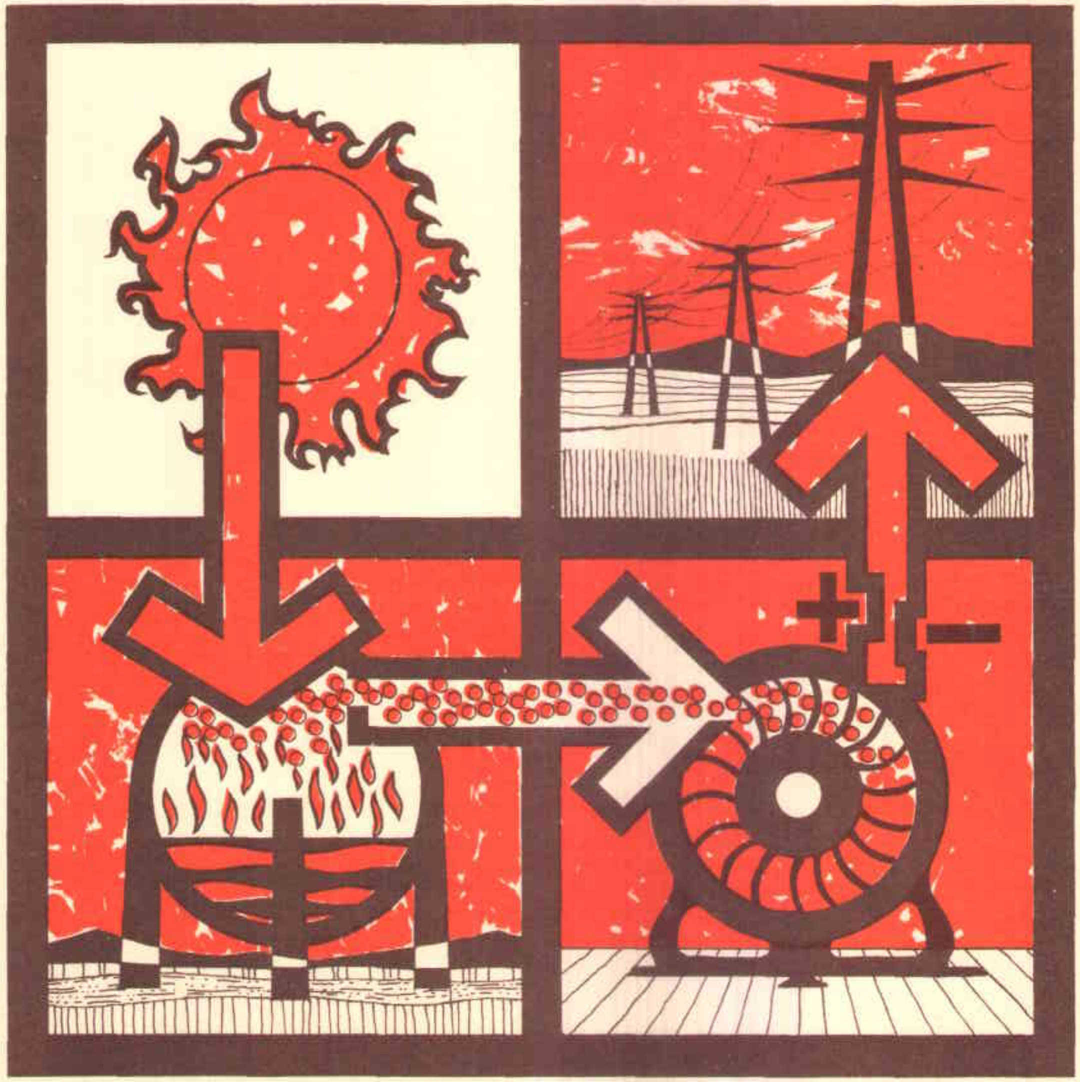
VOLUME I

SOLAR THERMAL CONVERSION MISSION ANALYSIS

Summary Report - Southwestern United States



THE AEROSPACE CORPORATION

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SOLAR THERMAL CONVERSION MISSION ANALYSIS – SOUTHWESTERN UNITED STATES

VOLUME I: SUMMARY REPORT

Prepared for:

THE NATIONAL SCIENCE FOUNDATION/
RESEARCH APPLIED TO NATIONAL NEEDS
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FOREWORD

This report presents a summary of the Solar Thermal Conversion Mission Analysis performed by The Aerospace Corporation, as applied to the Southwestern United States, under a follow-on contract to the National Science Foundation/Research Applied to National Needs (NSF/RANN).

This report presents a summary of the results of the Solar Thermal Conversion Mission Analysis, performed by The Aerospace Corporation as applied to the Southwestern United States, under a follow-on contract to the National Science Foundation/Research Applied to National Needs. The material presented is an extension of and is complementary to that covered by previously published reports describing the interim results of analyses as applied to Southern California only.

The time period of the follow-on contract was from November 1, 1973, to August 15, 1974. This Summary Report is the first of five volumes; the remaining four volumes describe in detail the findings of the Southwestern United States Area Definition and Siting Analysis, Insolation Climatology, Demand Analysis, and Comparative Systems and Economic Evaluation. A sixth report, "Power Plant Economic Model," describing the economic methodology, was published earlier.

This study was conducted under NSF Contract C-797 by the Energy Programs Group of the Energy and Resources Division. Mr. D.F. Spencer, and subsequently Mr. G. Kaplan, was the NSF Program Manager for this contract, and Dr. A.B. Greenberg, General Manager of the Energy and Resources Division, was the Principal Investigator. Dr. M.B. Watson is the Associated Group Director of the Energy Programs Group. Mr. P.B. Bos, Associated Director, Solar Projects, provided the Program Management.

This report was prepared by the following authors: Mr. P.B. Bos, Mr. W.A. Kammer, and Mr. E. Blond.

The Aerospace Corporation wishes to acknowledge the constructive program guidance of the previous NSF Program Manager, Mr. D.F. Spencer, who conceived the need for the Mission Analysis, and subsequently, Mr. G. Kaplan, the present NSF Program Manager.

In addition, the authors wish to acknowledge the diligent efforts of many people who have aided in bringing this study to completion. These include: Mr. N.A. Fiamengo, Mr. G.F. Kuncir, Mr. E.F. Lehnhof, Dr. S.L. Leonard, Dr. P.J. Peters, Dr. C.M. Randall, Mr. R.M. Selter, and Mr. S. Sugihara.

The authors also wish to acknowledge the many organizations that have provided information and counseling in the formulation of this study, particularly the various utility companies and agencies in the Southwestern United States which have supplied the historic demand data and the cooperation of the various system contractors in providing technical and cost data of the alternative systems considered.

The authors express their sincere appreciation to these people and organizations: to Mr. M.S. Ensign for producing the tables and figures, to Mr. F.C. Eggers for technical editing, to Mr. H.C. Fockler for production design and layout, and to Ms. Mari Bythway and Ms. Bobbie Devaney for typing and preparing this document.

This summary report presents the principal results of the Solar Thermal Conversion Mission Analysis applied to the Southwestern United States. The study reported provided for the application and extension of the mission analysis methodology initially developed in a previous contract and as described in previous reports (References 1 through 5). The material covered is an extension of and is complementary to that described in the previous reports. The mission analysis methodology was applied on a consistent basis to the evaluation of alternative solar thermal conversion concepts for providing electrical power under realistic operating environments. Based upon the comparative technical and economic evaluation of the alternative concepts, preferred concepts have been identified and technical and economic goals defined for these concepts. Subsequently, a preliminary market capture potential was made for the preferred systems.

Various sections of this report summarize the results of the Southwestern United States Area Definition and Siting Analysis, Insolation Climatology, Demand Analysis, and Comparative Technical and Economic Evaluation performed under this nine-month follow-on contract. Greater details of these analyses are described in four additional volumes. The methodology developed and preliminary results of the original study contract were published in five previous volumes. In addition, the details of the economic methodology have been published in an interim report "Power Plant Economic Model" (Reference 6).

The technical and economic results in this report reflect the latest available data obtained from the various systems contractors, sponsored under the NSF Solar Thermal Conversion Program, and, consequently, reflect reasonable estimates of Solar Thermal Conversion systems at this time. These data permit preliminary selection and definition of the preferred system concepts. As technical and economic characteristics of these systems evolve as a result of more detailed systems analyses, the mission analyses described in this report will be updated to incorporate the latest available technical and economic information.

Based upon the comparative technical and economic assessment of the alternative solar thermal conversion concepts and conventional power plants, the central receiver concept, operating in an intermediate or load following mode appears competitive and has been identified as the preferred concept. Alternatively, if a low-cost parabolic cylindrical trough collector can be found, this concept could be developed as a back-up system.

A preliminary market capture potential of 40,000 MWe by the year 2000 was estimated, assuming a first operational plant by 1985. No significant siting constraints were identified which would prevent achieving this market potential.

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INTRODUCTION AND OBJECTIVES

INTRODUCTION AND OBJECTIVES

This section describes the Solar Thermal Conversion Mission analysis objectives, scope, and methodology as applied to the Southwestern United States.

STUDY OBJECTIVES AND SCOPE

The objectives and scope of this study, as shown in Chart 1, were to formulate a methodology for evaluating alternative solar thermal conversion missions and systems in realistic operational environments. The purpose of this methodology is to make an assessment of the potential role or mission of solar thermal conversion systems and to identify those missions which have the greatest potential by considering technical, operational, economic, institutional, and environmental characteristics.

The alternative missions in this study represent the full range of potential applications of solar thermal conversion systems and can be divided by types of energy and by functional requirements. Solar thermal conversion systems may provide electrical or combined electrical and thermal service. Functionally these systems may be remote central power plants or municipal sized plants close to load centers. The plants may be sized to serve a community, such as is typically served by a substation, or the solar thermal conversion systems may be placed directly at such individual load centers as industrial plants, commercial complexes, or individual residences.

This follow-on study was to address the Southwestern United States for potential application of solar thermal conversion systems during the time period 1980 to 2000. Although regionally bounded, the mission analysis of solar power plants applied to this area may be indicative of the potential for other parts of the continental United States. As will be apparent from the study results, analyses for the Southwestern United States are broadly representative for solar thermal conversion applications because of the wide variety of climatic, demographic, geomorphic, and physiographic conditions within the region, as well as the presence of many major load centers.

Although the methodology has been applied to the Southwestern United States, the approach and individual analytical tools are applicable to other geographic regions.

The results of the application of the methodology provide a basis for the selection of preferred missions and systems through comparative technical, operational, economic, and environmental analyses. For these preferred missions and systems, the technical and economic bounds for systems and subsystems have tentatively been established. The technical and economic results reflect the latest available data obtained from the various systems contractors sponsored under the NSF/RANN program and, consequently, reflect reasonable estimates for solar thermal conversion systems at this time. These data permit preliminary selection and definition of the preferred system concepts. As technical and economic characteristics of these systems evolve as a result of further systems analyses, these mission analyses will be updated to incorporate the latest available information.

In addition, a preliminary market capture potential for the preferred solar thermal conversion missions, as well as an assessment of their impact on natural resources, was established.

Study Objectives and Scope

SOLAR THERMAL CONVERSION MISSION ANALYSIS

FORMULATE A METHODOLOGY TO EVALUATE ALTERNATIVE SOLAR THERMAL CONVERSION MISSIONS/SYSTEMS

ASSESS THE POTENTIAL ROLE OR MISSION OF SOLAR THERMAL CONVERSION SYSTEMS AND IDENTIFY THOSE MISSIONS OF GREATEST POTENTIAL

- TYPES OF ENERGY
  - ELECTRIC SERVICE ONLY
  - COMBINED ELECTRICAL AND THERMAL ENERGY SERVICE
- FUNCTIONAL REQUIREMENTS
  - CENTRAL STATION
  - MUNICIPAL POWER PLANT
  - COMMUNITY POWER PLANT (substation)
  - INDIVIDUAL LOAD CENTER SYSTEM
- GEOGRAPHIC AREA: SOUTHWESTERN UNITED STATES
- TIME PERIOD: 1980 - 2000

PROVIDE A BASIS FOR SELECTION OF PREFERRED MISSION(S) FOR SOLAR THERMAL CONVERSION SYSTEMS

ESTABLISH TECHNICAL AND ECONOMIC BOUNDS FOR SYSTEM, SUBSYSTEM, AND COMPONENT DESIGN AND PERFORMANCE REQUIREMENTS WHICH ARE TO BE ASSOCIATED WITH THE PREFERRED MISSION(S)

DETERMINE THE MARKET CAPTURE POTENTIAL AND IMPACT ON RESOURCES FOR THE PREFERRED SOLAR THERMAL CONVERSION MISSION (s)

SOLAR THERMAL CONVERSION MISSION CONCEPTS

The missions defined for solar thermal conversion applications are shown in matrix form in Chart 2. Because of the large scope of this study in relation to its duration and funds, the analytical effort was primarily limited to analyzing those missions providing electrical service only (top row of the matrix), and secondarily to considering those missions providing combined electrical and thermal service (bottom row).

Solar Thermal Conversion Mission Concepts

FUNCTION \ SCALE	SOLAR COLLECTOR AT DEMAND POINT	COMMUNITY OR SUBSTATION SOLAR PLANT	MUNICIPAL SOLAR PLANT	LARGE REMOTE SOLAR PLANT
PROVIDE ELECTRICAL ENERGY TO MEET DEMAND				
PROVIDE THERMAL ENERGY (heat) FOR USE OR CONVERSION AT DEMAND POINTS	INCLUDED IN SCOPE OF NSF/RANN STUDIES OF HEATING AND COOLING OF BUILDINGS			
PROVIDE ELECTRICAL AND THERMAL ENERGY TO DEMAND POINTS				

STUDY FLOW DIAGRAM

The specific approach to the study is shown in Chart 3, which represents a flow diagram of the Solar Thermal Conversion Mission Analysis. The left-hand side of this flow diagram shows the regional definition in terms of total and direct insolation data and demand projections for the 1980 to 2000 time period. These data are the required inputs for the mission/system definition and requirements analyses. Subsequent to the alternative mission/systems definition, a comparative mission and system evaluation is performed between alternative solar thermal conversion systems, as well as with conventional systems, to identify the most preferred or candidate missions and systems for solar thermal conversion applications.

Subsequently, the market capture potential and the impact on our national resources and environment are assessed as well as the system, subsystem, and component technical, operational, and economic requirements for the candidate missions and systems.

Solar Thermal Conversion Mission Analysis

Study Flow Diagraram

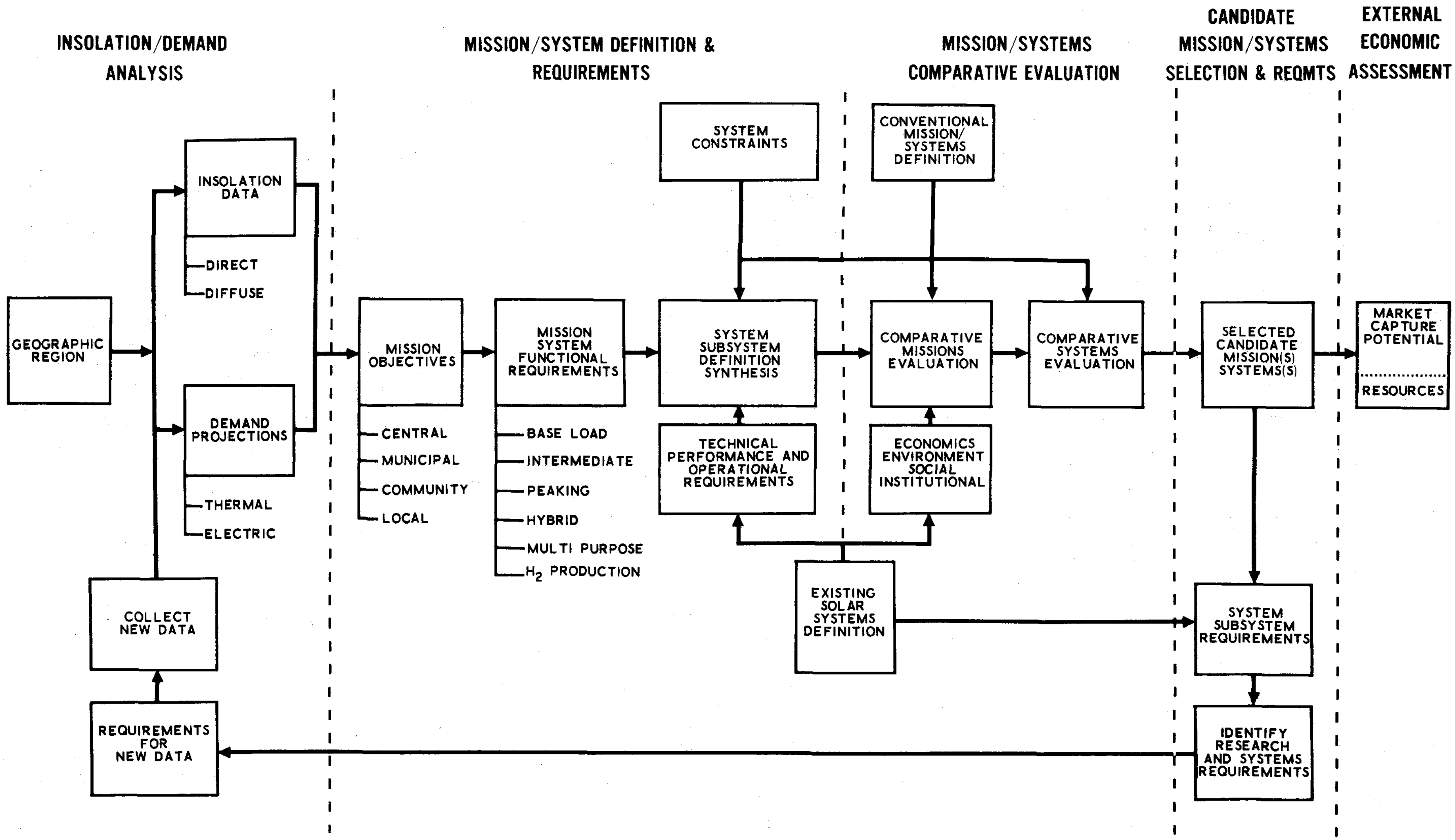


CHART 3

The issues and methodology of the Solar Thermal Conversion Mission Analysis are shown schematically in Chart 4.

A systems analysis typically involves the balancing of incoming insolation with a demand load. Much of the effect is directed at selecting the proper subsystems such as collectors, storage, and conversion units. When the insolation energy is insufficient to meet the demand, it is *assumed* that energy can be drawn from conventional power sources to make up the difference.

In contrast with the typical systems analysis, the mission analysis evaluates one or several solar power plants *integrated in a power grid* with a number of conventional power plants to supply the aggregate demand in a particular service district. The mission analysis concerns itself with the interactions of these various systems, particularly with the constraints and mode of operation that may be imposed upon the solar plants by the integrated system.

An example of such an interaction is derived from the reliability requirements imposed by all major utility systems. Besides the repetitive daily and seasonal variations in the insolation, there are also periods of poor weather with little or no insolation. This situation can be considered the equivalent of a forced outage for a conventional plant and can be compensated for in solar plants by providing a large energy storage subsystem. Unfortunately, energy storage is costly and may be impractical in some situations. In this case, the forced outage rate of the solar plant might be larger than for a similar conventional plant. The utility would then have to increase the generating capacity margin to provide the same degree of reliability. Margin is the excess of the generating capacity over the peak demand. The ability of a solar plant to displace a conventional plant while maintaining equal reliability for the total utility system is the "capacity displacement."

When a utility has built a solar plant, it is reasonable that it would be operated whenever possible. This is because the fuel is essentially free and the solar plant would probably have the minimum incremental or marginal cost. This would result in a saving of the conventional plant fuels or "energy displacement."

If the capacity displacement of a solar plant is found to be too low due to weather outages, it is possible that two or more plants, placed at different sites and of equivalent total size, would be preferred. This result depends on the statistical independence of insolation outages at the solar plant sites.

Another correlation of interest is that occurring between the insolation and the demand. If there is a correlation between periods of poor insolation and reduced demand, then the insolation reductions would be less important.

The tradeoff between thermal storage and collector size, and the impact on utility margin requirements, can be determined by system simulation. For this detailed simulation, hourly data for both insolation and demand must be determined. The hourly demand data must be for the 1980 to 2000 time period, which requires an hourly forecasting model for this time period. Both total and direct normal incidence hourly insolation data are required for each climatic region identified in the Southwestern United States. Correlations between insolation and geographically dispersed power plant sites and between insolation and demand are important for utility margin analysis and will be addressed subsequently in this report. The dynamic interaction between insolation, the solar power plant within the total system grid, and the aggregate demand will determine the technical, operational, and economic characteristics for comparative evaluation of alternative solar thermal conversion systems with conventional power plants. Based upon these results, technical and economic requirements can be established for system, subsystem, and component design. Subsequently, the market capture potential of these preferred solar plants can be determined.

Mission Methodology

INTEGRATED SOLAR AND CONVENTIONAL POWER GRID

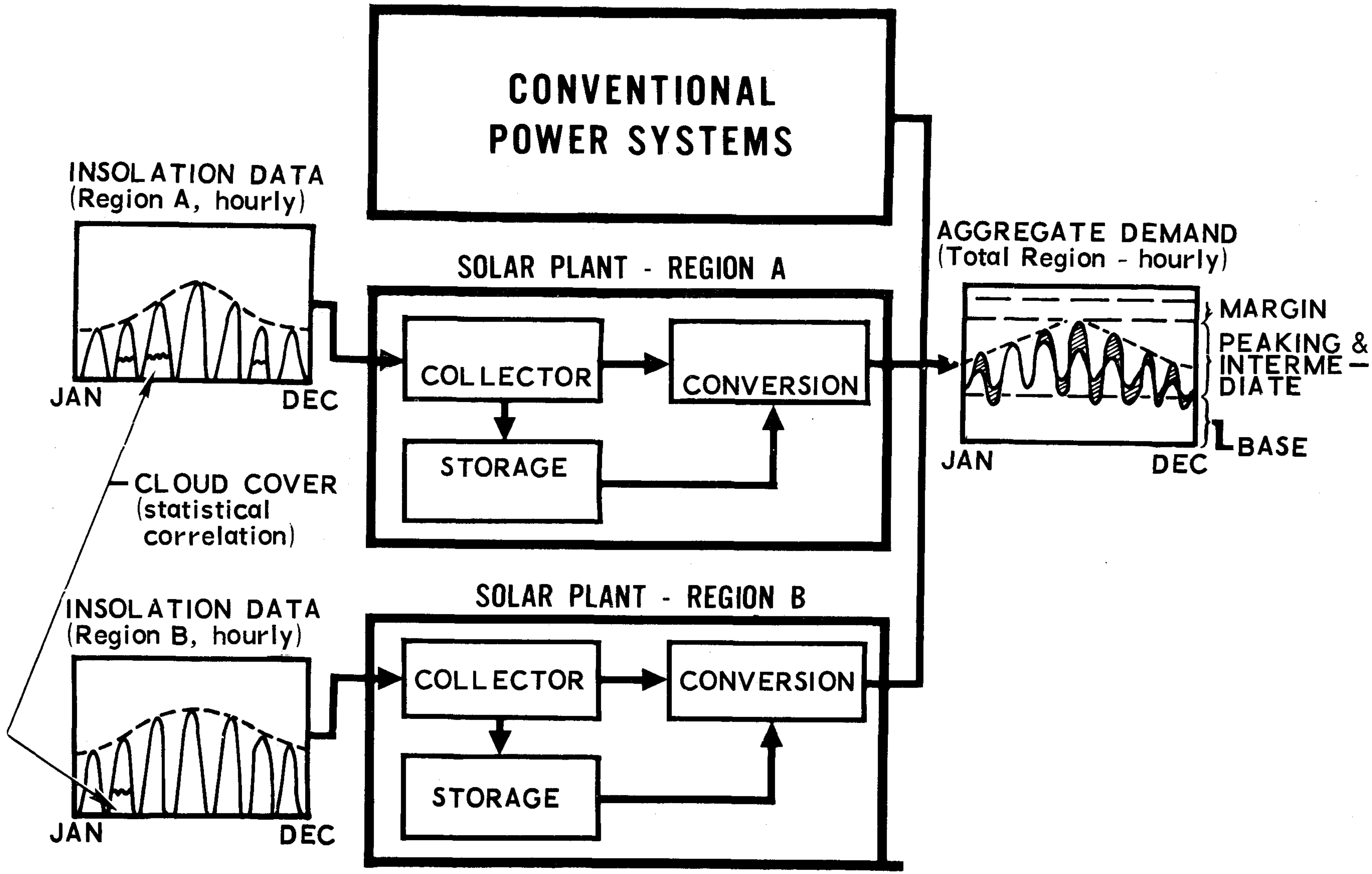


CHART 4

The major accomplishments of the previous and present phases of the Solar Thermal Conversion Mission Analysis are summarized in Chart 5.

The previous contract was constrained to consider the Southern California area only, in order to narrow the scope of the original effort. The Southern California area was defined in the beginning of that study by considering the various demographic, physiographic, and institutional characteristics as well as utility service territories (Reference 5). The follow-on mission analysis extended the geographic coverage to include the entire Southwestern United States. Consequently, one of the first tasks in this study was to define the boundaries of this geographic region.

Subsequent to the area definition, a demand analysis was performed to characterize the region defined in terms of the electrical demand for the 1980 to 2000 time period.

Representative historical hourly demand data and annual peak demand forecasts representing the major utilities serving this area were collected from various agencies and the utility industry. These data were subjected to a time series decomposition/recomposition analysis developed in order to forecast hourly demand data for the 1980 to 2000 period.

To determine the performance of alternative solar power plants, hourly total and direct insolation representative of the various climatic regions within the geographic area were required. Consequently, hourly standard data bases for a two-year period, including both total and direct insolation as well as various other weather data, were developed for 20 weather stations in the Southwestern United States.

In addition, the two data bases for Inyokern, California, and Albuquerque, New Mexico, were subjected to further analyses regarding the uncertainties in measurements and estimations. Based on these analyses, these data bases were degraded to represent the lowest insolation performance that can reasonably be expected at these sites, for the purpose of performing a worst-case analysis of solar power plant performance.

These standard insolation climatology data bases, as well as the results of the demand analyses, are available on magnetic tape to all participating contractors for consistent assessment of solar power plant performance.

To ensure against the probability that the electrical load or demand exceeds the available generating capacity for a particular electric power utility, the installed generating capacity for U.S. utility companies is designed to be in excess of the anticipated peak loads. This incremental generating capacity in excess of peak load is called the margin. The margin requirements for power plants arise due to unscheduled outages, which for conventional power plants are due to component failures. For solar power plants, these unscheduled outages are due to insolation outages as well as component failures.

In order to assess solar power plants in realistic operating environments, these plants must be evaluated by requiring the same reliability of operation of the grid as with conventional power plants. Consequently, a methodology was developed to determine the system margin requirements based upon a probabilistic approach. This methodology, when applied to a generation system with solar power plants included, identified the back-up generation requirements (capacity displacement) of solar power plants to compensate for the higher outage characteristic of such plants due to the additional insolation outages.

Utilizing the hourly insolation and demand data, a detailed parametric simulation for an entire year was made of the alternative system concepts. Collector area and storage capacity were varied parametrically while maintaining the turbine-generator rated capacity constant.

The technical characteristics of these alternative system concepts were obtained from interaction with various system contractors and, consequently, reflect the latest combined knowledge of these alternative system concepts.

A comparative technical evaluation of alternative system concepts was made using the results of these simulations. A sensitivity analysis was also performed to determine the impact on performance and economics due to changes in the technical characteristics of major subsystems.

Subsequent to the comparative technical assessment, a comparative economic evaluation was made of the alternative solar concepts considered and the corresponding conventional power plants. A discounted cash-flow method of analysis was used to perform these analyses. This methodology is described in detail in the report: "Power Plant Economic Model" (Reference 6) which was developed by The Aerospace Corporation and is available for use by other contractors. In addition, a cost sensitivity analysis was made of the major subsystems to determine the impact of cost uncertainties on busbar energy cost.

Based upon the comparative technical and economic assessment of the alternative solar and conventional system concepts, the central receiver concept operating in an intermediate or load-following mode appears to be economically competitive and was identified as the most preferred system. Alternatively, if a low-cost parabolic cylindrical trough collector can be developed, this concept could serve as an alternative back-up system. For these preferred systems, a preliminary technical and economic system definition has been made.

In order to determine the availability of solar power plant sites in the Southwestern United States, a siting analysis was performed. In addition, an assessment of the water resources and a preliminary environmental impact analysis was made. Sufficient suitable land was identified for potential use in the Southwestern United States. However, water resources were found to be scarce in these areas, and, consequently, the use of dry cooling towers may have to be considered for solar power plants.

Finally, a preliminary market capture potential of 40,000 MWe by the year 2000 was identified for the preferred system concept, providing the first commercial plant will be operational in 1985. This would result in the saving of 320 million barrels of oil per year. No significant obstacles to the achievement of this market potential were identified with the exception of the high capital investment requirements of solar power plants, placing additional burdens on the already difficult financing problems of the electric utility industry.

The following chapters will in sequence show the summary results of the Southwestern United States Area Definition and Siting Analysis, Demand Analysis, Insolation Analysis, Margin Analysis, and Comparative Technical and Economic Analyses, as well as the Preferred System Selection/Definition and associate Market Capture Potential.

Solar Thermal Conversion Mission Analysis
Major Accomplishments

- AREA DEFINITION
    - SOUTHERN CALIFORNIA
    - SOUTHWESTERN UNITED STATES
- DEMAND ANALYSES
    - DATA COLLECTION S.W. U.S. (UTILITIES; AGENCIES)
    - DECOMPOSITION/RECOMPOSITION METHODOLOGY
    - HOURLY DEMAND DATA FORECASTS (1980-2000)
- INSOLATION CLIMATOLOGY
    - 20 SOUTHWESTERN UNITED STATES DATA BASES
    - WORST CASE ANALYSIS (INYOKERN, ALBUQUERQUE)
- MARGIN ANALYSIS
    - PROBABILISTIC METHODOLOGY
    - CAPACITY DISPLACEMENT
- COMPARATIVE TECHNICAL EVALUATION
    - EVOLUTIONARY MISSION/SYSTEM SIMULATION
    - COMPARATIVE EVALUATION - ELECTRICAL SYSTEMS
    - SENSITIVITY ANALYSES
- COMPARATIVE ECONOMIC EVALUATION
    - POWER PLANT ECONOMIC METHODOLOGY
    - COMPARATIVE ECONOMIC EVALUATION - ELECTRICAL SYSTEMS
    - SENSITIVITY ANALYSES
- PREFERRED SYSTEM SELECTION/DEFINITION
    - PRIMARY AND BACK-UP SYSTEMS
    - ECONOMIC & TECHNICAL SYSTEM DEFINITION
- SITING ANALYSIS/ENVIRONMENTAL IMPACT
    - SOUTHERN CALIFORNIA
    - SOUTHWESTERN UNITED STATES
    - WATER RESOURCES
    - UTILITY DISPATCH MODEL
- MARKET CAPTURE POTENTIAL
    - PRELIMINARY RESULTS

SOUTHWESTERN UNITED STATES
AREA DEFINITION AND SITING ANALYSIS

SOUTHWESTERN UNITED STATES AREA DEFINITION AND SITING ANALYSIS

Investigations of the Southwestern United States region as described in this section have identified the boundaries of the Solar Thermal Conversion Mission Analysis study area. Additional investigations have resulted in the preliminary identification of potential solar thermal conversion power plant siting areas. The accomplishment of this later effort was recognized as an important factor in an assessment of overall system feasibility and market capture potential.

SOUTHWESTERN UNITED STATES AREA DEFINITION

One of the first tasks to be performed was to define the Southwestern United States study area. Several aspects were considered, including institutional, climatologic, and demographic characteristics, as well as utility service territories. Chart 6 shows the area selected for detailed study. Geographically the area can be defined by eight states: California, Nevada, Arizona, New Mexico, Utah, Colorado, Texas, and Oklahoma. These states incorporate several major load centers as indicated on the chart.

Not all of the area comprising these states was included within the Southwestern United States study area boundaries. One of the main considerations in defining the study area boundaries is the available solar energy. Shown on Chart 6 are contour lines of constant total insolation, expressed on an annual mean daily basis, in watt-hr/m^2/day (or watts/m^2). These high solar insolation values reflect one of the principal reasons for the selection of the Southwestern United States as the primary study area for solar thermal conversion applications. The insolation contours, which become more favorable for solar power plants in the southwest direction, indicate the degree of variation in solar energy throughout the area. One boundary criterion for the definition of the Southwestern United States study area is the condition that the average annual solar energy available be greater than 5 KWH/m^2 per day.

Another consideration is the characterization of the study area in terms of electrical demand data. To facilitate demand data characterization, the boundaries and number of the various power supply areas serving this area are also indicated on this chart. Also, demand data available from Federal sources (e.g., the Federal Power Commission), state and regional utility pools, as well as major individual utility companies serving this area, were included in this consideration.

The tentative boundary defining the Southwestern United States area selected for the Solar Thermal Conversion Mission Analysis is shown on Chart 6 by the heavy line. The characterization of this area in terms of electric power demand and solar insolation will be discussed in subsequent sections of this report. However, for purposes of the Siting Analysis, discussed in this section, a slightly different area with boundaries more coincident with those of the eight Southwestern states shown on this chart was used.

Southwestern United States

AREA DEFINITION

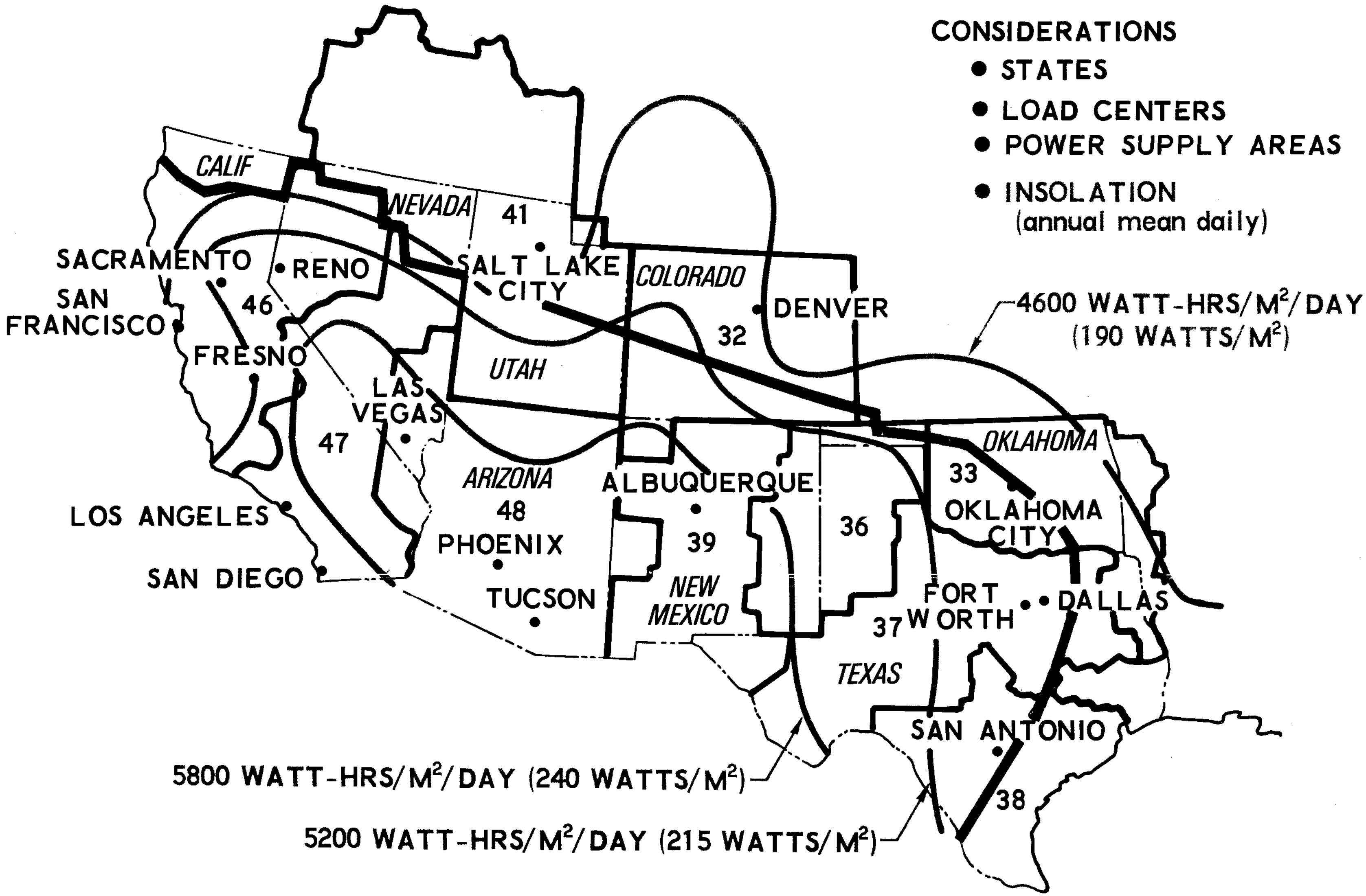


CHART 6

UTILITY DEMOGRAPHIC DATA (1972)

Demographic characteristics within the Southwestern United States study area are shown on Chart 7. As can be seen, 17 major electric utility companies, out of more than 400 companies in this area, serve 75 percent of the (1972) population and 46 percent of the total Southwestern United States area. These 17 utilities also generate nearly two-thirds of the electric energy consumed in the eight-state region. Significant diversity in recent electric demand growth rates for these utilities, from a low of 3 percent to a high of 17 percent, is also evident from this chart.

Utility Demographic Data (1972)

STATE	SERVICE TERRITORY (SQUARE MILES)	CUSTOMERS/ POPULATION (THOUSAND)	GROWTH RATE - Kwh SALES (PERCENT)
● CALIF			
PG&E	94,000	2800/8500	7.8
SCE	45,000	2600/ -	7.1
SMUD	656	245/ -	7.9
SDG&E	4,100	1600/ -	7.0
LADWP	460	1102/ -	
● NEVADA			
NPC	9,348	107/ -	9.1
SPP	39,600	101/ -	
● UTAH			
UP&C	57,000	322/ -	16.0
● COLORADO			
PSC	31,200	583/ -	9.7
● NEW MEXICO			
PSNM	26,000	152/1016	8.8
● OKLAHOMA			
OG&E	30,000	473/1300	11.7
● TEXAS			
TESCO	83,000	406/ -	
EPE	10,000	133/475	11.0
DP&L	600	247/ -	3.0
CPS (SA)	1,600	261/ -	11.0
● ARIZONA			
APS	40,000	278/1300	17.0
TG&E	1,155	130/403	14.0
TOTAL (Utility Service Area)	473,719	11,549/30,550 *	
TOTAL (S.W., US)	1,031,000	40,000	

* Adjusted from 1970 census data (3% annual growth)

CHART 7

The success in building and operating solar energy power plants is largely dependent upon an ability to find suitable sites for the construction of such plants. The purpose of the siting area evaluation effort undertaken in this study, as shown in Chart 8, was to examine the practicality and feasibility of siting solar plants. The area of investigation for this study, originally limited to the Southern California region, has been expanded to the eight Southwestern states of California, Nevada, Arizona, New Mexico, Utah, Colorado, Texas, and Oklahoma.

Although the scope of the investigation was limited to plants of large capacity (50-1000 MWe), many of the results of this study are also applicable to smaller plant sizes in the order of 1-50 MWe. However, the larger contiguous land area requirement makes the siting of larger capacity plants more difficult than for small capacity plants.

The approach used to evaluate the region for siting employs the process of exclusion. This method sequentially applies a set of criteria in the form of diagrams on maps. When all the maps are compiled, the area not excluded on any of the maps is identified as the area potentially suitable for siting.

Measurements taken from each map provide the information on size and location of potentially suitable solar power plant sites.

Siting Area Evaluation

PURPOSE

- EXAMINE THE ENGINEERING PRACTICALITY AND FEASIBILITY OF SITING SOLAR POWER PLANTS IN SOUTHWESTERN UNITED STATES

SCOPE

- LIMITED TO LARGE CENTRAL STATION SOLAR PLANTS RANGING IN SIZE FROM 50 TO 1000 MEGAWATTS EACH

APPROACH

- EXCLUSION PROCESS
- DEFINE CRITERIA AND APPLY TO MAPS

CHART 8

The criteria used in the siting area evaluations ultimately determine the characteristics of the results. Therefore, particular attention was given to the preparation of these criteria. The criteria were developed to specifically identify unsatisfactory siting conditions, hence, the term "Criteria for Exclusion."

Because of the preliminary nature of this solar plant siting evaluation, it was decided that the criteria should attempt to define the siting conditions only in broad terms. In this way the more important issues would be given priority attention. Subsequent detailed siting evaluation efforts will permit greater attention to lesser issues.

As shown in Chart 9, the criteria are in two parts: the first part addresses technical issues, while the second part addresses institutional issues.

Some of the exclusion criteria, shown on Chart 9 with an asterisk, are inherently judgmental and cannot be precisely defined in quantitative terms. These criteria, in general, involve alternative land use and environmental issues. Because of the impact of these criteria on the siting analysis results, two sets of criteria reflecting two levels of severity in application (most stringent and least stringent) were incorporated in the Siting Analysis.

The criteria listed do not imply that all factors have been included. The omission of certain factors was done purposely because of the unavailability of information on specific plant design characteristics. Where, in the judgment of the investigator, insufficient or confusing information on plant design parameters existed, the issue was not included as part of the rigid criteria. However, wherever possible, investigations relative to such omitted criteria items were prepared and the results applied as supplemental material separate from these criteria applications.

Siting Exclusion Criteria

- TECHNICAL
  - RELIEF, GRADE
  - SOIL TYPE AND CONDITION
  - METEOROLOGICAL (SNOW, HAIL, WIND)
  - SURFACE VEGETATION*
  - SEISMIC (GROUND SHAKING)
  - SURFACE STRUCTURES, PIPELINES, TRANSMISSION LINES*
  - NATURAL RESOURCES (COAL, SHALE OIL, OIL AND GAS)*
  - WATER RESOURCES*
- INSTITUTIONAL
  - NATIONAL AND STATE PARKS AND MONUMENTS
  - NATIONAL FORESTS, WILDERNESS AREAS*
  - MILITARY RESERVATIONS AND INDIAN RESERVATIONS*
  - URBAN AREAS
  - FARMING AND OTHER HIGH-VALUE LANDS*
  - PUBLIC DOMAIN

* Alternative criteria developed

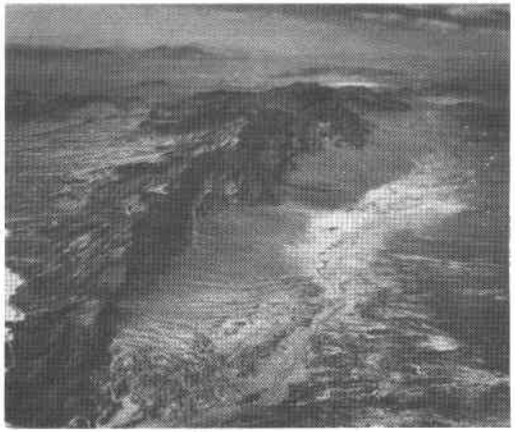
CHART 9

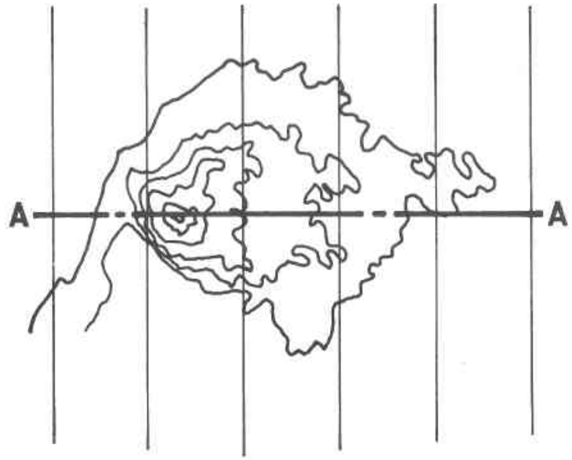
TERRAIN CRITERIA

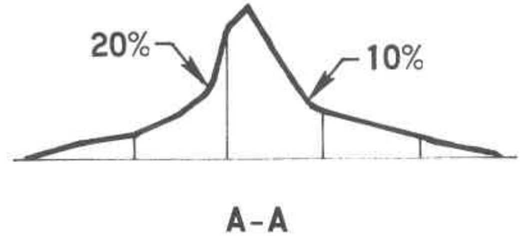
The terrain criteria reflect the large topographic relief typical of mountainous regions and, secondly, the smaller scale features of surface roughness. For several reasons (grade, access, etc.) mountainous areas are typically not suited for the location of large construction projects. Accordingly, all areas with a grade profile in excess of 20 percent were excluded. Furthermore, areas reflecting severe or moderate erosion were also excluded. Chart 10 shows how grade and erosion are typically expressed in terms of map symbology. Photographs corresponding to grade and erosion characteristics in excess of the acceptable criteria values are shown on the chart to visually illustrate typical grade and erosion situations.

Terrain Criteria

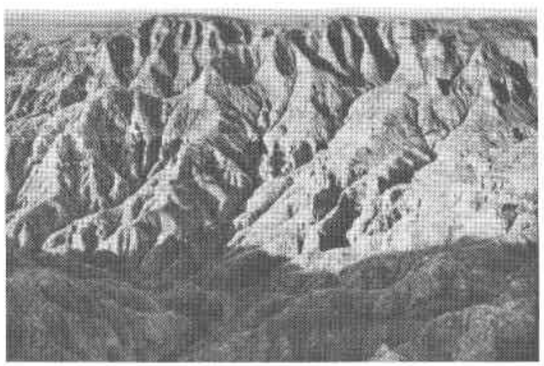
GRADE

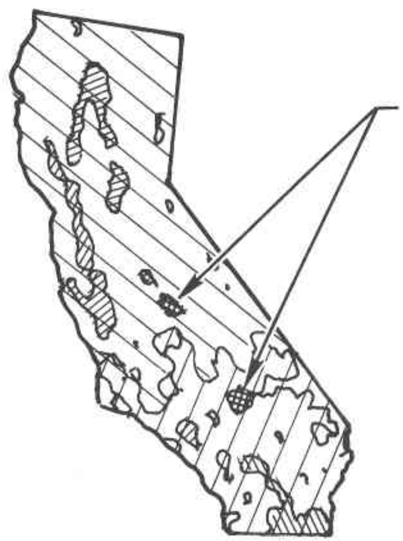






EROSION





Charts 11 and 12 depict the results of the application of the terrain criteria, i.e., 20 percent grade and surface erosion. Apparent on Chart 11 are large excluded regions of California, Utah, and Colorado, which correspond to the Sierra, Wasatch, and Rocky Mountain ranges. Also evident are the numerous smaller mountains, particularly in Nevada and Arizona. Included on this map are mountainous locations that exceed 5,000 foot altitude. These areas were excluded because of anticipated problems with winter snows and other difficult winter conditions. Chart 12 shows those locations (in black) unacceptable because of surface erosion.

