escalation during this brief installation period are neglected in the analysis. Finally, to these capital costs must be added a) the operation and maintenance costs associated with the photovoltaic systems throughout the service life of these systems, and b) the operation and maintenance costs and the fuel costs associated with the production of the backup energy that is required throughout the life of the photovoltaic systems.

As was implied in the discussion at the beginning of this section, all of the above costs are evaluated in terms of their present value as of the year of initial operation of the on-site systems. The capital and construction costs associated with the backup conventional capacity are treated as if financed by a construction loan. The present value of these costs at the year of initial operation is simply obtained by adding together the successive cash outlays and the accumulated interest. The successive outlays must be corrected for any escalation in costs during the interval between the time when costs were estimated and the time when the outlay is actually made. In adding the costs together, furthermore, they must all be expressed in constant dollars in order to remove the effect of

inflation. In this study, the total investment costs associated with conventional power plants (including the backup plants discussed in this paragraph) have been evaluated with the aid of The Aerospace Corporation's Power Plant Economic Model. This model is discussed further in Section 7.2.1 below.

The magnitudes of the operation and maintenance costs associated with the photovoltaic systems and of the operation and maintenance costs and fuel costs associated with the backup energy are also determined on a present value basis. These costs accrue in a more or less continuous fashion throughout the operational lives of the systems involved, their annual value in current dollars rising as a result of inflation. The present values of these cost flows as of the year of initial operation are obtained by expressing the annual costs in constant dollars, discounting them to the year of initial operation, and then summing them. Present value in this context, therefore, is interpreted as the lump sum which, if presently invested at a rate of return equal to the assumed discount rate, could sustain a flow of withdrawals identical to the analyzed cost flow, and end up with a balance exactly equal to zero at the end of the period of analysis (the presumed service life of the system involved). The appropriate discount rate in these cases is the "opportunity cost of money", the aggregate rate of return that would be expected by those providing the capital (either lenders or investors with an equity interest, or some combination of the two).

The total present value cost of serving the postulated load-point demand with photovoltaic systems must then be compared with the cost of meeting this same new demand by conventional means. The corresponding situation is one in which the postulated aggregation of new load points is introduced into the utility service area, but without any photovoltaic systems to help meet the demand. In this case, it is therefore the total aggregate new load point demand, $D_R + D_C + D_I$, that is added, hour-by-hour, to the baseline system demand. The margin analysis procedure is then used, as before, to determine the incremental amount

(considerably larger in this case) of additional conventional capacity that is required to meet the new total demand with adequate reliability. The present value cost of meeting the new incremental demand is then the present value cost of the backup plant, computed as before, plus the present value of the fuel and operation and maintenance charges associated with meeting all the energy requirements of the new load points throughout the lifetime of the backup plant. This lifetime is assumed to be equal to that of the on-site photovoltaic systems postulated in the previous scenario, so that the present value cost figures may be directly compared.

The comparative economic evaluation procedure described in the preceding paragraphs requires a number of inputs. Among these are the capital cost of the on-site photovoltaic system and the associated operation and maintenance costs; the values adopted in this study for these input parameters are discussed in Section 8, where the results of the evaluations carried out in the current study are presented. There are, in addition, a number of inputs that relate to the costs of conventional power generation (capital, fuel, operations, and maintenance). The origin of the values for these parameters that were used in this study is described in Section 7.4.

7.2 CENTRAL STATION MISSIONS

The economic evaluation of central station missions has been carried out with the aid of The Aerospace Corporation Power Plant Economic Model (PPEM), originally developed for use in the Solar Thermal Mission Analysis Program. The PPEM is a computer program that carries out a complete discounted cash flow analysis of the entire economic life of an electric power plant, from the purchase of the site to the end of the service life of the plant. The model has been used in its original form to calculate the costs associated with conventional power generation; these results are needed in order to calculate the cost of backup capacity and in order to provide a standard for comparison with the cost of photovoltaic power. It has also been used, in slightly modified form, for the economic evaluation of the photovoltaic central station power plants themselves.

The basic structure of the PPEM is described in Section 7.2.1 below, and a summary of the major subroutines in the program is given in Volume III, Appendix E. (In addition, a complete description of the model is contained in Reference 14). The general economic inputs required by the program are discussed in Section 7.2.2, and the minor modifications that were introduced in order to adapt the model for use with photovoltaic systems are described in Section 7.2.3.

7.2.1 Basic Structure of the Power Plant Economic Model

As was indicated above, the PPEM program carries out a complete discounted cash flow analysis of the construction and operation of an electric generating plant. In this procedure, sums of money that appear in the cash flow at different times are discounted, i. e., corrected to take into account their different "time values". This procedure corrects for the fact that, for example, current receipts (or expenditures) are worth more than those that occur at some future time because of the increment that currently available cash can be expected to earn in the interval. The analysis begins by determining the total investment cost of the completed power plant, including interest accrued during construction and correcting for the effect of cost escalation during construction. This total investment cost, minus the properly discounted residual value of the plant at the end of its service life, is then balanced against the discounted net value of the stream of operating costs and revenues over the life of the system. The magnitude of the revenue stream, evaluated at the generation plant busbar (i. e., not including transmission or distribution costs) is adjusted to bring these terms into balance. The busbar energy cost is thus determined by the requirement that the associated revenue stream must defray the operating costs over the life of the plant and also repay the net investment cost of the plant. The discounting procedure automatically includes the expected return on investment (dividends to stockholders, interest to lenders) in the balance.

A flow chart for the operation of the PPEM is shown in Figure 35. In the model the investment costs associated with plant construction are 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. The initial input data to the model, therefore, are the capital investment costs for each of these subsystem accounts; these are estimated for a power plant of a given size in terms of base year (e.g., 1975) dollars. To determine the corresponding costs for power plants of other sizes, an economics-of-scale subroutine has been included. This subroutine is separately applied (with different cost scaling relationships) to the individual subsystem investment accounts. When the input data are associated with a plant of the same size as the one being analyzed, of course, the economics-of-scale subroutine is without effect. Since there are no known scaling relationships for the cost accounts that are peculiar to photovoltaic plants, input data for these accounts were, in this study, always labeled as corresponding to a 100 MW plant, the size that was studied. It was therefore not necessary to develop estimates of the scaling relationships for these accounts.

A significant contribution to power plant cost results from escalation (inflation); this effect is accounted for in the model by an escalation subroutine. This subroutine determines the escalation in costs from the base year to the start of construction. During construction, cash flows are expended which incur interest-during-construction (IDC) expenses in addition to the continued escalation of costs during this construction time period.

The base year capital investment cost combined with escalation and IDC determine the total capital investment cost at the year of commercial operation. The capital investment cost at the year of commercial operation,

Figure 35

FLOW CHART FOR POWER PLANT ECONOMIC MODEL

together with other fixed charges, such as insurance and property taxes, determine the fixed charges.

Cash flows derived from pro forma income statements are discounted to the year of commercial operation. The rate of discount is the cost of capital typical of the utility industry. This rate is estimated by the weighted average after-tax cost of common and preferred equity and long-term debt. The discount rate is used to calculate the present value of the cash flows during the operating life of the plant. Total cash outflows over the plant lifetime are determined by adding estimated operating costs to the fixed charges. The total busbar energy cost is determined by the requirement that discounted plant lifetime cash inflows and outflows be equal. In this calculation the annual energy production (kWh/yr) of the power plant is, of course, an important element.

Transmission and distribution costs can be added to determine the retail energy costs for comparative evaluation of power plants with different locations and distances from the load center.

7.2.2 General Economic Inputs

The Power Plant Economic Model requires a number of inputs that represent projected economic conditions, both in the U.S. as a whole and in the electric utility industry in particular. The most important of these inputs are those that relate to escalation of costs as a result of inflation and those that determine the cost of investment capital (and therefore the discount rate). For the purposes of this study, the values that were used for these inputs were those that were developed in The Aerospace Corporation Solar Thermal Mission Analysis Program (Reference 2) on the basis of 1973 data for the most part. While it is true that there have been important changes in economic conditions in the last two years, it is also true that the current situation is so unsettled that the development of alternative projections on the basis of more recent data would be subject to considerable uncertainty. Furthermore, since the economic analysis

is based on comparisons of projected costs of photovoltaic electricity with projected costs of conventionally generated electricity, the results of the analysis are not strongly dependent on the actual economic parameters employed, so long as they are used consistently.

In this study, therefore, the basic rate of inflation, as measured by the gross national product implicit price deflator, was assumed to average 3.0% per year from 1975 into the future, albeit with substantial fluctuations about this average rate in certain time periods. While this rate is much smaller than the 1973-75 rate, it is consistent with the long-term (1958-1972) average rate of 2.9% per year. This rate of inflation has also been used as the basis for developing projected escalation rates for 10 standard price indices. These indices and the escalation rates that were adopted are shown in Table 14. These rates were used, in turn, to develop specific escalation rates for each of the investment accounts and for other categories of cash flow, as discussed below in Sections 7.2.3 and 7.4.1.

The after-tax cost of capital (the discount rate) is also related to the assumed rate of general inflation. The cost-of-capital rate used in this study is based on historical data for the period 1950-1972, on the assumption that the investment capital involved is made up of equal (50%) proportions of debt and equity and that the combined state and federal income tax rate is 40% (References 19 and 20). This historical time period was selected as a basis for estimated future debt and equity costs because interest rates are positively correlated with inflation and it was accordingly desirable to use the same base time period as was used in projecting inflation. The capital structure, tax rate, and cost-of-capital values used in the analysis reflect values that are representative of the electric utility industry, as is indicated in Table 15.

7.2.3 Adaptation for Photovoltaic Plants

The adaptation of the PPEM for use in the economic evaluation of photovoltaic power generation was a relatively simple and straight-

Table 14

PRICE INDEX ESCALATION RATES

<u>No.</u>	<u>Price Index</u>	<u>Projected Annual Escalation Rate</u>
1	Industrial and Commercial Construction Labor and Materials (Boeckh Index of Construction Costs) (Ref. 15, 16)	4.7%
2	Electrical Machinery and Equipment (Wholesale Price Index) (Ref. 15, 16)	1.0%
3	All Machinery and Equipment (Wholesale Price Index) (Ref. 15, 16)	1.8%
4	Iron and Steel Products (Wholesale Price Index) (Ref. 15, 16)	3.6%
5	Rural Land (Department of Agriculture Index) (Ref. 17)	6.1%
6	GNP Implicit Price Deflator (Ref. 15, 16)	3.0%
7	Industrial Chemicals (Wholesale Price Index) (Ref. 15, 16)	0%
8	Turbine/Generators (Handy-Whitman Index) (Ref. 18)	1.1%
9	Boilers (Handy-Whitman Index) (Ref. 18)	3.0%
10	Fuel Handling Equipment (Handy-Whitman Index) (Ref. 18)	1.6%

Table 15

UTILITY INDUSTRY DEBT AND EQUITY COSTS

<u>Year</u>	<u>Debt*</u>	<u>Equity</u>	<u>Net Cost of Capital**</u>
1956	4.18	11.1	6.80
1961	4.57	11.2	6.93
1966	5.36	12.8	8.01
1972	7.50	11.6	8.05
Projected	5.40	11.6	7.42

* Before taxes.

** After taxes (a tax rate of 40% and a 50% debt, 50% equity investment structure are assumed).

forward process. The only actual changes to the model itself (exclusive of changes in input values) were the introduction of investment accounts representing the elements of the plant that are not found in conventional plants and the adjustment of the internal logic associated with indirect costs to reflect the new investment account assignments. Application of the revised model to analysis of a photovoltaic plant then required only the insertion of appropriate input values for a) base year costs for each investment account (\$/kW), b) base year charges for operation and maintenance (\$/kW), c) escalation rates for each investment account and for fixed and operating costs, and d) parameters defining the schedule of cash flows during construction.

The investment accounts that are involved in the analysis of a photovoltaic plant and the escalation rate used with each account are shown in Table 16. The third column in the table refers to the price index escalation rates in Table 14 and indicates how the composite rate for each investment account was determined. Table 16 also contains the escalation rates used with the other main cash flow categories. The zero escalation rate for insurance and property tax reflects the fact that these costs are represented in the model as lifetime levelized rates that are applied to the initial undepreciated value of the total plant investment.

