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SOLAR THERMAL CONVERSION MISSION ANALYSIS

FINAL REPORT

THE AEROSPACE CORPORATION

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SOLAR THERMAL CONVERSION
MISSION ANALYSIS

FINAL REPORT

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ABSTRACT

The Aerospace Corporation has performed, under ERDA sponsorship (Contract No. E(04-3)-1082), analyses of conceptual systems, missions, and economic factors governing the generation of electrical power by solar thermal conversion techniques. These analyses have focussed on large (greater than 100 MW) central solar power plants intended for electric power generation. Most of the methodology developed during these analyses and some of the analytical results were described in an earlier document*. This report extends those results and describes the application of previously developed methodologies to the determination of solar thermal power plant performance and operating economics for additional sites throughout the U.S. It represents a compilation of material which has been published previously in other forms.

*Solar Thermal Conversion Mission Analysis, Midterm Report. Aerospace Report No. ATR-76(7506-05)-1

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This report represents the combined efforts of many different people within The Aerospace Corporation. A few of the major contributors are listed below along with their areas of investigation:

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Prem Munjal	Assessment of Materials and Resource Requirements, Section IV
Al Forster Seiji Sugihara Ron Janz Helen Wong	Central Power System Modeling and Economics, Sections II and III

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CONTENTS

ABSTRACT iii

ACKNOWLEDGEMENTS v

I. INTRODUCTION 1-1

II. DEMAND STUDIES 2-1

A. Selection of Representative Sites 2-1
B. Regionalization Studies 2-3
C. Demand Analysis. 2-8

III. INSOLATION AND CLIMATOLOGY STUDIES 3-1

A. Introduction and Background 3-1
B. Insolation Data Bases 3-1
a. Daily Total-Hemispheric Insolation Data Base . . 3-10
b. Hourly Data Base 3-14
C. Regional Comparisons of Direct-Normal Insolation. . 3-40
1. Introduction. 3-40
2. Estimation Procedures 3-40
3. Direct Insolation Comparisons 3-41
4. Discussion 3-64
D. Cloud Shadowing 3-66
1. Introduction 3-66
2. Computer Simulation 3-66

IV. CENTRAL POWER SYSTEMS ANALYSIS. 4-1

A. Introduction 4-1
B. Performance Simulation Modeling 4-2
1. Model Improvements. 4-2
2. Results. 4-8
C. Margin Analysis 4-27

CONTENTS (Cont.)

D. Solar Plant Economic Analysis 4-39
1. Introduction 4-39
2. Economics Methodology 4-39
3. Methodology Application 4-40
4. Economic Parameter Selection 4-49
5. Plant Construction Costs 4-56
6. Busbar Energy Costs 4-66

V. SOLAR PLANT IMPLEMENTATION IMPACT ON RESOURCES 5-1

A. Introduction 5-1

B. Current Designs of Solar Central Power Plant 5-1
1. Martin Marietta System Design. 5-3
2. McDonnell Douglas (MDAC) System Design 5-5
3. Honeywell System Design 5-8
4. Boeing System Design 5-14

C. Materials and Energy Requirements 5-14

D. Materials and Energy Impacts Under Different Scenarios. 5-27

REFERENCES R-1

APPENDIXES A-1
A. Daily Insolation/Climatology Data Base Format A-1
B. Hourly Insolation Climatology Data Base Format . . . B-1
C. Data Tape Procurement C-1
D. Modified Julian Day Numbers D-1

TABLES

3-1. Hourly Data Base Locations 3-5

3-2. Stations Included in Daily Hemispherical Insolation Data Base Arranged by Station Name 3-8

3-3. Meteorological Observables for Which Daily Mean Hourly Values are Available, 1961 to Daily Data Base End 3-11

3-4. Quantities Which Are Included for Every Hour for All Stations 3-15

3-5. Reliability of Quantities in the Hourly Data Base 3-19

3-6. Hourly Insolation Data Tape Catalog 3-21

3-7. Daily Total Insolation Data Tape Catalog 3-22

3-8. Average Daily Total-Hemispheric Insolation, 1962 (kWh/m^2) 3-23

3-9. Average Daily Total Hemispheric Insolation, 1963 (kWh/m^2) 3-27

3-10. Average Daily Direct Normal Insolation, 1962, (kWh/m^2) 3-30

3-11. Average Daily Direct Normal Insolation, 1963, (kWh/m^2) 3-34

3-12. Average Total-Hemispherical Insolation for Columbia, Mo. (kWh/m^2) 3-38

3-13. Average Daily Direct Normal Insolation for Columbia, Mo. (kWh/m^2) 3-39

3-14. Average Number of Cases with Insolation Greater Than - N - Kw. per Sq. Meter for Greater Than -M- Consecutive Hours. 3-42

3-15. Average Number of Cases of Continuous Insolation Greater Than .60 kW/m^2. 3-57

3-16. Total Fractional Shadow Area for Cumuliform Clouds. . . 3-74

TABLES (Cont.)

3-17.	Probability of Rate of Change of Power (PRCP)	3-95
4-1.	Normalized Thermal Energy Balance for CPSB 1990 Demand and Fort Worth Insolation	4-10
4-2.	Margin Analysis Assumptions.	4-30
4-3.	Cost Escalation Rates	4-51
4-4.	Conventional Power Plant Escalation Rates.	4-52
4-5.	Solar Thermal Power Plant Escalation Rates	4-53
4-6.	Projected Fuel Escalation Rates	4-54
4-7.	Summary Comparison of Mission Analysis Ecomonic Parameters.	4-55
4-8.	Capital Costs of Alternate 100 MW Central Receiver Configurations	4-60
4-9.	Comparison of 100 MW Central Receiver Capital Investment Costs	4-61
4-10.	Conventional Power Plant Construction Costs (Data Used in Earlier Studies)	4-63
4-11.	Conventional Power Plant Construction and Fuel Costs - Final Parameter Selection	4-64
4-12.	Comparison of Conventional and Solar Power Plant Construction Costs	4-65
4-13.	Allocation of Power Plant Busbar Energy Costs - Interim Results	4-69
4-14.	Geographical Location of Conventional and Solar Power Plants.	4-73
4-15.	Fossil Generation Unit Net Heat Rates	4-74
4-16.	Conventional Power Plant Busbar Energy Costs - Final Result	4-76
4-17.	SCE/Inyokern - Central Receiver Solar Plant Technical Characteristics and Operating Economics.	4-78

TABLES (Cont.)