Terrain

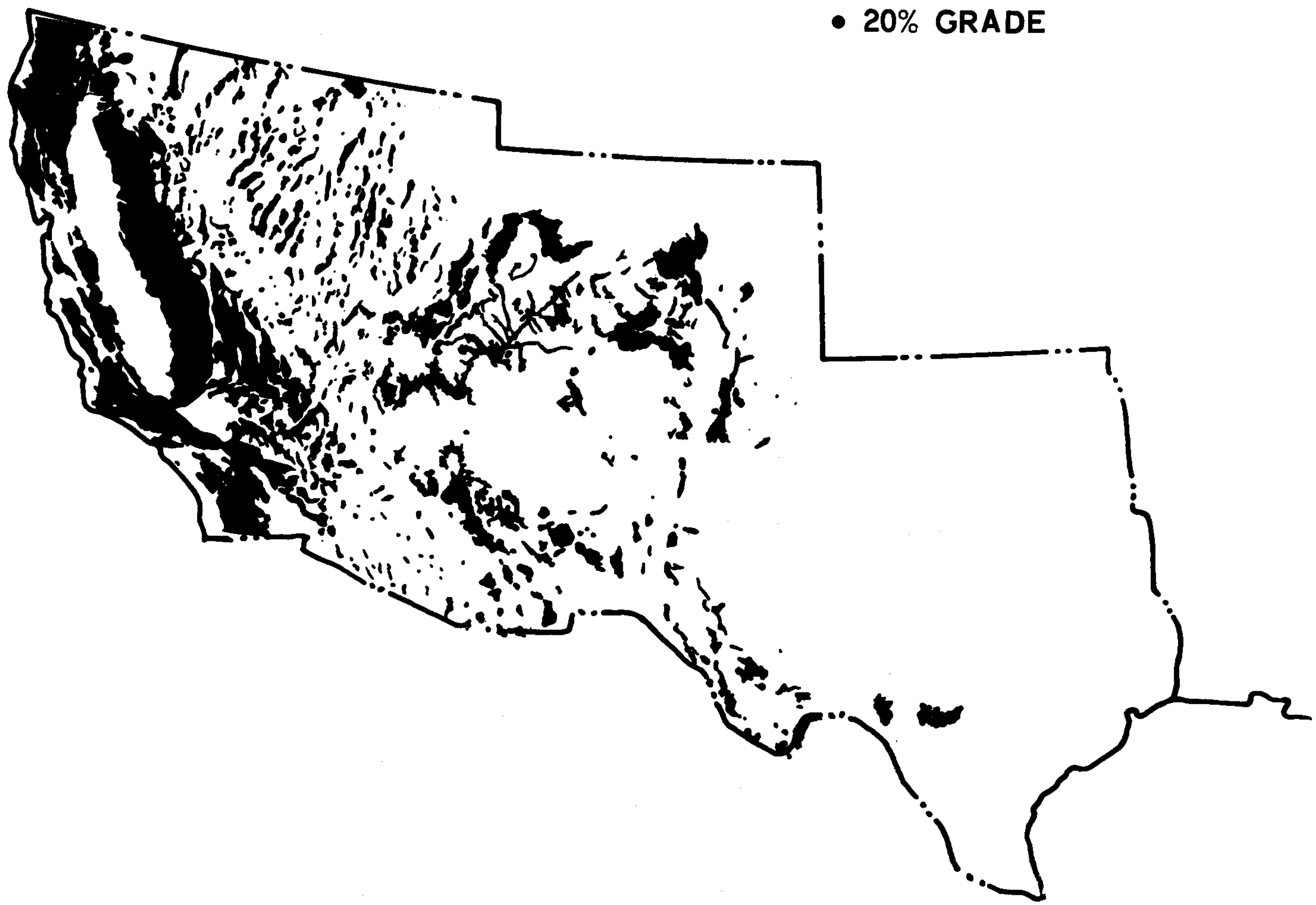


CHART 11

Terrain

CRITERION

• SURFACE EROSION

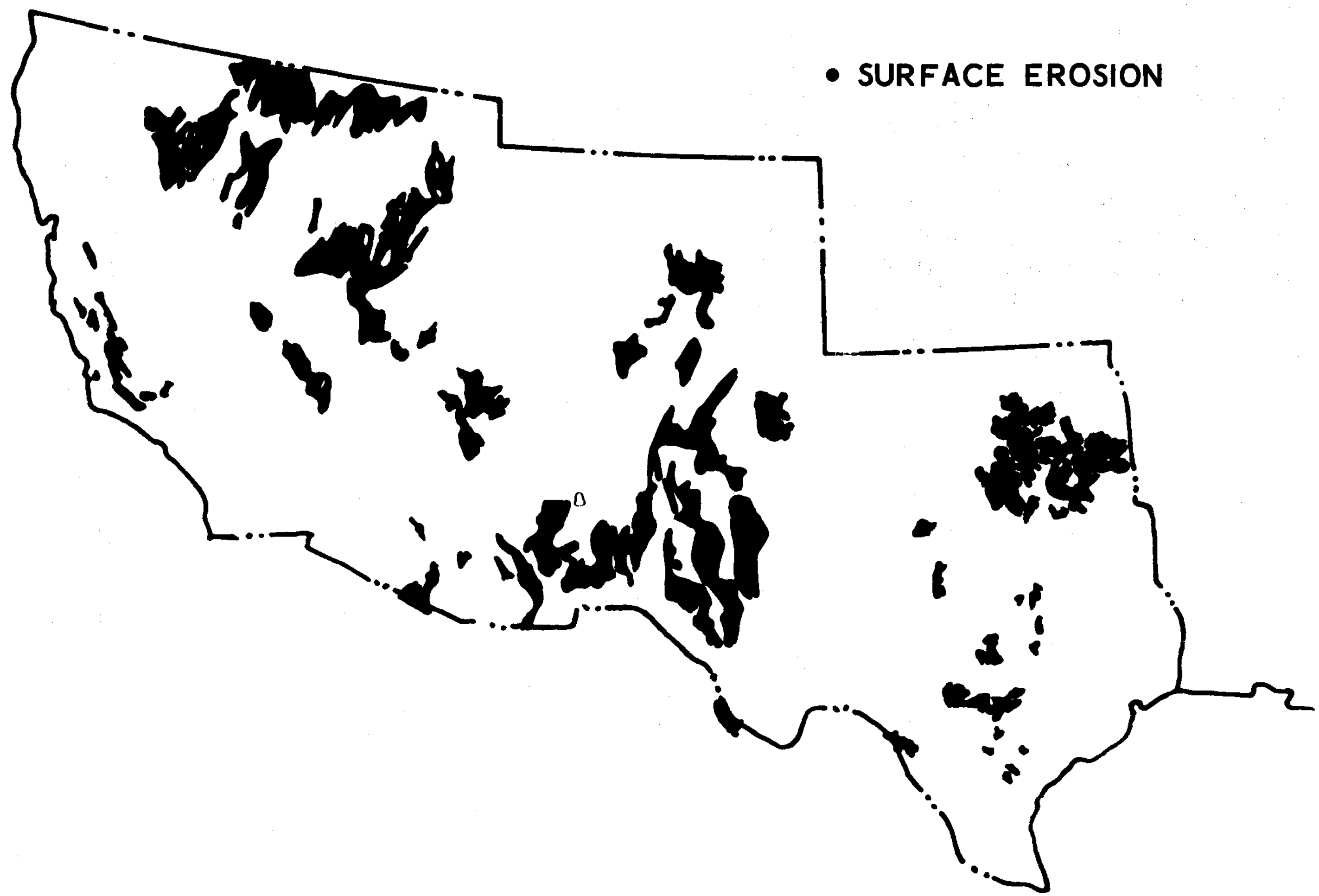


CHART 12

SOIL CRITERIA

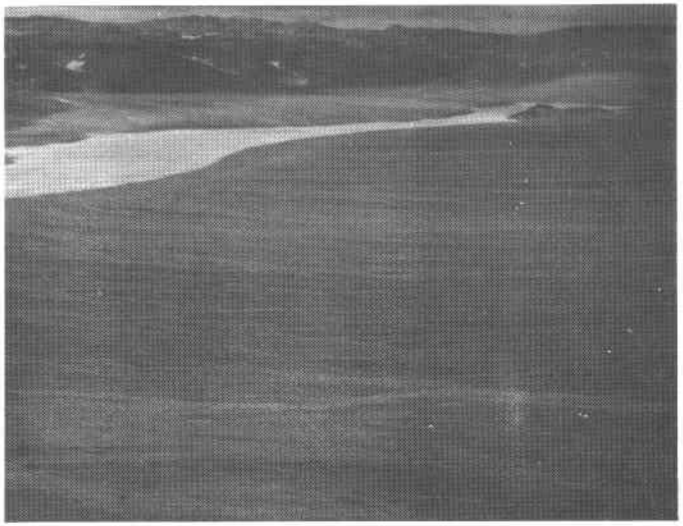
Photographs of several selected examples depicting unacceptable surface conditions are shown on Chart 13.

Among soil conditions that could present difficult problems are sand dunes and dry lake-bed areas. Sand dunes are unstable land forms which make construction of any substantial structure very difficult, if not impossible. More importantly, the presence of sand dunes suggests the occurrence of strong winds that can carry sand particles over long distances at high velocities. These sand particles are potentially harmful to solar collector surfaces.

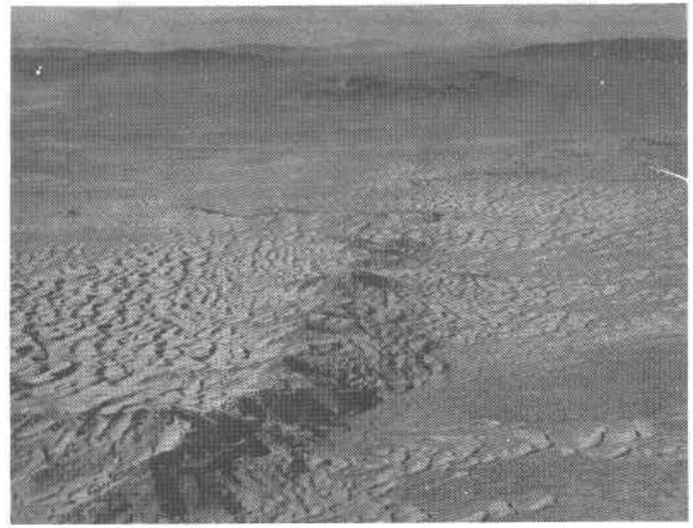
Dry-lake areas present the threat of flooding from flash thunderstorms. This type of flooding is usually very rapid and can cause considerable damage to both natural and man-made structures.

Soil Criteria

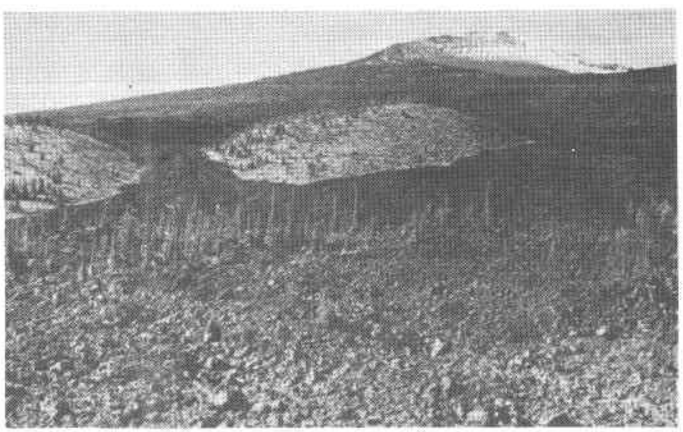
PLAYA



SAND DUNES



LAVA



WATER

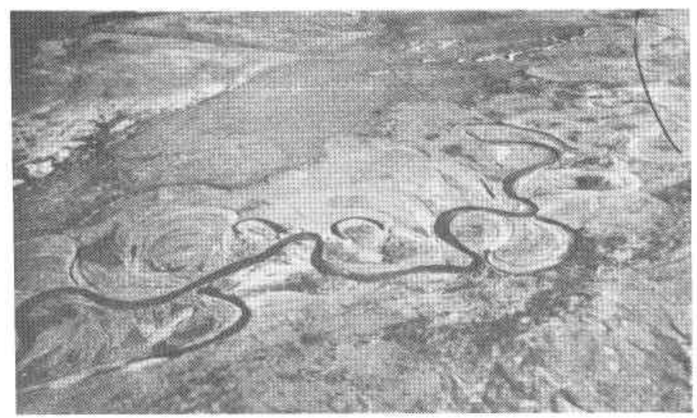


CHART 13

SOIL

The results of the application of the soil criteria are shown on Chart 14. A listing of the items comprising these exclusion criteria are shown on the chart. Also noted on the map are the courses of major rivers and water areas corresponding to natural and man-made lakes. The large excluded areas in New Mexico correspond to lava flows. The many smaller areas, primarily in California and Nevada, correspond to sand dunes and playa areas.

Soil

CRITERIA

- EXPANSIVE SOILS
- SAND DUNES
- DRY LAKE BEDS
- LAVA FLOWS
- LAKES, RIVERS, MARSHES

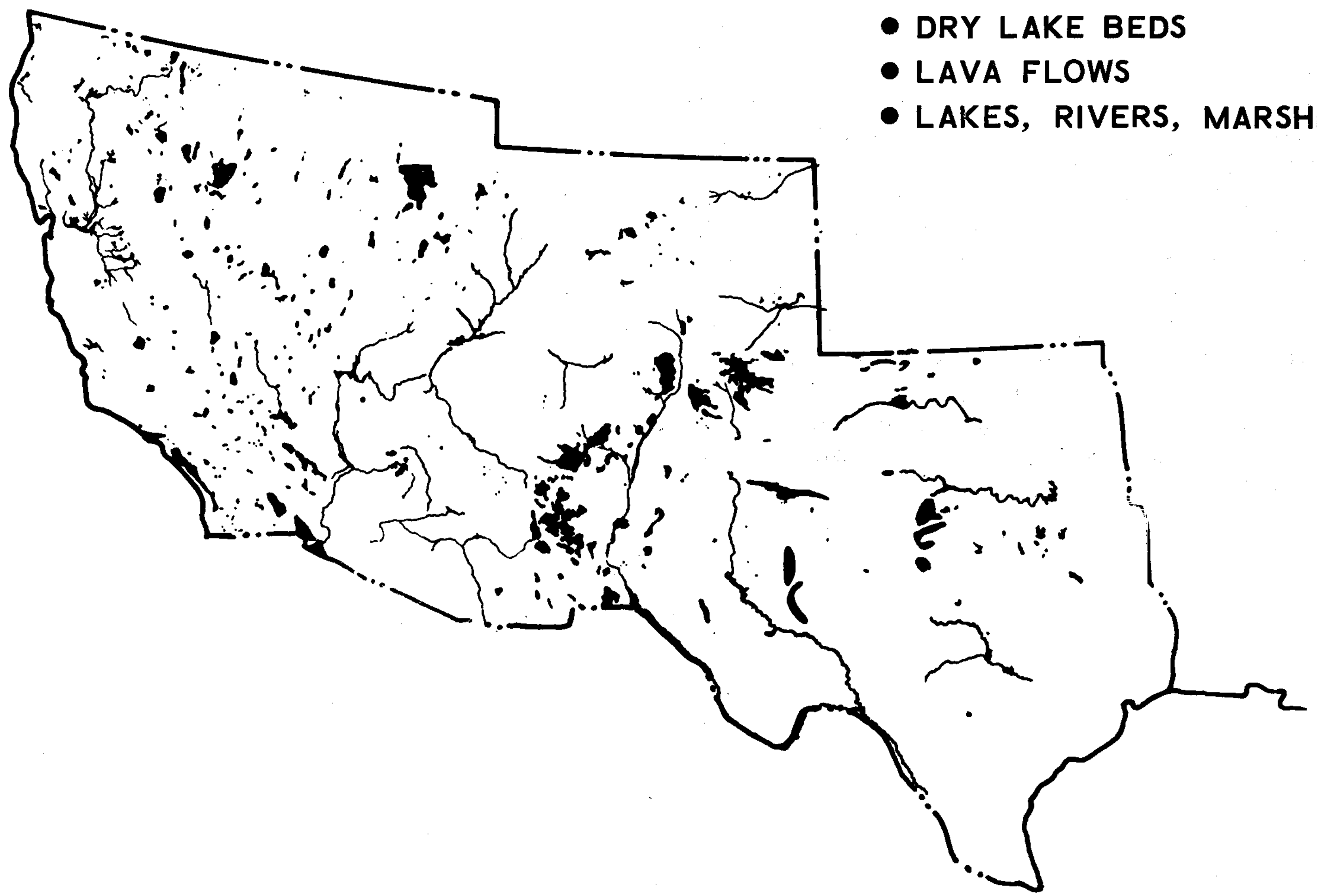
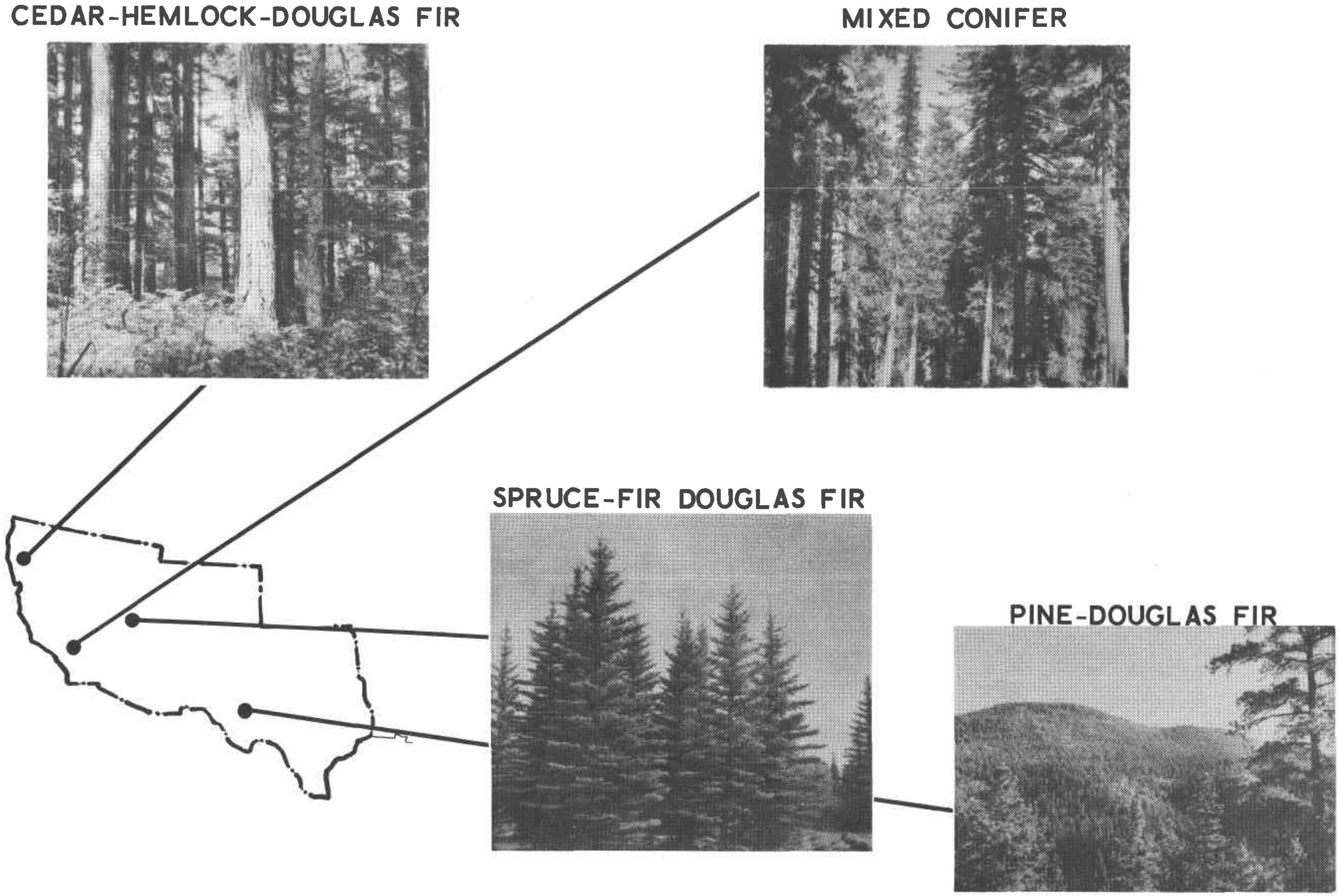


CHART 14

MAJOR RESOURCE VEGETATION

Of major importance in the assessment of locations for siting of solar plants is the impact of vegetation. In this siting study two sets of exclusion criteria were sequentially applied and have been identified by the labels "most stringent" and "least stringent." One of the differences between these two sets of criteria is the nature of the vegetation criterion included. The least stringent set of criteria included a "Major Resource" vegetation criterion, whereas the most stringent set of criteria also included a more demanding "Significant Impact" criterion. The "Major Resource" vegetation criterion excluded areas such as the western and southern dense forests, shown pictorially in Chart 15. The "Significant Impact" criterion excludes all vegetation areas that may be significantly impacted if disturbed, such as shown pictorially in Chart 16. Many individuals would not be concerned over the use of the "Significant Impact" areas although others would surely object, particularly where many power plants requiring very large areas would be proposed. The use of such areas for siting transmission lines and by recreational vehicles has already been strongly resisted.

Major Resource Vegetation



Significant Impact Vegetation

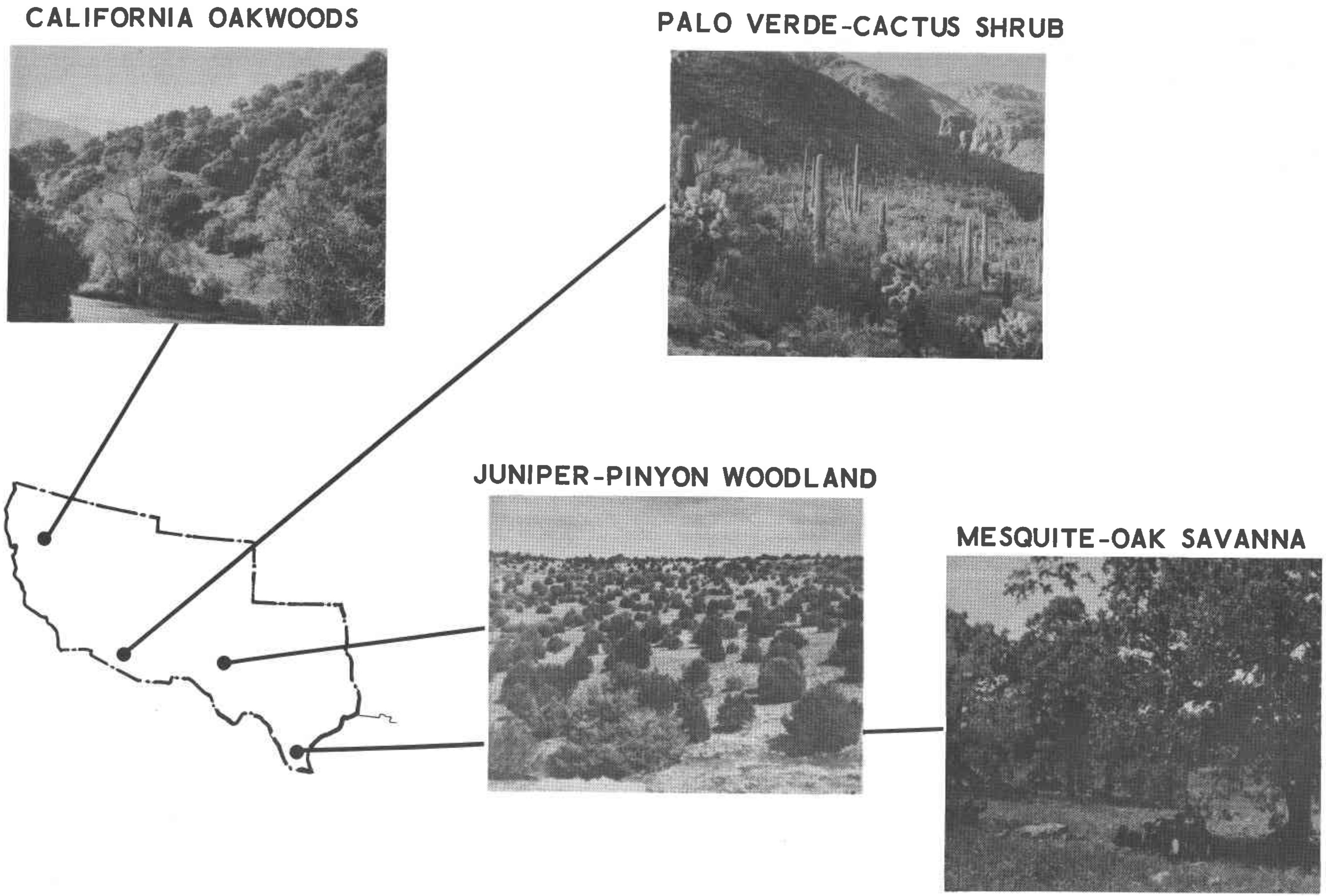


CHART 16

VEGETATION

The results of the application of the two alternative vegetation criteria are shown on Charts 17 and 18. It may be noticed that the areas excluded by the "Major Resource" vegetation criterion are located mainly in the mountainous regions. These locations tend to be more northerly, predominantly in California and Colorado.

Surface Vegetation

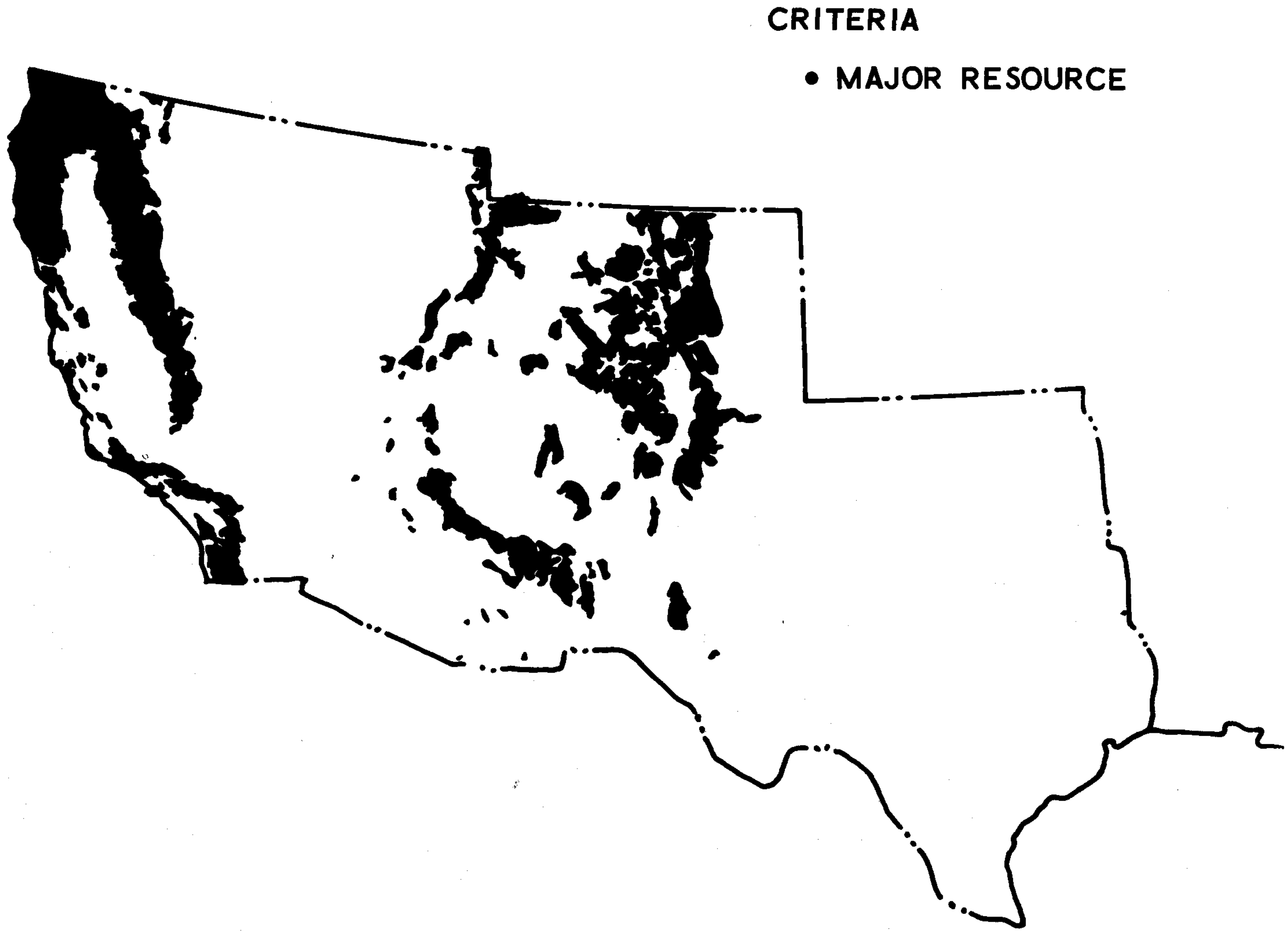


CHART 17

Surface Vegetation

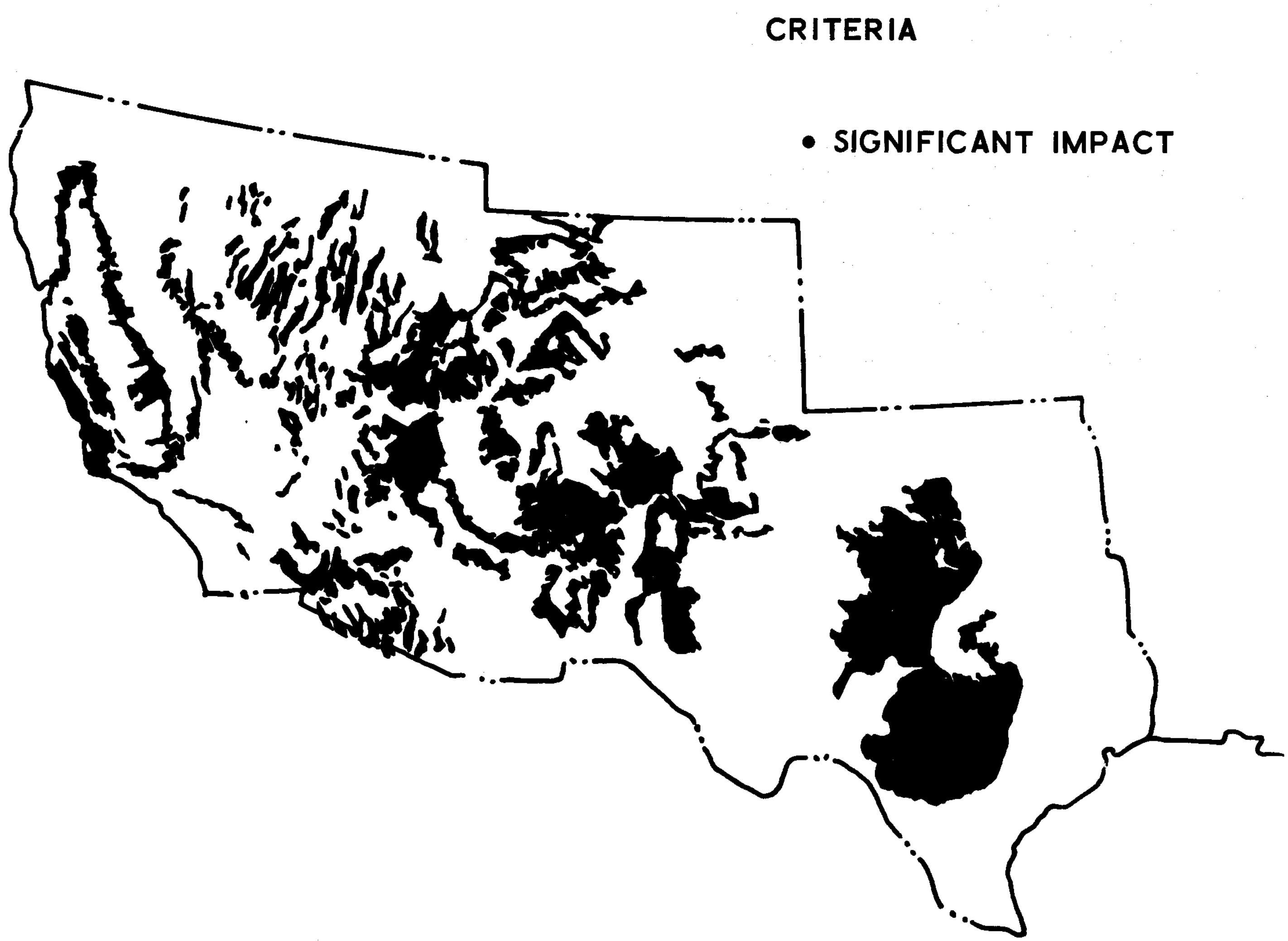


CHART 18

COMPOSITE EXCLUSION AREA CRITERIA

Shown on the previous charts are the application of several exclusion criteria to illustrate the methodology. A more detailed description of the Siting Analysis, including the detailed application of the remaining criteria, is included in Volume V of this report.

The individual exclusion criteria were combined into two alternative sets of criteria corresponding to severity: least stringent and most stringent. The various criteria included in each category are summarized in Chart 19. The most significant difference between the two alternative sets of criteria are the treatment of vegetation and agriculture. The remaining individual criteria, with the exception of terrain, erosion, and soil, also have different criteria, but the impact of these differences is minor.

Composite Exclusion Area Criteria

LEAST STRINGENT

ISSUE	REQUIREMENT
TERRAIN	> 20%
EROSION	FREQUENT GULLIES, SEVERE AND MOD. SHEET EROSION
SOIL	PLAYAS, LAVA, EXPANSIVE SOIL, LAKES, RIVERS, SAND, ETC.
VEGETATION	MAJOR RESOURCES
AGRICULTURAL	TILLED LAND - GRAIN, PRODUCE, FIBRE
SURFACE	CONFIRMED MINERALS AND FUELS
FEDERAL LANDS	USES DEFINED AREAS WITHIN NATIONAL FORESTS
INDIAN LANDS	LANDS THAT MIGHT BE TRADED OR LEASED
MILITARY	DEACTIVATED AREAS

MOST STRINGENT

ISSUE	REQUIREMENT
TERRAIN EROSION SOIL	SAME AS ABOVE
VEGETATION	SIGNIFICANT IMPACT AND MAJOR RESOURCES
AGRICULTURAL	GRAZING LANDS + GRAIN, PRODUCE, FIBRE
SURFACE	PROBABLE AND CONFIRMED MINERALS AND FUELS
FEDERAL LANDS INDIAN LANDS MILITARY	ALL AREAS WITHIN ESTABLISHED BOUNDARIES

SITING AREA LOCATION SUMMARY – SOUTHWESTERN UNITED STATES

Applying the two sets of exclusion criteria to the Southwestern United States results in the identification of potentially suitable sites for large solar power plant construction.

The resulting sites (in white) identified under the alternative most-stringent and least-stringent sets of criteria are summarized in Charts 20 and 21, respectively.

As can be seen from these charts, the application of the most-stringent criteria limits the potential sites mainly to the Colorado River Basin. Application of the least-stringent criteria results in significantly increased siting potential, distributed throughout the Southwestern United States. In this latter case, the issues of potential importance are utilization of land currently used for the production of food, or the potentially unacceptable environmental impact, particularly where many plant sites are involved.

Siting Area Location Summary

SOUTHWESTERN UNITED STATES

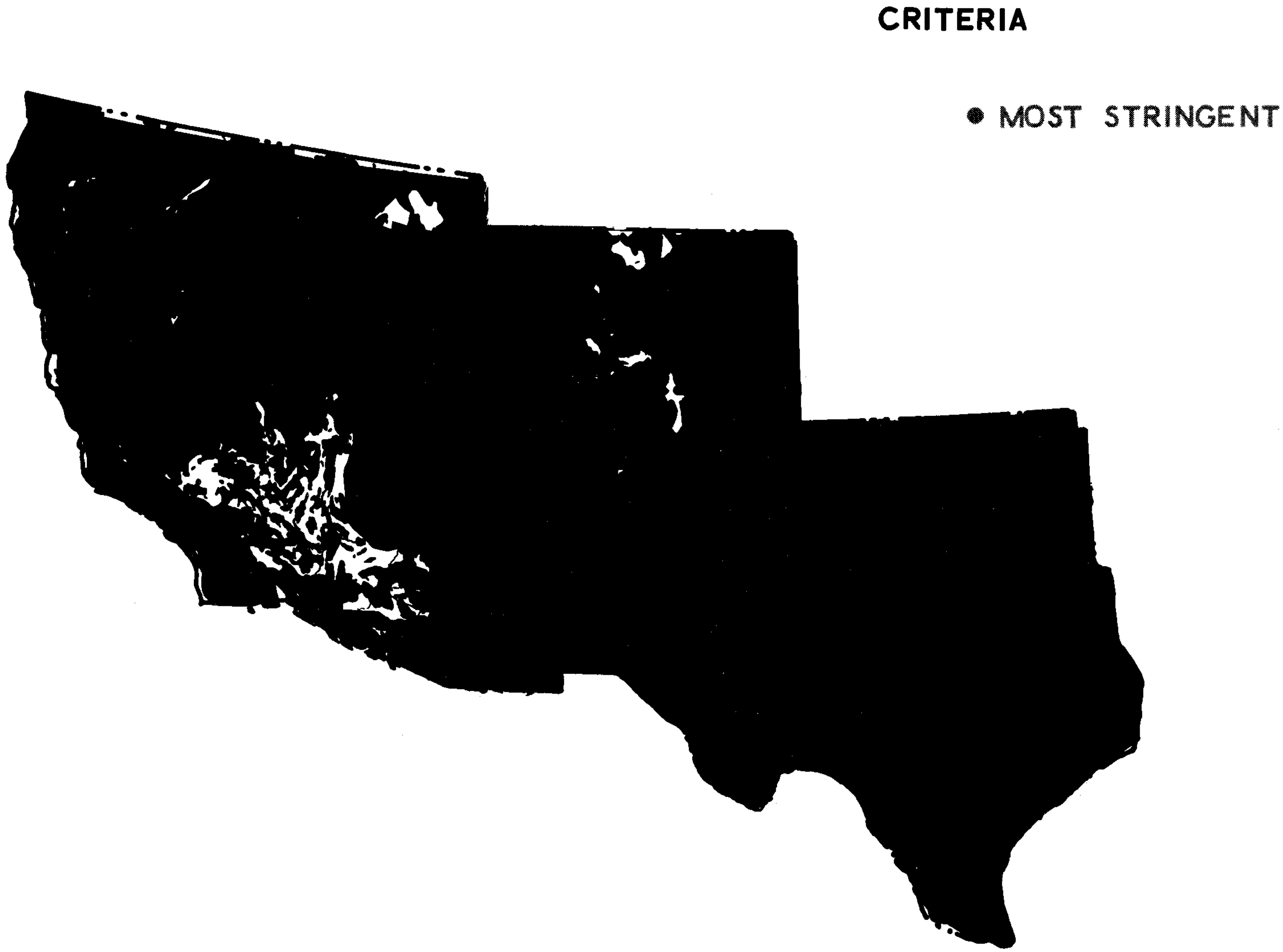


CHART 20

Siting Area Location Summary

SOUTHWESTERN UNITED STATES

CRITERIA

- LEAST STRINGENT

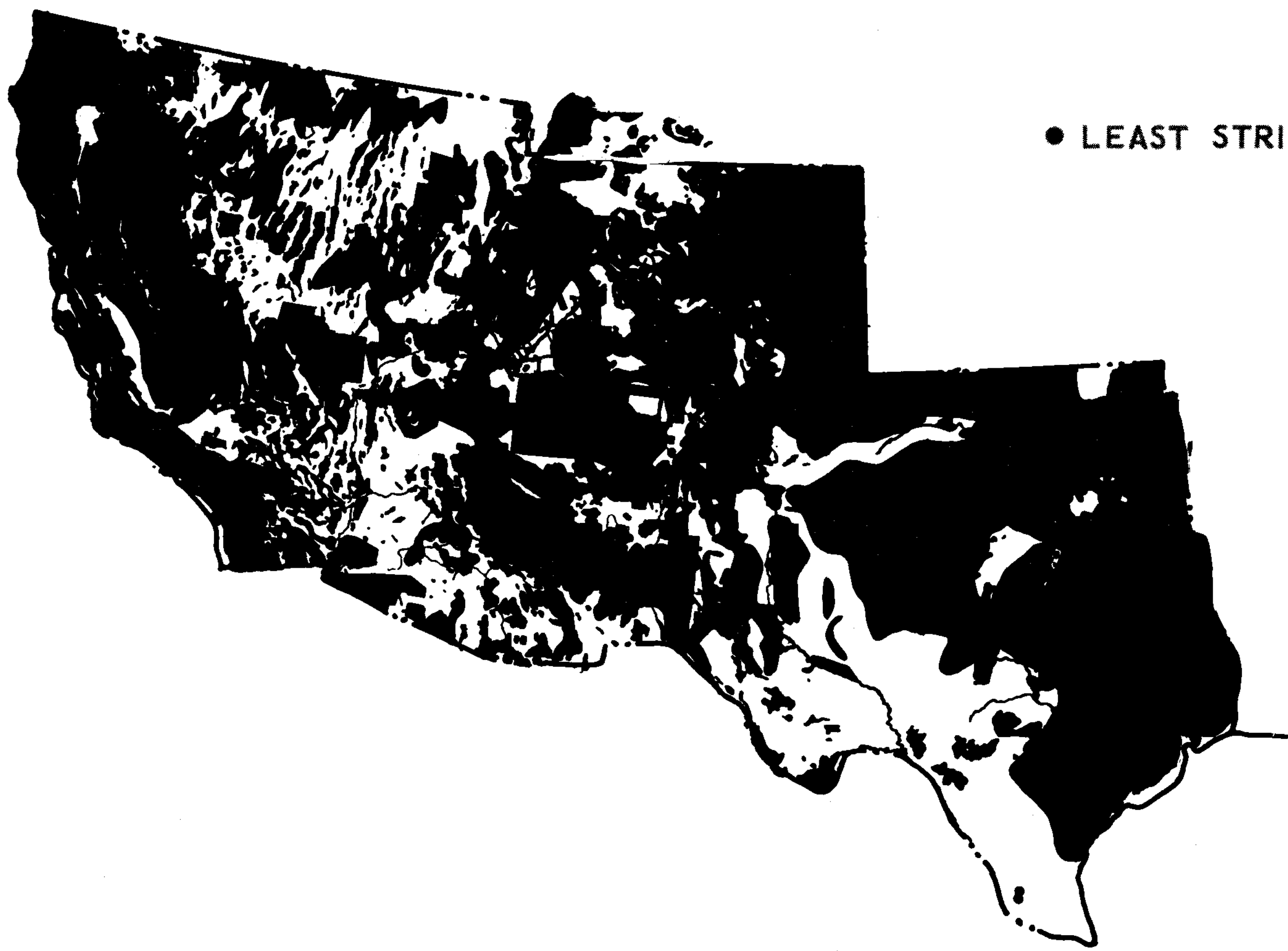


CHART 21

SITING AREA SUMMARY

Chart 22 summarizes separately the land area excluded under each criterion. If the noncoincident areas, remaining after the application of the most stringent composite criteria, are summed exclusive of seismic considerations, the remaining potentially suitable siting area in the Southwestern United States is approximately 161,000 sq. mi. out of a total of 1,031,000 sq. mi. This area is reduced to approximately 21,000 sq. mi. potentially suitable for solar plant siting if the most stringent composite criteria are assumed. The further application of seismic criteria resulted in only a small reduction in the non-excluded or potentially suitable siting area and, consequently, was disregarded in the final results for the Southwestern United States. However, as pointed out in the siting study for the Southern California area, the seismic exclusion impact is locally significant. The potentially suitable siting areas identified by this analysis are not necessarily available for solar power plant construction because of ownership and other detailed siting considerations.

Siting Area Summary

ISSUE	SIZE OF AREAS EXCLUDED (sq mi) LEAST STRINGENT	MOST STRINGENT
TERRAIN	135,529	135,529
EROSION	134,732	134,732
SOIL	37,180	37.180
VEGETATION	135,000	372,500
AGRICULTURAL	300,100	869,025
SURFACE	190,982	245,549
FEDERAL LANDS	137,239	137,339
INDIAN LANDS	44,703	45,284
MILITARY	21,702	22,742
AREA, EIGHT SOUTHWESTERN STATES	1,031,228	1,031,228
AREA EXCLUDED	870,038	1,009,682
SUITABLE AREA	161,190	21,546

CHART 22

SOUTHWESTERN UNITED STATES SITING AND ENERGY SUMMARY

The land area identified as suitable on the previous charts can be related to the potential for solar power generation. Chart 23 summarizes data for the Southwestern United States. If the suitable land areas are translated into energy terms by considering reasonable efficiencies for solar thermal conversion (16 percent overall) and area utilization (50 percent) an estimated 8,500 to 63,300 billion KWH of electric energy could be generated, depending upon the level of stringency of the exclusion criteria.

When compared to the forecasted demand for electric energy, it appears that adequate siting areas can be found for solar power plants in the Southwest United States to meet the electrical power needs through the year 2000.

Southwestern United States Siting and Energy Summary

	TOTAL	SUITABLE SITING AREA	
		MOST-STRINGENT	LEAST-STRINGENT
LAND AREA (mi^2)	1,031,000	21,500	161,000
INCIDENT SOLAR ENERGY (10^9 KWH/yr)	5,068,200	105,700	791,400
ELECTRICAL ENERGY* (10^9 KWH/yr)	N/A	8,500	63,300

YEAR	ENERGY DEMAND (10^9 KWH/yr)	
	SOUTHWESTERN U. S.	SOUTHERN CALIFORNIA
1980	468	116
1990	1025	260
2000	2023	500

*Assumes 16% Overall Conversion Efficiency and 50% Land Utilization

SOUTHWESTERN UNITED STATES DEMAND ANALYSIS

SOUTHWESTERN UNITED STATES DEMAND ANALYSIS

The following section describes the Southwestern United States electric power demand analysis performed in support of the Solar Thermal Conversion Mission Analysis Study.

OBJECTIVES AND APPROACH

As shown in Chart 24, the objective of this analysis was to develop a methodology capable of forecasting future Southwestern United States hourly electric power demand for the years 1980 to 2000. Forecasts of demand data, which exhibit anticipated cyclic variations derived from historic trends, are necessary inputs to the Solar Thermal Conversion System Simulation Model.

The approach used in fulfilling these objectives includes the acquisition and analysis of available information, technical reports, and actual utility data from various sources throughout the country and particularly the Southwestern United States. The methodology selected was a time series decomposition/recomposition model which separated the historic hourly demand data into an exponential growth trend, weather characteristics, seasonal influences, and hourly cylical variation components. To determine the weather influence, a correlation between demand and weather or insolation components must be performed. The methodology developed recomposes the historic cyclic demand variations with a predicted trend and with weather influences subject to statistical variation so as to forecast hourly aggregate utility electric power demand for the years 1980 to 2000.

Electric Power Demand Analysis

OBJECTIVE

- ELECTRIC DEMAND FORECASTING MODEL DEVELOPMENT
  - SOUTHWESTERN UNITED STATES
  - 1980-2000 TIME PERIOD

APPROACH

- DATA ACQUISITION FROM UTILITIES
- TIME SERIES DECOMPOSITION OF HISTORICAL DEMAND DATA
  - TREND (exponential)
  - WEATHER
  - SEASONAL INDICES
  - HOURLY INDICES
  - IRREGULARITIES
- INVESTIGATE CORRELATION BETWEEN DEMAND AND WEATHER (insolation variables)
- RECOMPOSITION OF TIME SERIES (predicted trend plus weather statistics)
  - HOURLY DATA FOR 1980-2000 TIME PERIOD FOR SOUTHERN CALIFORNIA REGIONS
  - STATISTICAL VARIATIONS DUE TO WEATHER VARIABLES

A number of organizations were contacted for information relevant to the electric power demand analysis. These data acquisition activities are summarized in Chart 25.

The Southwestern United States utilities were contacted for details describing their power load conditions and to obtain copies of the Form 12 Load Summaries supplied to the Federal Power Commission, as well as any technical material they could supply regarding load models, forecast models, and weather correlation studies. The largest generating utilities were also asked to supply a ten-year hourly load data history.

In addition to these industrial contacts, various agencies concerned with electric power regulation or with gathering data pertinent to power consumption and demand forecasting were requested to supply applicable information. Notably, these were the Federal Power Commission, the State Public Utilities Commissions, the Western Systems Coordinating Councils, the National Oceanographic and Atmospheric Administration, the Bureau of Census, and the State Corporation Boards. Other state, federal, and independent groups were contacted for background material and technical publications.

As a result of this industry and agency interface effort, many reports, comments, and constructive suggestions were received. These inputs were helpful in providing necessary insight into the demand forecasting problem and in formulating the analysis approach. Large amounts of data were also received, the primary contributions being FPC Form-12 Load Summaries, and 11 years (1962-1973) of detailed hourly demand records from eight major utility companies, as well as 10- and 20-year peak demand forecasts.

Major Electric Utilities and Agencies
Southwestern United States

UTILITIES	TYPE
SOUTHERN CALIFORNIA EDISON (SCE)	PRIVATE
LOS ANGLES DEPARTMENT OF WATER & POWER (LADWP)	PUBLIC
SAN DIEGO GAS & ELECTRIC (SDG&E)	PRIVATE
PACIFIC GAS & ELECTRIC (PG&E)	PRIVATE
SACRAMENTO MUNICIPAL UTILITY DISTRICT (SMUD)	PUBLIC
NEVADA POWER COMPANY (NPC)	PRIVATE
ARIZONA PUBLIC SERVICE (APS)	PRIVATE
TUCSON GAS & ELECTRIC CO (TG&E)	PRIVATE
UTAH POWER & LIGHT (UPL)	PRIVATE
PUBLIC SERVICE CO OF COLORADO (PSCC)	PRIVATE
PUBLIC SERVICE CO OF NEW MEXICO (PSCNM)	PRIVATE
TEXAS ELECTRIC SERVICE CO (TESC)	PRIVATE
EL PASO ELECTRIC CO (EPE)	PRIVATE
SAN ANTONIO PUBLIC SERVICE BOARD (SAPSB)	PUBLIC
OKLAHOMA GAS & ELECTRIC CO (OG&E)	PRIVATE
DALLAS POWER & LIGHT CO (DP&L)	PRIVATE

AGENCIES

FEDERAL POWER COMMISSION (FPC)
WESTERN SYSTEMS COORDINATING COUNCIL (WSCC)
PUBLIC UTILITIES COMMISSION (PUC)
STATE CORPORATION BOARD (SCB)
STATE GOVERNORS ENERGY OFFICE
UNIVERSITY COMPUTING SERVICES (USC)

DEMAND ANALYSIS ACTIVITIES

The Demand Analysis activities are summarized in Chart 26. Both historic demand and forecast data were collected by contacting the various electric utility agencies and companies. These data were subsequently compiled in standard Edison Electric Institute format to provide the demand data base for further analysis. Detailed long-term hourly data were obtained from eight utilities in the Southwestern United States. FPC Form 12 load data, consisting of 10-year hourly demand data for the first week of April, August, and December, were also obtained for all major utilities in this area. In addition, peak load and planned generation forecast data were obtained from these organizations.

Various computer methodologies were developed to utilize these data for hourly demand forecasting for the 1980 to 2000 time period and to obtain annual load duration and total energy curves. Descriptions of these analyses are included in this report, with details described in the supporting "Demand Analysis" volume.