The nature of the costs included within each of these investment accounts and the basis on which the base year cost was determined are outlined below:

a) Land acquisition cost: This account includes the cost of clearing, grading, and relocating utilities and buildings. The base year (1975) cost was predicated on an overall land acquisition cost of \$500/acre. It is assumed that 90% of the available site area is devoted to collectors and that these collectors are so spaced that their total aperture area is equal to one-third of the area devoted to collectors.

b) Structures: This account includes all structures and facilities required for the conventional portion of the solar plant (adminis-

Table 16

ESCALATION RATES FOR PHOTOVOLTAIC POWER PLANTS

<u>Investment Account</u>	<u>Composite Escalation Rate per Year</u>	<u>Price Index Basis</u>
Land	6.1	5
Structures	4.7	1
Collectors, Concentrators	2.8	1 (35%) 3 (65%)
Electric Plant Equipment	3.6	1 (69%) 2 (31%)
Misc. Plant Equipment	2.7	1 (30%) 3 (70%)
Photovoltaic Arrays	2.8	1 (35%) 3 (65%)
Power Conditioning Equipment	3.6	1 (69%) 2 (31%)
Electric Storage	3.6	1 (69%) 2 (31%)
<u>Other Cost Categories</u>		
Operation and Maintenance	2.0	
Revenue/kWh	2.0	
Insurance/Property Tax	0	
Spare Parts	2.0	
Indirect Construction Costs	4.7	

tration building, control room, auxiliary structures) and for housing the power conditioning and electric storage subsystems. The base year cost was estimated at \$10.85/kW on the basis of figures in the Westinghouse Data Book (Reference 21).

c) Collectors, concentrators: This account includes all of the elements of the collector or concentrator (including any tracking assembly with its drive) except for the cost of the photovoltaic array modules themselves. For this study the economic analyses considered only the case where the collectors are flat plates whose tilt about an east-west axis is adjusted monthly for optimum energy collection. The base year cost was taken to be \$15/m² on the basis of 1) cost estimates for more complicated structures in the solar thermal program and 2) a rough calculation of the materials and labor required to fabricate such a collector.

d) Electric plant equipment: This account includes switchgear, switchboards, wiring containers, control wiring, etc., associated with the conventional portion of the plant and also the heavy d. c. wiring between collector modules and the power conditioning equipment. The base year costs were based on a fixed cost of \$16.30/kW (estimated on the basis of numbers in Reference 21) for everything except the d. c. conductors, plus an additional amount, proportional to array area to the 1.5 power for the latter.

e) Miscellaneous plant equipment: This account includes transportation, communications, and lifting equipment; air and water systems; furnishings and fixtures. The base year cost, estimated on the basis of Reference 21, was taken to be \$5.97/kW.

f) Photovoltaic array: This account includes the assembled photovoltaic array modules, encapsulated and supported on suitable substrates. The base year costs were derived from an assumed array price of \$100/kWpk. In effect, it has been assumed that the price at the actual time of purchase will be the value obtained by multiplying the \$100/kWpk

figure by a factor representing escalation (at 2.8%) between 1975 and the year of purchase.

g) Power conditioning equipment: This account includes all the equipment needed to convert the d. c. output of the photovoltaic arrays into 60 Hz a. c. power, acceptably free from harmonics. Inverters, filters, and control circuitry are included and the base year price has been taken to be \$35/kW in accordance with estimates such as that contained in Reference 22.

h) Electric storage: This account includes batteries, interconnections, and control circuitry. The base year cost has been taken to be \$20/kWh in accordance with recent estimates (References 13, 23, and others).

The cost for operation and maintenance is included in the model as a fixed charge per unit of capacity. The base year cost used in this study, \$7.50/kW, is the same as that used in the solar thermal studies (Reference 2). It corresponds roughly (for a plant capacity factor of 0.4) to a charge against energy production of 2 mills/kWh.

The parameters defining the schedule of cash flows during construction are a) the duration of the construction period (taken in this study to be six years) and b) a set of eight numbers for each investment account defining the end points of the straight line segments making up nondimensional cash flow graphs like that shown in Figure 36. Each such graph is a generalized representation for the rate at which cash is expended in a given investment account. The actual dollar amounts expended are equal to the products of the normalized amounts (the ordinates in Figure 36) and the total investment cost in the account in question. The time of a given expenditure is equal to the product of the nondimensional time, τ (the abscissa in Figure 36), and the duration of the construction period (i. e., six years). The coordinates adopted in this study for the four points defining the cash flow graphs for each of the photovoltaic plant investment accounts are given in Table 17.

Figure 36

NONDIMENSIONAL CASH FLOW GRAPH: STRUCTURES

Table 17

COORDINATES DEFINING NONDIMENSIONAL CASH FLOWS

<u>Investment Account</u>	<u>Coordinates</u>
Land	(-.15, 0) (-.1, 1) (0, 1) (1, 1)
Structures	(.3, 0) (.6, .8) (.7, .95) (1, 1)
Collectors, Concentrators	(.2, 0) (.55, .5) (.9, 1) (1, 1)
Electric Plant Equip.	(.5, 0) (.75, .8) (.85, .95) (1, 1)
Misc. Plant Equip.	(.5, 0) (.7, .8) (.75, .9) (1, 1)
Photovoltaic Arrays	(.2, 0) (.55, .5) (.9, 1) (1, 1)
Power Conditioning Equip.	(.2, 0) (.55, .5) (.9, 1) (1, 1)
Electric Storage	(.2, 0) (.55, .5) (.9, 1) (1, 1)

7.3 FUEL PRODUCTION MISSIONS

The procedures that have been used in the economic assessment of fuel production (i. e., electrolytic hydrogen) missions are much more rudimentary than those described above. They have consisted, in fact, simply of a preliminary levelized fixed charge calculation of the unit cost of the hydrogen that is produced, in accordance with the relationship

$$\text{Unit Cost} = \frac{(\text{TIC}) \times \text{FCR} + \text{O\&M}}{(\text{Annual H}_2 \text{ Production})} \quad (3)$$

where TIC = Total Investment Cost
 FCR = Fixed Charge Rate
 O&M = Annual Operation and Maintenance Costs.

The value used for the fixed charge rate was 16.5%, consistent with values derived in the Aerospace Solar Thermal Mission Analysis Program for application to solar thermal plants. The assumed value for the operation and maintenance costs corresponded to a charge of about 2 mills/kWh for the photovoltaic part of the plant and about 2.5 cents per million Btu for the electrolytic part of the plant. The value for the annual hydrogen production was obtained through system simulation computations.

The unit cost figures generated in this simplified computation are, of course, subject to considerable uncertainty, but the error involved should be no more than $\pm 25\%$. Before attempting to refine the analysis, therefore, it was decided to carry out an investigation of the costs of fuels that would be economic competitors of hydrogen produced in this way. These competitors include a number of portable fossil fuels as well as hydrogen produced in other ways (including electrolytic hydrogen produced with electricity from conventional sources). This investigation, whose results are reported in Volume III, Appendix F, revealed that the projected prices for many of these competing fuels are very much lower than the price of photovoltaic/electrolytic hydrogen, as calculated in the

simplified analysis discussed above. Since the indicated price differentials were much greater than the uncertainty in the price estimate for photovoltaic/electrolytic hydrogen, it was decided that further effort to refine this price estimate would be an inappropriate use for the limited resources of this study.

7.4 CONVENTIONAL POWER GENERATION

Projected values for the investment costs associated with future conventional power plants and for the busbar costs of the energy produced in such plants are needed in this study for two different purposes: a) the evaluation of the cost of backup energy and backup capacity needed to ensure reliable service when photovoltaic systems are used, and b) the assessment of the comparative costs of using photovoltaic or conventional capacity in a given mission. Representative figures on future conventional power generation had already been developed in the Aerospace Solar Thermal Mission Analysis Program with the aid of the Power Plant Economic Model described in Section 7.2.1 above, in Appendix E of Volume III, and in Reference 14. The basic information about conventional power generation costs that was needed in this study was therefore simply abstracted from the body of computations carried out in the earlier program. The economic parameters (escalation rates, interest rates, rates of return on investment, etc.) used in these computations were the same as those used in this study in computing photovoltaic generation costs. Comparisons can therefore be made on a consistent basis.

The one area where the use of the figures generated in the earlier program could lead to significant distortions of the competitive position of solar energy is that of fuel price projections. For this reason, new projections, based on more recent data than was available to the earlier study, were made for the price of coal, the principal competitive fuel in the cases considered in this study. An estimate was then made of the effect of the new coal price projections on the busbar cost of conventional electric energy, as calculated in the earlier study.

In the remaining paragraphs of this section, the specific information that was transferred from the solar thermal study is summarized and an account is given of the revised coal price projections and their effect on the cost of conventional power.

In Table 18 are shown the comparative 1990 capital cost estimates for the conventional plants that were of interest in this study. Also shown are the associated 1991 busbar energy costs in each case and the plant capacity factor that was assumed in computing the energy cost. (The difference in the fuel costs shown for the 1000 MW coal plant and for the other coal plants simply reflects the fact that the analyses were carried out at different times and slightly different estimates for 1980 coal prices were used as inputs.) These costs are not, of course, representative of the average capital costs or energy costs of power plants in existence in 1990; they represent the marginal costs associated with new plants that begin operation in 1990.

The fuel prices used in calculating the busbar energy costs in Table 18 were based on values for 1980 fuel costs and for 1980-1990 and 1990-2000 escalation rates that were developed, for various Southwestern areas, in the Solar Thermal Mission Analysis. These fuel costs and escalation rates are listed in Table 19.

The 1980 coal prices for each area were based on five factors: (1) mine-mouth coal price, (2) coal price escalation rate, (3) transportation cost from mine to consumption area, (4) escalation rate for transportation cost, and (5) land reclamation costs. Mine-mouth 1972 coal prices per million Btu were obtained for two locations: Four Corners, Arizona (14.7¢/MBtu) area, and Hanna, Wyoming (15.0¢/MBtu) (Reference 24).

The coal escalation rate was obtained from a National Petroleum Council Study of Western Coal Mining Economics as a function of overburden ratios (Reference 25). Based on the extensive reserves of strippable coal, the constant dollar increase in the cost of coal due to reserve depletion was determined to be 0.8%/year. This rate, combined with

Table 18
CONVENTIONAL POWER GENERATION COSTS IN 1990
(1990 DOLLARS)

Investment Costs (\$/kW)	Coal			Gas Turbine
	1000 MW Baseload	250 MW Intermediate	100 MW Intermediate	100 MW Peaking
Land	1.0	1.0	1.0	1.0
Structures and Facilities	30.6	45.1	58.3	12.3
Boiler Plant	72.4	94.8	112.5	--
Turbine Plant Equipment	58.0	70.8	80.0	43.1
Electric Plant Equipment	15.2	18.6	21.0	12.3
Misc. Plant Equipment*	54.4	54.4	54.4	3.5
Total Direct Cost	231.6	284.7	327.2	72.2
Contingency Allowance	16.9	21.1	24.4	5.2
Spare Parts Allowance	1.2	1.4	1.6	0.4
Indirect Costs	61.0	118.5	169.6	37.3
Total Investment (1973)	310.7	425.7	522.8	115.1
Escalation to Start of Construction	153.4	217.8	273.4	75.3
Total at Start of Construction	464.1	643.5	796.2	190.4
Interest During Construction	65.1	88.8	109.2	12.8
Escalation During Construction	86.4	124.8	157.9	15.9
Total Investment Cost (1990)	615.6	857.1	1063.3	219.1
Plant Capacity Factor	0.8	0.4	0.4	0.07
Fuel (mills/kWh)	4.74	5.26	5.26	24.40
Busbar Energy Cost (mills/kWh)	19.23	41.89	49.07	98.61

* Includes SO₂ removal system, NO_x control, cooling towers, as appropriate.

Table 19

1980 DELIVERED FOSSIL FUEL COSTS & ESCALATION RATES

Fuel & Area	Fuel Price ¢/MM Btu	Escalation Rates/Year	
		1980-1990	1990-2000*
Coal			
Albuquerque, New Mexico	35.6	3.4	3.4
El Paso, Texas	45.4	3.4	3.4
Fort Worth, Texas	65.2	3.3	3.3
Mohave, Nevada	32.5	3.5	3.5
Phoenix, Arizona	47.4	3.4	3.4
Natural Gas			
Area 1	80.5	5.7%	5.4%
Area 2	46.7**	7.8%	7.4%

* Escalation rates for 1990 - 2000 were assumed for time periods beyond 2000.

** Quantity limited; the intrastate price is about double this level.

Area 1 - Southern California, Nevada, Arizona, New Mexico

Area 2 - Oklahoma and Texas

the assumed 3%/year rate of inflation, results in a current dollar coal escalation rate of 3.8%/year. Coal transportation costs were obtained for unit train shipments (Reference 25), and a 3%/year escalation rate was assumed for these coal transportation costs. Transport distances to each area were used to determine transportation costs (Reference 26). The last factor to be incorporated is the land reclamation cost. A \$0.30/ton levy (1.67¢/MBtu based on 9000 Btu/lb) was incorporated into legislation by a House Subcommittee (Reference 27). This amount was added to 1980 coal costs.

Natural gas prices were developed for two gas supply sources: (1) conventional domestic natural gas production*, and (2) new sources. New sources were: liquid natural gas (LNG) imports to the West Coast, coal gasification, and gas supply from the Arctic. Cost estimates were obtained for each new source, which were converted to 1980 dollars and averaged (References 28 and 29). An escalation rate of 3% per year was assumed for the delivered cost of gas from new sources. Projected future constant dollar conventional domestic natural gas wellhead prices were used to obtain a constant dollar escalation rate (Reference 30). This rate, combined with the assumed inflation rate of 3%/year, provided the escalation rates for conventional domestic wellhead gas prices. The national average 1972 wellhead gas price was escalated to 1980 and combined with transmission costs (Reference 31). Transmission costs were assumed to increase at the general inflation rate of 3%/year. Delivered prices were derived for two areas: Area 1 - Southern California, Nevada, Arizona, and New Mexico; and Area 2 - Texas and Oklahoma. The supply of gas in Area 2 was assumed to be entirely from conventional domestic sources. The gas supply to Area 1 was assumed to have an increasing proportion of supplies from new sources: 1980 - 25%, 1990 - 33%, 2000 and later - 50%. The remaining proportion of supply for Area 1

* Lower 48 states only

was from conventional domestic sources. Thus the gas price and escalation rates shown in Table 19 for Area 1 are composites.*

All of the above fuel price projections were based essentially on 1972-73 data. As is well known, there have been dramatic changes, in the intervening two years, in the whole structure of the fossil fuel market. Current costs and escalation rates are both sharply higher and the prospect for the future is that prices will continue to rise at a substantially higher rate than could have been predicted only two or three years ago. In particular, coal prices (national average) jumped by 75% between 1973 and 1974 and official estimates of future escalation rates are as high as 6% in constant dollar terms, or more than 10% in terms of current dollars.