4-18. SCE/Inyokern - Central Receiver Solar Plant Technical Characteristics and Operating Economics 4-79

4-19. PPL/Seattle - Central Receiver Solar Plant Technical Characteristics and Operating Economics 4-80

4-20. CPSB Fort Worth - Central Receiver Solar Plant Technical Characteristics and Operating Economics. . . . 4-81

4-21. Consumers Power/Madison - Central Receiver Solar Plant Technical Characteristics and Operating Economics 4-82

4-22. PJM/Sterling - Central Receiver Solar Plant Technical Characteristics and Operating Economics. 4-83

4-23. FPL/Miami - Central Receiver Solar Plant Technical Characteristics and Operating Economics. 4-84

5-1. Martin Marietta Solar Central Power Plant Preliminary Design Characteristics 5-6

5-2. MDAC Solar Central Power Plant Preliminary Design Characteristics 5-2

5-3. Honeywell Solar Central Power Plant Preliminary Design Characteristics 5-13

5-4. Boeing Solar Central Power Plant Preliminary Design Characteristics 5-16

5-5. Energy Requirement for Production of Different Materials 5-20

5-6. Energy Source, Payback Period, and Return Ratio. 5-26

5-7. Solar Plant Penetration Impacts on Current U.S. Materials/Manufacturing Facilities 5-29

FIGURES

2-1. Total Insolation Isopleths (Daily Average). 2-2

2-2. Population Distribution (1970) 2-4

2-3. Utility Load Regions 2-5

2-4. United States Climatology Temperature Zones. 2-7

2-5. Insolation Characteristics of Six Representative Sites. . . 2-9

2-7a. PJM Demand Forecast for April, 1990. 2-16

2-7b. PJM Demand Data for April, 1972. 2-17

2-9a. FPL Demand Forecast for April, 1990. 2-18

2-9b. FPL Demand Data for April, 1972. 2-19

2-11a. CPC Demand Forecast for April, 1990. 2-20

2-11b. CPC Demand Data for April, 1972 2-21

2-13a. PPL Demand Forecast for April, 1990. 2-22

2-13b. PPL Demand Data for April, 1972. 2-23

2-15a. SCE Demand Forecast for April, 1990 2-24

2-15b. SCE Demand Data for April, 1972 2-25

2-17a. CPSB Demand Forecast for April, 1990 2-26

2.17b. CPSB Demand Data for April, 1972 2-27

3-1. Southwestern United States Climatic Zones 3-2

3-2. Hourly Insolation Data Base Locations 3-6

3-3. Daily Hemispheric Insolation Data Base Locations for Which at Least 730 Values of Insolation are Available. . . 3-7

3-4. Isopleths of Annual Daily Average Direct-Normal Insolation (kWh m^{-2}). 3-54

FIGURES (Cont.)

3-5. Isopleths of Average Daily Insolation for the Month of June (kWh m^{-2}) 3-55

3-6. Isopleths of Average Daily Insolation for the Month of December (kWh m^{-2}) 3-56

3-7. Cases of Direct Insolation ≥0.6 kWm^{-2}) for Four or More Hours. 3-58

3-8. Cases of Direct Insolation ≥0.6 kWm^{-2}) for Four or More Hours. 3-59

3-9. Cases of Direct Insolation ≥0.6 kWm^{-2}) for Four or More Hours. 3-60

3-10. Cases of Direct Insolation ≥0.7 kWm^{-2}) for Five or More Hours. 3-61

3-11. Cases of Direct Insolation ≥0.7 kWm^{-2}) for Five or More Hours. 3-62

3-12. Cases of Direct Insolation ≥0.7 kWm^{-2}) for Five or More Hours. 3-63

3-13. Frequencies of Cloud Areas for Three Cumuliform Cloud Types 3-68

3-14. Cloud Shadow and Mirror Field Geometry. 3-70

3-15. Cloud Shadow Field. 3-73

3-16. Cloud Shadow Field. 3-76

3-17. Power Curve. 3-80

3-18. Power Change Curve. 3-81

3-19. Percent of Occurrence Curve. 3-82

3-20. Maximum Power Change vs Sky Cover. 3-86

3-21. Maximum Power Change vs Cloud Type 3-87

3-22. Maximum Power Change vs Cloud Velocity. 3-88

FIGURES (Cont.)

3-23. Maximum Power Change vs Solar Elevation 3-89

3-24. Probability of Occurrence of Rate of Change of Power vs Sky Cover 3-90

3-25. Probability of Occurrence of Rate of Change of Power vs Cloud Type 3-92

3-26. Probability of Occurrence of Rate of Change of Power vs Cloud Velocity 3-93

3-27. Probability of Occurrence of Rate of Change of Power vs Solar Elevation 3-94

4-1. Daily Scheduling of Solar Power Plants 4-4

4-2. Central Receiver Simulation Model 4-6

4-3. Central Receiver Regional Analysis. 4-9

4-4. PJM (1990) - Sterling, Vermont, Simulation Results, 8000 MW_e Solar Penetration (8.8%) 4-12

4-5. PJM (1990) - Sterling, Vermont, Simulation Results, 18,000 MW_e Solar Penetration (19.8%). 4-13

4-6. FPL (1990) - Miami, Florida, Simulation Results, 2000 MW_e Solar Penetration (8.2%) 4-14

4-7. FPL (1990) - Miami, Florida, Simulation Results, 6000 MW_e Solar Penetration (24.7%) 4-15

4-8. CPC (1990) - Madison, Wisconsin, Simulation Results, 1000 MW_e Solar Penetration (5.8%) 4-16

4-9. CPC (1990) - Madison, Wisconsin, Simulation Results, 3000 MW_e Solar Penetration (17.3%) 4-17

4-10. PPL (1990) - Seattle, Washington, Simulation Results, 1000 MW_e Solar Penetration (11.8%) 4-18

4-11. PPL (1990) - Seattle, Washington, Simulation Results, 1500 MW_e Solar Penetration (17.6%) 4-19

FIGURES (Cont.)