Analysis Activities

LOAD DATA FLOW & PROCESSING PROGRAMS

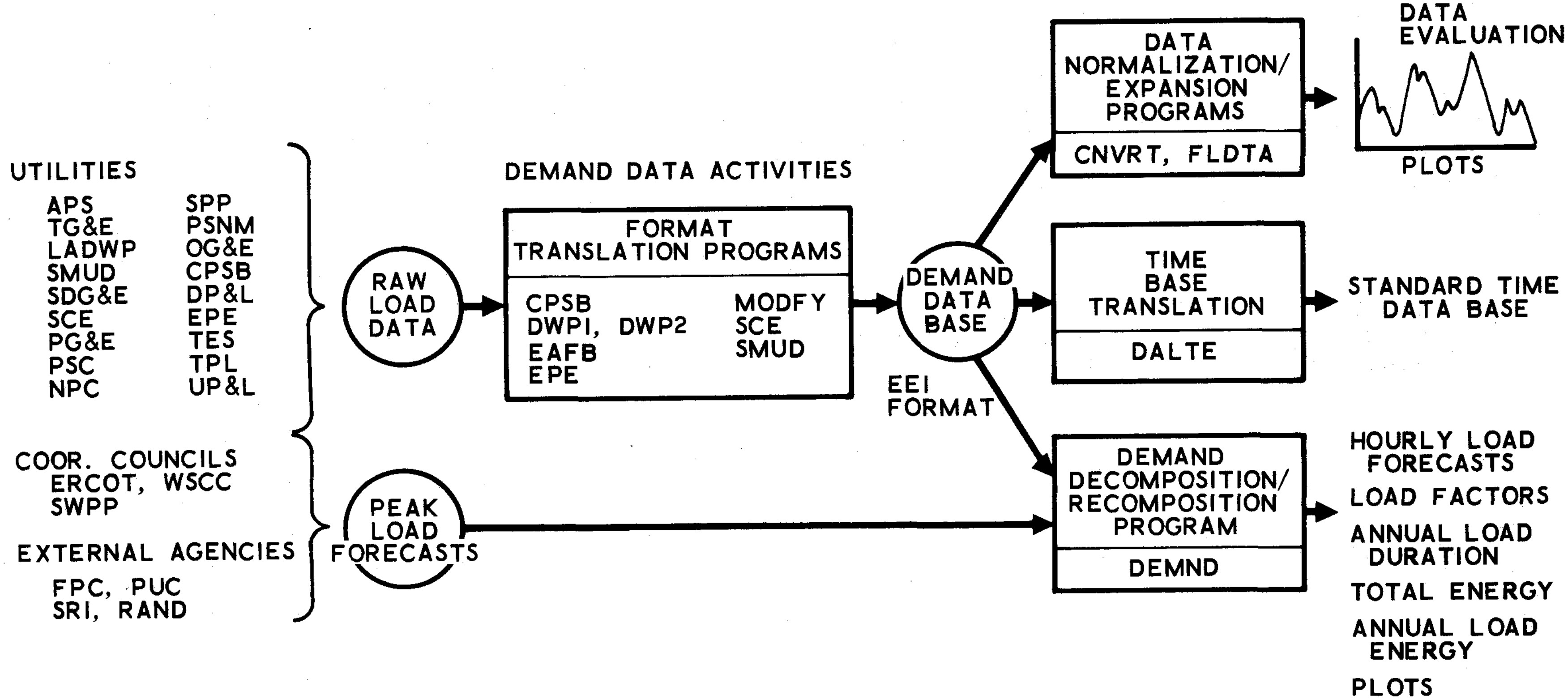


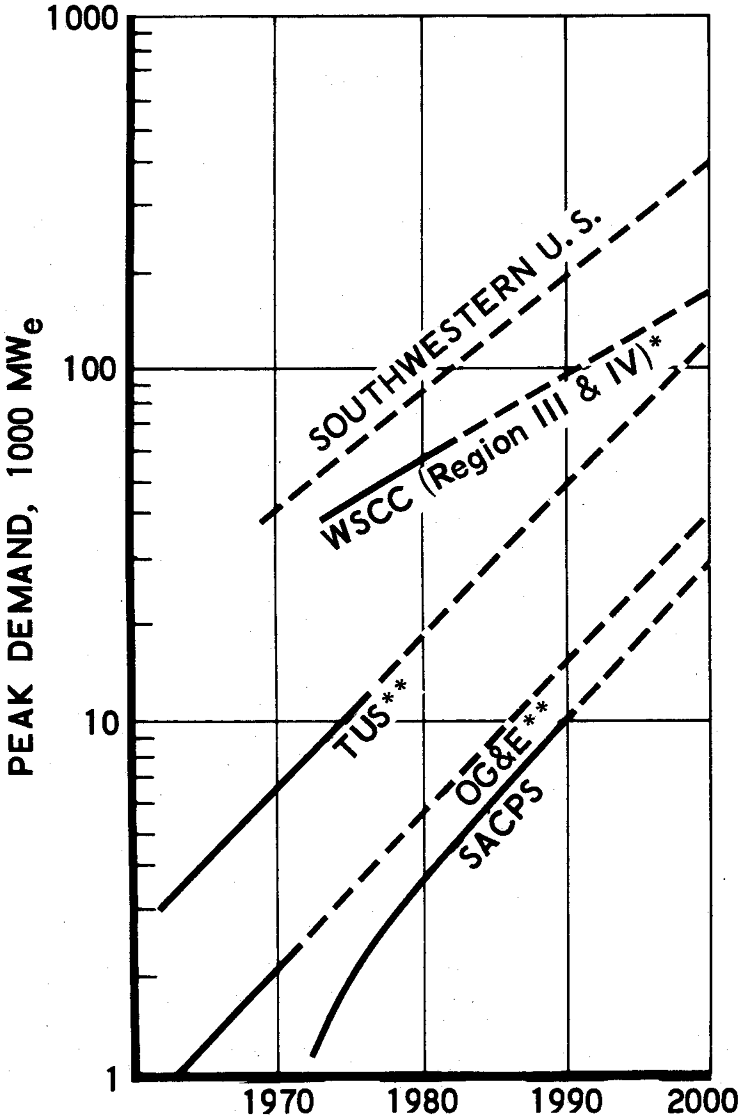
CHART 26

PEAK ELECTRIC DEMAND TRENDS

The peak electric power demand trends shown in Chart 27 were derived from forecasts made by the Western States Coordinating Councils (WSCC) and various regional utility reports. Depicted for the Southwestern United States area are forecasted peak electric demand trends as well as the individual peak demands associated with WSCC forecasts and Texas and Oklahoma utility reports. The Southwestern United States trend represents the aggregation of all electric utility peak demand trends, including those small utilities within the area not individually shown.

These projections represent the most authoritative current view of future Southwestern United States electric power demand based upon an analysis that considered historic demand trends, area population, and economic growth factors. The average compound growth rate for total Southwestern United States peak demand shown is 7.4 percent for years 1970 to 2000. Although difficult to see at this scale, the growth actually declines slightly between 1990 and 2000.

Southwestern United States
Peak Electric Demand Trends



YEAR	PEAK DEMAND, MW_e
1970	35,000
1980	79,000
1990	170,000
2000	334,000

(7.4% growth rate)

*WSCC 10 year forecasts (Sept 1973)

**Texas and Oklahoma Utility Reports (1972-1973)

CHART 27

The demand forecasting model presented in Chart 28 incorporates a time series decomposition/recomposition formulation. It is assumed that each term in the demand time series is the product of factors due to a long-term trend, weather conditions, seasonal influences, and hourly cyclic variations. The rationale for postulating this form for the demand model is that the cyclic phenomena contained in the demand measurements are separable and fairly consistent with time. It is further postulated that these cyclic components can be applied to a future prediction and modulated by statistical weather variations to form a realistic representation of the hourly demand for the 1980 to 2000 time period to be used for solar thermal conversion system simulation and margin analyses. Future cyclic variations need not be identical to the historical cyclic variations, but can be input separately if such information is available. The product form was selected for its convenience and traditional application in economics forecasting.

Demand Forecasting Model

DEMAND TIME SERIES FORMULATION

- DEMAND = (TREND) x (WEATHER FACTORS) x (SEASONAL FACTORS) x (HOURLY FACTORS) x (IRREGULARITIES)

RATIONALE FOR MODEL

- CYCLICAL PHENOMENA SEPARABLE FOR FUTURE PREDICTION
- STATISTICAL WEATHER/DESCRIPTION

DEMAND FORECASTING MODEL FLOW CHART

A flow chart of the demand forecasting model is shown in Chart 29. The time series decomposition phase is shown on the left portion of the chart, while the recomposition and forecast phase is shown at the right.

After some detailed selection and adjustment of utility supplied electric-power demand data to make it amenable for analysis, the data are subjected to a series of filters that extract the historic trend (TR), weather (W), and cyclic (C) factors, leaving a residual (I) which should tend toward a constant unity value if the model has successfully replicated each demand component. After each factor is determined, its contribution is removed. The historic trend is removed after treating the basic data with a least-squares filter, which assumes an exponential form. The weather contribution is extracted by a weather filter, and the seasonal and hourly cyclic phenomena are extracted by moving average and normalization filters.

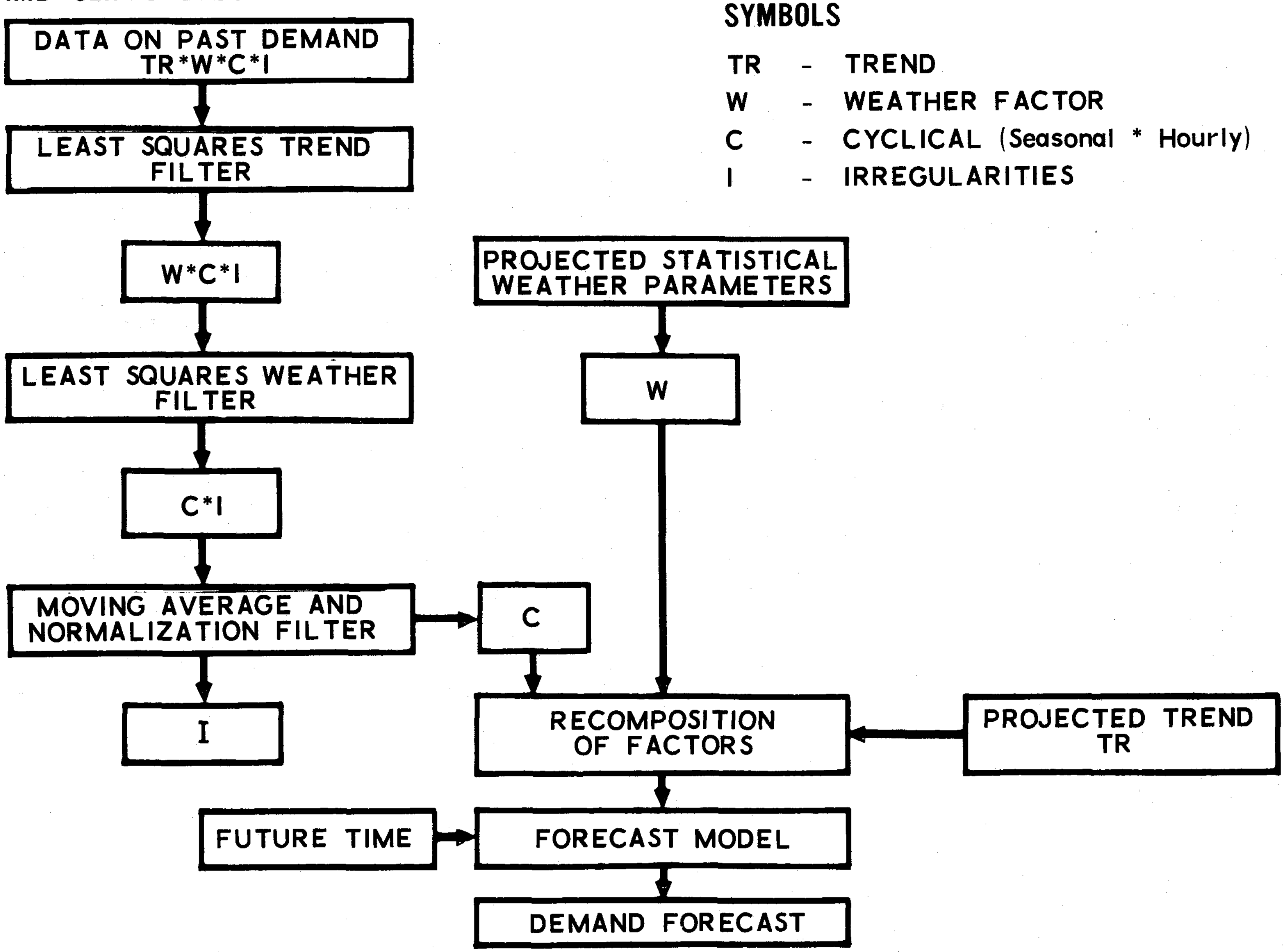
The purpose of the recomposition phase is to make an hourly demand forecast projection at a given future time. Given a projected demand trend, cyclical indices representing hourly and seasonal variation, and a statistical description of the expected weather, the model will combine these factors to generate a time series defining the hourly electric power demand for the future time period of interest. This time series is a necessary input to the detailed mission and system simulation studies.

A feature inherent in the recomposition model described above is its versatility. The form of each demand component can be altered if there is a basis for selecting something other than those developed from historic data. The analysis uses an externally determined projected demand trend. Different growth rates, hourly profiles, seasonal influences, and weather behavior can be used if this should be desirable.

The methodology is generally applicable. Any historic demand profile can be decomposed by the model, since the methodology is not unique to Southwestern United States applications.

Demand Forecasting Model

TIME SERIES DECOMPOSITION AND RECOMPOSITION



SYMBOLS

TR - TREND
W - WEATHER FACTOR
C - CYCLICAL (Seasonal * Hourly)
I - IRREGULARITIES

CHART 29

To illustrate the methodology, the Southern California Edison Company hourly demand data between 1965 and 1972 (8 years) were subjected to analysis. The 1965 start date was chosen because immediately prior to that time Southern California Edison acquired several small utilities which introduced a discontinuity in the demand data. Piecewise analysis could have been used to circumvent this problem, but its application would not appreciably add substance to the analysis.

Results of demand data decomposition are shown in Chart 30. It could be noted that only data segments associated with the first full weeks of April, August, and December in a 4-year time period (1969-1972) are plotted to simplify the presentation. The entire 8-year (1965-1972) hourly data base was used for analysis.

The initial Southern California Edison demand data are shown in the top trace of Chart 30. In examining the April profiles, the same demand shape is apparent throughout the 4-year time period, consisting of a fairly constant mid-afternoon level and a high evening peak. The August envelopes are also similar in shape, with a typical high mid-afternoon peak and a secondary lower evening peak. The December profiles all have the same characteristic high evening peak. The only noticeable difference between the segments of particular months from year to year is due to the demand growth trend.

Data in the second trace were corrected by removing the influence of an 8-year historical exponential trend. Dividing the data by the historical trend centers the resultant data about unity and reduces the magnitude proportional to the exponential's multiplicative value. Examining the data corrected for trend shows that the base of the daily profiles is fairly constant; however, the peaks differ for different months.

A 24-hour moving average filter, with secondary normalization, produces the seasonal index traces shown in the third figure in Chart 30. Each segment in that plot shows a fairly constant weekday level with a characteristic weekend tailoff.

An analysis was performed of the mean values of the 8-year weekly seasonal index segments, which showed that these means were scattered and exhibited no consistent trend as a function of time for the Southern California Edison data. As a consequence, the weekly seasonal indices were determined by averaging the weekly seasonal index means over the 8-year time period.

Following determination of the seasonal index means, the data corrected for trend were adjusted for seasonal effect, leaving only the data containing hourly and residual factors. Eight years of data in this form were then averaged on a corresponding hourly basis to produce hourly index profiles. The hourly indices were removed by division, leaving the residuals trace shown in the figure on the bottom of Chart 30. As can be seen these residuals are very small (± 5 percent) compared to the peak fluctuations of the original data. This substantiates the decomposition analysis technique. Long-term weather factors were removed by the seasonal index means, while short-term daily and hourly temperature variations are still present in the residuals. With the incorporation of an appropriate weather model, the residuals are expected to be even smaller, leaving only variations due to business cycles and certain unexplained events.

Electric Power Demand Decomposition

SCE — 1969-72

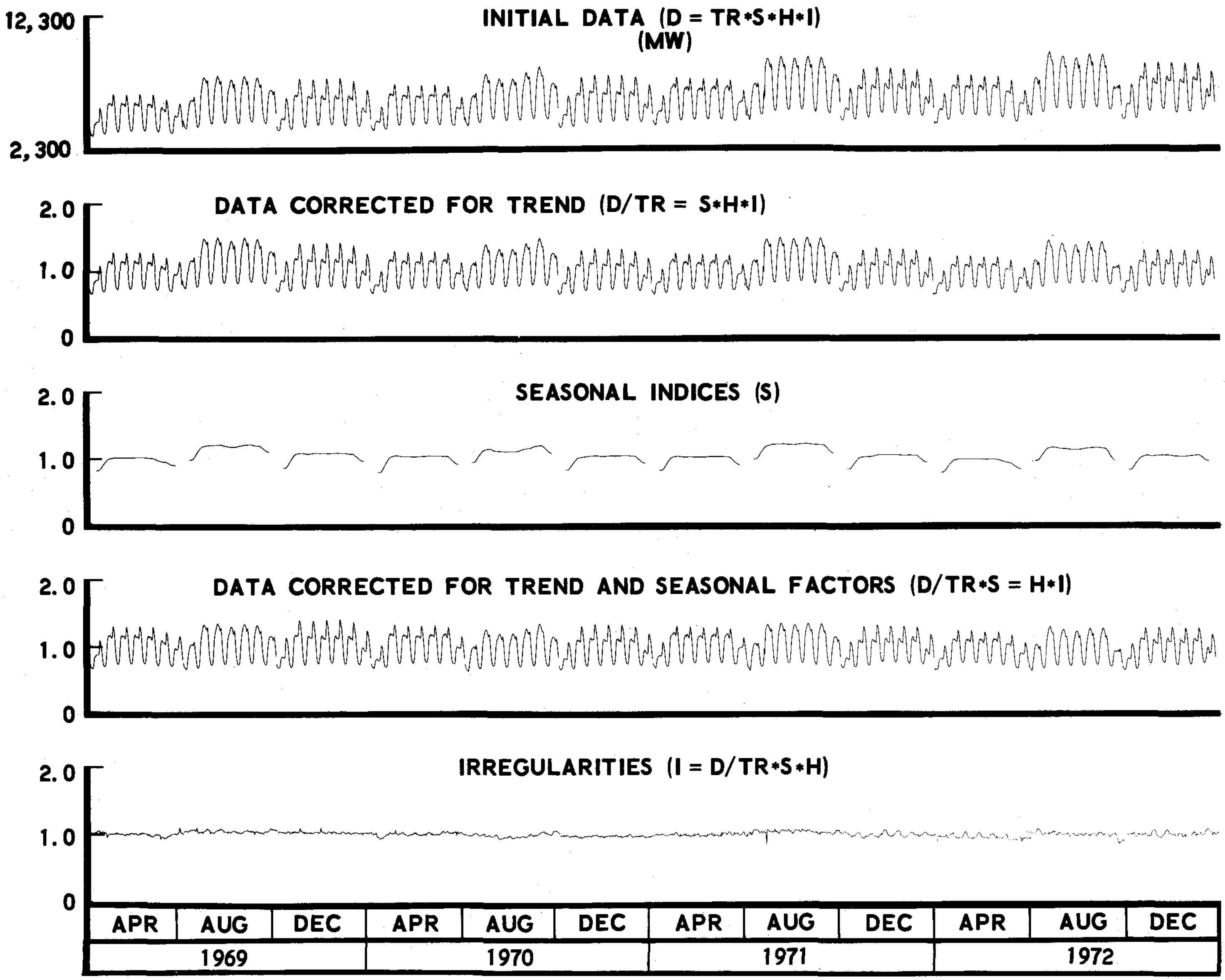


CHART 30

The Southern California Edison electric power forecast shown in Chart 31 was made using the 32,000 MWe peak demand projected by the California Public Utilities Commission/California State Resources Agency study, with seasonal indices and hourly variations extracted from the 1965 to 1972 Southern California Edison historical demand data. The peak demand for 1990 of 32,000 MWe compares with a 1973 peak demand of approximately 10,000 MWe. Again, segments corresponding to the first full weeks in April, August, and December are shown for illustrative purposes only. As can be seen, the recomposition methodology preserves the peak shapes and seasonal variation on a proportional basis.

Electric Power Demand Forecast

SCE ~ 1990

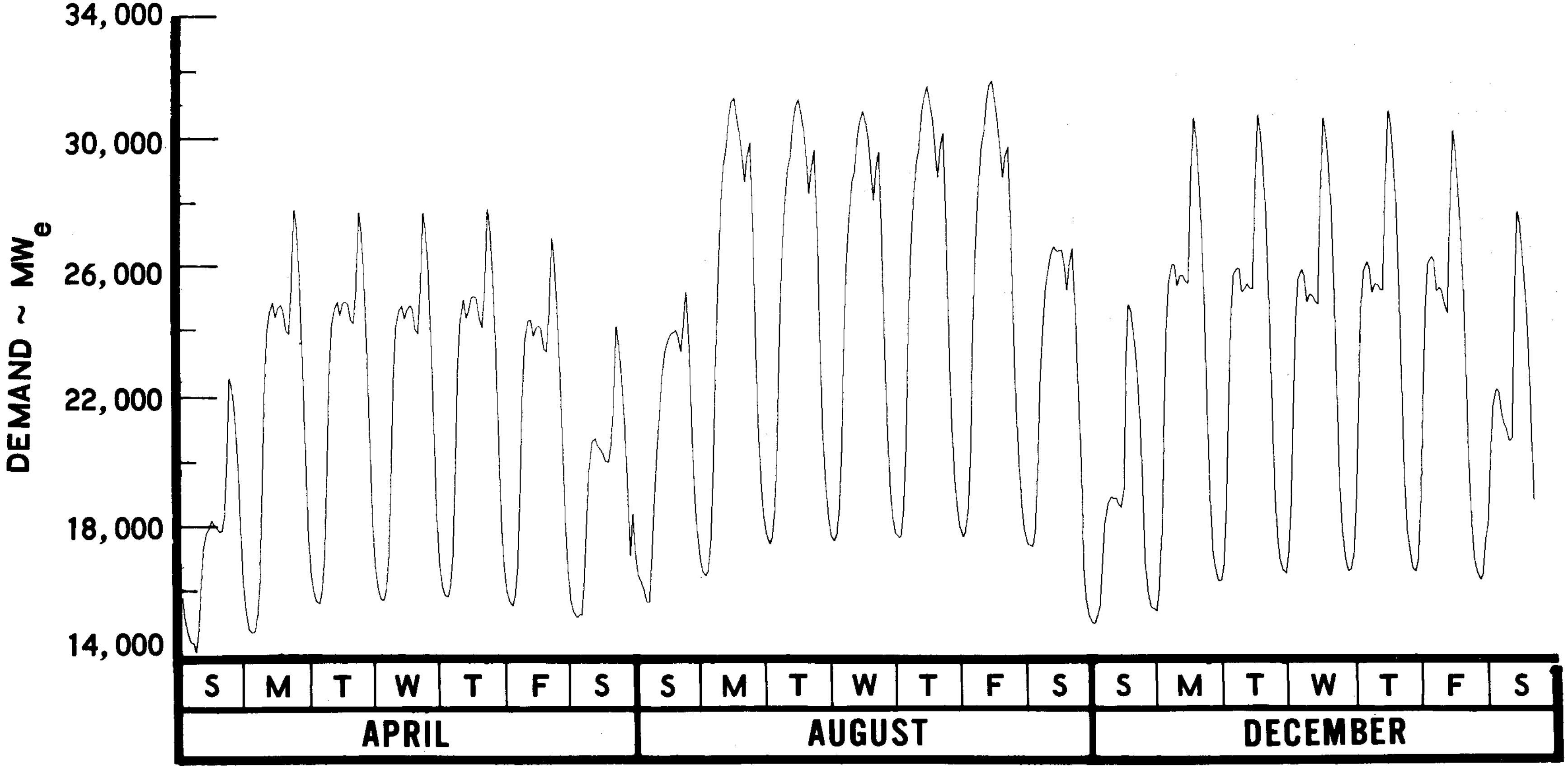


CHART 31

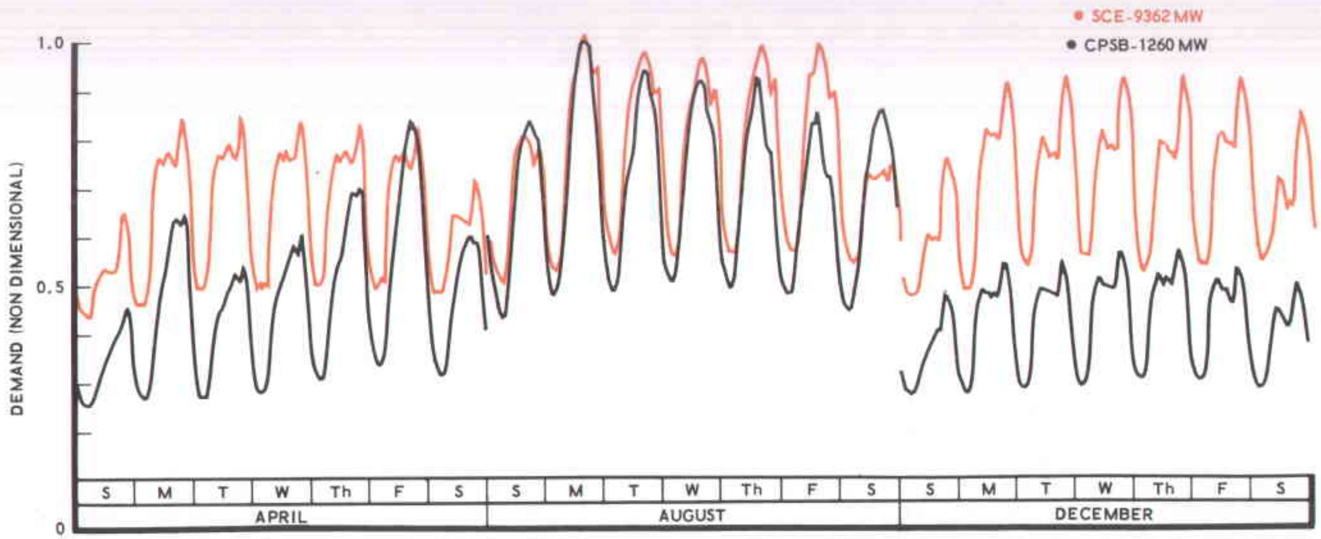
With the accumulated Southwestern United States utility demand data, it is possible to examine individual utility load profiles or to compare profiles of various utilities. These demand data were normalized to facilitate comparison of the various profiles during April, August, and December for four Southwestern United States utilities: City Public Service Board of San Antonio (CPSB), Dallas Power & Light (DP&L), El Paso Electric (EPE), and Southern California Edison (SCE), as shown in Chart 32. As can be seen from these data, even though there are similarities in the load profiles, significant variations in seasonal profiles exist.

The summer peaking, both in magnitude and time of day of occurrence, is much more pronounced for DP&L and CPSB than for SCE and EPE.

The absolute magnitude of the annual peak demand during 1972 for each of the utilities is also shown in this figure.

Comparison of Southwestern United States

UTILITY DEMAND PROFILES FOR 1972



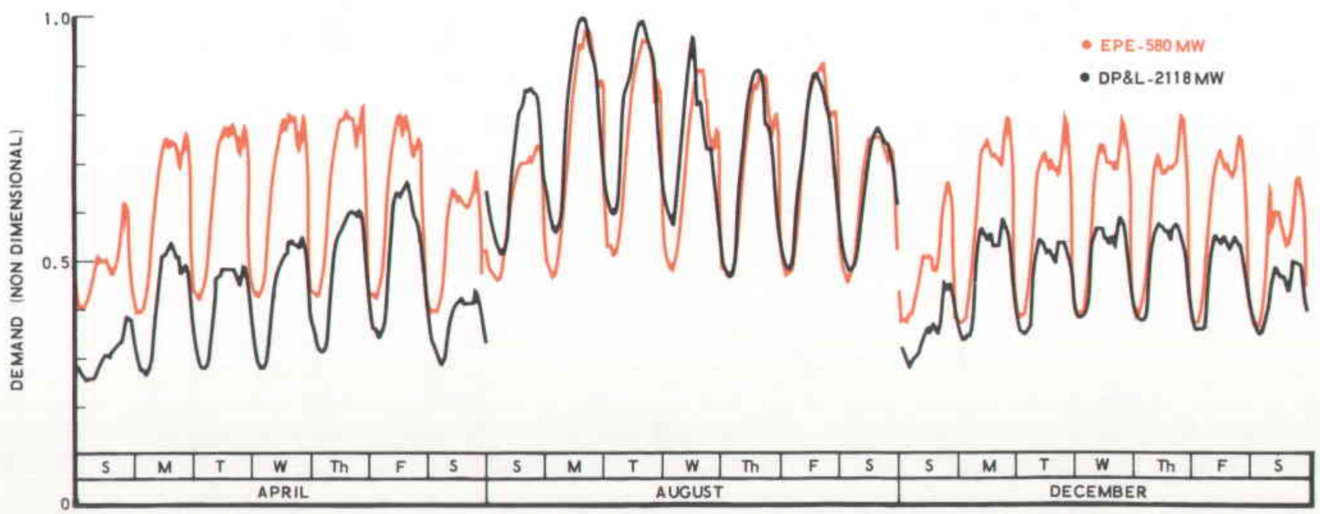


CHART 32

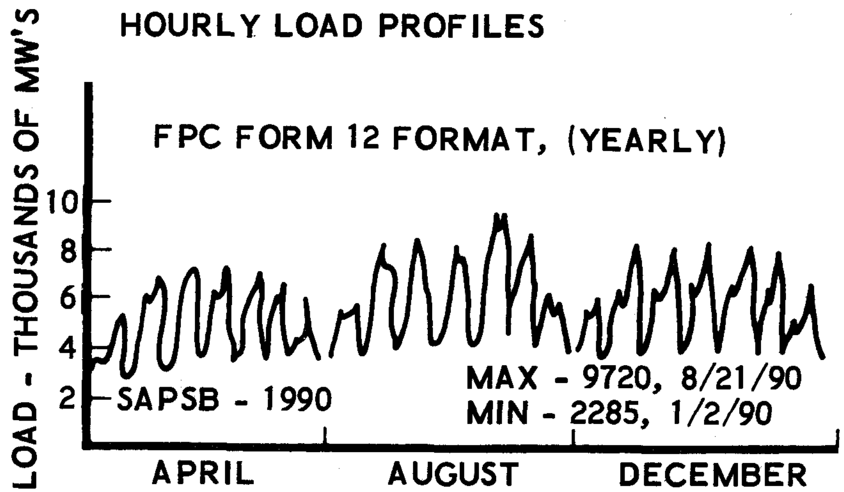
In summary, the Demand Analysis was performed in several phases. These are outlined in Chart 33. First, to establish a data base and to gain an insight into the problem, demand data, forecasts, and background information were gathered from various utilities and state agencies. Having obtained this information, a demand decomposition/recomposition model was formulated by describing the aggregate demand in terms of a growth trend, weather factors, and seasonal and hourly cyclic indices.

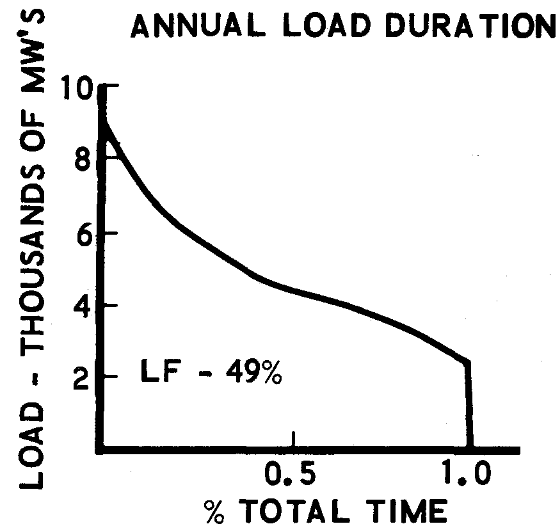
The raw demand data, consisting of punched cards representing long-term hourly load histories of eight utility companies or FPC Form 12 Format Load Summaries, were processed for computer analysis. With this demand data base, the demand decomposition/recomposition forecast model was used to project hourly load profiles for the time period 1980-2000, which combined the peak projection with historically determined seasonal and hourly cyclic patterns. This demand projection was subsequently used as an input to the system simulation.

In addition, these data were analyzed to determine the annual load duration and total energy profiles for the individual utilities within the Southwestern United States.

In preparation for an analysis of demand-weather/insolation correlations, utility studies were reviewed and data handling routines were developed. Future work will include further analysis of demand-weather factors.

Summary Accomplishments





HOURLY DEMAND FORECASTS, 1980 - 2000

DEPARTMENT OF WATER & POWER

SO. CALIFORNIA EDISON CO.

EL PASO ELECTRIC CO.

SAN ANTONIO PUBLIC SERVICE BOARD

PUBLIC SERVICE OF NEW MEXICO

PACIFIC GAS & ELECTRIC*

SACRAMENTO MUNICIPAL UTILITY DISTRICT

ARIZONA PUBLIC SERVICE*

* IN PROCESS

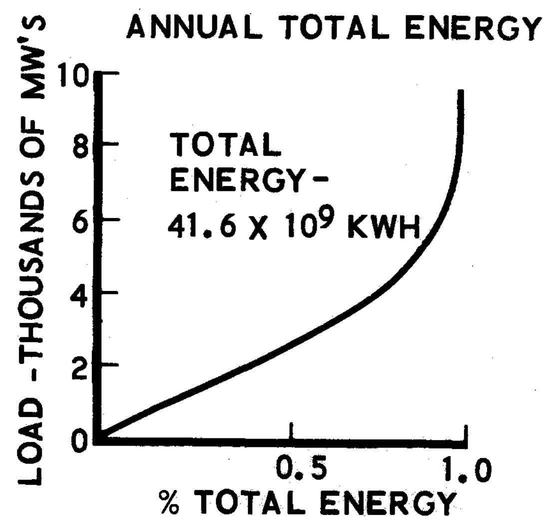


CHART 33

SOUTHWESTERN UNITED STATES INSOLATION ANALYSIS

SOUTHWESTERN UNITED STATES INSOLATION ANALYSIS

The following section describes the insolation climatology analysis for the Southwestern United States in support of the Solar Thermal Conversion Mission Analysis Study.

This section summarizes the insolation climatology studies performed as part of the Solar Thermal Conversion Mission Analysis. The objectives of the studies are summarized in Chart 34. The primary objective was to develop a data base of insolation information for the Southwestern United States. The primary requirement for this information is input data for mission/system analyses.

The time interval used for the insolation data must be small enough to permit variations in insolation during the day to be simulated and to perform correlation analyses. An hourly interval has been adopted for the present study since weather data and insolation data are routinely gathered and archived at hourly intervals.

Separate total and normal incidence insolation data are included in order to make the data base applicable to various collector concepts. Total insolation is that radiance coming from the entire celestial hemisphere, while normal incidence insolation is that portion of the insolation that can be focused. These two quantities have been specified in the data base in terms of the readings on two instruments commonly used to measure them. Total insolation is measured with a pyranometer, an instrument that measures all the energy incident on a horizontal flat plate from the entire celestial hemisphere. Normal incidence insolation is measured with a pyrheliometer, an instrument that tracks the sun and has a field of view of about six degrees, thereby including some sky radiance in addition to the radiation directly from the sun.

Because insolation has seasonal characteristics, a minimum of one year of data is required. Two years (1962 and 1963) were selected because these were relatively typical years in terms of weather and because they fell within the general period when insolation data were collected at the largest number of stations in the Southwestern United States.

The Southwestern United States climatology and geography prevents characterization of the entire region by a single location. Therefore, the data base includes data from 20 sites that represent the major climatic regions of the Southwestern United States.

The importance of weather information for demand analysis was discussed earlier in this report. Consequently, as much additional weather information as could be easily obtained has been included in the data base.

The data were received in various formats and have been put into a uniform computer-compatible format to facilitate their use in the mission analysis as well as by systems contractors. Gaps in the data were filled in with estimated values by use of the correlations established as part of the methodology. The methodology employed to formulate this data base is summarized in a previous report (Reference 3).

As a secondary objective, several issues were to be addressed in this analysis. From inspection of the long-term data, a decrease in total insolation over the years examined was noticed. An attempt to explain this decrease was made by investigation of the simultaneous long-term sunshine and cloud data.

In order to assess solar power plants under pessimistic climatic conditions, a worst-case hourly total and normal incidence insolation data base for both Inyokern, California, and Albuquerque, New Mexico, was prepared.

For those analyses that do not warrant full-time simulation, typical insolation days were identified, as were summaries of the annual total and direct insolation for comparing the various weather stations.

Since the condition of high winds may require solar collectors to be turned away from these winds, the resulting loss of insolation is of interest; and, consequently, a wind-insolation frequency analysis was made. Other weather information for these weather stations, important for input to the siting of solar power plants, was also compiled.

Insolation Analysis

PREPARE TWO YEAR HOURLY INSOLATION DATA BASE

- SOUTHWESTERN UNITED STATES

EXAMINE INSOLATION MISSION ANALYSIS QUESTIONS

- LONG TERM SUNSHINE - INSOLATION CORRELATION
- PREPARE WORST CASE INSOLATION DATA BASE
- TYPICAL INSOLATION DATA
- WIND-INSOLATION FREQUENCY ANALYSIS
- VALIDATE DATA BASE WITH STRIP CHART DATA
- PROVIDE WEATHER RELATED SITING INFORMATION

The Southwestern United States can be characterized by various climatic regions in terms of temperature, humidity, and precipitation, as well as physiographic provinces, based on surface land forms. Chart 35 shows these various climatic provinces based upon data compiled for agricultural uses. These climatic provinces are useful in defining the various weather regions which characterize the Southwestern United States. Also superimposed are annual mean daily total isolation contour lines in terms of watt-hr/m^2/day or, in parentheses, watts/m^2.

The selection of the various insolation data sources was made to characterize each of these various climatic zones and physiographic provinces. Consequently, every Southwestern weather station for which hourly total insolation data were available for the 1962–63 time period was included. In addition, in order to extend the coverage to climatic zones and physiographic provinces for which no insolation measurement data were available, weather (cloud cover) data were used to estimate hourly insolation values at five additional stations.

Southwestern United States Climatic Regions

SOLAR ENERGY AVAILABILITY (ANNUAL MEAN DAILY)

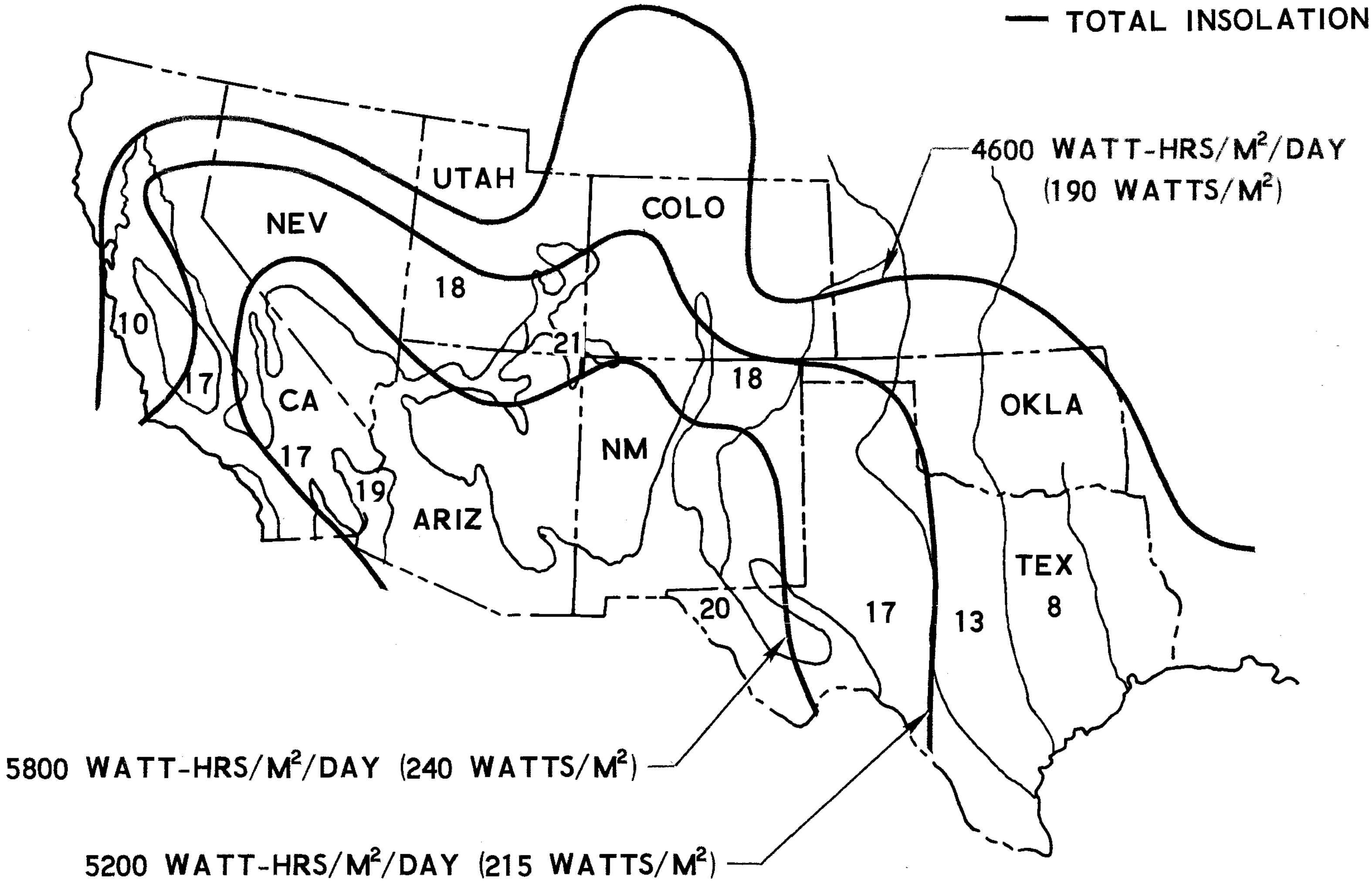


CHART 35

The weather stations selected to characterize the various climatic and physiographic provinces are shown in Chart 36. As finally constituted, the present data base includes data for 19 separate stations in the Southwestern United States and Omaha, Nebraska. As can be seen, hourly direct insolation measurement data are available for only three of these stations: Omaha, Nebraska; Albuquerque, New Mexico; and Tucson, Arizona. The hourly direct insolation data for the other stations were estimated from the total insolation.

For five of the stations, hourly total (or direct) insolation measurement data were not available, and hourly values of total and subsequently direct insolation were estimated from available data on cloud cover.

Southwestern United States Climatic Zones

INSOLATION AND WEATHER DATA STATIONS

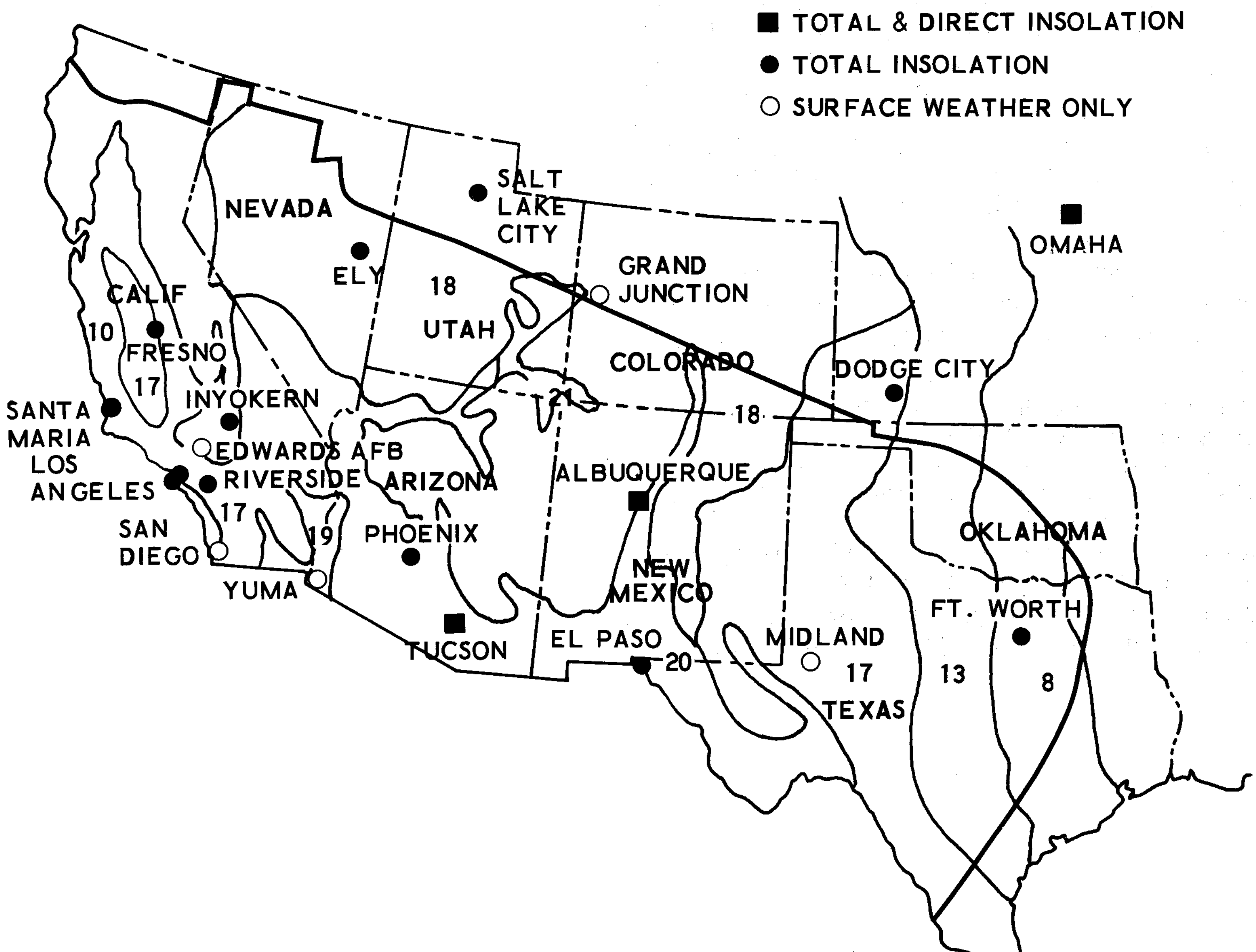


CHART 36

Characteristics of the insolation data base are summarized in Chart 37. The data base characterizes the Southwestern United States by 20 stations representative of the various climatic regions. The data for Omaha, Nebraska, were included into the data base. Omaha, Nebraska; Albuquerque, New Mexico; and Tucson, Arizona, are the only stations within the Southwest for which normal-incidence or direct insolation measurements are available. For the other stations, the direct insolation was estimated from the total insolation.

The data base is stored on computer-compatible magnetic tape, and contains hourly insolation data for a two-year time period.

The contents of the data base can be summarized in three categories:

- Identifying information, which includes such information as date, time, and solar position.
- Insolation data, including the extraterrestrial, normal incidence and total insolation, as well as the ratio of total to extraterrestrial insolation.
- Weather data including temperature, humidity, sky cover, and information on cloud cover and winds.

In contrast to the insolation data, the weather information is incomplete; no effort has been made to fill in the missing data.

Insolation Climatology Data Base

- REPRESENTATIVE CLIMATIC REGIONS IN SOUTHWESTERN UNITED STATES
- TIME PERIOD 1962 - 1963 (2 year data base)
- HOURLY DATA ON MAGNETIC TAPE
  (optionally available on 7-track BCD or 9-track EBCDIC tapes)
- TAPE 1
  - ALBUQUERQUE, N.M.
  - INYOKERN, CA
  - YUMA, AZ
  - EDWARDS A.F.B., CA
  - RIVERSIDE, CA
- TAPE 2
  - LOS ANGELES CIVIC CENTER, CA
  - LOS ANGELES AIRPORT, CA
  - SAN DIEGO, CA
  - SANTA MARIA, CA
  - FRESNO, CA
- TAPE 3
  - TUCSON, AZ
  - SALT LAKE CITY, UT
  - PHOENIX, AZ
  - ELY, NV
  - GRAND JUNCTION, CO
- TAPE 4
  - OMAHA, NE
  - FORT WORTH, TX
  - DODGE CITY, KS
  - MIDLAND, TX
  - EL PASO, TX
- CONTENTS:
  - IDENTIFYING INFORMATION
    - DATE, TIME, SOLAR POSITION
  - INSOLATION
    - EXTRATERRESTRIAL, NORMAL INCIDENCE, TOTAL
      PERCENT OF POSSIBLE TOTAL INSOLATION
  - WEATHER DATA
    - TEMPERATURE, HUMIDITY, SKY COVER, CLOUDS
    - WINDS

While the principal use of the insolation data was to prepare a standard hourly data base for mission and systems analyses, the next several charts summarize some of the additional studies performed as part of the insolation analysis effort.

The total insolation at the 20 stations included in the hourly data base is compared in Chart 38. Annual averages of daily total insolation as well as monthly averages for the extreme months of June and December are presented. As can be seen, the average daily total insolation at Inyokern, Edwards AFB, Yuma, Phoenix, Tucson, Albuquerque, and El Paso have the highest insolation values throughout the year. Fresno, California, has high annual and summer insolation; however, the winter values are considerably lower at this station, due to increased cloud cover characteristics of the Imperial Valley during the winter months.