Although the coal price situation is still far from clear and there is no general agreement on the future course of the market, an attempt has been made to take the recent changes into account in estimating the future cost of power generation in coal fired plants. A new coal price projection was made on the basis of an assumed 1974 price of \$0.36/10⁶ Btu (in the Southwest) and assumed escalation rates of 10%, in the period between 1974 and 1990, and 8% thereafter. The resulting 1991 fuel price is \$1.79/10⁶ Btu or 16.4 mills/kWh at a heat rate of 9200 Btu/kWh. When this fuel price and the associated escalation rates are substituted for the values used in the computations summarized in Table 18, the range of 1991 busbar costs for intermediate-mode electric energy is changed from 42-49 mills/kWh to 58-65 mills/kWh.

* The average 1980 price for gas from new sources is \$1.36/MBtu; the delivered price from conventional domestic sources is \$0.62/MBtu. It is recognized that the composite average price is likely to be lower than the price new power plants would pay for marginal supplies of gas in the future.

SECTION 8

EVALUATION RESULTS, ON-SITE MISSIONS

The methodology that is described in the preceding sections of this report has been exercised in the evaluation of a number of illustrative examples of on-site applications. The bulk of this effort has been devoted to a fairly detailed examination of a selected baseline case in which individual photovoltaic systems are employed to provide domestic power to a large number of single-family residences in Phoenix, Arizona. The use of flat plate collectors, tilted about an east-west axis, was assumed in this case. These results then served as a frame of reference for a series of brief investigations of the changes in the technical and economic performance of an on-site system that are produced by variations in a) the physical characteristics of the mission (geographic location, demand profile) or of the system (collector type, array efficiency), or b) the projected economic conditions (fuel costs, subsystem costs).

It should be emphasized that the main objective of these evaluations was to test and demonstrate the methodology that has been developed. They do not in any sense constitute a definitive or exhaustive study of the on-site mission class, even for the restricted region constituting the southwestern United States. There are a great many variations in system configuration, in mission strategy, and in demand type that could not be examined even in a cursory way within the time and resource constraints of this study.

8.1 PERFORMANCE ANALYSIS

8.1.1 Baseline Case

As was mentioned at the beginning of this section, the on-site application that has been subjected to the most complete examination in this study is one involving the use of individual photovoltaic systems to

provide domestic electric power to a large number of single-family residences in Phoenix, Arizona. The insolation representation used in the system simulation computations was derived from the 1963 historical record for Phoenix. The demand representation used was the Arizona residential demand model described in Section 4.1.4; the average power per residence in this model is 3.47 kW and the peak power is 8.19 kW. In assessing the impact of the installation of these photovoltaic systems on the local utility grid, it was assumed that the total number of homes involved was approximately 35,000, corresponding to a total average power of 121.8 MW and a total peak power of 287 MW. The daily demand profile for these 35,000 homes, it should be noted, was obtained by simply multiplying the profile in the Arizona residential demand model (which is based on the combined demand record for 22 homes) by the requisite factor. This procedure neglects the effect of increased diversity (non-coincidence of demand in different homes) on the ratio of peak demand to average demand, but it should not have a significant effect on the results of the performance computations.

In these baseline calculations, it was assumed that the collector subsystem was a flat plate, tilted about an east-west axis, and that the array packing factor (fraction of total array area occupied by solar cells) was 0.9. The assumed values for the other system parameters are those listed in Section C.2 of Appendix C, Volume III.

8.1.1 Tilt Angle Adjusted Monthly

The photovoltaic system configuration assumed in the first computations of system performance in the baseline on-site mission included a provision for periodic adjustment of the tilt angle of the photovoltaic array. In the computations, therefore, the tilt angle was changed monthly to maximize total collection of solar energy.

Some of the results of these computations are presented in Figure 37 where the energy displacement achieved is displayed in "carpet plot" format, as a function of array area and electric storage capacity.

The term "energy displacement" is used here to mean the fraction of the total (annual) load point demand that is supplied by the photovoltaic systems. The abscissa in the figure is not labeled because, in the carpet plot format, it does not represent a specific single variable. Instead, it serves simply as a linear horizontal scale for use in interpolation between the curves that comprise the quasi-three-dimensional surface displayed in the figure. Along a given constant array area curve, for example, points corresponding to different amounts of storage are spaced horizontally in direct proportion to the amount of storage. Correspondingly, along a given constant storage curve, the horizontal separations between points for different array areas are proportional to the differences in array area. The array areas are expressed in m^2/kWav as well as in m^2 and the storage capacities both in hours and in kWh because the results of these performance computations are independent of the absolute magnitudes of these quantities or of the demand, provided that the ratios of average demand to array area and storage capacity are kept constant. The array area values shown in the figure correspond to array areas per residence that range from $\sim 57 \text{ m}^2$ to 285 m^2 .

The curves of Figure 37 summarize the results of a number of individual one-year simulation runs, for different values of array area and storage capacity. When viewed as a three-dimensional surface, the display permits immediate identification of the ranges in both independent variables over which the effect on system performance is marginal. Since both array area and storage capacity are costly, it is clear that points above the "knee" of the surface represent system configurations that are unfavorable from an economic point of view. Points below the knee obviously represent more favorable configurations, but the selection of the optimum point can only be made, of course, on the basis of an economic analysis that takes into account a number of other factors.

The system simulation computations on which Figure 37 is based provide most of the additional information required by the economic analysis, but one important input must be calculated separately, namely the required amount of backup capacity.

LOCATION: PHOENIX, ARIZONA
 DEMAND: ARIZONA RESIDENTIAL
 COLLECTOR: FLAT PLATE, TILT
 ADJUSTED MONTHLY
 ARRAY EFFICIENCY (20°C): 0.1125

Figure 37

ENERGY DISPLACEMENT IN ARIZONA ON-SITE RESIDENTIAL
 APPLICATION: COLLECTOR TILT ADJUSTED MONTHLY

The capacity displacement methodology described in Section 6 was used to compute the amount of backup capacity required in many of the specific examples represented in Figure 37. For each such example, three different hypothetical situations were examined; these are illustrated schematically in Figure 38. In Case 1, the utility system model used was the central Arizona model discussed in Section 6.1. The total average demand served by on-site photovoltaic systems in this case represented about 3% of the average demand of the entire utility system. Thus, on sunny days, there was about a 3% solar penetration of the system demand. In Cases 2 and 3, the utility system model was the Southern California model that was also discussed in Section 6.1. In Case 2 the average on-site demand was taken to be 121.8 MW, as before, corresponding to a solar penetration of $\sim 0.6\%$. In Case 3, the system simulation results were all multiplied by a factor of 10, so that the solar penetration in this case was $\sim 6\%$. For each case in Figure 38, two different incremental capacity figures are listed. The upper figure (for non-zero array area and storage) is the back-up capacity that is required when the on-site demand is served by photovoltaic systems. The lower figure (for 0 array area and storage) represents the incremental capacity that would be required if the on-site demand were simply added to the total system demand, without photovoltaic systems to carry most of the added load.

There are significant differences in the hypothetical situations represented by Cases 1, 2, and 3 in Figure 38. Not only are different solar penetrations involved (albeit none that is really large), but there are also important differences between the overall system demand profiles in the Arizona and California models. Both are summer-peaking but the Arizona peak is more pronounced; the corresponding load factor is only 0.56, in comparison with the California utility load factor of 0.66. Comparison of the results (and of their impact on the economic analysis) therefore can give a fairly good indication of the sensitivity of the mission evaluations to the characteristics of the utility system that provides backup power. The

Figure 38

CAPACITY DISPLACEMENT IN ARIZONA ON-SITE
RESIDENTIAL APPLICATION: COLLECTOR TILT ADJUSTED MONTHLY

economic analyses (discussed in Section 8.2.1, below) have, in fact, indicated that the results are relatively insensitive to the differences in the utility system models or to the degree of solar penetration, within the fairly narrow range that was explored (up to ~6%).

The results of the capacity displacement calculations for the other system configurations represented in Figure 37 are presented in Table 20. These results, together with the results of the system simulation computations are the basis for the economic evaluations discussed in Section 8.2.

8.1.1.2 Fixed Tilt Angle

In the second set of computations of system performance in the baseline residential application, it was assumed that the tilt angle of the array was fixed (as would be the case if the arrays were mounted directly on south-facing roofs with the assumed slope). The magnitude of the tilt angle was chosen to provide optimum performance in the mission, on the basis of preliminary performance computations for a range of values of the angle. (This procedure results in optimum matching of the tilt angle to the seasonal variations in both insolation and demand). For these preliminary computations, the photovoltaic array area was taken to be $\sim 114 \text{ m}^2$ per residence ($32.8 \text{ m}^2/\text{kWav}$) and the electric storage capacity to be $\sim 28.6 \text{ m}^2$ per residence (8.2 hours at average power).

The results of these initial computations, shown in Figure 39, led to the selection of 24° as the fixed tilt angle to be used in the performance evaluation computations discussed in this section. The ordinate in the figure is the annual energy displacement, and the straight line across the top of the figure represents the energy displacement that could be achieved if the tilt angle were adjusted monthly for optimum energy collection, the operational strategy that is considered in Section 8.1.1.1, above. Figure 39 indicates that, if the fixed tilt angle is properly chosen (matching the combined effects of insolation and demand), a level of system performance can be achieved that is less than 2% poorer than that obtainable when the tilt angle is adjusted monthly.

Table 20

BACKUP CAPACITY REQUIREMENTS
ARIZONA RESIDENTIAL APPLICATIONS

Flat Plate Collector, Tilt Adjusted Monthly
Array Efficiency (20°C): 0.1125

Array Area (10 ⁶ m ²)	Storage Capacity (10 ⁶ kWh)	Energy Displacement	Backup Capacity	
			Central Arizona Utility	Southern California Utility
2.0	0	.320	171.6	112.4
	1.0	.359	167.8	82.8
4.0	0	.434	101.8	71.3
	1.0	.629	70.0	18.1
	1.5	.653	70.0	18.1
6.0	0	.469	75.0	56.6
	1.0	.727	28.1	8.9
	1.5	.806	28.0	8.9
8.0	1.0	.753	14.7	7.7
	1.5	.856	14.4	7.4
20.0	0	.320		1411
	10.0	.359		1288
40.0	0	.434		1045
	10.0	.629		561
	15.0	.653		561
60.0	0	.469		928
	10.0	.727		211
	15.0	.806		210
80.0	10.0	.753		131
	15.0	.856		126

Figure 39

ENERGY DISPLACEMENT IN ARIZONA ON-SITE RESIDENTIAL
APPLICATION AS A FUNCTION OF COLLECTOR TILT ANGLE

The dependence of system performance on array area and storage capacity, in the case where the array tilt angle is kept fixed at 24° , is displayed in Figure 40. In this case, in order to minimize computational costs, the examples corresponding to the plateau area of the carpet plot (above the knee of the figure) were omitted; these portions of the carpet plot do not represent attractive examples for economic analysis in any case.

Calculations were made of the amount of conventional generation capacity required as backup in these missions, also. The results are presented in Table 21.

8.1.2 Sensitivity Studies

In addition to the computations described above of the performance of photovoltaic systems in the baseline on-site missions, a number of less complete sets of computations were made with the goal of determining the sensitivity of the results to variations in mission or system parameters or in mission strategy (e. g., storage management). These sensitivity studies are discussed briefly in this section.

8.1.2.1 Effect of Insolation/Demand Forecasting

Fairly early in this study, it was recognized that the availability of accurate forecasts of insolation would make feasible operational strategies leading to significant reductions in the required amount of backup generation capacity. On the basis of a forecast of insufficient insolation, for example, the operator of a photovoltaic system could extract the necessary amount of backup energy from the utility grid during the off-peak hours of late evening or early morning and store it for use during the following day. In this way, the impact of the backup energy requirement on the peak demand in the utility system could be minimized, with a consequent reduction in the required additional generation capacity. For this reason, provision was made in the system simulation model (as discussed in Section 5.2.1 above) for simulating, in an approximate way, the effect of very accurate insolation forecasting and of the storage management strategy it makes possible.

Figure 40

ENERGY DISPLACEMENT IN ARIZONA ON-SITE RESIDENTIAL
 APPLICATION: FIXED 24° COLLECTOR TILT

Table 21

BACKUP CAPACITY REQUIREMENTS
PHOENIX RESIDENTIAL APPLICATIONS

Flat Plate Collector, 24° Fixed Tilt Angle

Array Efficiency (20°C): 0.1125

Array Area (10 ⁶ m ²)	Storage Capacity (10 ⁶ kWh)	Energy Displacement	Backup Capacity	
			Central Arizona Utility	Southern California Utility
2.0	0	.306	176.5	116.6
	1.0	.340	168.9	83.3
4.0	0	.420	107.3	75.3
	1.0	.605	73.3	18.4
	1.5	.619	73.3	18.4
6.0	0	.457	79.2	60.7
	1.0	.714	29.3	9.0
	1.5	.791	29.2	9.0
8.0	1.0	.741	15.1	7.8
	1.5	.847	14.8	7.6
20.0	0	.306		1440
	10.0	.340		1326
40.0	0	.420		1075
	10.0	.605		575
	15.0	.619		575
60.0	0	.457		951
	10.0	.714		218
	15.0	.791		217
80.0	10.0	.741		130
	15.0	.847		125

In order to assess the potential impact of insolation forecasting on photovoltaic system performance and economics, the perfect forecasting option was exercised in a limited number of system simulations. The flow of energy in the photovoltaic system when this option is used is illustrated in Figures 41 and 42. The graphs in these figures show the hourly energy flows (or hourly average power levels) at the eight identified locations. The insolation representation used in this simulation was that for Phoenix in 1963, and the graphs cover a 48-hour period of operation on 24 and 25 April. The 24th was clear and sunny, but the following day was cloudy, with very low insolation. On the basis of the assumed perfect 24-hour forecast of insolation and demand, backup energy was obtained principally between midnight and 7 am, although the finite size of the storage capacity (here taken to be 8.2 hours at average power) prevented perfect realization of this goal. It is clear from these graphs that the demand for backup energy has indeed been shifted away from the afternoon and evening hours to a very significant extent.