4-12. SCE (1990) - Inyokern, California, Simulation Results, 3000 MW_e Solar Penetration (8.2%) 4-20

4-13. SCE (1990) - Inyokern, California, Simulation Results, 10,000 MW_e Solar Penetration (27.5%) 4-21

4-14. CPSB (1990) - Fort Worth, Texas, Simulation Results, 500 MW_e Solar Penetration (7.5%) 4-22

4-15. CPSB (1990) - Fort Worth, Texas, Simulation Results, 1500 MW_e Solar Penetration (22.7%) 4-23

4-16. Correlation Between Solar Capacity Factor and Insolation 4-24

4-17. Relationship Between Solar Capacity Factor and STBASE 4-28

4-18. PJM (1990) - Sterling, Vermont, Margin Analysis Results, 8000 MW_e Solar Penetration (8.8%) 4-31

4-19. SCE (1990) - Inyokern, California, Margin Analysis Results 4-32

4-20. FPL (1990) - Miami, Florida, Margin Analysis Results 4-33

4-21. CPL (1990) - Madison, Wisconsin, Margin Analysis Results 4-34

4-22. PPL (1990) - Seattle, Washington, Margin Analysis Results 4-35

4-23. CPSB (1990) - San Antonio, Texas, Margin Analysis Results 4-36

4-24. Dependence of Backup Capacity on Solar Penetration . . . 4-38

4-25. Economic Analysis Methodology 4-42

4-26. Aerospace Power Plant Economic Model (PPEM) 4-44

4-27. Levelized Cost of Service Model 4-45

FIGURES (Cont.)

4-28. Aerospace Public Utility Financial Analysis and Planning Model 4-48

4-29. Central Receiver Power Plant Costing Work Breakdown Structure. 4-57

4-30. Summary Comparison of Aerospace Power Plant Construction Costs 4-67

4-31. Comparative Busbar Energy Costs of Representative Power Plants Interim Results. 4-71

4-32. Operation and Maintenance Costs - (1975 Dollars) 4-75

4-33. SCE/Inyokern Central Receiver Power Plant Busbar Costs 4-85

4-34. SCE/Inyokern Central Receiver Power Plant Busbar Costs 4-86

4-35. PPL/Seattle Central Receiver Power Plant Busbar Costs 4-87

4-36. CPSB/Fort Worth Central Receiver Power Plant Busbar Costs. 4-89

4-37. Consumers Power/Madison Central Receiver Busbar Costs 4-90

4-38. PJM/Sterling-Central Receiver Power Plant Busbar Costs 4-91

4-39. FPL/Miami - Central Receiver Power Plant Busbar Costs 4-92

5-1. Martin Marietta 25-Mirrored Warped Heliostat 5-4

5-2. MDAC Canted Octagonal-Disks Heliostat 5-7

5-3. Tilt-Tilt Configuration Heliostat 5-10

5-4. Details of Honeywell Mirror Module Configuration 5-11

5-5. Boeing Heliostat with Aluminized Mylar Reflector and Transparent Dome Enclosure 5-15

FIGURES (Cont.)

5-6.	Materials and Energy Requirements for 100 MW_e Solar Power Plant Collector Subsystems	5-18
5-7.	Energy Requirement Calculations for Two Interlinked Material Industries	5-21
5-8.	100 MW_e Power Plant Energy Investment	5-23
5-9.	Growth Scenarios for Solar Power Plants	5-28
5-10.	Yearly Energy Balance	5-31
5-11.	Cumulative Net Energy Balance Scenario I	5-32
5-12.	Cumulative Net Energy Balance Scenario II	5-33
5-13.	Cumulative Net Energy Balance Scenario III	5-34
5-14.	Yearly Net Energy Balance for Materials Enrichment and Nuclear Power Plant	5-35
5-15.	Cumulative Net Energy Balance for Materials Enrichment and Nuclear Power Plants	5-36
5-16.	Available Energy Reserve Equivalent of Installed Solar Thermal Power Plants	5-38

I. INTRODUCTION

Under the sponsorship of the Energy Research and Development Administration (ERDA) Contract Number E(04-3)-1082 and previously under NSF funding, The Aerospace Corporation has carried out a series of applications analysis and system concept trade-off studies for solar thermal energy conversion. The goals of these studies are as follows:

- Formulate methodologies for evaluating alternative solar energy concepts
- Assess the technical and economic feasibility of various solar thermal energy concepts and applications and identify those having the greatest potential
- Establish technical and economic bounds for solar energy systems, subsystems, and major component design and performance parameters for selected applications
- Determine the market capture potential and assess the resource, environmental, and institutional impacts of a significant market penetration by solar thermal conversion systems.

The information developed in these studies is intended to assist in formulating and directing the Solar Thermal Power Systems Program for which ERDA is responsible. An additional goal has been to establish and promulgate standardized reference data and techniques for analyzing selected solar energy system concepts so that study results obtained by other organizations can be compared within a common framework. Toward this end, standard insolation records for selected sites throughout the U.S. have been prepared and made available to the solar energy community, and several computer simulations for solar thermal systems have been developed and transmitted to other contractors. These analysis standards and techniques are discussed in subsequent sections of this report.

This report compiles the results presented at program reviews and other public forums as well as in separate task reports. For the central power system concept, emphasis is on the extension to other areas of the continental U.S. of analysis results for the southwestern U.S. which were presented in the Midterm Report (Reference 6). These results were presented in terms of (a) solar plant capital costs, (b) the plant annual capacity factor (essentially a measure of average annual insolation), (c) conventional plant backup capacity required, and (d) the resulting solar plant busbar energy costs.