Average Daily Total Insolation (1963)

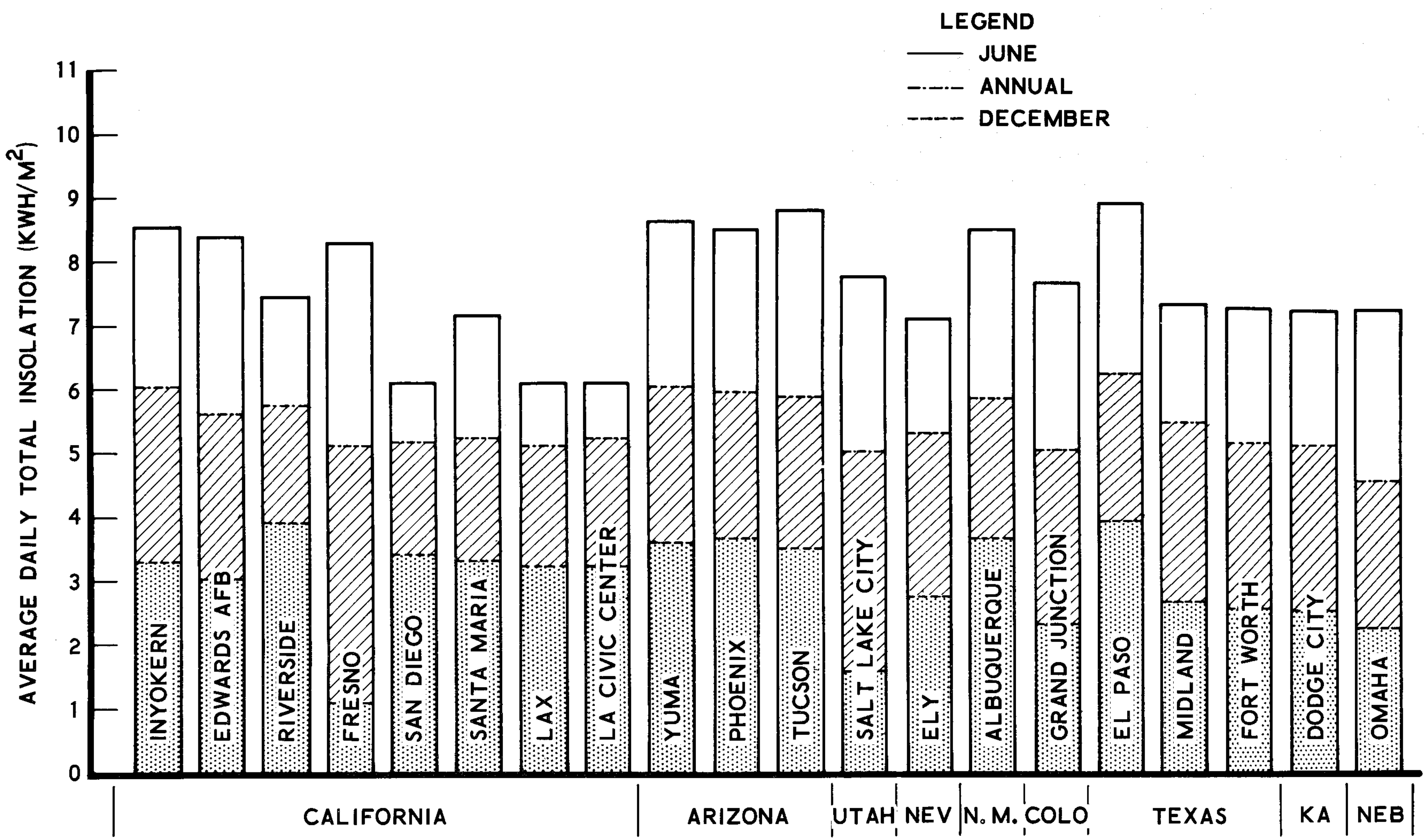


CHART 38

COMPARISON OF DIRECT INSOLATION AT DIFFERENT STATIONS

A similar comparison was made of the average daily direct insolation for the 20 stations used to characterize the Southwestern United States. The direct or focusable insolation data are required for input to solar systems using concentrating type collectors. These comparisons are summarized in Chart 39. As can be seen from these data, similar conclusions regarding the comparative direct insolation data at the various weather stations can be noted as for the total insolation comparison. As can be expected, stations with higher total insolation typically also experience relatively higher direct insolation values.

Average Daily Direct Insolation (1963)

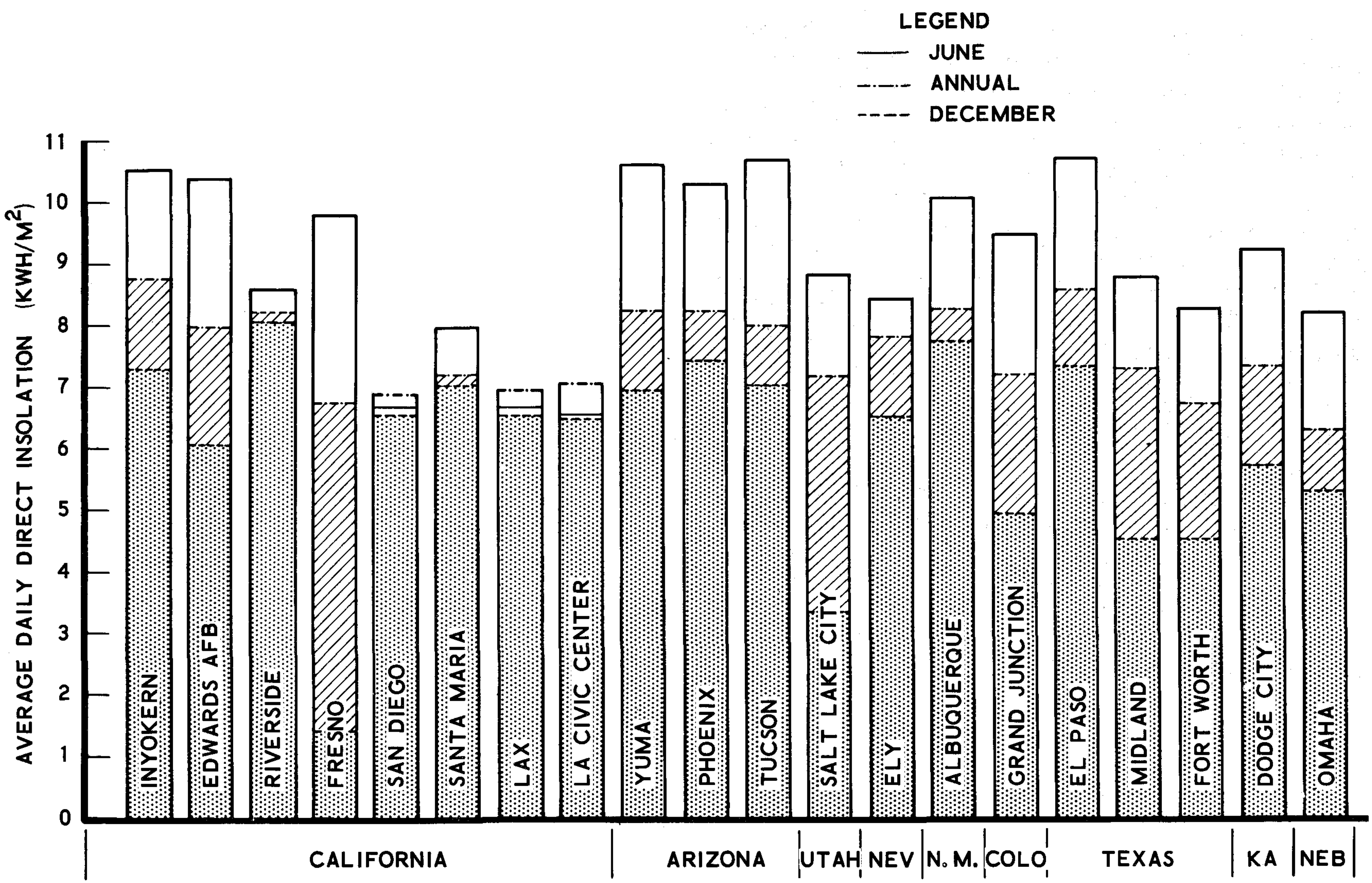


CHART 39

The choice of 1962 and 1963 as representative years for the Southwestern United States insolation data base is supported by data such as shown in Chart 40. This figure displays the long-term data for Albuquerque, New Mexico. Similar graphs were prepared for all stations for which long-term data were available. Plotted by years is the average percent of possible total insolation. The annual average was computed by dividing the total insolation during the year by the total possible during the year. There are variations from year to year, but the years 1962 and 1963 do not appear unusual. A similar conclusion can be drawn for the other stations for which long-term data exist.

As can be seen from this figure, the insolation values over the time period considered display a slightly downward trend. In order to determine the possible causes for this decrease, if real, long-term data for percent of possible sunshine and cloudiness were also obtained for these stations.

As was expected, the percent of possible sunshine decreases concurrently over this time period. Both trends may be accounted for by the increase in cloudiness which occurs; however, as yet no good explanation has been found for the underlying reasons for this increase. It would be of interest to know whether the increase in cloud cover experienced is of a long-term cyclical or permanent nature.

Long-Term Trend Data

ALBUQUERQUE, N.M.

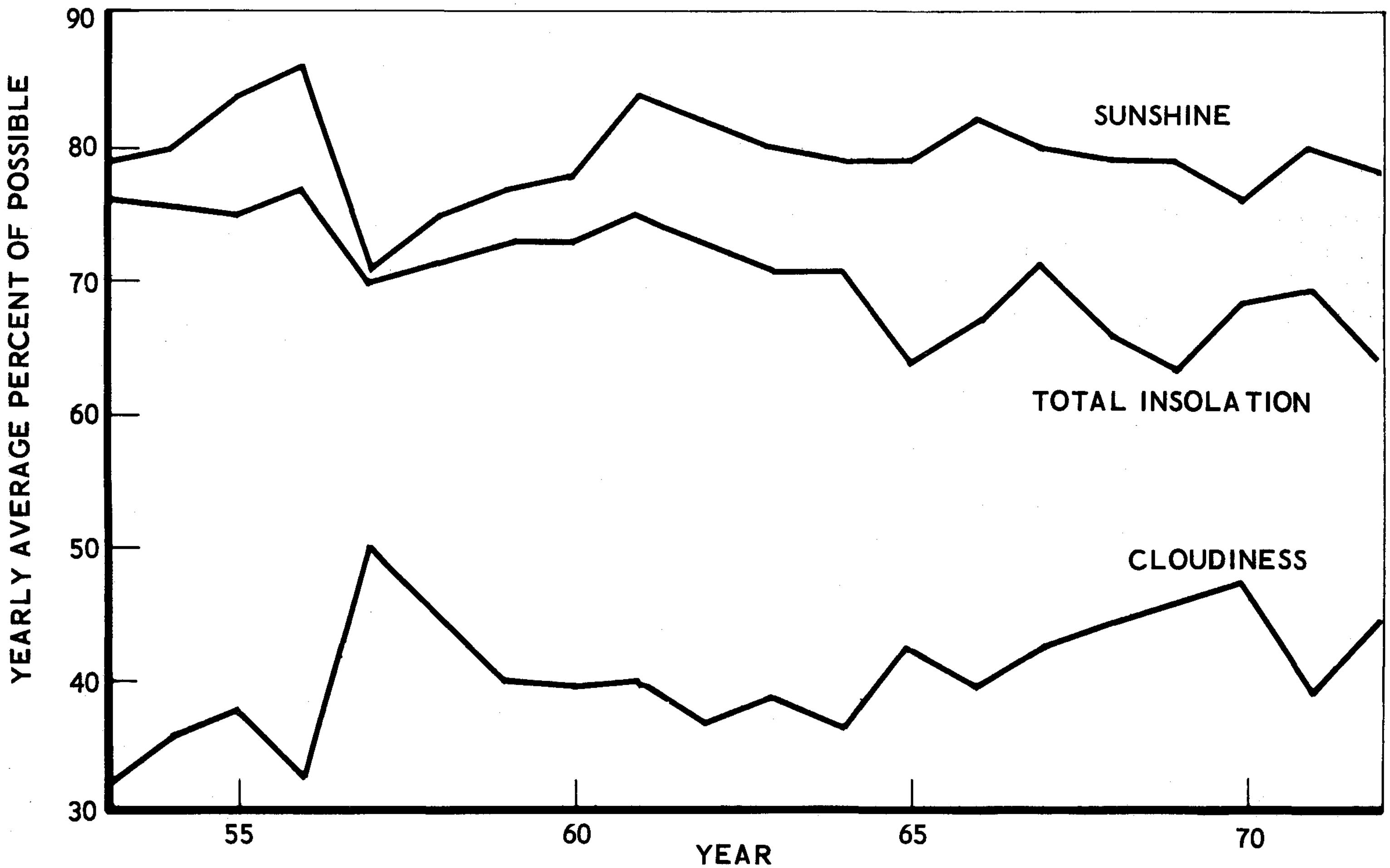


CHART 40

Because of uncertainties in the insolation data measurements and estimations shown in Chart 41, the data bases for Inyokern, California, and Albuquerque, New Mexico, were revised to represent the lowest insolation performance that can reasonably be expected at these stations. These downgraded data bases were developed to perform a worst case analysis of solar power plant performance.

The uncertainty sources in the data bases considered are: long-term climatic trends, yearly climatic variability, instrumental calibration and drift, and estimation uncertainty. The effect of each of those uncertainties on the insolation data base were estimated individually and subsequently combined to obtain the worst case analysis data base.

Worst Case Insolation Analysis

WORST CASE HOURLY INSOLATION DATA BASE FOR

- INYOKERN, CALIFORNIA
- ALBUQUERQUE, NEW MEXICO

UNCERTAINTY SOURCES IN DATA BASE

- LONG TERM CLIMATIC TRENDS
- YEARLY CLIMATIC VARIABILITY
- INSTRUMENTAL CALIBRATION AND DRIFT
- ESTIMATION UNCERTAINTY

As shown in Chart 42, a long-term decreasing trend exists in the insolation data. Because of the uncertainty about the cause and nature of this decrease, no degradation due to this factor was assumed in the worst case data base analysis.

The yearly climatic variability, expressed in terms of percent of possible total insolation, was derived from the long-term (20-year) data base. The uncertainty in this parameter is summarized in Chart 42. Shown are the mean and standard deviation of the total insolation for Inyokern and Albuquerque, and the 1962–1963 hourly insolation data relative to these long-term data. As can be seen, the 1963 data base for both stations is quite representative of the mean values of total insolation at these stations. For this worst case data base analysis, these total insolation values were adjusted to represent a minus 1σ (84 percent) condition.

Instrument calibration uncertainty and drift information were very limited. The various pyrheliometer and pyranometer calibration and drift uncertainties are under investigation by the National Oceanographic and Atmospheric Agency. The data summarized in Chart 42 were used to develop the worst case data base.

Worst Case Analysis Insolation Data Base

LONG TERM CLIMATIC TRENDS

- ASSUMED ZERO

YEARLY CLIMATIC VARIABILITY

- PERCENT OF POSSIBLE TOTAL INSOLATION

(20 year data base)

	ALBUQUERQUE	INYOKERN
MEAN	70.72	72.00
STANDARD DEVIATION	4.33	4.40
1962 DEVIATION	2.47 (+0.57σ)	5.34 (+1.21σ)
1963 DEVIATION	0.12 (+0.03σ)	1.32 (+0.30σ)

INSTRUMENT CALIBRATION AND DRIFT

- UNDER INVESTIGATION BY NOAA

		CALIBRATION	DRIFT	
			1962	1963
ALBUQUERQUE	PYRHELIOMETER	1.5%	0	0
	PYRANOMETER	4.0%	0.9%	2.7%
INYOKERN	PYRANOMETER	3.0%	3.5%	3.5%

Since no direct (normal-incidence) insolation measurement data exist for Inyokern, California, these data were derived from the total insolation by correlation analysis. The methodology of this analysis was developed during the previous contract (Reference 3). The uncertainties in the correlation coefficients are summarized in Chart 43. For development of the worst case normal insolation data base for Inyokern, minus 1σ estimation values were used. This (-1σ) line is shown in Chart 43. Since the total insolation data base used for estimation of the direct insolation was already revised downward, no additional adjustments were necessary.

Estimation Uncertainty
Normal Incidence Insolation
ALBUQUERQUE, 1962, 1963

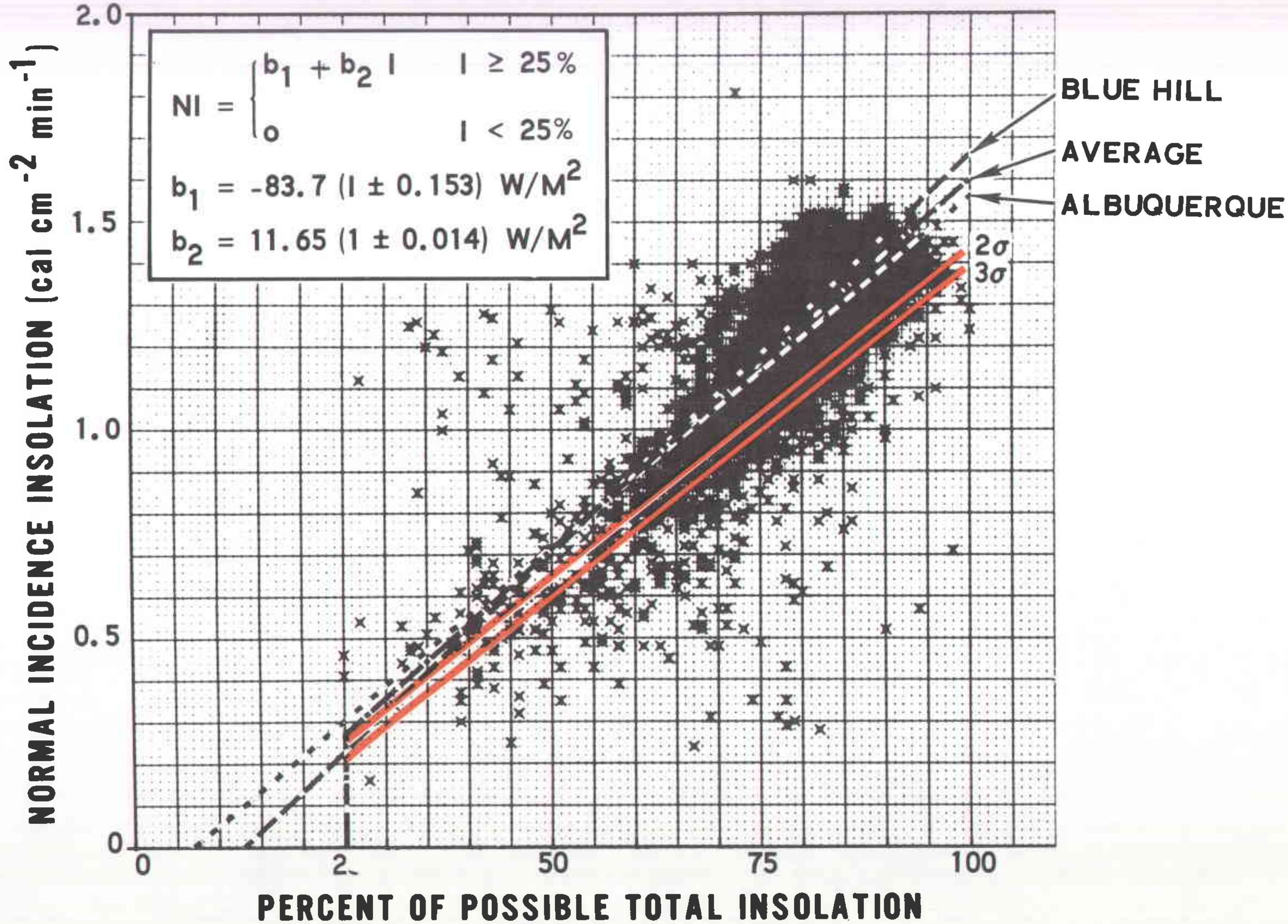


CHART 43

The effects of the various uncertainties in the data base were combined to derive the degradation factors necessary for the development of the worst case insolation data base.

These factors, shown in Chart 44, were applied to the 1962 and 1963 standard data bases for Inyokern, California, and Albuquerque, New Mexico. The effect of these reductions is to degrade the hourly insolation values by these factors and, consequently, to reduce the energy content of the insolation data by the same amount. The worst degradation determined was nearly 17 percent for 1962 at Inyokern, while the least degradation of less than 8 percent was applied to the 1963 direct insolation data for Albuquerque.

Worst Case Insolation Data Base

COMBINATION OF FACTORS

FACTOR	INYOKERN, CA				ALBUQUERQUE, NM			
	TOTAL		DIRECT		TOTAL		DIRECT	
	1962	1963	1962	1963	1962	1963	1962	1963
CLIMATIC VARIABILITY	0.874	0.922	---	---	0.907	0.937	0.907	0.937
ESTIMATION ERROR	---	---	ERROR IN CORRELATION COEFFICIENTS		---	---	---	---
CALIBRATION FACTOR	0.970	0.970	---	---	0.960	0.960	0.985	0.985
DRIFT FACTOR	0.965	0.965	---	---	0.990	0.970	1.000	1.000
COMBINED REDUCTION FACTOR	0.834	0.879	---	---	0.869	0.890	0.893	0.923

CHART 44

To determine the impact of winds on the performance of solar power plants, the concurrent frequency distribution of direct insolation and wind speed was estimated. The 1962 and 1963 hourly data bases for Inyokern, California, and Albuquerque, New Mexico, were used to derive the results shown in Chart 45. This chart shows the percent of direct insolation above specific values of wind velocity. For example, for Edwards AFB and Inyokern, 40 and 20 percent of the direct insolation, respectively, occurs at wind speeds of 10 miles per hour and above. As can be seen from this figure, a requirement of rotating the solar collectors away from the wind, at winds above 30 miles per hour results in a loss of less than one percent of the direct insolation at either station.

Direct Insolation Versus Wind Frequency

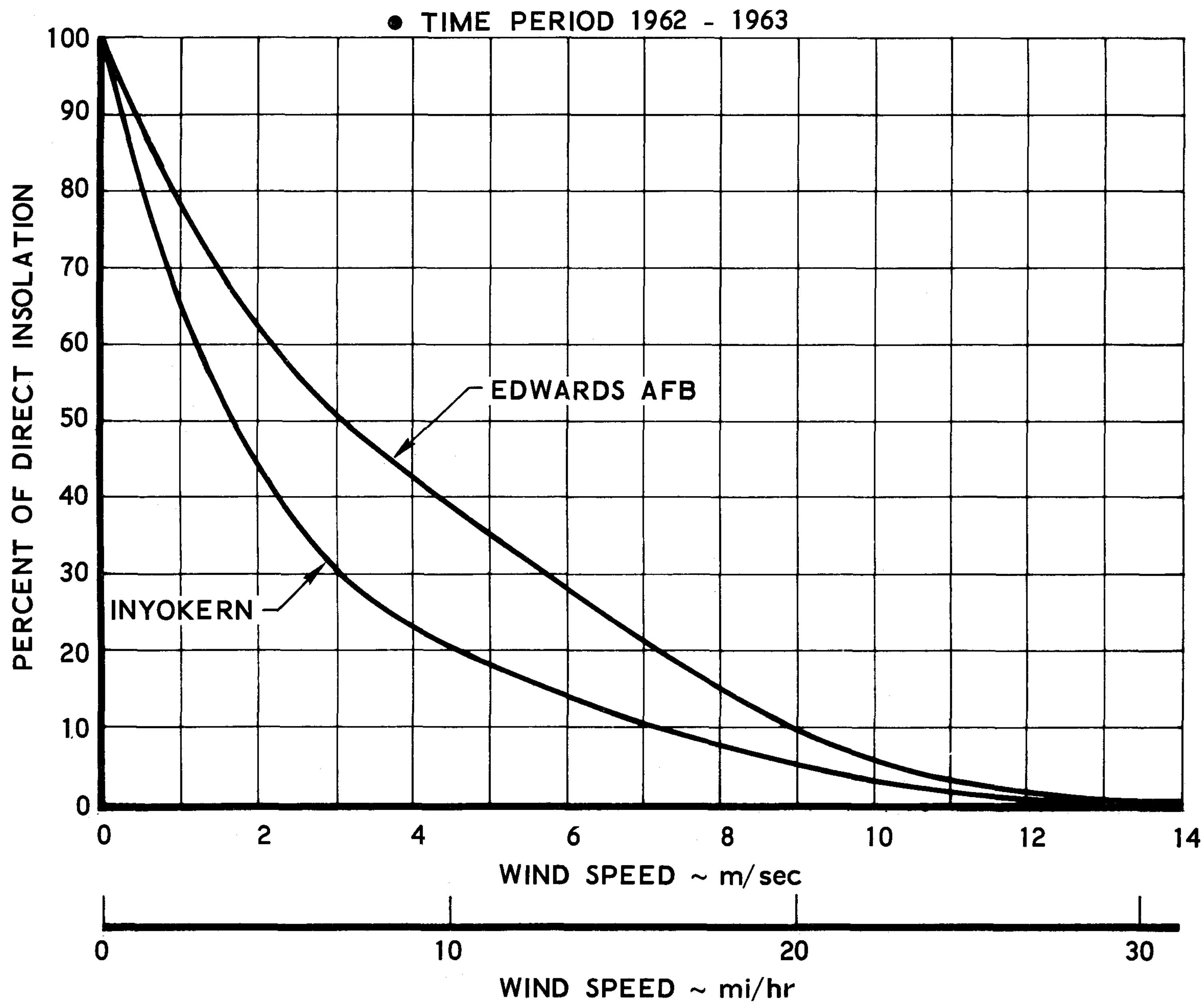


CHART 45

MARGIN ANALYSIS

MARGIN ANALYSIS

In order to ensure that the electrical demand does not exceed the available generating capacity, the installed generating capacity for United States utility companies is designed to be in excess of the anticipated peak loads. The incremental generating capacity over peak load is called the margin. A margin analysis determines the excess electrical generating capacity required above the anticipated peak load in order to provide reliable service to the public during periods when forced outages are experienced at some generating stations. Unscheduled outages for conventional plants are due to component failures, while for solar plants they can result from either component failures or insolation outages. These unscheduled outages are separate from scheduled plant outages for maintenance and seasonal deratings.

When solar power plants are substituted for conventional plants into a total power grid, a margin analysis must be performed to ensure that the new system including solar power plants provides service equally reliable as the conventional system. If, as a result of increased outages, a solar plant requires backup generating capacity to satisfy this reliability criterion, this backup capacity must be taken into account when making comparative economic evaluations. Consequently, as shown in Chart 46, the principal issue is to establish the potential of solar power plants to provide capacity displacement in addition to energy displacement when functioning in realistic operating environments.

A characteristic of solar plants is that in addition to component outages, solar plants may incur solar insolation outages. These insolation outages occur during nonsunshine hours and periods of cloud cover. The occurrence and time durations of these outages will greatly affect the amount of energy storage required or conventional backup needs such as in a hybrid plant. Since energy storage or hybrid plants are expensive, an economic tradeoff must be made between the amount of storage and associated larger collector field and the outage rate with the associated requirement for backup capacity.

Two correlation analyses that may significantly impact the margin requirements for solar power plants were identified. In contrast to component outages between different power plants, which are statistically independent, insolation outages are concurrent for solar plants in the same geographic region. By geographic dispersion of solar power plants, a degree of statistical independence may be introduced related to the variability of cloud cover between different locations.

In addition to the potential for statistical independence of geographically dispersed solar plants, the correlation between insolation and demand has significant bearing on the margin requirements and, hence, the potential of capacity displacement of solar power plants. In addition to the normal seasonal and daily insolation and demand variations, a statistical dependence between high insolation and peak demand would reduce the margin requirements of solar power plants.

Margin Analyses - Electrical Power Systems

PRINCIPAL ISSUE

- ESTABLISH THE POTENTIAL OF SOLAR POWER PLANTS, IN REALISTIC OPERATIONAL ENVIRONMENTS, TO PROVIDE CAPACITY AS WELL AS ENERGY DISPLACEMENT

SOLAR PLANT IMPLICATIONS

- SOLAR PLANT OUTAGE RATE
  - MECHANICAL & INSOLATION
  - STORAGE OR HYBRID OPERATION
- CORRELATION OF INSOLATION OUTAGE AT SEPARATE PLANTS
  - GEOGRAPHIC DISPERSION
  - PLANT SIZE
- CORRELATION OF INSOLATION AND DEMAND
  - SEASONAL & DAILY INSOLATION WITH DEMAND VARIATIONS
  - WEATHER IMPACT ON INSOLATION & DEMAND

The basic methodology used in the margin analysis is depicted in Chart 47. The analysis is probabilistic in nature, defining a loss-of-load probability on an hourly basis.

The necessary inputs required for computing the loss-of-load probability are the available electrical generating capacity and the variability and magnitude of the electric load.

The generation capacity model incorporates the various power plant units within a power grid as a function of their individual capacities and outage rates. The forced-outage rates for conventional power plants are a function of type, size, and maturity of power plants. Solar power plants, in addition to the component failure outages, may experience insolation outages, such as due to cloud cover or at night. The effective insolation outage rate is a function of the amount of energy storage provided and must be determined from hourly systems simulation over an entire year.

Total utility system available generating capacity probability distributions were derived on a monthly basis and for several different mixes of solar and conventional power plants. Component failure outages were treated as being statistically independent between various power plants, while insolation outages were conservatively assumed to be statistically dependent between solar plants.

The load or demand model is a statistical description of the electric demand for a full year. Two separate methods of modeling the electrical power demand were implemented. Method I utilizes deterministic hourly forecasted demand data for an entire year. Method II summarizes the demand data in terms of 24 separate hourly load probability distributions for each of the 12 months of the year. Method II tends to be more conservative than Method I because it takes into account the non-zero probability of exceeding the maximum load data forecasted. Method I however, requires significantly less computer time than Method II and is, therefore, preferred from a computer cost standpoint.

By combining the total utility system available generating capacity probability distribution with the projected electrical load distribution, a probability can be developed for the load not to exceed the available capacity ("loss-of-load" condition). By varying the number of plants assumed in the grid, the total generation capacity required to satisfy a given criterion, such as loss-of-load of only one day in 10 years, can be established. The system loss-of-load calculations are performed on an hourly basis and are summed over an entire year of operation.

Margin Analysis Methodology

- ELECTRIC GENERATION CAPACITY
  - ALGORITHM USED TO DERIVE AVAILABLE CAPACITY PROBABILITY DISTRIBUTION ON MONTHLY BASIS

- ELECTRICAL POWER DEMAND
  - METHOD I - DETERMINISTIC HOURLY DEMAND DATA
  - METHOD II - PROBABILISTIC DEMAND DISTRIBUTION FOR EACH HOUR OF DAY FOR EACH MONTH (288 separate probability distributions)

- MARGIN ANALYSIS
  - COMPUTATION OF LOSS OF LOAD PROBABILITY ON HOURLY BASIS
- RELIABILITY CRITERION
  - LOSS OF LOAD NOT TO EXCEED 1 DAY/10 YEARS ($\sim$2.4 hrs/yr)

Prior to the assessment of solar power plant capacity displacement, a conventional plant baseline generation system must be determined. The total conventional baseline generation capacity required to meet a projected Southern California Edison Company (SCE) demand for the year 1990 is shown by the top line in Chart 48. As can be seen from this figure, the total installed generation capacity required is 37,000 MWe, consisting of 83 separate power plants, to meet the load shown by the lowest line. This generation capacity was determined to be adequate to permit a 10 percent (5 week) scheduled maintenance period for all power plants and the remaining on-line generation to satisfy the reliability criterion that the loss-of-load not exceed one day in 10 years. The scheduled maintenance provision, represented by the cross-hatched area of the figure, falls primarily during periods of relatively low demand. The margin requirement for the conventional baseline system, as determined by computer summation, assuming a uniform 4 percent unscheduled component outage rate at each plant, is 15.6 percent.

The identical on-line generation capacity profile shown in Chart 48 was obtained by both Methods I and II, although Method II resulted in a slightly greater computed loss-of-load (2.38 hours/year versus 1.78 hours/year).

Conventional Plant Baseline Generation Capacity

(SCE~1990)

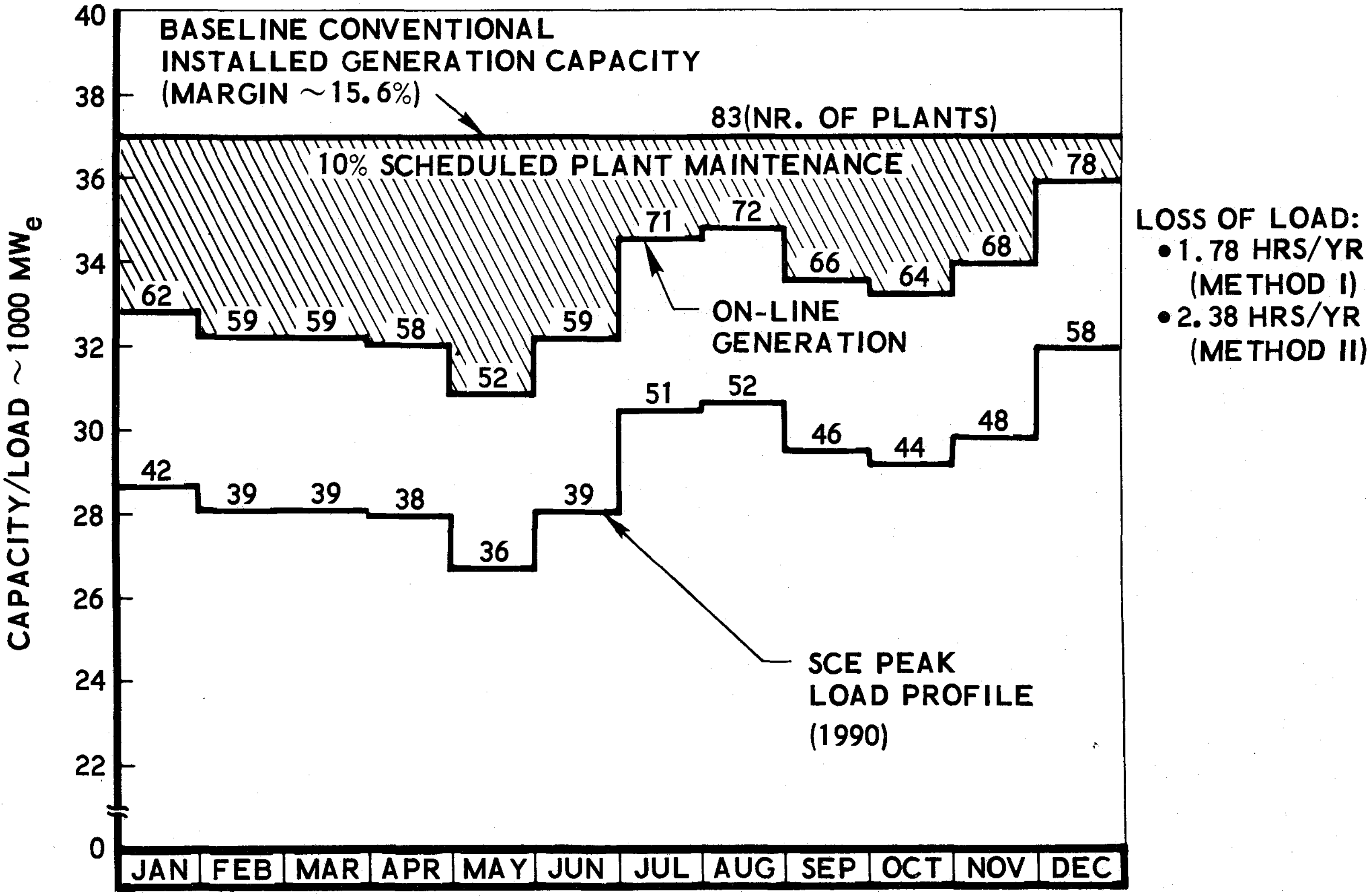


CHART 48

Starting with the previously described conventional baseline generation model, individual solar plants were substituted for conventional plants in order to determine their capacity displacement potential. Chart 49 outlines the general approach followed.

As shown in the previous chart, the conventional baseline generation model consists of 83 conventional power plants, incorporating baseload, intermediate, and peaking units, to meet a projected SCE demand profile for the SCE service territory with a peak load of 32,000 MWe in 1990.

Intermediate solar plants, parametrically varied in size from 100 to 500 MWe, were substituted for conventional plants. Due to the additional insolation outages incurred, solar plants, when substituted for conventional plants with similar rated capacities, may require conventional back-up capacity to achieve the same overall system reliability criterion of loss-of-load not to exceed one day in 10 years. The ability of solar plants to displace conventional plants is termed capacity displacement. The larger the capacity displacement, the smaller the conventional backup capacity required for equal system reliability.

The total conventional capacity penetration of the solar plants was also parametrically varied between 1,000 and 5,000 MWe, requiring varying numbers of solar plants depending on their individual size. Individual plant component outage rates of 4 per cent were assumed for solar as well as conventional plants. Solar plant insolation outages are determined by performance simulations of alternative solar plant configurations.

Subsequently, solar plant capacity displacements were determined using the margin analysis methodology described.

Margin Analysis

- SCE PEAK DEMAND (1990) - 32,000 MW_e
- GENERATION MODEL - CONVENTIONAL (idealized)

PLANT TYPE	SIZE (MWe)	NR. OF UNITS	CAPACITY (MWe)	PERCENT (%)	COMPONENT OUTAGE (%)
BASE LOAD	1000	18	18,000	49	4
INTERMEDIATE	500	20	10,000	27	4
PEAKING	200	45	9,000	24	4
TOTAL		83	37,000	100	

- SOLAR THERMAL PLANTS (substituted for conventional units)

PLANT TYPE	SIZE (MWe)	NR. OF UNITS	CAPACITY (MWe)	COMPONENT OUTAGE (%)	SOLAR* OUTAGE (%)
INTERMEDIATE	500	2, 4, 6, 8, 10	1000-5000	4	0-100
↓	250	4, 8, 12, 16, 20	↓	↓	
	100	10, 20, 30, 40, 50			

- RELIABILITY CRITERION
  - LOSS OF LOAD ~1 DAY/10 YEARS
- CONVENTIONAL BACK-UP CAPACITY REQUIRED

*Determined from system simulation

Typical results of the margin analysis to determine the potential capacity displacement of solar plants are presented in Chart 50. The solar plant capacity displacement and the associated conventional backup capacity required are described as a function of solar plant insolation outage.

The amount of conventional backup capacity required to maintain the system loss-of-load reliability criterion associated with the baseline conventional grid depends on a number of parameters.

- Order of substitution.
- Total capacity of solar power plant penetration.
- Size of the solar plants replacing the conventional plants.
- Size of the conventional plants substituted.
- The size of the conventional backup plants.

The specific cases presented on this chart consider the substitution of ten individual 100 MWe solar plants for an equivalent 1,000 MWe of conventional plant capacity. Three different conventional plant sizes are shown, indicating the sensitivity of solar plant substitution to the displaced conventional plant size for this penetration.

As indicated on Chart 50, small insolation outages of solar plants do not require conventional backup capacity; and, therefore, their capacity displacement is effectively 100 percent. The reason for this is due to the replacement of one large conventional plant with two or more solar plants, thus spreading the relative effect of component outages. Also, for theoretical solar plant outages of 100 percent, the required backup capacity is less than 1,000 MWe. The reason is the use of conventional backup plants of 100 MWe capacity or smaller.

The capacity displacement of the alternative solar thermal conversion systems and the associated conventional backup capacity requirements for equal system reliability of operation must be accounted for in the comparative economic evaluation of solar plants and conventional power plants.

Margin Analysis - Capacity Displacement

• CONVENTIONAL SYSTEM CAPACITY	~ 37,000 MW_e (83 units)
• PEAK DEMAND	~ 32,000 MW_e
• CONVENTIONAL SYSTEM MARGIN	~ 15.6%
• SOLAR PLANT SIZE	~ 100 MW_e
• SOLAR PLANT PENETRATION	~ 1000 MW_e

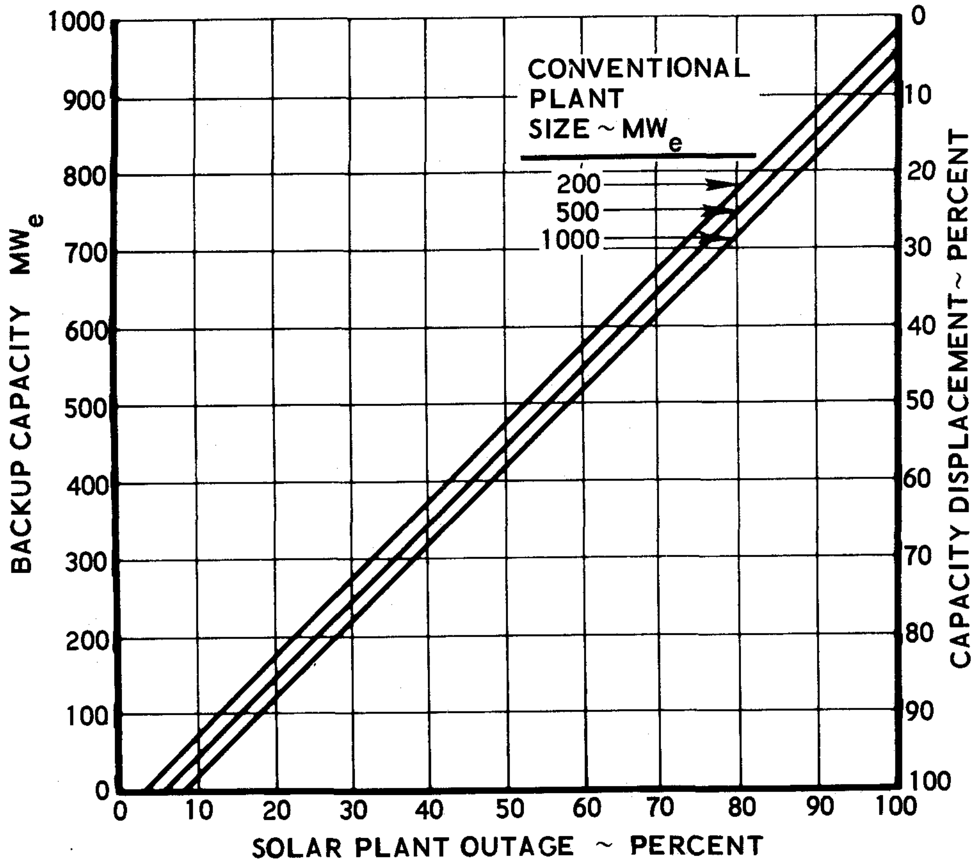


CHART 50

COMPARATIVE TECHNICAL EVALUATION

COMPARATIVE TECHNICAL EVALUATION

This section describes the mission/systems analyses performed to examine the dynamic interaction of insolation, demand, and solar thermal conversion systems. These analyses utilize the hourly demand projections and regional insolation data described in the previous sections.

A methodology was developed under the previous contract to parametrically assess the performance characteristics of alternative solar thermal conversion missions and systems in realistic operating environments on a consistent basis. This model has been extended, under the present contract, to incorporate solar plant subsystem design characteristics obtained from point design studies conducted by other NSF system contractors. Based on the mission/system analysis results, a comparative economic analysis was performed to assess the potential of these alternative solar thermal conversion systems.

The primary objectives of the comparative technical evaluation, as shown in Chart 51, are to examine the dynamic interaction of alternative solar thermal conversion systems with varying insolation and electrical demand. The solar power plants are evaluated in a realistic operating environment by simulating the solar plant performance as part of an integrated total utility system.

In order to determine the preferred mission applications of the solar thermal conversion systems, alternative operational modes to provide base, intermediate, and peaking power were examined.

Alternative solar thermal conversion systems were parametrically evaluated on a consistent basis in order to establish comparative performance results.

Four different solar power plant concepts were considered for evaluation:

- Central receiver system
- Parabolic cylindrical trough (including North-South, East-West, and Polar orientations)
- Paraboloidal dish
- Planar collector

The low-concentrating planar collector concept evaluation has not been completed, and results are not presented in this report.

The approach used was to apply the basic methodology developed under the previous study contract (References 1 through 5) in conjunction with the expanded insolation and demand data bases characterizing the Southwestern United States.

However, significant additional development has been achieved in the methodology. Specifically, the modular system simulation program was expanded to permit incorporation of additional technical parameters and more complex power plant subsystem descriptions to accurately represent alternative concepts proposed by other NSF system design contractors.

For the alternative solar power plant concepts, collector area and storage capacity were parametrically varied for different modes of operation. The energy displacement and solar plant outage rates were determined from simulation. The solar plant outage rate determines the capacity displacement of these solar plants which, when combined with the energy displacement, permits the economic assessment of the alternative systems concepts and mode of operation.

Comparative Technical Evaluation

- OBJECTIVES
  - EXAMINE DYNAMIC INTERACTION OF INSOLATION, DEMAND AND ALTERNATIVE SOLAR THERMAL CONVERSION SYSTEMS IN TOTAL POWER GRID
  - INVESTIGATE ALTERNATIVE OPERATIONAL MODES
  - DETERMINE ALTERNATIVE SYSTEM PARAMETRIC PERFORMANCE ON A CONSISTENT BASIS
- ALTERNATIVE SYSTEMS
  - CENTRAL RECEIVER
  - PARABOLIC CYLINDRICAL TROUGH
    - POLAR
    - N-S
    - E-W
  - PARABOLOIDAL DISH
  - PLANAR COLLECTOR
- APPROACH
  - APPLY MISSION/SYSTEM METHODOLOGY AND INSOLATION/DEMAND DATA BASES DEVELOPED FOR SIMULATION OF ALTERNATIVE SYSTEMS
  - COMPUTER MODEL WITH FLEXIBLE MODULAR SUBSYSTEM ROUTINES
  - INTERFACING WITH SYSTEM CONTRACTORS TO INCORPORATE TECHNICAL AND ECONOMIC SYSTEM CHARACTERISTICS

A pictorial representation of the four basic solar thermal conversion concepts considered in the comparative systems analysis is presented in Chart 52. The concepts portrayed include the central receiver, paraboloidal dish, parabolic cylinder, and the planar collector. Though these concepts incorporate major design differences, the system methodology presented in this section can accommodate the various design concepts for comparison on a consistent basis.

The central receiver concept uses optical transmission for redirecting the incident solar energy from a field of heliostats (i.e., mirrors) onto a receiver located on top of a tower, thereby achieving high solar concentration and associated temperatures. Each heliostat can be rotated about two axes to enable directing the insolation to the receiver under varying relative solar positions. The energy absorbed at the receiver is transferred to a fluid (e.g., water, steam, hitec, etc.), and transported directly to a turbine/generator located in close proximity to the tower for the conversion to electrical energy or to storage for later delivery to the turbine/generator.

The other three concepts are distributed systems. These concepts utilize distributed solar collectors, which locally convert the incident insolation to thermal energy and require long pipe runs to collect and transport heated fluid to the turbine/generator and/or central storage system. Long pipe runs, even with good insulation, can incur significant thermal losses and are very costly.

The paraboloidal concept consists of large individual paraboloidal dish reflectors that direct the incident insolation to a single focus (receiver) located at the focal point of each reflector. Each paraboloidal dish tracks in two directions and can theoretically achieve high concentration ratios and associated temperatures.

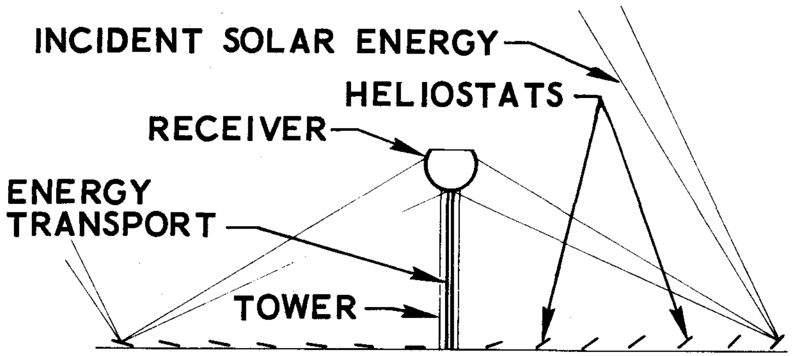
The parabolic cylinder concept consists of cylindrical troughs with a parabolic cross section, which directs the incident insolation to an absorbing pipe located at the focus of the parabola. The central pipe, or receiver, contains the thermal transfer fluid. The receiver is surrounded by an evacuated glass envelope to prevent excessive thermal losses and to protect against atmospheric corrosion. Each collector tracks only in one direction about its longitudinal axis. Because of the lower concentration ratios achievable with this concept, the collector pipe may utilize a high absorptivity/low emissivity coating in order to achieve high operating temperatures. The parabolic cylinder system, like the paraboloidal system, is distributed over a large ground area requiring long pipe runs to transport the thermal transfer fluid to the turbine/generator or storage. Three separate types of parabolic cylinders are considered in the analyses, differing primarily in the orientation of the rotation axis. The three orientations are:

- North-South
- East-West
- Polar

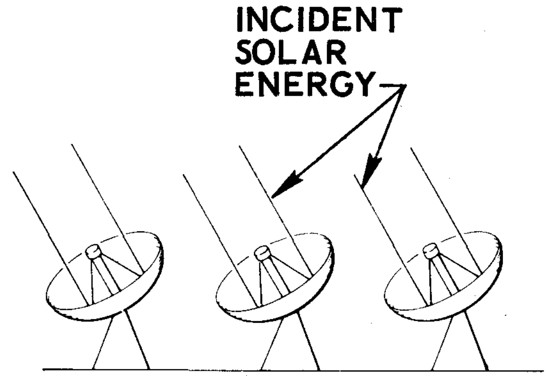
The polar orientation has the rotation axis tilted with respect to the horizon at an angle equal to the latitude of the site. This reflects an optimal setting for collecting solar insolation on an annual integrated basis by minimizing geometric losses. As the parabolic cylinder concepts employ one-directional tracking, tracking efficiencies vary for each of the three orientations.

Planar collectors either have no concentration (flat plate) or low concentration. These concepts have the ability to utilize total (direct and diffuse) radiation, as compared to those concepts employing higher concentration which can only utilize direct (or focusable) insolation. The planar collector concept typically employs fixed collectors or requires seasonal orientation adjustments only, depending upon the amount of concentration.