The upper two graphs in Figure 42 also illustrate another interesting point. When the storage management strategy considered here is applied, the result is a peak in the demand for backup power that can be even larger than the daytime peak in on-site demand. In the absence of forecasting, a sequence of cloudy days would quickly lead to a situation where the early evening peak in load point demand is met entirely by backup power from the utility grid. In either case, therefore, with or without accurate insolation forecasting, the maximum backup power level is at least comparable to the maximum power level in the load point demand. The power rating in the distribution system used to bring in the backup power can therefore be no smaller than it would be if there were no photovoltaic system and the utility grid were meeting the entire load. It thus appears that, so long as the required backup power is obtained from the utility grid, the use of photovoltaic systems does not lead to appreciable savings in distribution costs.

INSOLATION: PHOENIX
 DEMAND: ARIZONA RESIDENTIAL
 COLLECTOR: FLAT PLATE,
 24° FIXED TILT

Figure 41
 ENERGY FLOWS IN RESIDENTIAL ON-SITE SYSTEM,
 PERFECT INSOLATION FORECASTING: PART 1

INSOLATION: PHOENIX
 DEMAND: ARIZONA RESIDENTIAL
 COLLECTOR: FLAT PLATE, 24°
 FIXED TILT

Figure 42
 ENERGY FLOWS IN RESIDENTIAL ON-SITE SYSTEM,
 PERFECT INSOLATION FORECASTING: PART 2

An indication of the effect of the use of the perfect forecasting option on annual backup energy requirements and on the amount of required backup capacity can be obtained from the computational results shown in Table 22. These results show that the required backup capacity can, indeed, be very appreciably reduced through the use of forecasting. A price is paid for this advantage, however, in the form of significant increases in the total requirement for backup energy. These increases are a result of the fact that, in the new mode of operation, a substantial fraction of the backup energy passes through the photovoltaic storage system enroute from the grid to the load point. In this process, input a. c. power is first rectified to d. c. and used to charge the storage batteries; it is later extracted from storage and inverted again to a. c. In each of these steps, losses occur. As will be shown in the discussion of mission economics in Section 8.2, the incremental cost of the additional backup energy offsets the economic gain arising from reduced backup capacity requirements to an important extent, and in some cases completely.

(Note: A comparison will reveal that the backup capacity values listed under Case 1 in Table 22 are not consistent with the values for the corresponding examples in Table 20. The reason for this discrepancy is that the computations leading to the values in Table 22 for this case were carried out with an early version of the margin analysis procedure in which no allowance was made for unscheduled outages or output reductions resulting from subsystem or component failure. In calculating all of the other backup capacity values cited in this report, a 4% rate for this type of unscheduled outage was assumed. Since the point of Table 22 is to illustrate the effect of forecasting, rather than to report absolute magnitudes of the backup capacity values, these early results have been included.)

8.1.2.2 Effect of Geographic Location

An indication of the sensitivity of the performance evaluation results discussed earlier in this section to geographic location was obtained through a set of simulation computations whose results are

Table 22

EFFECT OF INSOLATION/DEMAND FORECASTING

Phoenix Residential Demand/Phoenix Insolation (1963)
 Flat Plate Collector, Tilted About East-West Axis
 Array Efficiency (20°C): 0.1125

Case 1. Collector Tilt Adjusted Monthly
 Southern California Utility System as Backup

Array Area		Storage Capacity		Backup Energy (10^9 kWh)		Backup Capacity (MW)	
(10^6 m^2)	(m^2/kWav)	(10^6 kWh)	hr	NoF*	F**	NoF*	F**
6.0	49.3	1.5	12.3	0.175	0.238	4.0	0.019
8.0	65.7	1.5	12.3	0.118	0.142	1.8	0
60.0	49.3	15.0	12.3	1.750	2.386	150.0	4.7
80.0	65.7	15.0	12.3	1.179	1.418	58.0	0

Case 2. Collector Tilt Fixed at 24°
 Central Arizona Utility System as Backup

4.0	32.8	1.0	8.2	0.407	0.553	73.3	9.1
6.0	49.3	1.0	8.2	0.282	0.393	29.3	1.1

* NoF = no insolation/demand forecasting

** F = perfect insolation/demand forecasting

summarized in Figure 43. As is indicated in the figure, two different demand representations were used: the California residential demand model and the Arizona residential demand model that are described in Section 4.1.4 of this report. The insolation representation used in each case was derived from the 1963 historical records for the city in question. For all of these computations a flat-plate collector of area $49.3 \text{ m}^2/\text{kWav}$ ($\sim 170 \text{ m}^2$ per residence in the Arizona model, $\sim 94 \text{ m}^2$ per residence in the California model) was assumed, with the tilt angle about an east-west axis adjusted monthly for optimum energy collection. The storage capacity in each case corresponded to 8.2 hours of storage at average demand. The results displayed in Figure 43 contain no surprises; the high insolation sites (Inyokern, Phoenix, Albuquerque, El Paso) show markedly better performance in both cases. The energy displacement at these sites is smaller for the Arizona model than for the California model simply because the very high summer peak in the Arizona model makes more severe demands on the output of the photovoltaic array; this summer demand peak is more pronounced than the summer peak in available insolation. Not surprising, either, is the relatively poor performance at Blue Hill, Massachusetts, although even at this obviously unfavorable location for solar energy the energy displacement is still only about 22% lower than at the most favorable location (El Paso).

8.1.2.3 Effect of the Use of a Winston Collector

In the great majority of the system simulation computations carried out in the course of this study, the use of a flat plate collector was assumed. In an attempt to get a preliminary indication of the sensitivity of these results to the choice of collector, a limited number of supplementary computations were made in which the flat plate collector was replaced by a Winston (Reference 32) collector of low concentration ratio. The results of a set of such computations, for concentration ratio $X = 4$, are displayed in carpet plot format in Figure 44. The insolation representation used was again that for Phoenix (1963 data) and the demand

Figure 43

ENERGY DISPLACEMENT IN RESIDENTIAL ON-SITE SYSTEMS,
VARIOUS LOCATIONS

Figure 44

ENERGY DISPLACEMENT IN ARIZONA ON-SITE
 RESIDENTIAL APPLICATION: WINSTON COLLECTOR

representation was the Arizona residential demand model. The collectors were assumed to be oriented in an east-west direction and tilted about the east-west axis; the tilt angle was adjusted monthly for optimum energy collection.

A comparison of the curves in Figure 44 with those in Figure 37 reveals that the energy displacement achievable with these concentrating collectors is appreciably smaller than is accomplished with a flat plate collector of the same aperture area. The principal reasons for the difference are a) the fact that the Winston collector, even for a concentration ratio as small as 4, collects a much smaller fraction of the diffuse insolation, and b) losses resulting from the less-than-perfect reflectivity of the Winston collector surfaces (the assumed reflectivity was 0.9).

8.1.2.4 Effect of Variations in Demand Profile

A very limited investigation was also made of the relative performance of photovoltaic systems in commercial and industrial on-site applications, as compared to their performance in the baseline residential application. The same insolation representation was used (Phoenix 1963), but the demand representations were the Arizona commercial (both department store and supermarket) and industrial models described in Section 4.1.4 (and Table 9).

The energy displacements achieved, for one particular set of system parameters, when these three demand models were used are shown in Figure 45; the array area in each case was $49.3 \text{ m}^2/\text{kWav}$, and 12.3 hours of storage (at average power) was assumed. The approximately 10% greater energy displacement in the department store application than in the residential application is undoubtedly the result of the much higher day-to-night ratio in the department store demand profile (Figure 15) and the correspondingly better match between insolation and demand patterns.

It is interesting that the industrial example also yielded a higher energy displacement, however, even though the day-to-night ratio in this

Figure 45

ENERGY DISPLACEMENT: RESIDENTIAL, COMMERCIAL,
AND INDUSTRIAL ON-SITE APPLICATIONS

demand model was unity. The origin of the better performance in the industrial mission is made clear when the monthly (rather than annual) energy displacement values are compared. These monthly values are listed in Table 23. Because of the very pronounced summer peak in the residential demand record, summer energy displacement values were relatively low, especially in July, August, and September; even the higher summer insolation was not enough to make up for the enhanced summer demand. In the industrial mission, on the other hand, summer energy displacement was very good because the summer increase in demand was relatively modest; and this good summer performance was more than enough to compensate for poorer performance in November, December, March, and April.

The results shown in Figure 45 suggest that commercial on-site applications may well be better suited to the use of photovoltaic systems than residential applications, in spite of the fact (as discussed in Section 4.1.6) that the total land area available to commercial load points is insufficient, in general, to permit photovoltaic solar energy conversion to meet the full load point demand. A quite suitable mission for photovoltaic systems might therefore be one in which solar energy is intended only to be supplemental, perhaps dedicated to meeting a part of the air-conditioning load. This possibility could not be examined more thoroughly in the study reported here, because of time and resource limitations, but it would appear to be an appropriate topic for further investigation.

8.2 ECONOMIC ANALYSIS

The economic evaluation methodology described in Section 7.1 has been used to carry out a fairly complete economic analysis of the baseline cases discussed in the previous section. In addition, the sensitivity of these results to variations in some of the critical technical and economic parameters has been investigated to a limited extent.

Table 23

MONTHLY VALUES FOR ENERGY DISPLACEMENT
IN RESIDENTIAL, COMMERCIAL, AND INDUSTRIAL APPLICATIONS

Insolation Representation: Phoenix 1963

Array Area: $49.3 \text{ m}^2/\text{kWav}$

Storage: 12.3 hours at average power

Collector: Flat Plate, Tilt Adjusted Monthly

Array Efficiency (20°C): 0.1125

Month	Energy Displacement			
	Residential	Supermarket	Department Store	Industry
January	.777	.838	.918	.777
February	.898	.901	.948	.784
March	.978	.943	.979	.824
April	.985	.961	.984	.832
May	1.00	.982	1.00	.863
June	.980	.983	1.00	.922
July	.766	.898	.961	.895
August	.607	.782	.834	.821
September	.706	.791	.843	.831
October	.895	.866	.937	.873
November	.963	.904	.978	.866
December	.958	.977	.997	.896

The results of the economic evaluations discussed in this section and in Sections 9 and 10 are strongly dependent, of course, on a number of basic assumptions that have been made in this study about a) system or subsystem design, b) subsystem performance parameters, c) subsystem costs, and d) external conditions affecting mission requirements or economics. Discussions of all of these assumptions will be found at the appropriate places in this report. For reference purposes, however, those that apply across the board in all of the economic evaluations reported here are listed in Table 24. (Note that, although performance computations have been carried out for systems employing Winston concentrators, no economic evaluations have been made of systems using concentrators).

8.2.1 Economic Evaluation - Baseline Case

The approach used in evaluating on-site missions (as described in detail in Section 7.1) is to compare the present value cost of meeting the entire electric power demand of a hypothetical group of load points either a) by conventional means or b) by means of on-site photovoltaic systems backed up by conventional capacity. On the basis of this comparison a determination is made of the photovoltaic array price that would equalize the two present value costs; this array price is then identified as the goal that must be reached if photovoltaic technology is to be competitive in the application in question.

The details of the calculation are displayed in Table 25 for a typical case in which the collector was a flat plate whose tilt angle, about an east-west axis, was fixed at 24° . The backup utility system was represented in these calculations by the central Arizona utility model (described in Section 6.1). In the absence of photovoltaic systems, the required amount of additional capacity, as determined by margin analysis, was 267 MW, only a little smaller than the peak magnitude of the new demand (287 MW). When photovoltaic systems were assumed to be present, 73.3 MW of backup capacity was required (as shown in Table 21). The assumed total array area was $4(10^6) \text{ m}^2$ (corresponding to $114 \text{ m}^2/\text{residence}$ or $32.8 \text{ m}^2/\text{kWav}$)

Table 24

BASIC ASSUMPTIONS AND RESTRICTIONS
IMPACTING ECONOMIC EVALUATIONS

System/Subsystem Design

Collector Type: flat plate, tilted about east-west axis

Energy Utilization: electric energy only; no utilization of thermal energy removed from arrays in cooling

Subsystem Performance Parameters

Cell Efficiency: $\eta_C (20^\circ\text{C}) = 0.125$

Array Packing Factor: $f = 0.9$

Array Efficiency: $\eta_A (20^\circ\text{C}) = 0.9 (0.125) = 0.1125$

Power Conditioning Efficiency: $\eta_{PC} = 0.85$

Storage Efficiency (overall): $\eta_{ES} = 0.70$

System Service Life: 30 years

Subsystem Costs (1975 Dollars)

Array Support Structures

On-site, adjustable tilt: $\$10/\text{m}^2$

On-site, fixed tilt: $\$5/\text{m}^2$

Central station, adjustable tilt: $\$15/\text{m}^2$

Power Conditioning: $\$35/\text{kW}$

Storage: $\$20/\text{kWh}$

External Conditions

Reliability: utility systems loss of load not to exceed one day in ten years

General Inflation Rate: 3%

Incentives: no governmental incentives or subsidies for solar energy

Table 25

COST OF MEETING NEW RESIDENTIAL DEMAND
1990 PRESENT VALUE COSTS* IN MILLIONS OF DOLLARS

New demand to be served: average, 121.8 MW; peak, 287 MW
 Unit costs in 1990 dollars.