Busbar energy cost is the single most important parameter describing the design and operation of a solar central power plant. The annualized busbar energy cost takes into account the incident insolation, the annual plant performance, the degree of match (or mismatch) between plant electrical output and applied load, and the amount of conventional backup capacity (additional margin) required. Busbar energy cost also reflects the capital investment cost of the solar plant, which must be amortized during its assumed lifetime by the conventional fuel and capacity displaced, and it reflects O&M costs. These have been assumed equal to the O&M costs of a conventional (fossil) plant of equal capacity.

For this analysis, a baseline 100 MW_e solar plant was assumed. The conceptual design of this baseline plant is described in Appendix A of Reference 6. This plant has 1.0 km^2 collector area, 6 hours of thermal storage, and an overall annual average efficiency (excluding the storage system) of 0.17. Regional variations in the performance of this system result from (a) differences in insolation, and (b) variations in the hourly load profile. However, load profile variations have a rather minor effect on performance for the cases which have been examined, and insolation remains a major determinant of system performance and of busbar energy costs.

Several different economic analysis techniques are discussed in Section IV of this report. Previous mission analyses (for example those of

References 1 and 4) have used an Aerospace-developed model known as the Power Plant Economic Model (PPEM) which is described in Reference 7. This model was used to calculate solar plant busbar energy costs for the first year of commercial operation (Yco). These costs were adequate for rank-ordering by their operating economies of the various solar plant concepts of interest.

The technique used in the current analysis for estimating and comparing busbar energy costs is the Aerospace Public Utility Financial Analysis and Planning Model, PUFAP. The PUFAP model was developed to provide precise techniques for cost accounting and financial analysis similar to those used by large public utilities and by the state and federal regulatory commissions for setting rates. This model correctly takes into account all of the utility cash flows, both expenses and revenues, and it provides for the investment of utility retained earnings. The model provides balance sheets and cash flow summaries for each year of plant operation during the plant lifetime, and the resulting cost of service figures decline beyond Yco to reflect retirement of debt.

Section IV also discusses and compares the results of using the levelized cost methodology described in the EPRI/JPL cost model (Reference 8). This model can be adjusted to give cost-of-service values equal to those provided by PUFAP at Yco, with the adjustment being made through proper selection of tax rates and of other economic parameters which enter into the calculations. An exemplary calculation based on the EPRI/JPL model is given in Section IV for comparison with PUFAP results.

Section V of this report addresses the potential costs (in materials and in energy) of the large-scale implementation of solar central power plants. The energy payback period for a solar power plant is an important consideration in establishing how rapidly the commercialization of solar plants can reduce the current U.S. dependence on fossil fuels. As demonstrated in Section V, scenarios involving exponential rates of solar

capacity increase can result in periods during which all of the energy produced by on-line solar plants is required for the fabrication of new ones.

The information contained in this report supplements but generally does not duplicate that of Reference 6. The two reports are intended to serve together in providing direction to the development and commercialization of solar central power systems during the post 1980 period. These systems were found during the study to be both technically feasible and economically competitive with fossil or nuclear power plants within the southwestern U. S. during the late 1980 time period. As fossil and nuclear fuel prices continue to escalate at rates greater than the general rate of inflation, solar plants in other parts of the country are also expected to become economically competitive. Thus, the comparative performance (and hence economics) of solar plants in different regions of the country can be interpreted as a preferred sequence for large-scale solar plant implementation.

II. DEMAND STUDIES

A. SELECTION OF REPRESENTATIVE SITES

Previous studies (Reference 1) examined the performance of Solar Thermal Central Power Systems in the southwestern U.S., with emphasis on the performance to be expected within those areas (Figure 2-1) where insolation levels average 7 kWh/m^2/day or greater. It was assumed for these earlier studies that solar thermal systems were most likely to be technically and economically feasible where average annual insolation levels are highest. The results of these earlier studies showed that, within certain bounds, solar central power systems within the southwestern U.S. will be both feasible and economically competitive with conventional (fossil fueled) systems. These findings have led to renewed interest in the performance and operating economics of similar solar plants located in other sections of the country, and the effects of different insolation levels and load profiles on system optimum design. The present study was therefore intended to provide a fairly detailed comparison of solar plants operating in regions of the U.S. outside of the Southwest, and to explore the potential market for solar plants in those regions not previously considered.

Because of the large number of utilities operating within the U.S., it was necessary, in order to keep the study within manageable limits, to select one or more "representative" utilities from various regions, and to pair these with selected insolation stations for which credible insolation measurements were available. By doing this for a sufficient number of geographically distributed utilities, it appeared possible to develop a detailed understanding of where solar plants should be sited and where they should not.

The selection of appropriate utilities, and the definition of the regions to be represented by simulations performed using demand and insolation