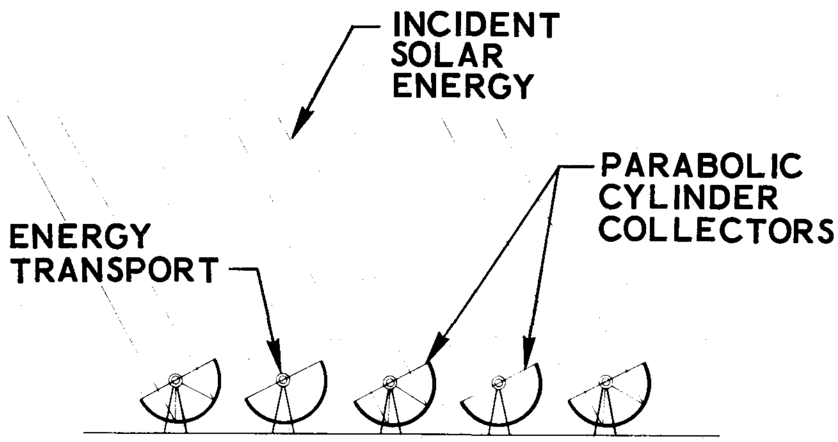
Typical Solar Thermal Conversion System Concepts



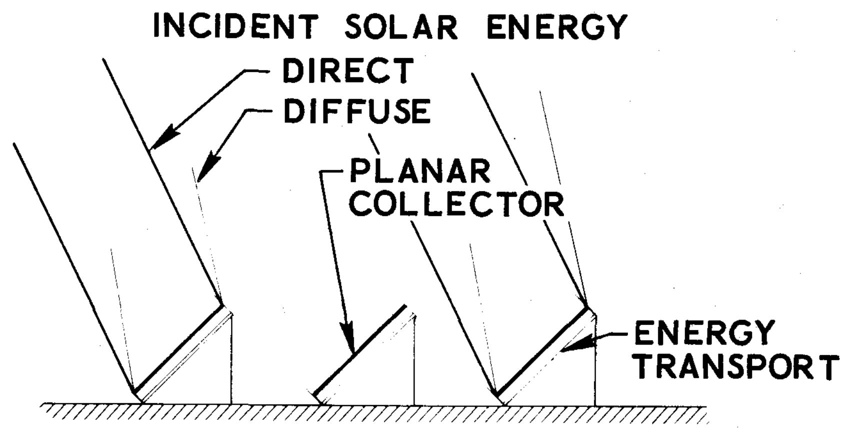
CENTRAL RECEIVER



PARABOLOIDAL



PARABOLIC CYLINDER



PLANAR COLLECTOR

CHART 52

A block diagram of the modular system simulation model is shown in Chart 53. This model consists of modular subsystem routines to facilitate substitution of more complex subroutines as design characteristics become better defined. The insolation subroutines are the hourly total or normal-incidence insolation data representative of the various climatological subregions of the Southwestern United States.

The tracking, collector/receiver, transport, storage, turbine/generator, and transmission subroutines compute the various subsystem energy losses between the incident insolation and the delivery of electrical energy. Subsystem design characteristics available from point design studies conducted by other NSF study contractors were used in modeling subsystem losses.

Since total insolation is measured on a horizontal plane and normal-incidence radiation is measured normal to the direction of the sun, the tracking model applies the appropriate geometrical and tracking corrections for the alternative configurations analyzed. The tracking model will, therefore, compute the insolation energy which can potentially be collected.

The collector subsystem defines the total collector area and the losses associated with its design configuration (e.g., reflectivity, aiming losses, shading). The receiver subsystem, which receives the collected solar energy, is represented by an absorption efficiency and convective and reradiative thermal losses which are temperature dependent. A threshold insolation level is incorporated below which the received does not operate.

The energy transport subsystem represents the primary energy fluid pumping losses and the line thermal energy losses. The thermal energy can be utilized directly by the turbine/generator or stored for future utilization, depending on the power demand and generator rating.

The storage subroutine incorporates a maximum and minimum storage capability as well as an overflow provision. Representative thermal energy heat losses are incorporated within this model to account for energy input/output losses as well as heat loss rates during storage.

The turbine/generator subroutine accounts for the conversion of the thermal energy into electrical energy with a conversion efficiency which is a function of the operating temperature. The turbine/generator model incorporates a maximum design (name-plate) rating, as well as a minimum level of operation.

The electrical energy generated, when transmitted and combined with the conventional systems power output, is matched to meet the aggregate electrical base, intermediate, or peaking hourly load for any given year as forecasted by the demand methodology discussed in a previous section.

This model permits the simulation of solar power plants integrated into a power grid on an hour-by-hour basis. Typically the simulation is carried out for a full year.

Simulation Block Diagram

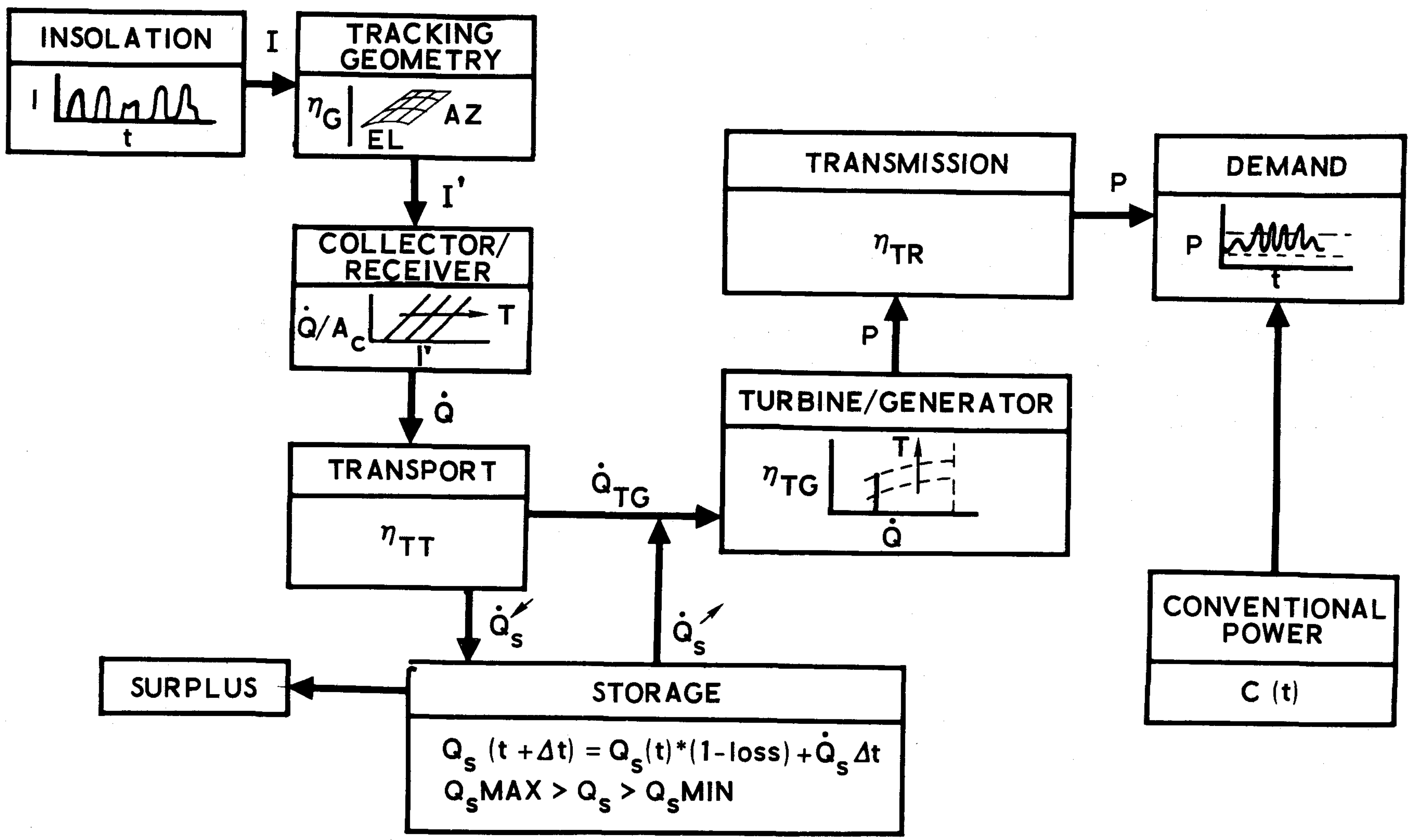


CHART 53

Chart 54 shows the electric power demand used for system simulation. For illustration, only the first weeks in April, August, and December are shown. This demand is a projected hourly electrical load for the Southern California Edison service area during the year 1990 with a peak demand of 32,000 MWe.

Different modes of operation for solar power plants were examined by selecting the various operating ranges shown in Chart 54:

- Base between 0 and 100 MWe
- Intermediate between 22,000 and 22,100 MWe
- Peaking between 27,300 and 27,400 MWe

The 0-100 MWe demand range was selected for base power applications of solar plants because, once the capital investment is made, the marginal cost of solar power plants is lower than for conventional nuclear or fossil base load power plants.

Electric Power Demand 1990

SO. CALIFORNIA EDISON CO.

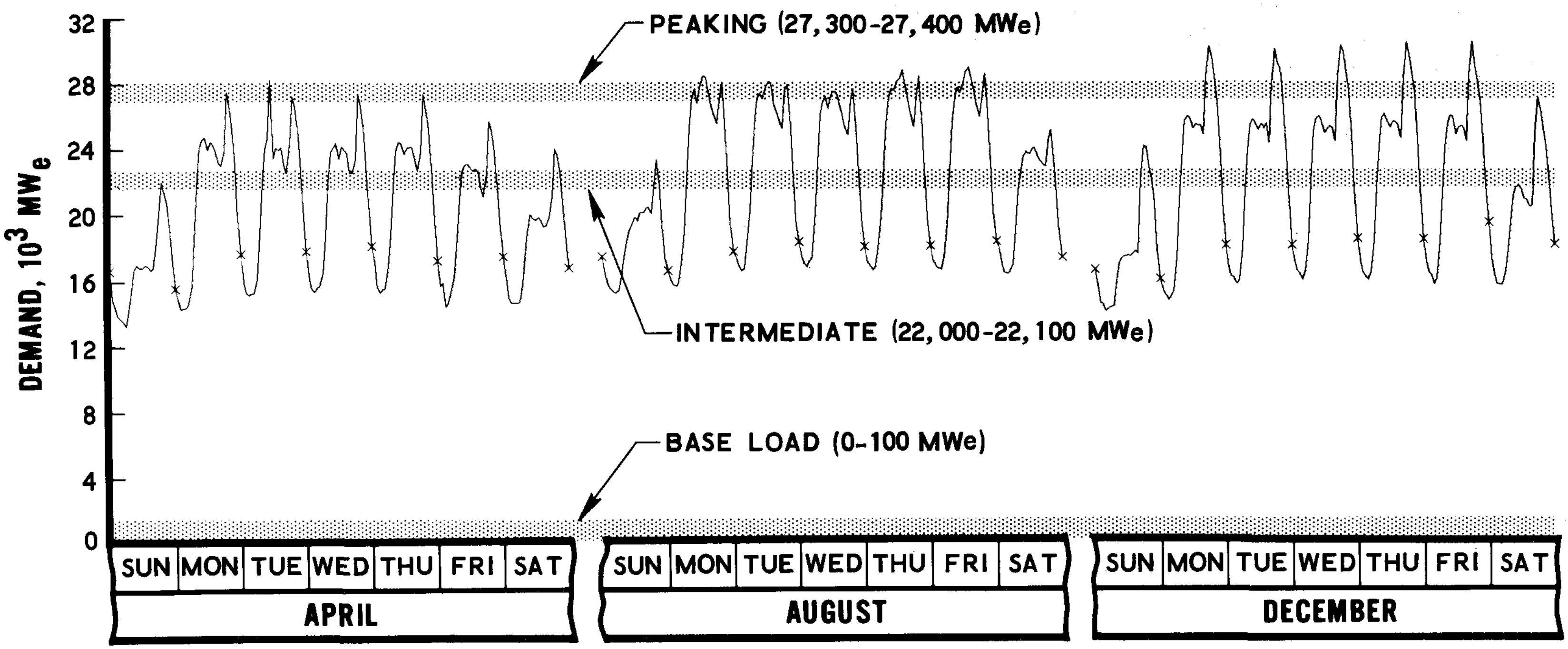


CHART 54

Solar plant simulations were performed to evaluate base, intermediate, and peaking operating modes, as summarized in Chart 55.

In addition, the collector areas and thermal storage capacities were varied parametrically in the system simulations to determine the technical performance of various combinations of these parameters. The system combination with the lowest cost was determined by means of economic and financial evaluation of the energy and capacity-displacement potential for each mode of operation of the solar plants.

Solar Thermal Conversion Systems Simulation

BASE LOAD SOLAR PLANT

- DEMAND RANGE — 0 - 100 MW_e
- COLLECTOR AREAS — 1 - 4 KM^2
- THERMAL STORAGE — 0 - 18 HR

INTERMEDIATE SOLAR PLANT

- DEMAND RANGE — 22,000 - 22,100 MW_e
- COLLECTOR AREAS — 0.5 - 2.5 KM^2
- THERMAL STORAGE — 0 - 9 HR

PEAKING SOLAR PLANT

- DEMAND RANGE — 27,300 - 27,400 MW_e
- COLLECTOR AREA — 0.5 - 1.5 KM^2
- THERMAL STORAGE — 0 - 6 HR

The technical characteristics incorporated in the performance simulations of the alternative solar thermal conversion concepts examined are summarized in Chart 56. These subsystem design characteristics reflect preliminary point design studies of these alternative solar thermal conversion concepts conducted by other NSF system contractors. Additional performance design data can be incorporated when it becomes available.

The individual subsystem losses are computed from these design characteristics by means of efficiencies, unit heat losses, graphs, tables, and computational subroutines. Pump power losses are simulated as a function of flow rate. The terms "graphical winter perturbed," "tabular," and "calculated" refer to preprogrammed graphs, tables, and computer subroutines incorporated to accurately match contractor defined performance of the related system, while minimizing computer costs for full-year simulation.

The turbine/generator efficiencies shown reflect dry cooling tower operation.

Solar Thermal Conversion Systems

TECHNICAL CHARACTERISTICS

COMPARATIVE SUBSYSTEM DESCRIPTION	CENTRAL RECEIVER	PARABOLIC CYLINDER	PARABOLOIDAL DISH
COLLECTOR			
PRIME REFLECTIVITY	0.88	0.88	0.88
SECONDARY REFLECTIVITY	--	0.96	--
AIMING EFFICIENCY	(Graphical Winter - Perturbed)	CALC[1]	0.94[1]
SHADING		TABULAR	TABULAR
TRACKING EFFICIENCY		CALC	CALC
RECEIVER			
ABSORPTIVITY	0.90	0.90	0.85[1]
EMISSIVITY	0.95	--	--
SURFACE TEMP	538° C(1000° F)	--	--
UNIT HEAT LOSS	--	0.0472 KW_t/M^2	0.0126 KW_t/M^2
DISTRIBUTION PUMP			
PUMP CONSTANT[2]	66×10^{-3}	132×10^{-3}	132×10^{-3}
LINE THERMAL LOSS			
LINE EFFICIENCY	1.00	0.90	0.90
STORAGE			
INPUT/OUTPUT-EFFICIENCY	0.85	0.85	0.85
IN STORAGE LOSS	0.1 %/hr	0.1 %/hr	0.1 %/hr
TURBINE GENERATOR			
STEAM TEMP	482° C(900° F)	316° C(600° F)	427° C(800° F)
OVERALL EFFICIENCY[3]	0.36	0.32	0.34

(1) Simulate Honeywell Performance Results

(2) Pump Constant = Pump Power x $(\text{collector area})^2/(\text{pump flow rate})^3$

(3) Dry Cooling

To illustrate the incorporation of detail design data for hourly system simulation over an entire year, the tracking efficiency input data for the central receiver concept is shown in Chart 57. The data shown were obtained from detailed analyses of the winter-perturbed central receiver design by the University of Houston for various combinations of solar azimuth and elevation. The tracking efficiency includes collector losses due to the relative orientation of the heliostats and the effects of shading and blocking by adjacent heliostats.

Rather than duplicating these complex analyses, these data were input parametrically to the simulation program for hourly simulation of this concept. For each hour of the day throughout an entire year, the direct insolation and solar position, as defined in the insolation data base, are input to determine the total redirected insolation to the central receiver. Consequently, the tracking performance accurately reflects the actual performance results as determined by the system design contractor without incurring the large costs of duplicating and simulating on an hourly basis the contractor computer calculations.

Superimposed on the data in Chart 57 are constant time lines as measured from noon for the extreme solar days as measured by the equinox and solstices.

Similar representations of the other solar collector concepts, based upon contractor designs, were incorporated in the system simulation to accurately and consistently reflect the design characteristics.

Central Receiver Concept Tracking Efficiency

UNIV. OF HOUSTON/MDAC (winter orientation)

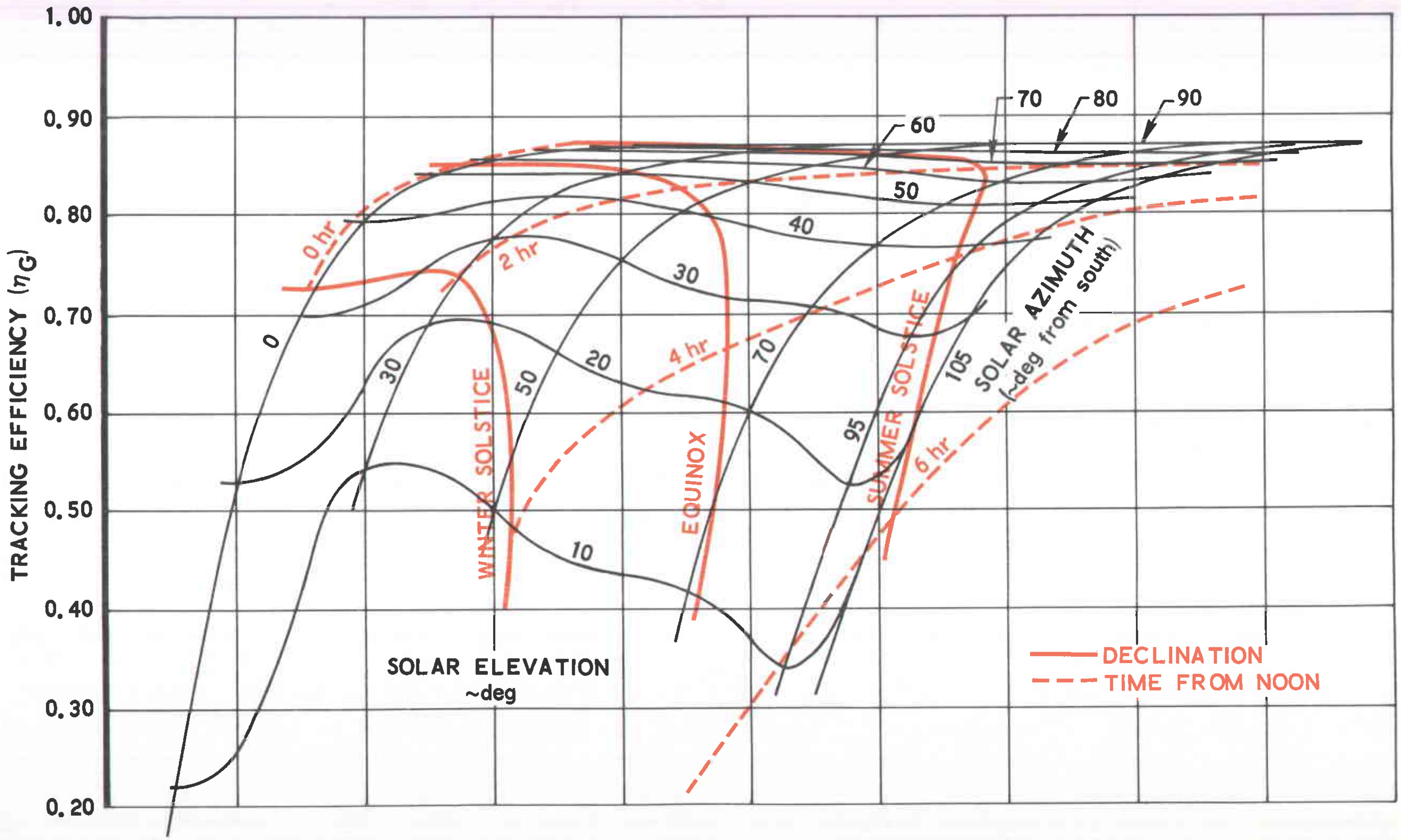


CHART 57

Solar plant performance for an entire year of operation was simulated for each of the alternative solar plant concepts using the subsystem characteristics defined in Chart 56.

The performance simulations were based on a 100 MWe solar plant located in Inyokern, California, using the 1963 direct insolation data base developed for this station and using the Southern California Edison Company service area hourly demand forecast for the year 1990.

The resultant yearly average subsystem efficiencies are shown in Chart 58 for each of the alternative configurations. The overall efficiency reflects all the losses from insolation input to electric power output and, consequently, is of primary significance in comparing the various system concepts. The overall efficiency does not include waste heat or storage losses, as these are a function of the particular operational mode considered.

As can be seen from this chart, the central receiver concept has the highest overall efficiency (19.2 percent), and the E-W oriented parabolic cylindrical trough the lowest (11.1 percent).

Solar Thermal Conversion Systems

SUBSYSTEM EFFICIENCIES

SUBSYSTEMS	CENTRAL RECEIVER	PARABOLIC CYLINDRICAL TROUGH			PARABOLOIDAL DISH
		POLAR	N-S	E-W	
COLLECTOR					
TRACKING	0.703	0.957	0.876	0.724	1.000
AIMING		0.945	0.918	0.849	0.940
SHADING		0.867	0.888	0.978	0.860
BLOCKING		--	--	--	--
FIRST REFLECTIVITY	0.880	0.880	0.880	0.880	0.880
SECOND REFLECTIVITY	--	0.960	0.960	0.960	--
RECEIVER					
ABSORPTIVITY	0.900	0.900	0.900	0.900	0.850
THERMAL LOSSES	0.970	0.895	0.884	0.873	0.972
DISTRIBUTION PUMP LOSSES	0.985	0.970	0.970	0.970	0.962
DISTRIBUTION LINE THERMAL LOSSES	1.000	0.900	0.900	0.900	0.900
TURBINE/GENERATOR	0.360	0.320	0.320	0.320	0.340
OVERALL EFFICIENCY(1)	0.192	0.149	0.134	0.111	0.173

(1) Does not include Waste Heat or Storage Losses

CHART 58

Some of the results of actual simulation of a central receiver solar power plant with previously defined characteristics for base load application are shown in Chart 59. Even though the simulation was performed on an hourly basis for a full year (1990) and for many combinations of collector area and storage, this chart shows only the results for the first week in December and a single combination of collector area and storage capacity for illustration purposes. These results are for a 100 MWe generator rated central receiver power plant with a 2 km^2 collector area and a 12 hour storage capacity.

The top figure shows the relationship between the 100 MWe base load electrical demand (100 MWe line), the power output of the turbogenerator to meet this demand (line between 0 and 100 MWe), and the electrical equivalent insolation at the collector (sinusoidal-shaped curves). The electrical equivalent insolation is the actual normal-incidence insolation, corrected for geometry, multiplied by the respective collector and turbogenerator efficiencies and the collector area.

The bottom figure shows the dynamics of storage in terms of power from the collector to storage (sinusoidal-shaped curves), power from storage to the turbogenerator (trapezoidal-shaped curves), and energy available in storage (triangular-shaped curves).

As can be seen, power not used by the turbogenerator during sunshine hours flows to storage, thereby increasing the energy in storage. During nonsunshine hours, the turbogenerator draws power from storage to meet the demand and, consequently, reduces the energy in storage.

Each of the significant parameters is integrated over the full year of operation to provide a measure of the technical performance.

Base Load Solar Thermal Conversion Plant (100 mW_e)

OPERATING CHARACTERISTICS

- CENTRAL RECEIVER CONCEPT (winter orientation)
- CONCENTRATING COLLECTOR AREA 2 KM^2
- THERMAL STORAGE 12 hr
- INYOKERN, CALIFORNIA

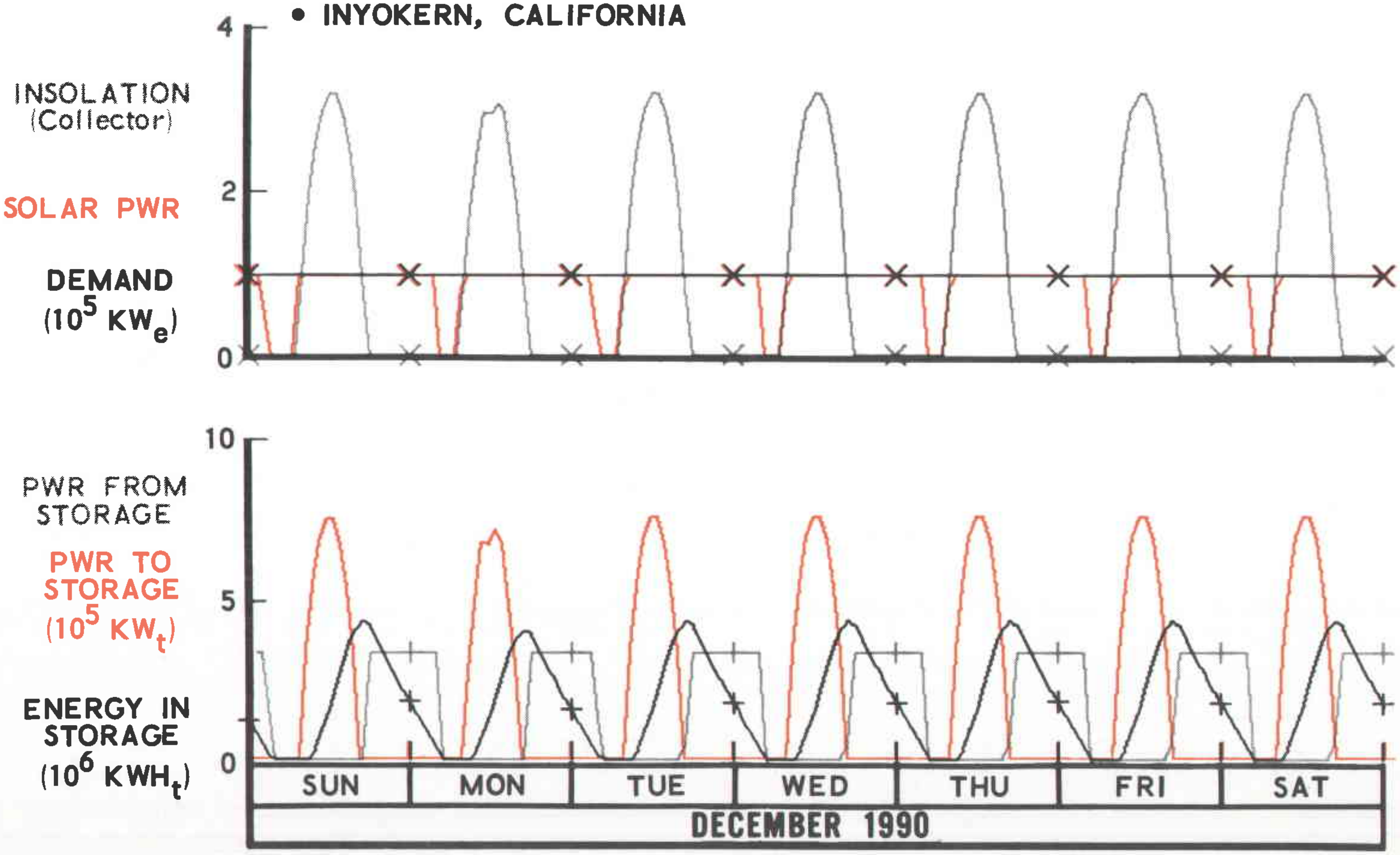


CHART 59

A simulation of a 100 MWe receiver system operating in the base load mode was performed for a parametric combination of collector areas and storage capacities. The performance results based on a full year of hourly simulations are summarized in carpet plot format in Chart 60.

The solar capacity factor, plant capacity factor, and energy displacement are shown for different combinations of solar collector areas and storage capacities while maintaining a constant turbine/generator rating. The solar capacity factor is the actual turbine/generator energy output, integrated over the year, divided by the maximum theoretical total output for the year. The plant capacity factor is 90 percent of the solar capacity factor based on the assumption of a 5 week per year (10 percent) scheduled maintenance period. The energy displacement is the integrated turbine/generator output divided by the total demand energy for the year (1990). Since the base load demand is always equal to the rated capacity of the plant, the energy displacement is the same as the solar capacity factor for base load applications.

The energy displacement is a measure of the performance of a solar power plant in meeting the specified demand and, therefore, provides an estimate of the solar power plant outage rate. The outage rate is necessary to determine the capacity displacement of solar plants when substituted for conventional plants in a total power grid system, as was discussed in the margin analysis section. The plant capacity factor provides a measure of actual useful electrical energy per year delivered by the solar power plant. The combination of generated energy and capacity displacement are important inputs to the economic evaluation of solar power plants as will be discussed in the following section.

As indicated in Chart 60, for a particular collector area, such as 1.5 km^2, a significant improvement in performance is attained by increasing storage capacity. Beyond about 18 hours of storage, however, this improvement has diminishing returns and little improvement in performance can be attained for this particular collector area. At this point, the collector area is too small to add additional energy to storage. This limit condition of maximum storage is shown in Chart 60 by the near vertical dot-dashed line. In this case, additional performance can only be attained by increasing the collector area which permits additional useful storage capacity to be added.

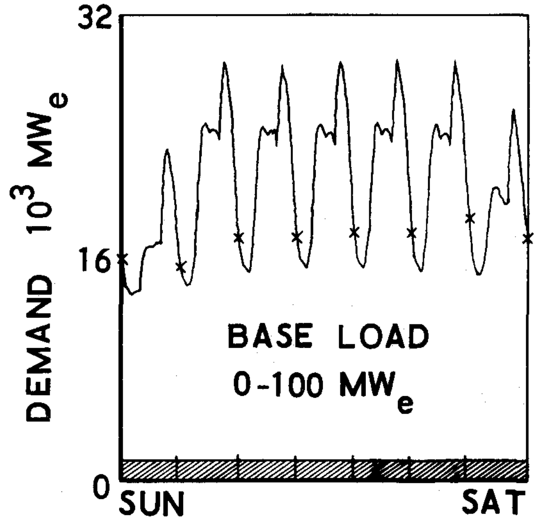
As can be seen from Chart 60, a 100 MWe base load central receiver system with a collector area of 1.5 km^2 and 12-hour storage capacity located in Inyokern, California, attains a plant capacity factor of 79 percent. This case has an energy displacement of almost 90 percent (and a corresponding unscheduled outage of approximately 10 percent).

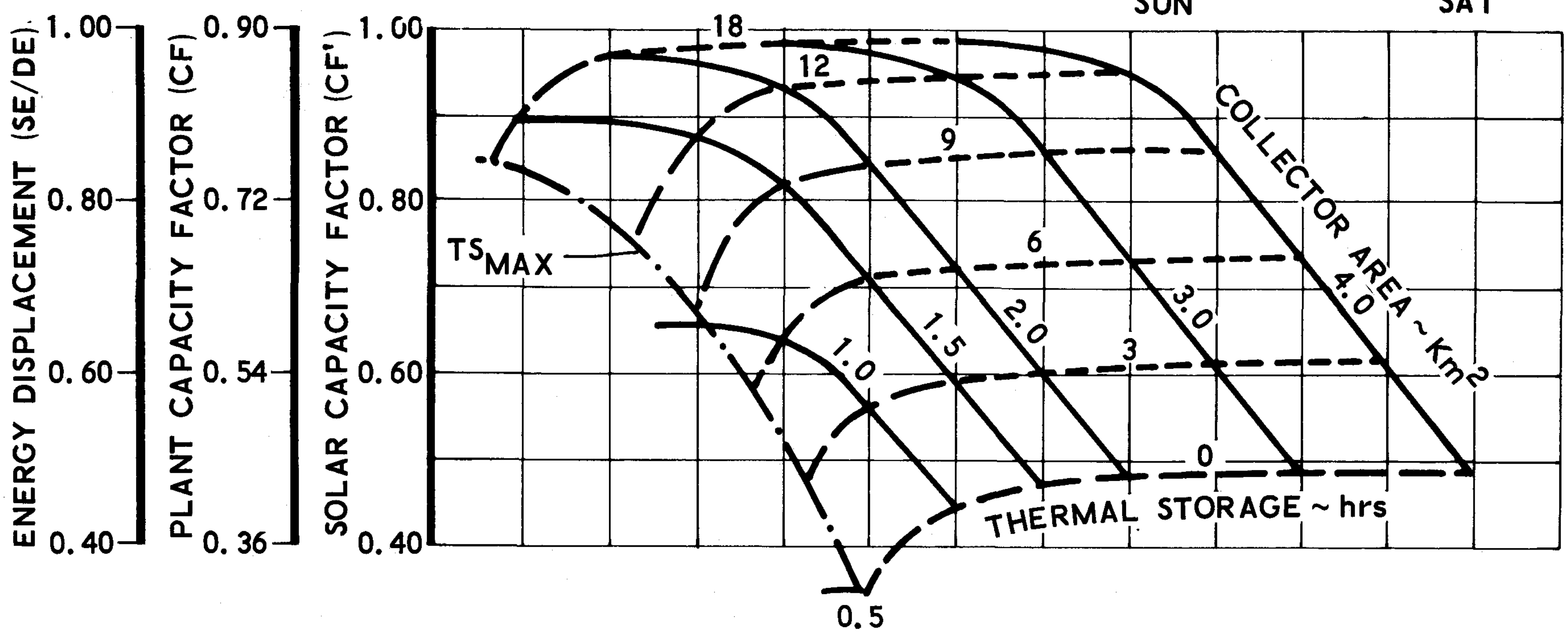
The relative economic merits of the various combinations of collector areas and storage capacities for this system concept are the subject of the economic and financial analyses summarized in the following section.

Base Load Solar Thermal Conversion Plant

CENTRAL RECEIVER (Winter perturbed)

- TURBINE-GENERATOR RATING ~ 100 MW_e (η_{TG} = .36)
- LOCATION ~ INYOKERN, CALIFORNIA
- DEMAND DATA ~ SCE
- TIME PERIOD ~ 1990





The parametric technical performance characteristics for an intermediate-load central receiver solar power plant, based upon a full year of hourly simulation, are shown in Chart 61.

For the 100 MWe rated solar power plant, the collector area and storage capacity were varied in order to parametrically assess the technical performance for various combinations of these subsystems.

Shown in Chart 61 are the solar capacity factor, plant capacity factor, and energy displacement for various combinations of collector area and storage capacity, when operating within the 22,000-22,100 MWe intermediate-demand range.

Again, the plant capacity factors were assumed to be 90 percent of the solar capacity factor, assuming a 5 week per year (10 percent) scheduled maintenance period.

The energy displacement within the 22,000-22,100 MWe intermediate demand range is the integrated turbine/generator energy output divided by the integrated energy demand within this range, which is different from the solar capacity factor.

The energy displacement is a measure of the unscheduled outage characteristics which, in turn, provides a measure of the capacity displacement potential.

As can be seen from Chart 61, the storage requirements for intermediate-load solar plant applications are much smaller than for base load operation.

In the intermediate demand applications for certain combinations of collector area and storage, there may be situations where solar plant power is available and storage is full during periods of low or zero demand within the 22,000-22,100 MWe range. Because of the low marginal cost of solar energy, once the solar plant has been built (because of zero fuel cost), it was assumed to continue operating, displacing energy in the base load region; however, no capacity displacement was assumed for this base load energy displacement. This additional energy displacement and associated incremental capacity factor in the base load region were calculated for the various combinations of collector area and storage capacity analyzed.

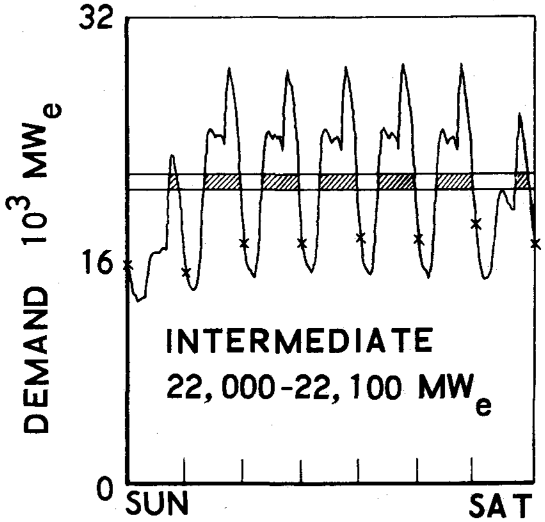
For certain combinations of large collector areas and small storage capacity, the turbine/generator with a rating of 100 MWe cannot handle all the insolation energy available; consequently, this energy was assumed to be lost.

In the economic assessment of the intermediate mode solar power plants, credit was taken for the displaced conventional base load fuel only, since no capacity displacement in the base load region was assumed.

Intermediate Solar Thermal Conversion Power Plant

CENTRAL RECEIVER (Winter perturbed)

- TURBINE-GENERATOR RATING 100 MW_e (η_{TG} = .36)
- LOCATION ~ INYOKERN, CALIFORNIA
- DEMAND DATA ~ SCE
- TIME PERIOD ~ 1990



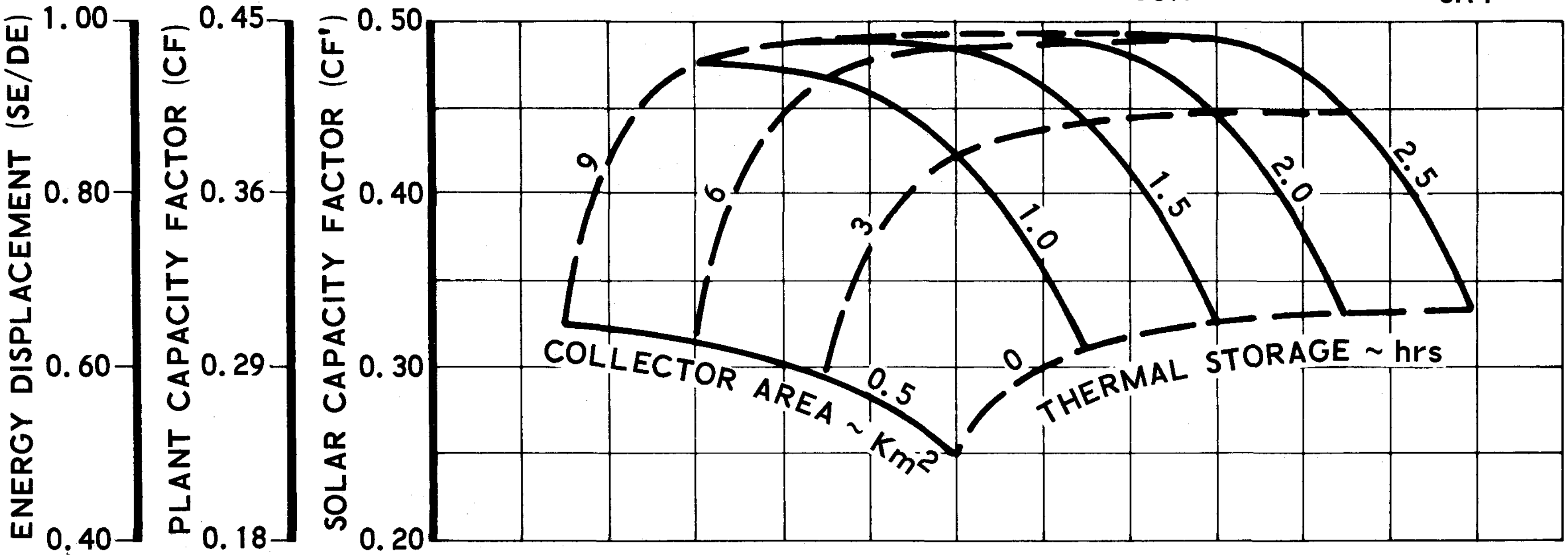


CHART 61

The parametric technical performance characteristics for a peak load central receiver solar power plant are shown in Chart 62.

The collector area and storage capacity were varied parametrically for the solar plant with a fixed 100 MWe generator rating.

Shown in Chart 62 are the plant capacity factor and energy displacement for the various combinations of collector area and storage capacity when operating within the 27,300 to 27,400 MWe peak demand range.

The plant capacity factor is the same as the solar capacity factor (not shown), since maintenance for this case can be scheduled during periods in the year where no demand exists within the defined peak demand range.

For these peaking solar plants solar energy may be available during periods of low or zero peak load demand within the 27,300-27,400 MWe range. Because of the low marginal cost of this electrical output, the solar plant was assumed to continue operating during these periods to displace intermediate and base load energy. Again no capacity displacement was assumed for this additional energy displacement. Thus the plant essentially operates in a load following mode, with only capacity displacement assumed within the specified peak demand range of 27,300-27,400 MWe.

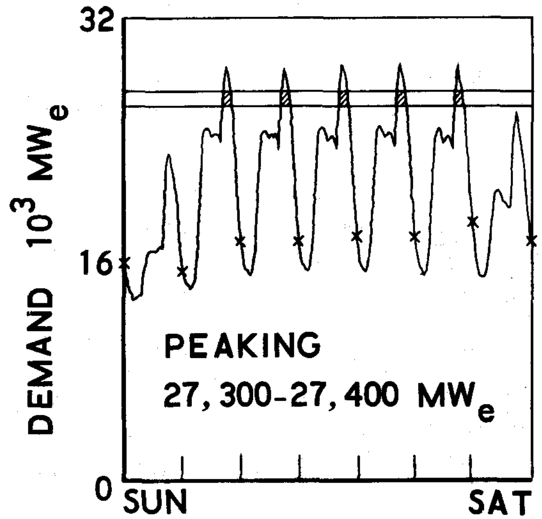
Those collector-area and storage-capacity combinations where the solar energy available is in excess of the turbine/generator rating and storage capability represent the maximum intermediate and base load energy displacement potential.

The plant capacity factor, capacity displacement, and intermediate and base-load fuel displacement are the factors required for economic evaluation of solar thermal conversion plants applied to peak load applications.

Peaking Solar Thermal Conversion Power Plant

CENTRAL RECEIVER (Winter perturbed)

- TURBINE-GENERATOR RATING ~ 100 MW_e (η_{TG} = .36)
- LOCATION ~ INYOKERN, CALIFORNIA
- DEMAND DATA ~ SCE
- TIME PERIOD ~ 1990



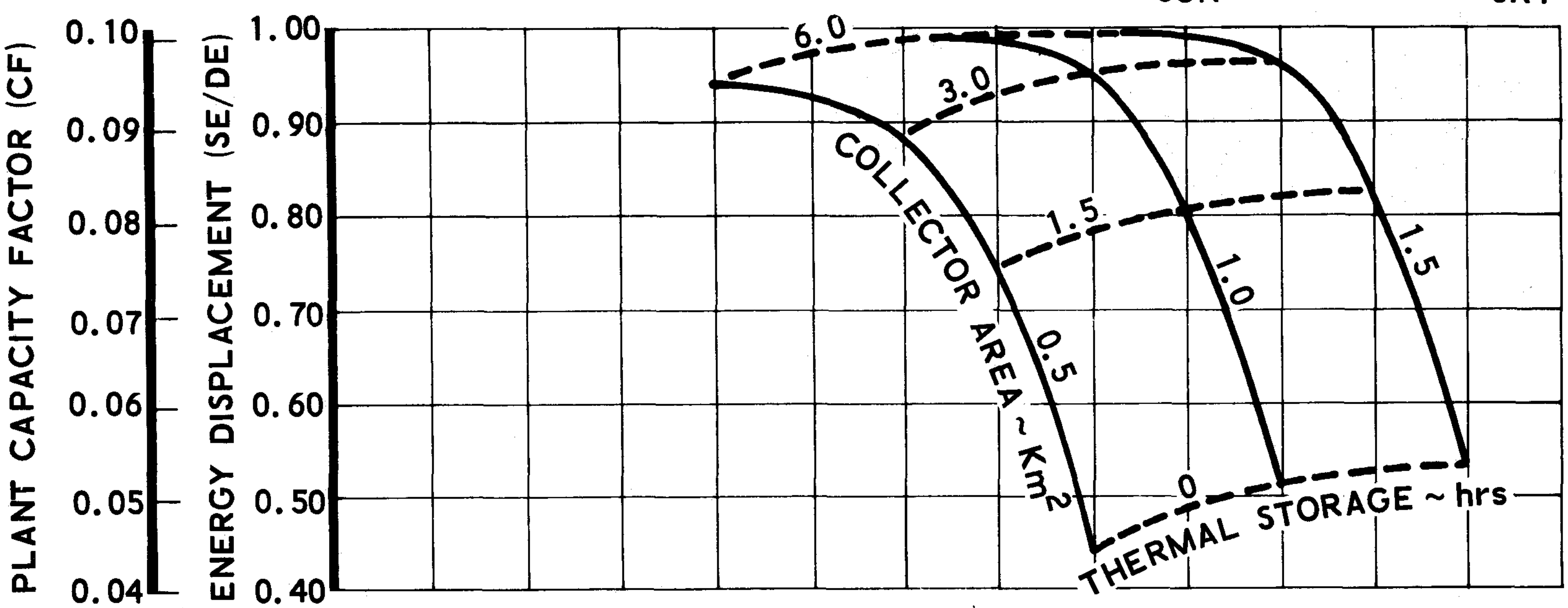


CHART 62

The parametric technical performance characteristics for a 100 MWe intermediate load paraboloidal dish solar plant are shown in Chart 63.

As compared with the intermediate load central receiver plant, the performance in terms of plant capacity factor and energy displacement is slightly less for equivalent combinations of collector area and storage capacity.

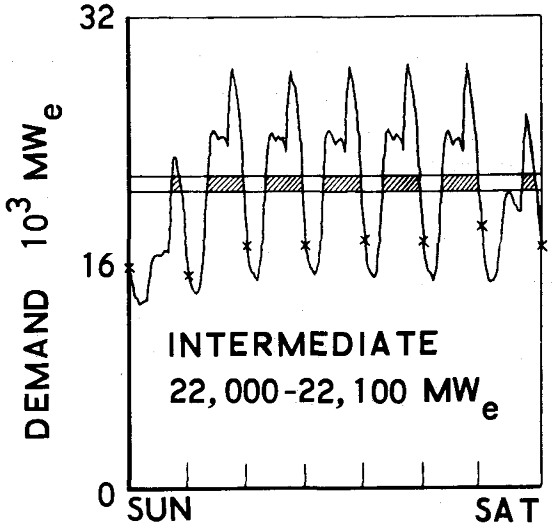
These data are based upon a full year of hourly simulation and use identical insolation and demand data inputs for consistent evaluation of the alternative concepts. The technical characteristics used in the simulation of this concept are summarized in Chart 56, which were derived from system studies conducted by other NSF contractors.

Even though base load and peaking solar plants were also analyzed, the intermediate load or load following operational mode was determined to be preferred; and, consequently, the comparative technical evaluation of the alternative concepts is shown for this operating mode only.

Intermediate Solar Thermal Conversion Plant

PARABOLOIDAL DISH

- TURBINE-GENERATOR RATING 100 MW_e (η_{TG} = .34)
- LOCATION ~ INYOKERN, CALIFORNIA
- DEMAND DATA ~ SCE
- TIME PERIOD ~ 1990



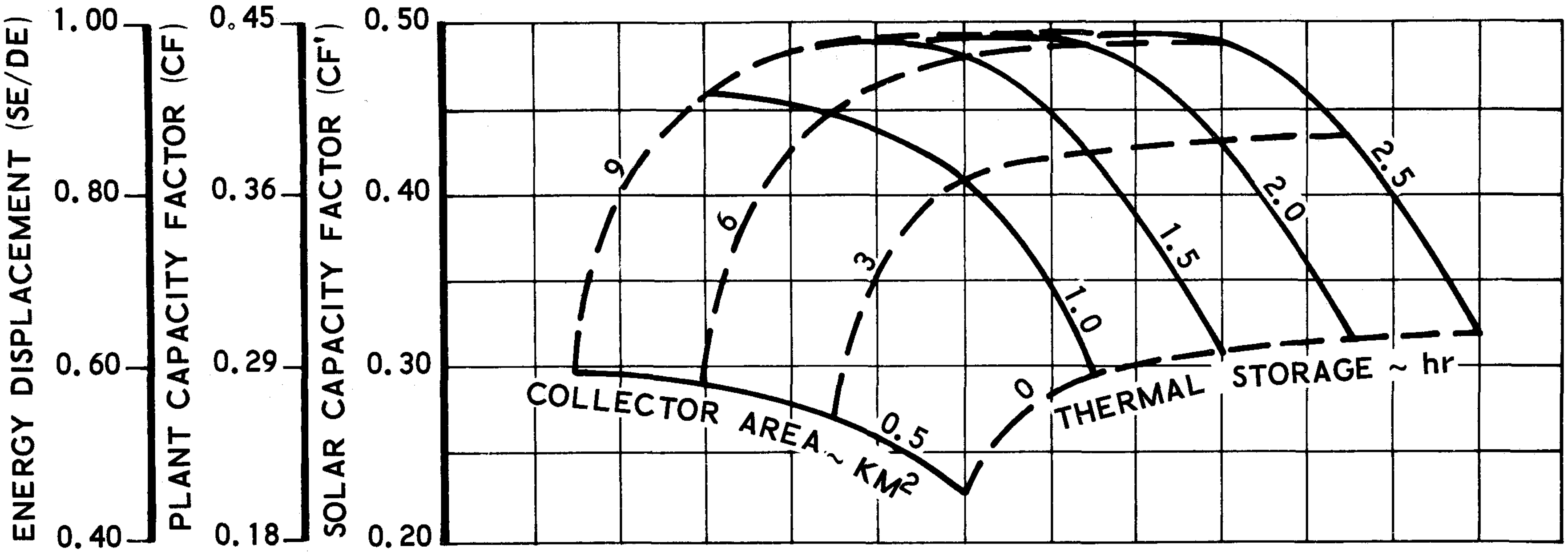


CHART 63

The parabolic cylindrical-trough collector concepts were investigated for three different orientations: Polar, North-South, and East-West. Charts 64, 65, and 66 show the parametric technical performance characteristics for 100 MWe intermediate load solar plants incorporating these alternative collector concepts.