	<u>1990 dollars</u>	<u>1975 dollars</u>
Conventional Alternative		
Capital Cost (coal plant, 267 MW at \$615/kW)	164.2	105.4
Operating Cost		
Fuel (coal at 4.54 mills/kWh)	84.4	54.2
O&M (coal plant, \$15.97/kW)	36.5	23.4
Transmission (200 miles at \$450/mW-mile)	24.0	15.4
TOTAL	309.1	198.4
Photovoltaic (flat plate collector, 24° fixed tilt)		
Capital Cost		
Storage (\$31.2/kWh)	31.2	20.0
Power Conditioning (\$54.6 kW)	15.7	10.0
Installation/Wiring	10.9	7.0
Array Support Structure (\$7.8/m ²)	31.2	20.0
Array (\$X/m ²)	4X	4X
Photovoltaic O&M Cost (2 mills/kWh)	24.9	16.0
Backup Energy		
Fuel (coal at 4.54 mills/kWh)	34.4	22.1
O&M (coal plant, \$15.97/kW)	14.9	9.6
Backup Capacity (coal plant, 73.3 MW at \$615/kW)	45.1	29.0
Backup Transmission (200 miles at \$450/MW-mile)	6.6	4.2
TOTAL	214.9 + 4X	137.9 + 4X
Array Price } \$/m ²	23.6	15.2
Goal, X } \$/kWpk	209.7	134.6

* The computations on which this table is based were governed by the basic assumptions and restrictions listed in Table 24.

and the assumed value for storage capacity was 10^6 kWh (28.5 kWh/residence or 8.2 hours at average demand).

In Table 25, the price of photovoltaic arrays is initially taken to be unknown and is listed as $\$X/m^2$; the total cost of a $4(10^6) m^2$ array is then just $4X$ millions of dollars. The value of X is obtained by solving the equation constructed by setting the total present value costs for the two alternative energy sources equal to each other. The unit costs in the table are given in 1990 dollars but the resulting total costs are expressed both in 1990 dollars and in 1975 dollars.

In the calculations shown in Table 25, and in all the others discussed in this section, the capital cost associated with conventional power was set at $\$615/kW$, the projected investment cost for a 1000 MW baseload coal plant as shown in Table 18 of Section 7.4. This choice was based on the recognition that the hypothetical new demand would show up principally in the baseload portion of the total utility demand. No adjustment was made for economics of scale because the typical baseload plant in Arizona is rated at ~ 1000 MW. Such plants are often jointly owned by several utility companies, and it appears reasonable to assume that a requirement for, say, 267 MW of additional baseload capacity would be satisfied by a 26.7% share of a 1000 MW plant. The assumed 1990 fuel cost was based on a projected 1980 coal price of $\$8.90/ton$ ($\$0.356$ per million Btu) and an assumed escalation rate of 3.4%. The operation and maintenance (O & M) cost was based on a figure of about $\$8.20/kW$ for 1973, with a presumed escalation rate of 4%; the resultant value corresponds to about 2 mills/kWh in 1990. The transmission cost was based on a 1969 figure of $\$200/MW-mile$ for a 230 kV line (Reference 20) and an assumed escalation of 4%; 200 miles is the approximate distance from Phoenix of the sites for most of the new coal-fired power plants in the Arizona-Utah border region.

In the calculation of photovoltaic system costs, an escalation rate of 3% was assumed (equal to the assumed rate of general inflation).

The indicated prices for the storage, power conditioning, and array support structure were based on projected prices, in 1975 dollars, of \$20/kWh, \$35/kW, and \$5/m², respectively. The storage cost figure is based principally on a Westinghouse projection for advanced technology lead-acid batteries (Reference 13). Prices ranging from \$10/kWh to ~\$25/kWh have been projected at the successive Intersociety Energy Conversion Engineering Conferences for advanced batteries of various types. The \$35/kW price for power conditioning is more tentative but is consistent with previous estimates (Reference 22). This cost figure is multiplied, in Table 25, by the peak demand figure, 287 MW, as is appropriate if the power conditioning units are sized just large enough to accommodate the annual peak in demand. The assumed price for the array support structure is based on a rough materials-and-labor estimate for the incremental cost of mounting photovoltaic arrays on a roof already having the required orientation. The cost for installation and wiring was obtained by simply taking 10% of the total cost for storage and power conditioning and adding \$1.57/m² (\$1.00/m² in 1975 dollars) for bus conductors and wiring cost. The conversion of array cost in \$/m² to the equivalent in \$/kWpk was accomplished by dividing by the assumed overall nominal array efficiency of 11.25% (based on a cell efficiency, at 20°C, of 12.5%, and an array packing factor of 0.9).

Analyses like those outlined in Table 25 were carried out for a number of additional on-site examples for which performance evaluations (including determinations of required backup capacity) had been carried out. The results are summarized in Tables 26 and 27. Those in Table 26 correspond to examples in which it was assumed that the tilt angle of the flat plate array was adjusted monthly for optimum energy collection. For these cases, the assumed cost of the array support structure (including the mechanism to adjust the tilt angle) was \$10/m² (1975 dollars). The figures in Table 27 represent cases in which the tilt angle of the flat plate array was assumed to be fixed permanently at 24°. In these cases, as was mentioned above, the assumed support structure price was taken to be

Table 26

1990 ARRAY PRICE GOALS*: ON-SITE RESIDENTIAL APPLICATIONS
FLAT PLATE COLLECTOR, TILT ADJUSTED MONTHLY

Array Area (10^6 m^2)	Storage Capacity (10^6 kWh)	Energy Displ.	Southern California Utility			Arizona Utility		
			Backup Capacity (MW)	Array Price Goal (\$/kWpk)		Backup Capacity (MW)	Array Price Goal (\$/kWpk)	
				1990 Dollars	1975 Dollars		1990 Dollars	1975 Dollars
2.0	0	.320	112.4	133.04	85.39	171.6	188.87	121.33
	1.0	.359	82.8	88.04	56.51	167.8	62.97	40.42
4.0	0	.434	71.3	67.72	43.46	101.8	140.57	90.23
	1.0	.629	18.1	110.91	71.19	70.0	150.24	96.43
	1.5	.653	18.1	77.29	49.61	70.0	116.62	74.85
6.0	0	.469	56.6	14.07	9.03	75.0	75.27	48.31
	1.0	.727	8.9	44.95	28.85	28.1	105.32	67.60
	1.5	.806	8.9	29.35	18.84	28.0	89.82	57.65
8.0	1.0	.753	7.7	0.00**	0.00**	14.7	53.75	34.50
	1.5	.856	7.4	0.00**	0.00**	14.4	44.55	28.59
20.0	0	.320	1411	127.43	81.79			
	10.0	.359	1288	28.21	18.11			
40.0	0	.434	1045	57.86	37.13			
	10.0	.629	561	93.54	60.04			
	15.0	.653	561	59.91	38.46			
60.0	0	.469	928	4.37	2.80			
	10.0	.727	211	60.30	38.70			
	15.0	.806	210	44.80	28.75			
80.0	10.0	.753	131	15.76	10.11			
	15.0	.856	126	6.72	4.31			

* The computations on which this table is based were governed by the basic assumptions and restrictions listed in Table 24.

** The actual numbers that emerge from the analysis in this case are negative, i. e., for this array area, the use of photovoltaic arrays is not competitive at any array price.

Table 27

1990 ARRAY PRICE GOALS*: ON-SITE RESIDENTIAL APPLICATIONS
 FLAT PLATE COLLECTOR, FIXED 24° TILT

Array Area (10 ⁶ m ²)	Storage Capacity (10 ⁶ kWh)	Energy Displ.	Southern California Utility			Arizona Utility		
			Backup Capacity (MW)	Array Price Goal (\$/kWpk)		Backup Capacity (MW)	Array Price Goal (\$/kWpk)	
				1990 Dollars	1975 Dollars		1990 Dollars	1975 Dollars
2.0	0	.305	116.6	184.25	118.26	176.5	237.84	152.66
	1.0	.340	83.3	148.50	95.32	168.9	121.60	78.05
4.0	0	.420	75.3	127.98	82.15	107.3	198.50	127.40
	1.0	.605**	18.4	175.10	112.39	73.3	209.74	134.62**
	1.5	.619	18.4	139.70	89.66	73.3	174.34	111.90
6.0	0	.457	60.7	77.46	49.72	79.2	138.57	88.94
	1.0	.714	9.0	112.37	72.12	29.3	171.60	110.14
	1.5	.791	9.0	96.55	61.97	29.2	155.88	100.05
8.0	1.0	.741	7.8	66.99	43.00	15.1	121.59	78.04
	1.5	.847	7.6	57.83	37.12	14.8	112.51	72.21
20.0	0	.306	1440	182.71	117.27			
	10.0	.340	1326	78.34	50.28			
40.0	0	.420	1075	119.70	76.83			
	10.0	.605	575	156.01	100.14			
	15.0	.619	575	120.61	77.41			
60.0	0	.457	951	69.63	44.69			
	10.0	.714	218	127.11	81.58			
	15.0	.791	217	111.39	71.49			
80.0	10.0	.741	130	83.99	53.91			
	15.0	.847	125	75.06	48.18			

* The computations on which this table is based were governed by the basic assumptions and restrictions listed in Table 24.

** This example is the one cited in the Summary as representative of on-site residential applications.

$\$5/\text{m}^2$ (1975 dollars). The effect of the $\$5/\text{m}^2$ reduction in the assumed price of the array support structure is an increase in the array price goal of $\$44.44/\text{kWpk}$ (1975 dollars) over the value that would have been calculated if the higher support structure price had been retained.

The numbers displayed in these two tables indicate that, for the more appropriate choices of array size and storage capacity, the use of photovoltaic technology in this type of on-site application can be economically competitive, even for currently available conversion efficiencies, if array prices in the $\$100\text{-}200/\text{kWpk}$ (1975 dollars) can be achieved. This analysis, furthermore, has not taken into account the possible advantages associated with a) the productive use of the thermal energy that is removed from the arrays by cooling, b) the use of concentrators, c) any relaxation in the current rigid standards for utility system reliability, or d) the introduction of economic incentives to encourage the use of solar energy. The effect of any of these possibilities would be to increase, perhaps substantially, the array prices at which photovoltaic systems became competitive. These array price goals are also strongly dependent on array conversion efficiency, on subsystem costs, and on the assumed cost of fuel for competitive systems. The sensitivity of the price goals to these latter three factors has been investigated briefly, with results that are discussed in the next section.

The results shown in Tables 26 and 27 support another interesting observation. The more cost-effective examples appear to be those in which the array area is small and the storage capacity is either small or zero, even though the energy displacement in these cases is also small and the photovoltaic system is therefore strictly supplementary. In these cases, the solar energy system is used primarily to relieve the utility grid of some of the burden of serving the high daytime residential demand (much of it the result of air conditioning). This observation suggests that it would be worthwhile to take a closer look than was possible in this study

at applications where the photovoltaic system is only intended to carry part of the load. In particular, in Phoenix, the use of solar energy to supply the bulk of the air-conditioning load in a residence or business might be an especially suitable application.

8.2.2 Sensitivity Studies

A brief investigation has been made of the sensitivity of the results reported in the previous section to a) the utilization of the perfect forecasting option in the simulation computations, b) changes in the assumed price of the fuel used in generating backup energy, c) variations in array efficiency, and d) changes in the assumed cost of power conditioning equipment and of the electric storage subsystem.

The economic effect of the use of insolation forecasting (and the associated storage management strategy, as discussed in Section 8.1.2.1 above) is illustrated by the figures in Table 28. (These values correspond to Case 2 of Table 22). In the two cases displayed in the table, it is evident that the increases in backup energy costs offset to a considerable extent the reductions in backup capacity cost that are realized as a result of perfect forecasts of insolation. In the case where the array area is $6(10^6)\text{m}^2$, in fact, the economic advantage associated with forecasting is essentially eliminated. When it is recognized that less-than-perfect forecasting would lead to appreciable energy wastage, and therefore to further reductions in the economic advantage produced by the availability of forecasts, it is clear that the economic value of even reasonably good forecasts in the operation of an on-site photovoltaic system would be fairly small (or, in many cases, zero).

The sensitivity of the economic evaluation of one particular reference case to the assumed value of array efficiency and to the cost figures for power conditioning and storage is illustrated by the figures in Table 29. The indicated 70°C efficiency of 16% corresponds to a room temperature (20°C) efficiency of 20%, a value that should be achievable

Table 28

ECONOMIC EFFECTS OF INSOLATION FORECASTING*

Insolation: Phoenix 1963

Demand: Arizona Residential Model (121.8 MW average)

Backup Utility: Central Arizona Model

Array Type: Flat Plate, Fixed 24° Tilt

	No Forecasting		Perfect Forecasting	
Array Area (10^6 m^2)	4.0	6.0	4.0	6.0
Storage Capacity (10^6 kWh)	1.0	1.0	1.0	1.0
Backup Capacity Required (MW)	73.3	29.3	9.1	1.1
Backup Power Costs (millions of 1990 dollars)				
Energy (Fuel and O&M)	49.26	35.62	65.68	47.97
Capacity	45.08	18.02	5.60	0.68
Transmission	6.60	2.64	.82	.10
Array Price Goals (\$/kWpk)				
1990 Dollars	209.74	171.60	264.02	180.91
1975 Dollars	134.62	110.14	169.46	116.11

* The computations on which this table is based were governed by the basic assumptions and restrictions listed in Table 24.