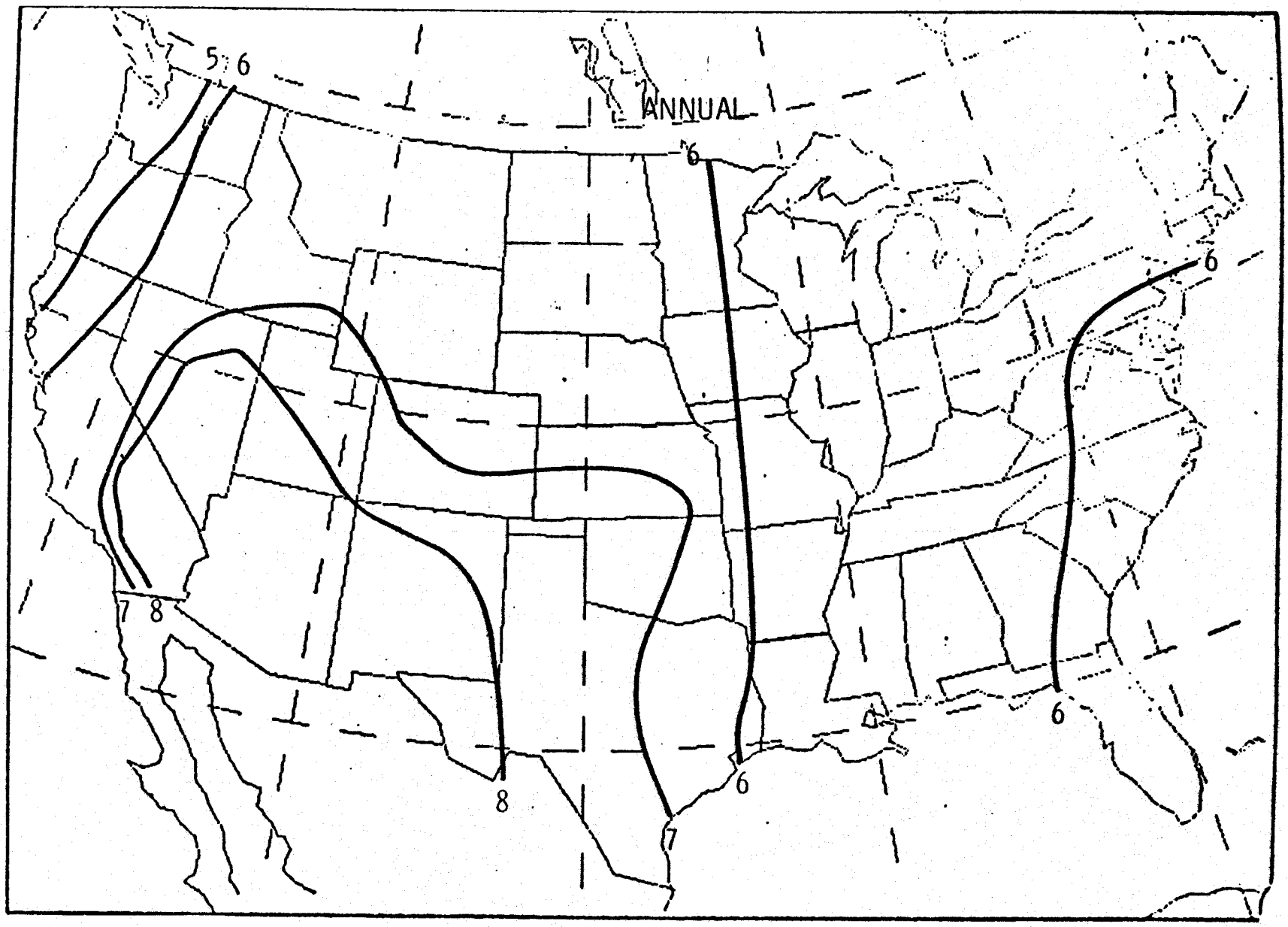


Figure 2-1. Total Insolation Isopleths (Daily Average)

data for those utilities has been based on regionalization studies which are further described below. The selection was also based in part on the response (or lack of response) of those utilities which were contacted and asked for demand data. Many utilities failed to respond to these requests, and for this reason the north-central and western U.S., including the states of Kansas, Nebraska, Iowa, Missouri, Arkansas, Montana and the Dakotas, are not as well characterized as are other regions. However, as indicated in Figure 2-2, the population density (and hence fossil fuel usage) is very non-uniform throughout the country. The density distribution for 1970, the latest date for which data in the format of Figure 2-2 are available, falls off sharply west of mid-Texas (about 10.7 deg W. longitude) except for a strip along the West Coast. Thus, it appeared reasonable for this study to focus on those areas in the eastern and east/central U.S. simultaneously having high population density and reasonably good annual insolation. These areas plus a strip along the West Coast encompassing the southern half of California are the areas judged most likely to be involved in early phases of solar plant commercialization.

B. REGIONALIZATION STUDIES

Previous phases of this study (Reference 2) have examined the characteristics of electric utility demand profiles and load duration curves in various regions of the U.S. and have attempted to identify elements of commonality among utilities serving these regions. The objective of these efforts was to characterize various categories of utility demand, such that, for each category and region, a single "representative" utility demand profile could be used for subsequent analysis of solar plant performance. These efforts resulted in the identification of 10 regions within which all the utility demand data appeared to have common features. Three utilities were also found (TVA, Omaha Public Power, and Commonwealth Edison of Illinois) with singular demand features which were non-representative of other nearby utilities. These demand regions and the service areas of the three singular utilities are shown in Figure 2-3.