As with the other plant concepts, these data are based upon a full year of hourly simulation using identical insolation and demand data inputs for consistent evaluation of the alternative concepts. The technical characteristics used in the simulation of this concept are summarized in Chart 56, which were derived from system studies conducted by other NSF contractors.

The comparative technical evaluation shown is for the preferred intermediate load application only.

As compared with the central receiver and paraboloidal dish power plants, all three parabolic cylindrical-trough concepts have lower relative performance characteristics. The polar-oriented plant has the highest performance of the three parabolic trough concepts and the E-W oriented plant the lowest.

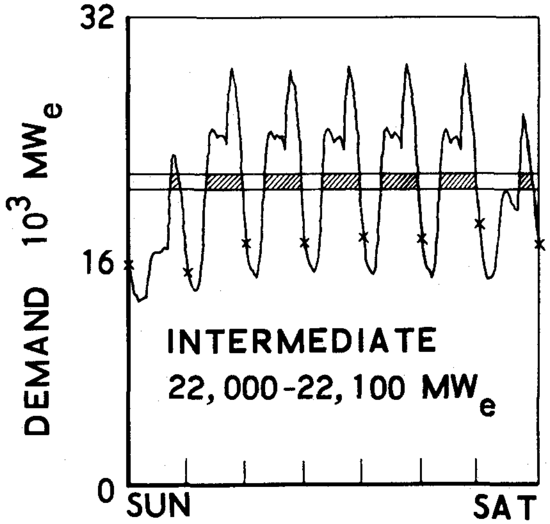
Performance of the N-S parabolic cylinder plant is severely restricted at winter solstice due to its inability to track the sun in elevation. This results in a deterioration in performance below that exhibited by the polar oriented parabolic cylinder (on a yearly integrated bases) for all combinations of collector area and storage capacity.

Performance of the E-W parabolic cylinder plant is restricted by its inability to track the sun in azimuth, which strongly affects its morning and late afternoon efficiency but results in a more level performance over the entire year than exhibited by the N-S oriented parabolic cylinder concept.

Intermediate Solar Thermal Conversion Plant

POLAR PARABOLIC CYLINDER

- TURBINE-GENERATOR RATING 100 MW_e (η_{TG} = .32)
- LOCATION ~ INYOKERN, CALIFORNIA
- DEMAND DATA ~ SCE
- TIME PERIOD ~ 1990



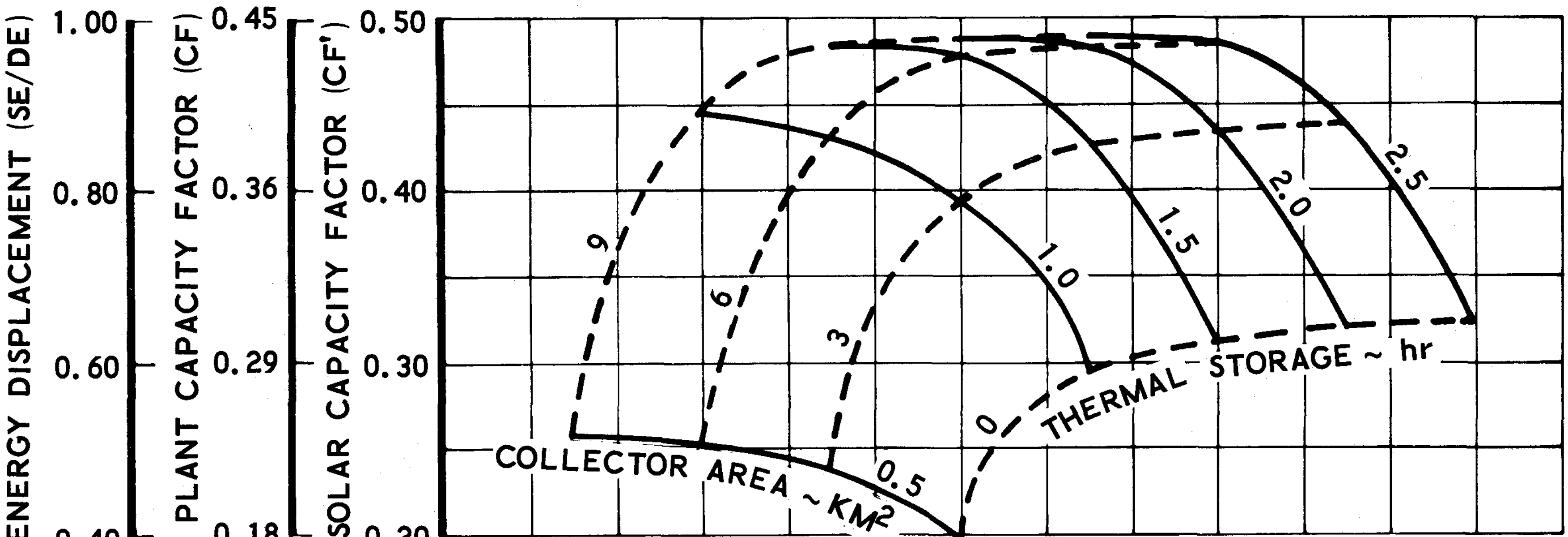
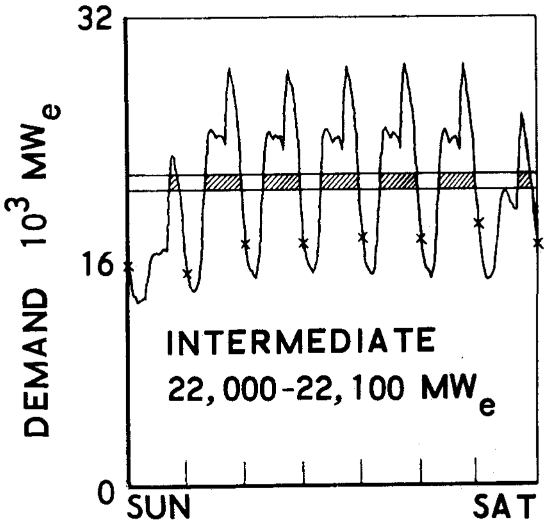


CHART 64

Intermediate Solar Thermal Conversion Plant

N-S PARABOLIC CYLINDER

- TURBINE-GENERATOR RATING 100 MW_e (η_{TG} = .32)
- LOCATION ~ INYOKERN, CALIFORNIA
- DEMAND DATA ~ SCE
- TIME PERIOD ~ 1990



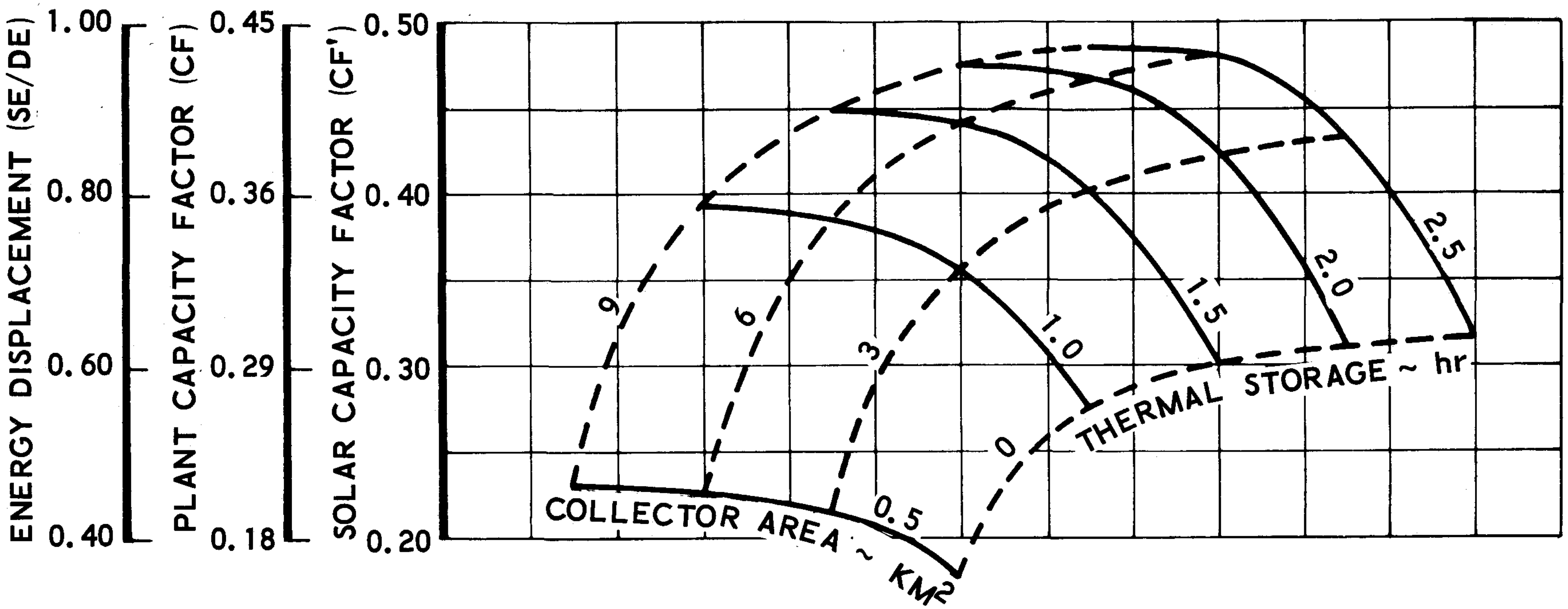
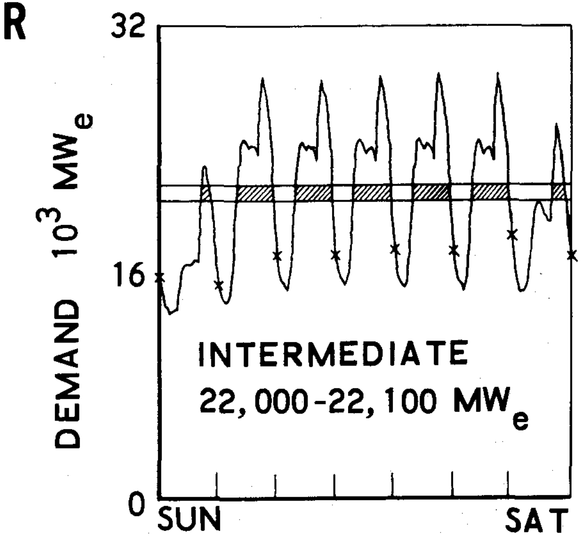


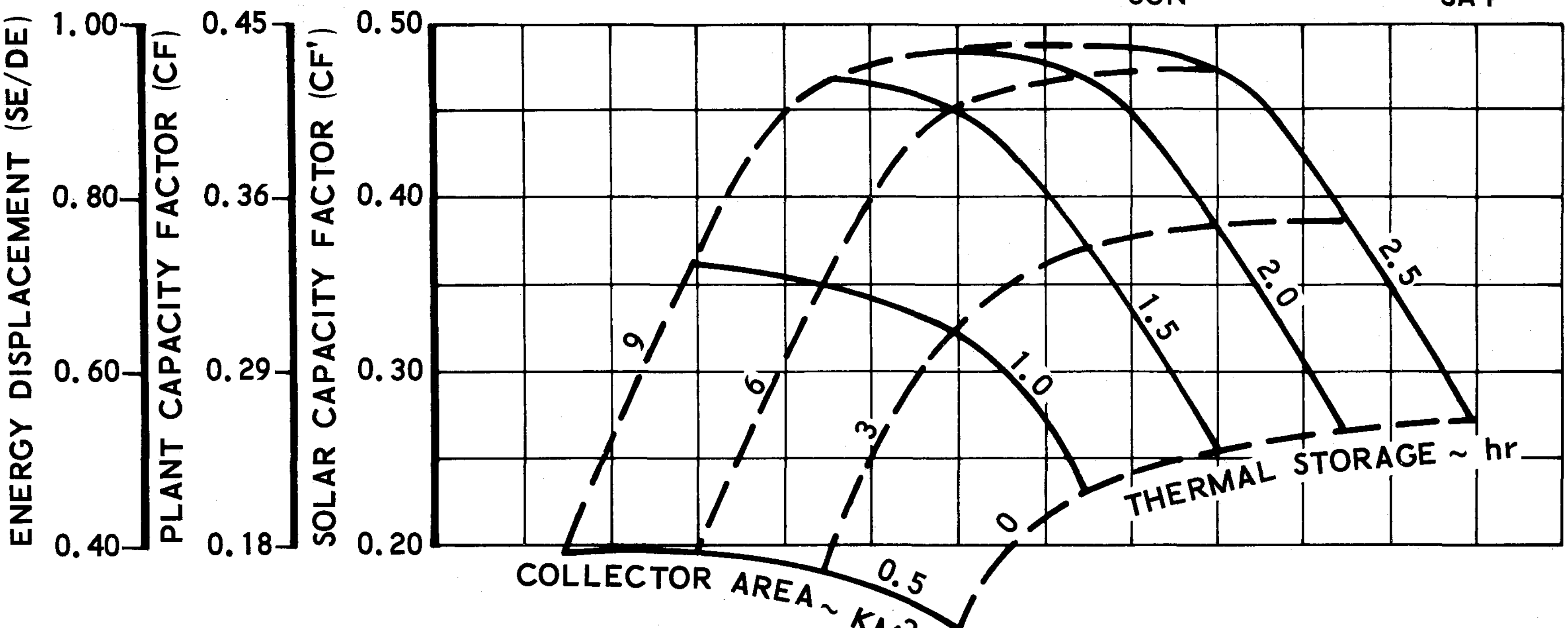
CHART 65

Intermediate Solar Thermal Conversion Plant

E-W PARABOLIC CYLINDER

- TURBINE-GENERATOR RATING 100 MW_e (η_{TG} = .32)
- LOCATION ~ INYOKERN, CALIFORNIA
- DEMAND DATA ~ SCE
- TIME PERIOD ~ 1990





COMPARATIVE TECHNICAL SOLAR THERMAL CONVERSION SYSTEM PERFORMANCE

A relative technical performance comparison of the alternative solar thermal conversion systems: central receiver, paraboloidal dish, and three parabolic cylinder concepts for base and intermediate load operation, is shown in Chart 67. The technical performance of the alternative system concepts was determined on a consistent basis using the systems methodology and input data previously described. The comparisons are made on the basis of the collector area required to achieve equivalent technical performance for a fixed storage capacity.

As can be seen from this chart, the central receiver system requires the smallest collector area and the parabolic cylindrical trough systems the largest. Though the central receiver system appears preferred on the basis of performance, a final selection must await the comparative economic evaluation, which incorporates the various solar plant costs as well as the performance attributes prior to identifying preferred system concepts.

The analyses described in this section illustrate the application of the system simulation methodology. The technical performance of alternative solar thermal conversion concepts has been parametrically assessed for base, intermediate, and peaking operational modes. Additional parametric analyses can also be conducted to examine other operating ranges, increased numbers of solar plants of varying sizes, and geographically dispersed solar plants. Furthermore, when more detailed subsystem descriptions of alternative solar power plant concepts become available, these design characteristics will be incorporated in future system analyses.

Solar Thermal Conversion Systems

TECHNICAL EVALUATION
EQUIVALENT PLANT PERFORMANCE

- PLANT CAPACITY ~100 MWe
- LOCATION ~INYOKERN
- DEMAND DATA ~SCE 1990

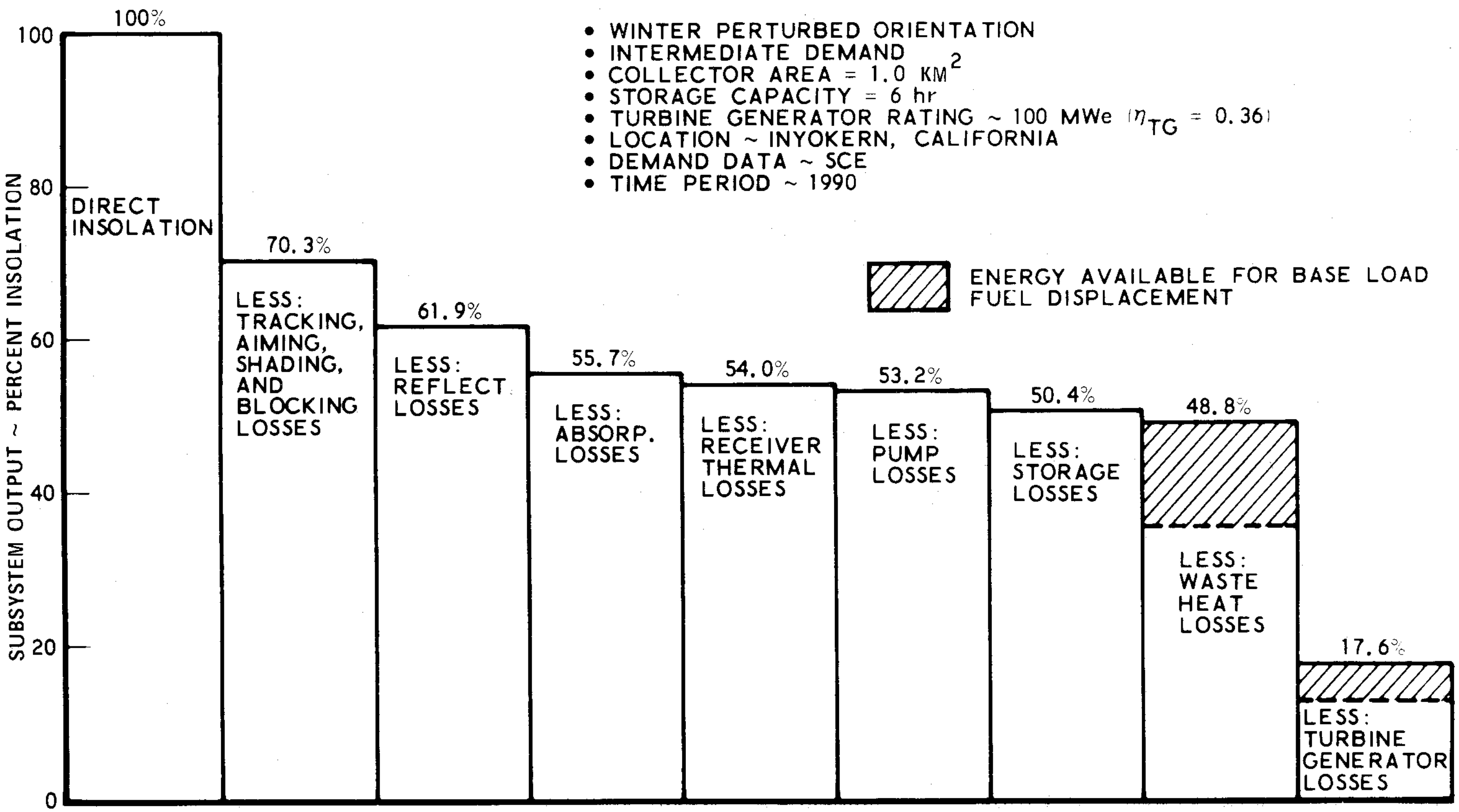
SYSTEM	COLLECTOR AREA REQUIRED ~ KM^2	
	BASE LOAD 12 hr STORAGE	INTERMEDIATE LOAD 6 hr STORAGE
CENTRAL RECEIVER	1.5	1.0
PARABOLIC CYLINDER		
POLAR	~2.0	~1.3
NORTH-SOUTH	~3.0	~2.0
EAST-WEST	~3.0	~2.0
PARABOLOIDAL DISH	~1.8	~1.2

Evaluating the performance of a solar plant involves a close determination of the individual subsystem losses. A representation of these losses for a central receiver system operating in the intermediate demand range is presented in Chart 68. These results are based on a full-year hourly simulation of a central receiver power plant with a 100 MWe rated generator capacity, a collector area of 1 km^2, and 6 hour storage capacity, located at Inyokern, California.

All subsystem losses are referenced to the direct insolation incident on the total collector area, which reflects the theoretical maximum energy available. The tracking, shading, and blocking losses, for example, represent a 29.7 percent loss of total available insolation energy. The reflectivity losses represent a further 8.4 percent loss in total available energy based on an 88 percent reflectivity.

The cross-hatched areas reflect energy available for base-load fuel displacement. This energy is above that required to satisfy the intermediate demand, and provides a total utility system cost benefit in terms of fuel savings, even though no capacity displacement credit has been assumed in the base load region.

Central Receiver System Performance



INTERMEDIATE SOLAR PLANT RELATIVE PERFORMANCE

Solar plant performance is directly dependent on the available insolation, which varies according to the specific site selected. Insolation data bases were formulated for 20 separate stations representative of the climatic regions in the Southwestern United States as described in a previous section. The performance of a representative central receiver system, operating in the intermediate mode, was simulated at each of these separate sites. The relative performance of these various sites is compared in Chart 69 to a reference plant located at Inyokern, California.

As can be seen from this chart, the maximum performance variation on the basis of a complete year simulation for the 20 different sites is less than 20 percent. Elimination of the lower insolation sites such as Fresno, California; Salt Lake City, Utah; Fort Worth, Texas; and Omaha, Nebraska, reduces the maximum performance variation to approximately 11 percent. Furthermore, solar power plants located at Inyokern and Edwards AFB, California; Yuma, Phoenix, and Tucson, Arizona; Albuquerque, New Mexico; and El Paso, Texas, have nearly identical performance characteristics.

Intermediate Solar Thermal Conversion Plant Relative Performance (Inyokern, 1963 = 100)

- CENTRAL RECEIVER
- COLLECTOR AREA ~ 1.0 KM^2
- STORAGE CAPACITY ~ 6 HRS
- INSOLATION DATA ~ 1963

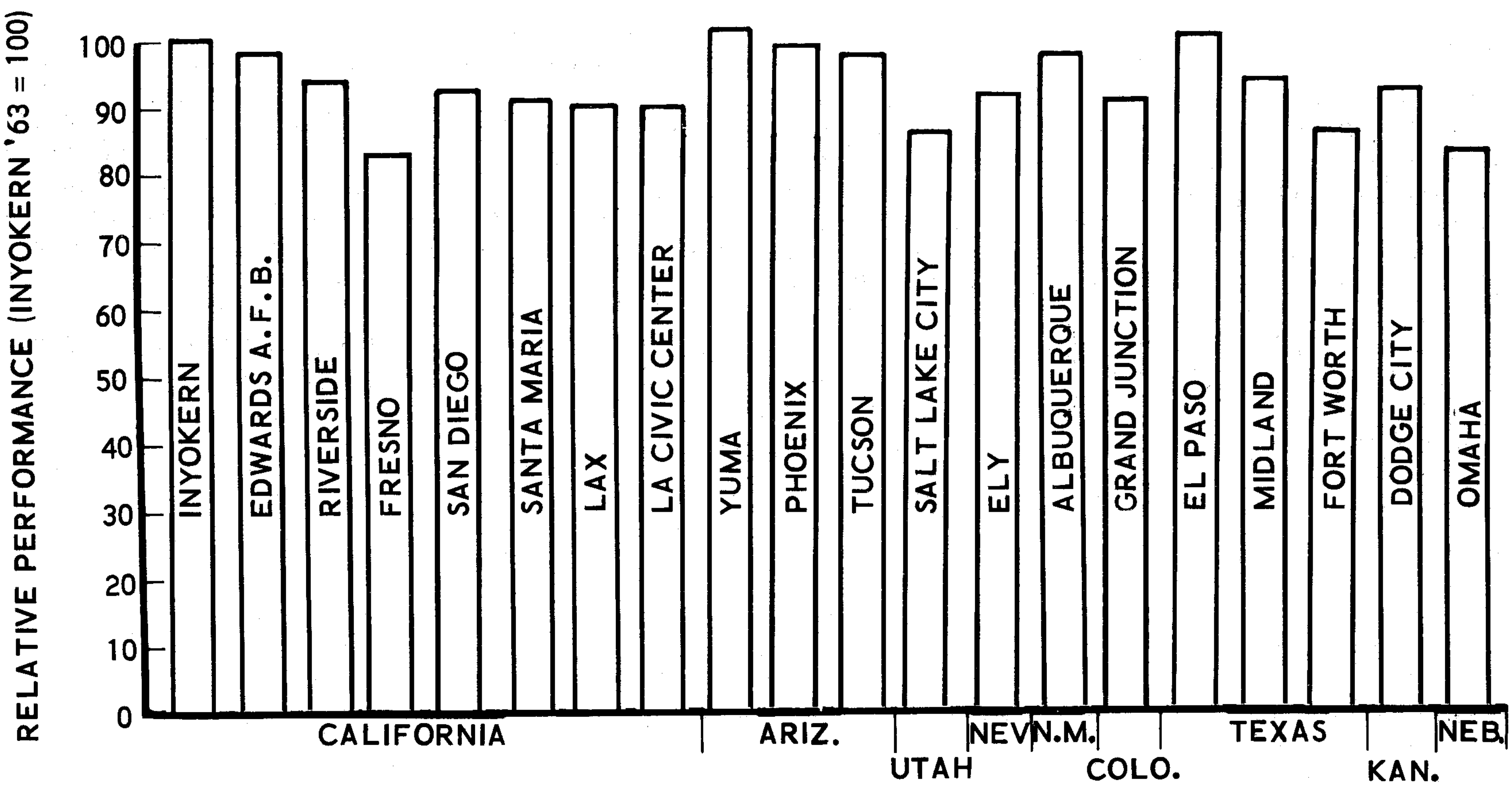


CHART 69

Periods of cloud cover resulting in little or no insolation may result in forced outages of solar plants, depending upon the energy storage capacity provided. Geographical dispersion of plants at statistically independent weather sites has been suggested as a means of reducing the impact of single solar plant outages on the total power grid.

Chart 70 presents the comparative performance simulation results of individual solar plants operating independently at either Inyokern, California, or Yuma, Arizona, with two dispersed but jointly operating solar plants located at each of these sites. The individual power plants are sized for 100 MWe rated generator capacity with 1.0 km^2 collector area and 6 hour storage capacity. The jointly operating dispersed plants were each sized for 50 MWe rated generator capacity, 0.5 km^2 collector area, and 6 hour storage capacity (one-half the 100 MWe, 6 hour thermal capacity). All simulations were performed hourly for an entire year, with the solar plants operating in the intermediate (22,000-22,100 MWe) demand range.

The performance results of each of the individual plants were compared with the joint performance of the dispersed plants to determine the relative advantages of solar plant dispersion. The outage rate determined for the dispersed plants is 5.6 per cent, which is the average value found for the single plants operating independently at Inyokern and Yuma (i.e., 6.4 percent and 4.8 percent). This indicates that solar plant dispersions average out the better and poorer site locations rather than improve the overall system performance. Each of the dispersed plants individually can only supply 50 percent of the combined 100 MWe demand. Consequently, when either plant has a forced outage, only one-half of this demand can be met. This generally accounts for the averaging effect of these dispersed plants.

Central Receiver System Performance

SOLAR PLANT GEOGRAPHIC DISPERSION

- INTERMEDIATE SOLAR THERMAL CONVERSION PLANT
- DEMAND DATA ~ SCE
- TIME PERIOD ~ 1990
- TURBINE GENERATOR EFFICIENCY $\sim \eta_{TG} = 0.36$

SOLAR PLANT CHARACTERISTICS	SINGLE SOLAR PLANT		DISPERSED SOLAR PLANTS	
PLANT LOCATION	INYOKERN	YUMA	INYOKERN	YUMA
PLANT SIZE				
TURBINE/GEN. RATING	100 MWe		50 MW_e	
COLLECTOR AREA	1.0 Km^2		0.5 Km^2	
STORAGE CAPACITY	6 hrs		6 hrs*	
SOLAR PLANT PERFORMANCE				
PLANT CAPACITY FACTOR	0.419	0.427	0.423	
SOLAR PLANT OUTAGE	6.4%	4.8%	5.6%	

*50% thermal energy capacity of single 100 MW_e solar plant

The overall performance of a solar plant is subject to the individual characteristics of the various subsystems. Sensitivity analyses were performed for a central receiver system operating in the intermediate mode to determine the impact of varying subsystem characteristics on overall system performance.

The sensitivity was assessed by noting the performance variations from nominal on a subsystem basis. The sensitivity results are presented in Chart 71, in terms of solar plant capacity factor and busbar energy cost deviations.

As can be seen in this chart, the system performance is not overly sensitive to the anticipated changes in subsystem characteristics. The maximum deviations in solar plant capacity factor result from changes in receiver absorptivity and turbine/generator efficiency. The sensitivity in either parameter is represented by a 1.9 percent improvement (2.8 percent degradation) in plant capacity factor due to a 10 percent increase (decrease) in the system parameter. These same results also represent the sensitivity for similar percentage changes in insolation or collector efficiencies, as these impact overall system efficiency in a similar manner. The other subsystem uncertainties display a decidedly reduced impact on overall system performance. The receiver temperature sensitivity shown reflects only the change in radiative and convective losses and does not include the effect on turbine/generator performance due to the different input steam temperature.

Central Receiver System (Winter perturbed)

TECHNICAL AND ECONOMIC SENSITIVITY ANALYSIS

- INTERMEDIATE DEMAND
- COLLECTOR AREA ~1.0 kM^2
- STORAGE ~6 hr

SUBSYSTEM	SUBSYSTEM NOMINAL PERFORMANCE	SUBSYSTEM PERFORMANCE VARIATIONS	SYSTEM SENSITIVITY	
			CAPACITY FACTOR	BUSBAR COST 1991 mills/kWh
COLLECTOR/RECEIVER: ABSORPTIVITY*	90%	99%(+10%) 81%(-10%)	+1.9% -2.8%	-0.9 +1.3
RECEIVER: SURFACE TEMP	538°C(1000°F)	1200°F(+20%) 800°F(-20%)	+0.4% +0.4%	-0.2 +0.2
DISTRIBUTION PUMP POWER	0.5 MW_e(max)	1.0 MW_e(+100%) 0.25 MW_e(-50%)	+0.2% -0.2%	-0.1 +0.1
STORAGE INPUT EFFICIENCY	85%	100%(+18%) 70%(-18%)	+1.1% -1.3%	-0.5 +0.6
TURBINE/GENERATOR EFFICIENCY	36%	39.6%(+10%) 32.4%(-10%)	+1.9% -2.8%	-0.9 +1.3

* Similar Effects Result from percent changes to collector efficiencies

COMPARATIVE ECONOMIC EVALUATION

COMPARATIVE ECONOMIC EVALUATION

Having parametrically determined the technical performance of the solar power plants for different modes of operation, a comparative economic evaluation of these alternative solar thermal conversion power plants and conventional power plants was made, which is discussed in this section.

The scope of the comparative economic analysis is listed in Chart 72. The National Science Foundation (NSF) has directed the development of data standards which are to be used by all the NSF Solar Thermal Conversion Mission Analysis contractors for consistent economic evaluation.

In addition, a methodology was developed for comparative economic analyses of solar thermal power plants and conventional power plants. This methodology is documented in an interim report: "Power Plant Economic Model" (Reference 6).

The Comparative Economic Evaluation depends heavily on the results of the Comparative Technical Evaluation which precedes this section. For the solar thermal power plants a cost sensitivity analysis was performed of those items which have either a large impact on the total cost or have a substantial uncertainty associated with their estimates.

Economic Analysis

- DATA STANDARDS
- METHODOLOGY
- COMPARATIVE ECONOMICS
  - DATA SOURCES
  - CONVENTIONAL POWER PLANTS
  - SOLAR THERMAL CONVERSION POWER PLANTS
- COST SENSITIVITY ANALYSIS

As shown in Chart 73, 1973 was selected as the base year for economic data since this is the most recent complete calendar year for which published capital and operating cost data are available. The rate of inflation, as measured by the gross national product implicit price deflator, was assumed to average 3 percent per year from 1973 into the future, even though fluctuations in this rate will occur for certain time periods. It is recognized that this 3 percent rate may be too low for an analysis with 1980 as the year of commercial operation. However, since all escalation rates are consistently expressed in terms of the assumed inflation rate, the comparative economic analyses remain valid regardless of the actual rate of inflation.

Escalation rates for 15 different capital-investment-cost categories were developed. These are essentially the Federal Power Commission two-digit accounts, such as facilities and structures, to which were added special accounts for solar collectors and thermal storage subsystems (those subsystems not found in conventional-type power plants). Each of these accounts has a composite escalation rate, and these rates are based on the proportions of construction materials, construction labor, and factory equipment. The projected rate of inflation is used as the basis for these escalation values, so that a higher rate of inflation implies higher escalation rates.

The projected escalation rates for fuels and the effect of resource depletion on future nuclear fuel cycle costs were investigated and estimates of fossil fuel prices were made.

The cost-of-capital (after taxes) is also related to the assumed rate of inflation. It is based upon historical data for years 1956 to 1972, assuming equal debt-and-equity ratios of 50 percent and a combined state and federal income tax rate of 40 percent. The capital structure, tax rate, and cost-of-capital used reflect values representative of the electric utility industry.

Data Standards

BASE YEAR	-	1973
INFLATION	-	3%/year
PLANT LIFE	-	30 years
DEPRECIATION	-	STRAIGHT LINE
COST OF CAPITAL	-	7.4% (after tax)
DEBT/EQUITY	-	50%/50%
TAX RATE	-	40%
LAND AND SOLAR MATERIALS	-	NON-DEPRECIABLE

ESCALATION RATES

INVESTMENT COSTS	-	0 - 6.1%/year
OPERATION & MAINTENANCE	-	4.0%/year
FUEL	-	5.5 - 12.8%/year
REVENUES	-	2%/year
INSURANCE/PROPERTY TAX	-	0%/year

CHART 73

Several methods exist for the economic assessment of power plants, as shown in Chart 74. The discounted cash flow (DCF) analysis is the most sophisticated method used in financial investment analyses. This method has the greatest flexibility but is also the most complex, often requiring the use of a digital computer. The output of this method can either be in constant or current dollars.

Alternatively, the utility industry frequently uses the levelized fixed charge method, which on the surface is relatively simple to use, but is less flexible. This method is derived from the discounted cash flow analysis and utilizes a predetermined (from DCF analysis) levelized fixed charge rate to compute the fixed charges. To be consistent, levelized variable costs should also be input to this method, which results in a levelized value of the busbar energy cost output.

Power Plant Economic Analyses

1. POWER PLANT ECONOMIC MODEL
   - DISCOUNTED CASH FLOW ANALYSIS
   - CURRENT DOLLARS
2. POWER PLANT ECONOMIC MODEL
   - DISCOUNTED CASH FLOW ANALYSIS
   - CONSTANT DOLLARS
3. LEVELIZED FIXED CHARGE RATE METHOD

The economics of solar systems is an important criterion for determining the market capture potential. By comparing the capital investment requirements and operating costs of the alternative solar missions and systems, preferred concepts can be identified. The economic feasibility of these preferred missions and systems can be determined by comparative economic evaluation of these and conventional nuclear and fossil power plants for identical periods of commerical operation. The economic analysis methodology developed for conducting these assessments on a consistent basis is shown in Chart 75. The capital investment costs for each subsystem account can be estimated for a given size power plant in terms of base year (1973) dollars. To determine the relative economics of different size power plants, an economics of scale subroutine has been included, consisting of cost scaling relationships.

A significant contribution to power plant cost is due to escalation. This is included in the model by an escalation subroutine, which determines the escalation in costs until the start of construction. During construction, cash flows are expended which incur interest-during-construction (IDC) expenses in addition to the escalation of costs during this construction time period.

The base year (1973) capital investment costs combined with the escalation and IDC determine the total capital investment cost at the year of commercial operation. Using the discounted cash flow method, the capital investment cost at the year of commercial operation together with other fixed charges such as insurance and property taxes determine the fixed charges. Cash flows are determined from pro-forma income statements, while the rate of discount is the cost of capital typical of the utility industry, which is the weighted average cost of common and preferred equity and long-term debt.

The discount rate is used to calculate the present value of all future income and cost cash flows during the operating life of the plant. Estimated operating costs are combined with fixed charges to determine the total busbar energy cost (either in current or constant dollars) using the discounted-cash-flow analysis method.

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

The computer program developed for this economic methodology is described in detail in an interim report: "Power Plant Economic Model" (Reference 6).

Economic Analysis Methodology

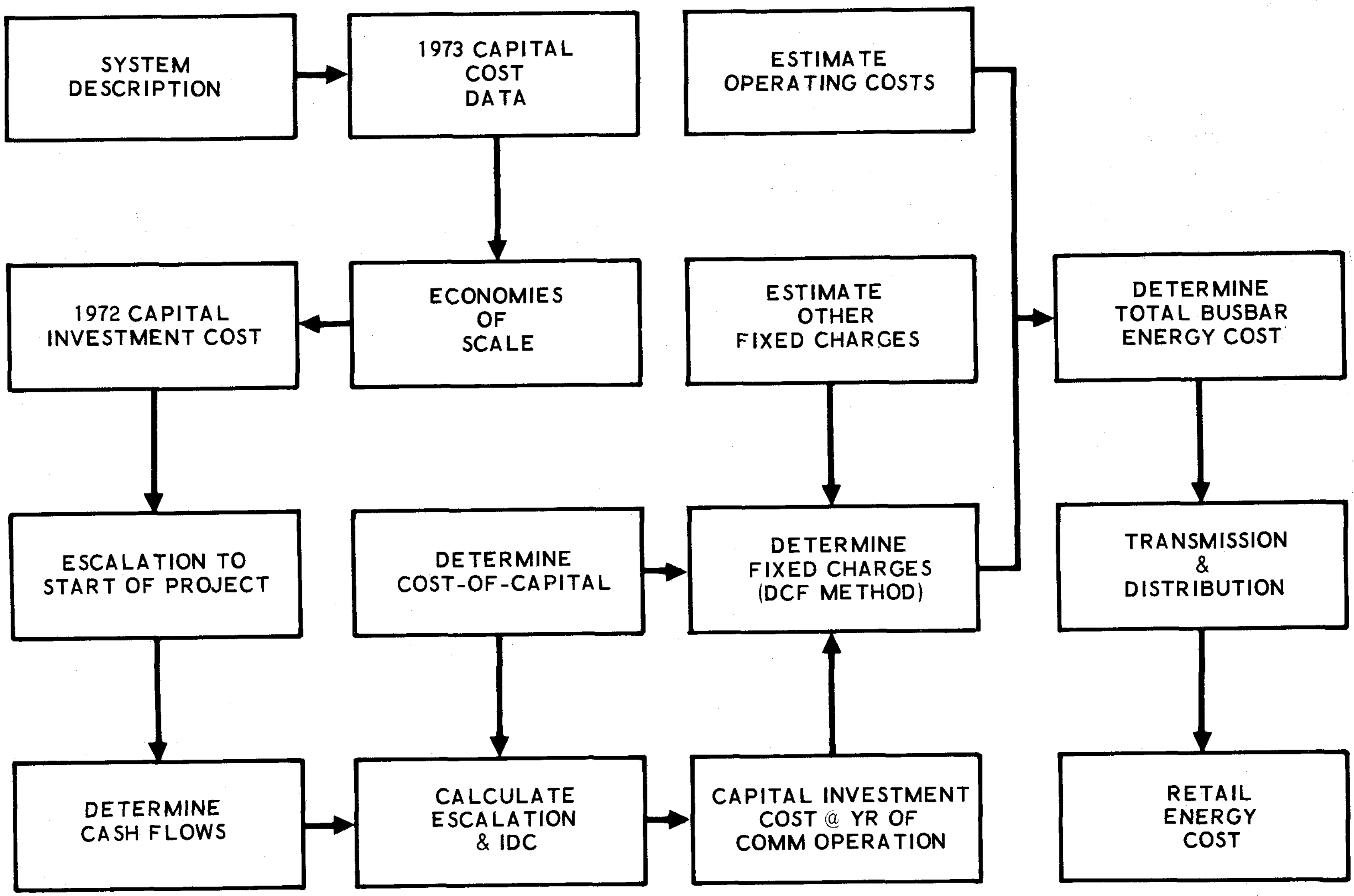


CHART 75

TYPICAL POWER PLANT ECONOMIC MODEL OUTPUT

A typical computer output of the power plant economic model described (Reference 6) is shown in Chart 76.

This chart only shows the busbar energy cost output, both in current and constant 1973 dollars for the first year of commercial operation. Other typical outputs are capital investment costs at the start of design and construction, capital costs at year of commercial operation, cost of capital, income statements, busbar energy costs at other years of commercial operation, levelized busbar energy costs, as well as the various economic and cost input data.

POWER PLANT ECONOMIC MODEL

Intermediate-Load 100 MW_e Central Receiver Power Plant

(Revenue Escalated Rate - 2%)

BUSBAR ENERGY COSTS FOR YEAR 1991

	CURRENT DOLLARS MILLS/KWH	CONSTANT 1973 DOLLARS MILLS/KWH
FUEL	0.00	0.00
OPERATION AND MAINTENANCE	4.14	2.43
FUEL DISPLACEMENT CREDIT	(1.63)	(.96)
BACKUP CAPACITY COST	0.00	0.00
TOTAL OPERATING COST	2.51	1.47
COST OF MONEY	23.61	13.87
DEPRECIATION	11.45	6.72
INSURANCE AND PROPERTY TAXES	1.55	.91
INCOME TAXES	9.07	5.33
TOTAL FIXED CHARGES	45.68	26.83
TOTAL BUSBAR COST	48.19	28.30

CHART 76

An alternative method to the discounted cash flow or present value economic evaluation of power plants is the levelized fixed charge method. This method is widely used in the utility industry for quick calculation of the busbar energy cost.

The levelized fixed charge method, shown in Chart 77, computes the busbar energy cost by adding the fixed and variable cost components. As will be shown in detail in Volume IV, the levelized fixed charge method is derived from the discounted cash flow methodology, and when applied correctly, will yield equivalent results. Levelized values of fuel and operating and maintenance costs must be input which, when combined with the fixed charges as estimated by the levelized fixed charge rate, result in a levelized busbar energy cost.

These levelized values do not precisely correspond to the actual costs experienced in any year during the operational lifetime of the plant. Values of levelized fixed charge rates are shown in the following chart, as determined by the various economic parameters.

Even though the levelized fixed charge method appears simple at first glance, the correct use of this method is often quite complex and, consequently, time consuming as well as subject to errors in interpretation.

Levelized Fixed-Charge Method

GENERATION COST

- BUSBAR ENERGY COST = FIXED CHARGES + INCR. FUEL COST + O & M

$$BBEC = \frac{CC \times FCR}{CF \times 8.76} + \frac{HR \times FC}{10^5} + O\ \&\ M$$

WHERE
CC = CAPITAL COST, \$/KW*
FCR = FIXED CHARGE RATE, %/year
CF = CAPACITY FACTOR, %
HR = HEAT RATE, BTU/KWH
FC = LEVELIZED FUEL COST, ¢/MILLION BTU
O&M = LEV. OPERATING AND MAINTENANCE COST, MILLS/KWH

FIXED CHARGES

- FIXED CHARGES = DEPRECIATION + COST OF MONEY + INSURANCE + TAXES
- FIXED CHARGE RATE IS LEVELIZED AVERAGE DISCOUNT EXPRESSED AS PERCENT OF CAPITAL INVESTMENT AT YEAR OF COMMERCIAL OPERATION

* YEAR OF COMMERCIAL OPERATION

Typical values for the levelized fixed charge rate (FCR) are shown in Chart 78 for both private and municipal utility companies. These levelized FCRs were derived from the discounted cash flow analysis as discussed in Volume IV of this report. As can be seen, the FCR is a function of the financial structure (equity/debt) and costs of financing, the corporate tax rate, plant operational lifetime, and salvage value of the investment. Also shown is the after-tax cost of capital, as determined by the financial structure of the utility. In the case of municipal utility companies, no corporate taxes are levied and the cost of financing is by means of debt only, often in the form of tax-free municipal bonds.

Levelized Fixed Charge Rate (FCR)

UTILITY TYPE	COST OF COMMON EQUITY (k_C)	COST OF PREFERRED EQUITY (k_P)	COST OF LONG-TERM DEBT (k_D) (before taxes)	PERCENT OF COMMON EQUITY (C/V)	PERCENT OF PREFERRED EQUITY (P/V)	PERCENT OF LONG-TERM DEBT (D/V)	COMPOSITE CORPORATE TAX RATE (τ)	COST-OF-CAPITAL (k) (after taxes)	PLANT OPERATING LIFE-TIME (N)	LOCAL TAXES OR PAYMTS (percent of orig. inv.)	LEVELIZED FIXED CHARGE RATE (FCR)
PRIVATE	10	6	6	40	10	50	40	6.4	30	2	15.4
	10	-	6	50	-	↓	↓	6.8	↓	↓	15.9
	12	-	8		-	↓	↓	8.4	↓	↓	19.1
	12	8	8	40	10	↓	↓	8.0	↓	↓	18.6
	↓	↓	↓	↓	↓	↓	↓	↓	↓	1	17.6
	↓	↓	↓	↓	↓	↓	↓	↓	↓	3	19.6
	↓	↓	↓	↓	↓	↓	50	7.6	↓	2	19.8
	↓	↓	↓	↓	↓	↓	40	8.0	25	↓	18.9
	↓	↓	↓	↓	↓	↓	↓	↓	20	↓	19.6
MUNICIPAL	N/A	N/A	5	N/A	N/A	100	0	5.6	30	2	8.5
	↓	↓	6	↓	↓	↓	↓	6.0	↓	↓	9.3
	↓	↓	7	↓	↓	↓	↓	7.0	↓	↓	10.1
	↓	↓	8	↓	↓	↓	↓	8.0	↓	↓	10.9

LEVELIZED FIXED CHARGE METHOD

The levelized fixed charge method is illustrated in Chart 79. Shown in this chart are the variable [fuel; operations and maintenance (O&M)] and fixed charge components that make up the busbar energy cost in current dollars over the lifetime of the plant. As can be seen, the busbar energy cost and variable costs increase during the lifetime, while the fixed charges typically decrease. All costs (mills/KWH) are expressed in current dollars.

The levelized values of these costs as derived by either the discounted cash flow or the fixed charge methods are also indicated in this chart. These levelized costs fall somewhere in between the first and last year costs as indicated by the bar chart. The levelized values are constant costs over the lifetime of the plant which give the equivalent net present value when discounted at the cost of capital as the actual current costs.

This chart indicates clearly the limitations of the fixed chart method since the busbar energy cost obtained, and the requirement of utilizing levelized fuel and operating and maintenance costs in this method, represents a levelized value.

In the comparative economic evaluation of the alternative solar thermal conversion systems and conventional power plants, the more flexible computerized discounted cash flow method, as described previously, was used.

Levelized Fixed Charge Method

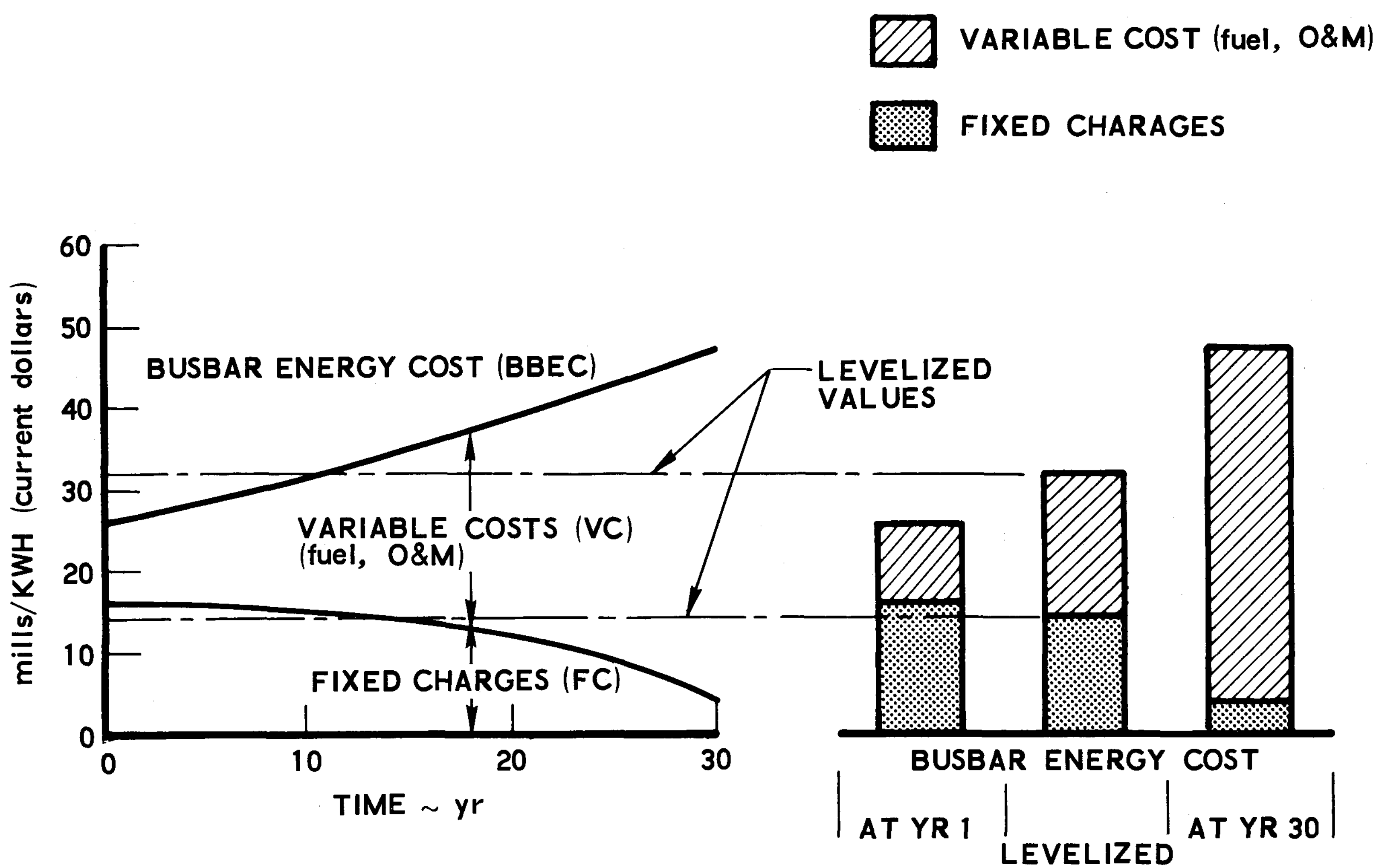


CHART 79

The total busbar energy cost was determined for the 100 MWe base load central receiver power plant configurations with characteristics and parametric performance described in the previous comparative technical evaluation. The results of the economic evaluation are shown in carpet plots in Chart 80.