Table 29

SAMPLE ECONOMIC SENSITIVITY CALCULATIONS*

Insolation: Phoenix, 1963

Demand: Arizona Residential Model (121.8 MW average)

Backup Utility: Central Arizona Model

Array Type: Flat Plate, 24° Fixed Tilt

Array Area: $4.0(10^6)\text{m}^2$ ($\sim 114\text{ m}^2/\text{residence}$, $32.8\text{ m}^2/\text{kWav}$)

Storage Capacity: $1.0(10^6)\text{m}^2$ (~ 8.2 hours at average power)

	Array Price Goals	
	1990 Dollars	1975 Dollars
Case 1. Baseline Conditions	209.74	134.62
Case 2. $\eta(70^\circ) = 16\%$	235.72	151.30
Case 3. Power Conditioning at \$100/kW (1975 dollars)	145.11	93.14
Case 4. Storage at \$50/kWh (1975 dollars)	105.87	67.95

* The computations on which this table is based were governed by the basic assumptions and restrictions listed in Table 24.

within the next few years. Such high-efficiency cells, however, will undoubtedly be very expensive and the obstacles to reaching this efficiency in low-cost (\$100-500/kWpk) arrays are formidable. The power conditioning and storage costs listed in Cases 3 and 4, respectively, of Table 29 are each near the high end of the range of estimates of 1985-1990 costs for these subsystems when produced in large volume.

The sensitivity of the economic analyses carried out in this study to the cost of fuel for the backup power generation system is illustrated in Figure 46. The photovoltaic example represented there (for two different array prices) is the same as that in Case 1 in Table 29, while the "coal-fired alternative system" is the same conventional alternative that has been used as a reference throughout Section 8. The ordinate in the figure is the total present value cost (in 1990) of meeting the on-site residential demand represented by the Arizona residential demand model described in Section 4.1.4. The straight-line graphs represent the dependence of this present value cost on fuel cost alone, assuming that all other variables remain unchanged.

8.2.3 Conclusions

The economic analyses reported in this section were intended primarily to serve as illustrations of the operation of the methodology. They do not represent a definitive study of on-site missions. Taken together, however, they support the tentative conclusion that there are attractive on-site applications in which photovoltaic solar energy conversion would be economically competitive, at presently achievable conversion efficiencies, for array costs in the \$100-200/kWpk range. The analyses, furthermore, did not take into account a number of possibilities that could further improve the economic competitiveness of the technology: a) the productive use of the thermal energy that is removed in cooling the arrays, b) the use of concentrators, c) relaxation in the current rigid standards for utility system reliability, or d) the introduction of government incentives to encourage the use of solar energy in order to save fuels.

Figure 46

PRESENT VALUE COST OF MEETING ON-SITE RESIDENTIAL
 DEMAND: DEPENDENCE ON FUEL COST

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SECTION 9

EVALUATION RESULTS; CENTRAL STATION MISSIONS

A limited number of illustrative examples of central station missions have been evaluated in accordance with the procedures described in Sections 5 through 7 of this report. As in the case of the on-site missions discussed in the preceding section, these examples were intended primarily to test and demonstrate the methodology and only secondarily to provide preliminary quantitative evaluations of the competitive position of photovoltaic technology in this class of missions. They do not constitute a definitive study of the mission class and the results reported here should be considered as indicative only.

In all of the central station mission evaluations that are discussed below, the photovoltaic plant was taken to be a single 100 MW plant equipped with south-facing flat plate collectors, whose inclination about an east-west axis was adjusted monthly for optimum energy collection. Two different geographical locations were considered: Inyokern, California, and Phoenix, Arizona. The Inyokern plants were evaluated as if they were part of the generation capacity of the model Southern California utility system described in Section 6.1, while the Phoenix plants were assumed to be part of the model central Arizona utility.

9.1 PERFORMANCE ANALYSIS

9.1.1 Intermediate/Baseload Plants

The system simulation model used in computations of the performance of a photovoltaic central station plant incorporates dispatch logic that permits investigation of several different dispatching strategies. This dispatch logic and the rationale for its adoption are discussed in some detail in Section 5.2.2 and therefore need only be outlined briefly here.

The operation of the dispatch logic is controlled through the choice of two input variables: PMULT, representing a prescribed fraction of the daily peak in the utility system demand, and STBASE, representing a prescribed fraction of the total storage capacity of the photovoltaic plant. Power is dispatched from the solar plant into the utility system load only when the system demand is larger than the prescribed fraction PMULT of the daily peak or when the storage capacity of the solar plant has been filled to the predetermined level, STBASE. The choice of PMULT acts to cause the solar plant preferentially to supply power to a predetermined portion of the utility load (baseload, intermediate, or peaking), as indicated in Figure 30, but this effect is modified by the choice of STBASE. In particular, if STBASE is set equal to 0, the solar plant dispatches power (up to the limit set by the rated capacity, 100 MW) whenever solar energy is available (either directly from the array or from the storage subsystem). In this case, the value of PMULT has no influence and the dispatch logic functions like that for a baseload plant, regardless of the choice of PMULT.

As a first step in the evaluation of intermediate mode operation of a 100 MW photovoltaic power plant, therefore, it was necessary to determine the appropriate values for PMULT and STBASE. On the basis of a preliminary set of computations, a value of PMULT was selected that would have resulted in a solar plant capacity factor of 0.5 if only the 100 MW wide band above the level defined by PMULT were supplied (Figure 30). (The plant capacity factor, PCF, is the ratio of the total annual energy output, in MWh, of a generating plant to the product of the rated plant capacity, in this case 100 MW, and the number of hours in a year, 8760.) Then, with PMULT set at this value, simulation computations were carried out for STBASE values ranging from 0 to 1, and the results were used as inputs to the capacity displacement methodology described in Section 6. On the basis of the values for solar plant capacity factor and for the required backup capacity derived by this procedure, economic evaluations were carried out for each case.

It was found that the lowest cost of photovoltaic power occurred for STBASE = 0. Thus, the rather complicated process described above led to the not very surprising result that, in general, the best dispatching strategy for a solar plant sized to provide intermediate mode power is to dispatch power whenever it is physically possible. In other words, intermediate mode and baseload photovoltaic power plants should be operated with the same dispatching philosophy; array size and storage capacity will determine whether the plant operates more like an intermediate mode plant or more like a baseload plant. The value of STBASE was therefore set equal to zero in the intermediate/baseload computations described in this section. (In the case of photovoltaic power plants with smaller array areas, so that the plant capacity factor corresponds roughly with that of a peaking plant, it turns out that there is a certain amount of economic advantage to the selection of a non-zero value for STBASE. This case is discussed more fully in Section 9.1.2.)

Another input variable that had to be chosen on the basis of a preliminary economic analysis was the one describing the spacing between the rows of photovoltaic array modules. The system simulation model requires this input information in order to take proper account of the reduction in collected solar energy that results from the shading of arrays in one row by those in the adjacent row. The selection of the appropriate spacing was based on a calculation of the tradeoff between the economic effects of a) energy losses as a result of shading when the spacing is small and b) increased costs for land and for d.c. conductors when the spacing is large. The value adopted, and used in all the central station power plant calculations described in this report, corresponded to a spacing such that the distance between corresponding points in adjacent rows was three times as large as the array dimension in the same direction, as measured along the array surface (i.e., not the projected dimension).

In Figure 47 are displayed the results of a set of simulation computations of the performance, as a function of array size and storage capacity, of a 100 MW photovoltaic power plant located at Inyokern, California.

RATED PLANT CAPACITY: 100 MW
 LOCATION: INYOKERN, CALIFORNIA
 DEMAND: SOUTHERN CALIFORNIA
 UTILITY SYSTEM MODEL, 1990
 COLLECTOR: FLAT PLATE, TILT
 ADJUSTED MONTHLY
 ARRAY EFFICIENCY (20°C): 0.1125

Figure 47

CAPACITY FACTORS, INTERMEDIATE/BASELOAD
 PHOTOVOLTAIC POWER PLANTS, INYOKERN, CALIFORNIA

The insolation representation used in the calculations was based on 1963 data for Inyokern; the demand representation was the one that appears in the model for a 1990 Southern California utility system, as described in Section 6.1. The adopted measure of performance represented in the figure is the capacity factor, expressed either as a "solar capacity factor" or as a net plant capacity factor. The solar capacity factor, SCF, is the capacity factor that is computed if no allowance is made for scheduled maintenance outages. The net plant capacity factor, PCF, is obtained by multiplying the SCF value by 0.9 in order to correct for an assumed 10% scheduled downtime for planned maintenance procedures. No computations were made for points lying above the knee of the three-dimensional carpet plot surface because economic analysis showed at an early stage that such points represent very unfavorable configurations from an economic point of view.

Calculations of the required amount of conventional backup capacity were carried out for each of the points used in constructing Figure 47. The methodology described in Section 6 was employed, and the utility system model used in the calculations was the Southern California model described there. These backup capacity values have been listed in Table 30, which is located in Section 9.2.

The computed performance, again as a function of array size and storage capacity, of a similar 100 MW photovoltaic plant in Phoenix, Arizona, is represented in Figure 48. The differences between corresponding curves in Figures 47 and 48 are small, indicating that these two Southwestern sites are about equally favorable locations for a solar energy plant. The required amounts of backup capacity, however, are significantly different in some cases, as a result of the substantial differences between the Southern California and central Arizona utility system models. The backup capacity values for the cases represented in Figure 48 are listed in Table 32 of Section 9.2.

Figure 48

CAPACITY FACTORS, INTERMEDIATE/BASELOAD
 PHOTOVOLTAIC POWER PLANTS, PHOENIX, ARIZONA

9.1.2 Peaking Plants

As another illustrative example, the operation of a 100 MW photovoltaic power plant in the peaking mode was investigated. It was assumed that the plant was located in the Southern California desert near Inyokern and was a part of the utility system represented by the Southern California model described in Section 6.2. For the purposes of this study, the peaking mode of operation was defined simply as one in which the plant capacity factor of the solar plant is in the range ($PCF \sim 0.1-0.2$) characteristic of conventional peaking plants. It was left to the analysis itself to determine the extent to which a solar plant meeting this criterion actually functions like a peaking plant.

As was the case with the intermediate/baseload calculations discussed in the preceding section, the first step in evaluating the performance of a photovoltaic power plant in the peaking mode was the selection of an appropriate dispatch strategy, i.e., the choice of the input variables PMULT and STBASE. The procedure used in selecting the values for these variables was the same as that described above. A value for PMULT was chosen that would result in a plant capacity factor of 0.1 if power were delivered exclusively into the 100 MW wide band defined by PMULT (Figure 30). Then, with PMULT set at this value, complete technical and economic evaluations were made for values of STBASE ranging from 0 to 1. In this case, it was found that the optimum value, in terms of the busbar cost of the electric energy produced, was approximately 0.4, and the value of STBASE was therefore set equal to 0.4 in the computation runs discussed in this section. The dispatching strategy employed therefore is one in which the solar plant stores energy (up to 40% of the available capacity) early in the day for later dispatching at a time when the utility system demand is nearing its daily peak. The effect of this use of the storage is, of course, to reduce the peak demand to be met by the rest of the generation capacity of the utility system and therefore to increase the capacity displacement achieved by the solar plant (or, in other words, to reduce the amount of backup capacity required for the solar plant).

The results of the performance evaluations, for a range of values of array area and storage capacity, are presented in Figure 49. (There being no advantage to the carpet plot format in this case, a simpler parametric display was chosen.) Computations were also made of the amount of required backup capacity for each of the specific cases used in constructing Figure 49; the Southern California utility system model (Section 6.1) was used. These backup capacity values are included in Table 33 (Section 9.2), along with the values for the plant capacity factor that are represented in Figure 49 and also values for the "in-band" plant capacity factor. This latter parameter is the ratio of the total solar energy, in MWh, delivered into the "assigned" band (the 100 MW wide portion of the total utility system demand that lies directly above the level defined by PMULT, as illustrated in Figure 30) to the product of the rated capacity of the solar plant, 100 MW, and the number of hours in a year, 8760.

9.2 ECONOMIC ANALYSIS

The illustrative examples of central station missions discussed in the preceding section have also been analyzed from the point of view of economics. The discounted cash flow methodology described in Section 7.2 was used in the analysis and the results were expressed ultimately in terms of the busbar cost of energy during the first full year of commercial operation. It was assumed in every case that the plant construction began in 1984 and that 1990 was the year when the plant first went into commercial operation, so that the busbar energy costs refer to the year 1991. (It might have been more realistic, perhaps, to have assumed that the duration of the plant construction period was roughly proportional to the total array area. The result would have been manifested mainly in the charges for interest during construction, with a consequent but modest effect on the total investment cost of the plant.)