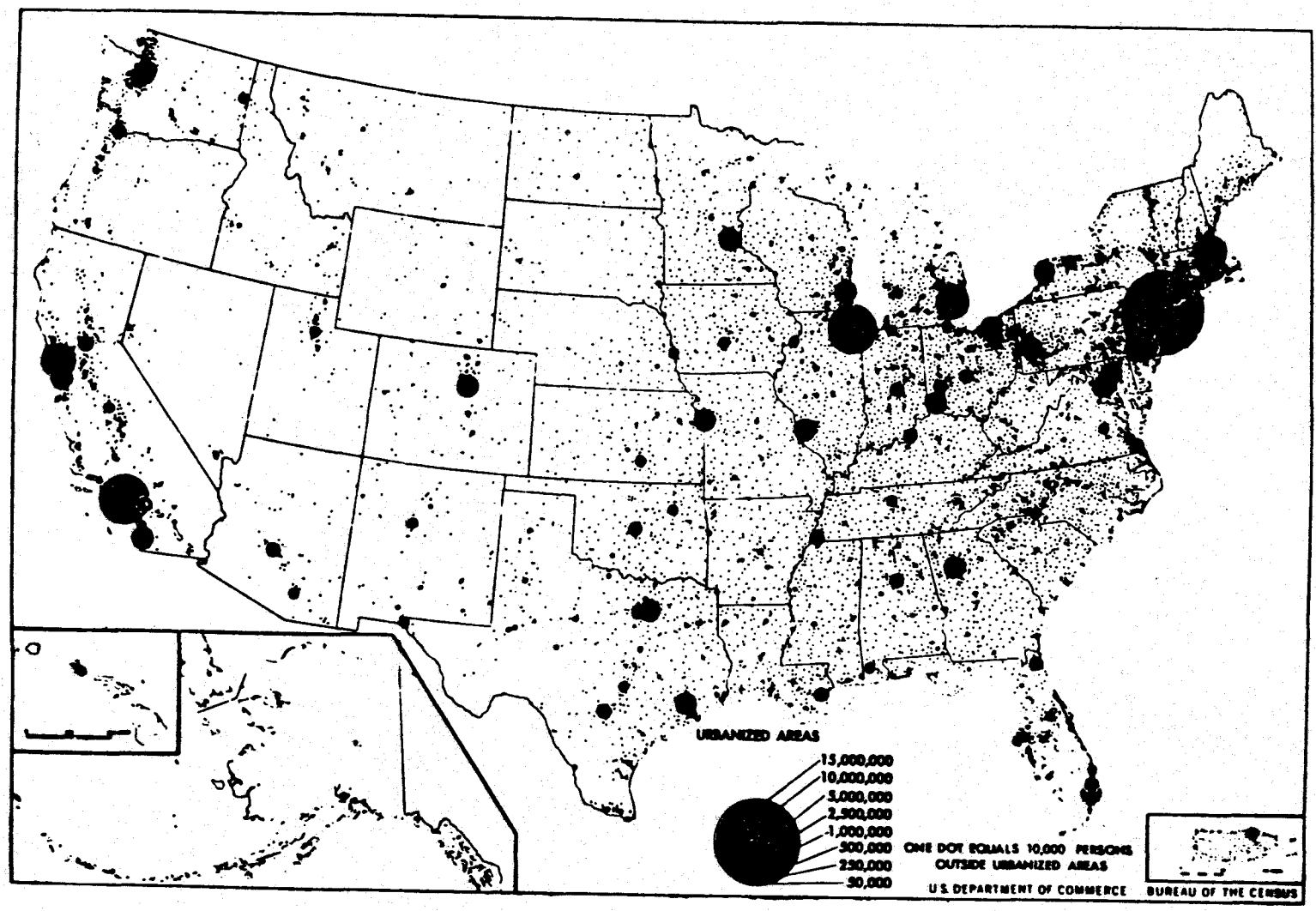


Figure 2-2. Population Distribution (1970)