For the first year of commercial operation (1991) total busbar energy costs (in current and constant 1974 dollars) are shown parametrically for various collector area and storage capacity combinations. The carpet plot reflects a $30/m^2 collector area cost and a $15/KWHe storage cost (1973 dollars).

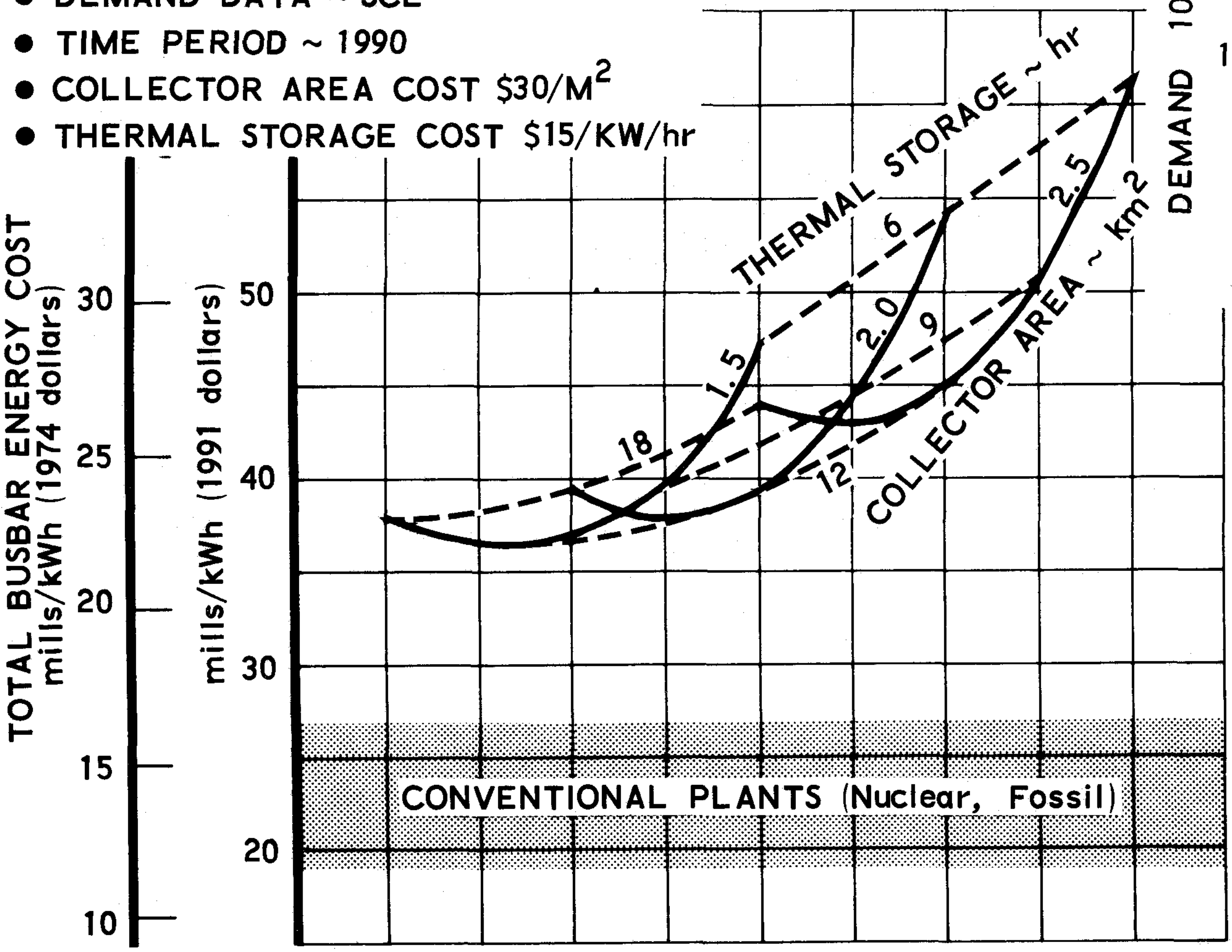
As can be seen from this chart, for base load application, the lowest busbar energy cost (37 mills/KWH, 1991 dollars) is for a solar plant with a 1.5 km^2 collector area and 12 hour storage capacity.

The wide band at the bottom of the chart is the busbar energy cost for 1,000 MWe conventional (nuclear and fossil) power plants. These busbar energy costs were computed using the same economic analysis methodology and data standards as used for the solar power plants. The width of the conventional power busbar energy cost band (19-27 mills/KWH, 1991 dollars) reflects both nuclear (PWR) and fossil (coal) power plants with variations in the assumed plant capacity factors of 70 percent to 80 percent.

Base Load Solar Thermal Conversion Plant

CENTRAL RECEIVER (winter orientation)

- CENTRAL RECEIVER CONCEPT (winter orientation)
- TURBINE-GENERATOR RATING ~ 100 MW_e (η_{TG} = 0.36)
- LOCATION ~ INYOKERN, CALIFORNIA
- DEMAND DATA ~ SCE
- TIME PERIOD ~ 1990
- COLLECTOR AREA COST $30/$M^2$
- THERMAL STORAGE COST $15/KW/hr



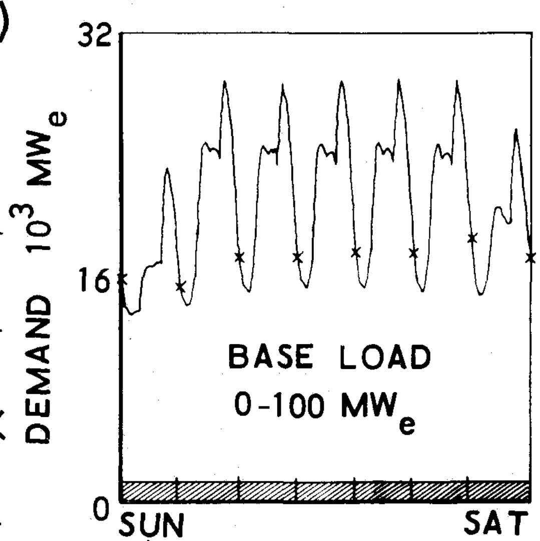


CHART 80

The total busbar energy costs for 100 MWe central receiver solar power plants for intermediate and peak load applications are shown in Charts 81 and 82, respectively.

The results are shown parametrically for various combinations of collector area and storage capacity. The carpet plots reflect a $30/m^2 unit-area collector cost and a thermal storage cost of $15/KWHe (1973 dollars).

Included in the solar plant busbar energy cost is an allowance for backup capacity. This is the cost for maintaining sufficient conventional backup capacity to achieve equal utility system reliability as for a conventional plant. The rationale for and the amount of backup capacity required were determined previously in the margin analysis.

For intermediate and peaking solar plants, in addition to the additional fixed charge to account for conventional backup capacity required, an energy-displacement credit is incorporated to account for the additional base or intermediate load energy (fuel) displacement. No additional capacity displacement was assumed.

For intermediate load application, a solar plant with a 1.0 km^2 collector area and 6-hour storage capacity has the lowest total busbar energy cost.

In the case of peak load applications, the minimum solar plant busbar energy occurs with a 0.5 km^2 collector area and 3 hours of storage capacity.

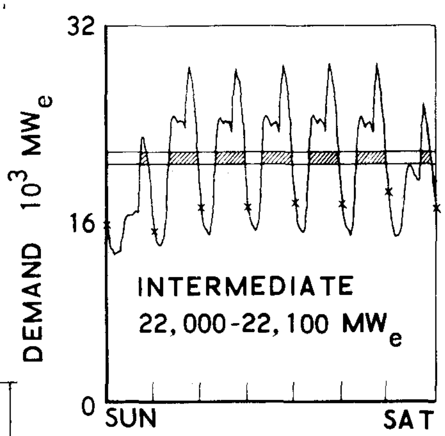
The fossil fuel busbar energy costs for intermediate and peaking plants, as shown by the wide band in Charts 81 and 82, were based on a 400 MWe combined-cycle plant for intermediate load and a 100 MWe gas turbine plant for peak load application, respectively. A 1991 fuel cost range (in 1990 dollars) of $1.65 to $2.40 per MBTU was assumed, with an escalation rate of 5 percent per year. The busbar energy costs for these intermediate and peaking fossil plants are representative of intermediate and peaking power plants for the 1990 time period.

As can be seen from Chart 81, the central receiver solar plant with a collector area of 1.0 km^2 and 6 hour storage capacity operating in the intermediate mode appears competitive with the intermediate load conventional power plants for the 1990 time period, assuming that the collector cost of $30/m^2 can be realized.

Intermediate Solar Thermal Conversion Power Plant

CENTRAL RECEIVER (winter orientation)

- TURBO-GENERATOR RATING ~ 100 MW_e (η_{TG}=0.36)
- LOCATION ~ INYOKERN, CALIFORNIA
- DEMAND DATA ~ SCE
- TIME PERIOD ~ 1990
- COLLECTOR AREA COST $30/$M^2$
- THERMAL STORAGE COST $15/KW/hr



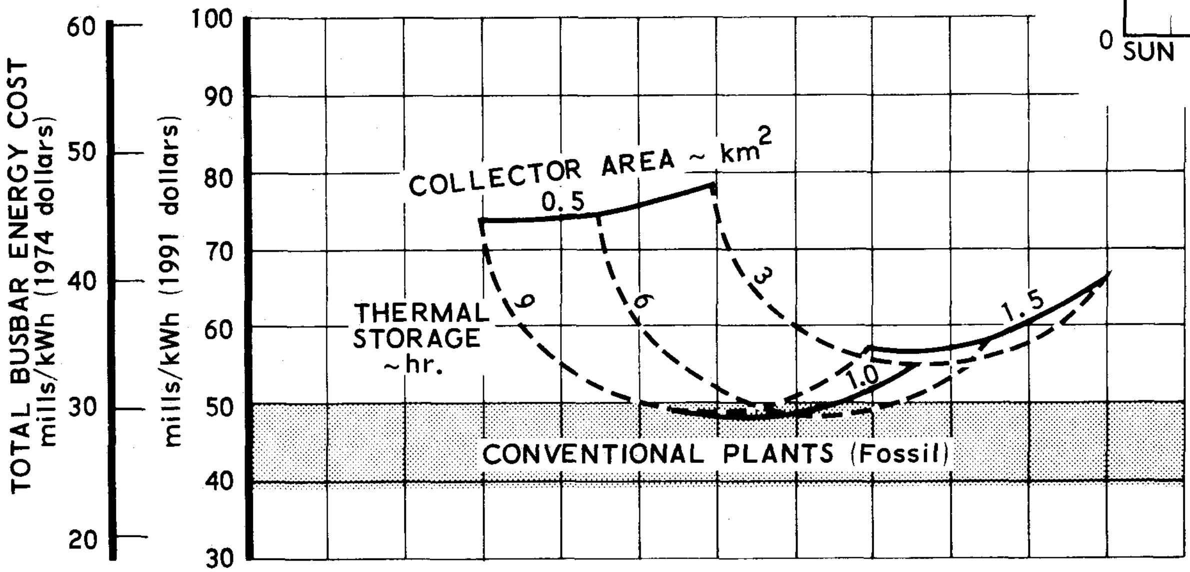
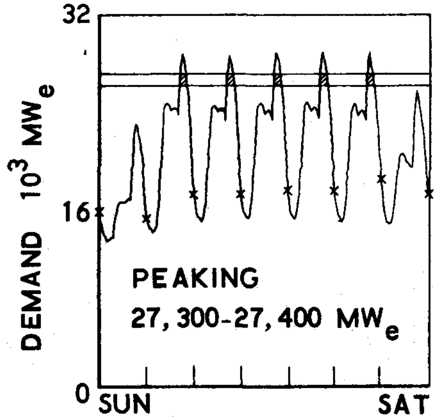


CHART 81

Peaking Solar Thermal Conversion Power Plant Central Receiver (Winter Perturbed)

- TURBO-GENERATOR RATING ~ 100 MW_e (η_{Te} = 0.36)
- LOCATION ~ INYOKERN, CALIFORNIA
- DEMAND DATA ~ SCE
- TIME PERIOD ~ 1990
- COLLECTOR COST ~ \$30/m^2
- THERMAL STORAGE COST ~ \$15/kW/hr



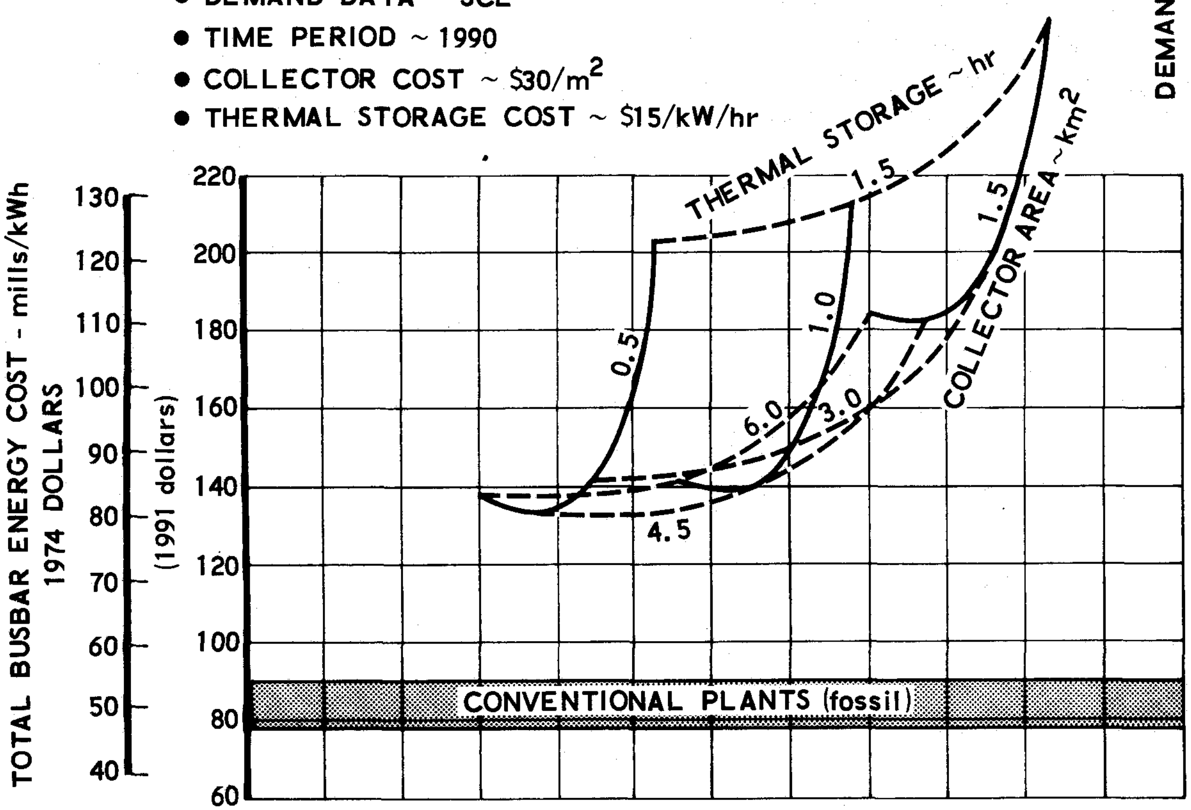


CHART 82

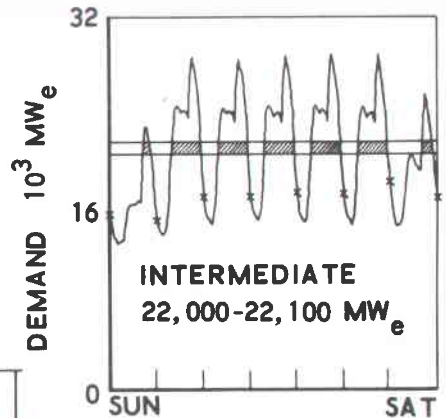
One of the assumptions in the central receiver power plant is the cost of thermal energy storage of $15/KWHe. Since energy storage concepts are least well defined at the present time, the sensitivity of the preceding results to this cost assumption was evaluated. Shown on Chart 83 is the 100 MWe intermediate load central receiver power plant busbar energy cost, assuming a thermal storage cost of $30/KWHe, as compared to the previous results reflecting the $15/KWHe storage cost. As can be seen, the increase in busbar energy cost for the intermediate load central receiver plant (with 1 km^2 collection area, 6-hour storage capacity) due to doubling the storage cost is minimal (50.0 mills/KWH versus 47.5 mills/KWH, respectively, in 1991 dollars).

As is apparent from this economic evaluation of the central receiver solar power plants, the preferred mode of operation is the intermediate load application. Consequently, all the alternative solar thermal conversion system concepts are compared for this intermediate load operational mode.

Intermediate Solar Thermal Conversion Power Plant

CENTRAL RECEIVER (winter orientation)

- TURBO-GENERATOR RATING ~100 MW_e (η_{TG}=0.36)
- LOCATION ~ INYOKERN, CALIFORNIA
- DEMAND DATA ~ SCE
- TIME PERIOD ~ 1990
- COLLECTOR AREA COST \$30/M^2 — \$ 30/M^2
- THERMAL STORAGE COST \$15/KW/hr — \$ 30/KW/hr



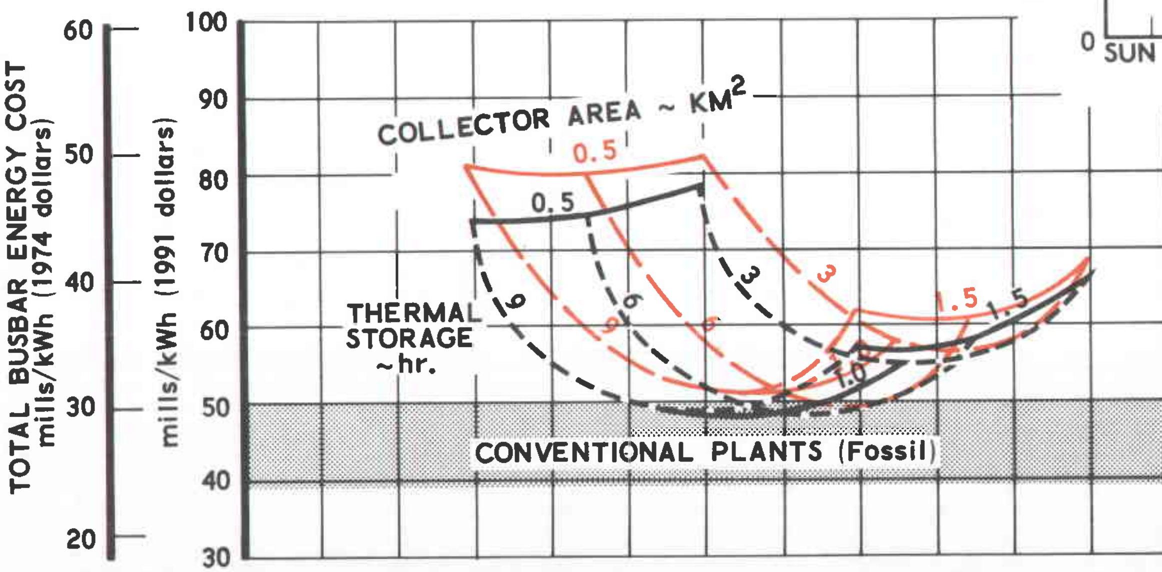


CHART 83

Because the thermal energy storage concepts are the least well defined at the present time, a hybrid power plant may be an alternative to the stand-alone solar power plant. Such a hybrid plant still requires some limited thermal storage capacity (approximately 1/2 hour) for dynamic stability of operation during short periods of intermittent cloud cover. In lieu of the long-term storage required for reliable and economic operation as discussed in the preceding sections, the hybrid plant incorporates a conventional fossil fueled boiler. The remainder of the plant is common to both the solar and fossil fuel thermal inputs.

Such a hybrid central receiver power plant is compared to the previously discussed stand-alone central receiver plant economic performance for the intermediate-load application in Chart 84. The 100 MWe hybrid plant has a collector area of approximately 0.5 km^2, since no storage capacity exists to store excess energy above the turbine/generator capacity rating of 100 MWe. Both the hybrid and conventional combined-cycle plant busbar energy costs are shown parametrically as a function of the fuel cost.

As can be seen from this chart, the 1991 busbar energy cost of the hybrid central receiver plant is less than for a conventional fossil plant when 1991 fuel costs rise above $2.10 per MBTU (1973 dollars).

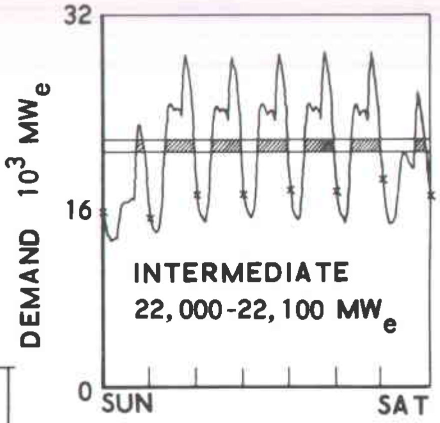
In contrast, the stand-alone central receiver plant for intermediate application is competitive with this conventional plant at 1991 fuel costs of $1.40 MBTU (1973 dollars) or higher.

Intermediate Solar Thermal Conversion Power Plant

CENTRAL RECEIVER (winter orientation)

HYBRID PLANT (0.5 KM^2/0.5 hr)

- TURBO-GENERATOR RATING ~ 100 MW_e (η_{TG}=0.36)
- LOCATION ~ INYOKERN, CALIFORNIA
- DEMAND DATA ~ SCE
- TIME PERIOD ~ 1990
- COLLECTOR AREA COST \$30/M^2
- THERMAL STORAGE COST \$15/KW/hr



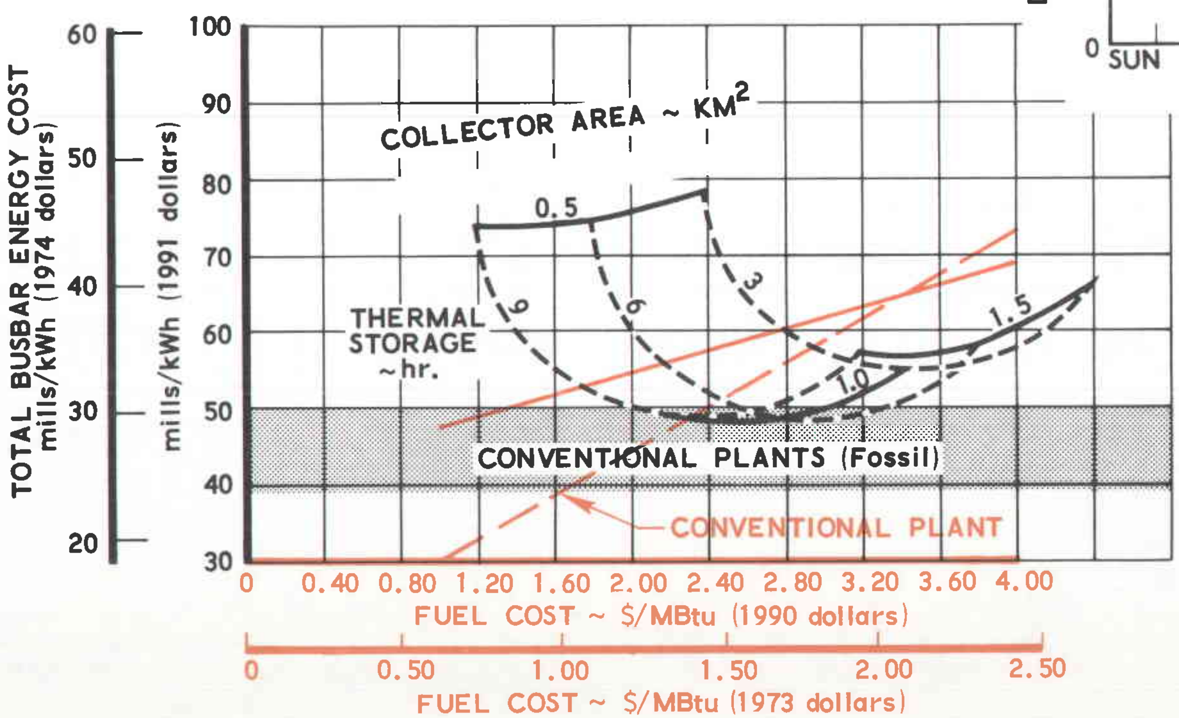


CHART 84

Representative stand-alone and hybrid central receiver solar thermal conversion power plant capital cost estimates are shown in Chart 85 for base, intermediate, and peaking-load applications, respectively. Characteristics of each of these solar plants are those described and analyzed in the preceding comparative technical evaluation. Each plant has a turbine/generator rating of 100 MWe, and the numbers 1.5/12; 1.0/6; 0.5/3; and 0.5/0.5 refer to the respective collector areas (in km^2) and storage capacities (in hours).

The capital investment costs (in 1973 dollars) as shown by the various accounts, when combined with the escalation and interest-during-construction costs, result in the total capital investment cost of these plants at the year of commercial operation (in 1990 dollars).

The capital costs are shown by investment account (in $/KWe) in accordance with the account structure used by the Federal Power Commission.

Three accounts were added specifically for solar plants. These are: solar collectors/heliostats; receiver/tower/heat exchanger; and storage/tanks.

These costs reflect the cost estimates of the various system contractors. The collector cost of $30/$m^2$, as shown in this chart, represents the lowest cost estimate. A representative cost may be $40/$m^2$; other estimates indicate collector costs as high as $70/$m^2$. The impact of increasing the collector cost can be estimated from the cost sensitivity analysis shown in Chart 95. The impact of thermal storage cost was evaluated parametrically by considering $15/KWHe and $30/KWHe unit costs (Chart 84).

Power Plant Cost Estimates
Central Receiver Concept (100 MW_e (Rated))

($/$KW_e$)

PLANT TYPE	BASELOAD	INTERMEDIATE	PEAKING	HYBRID
COLLECTOR AREA (KM^2)	1.5	1.0	0.5	0.5
STORAGE TIME (hr)	12	6	3	0.5
ACCOUNT				
LAND	3	2	1	1
STRUCTURES AND FACILITIES	44	44	44	51
HELIOSTATS*	450	300	150	150
CENTRAL RECEIVER/TOWER**/HEAT EXCH.	124	95	68	68
STORAGE/TANKS***	180	90	45	7
BOILER PLANT	-	-	-	73
TURBINE PLANT EQUIPMENT	80	80	80	80
ELECTRIC PLANT EQUIPMENT	21	21	21	21
MISC PLANT EQUIPMENT	4	4	4	4
ALLOWANCE FOR COOLING TOWERS	20	20	20	20
TOTAL DIRECT COST	926	656	433	475
CONTINGENCY ALLOWANCE	51	39	27	32
SPARE PARTS ALLOWANCE	5	3	2	3
INDIRECT COSTS	92	78	66	88
TOTAL CAPITAL INVESTMENT (1973)	1074	776	528	598
ESCALATION TO START OF CONSTRUCTION	381	296	213	270
TOTAL AT START OF CONSTRUCTION	1455	1072	741	868
INTEREST DURING CONSTRUCTION	152	119	88	105
ESCALATION DURING CONSTRUCTION	218	169	121	156
TOTAL COST AT YR OF COMM'L OPN. (1990 dollars)	1825	1360	950	1129

* Collector Cost - $30/$M^2$
** Tower Height - 260 M (3, 2, 1, 1 Tower(s), Respectively)
*** Thermal Storage Cost - $15/KW/hr

CONVENTIONAL POWER PLANT CAPITAL COST ESTIMATES

The comparative 1990 capital-cost estimates of representative conventional nuclear and fossil plants are shown in Chart 86.

The representative conventional base load plants are pressurized water reactor (PWR) nuclear and low-sulphur coal fossil plants, respectively, each with a base-load rating of 1,000 MWe. The 400 MWe combined-cycle plant is representative for intermediate-load applications, and the 100 MWe gas-turbine plant for peaking application.

The capital costs are shown by investment account (in $/KWe) in accordance with the account structure used by the Federal Power Commission. Added are allowances for environmental protection systems and cooling tower variations which apply as appropriate.

All components of the total capital investment cost accounts are in 1973 dollars, including contingency, spare parts, and indirects. The 1990 cost in current dollars is the sum of the 1973 cost, escalation to start of design and construction, and interest during construction. The escalation and interest during construction are functions of the cash expenditures flow rate for each investment account.

Power Plant Capital Cost Estimates

CONVENTIONAL SYSTEMS

($/KWe)

	NUCLEAR (PWR) (1000)	FOSSIL (coal) (1000)	COMBINED CYCLE (400)	GAS TURBINE (100)
LAND	1	1		
STRUCTURES AND FACILITIES	54	31		
REACTOR/BOILER PLANT	75	72		
TURBINE PLANT EQUIPMENT	79	58		
ELECTRIC PLANT EQUIPMENT	30	15		
MISC PLANT EQUIPMENT	5	4		
ALLOWANCE FOR COOLING TOWERS	27	19		
SO_2 REMOVAL SYSTEM	--	31		
ZERO RADWASTE SYSTEM	4	--		
TOTAL DIRECT COST	275	231		
CONTINGENCY ALLOWANCE	19	17		
SPARE PARTS ALLOWANCE	1	1		
INDIRECT COSTS	68	61		
TOTAL CAPITAL INVESTMENT (1973)	363	310	179	115
ESCALATION TO START OF CONSTRUCTION	154	153	99	75
TOTAL AT START OF CONSTRUCTION	517	463	278	190
INTEREST DURING CONSTRUCTION	102	65	28	13
ESCALATION DURING CONSTRUCTION	125	86	36	16
TOTAL COST AT YEAR OF COMMERCIAL OPERATION (1990 dollars)	744	614	342	219

CHART 86

The total busbar energy costs of a 100 MWe intermediate load paraboloidal dish power plant and the previously defined intermediate load central receiver power plant are compared on a consistent basis in Chart 87. These data are based on a $60/m^2 collector cost and a thermal storage cost of $15/KWHe (1973 dollars).

The technical performance of these alternative plants was described in the preceding comparative technical evaluation section (Charts 61 and 63).

For intermediate load application of the paraboloidal dish power plant, the combination of a 1.15 km^2 collector area and 6-hour storage capacity results in the lowest total busbar energy cost. This busbar cost is higher than the equivalent central receiver (and conventional) power plant busbar energy costs. (77 mills/KWH versus 47 mills/KWH, 1991 dollars). This is due to the relatively lower technical performance and higher unit solar collector and thermal transport costs.

Intermediate Solar Thermal Conversion Power Plant

CENTRAL RECEIVER (winter orientation)

PARABOLOIDAL DISH

- TURBO-GENERATOR RATING ~ 100 MW_e (η_{TG}=0.36) (η_{TG}= 0.34)
- LOCATION ~ INYOKERN, CALIFORNIA
- DEMAND DATA ~ SCE
- TIME PERIOD ~ 1990
- COLLECTOR AREA COST $30/$M^2$ $ 60/M^2
- THERMAL STORAGE COST $15/KW/hr $ 15/KW/hr

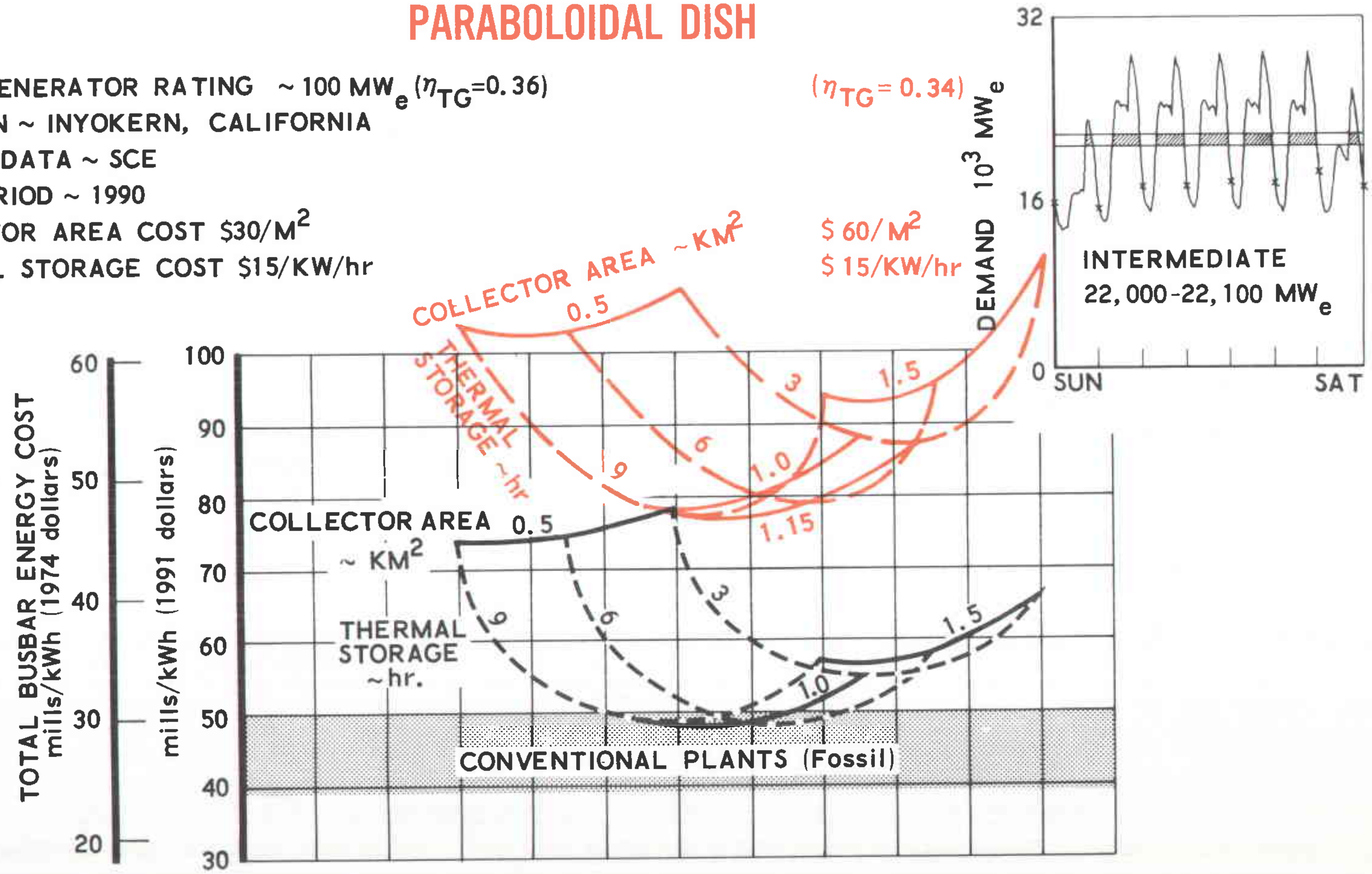


CHART 87

The total busbar energy costs of 100 MWe intermediate load parabolic trough power plants with Polar, N-S, and E-W oriented collectors are compared in Charts 88, 89, and 90, respectively, with the previously defined intermediate load central receiver power plant. The carpet plots reflect a \$60/m^2 (\$70/m^2 for the Polar oriented configuration) collector cost, and a thermal storage cost of \$15/KWHe (1973 dollars).

The technical performance of these alternative plants was described in the preceding comparative technical evaluation section (Charts 64 thru 66), and the corresponding investment cost data are summarized in Chart 93 for unit area collector costs indicated.

For each alternative parabolic trough collector configuration, the combination of collector area and storage capacity resulting in the lowest busbar energy cost was determined. The resulting 1991 busbar energy costs (and associated collector area/storage capacity) are 90 mills/KWH (1.2 km^2/8 hr), 93 mills/KWH (1.2 km^2/8 hr), and 100 mills/KWH (1.5 km^2/8 hr), respectively, for the Polar, N-S, and E-W oriented parabolic trough collectors. As can be seen from these charts, these busbar energy costs are higher than for the intermediate load central receiver or conventional power plants (47 mills/KWH, 1991 dollars). This is a result of the relatively lower technical performance, and the higher solar collector and thermal transport costs for the parabolic trough configurations.

Intermediate Solar Thermal Conversion Power Plant

CENTRAL RECEIVER (Winter perturbed)

PARABOLIC CYLINDRICAL TROUGH (Polar Orientation)

- TURBO-GENERATOR RATING ~ 100 MW_e (η_{TG} = 0.36) (η_{TG} = 0.32)
- LOCATION ~ INYOKERN, CALIFORNIA
- DEMAND DATA ~ SCE
- TIME PERIOD ~ 1990
- COLLECTOR AREA COST ~ \$ 30/M^2 \$ 70/M^2
- THERMAL STORAGE COST ~ \$15/KW_e/hr \$15/KW_e/hr

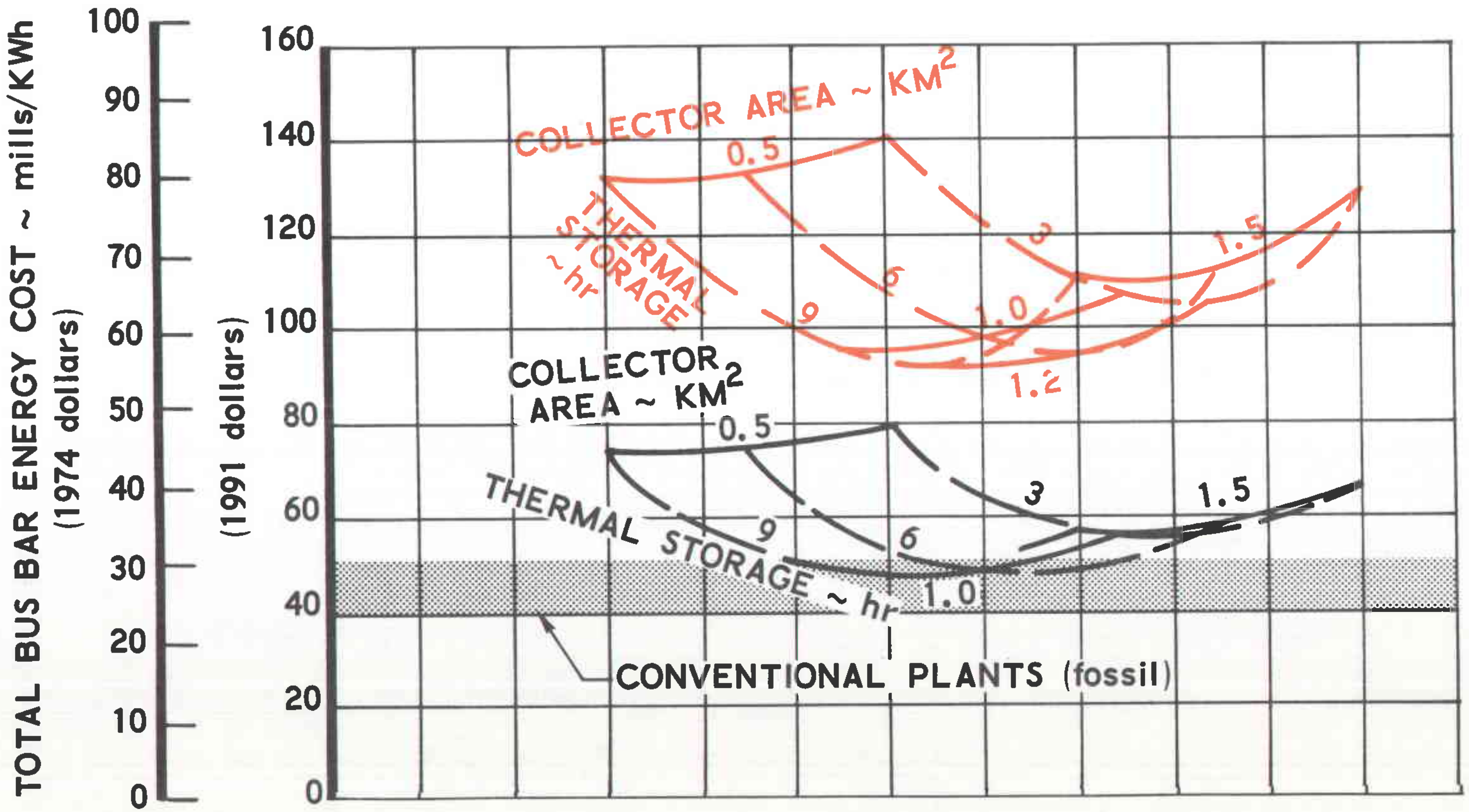


CHART 88

Intermediate Solar Thermal Conversion Power Plant

CENTRAL RECEIVER (Winter perturbed)

PARABOLIC CYLINDRICAL TROUGH (N-S Orientation)

- TURBO-GENERATOR RATING ~ 100 MW_e (η_{TG} = 0.36) (η_{TG} = 0.32)
- LOCATION ~ INYOKERN, CALIFORNIA
- DEMAND DATA ~ SCE
- TIME PERIOD ~ 1990
- COLLECTOR AREA COST ~ \$ 30/M^2 \$ 60/M^2
- THERMAL STORAGE COST ~ \$15/KW_e/hr \$15/KW_e/hr

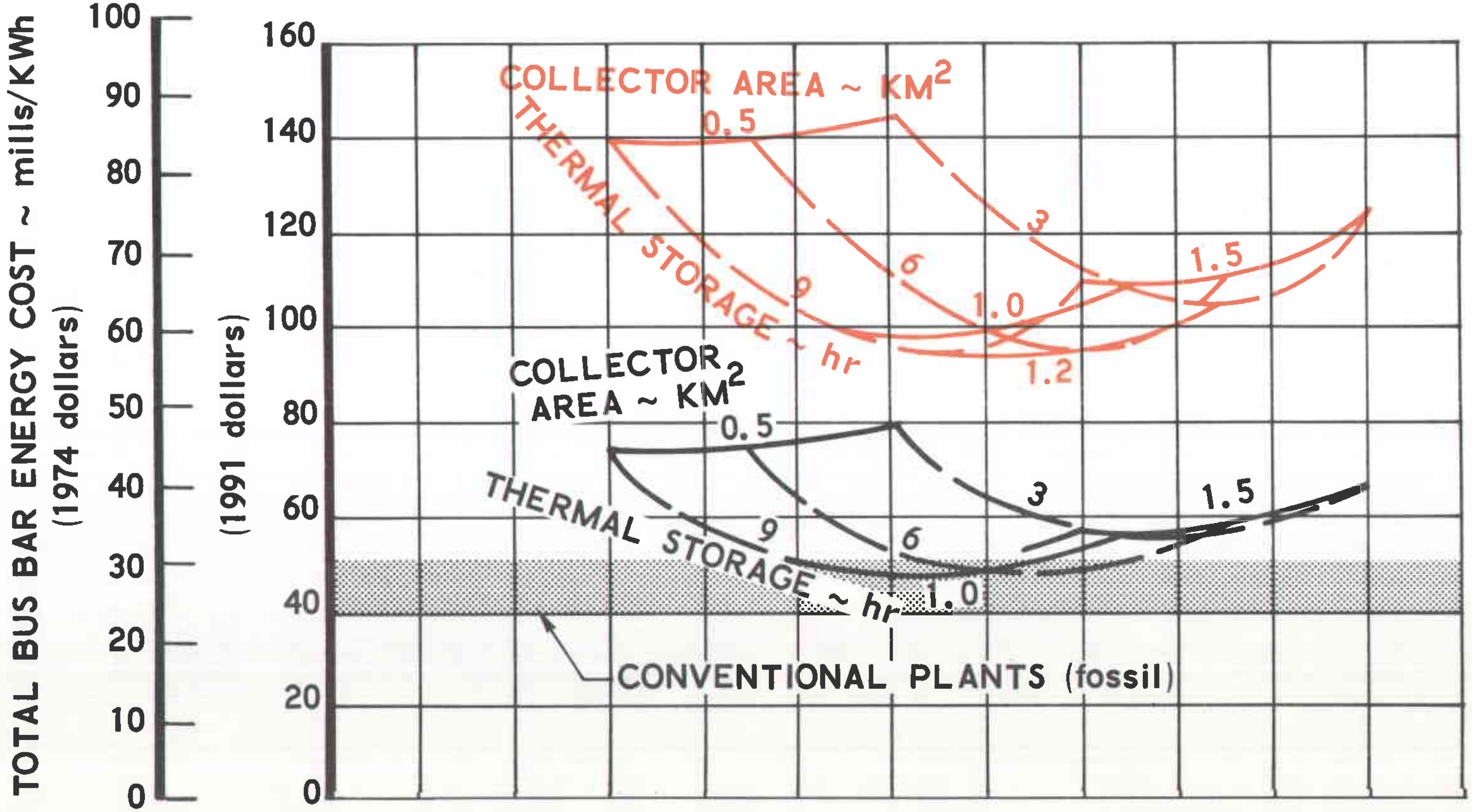


CHART 89

Intermediate Solar Thermal Conversion Power Plant

CENTRAL RECEIVER (Winter perturbed)

PARABOLIC CYLINDRICAL TROUGH (E-W Orientation)

- TURBO-GENERATOR RATING ~ 100 MW_e (η_{TG} = 0.36) (η_{TG} = 0.32)
- LOCATION ~ INYOKERN, CALIFORNIA
- DEMAND DATA ~ SCE
- TIME PERIOD ~ 1990
- COLLECTOR AREA COST ~ \$ 30/M^2 \$ 60/M^2
- THERMAL STORAGE COST ~ \$15/KW_e/hr \$15/KW_e/hr

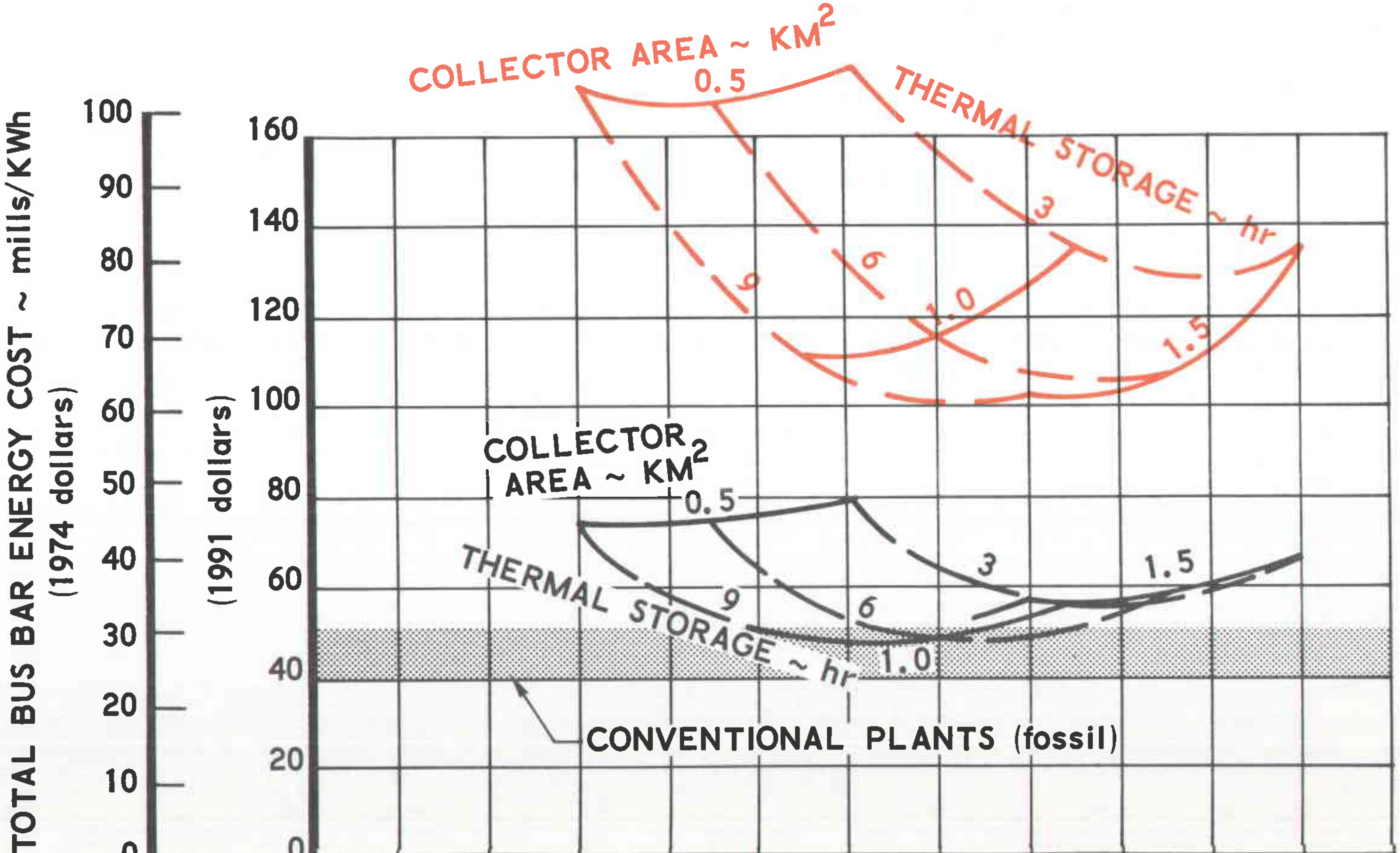


CHART 90

Alternative E-W oriented parabolic trough concepts have been proposed, which may have the potential of lower unit collector costs. As compared to the trough collector concept analyzed, these concepts include the fixed concentrator/variable receiver concept, the Winston-type concentrator, and the segmented (Fresnel) collector concept.

No detailed systems analyses have been performed to adequately define the cost-savings potential of these systems. Even though the actual cost data are not available, unit collector cost objectives can be determined, based upon the technical performance, which yield economically competitive busbar energy costs. These data are shown in Chart 91. As can be seen, if a unit collector cost of $\$15/m^2$ can be achieved with any of these alternative collector concepts, the system may be competitive with the conventional fossil intermediate load power plants for the 1990 time period.