As was indicated in the description in Section 7.2.3 of the photovoltaic version of the Power Plant Economic Model, the analyses reported here were based on an assumed investment cost for the photovoltaic arrays

Figure 49
CAPACITY FACTORS, PHOTOVOLTAIC PEAKING PLANT,
INYOKERN, CALIFORNIA

themselves of $\$11.25/\text{m}^2$. This value corresponds to $\$100/\text{kWpk}$ at the nominal (20°C) array efficiency of 11.25%. Since the estimated price, $\$15/\text{m}^2$, for the supporting structure in the flat plate collector assembly is not based on a detailed design and cost analysis, it is subject to appreciable uncertainty. It might therefore be appropriate to simply consider that these analyses are based on an assumed total cost for the flat plate collectors, including the photovoltaic arrays and the entire support structure, of $\$26.25/\text{m}^2$ (or $\$233/\text{kWpk}$).

In all of the economic evaluations of central station missions discussed below, the same procedure has been used to take into account the costs associated with the required backup capacity. It has been assumed in every case that the backup conventional plant is a new gas turbine peaking plant, whose first year of commercial operation is the same as that of the solar plant, i.e., 1990. As indicated in Table 18 in Section 7.4, the total 1990 investment cost of such a plant is about $\$219/\text{kW}$. The annual cost of this investment (interest on debt, return on equity) and the other fixed charges (e.g., insurance) associated with the existence of the backup plant must be included in the annual cost of operating the photovoltaic plant. In order to determine the incremental effect of these costs on the busbar cost of photovoltaic energy, the power plant economic model was used in an analysis of the economics of a standard 100 MW gas turbine backup plant, with a) fuel cost set equal to zero and b) plant capacity factor set equal to that calculated for the associated solar plant. The 1991 busbar energy cost resulting from this calculation was then simply multiplied by the ratio of the required backup capacity to 100 MW; the product was the annual cost, per kWh of photovoltaic energy, of the backup capacity. This amount was then included in the final value for the busbar cost of photovoltaic energy.

9.2.1 Intermediate/Baseload Plants

The results of the economic evaluation of the 100 MW intermediate/baseload plant at Inyokern are displayed in Table 30. Listed in the table,

Table 30

**ECONOMIC RESULTS: CENTRAL STATION POWER PLANT
INTERMEDIATE/BASELOAD OPERATION**

Rated Plant Capacity: 100 MW

Location: Inyokern, California

Utility System Model: Southern California Model

Array Area ₂ (10 ⁶ m ²)	Storage Capacity (10 ⁶ kWh)	PCF	Backup Capacity (MW)	Investment Cost* (\$/kW)		1991 Busbar Energy Cost* (mills/kWh)	
				1975 Dollars	1990 Dollars	1975 Dollars	1991 Dollars
1.0	0	.220	76.1	523.75	816.00	45.83	73.56
	0.5	.220	76.1	731.05	1138.98	58.04	93.15
	1.0	.220	76.1	938.40	1462.03	70.27	112.78
	1.5	.220	76.1	1145.78	1785.13	82.50	132.42
2.0	0	.332	66.0	918.43	1430.92	44.83	71.96
	0.5	.407	25.8	1125.69	1753.83	40.40	64.85
	1.0	.407	25.8	1332.99	2076.80	47.02	75.47
	1.5	.407	25.8	1540.32	2399.82	53.62	86.06
3.0	0	.361	65.3	1321.40	2058.74	55.55	89.16
	0.5	.506	6.7	1528.64	2381.62	41.70	66.93
	0.75	.561	6.6	1632.27	2543.08	40.01	64.22
	1.0	.570	6.6	1735.91	2704.54	41.74	66.99
	1.5	.570	6.6	1943.20	3027.51	46.46	74.57
4.0	0.75	.597	3.4	2044.00	3184.55	46.34	74.38
	1.0	.665	3.4	2147.63	3346.00	43.61	70.00
	1.25	.713	3.4	2251.26	3507.47	42.57	68.32
	1.5	.726	3.4	2354.90	3668.94	43.66	70.07
5.0	0.75	.610	3.2	2461.26	3834.65	54.16	86.93
	1.0	.683	3.2	2564.89	3996.10	50.34	80.80
	1.25	.754	3.2	2668.52	4157.55	47.38	76.04
	1.5	.805	3.2	2772.16	4319.02	46.05	73.91

* The computations on which the values in this table are based were governed by the basic assumptions and restrictions listed in Table 24.

** These examples were cited in the Summary as typical examples for intermediate (upper example) and baseload (lower example) operation.

in addition to the principal performance parameters and the 1991 busbar energy costs, are values for the total plant investment cost as of 1990, the year the plant was assumed to go on line. It is clear from these numbers that a photovoltaic power plant, particularly one with a large enough plant capacity factor to function as a baseload plant ($PCF \geq 0.6$), is a very capital-intensive energy source. These costs are, of course, strongly impacted by the basic assumptions used in the analysis (as summarized in Table 24) but particularly by the efficiency values employed. As a result of assumed ohmic losses, power conditioning losses, and storage losses, the effective overall energy conversion efficiency reflected in these computations is about 8% (as compared to the nominal 20°C array efficiency of 11.25%).

A breakdown of the 1990 investment cost into its constituent elements is presented, for three representative examples, in Table 31. The plants represented in the table are labeled as baseload, intermediate, or peaking on the basis of their plant capacity factor values.

The 1991 busbar cost of the energy produced by the Inyokern solar plant is also displayed, as a function of array size and storage capacity, in Figure 50. The broad crosshatched band in the figure represents the estimated range of projected 1991 costs of generating intermediate mode power in newly constructed conventional plants. The basis for the estimates represented by this band is discussed in Section 7.4. The upper portions of the band, corresponding to busbar costs at which photovoltaic power would be competitive, represent recent fuel-cost projections based upon developments that have taken place since 1973. The graphs in Figure 50 indicate that a 100 MW photovoltaic plant with a total array area of $\sim 2.5(10^6)\text{m}^2$ and about $0.5(10^6)\text{kWh}$ (5 hours) of storage capacity would provide power at the lowest cost, and this this cost would indeed be competitive with that of conventional intermediate mode power. The carpet plot in Figure 47 indicates that such a plant would have a plant capacity factor of about 0.46, a very appropriate value for an intermediate mode plant.

Table 31
INVESTMENT COST BREAKDOWN* (\$/kW)

	Peaking	Intermediate	Baseload
Array Area (10^6 m^2)	1.0	2.0	5.0
Storage Capacity (10^6 kWh)	0.2	0.5	1.5
Land	4.12	8.24	20.60
Structures, Facilities	10.85	10.85	10.85
Array Support Structure	150.00	300.00	750.00
Photovoltaic Arrays	112.50	225.00	562.50
Power Conditioning Equipment	35.00	35.00	35.00
Electric Storage	40.00	100.00	300.00
Electric Plant Equipment	24.49	39.46	107.83
Miscellaneous Plant Equipment	5.97	5.97	5.97
Total Basic Plant Cost	382.93	724.52	1792.75
Contingency Allowance	26.28	49.02	120.92
Spare Parts Allowance	2.32	4.52	11.26
Indirect Costs	105.62	187.28	457.44
Total Capital Investment (1975)	517.15	965.34	2382.37
Escalation to Start of Construction	185.04	339.20	832.21
Total at Start of Construction	702.19	1304.54	3214.58
Interest During Construction	133.64	250.57	617.38
Escalation During Construction	109.35	198.72	487.06
Total Cost at Year of Commercial Operation, 1990 Dollars (1975 Dollars)	945.18 (606.66)	1753.83 (1125.69)	4319.02 (2772.16)

* The computations on which the numbers in this table are based were governed by the basic assumptions and restrictions listed in Table 24.

Figure 50
 BUSBAR ENERGY COST: INTERMEDIATE/BASELOAD
 PHOTOVOLTAIC POWER PLANT, INYOKERN, CALIFORNIA

The results displayed in Table 30 and in Figure 50 also indicate that, although photovoltaic power plants can operate as baseload plants (with plant capacity factors as high as 0.8), they would probably not be able to compete effectively with conventional baseload plants. Even when the projected 1991 busbar energy cost for a 1000 MW coal-fired baseload plant (as shown in Table 18) is adjusted upward on the basis of the new coal price projections discussed at the end of Section 7.4, the resultant figure is ~35 mills/kWh (1991 dollars), still well below the corresponding figures for photovoltaic power.

The effects on mission economics of shifting the location of the 100 MW intermediate/baseload plant to Phoenix, Arizona, and of incorporating it into the model central Arizona utility system are displayed in Table 32 and in Figure 51. There appear to be no significant differences in the resultant busbar cost of power.

9.2.2 Peaking Plants

The economics of operating a photovoltaic power plant in peaking mode are illustrated in Table 33. The indicated busbar energy costs for many of the listed configurations compare quite favorably with the 99 mills/kWh value listed for a gas turbine peaking plant in Table 18 of Section 7.4. This comparison is probably not a legitimate one, however. As is indicated by the difference in the in-band and total plant capacity factors, these solar plants deliver considerably more of their power outside the assigned peaking band than within the band. This out-of-band power is really competing with conventional intermediate mode power (at 40-65 mills/kWh in 1991).

A more legitimate indication of the competitive position of solar power in these cases can be obtained by computing a composite figure for the cost of replacing the solar power in each case by conventional power. If, for example, it is assumed that the cost of conventional power delivered to the assigned peaking band is 100 mills/kWh while power delivered outside the band costs 65 mills/kWh, the composite figures shown in Table 34

Table 32

ECONOMIC RESULTS: PHOTOVOLTAIC POWER PLANT,
INTERMEDIATE/BASELOAD OPERATION

Rated Plant Capacity: 100 MW

Location: Phoenix, Arizona

Utility System Model: Central Arizona Model

Array Area (10^6m^2)	Storage Capacity (10^6kWh)	PCF	Backup Capacity (MW)	Investment Cost* (\$/kW)		1991 Busbar Energy Cost* (mills/kWh)	
				1975 Dollars	1990 Dollars	1975 Dollars	1991 Dollars
2.0	0	.325	30.2	918.43	1430.92	42.72	68.57
	0.5	.393	15.9	1125.69	1753.83	40.52	65.03
	1.0	.393	15.9	1332.99	2076.80	47.99	77.03
3.0	0	.356	23.9	1321.40	2058.74	53.08	85.20
	0.5	.499	2.2	1528.64	2381.62	42.04	67.47
	0.75	.545	2.1	1632.27	2543.08	40.95	65.73
	1.0	.549	2.1	1735.91	2704.54	43.11	69.19
4.0	0.75	.592	0.6	2044.00	3184.55	46.60	74.80
	1.0	.657	0.6	2147.63	3346.00	44.02	70.66
	1.25	.695	0.6	2251.26	3507.47	43.56	69.91
	1.5	.702	0.6	2354.90	3668.94	45.04	72.29

* The computations on which these cost figures are based were governed by the basic assumptions and restrictions listed in Table 24.

Figure 51
 BUSBAR ENERGY COST: INTERMEDIATE/BASELOAD
 PHOTOVOLTAIC POWER PLANT, PHOENIX, ARIZONA

Table 33

ECONOMIC RESULTS: PHOTOVOLTAIC POWER PLANT,
PEAKING OPERATION

Rated Plant Capacity: 100 MW

Location: Inyokern, California

Utility System Model: Southern California Model

Array Area (10 ⁶ m ²)	Storage Capacity (10 ⁶ kWh)	PCF		Backup Capacity (MW)	Investment Cost* (\$/kW)		1991 Busbar Energy Cost* (mills/kWh)	
		Total	In Band		1975 Dollars	1990 Dollars	1975 Dollars	1991 Dollars
0.5	0	.110	.013	91.3	330.89	515.52	72.93	117.05
	0.2	.0989	.038	65.2	413.82	644.73	84.64	135.84
	0.4	.0904	.059	41.3	496.77	773.97	97.06	155.78
	0.6	.0856	.070	28.8	579.72	903.21	111.01	178.17
1.0	0	.220	.026	76.1	523.75	816.00	45.83	73.56
	0.2	.209	.052	45.9	606.66	945.18	49.33	79.18
	0.4	.201	.072	27.9	689.59	1074.38	54.16	86.93
	0.6	.195	.083	19.1	772.52	1203.59	60.09	96.44
1.5	0	.301	.035	67.7	719.79	1121.44	41.10	65.97
	0.2	.312	.058	37.0	802.70	1250.60	40.36	64.78
	0.4	.305	.075	21.6	885.61	1379.78	43.39	69.64
	0.6	.301	.086	14.9	968.53	1508.97	46.92	75.31

* The computations on which these cost figures are based were governed by the basic assumptions and restrictions listed in Table 24.

Table 34

COMPARISON OF 1991 BUSBAR COSTS FOR SOLAR ENERGY
(PEAKING PLANT) AND FOR COMPETITIVE CONVENTIONAL ENERGY

Array Area (10^6m^2)	Storage Capacity (10^6kWh)	PCF	1991 Busbar* Cost of Solar Energy mills/kWh	Composite 1991 Busbar Cost of Conventional Energy mills/kWh
0.5	0	.110	117.05	69.14
	0.2	.099	135.84	78.45
	0.4	.090	155.78	87.84
	0.6	.086	178.17	93.62
1.0	0	.220	73.56	69.14
	0.2	.209	79.18	73.71
	0.4	.201	86.93	77.54
	0.6	.195	96.44	79.90
1.5	0	.301	65.97	69.07
	0.2	.312	64.78	71.51
	0.4	.305	69.64	73.61
	0.6	.301	75.31	75.00

* The computations on which these cost figures are based were governed by the basic assumptions and restrictions listed in Table 24.

are obtained. These numbers indicate that photovoltaic power is not competitive except for those cases when the array area is $1.5(10^6)\text{m}^2$. In these cases, however, the total plant capacity factor is ~ 0.3 and the plant is really functioning like one of the intermediate mode plants represented in Tables 30 and 32 and in Figures 50 and 51.