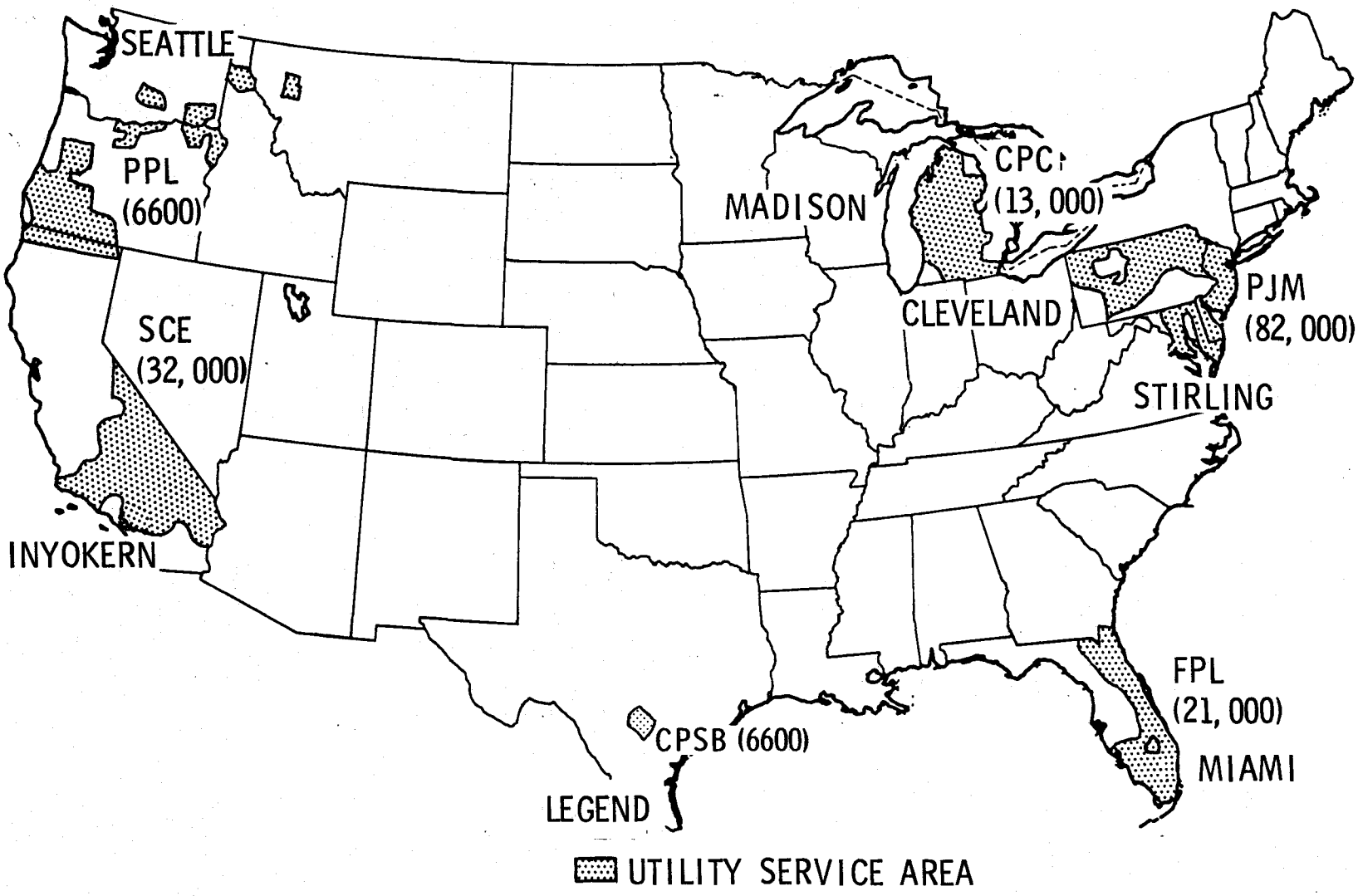


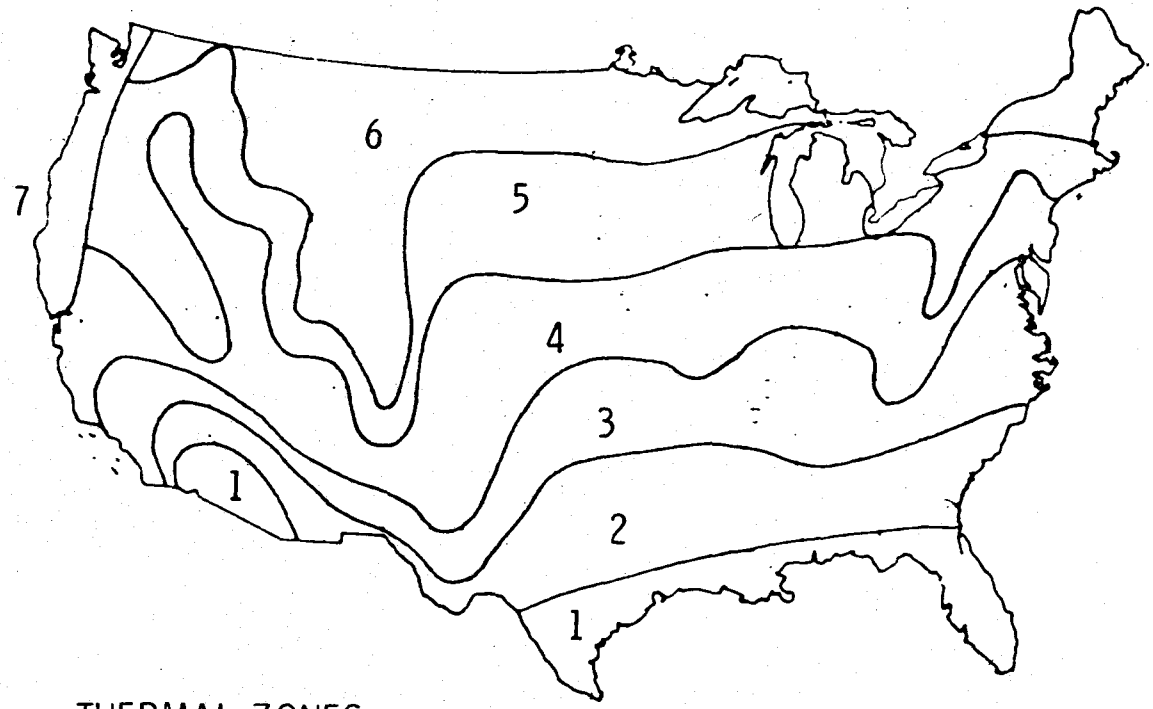
Figure 2-3. Utility Load Regions

It was also found possible to draw boundaries (Reference 6) separating the various demand regions which closely matched the boundaries (Figure 2-4) which had previously been established for climatological characteristics, particularly heating or cooling degree days. The implications of this similarity appear to be that the demand profile features examined during the study are significantly influenced by climatology.

As a result of these findings, a decision was made to attempt to evaluate the performance of solar plants in each of the "demand regions" which had been defined. This goal was later reduced to the goal of examining five additional sites outside the Southwest when problems were encountered in obtaining sufficiently detailed demand data from utilities in several regions. The additional sites selected for detailed performance simulation (also the locations for insolation data to be used) were:

Demand Region	Representative Utility	Insolation Site
1	Consumer Power Company (CPC)	Madison, Wis.
3	Florida Power & Light Co. (FPL)	Miami, Fla.
4	Pacific Power & Light Co. (PPL)	Seattle, Wash.
6	San Antonio City Public Service Board (CPSB)	Fort Worth, Tex.
9	Pennsylvania, New Jersey Maryland Intertie (PJM)	Sterling, Va. (Dulles Airport)

These regions, plus the southwestern U.S. as represented by Inyokern, California/Southern California Edison Co., are thought to span the range of performance to be expected in other areas of interest. Seattle, Washington, because of its very poor insolation, was expected to provide a lower bound on the performance of a solar system.



THERMAL ZONES

	COLD °F DAYS	HOT °F DAYS
1	<1500	>1500
2	1500 - 3000	1000 - 1500
3	3000 - 5000	500 - 100
4	5000 - 7000	100 - 500
5	7000 - 8000	0 - 100
6	>8000	0
7	3000 - 5000	0

Figure 2-4. United States Climatology Temperature Zones

The insolation characteristics of the six sites are summarized in Figure 2-5 for the year 1963. These sites are representative of the available insolation across the U. S., with Inyokern having the most favorable insolation and Seattle the least favorable. The four other sites are intermediate, and generally represent the insolation to be expected in selected areas of the eastern seaboard and within the industrial belts near the Great Lakes and Gulf Coast. It is noteworthy that the average annual insolation varies between these sites by less than a factor of two: Inyokern/Seattle = 1.96. For the intermediate sites (Madison, Sterling, Miami, Fort Worth) the maximum value of this ratio (Inyokern/Madison) is 1.42.

C. DEMAND ANALYSIS

Demand forecasts for the year 1990 were made for the six selected utilities. These forecasts were used in subsequent simulation analyses to evaluate the efficiency of solar power in helping satisfy total power demand. They were also used in comparing methods of utilizing stored solar energy.

The demand forecasts were made with the new forecasting procedure detailed in Reference 6. This procedure was developed since the previous forecast model identified and utilized only a single trend in predicting future electrical demand requirements for a given utility. This trend corresponded to the yearly average growth of peak demand which was forecast for that utility. Consequently, the forecasted variation in demand within a year (yearly demand distribution) was independent of the forecast year. This distribution was essentially assumed to be the same as the average of the last few years in the demand data base (geometric weighting) or the average of all years in the data base (no weighting).