As can be seen from this chart, the lowest busbar energy cost for a 100 MWe intermediate load plant corresponds to the combination of collector area of 1.5 km^2 and storage capacity of 8 hours.

Intermediate Solar Thermal Conversion Power Plant

CENTRAL RECEIVER (Winter perturbed)

PARABOLIC CYLINDRICAL TROUGH (E-W Orientation)

- TURBO-GENERATOR RATING ~ 100 MW_e (η_{TG} = 0.36) (η_{TG} = 0.32)
- LOCATION ~ INYOKERN, CALIFORNIA
- DEMAND DATA ~ SCE
- TIME PERIOD ~ 1990
- COLLECTOR AREA COST ~ \$ 30/M^2 \$ 15/M^2
- THERMAL STORAGE COST ~ \$15/KW_e/hr \$15/KW_e/hr

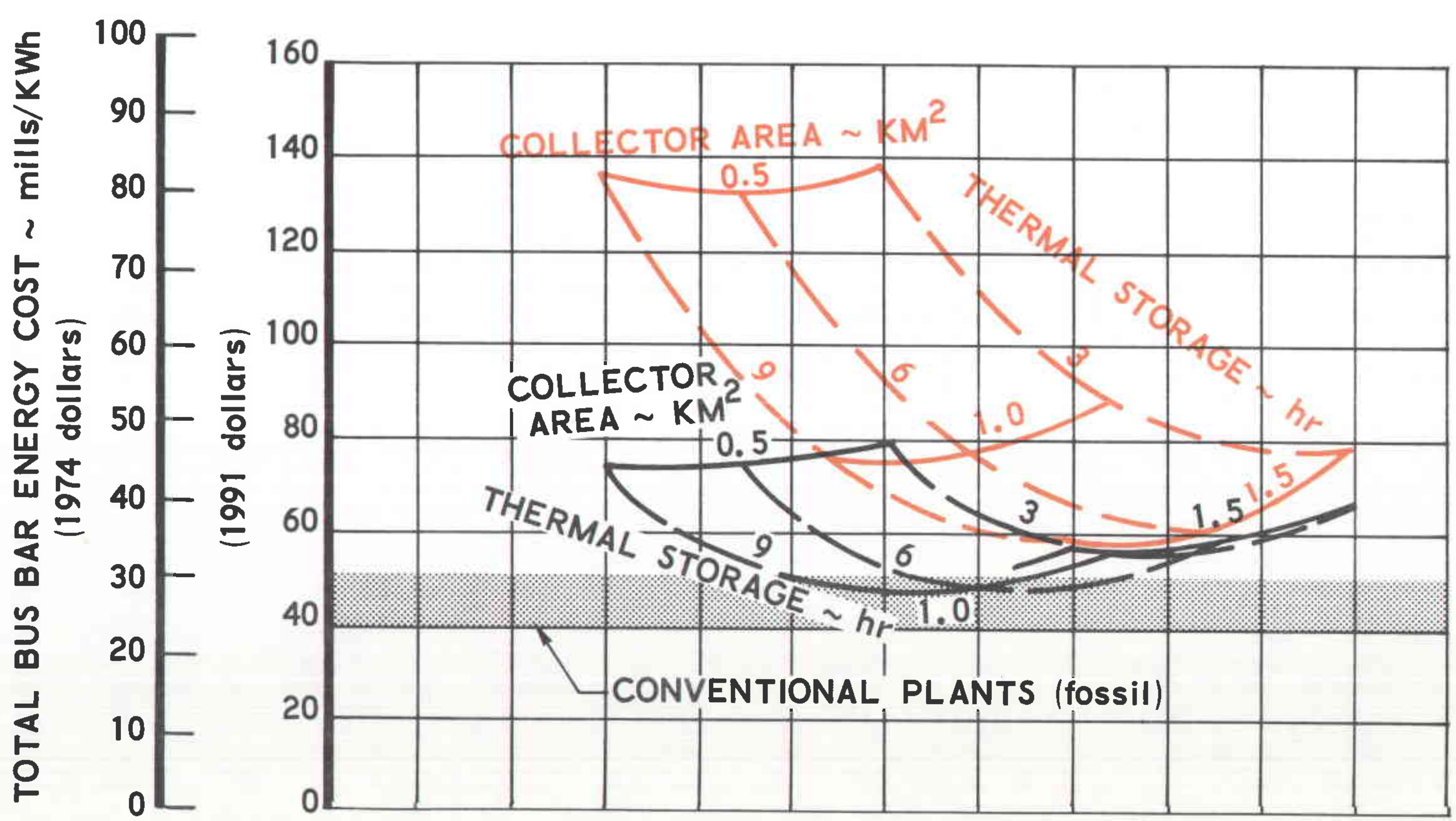


CHART 91

The results of the comparative economic assessment of the alternative 100 MWe intermediate load solar thermal conversion systems are summarized in Chart 92. Shown on this chart are the comparative busbar energy costs for these alternative systems corresponding to the individual combination of collector area and storage capacity which resulted in the lowest busbar energy cost.

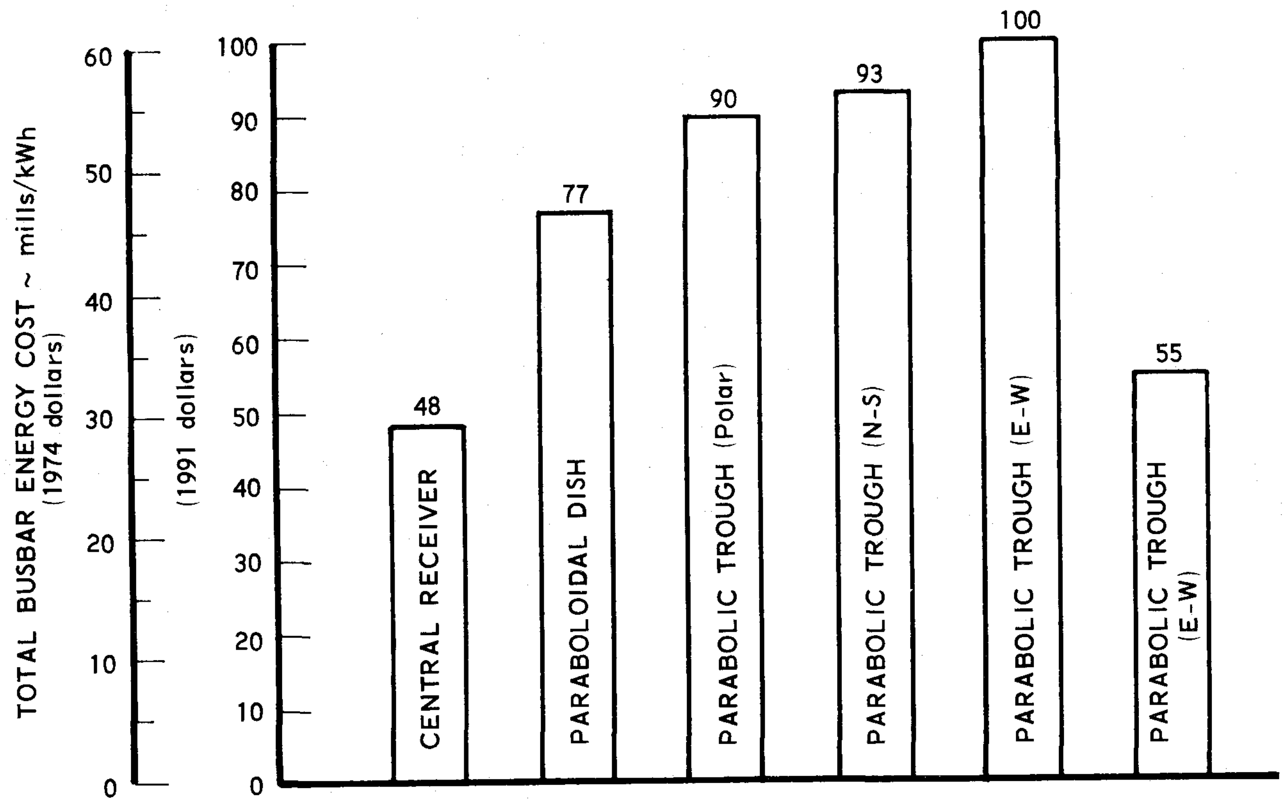
As can be seen from this economic comparison, the central receiver concept appears to be the economically preferred concept. As was shown in Chart 81, the busbar energy cost for this system is competitive with equivalent intermediate load conventional fossil power plants, if the projected unit collector cost of approximately $30/m^2 can be realized.

The comparative economic assessment remains valid even though the absolute values of unit collector cost may vary, since the relative collector costs will tend to remain the same. An exception may be found for the E-W oriented parabolic trough concept, if any one of the proposed low-cost collector concepts can achieve the $15/m^2 cost objective, as shown by the last bar in Chart 92. The potential for attaining this cost objective must be verified by detailed systems analysis of the candidate concepts, such as the fixed collector/variable receiver concept, the Winston-type collector, or the segmented (Fresnel) collector concept.

Any one of such potentially low-cost collector concepts, if economically feasible, can be integrated into a distributed solar power plant to provide an alternative backup candidate system to the preferred central receiver concept.

Intermediate Solar Thermal Conversion Power Plants

COMPARATIVE ECONOMIC EVALUATION



COLLECTOR AREA (km^2)	1.00	1.15	1.20	1.20	1.50	1.50
COST ($\$/m^2$)	30	60	70	60	60	15
STORAGE CAPACITY (hr)	6	8	8	8	8	8
COST ($/kW/hr)	15	15	15	15	15	15

Solar thermal conversion solar power plant cost estimates for the alternative collector concepts analyzed for intermediate power application are shown in Chart 93.

The technical and performance characteristics of these alternative solar plants are described and analyzed in the preceding comparative technical evaluation. Each plant has a turbine/generator rating of 100 MWe. The collector areas and thermal storage capacities, derived from the comparative economic analysis and corresponding to the lowest attainable busbar energy cost, are shown in Chart 93 for each concept. Also shown are the unit collector cost estimates based upon the various system contractor designs. The collector costs shown represent the lowest cost estimates; other cost estimates indicate unit collector costs as much as twice the values shown. However, in most cases, the relative costs for the alternative collectors remain similar to those shown. Consequently, the conclusions drawn from the comparative economic evaluation remain valid, even though the absolute cost estimates may vary.

As can be seen in Chart 93, for the distributed systems, besides the collector cost and energy storage cost, another significant capital cost is the thermal transport cost. The somewhat higher unit collector and thermal transport costs for the polar-oriented parabolic trough, as compared to the E-W or N-S orientation, is due to increased installation, structural, and piping costs associated with the inclined attitude (equal to the local latitude) of the collectors.

Also shown in the last column is the capital cost estimate for an E-W oriented parabolic trough power plant using a low-cost collector concept. As shown in Chart 91, in order to be economically competitive with conventional power plants operating in the intermediate range, a unit collector cost of $\$15/m^2$ must be achieved. Low cost E-W parabolic collector concepts, such as the fixed trough/variable absorber concept, the Winston type of collector, or the segmented mirror (Fresnel) concept, have been proposed. However, no detailed system cost analyses are available for these concepts to assess if the $\$15/m^2$ cost objective is attainable for these concepts.

Intermediate Solar Thermal Power Plant Cost Estimates

$\$/KW_e$ (100 MW_e (RATED))

PLANT TYPE	C.R.	DISH	POLAR	N-S	E-W	E-W
COLLECTOR AREA (KM^2)	1	1.15	1.20	1.2	1.5	1.5
COLLECTOR COST ($\$/m^2$)	30	60	70	60	60	15
STORAGE CAPACITY (hr)/COST ~$15/$KW_e$/hr	6	8	8	8	8	8
ACCOUNT						
LAND	2	2	2	2	3	3
STRUCTURES AND FACILITIES	44	49	49	49	49	49
HELIOSTATS/COLLECTORS	300	690	875	720	900	225
RECEIVER/TOWER/HEAT EXCHANGER/THERMAL TRANSPORT	95	244	319	254	318	318
STORAGE/TANKS	90	120	120	120	120	120
TURBINE PLANT EQUIPMENT	80	80	80	80	80	80
ELECTRIC PLANT EQUIPMENT	21	21	21	21	21	21
MISC PLANT EQUIPMENT	4	4	4	4	4	4
ALLOWANCE FOR COOLING TOWERS	20	20	20	20	20	20
TOTAL DIRECT COST	656	1230	1490	1270	1515	840
CONTINGENCY ALLOWANCE	39	72	88	74	89	45
SPARE PARTS ALLOWANCE	3	8	10	8	10	5
INDIRECT COSTS	78	90	101	92	102	78
TOTAL CAPITAL INVESTMENT (1973)	776	1400	1689	1444	1716	968
ESCALATION TO START OF CONSTRUCTION	296	499	603	515	614	342
TOTAL AT START OF CONSTRUCTION	1072	1899	2292	1959	2330	1310
INTEREST DURING CONSTRUCTION	119	178	210	183	214	127
ESCALATION DURING CONSTRUCTION	169	291	355	301	360	198
TOTAL COST AT YR COMMERCIAL OPERATION (1990 dollars)	1360	2368	2858	2443	2904	1635

CHART 93

The comparative economic evaluation of the alternative solar systems was performed for 100 MWe rated turbine/generator capacity power plants. These 100 MWe solar plants were compared to larger conventional power plants (1000 MWe base load, 400 MWe intermediate and 100 MWe peaking, respectively). Consequently, the comparative evaluation of solar with conventional power plants is conservative, since the economics-of-scale favor the larger conventional power plants.

To assess the reduction in busbar energy cost due to economics-of-scale for solar power plants, the size of the preferred central receiver solar plant, operating in the intermediate load mode, was increased in size.

As will be shown subsequently (Chart 98), the central receiver concept envisioned may be modular, with each module having a 260 meter tower and a collector area of 0.5 km^2. Consequently, two such modules would constitute a 100 MWe intermediate load central receiver power plant.

The plant size can be increased by adding additional modules with a common but larger turbine/generator plant. The larger turbine/generator plant size will benefit from the associated economics-of-scale; on the other hand, increased piping costs are incurred due to connecting the additional modules to the central turbine/generator. The resulting decrease in busbar energy cost is shown in Chart 94 for central receiver plant ratings of 100 MWe to 500 MWe. Also shown are the number of modules required for these plant capacities.

Intermediate Central Receiver System

ECONOMICS OF SCALE (Modular Concept)

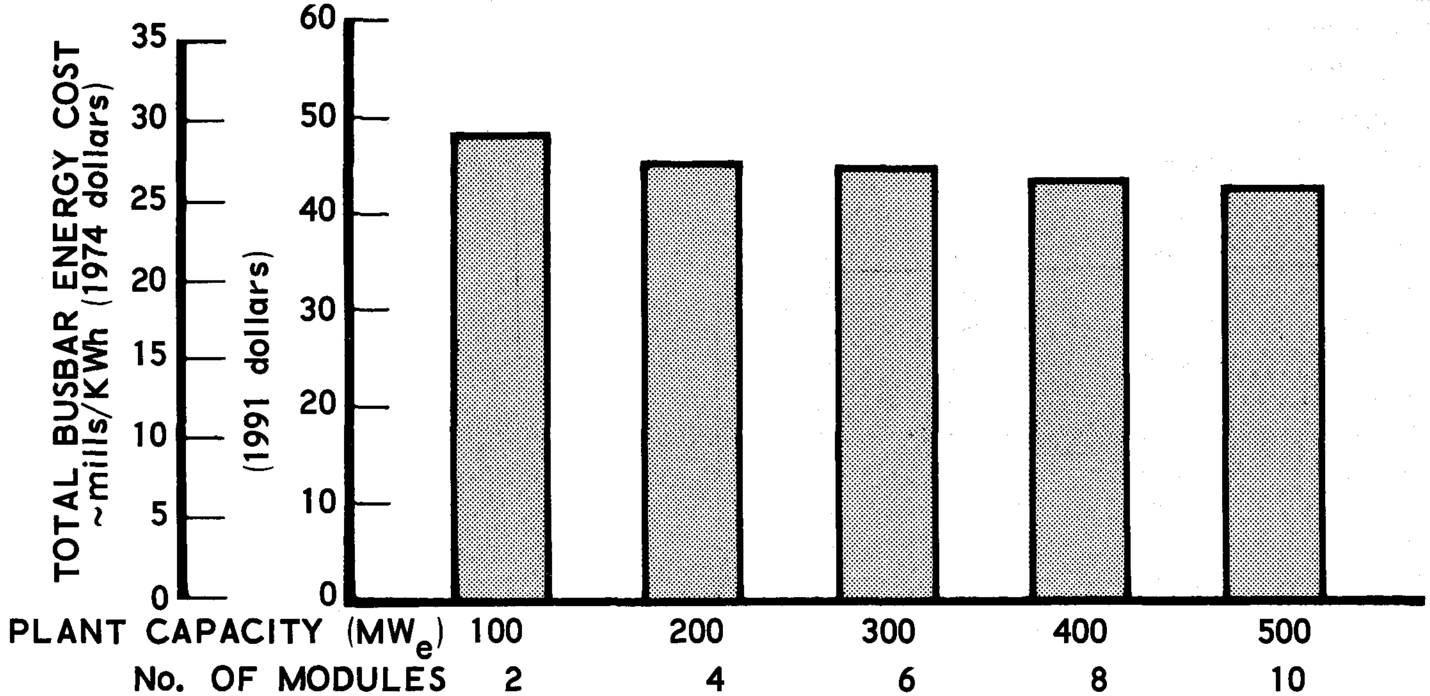


CHART 94

Because of the uncertainty in cost estimates of the solar plant peculiar subsystems, as well as in the operating costs, a cost sensitivity analysis was performed. This sensitivity analysis pertains to the preferred 100 MWe central receiver system, operating in the intermediate load mode.

The impact on the busbar energy cost due to changes in the following major subsystem and operating cost estimates was examined in this analysis:

- Heliostat unit collector cost
- Thermal storage cost
- Operating and maintenance costs
- Conventional backup capacity cost

The cost sensitivity results are summarized in Chart 95. As can be seen from this chart, the busbar energy cost is quite sensitive to changes in heliostat unit cost, while doubling the energy storage cost increases the busbar energy cost by only 5 percent.

This cost sensitivity analysis of major subsystem and operating cost variations is in addition to the sensitivity analysis performed in the comparative technical evaluation section (Chart 71). This analysis assessed the impact of changes in the technical parameters on the performance and busbar energy cost for the 100 MWe intermediate load central receiver solar plant.

Cost Sensitivity Analysis
Intermediate Central Receiver Plant
(100 MW_e)

CATEGORY	NOMINAL VALUE (1973 dollars)	CHANGE (1973 dollars)	Δ1991 BUSBAR COST	
			MILLS/KWH (1991 dollars)	PERCENT
HELIOSTAT COST	$30/m^2	±$10/m^2	±7.2	±14.9%
STORAGE COST	$15/Kwh	+$15/Kwh	+2.5	+5.2%
OPERATING AND MAINTENANCE COSTS	$7.5/$KW_e$	+$7.5/$KW_e$	+5.3	+11.0%
CONVENTIONAL BACKUP CAPACITY REQUIRED	0.0 MWe	+20 MWe	+6.6	+13.7%

CHART 95

PREFERRED SYSTEM SELECTION/DEFINITION

PREFERRED SYSTEM SELECTION/DEFINITION

From the results of the comparative technical and economic evaluation of the alternative solar thermal conversion concepts, a preliminary system selection and definition can be made. The identification of preferred systems is one of the objectives of the solar thermal conversion mission analysis.

One of the solar thermal conversion mission analysis objectives is to identify preferred systems for further evaluation and development.

The criteria for the selection of the preferred solar systems are long-term economic viability, technical feasibility, and development risk. These criteria were addressed in the technical and economic evaluation of the alternative solar thermal conversion concepts discussed in the previous sections.

The preferred solar thermal conversion systems identified for providing electric power and their associated system definition are summarized in Chart 96. The selection and definition of the preferred solar systems are based upon the results of the comparative technical and economic evaluation of the alternative solar thermal conversion concepts for electric power application in realistic operating environments. The input data to these analyses reflect the various system contractor technical and cost inputs, and consequently, these systems reflect the current combined assessment. When additional data become available, these will be incorporated in future assessment of these systems.

The primary preferred system identified is the intermediate-load stand-alone central receiver power plant. As will be discussed subsequently (Charts 97 through 99), a modular concept for this system appears desirable, limiting the tower height to less than 300 m. As shown in Chart 92, this system, with a collector area of 1 km^2 and thermal storage capacity of 6 hours per 100 MWe rated plant capacity, was found in the preceding section to result in the lowest busbar energy cost. The heliostat and thermal storage cost objectives of $\$30/m^2$ and \$15/KWHe, when realized, will meet the long-time economic viability criterion of providing electric power with a competitive busbar energy cost of 40-50 mills/KWH (1991 dollars). This concept appears to be technically feasible, although the relative development risk associated with the receiver is considered high.

Because the thermal storage at present is not well defined, a hybrid concept central receiver power plant with limited storage (~0.5 hr) operating in the intermediate-load mode is identified as a backup system (see Chart 84). Since a conventional fossil fuel boiler replaces the long-term thermal storage subsystem, the collector area required per 100 MWe rated plant capacity is 0.5 km^2. Otherwise, the same system definition and cost objectives as defined above for the stand-alone central receiver power plant apply.

As discussed in the preceding sections, a low-cost ($\$15/m^2$) E-W oriented parabolic trough collector, such as the fixed collector/variable receiver, Winston-type, or segmented (Fresnel) collector concept, if attainable, may result in an economically attractive backup distributed system. The technical or economic feasibility of any of these latter concepts has not been verified since at present no detailed systems studies results are available for these concepts.

Preferred System Selection/Definition

- CRITERIA
  - LONG-TERM ECONOMIC VIABILITY ~ 40-50 mills/kWh (1991 dollars)
  - TECHNICAL FEASIBILITY
  - DEVELOPMENT RISK
- PREFERRED SYSTEMS
  - PRIMARY SYSTEM
    - INTERMEDIATE CENTRAL RECEIVER POWER PLANT
      - MODULAR CONCEPT ~ 50 MW_e/MODULE
      - COLLECTOR AREA/THERMAL STORAGE ~ 1 km^2/6 hr/100 MW_e
      - TOWER HEIGHT ~ 260 m (850 ft)
      - HELIOSTAT/STORAGE COST OBJECTIVES ~ \$30/m^2; \$15/KW_e/hr
  - BACK-UP SYSTEMS
    - HYBRID INTERMEDIATE CENTRAL RECEIVER POWER PLANT
      - COLLECTOR AREA/THERMAL STORAGE ~ 0.5 km^2/0.5 hr/100 MW_e
      - TOWER HEIGHT ~ 260 m
      - HELIOSTAT/STORAGE COST OBJECTIVES ~ \$30/m^2; \$15/KW_e/hr
    - INTERMEDIATE E-W PARABOLIC TROUGH POWER PLANT
      - FIXED TROUGH/VARIABLE COLLECTOR PIPE; FRESNEL TYPE
      - COLLECTOR AREA/THERMAL STORAGE ~ 1.5 km^2/8 hr/100 MW_e
      - COLLECTOR/STORAGE COST OBJECTIVES ~ \$15/m^2; \$15/KW_e/hr
      - TECHNICAL OR ECONOMIC FEASIBILITY UNVERIFIED BY THE AEROSPACE CORPORATION

The relative geometric relationships were maintained throughout the parametric analysis of the central receiver concept to maintain identical technical characterization for consistent comparative evaluation.

These geometric relationships for the central receiver concept are shown in Chart 97. Presented are the height and number of towers and the size of the heliostats for different collector areas. The area utilization of 38.6 percent and size and number of reflectors per tower reflect a winter-perturbed central receiver configuration based upon system design data obtained from the University of Houston (McDonnell-Douglas).

As was determined in the preceding technical evaluation of the stand-alone central receiver concept, the collector area required per 100 MWe rated plant capacity is 1.5 km^2, 1.0 km^2, and 0.5 km^2 for base load, intermediate, and peaking operation, respectively. For a 100 MWe hybrid central receiver plant, the required collector area is 0.5 km^2.

As can be seen from Chart 97, a 1.5 km^2 collector area with a single tower requires a tower height of 450 m and heliostat size of 10 x 10 m, while a three-tower configuration, each with 0.5 km^2 collector area, reduces the individual tower height to 260 m and the heliostat size to 6 x 6 m.

Consequently, as shown on this chart, central receiver modules with a tower height of approximately 260 m and a collector area of 0.5 km^2 can be combined so that 3, 2, and 1 modules constitute a 100 MWe base load, intermediate, peaking or hybrid plant, respectively.

Solar Thermal Conversion Power Plant
CENTRAL RECEIVER CONCEPT

AREA UTILIZATION ~ 38.6%
NR OF REFLECTORS/TOWER ~ 15,442

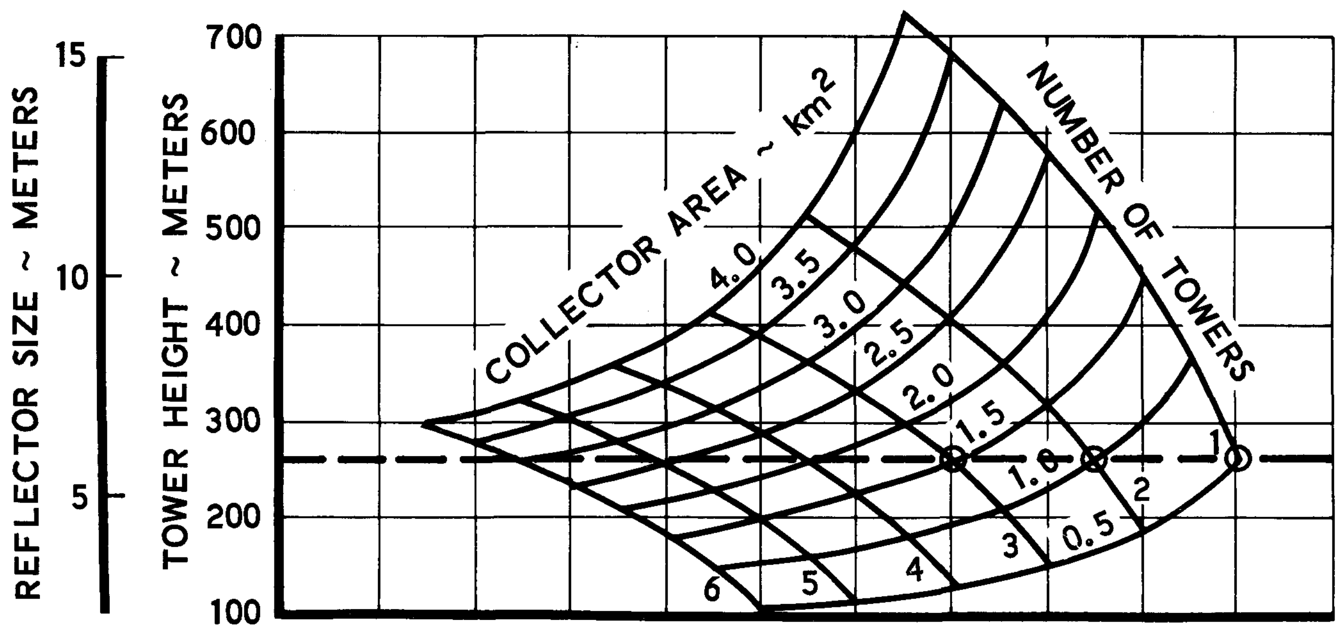


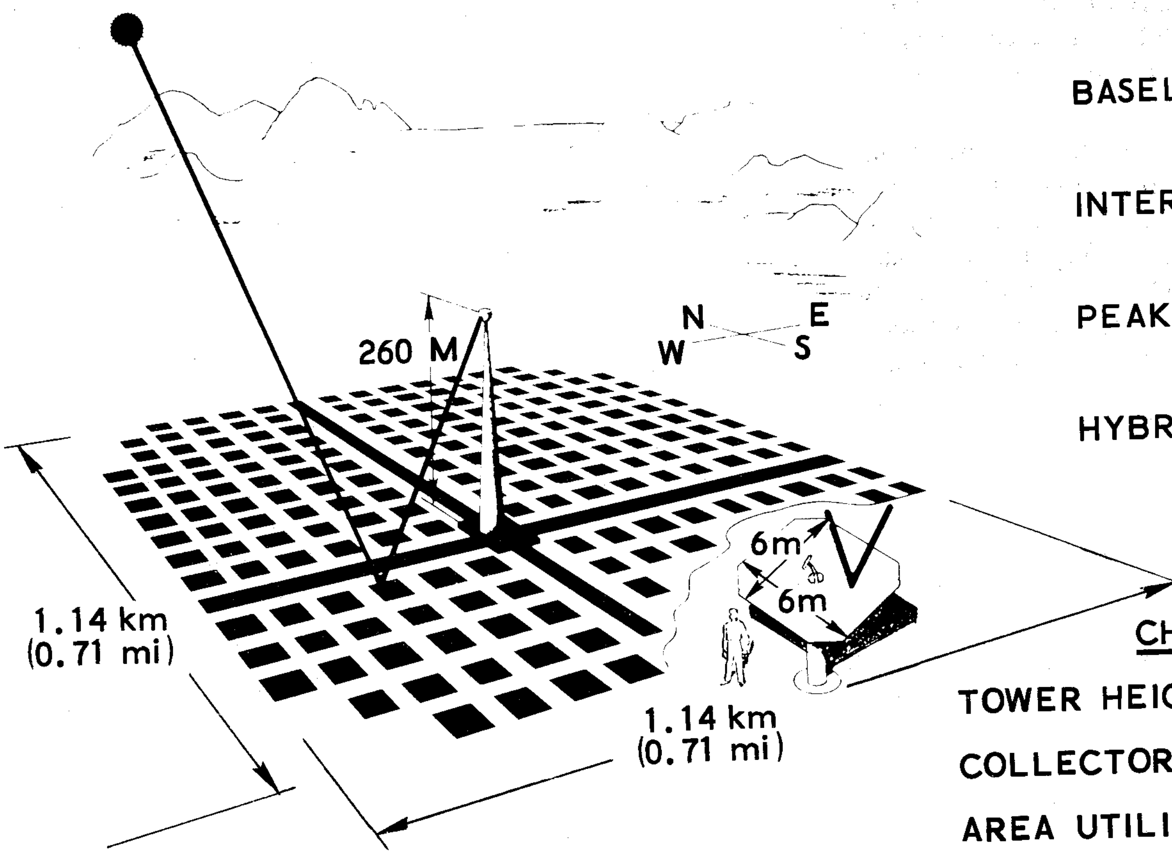
CHART 97

In the previous chart, it was shown that a modular central receiver system consisting of a collector area of 0.5 km^2 per module with a tower height of approximately 260 m can be combined so that 3, 2, and 1 modules comprise a 100 MWe base load, intermediate, and peak, or hybrid plant, respectively.

Typical geometric characteristics of such a central receiver module are shown in Chart 98. As can be seen, with an area utilization of 38.6 percent, the total land area required per module is approximately 0.5 mi^2 (1.3 km^2).

Solar Thermal Conversion

CENTRAL RECEIVER CONCEPT



100 MW_e PLANT	
BASELOAD	3 MODULES (12 hr storage)
INTERMEDIATE	2 MODULES (6 hr storage)
PEAKING	1 MODULE (3 hr storage)
HYBRID	1 MODULE (1/2 hr storage)

CHARACTERISTICS	
TOWER HEIGHT	260 m
COLLECTOR AREA	0.5 km^2/MODULE
AREA UTILIZATION	38.6%
TOTAL LAND AREA	1.3 km^2/MODULE
No. OF COLLECTORS	15,400/MODULE
SIZE OF COLLECTORS	32.4 m^2

A modular approach for central receiver power plants appears very attractive at this time. The advantages and disadvantages of the modular approach are shown in Chart 99. As was shown in the previous charts, the individual modules can be combined to comprise either base-load, intermediate, peaking or hybrid plants.

Limiting the tower height to 260 m appears better suited from seismic and aesthetic considerations than the taller towers required in the non-modular approach. Furthermore, the modular approach offers maximum flexibility in plant size, development, and construction, as well as standardization of major subsystems. A disadvantage arises due to the additional piping costs of connecting the various modules to a common turbine/generator plant.

Central Receiver Modular Concept

ADVANTAGES

- MODE OF OPERATION
  - BASE-LOAD (3 modules/100 MW_e)
  - INTERMEDIATE (2 modules/100 MW_e)
  - PEAKING (1 module/100 MW_e)
  - HYBRID (1 module/100 MW_e)
- LIMITED TOWER HEIGHT
  - 260 m (850 ft) (SEISMIC, ENVIRONMENTAL)
- FLEXIBILITY
  - SIZE OF POWER PLANT
  - STANDARDIZATION (TOWER, HELIOSTATS)
  - SITING (1.3 km^2 (0.5 mi^2)/module)
  - CONSTRUCTION
  - PROXIMITY TO LOAD CENTERS
  - TESTING/DEVELOPMENT (FULL SCALE COMPONENTS)
  - TOTAL ENERGY SYSTEMS APPLICATION
- MINIMUM DEVELOPMENT RISK
  - COMMERCIAL PLANT, DEMONSTRATION, PROOF-OF-CONCEPT
- IMPROVED RELIABILITY OF OPERATION

DISADVANTAGES

- INTERCONNECTION/PIPES
- ECONOMIES OF SCALE

CHART 99

ENVIRONMENTAL IMPACT / MARKET CAPTURE POTENTIAL

ENVIRONMENTAL IMPACT/MARKET CAPTURE POTENTIAL

In addition to the technical, economic, and siting comparative assessment of solar thermal conversion applications, the relative environmental characteristics of alternative power plants has of late become a major issue. This environmental impact issue was addressed in a preliminary fashion. Furthermore, for the preferred solar thermal conversion system identified, a preliminary analysis of the market capture potential was made, as described in this section.

The environmental impact of solar power plants is an important factor in determining the potential of such plants for electric power generation.

The comparative environmental impact of solar versus conventional plants can be evaluated with the electric power planning model shown schematically in Chart 100. The model treats two separate types of issues: those related to growth in the generation system of a utility over a period of years and those related to the operating consequences of a fixed generation system over the course of a single year. As indicated in Chart 100, the principal issues of the first type include resources, industrial capacity, manpower availability, and economic (capital) resources. This part of the model is now being completed and will be used to examine the growth in land and capital requirements as a utility system expands with and without solar power plants. Investment capital is recognized as a major current problem for the utility industry which may be aggravated by the construction of capital intensive solar power plants even though substantial fuel savings would be achieved.

The model presently is capable of defining the wastes produced, effluents released, resources consumed, and total power costs of a given utility system over a full year of operation. The model provides for scheduled maintenance and optimizes the dispatch of individual power plants to satisfy the total system demand consistent with minimum fuel costs, atmospheric effluents (e.g., as in Los Angeles) or any other operating strategy that can be quantitatively defined. A key subsystem in the logic of the model is the dispatch subroutine which properly selects from the total available capacity (reliability considerations require that capacity exceed demand to accommodate forced or unscheduled outages) only those power plants required to satisfy the total system demand consistent with imposed operating constraints. This subroutine has been developed specifically to handle solar power plants and incorporates information on the availability of insolation and the status of energy storage subsystems at solar power plants. Parametric calculations using this model will be performed in subsequent studies.

Electric Power Planning Model

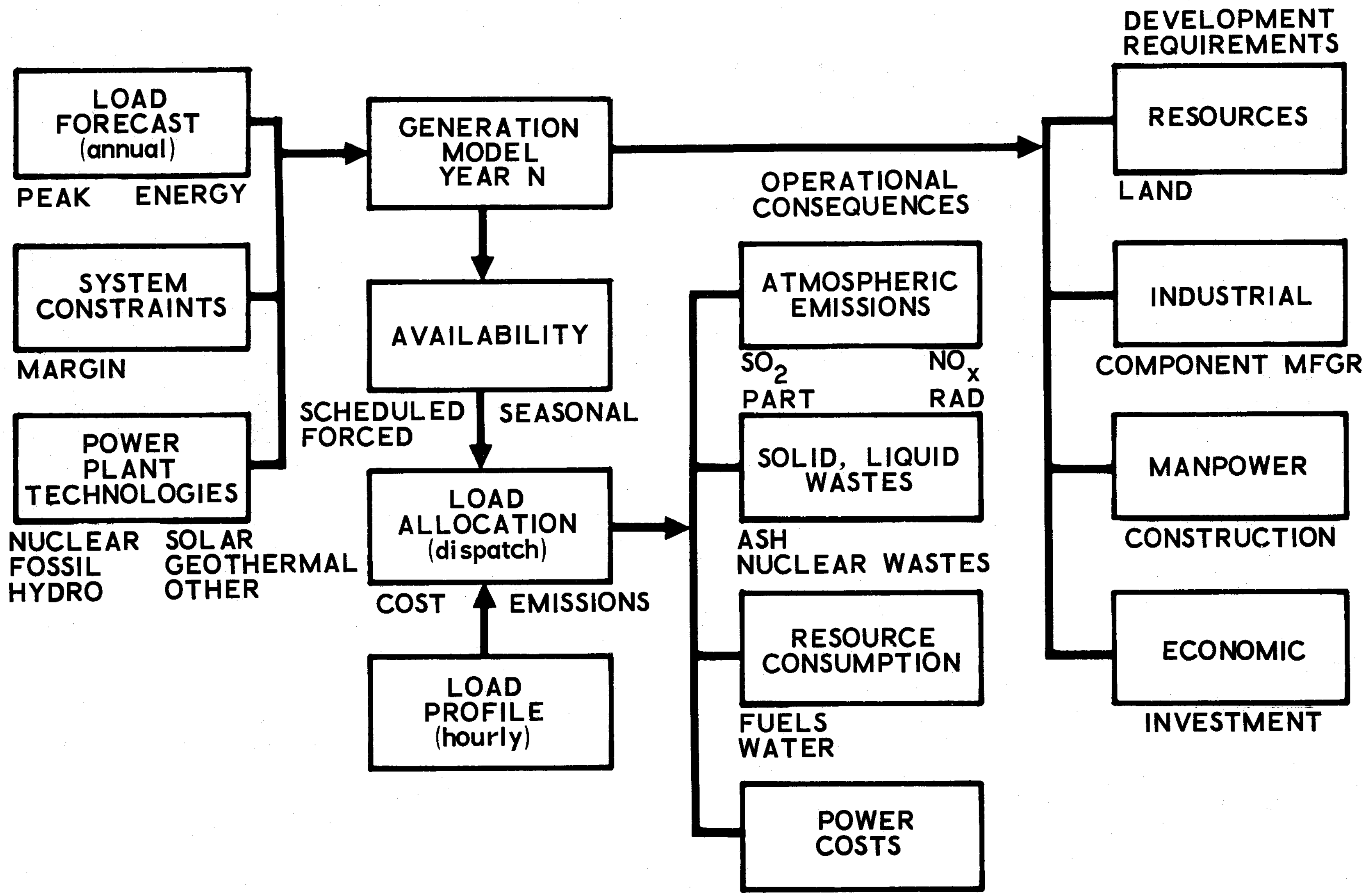


CHART 100

A preliminary assessment of the market capture potential has been made for the preferred intermediate load central receiver system described in the previous section. This central receiver concept has the potential of long-term economic viability, as a result of the relative economics as compared to conventional plants for intermediate load application (40-50 mills/KWH, 1991 dollars).

With the demonstration of long-term economic viability and technical feasibility, the potential market for solar thermal conversion power plants for the Southwestern United States can be assessed. Factors contributing to this potential market that must be considered include the projected growth in installed generation capacity, the allocation of the load by operational mode (base, intermediate, peaking), manufacturing rate capabilities, construction lead times, siting constraints, relative economics, environmental factors, and conventional fuel availability.

Based upon the peak demand load forecast for the Southwestern United States (Chart 27) and the margin requirements, the total generation capacity can be determined, as shown in Chart 101. From analysis of the load duration curve, the intermediate load generation capacity forecast can be derived. The intermediate load generation capacity that must be installed each year to meet the forecasted total installed capacity, as well as for replacement of retired power plants, is also shown in this chart. This newly installed intermediate capacity per year constitutes the maximum construction rate.

Assuming commercial demonstration of a 100 MWe central receiver plant by 1985, and a 50 percent growth rate in construction subsequently, results in a total installed solar thermal electric power plant capacity of 40,000 MWe by the year 2000 and a corresponding fossil fuel displacement of approximately 320 million barrels of oil per year.

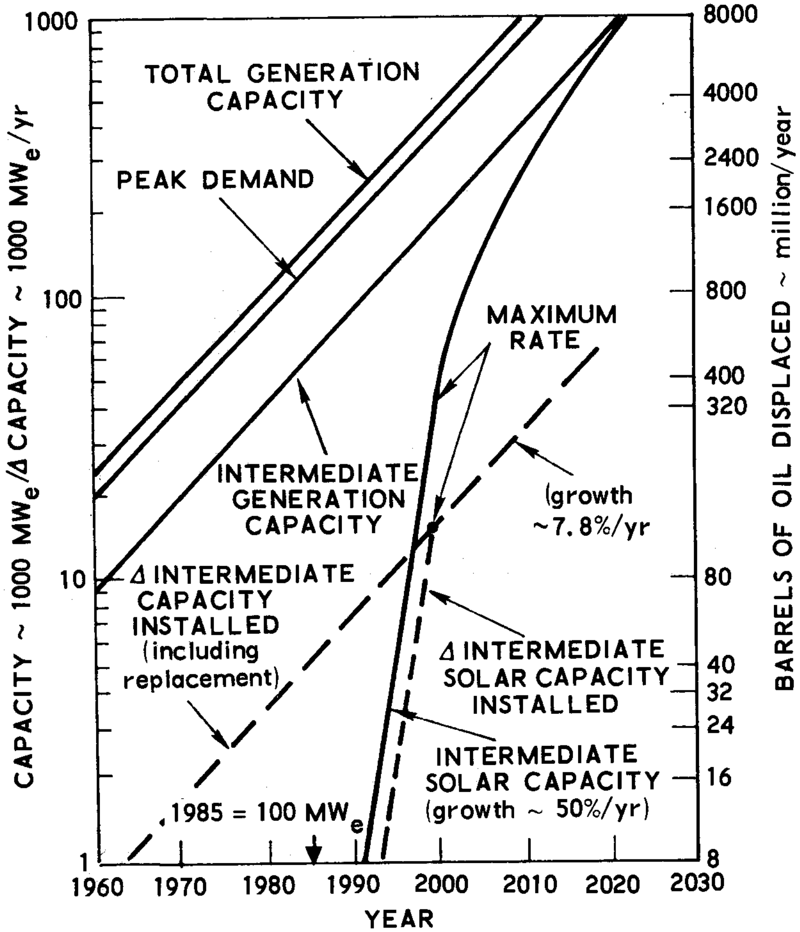
After the year 2000, the maximum growth rate in new intermediate load solar power plant construction is constrained to the maximum growth rate of 7.8 percent per year. The total installed intermediate load solar plant capacity can reach 100 percent of the intermediate capacity by the year 2030.

The siting analysis for the Southwestern United States under the most stringent criteria identified approximately 21,500 sq. mi. of potentially suitable land area, which corresponds to 2,150,000 MWe of intermediate-load central receiver capacity. Consequently, the siting of these solar power plants does not appear to impose a constraint on the market capture potential. Cooling water availability in the Colorado River Basin siting area, however, may be limited to approximately 60,000 MWe of generating capacity, assuming wet cooling towers. Consequently, the technical and economic evaluation assumed the use of dry cooling towers.

The major barrier to implementation is expected to be the comparatively high initial capital investment requirements presently projected for solar power plants. This would place an additional burden on the already difficult financing problems of the electric utility industry.

Market Capture Potential

INTERMEDIATE SOLAR THERMAL CONVERSION PLANT



- PLANT TYPE:
  - CENTRAL RECEIVER
  - HELIOSTAT AREA/STORAGE ~ 1 km^2/6 hr
  - INTERMEDIATE MODE
- RELATIVE ECONOMICS:
  - TOTAL BUSBAR COST (1991 dollars)
    - SOLAR ~48 mills/kWh
    - CONVENTIONAL ~ 40-50 mills/kWh
- CAPACITY/FUEL DISPLACEMENT

YEAR	MW_e	INT. CAP. DISPL. (%)	BBLS OIL (million/yr)	LAND (sq mi)
1985	100	0.17	0.8	1
1990	700	0.85	5.6	7
1995	5400	4.32	43.2	54
2000	40,000	21.83	320.0	400
2005	145,000	50.00	1160.0	1450

- SITING CONSTRAINT
  - SUITABLE AREA (SW US) ~ 21,500 sq mi
  - COOLING WATER
- ENVIRONMENTAL IMPACT
  - LAND USE (1 sq mi/100 MW_e)
  - NO POLLUTANTS
  - AESTHETIC
- INSTITUTIONAL
  - HIGH CAPITAL INVESTMENT COST
    - SOLAR $1360/$KW_e$
    - CONVENTIONAL $343/$KW_e$

SUMMARY AND CONCLUSIONS

SUMMARY AND CONCLUSIONS

The Solar Thermal Mission Analysis is a continuing effort. Preliminary interim results obtained to date are summarized in this section. Tentative conclusions drawn from these results are also presented.

SUMMARY/CONCLUSIONS

The mission analysis efforts to date have successfully consolidated the diverse solar thermal conversion system, subsystem, and component contractor studies for electric power applications. These activities and conclusions are summarized in Chart 102.

- A number of basic computer methodologies have been developed to assess the potential of solar thermal conversion missions and systems in realistic operating environments. These methodologies were applied on a consistent basis to assess the alternative system concepts for electric power application in the Southwestern United States.
- An insolation climatology data base for 20 weather stations representative of the various climatic regions of the Southwestern United States has been developed. Also, a "worst-case" data base was developed for two lcoations. These standard data bases are available to NSF contractors.
- Hourly demand projections for the 1980 to 2000 time period of the major Southwestern United States electric utility companies were generated using the electric power demand forecast methodology developed. These data are also available to other NSF contractors.
- The generating capacity displacement potential of solar power plants operating in a total utility grid with conventional power plants was assessed in the margin analysis.
- A comparative technical and economic evaluation was made of the alternative solar power concepts and modes of operation (i.e., base load, intermediate, or peak). These assessments were made on a consistent basis using the detailed system simulation and economic methodologies developed and incorporating the combined technical and cost information obtained from the other NSF system contractors.
- Based upon the results of the comparative evaluation, a preliminary selection and definition of the preferred system concept was made. The primary preferred concept identified is a stand-alone central receiver power plant. The back-up systems identified are a hybrid central receiver power plant, and a potentially low-cost E-W parabolic trough distributed system. The technical and economic potential of this latter concept has not been verified by detailed system studies. For each of these systems the intermediate or load-following mode of operation was identified as being economically most competitive with a busbar energy cost of 25-30 mills/KWH (1974 dollars).
- The siting analysis performed for the Southwestern United States has under the most stringent criteria identified a potentially suitable land area of 21,000 sq. mi. Consequently, siting does not appear to impose a constraint on the potential of these solar power plants. However, the water resources in this area were found to be scarce, which may require the use of dry cooling towers.
- For the preferred intermediate load central power plants a preliminary market capture potential of 40,000 MWe (cumulative) was projected for the Southwestern United States by the year 2000.
- The above market potential of 40,000 MWe by the year 2000, if realized, would result in a fossil fuel savings of approximately 320 million barrels of oil per year. No major environmental impact of these solar power plants was identified other than the waste-heat disposal problem common to all electric power plants. Furthermore, no unusual critical materials have been identified that are necessary for the preferred central receiver system. The major barrier to implementation is expected to be the high initial capital investment projected for the solar power plants.

These conclusions are based upon the latest available data. However, subsequent analyses will incorporate new data as these become available. Subsequent studies will also address the total energy concept on a consistent basis using the various methodologies developed.

Summary/Conclusions

MISSION/SYSTEMS ANALYSIS - SOUTHWESTERN UNITED STATES
- DEVELOPMENT OF BASIC COMPUTER METHODOLOGIES
- APPLIED TO ELECTRIC POWER MISSION

INSOLATION CLIMATOLOGY DATA BASE
- 20 SOUTHWESTERN U.S. LOCATIONS
- WORST CASE ANALYSIS

HOURLY ELECTRIC DEMAND PROJECTIONS
- REPRESENTATIVE SOUTHWESTERN U.S. UTILITIES
- 1980 - 2000 TIME PERIOD

MARGIN ANALYSES
- CAPACITY DISPLACEMENT OF SOLAR POWER PLANTS

COMPARATIVE TECHNICAL & ECONOMIC EVALUATION
- ALTERNATIVE SOLAR THERMAL CONVERSION SYSTEMS
- OPERATIONAL MODE

SELECTION/DEFINITION OF PREFERRED SYSTEMS (preliminary)
- PRIMARY - CENTRAL RECEIVER SOLAR PLANT (1 km^2/6 hr/100 MW_e)
- BACKUP - CENTRAL RECEIVER HYBRID PLANT (0.5 km^2/0.5 hr/100 MW_e)
  - LOW COST E-W PARABOLIC TROUGH (1.5 km^2/8 hr/100 MW_e)
- OPERATIONAL MODE - INTERMEDIATE (load following)
- COMPETITIVE BUSBAR ENERGY COST (25-30 mills/kWh, 1974 dollars)

SITING ANALYSIS - SOUTHWESTERN U.S.
- SUITABLE LAND AREA ~21,000 sq mi
- WATER RESOURCES ~30,000 MW_e GENERATION CAPACITY

PRELIMINARY MARKET CAPTURE POTENTIAL
- SOLAR GENERATION CAPACITY~40,000 MW_e (cumulative) IN YEAR 2000

IMPACT ON RESOURCES/ENVIRONMENT
- FUEL SAVINGS ~320 MILLION BARRELS OF OIL IN YEAR 2000
- SOLAR PLANTS DO NOT REQUIRE CRITICAL MATERIALS

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