9.2.3 Conclusions

In summary, the economic analyses discussed in this section suggest that the most suitable mode of operation for a photovoltaic central station power plant would be the intermediate mode, corresponding to a plant capacity factor of 0.4 - 0.5. The results indicate that, for array costs in the \$100-150 kWpk range (depending on the cost of the supporting structure), a photovoltaic plant operating in this mode would, indeed, be competitive with a newly constructed fossil-fuel plant operating in the same mode. It should be reiterated, however, that the principal purpose of these analyses was to test and demonstrate the methodology rather than to carry out a definitive evaluation of central station missions for photovoltaic energy conversion. No consideration was given to a number of possibilities (e.g., use of concentrators) that might well substantially improve the competitive position of photovoltaic plants.

SECTION 10

EVALUATION RESULTS, FUEL PRODUCTION MISSION

A very much briefer study than those reported in the preceding two sections was made of a third type of mission for the photovoltaic conversion of solar energy: the electrolytic production of hydrogen for use as a portable general purpose fuel. The specific application that was studied was one in which the electric power generated in the photovoltaic arrays of a large remotely-located plant is used solely for the production of hydrogen. The hydrogen, therefore, is not considered as a byproduct or solely as a medium for local energy storage but rather as a commercial product intended for wide distribution, in competition with portable fossil fuels.

In the analysis, the plant was assumed to be located at Inyokern, California, and the 1963 insolation data base for this location was used in simulation computations of system performance. It was also assumed that the solar energy collectors were flat plates whose tilt angle about an east-west axis was adjusted monthly for optimum energy collection. For the reasons discussed in Section 5.2.3, no electric storage was included in the system model; instead, sufficient electrolytic-cell capacity was provided to ensure that all, or virtually all, of the available electric power could be productively used.

The total array area was arbitrarily chosen large enough ($8.24 \times 10^6 \text{ m}^2$) to generate power at a maximum rate of 1000 MW, after correcting for an assumed 2% ohmic loss between array modules and electrolytic cells. Then, on the basis of preliminary simulation computations, a tradeoff analysis was made in which cost savings realized by marginally reducing electrolytic capacity were balanced against the incremental value of the solar energy that would be wasted as a result. It was found that the optimum configuration, from an economic point of view, was

one in which the total electrolytic capacity, measured in terms of input electric power, was between 80 and 90% of the annual maximum in array output if the cost of the photovoltaic arrays was assumed to be \$100/kWpk. Accordingly, the electrolytic capacity in the model was set at 900 MW; whenever the total output power from the array (minus the assumed 2% ohmic losses) was greater than 900 MW, accordingly, the excess was assumed to be dissipated in some non-productive fashion.

The simulation computations carried out for the above choices of parameters yielded a value of $2.40 (10^9)$ kWh for the total (annual) amount of electric energy used in the electrolysis of water. At a presumed production efficiency of 0.05 lb of hydrogen per kWh of electric energy, somewhat better than the efficiency in currently available cells (Reference 11), the total annual production of hydrogen was therefore $1.2 (10^8)$ pounds or $7.73 (10^{12})$ Btu (at a conversion rate of 325 Btu per standard cubic foot).

The economic evaluation procedures used in this case were considerably more elementary than those employed in analyzing the on-site and central station missions. As was discussed in Section 7.3, the determination of the unit cost of the hydrogen produced by the plant described above was accomplished through a simple levelized fixed-charge calculation. This procedure did not, of course, constitute a genuine economic analysis, because the assumed fixed-charge rate (16.5%) was based on rates derived in the Aerospace Solar Thermal Mission Analysis Program for use in evaluating solar thermal plants, rather than on a detailed study of the fuel production mission. The error introduced by the uncertainty in the fixed-charge rate, however, is not believed to be larger than about $\pm 25\%$.

The application of the levelized fixed-charge procedure required a determination of the total investment cost of the production facility, as of the year in which commercial operation began. The elements of the calculation of the total investment cost of the photovoltaic hydrogen production plant described above are displayed in Table 35. (They are expressed in terms of 1975 dollars, in this case, in order to facilitate comparison

Table 35

TOTAL INVESTMENT COST
FOR PHOTOVOLTAIC/ELECTROLYTIC HYDROGEN PLANT

Maximum Electric Power: 1000 MW (~250 MW_{av})

Electrolytic Plant Maximum Capacity: 900 MWe

Location: Inyokern, California

Collectors: Flat Plate, Tilt Adjusted Monthly,
Total Area 8.24 (10⁶) m²

	Cost (Millions of 1975 Dollars)
Photovoltaic Plant	
Land Acquisition	3.39
Structures (\$8/kW _{av})	2.00
Array Support Structures (\$15/m ²)	123.60
Photovoltaic Arrays (\$100/kW _{pk} ; \$11.25/m ²)	92.70
Electric and Misc. Plant Equipment (\$20/kW _{av})	5.00
Electrolytic Plant	<u>27.63</u>
Total	254.32
Contingencies (7%)	17.80
Spare Parts (1%)	<u>2.54</u>
Total Direct Cost	274.66
Indirect Costs (10% of Solar Equipment, 53% Otherwise)	52.56
Interest During Construction (16%)	<u>52.36</u>
Total Investment Cost (Year of Startup)	379.58

of the resultant unit cost of the hydrogen product with the unit costs of competitive fuels, as described below.) The capital costs for the photovoltaic portion of the plant are consistent with those used in the analysis of photovoltaic central station plants (Section 9). The figure for the electrolytic portion of the plant is based on cost estimates quoted in Reference 11 (\$48/kWe, of which 36% is allocated to a power supply that is not needed if photovoltaic power is used) for an "advanced system" capable of producing hydrogen at efficiencies yielding 0.05 lb/kWh.

When the investment cost figures shown in Table 34 are inserted into the levelized fixed-charge equation for unit cost (Equation 3 of Section 7.3), the result is

$$\begin{aligned}\text{Unit H}_2 \text{ cost} &= \frac{(379.58) (10^6) (.165) + 4.8 (10^6) + 1.47 (10^6)}{7.73 (10^{12})} \\ &= \$8.91/10^6 \text{ Btu. (1975 dollars)}\end{aligned}$$

The second and third terms in the numerator of the equation represent estimates for the annual operation and maintenance costs of the photovoltaic plant (at 2 mills/kWh) and the electrolytic plant (\$0.19/10⁶ Btu, as reported in Reference 11), respectively.

The next step in the economic evaluation procedure was to compare this unit cost figure with the projected costs of other portable fuels that might be considered potential economic competitors of photovoltaic/electrolytic hydrogen. Accordingly, an independent auxiliary study was carried out with the objective of developing such projections. This study is described in detail in Appendix F of Volume III of this report and therefore will not be elaborated upon here. The principal results, however, are displayed in Figure 52. The message of Figure 52, for the purposes of this discussion, is that there are a number of portable fossil fuels (those labeled "synthetics" in the figure) for which the projected 1990 cost is less than about \$2/10⁶ Btu (in 1973 dollars) and that the projected 1990 cost of hydrogen itself, from several different sources, is less than \$4/10⁶ Btu.

- SYNTHETICS {
- a - HI-Btu COAL GAS
 - b - COAL SYNCRUDE
 - c - LO-Btu COAL GAS
 - d - COAL METHANOL
 - e - SHALE GAS
 - f - SHALE SYNCRUDE

Figure 52
PROJECTED UNIT FUEL PRICES TO YEAR 2000

The estimates of projected costs in Figure 52 are subject to a number of uncertainties, not the least of which are those associated with forecasts of the costs of the principal raw fuels, bituminous coal and lignite. Similarly, of course, there are several potentially important sources of error in the estimate of the unit cost of photovoltaic/electrolytic hydrogen that was obtained earlier in this section. The assumed fixed-charge rate could be off by as much as 25%, and the uncertainty in the estimate of total investment cost is probably as large. (This cost estimate is more likely to be too low than too high, however.) Nonetheless, the indicated price differentials between photovoltaic/electrolytic hydrogen and a number of potential competitors (including both the "synthetics" of Figure 52 and hydrogen from other sources) appear to be substantially greater than the combined uncertainties in the cost estimates. Since it was judged to be quite unlikely that refinement of the analysis would result in a major change in the competitive position of photovoltaic/electrolytic hydrogen, such a refinement was not considered to be justified and none was carried out.

It thus appears that, even for array costs of \$100/kWpk (1975 dollars), the use of photovoltaic electricity to generate hydrogen for use as a general-purpose fuel is not nearly so attractive an application for the technology as are either the on-site missions or the central station missions to which most of this study has been devoted.

SECTION 11

SUMMARY OF RESULTS AND CONCLUSIONS

The results that have been achieved in this study can be summarized as follows:

- o Improvements were made in the available insolation data base and several insolation-related studies were completed.
 - Three new sites were added to the existing insolation data base and the records for six other sites were augmented through the insertion of wind and nighttime weather data.
 - The effect on solar cell output of spectral variations resulting from atmospheric absorption and scattering was investigated analytically and found to have too small a potential impact on mission evaluations to justify an attempt to model the variations.
 - A preliminary investigation was made of the probable accuracy of insolation forecasting on the basis of current weather prediction techniques; the probable accuracy was judged to be low.
- o Suitable demand representations were prepared for use in simulating both on-site and central station missions.
 - Hourly load point demand representations were synthesized for residential, commercial, and industrial loads in central Arizona and Southern California.
 - An existing procedure for projecting hourly utility system demand records was used to prepare an hourly demand record for a representative utility system in central Arizona in the year 1990.

- o Procedures for evaluating the performance of photovoltaic systems in on-site, central station, and fuel production missions were formulated and implemented.
 - A modular system simulation model, with adaptations appropriate for each class of mission, was prepared; the model includes provisions for simulating a number of different types of collectors and collector orientations and permits investigation of the use of insolation forecasting.
 - An available reliability analysis methodology, including a margin analysis procedure and a model for a California utility system, was adapted for application to photovoltaic systems; a model for a central Arizona utility system was added.
- o Methodology for the economic evaluation of on-site and central station missions was developed.
 - In the on-site case, a procedure was adopted and implemented in which determinations are made of the present value cost of meeting the total on-site demand either with a photovoltaic system or by conventional means.
 - The existing power plant economic model was adapted to carrying out discounted cash flow analyses of photovoltaic central station power plants.
- o A number of illustrative examples of on-site missions were analyzed.
 - Detailed performance analyses were made of a baseline residential application in Phoenix, Arizona; a flat plate collector with a nominal (20°C) conversion efficiency of 11.25% was assumed.

- Brief investigations were made of the sensitivity of the baseline performance results to the use of insolation forecasting and to variations in geographical location, type of demand profile, and collector type (flat plate vs Winston).
- An economic analysis of the baseline application was made; it was found that photovoltaic technology would be competitive with alternate energy sources, under the assumed conditions, for array prices in the \$100-200/kWpk range.
- Brief studies were made of the effect on the baseline economic results of variations in array efficiency, subsystem cost, and the price of fossil fuels.
- o Several illustrative examples of central station missions were evaluated.
 - Performance analyses were carried out for 100 MW photovoltaic power plants at Inyokern, California, and Phoenix, Arizona; flat plate collectors and array efficiencies, at 20°C, of 11.25% were assumed.
 - Economic analyses were made for these examples; it was found that for array prices in the \$100-200/kWpk range, photovoltaic power plants operating in the intermediate mode would be able in 1990 to compete successfully with conventional plants operating in the same mode.
- o A limited study was made of a fuel-production mission in which electricity from a 1000 MWpk photovoltaic system is used to generate hydrogen by electrolysis; it was concluded that, under the assumed conditions (flat plate collector, 11.25% array efficiency at 20°C, \$100/kWpk

array price), the use of photovoltaic technology would not be competitive.

On the basis of these preliminary results, several tentative conclusions can be drawn:

1. On-site and central station missions appear to be about equally attractive as future (1990) applications for photovoltaic solar energy conversion.

2. In both of these applications photovoltaic technology, for array prices in the \$100-200/kWpk range and currently achievable array efficiencies, would be competitive with conventional alternatives even a) without the constructive utilization of the thermal energy removed in cooling the cells, b) without the use of concentrators, c) without reduction in utility system reliability, and d) without the introduction of incentives designed to encourage the use of solar energy.

3. The competitive position of the photovoltaic technology in either of these two classes of missions would be improved, perhaps substantially, by the relaxation in a realistic manner of the constraints imposed in the illustrative calculations carried out in this study.

SECTION 12

RESEARCH UTILIZATION ACTIVITIES

The principal prospective users of the information generated in this study are the various participants in the ERDA/NSF Photovoltaic Solar Energy Conversion Program. The most important research utilization activities, therefore, have been oral presentations of project results at the semiannual program review meetings and the circulation of printed progress reports to program participants. These documents also are being made available to interested groups outside the NSF/ERDA program. The dissemination of the results to a wider audience has been accomplished through reports presented at technical meetings sponsored by appropriate professional organizations. In particular, papers describing the work were presented at the AIAA/ASA Solar Energy for Earth Conference in Los Angeles in April 1975, and at the 11th IEEE Photovoltaics Specialists Conference in Phoenix in May. In addition to these relatively formal research utilization activities, continuing informal two-way communications have been maintained with another major class of potential users of photovoltaic technology, the electric utility industry. The most important such interactions have been with the Electric Power Research Institute and with such local Southwestern utility companies as the Southern California Edison Company, the Los Angeles Department of Water and Power, and the Arizona Public Service Company.

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SECTION 13
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