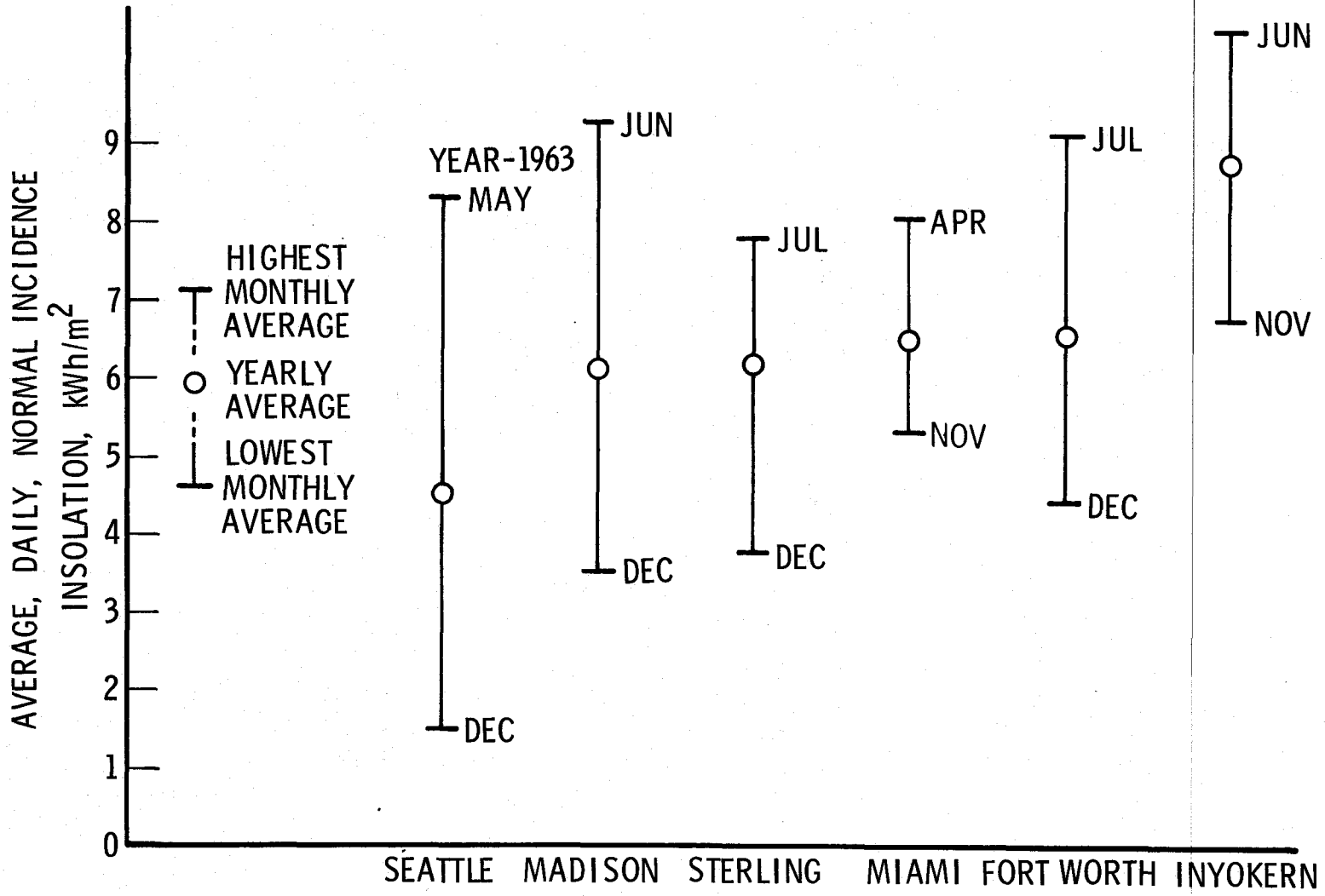


Figure 2-5. Insolation Characteristics of Six Representative Sites

This characteristic of the previous model is not a serious limitation if a given utility has a history of reasonably stable yearly load distributions. However, if major redistributions in demand have occurred (such as a shift from winter to summer peaking or a shift from morning to evening peaking) and these redistributions have a trend associated with them, the model should be able to quantify this behavior and utilize it in making forecasts. It is for this reason that a new, more flexible model was formulated.

The new procedure begins with the decomposition of historical demand into component factors. The choice of these factors may easily be adapted to a given utility without seriously perturbing the overall methodology. However, the factors which are discussed below appear to be adequate for the utilities considered in this study. These factors are defined as follows:

a. PD = peak yearly demand (MW)

b. LF = TE/PD (hr)
   where TE = total yearly energy (MWh)
   (Note that LF is directly proportional to the load factor.)

c. W = WE/TE (dimensionless)
   where WE = total weekly energy (MWh)

d. D = DE/WE (dimensionless)
   where DE = total daily energy (MWh)

e. HD = HDE/DE (dimensionless)
   where HDE = total half-day (either 1 a.m. to 12 noon or 1 p.m. to midnight) energy (MWh)

f. H = DH/HDE (hr^{-1})
   where DH = hourly demand (MW)

That is,

$$DH = PD * LF * W * D * HD * H$$

$$= PD \left(\frac{TE}{PD}\right) \left(\frac{WE}{TE}\right) \left(\frac{DE}{WE}\right) \left(\frac{HDE}{DE}\right) \left(\frac{DH}{HDE}\right)$$

The first factor in this equation, namely peak yearly demand (PD), usually exhibits exponential growth regardless of the utility. However, the second factor, which is directly proportional to load factor, is typically quite stable for a given utility. The next three factors (W, D, and HD), which characterize the weekly, daily, and half-day distributions in energy, exhibit variable behavior. A gradual trend away from winter toward summer peaking would show up as a decrease in the weekly index (W) for winter weeks and a corresponding increase in this index for the summer weeks. A shift in energy demand between mid-weekdays and weekends would show up in corresponding changes in the daily index (D) for those weeks so affected. Similarly, a shift in energy demand between mornings and afternoons of certain days would show up as changes in the half-day index for those days. Trends in these three factors will be highly dependent upon the specific utility under investigation. Also, for a given utility, certain portions of the yearly energy distribution may be stable while other portions may exhibit strong trends. The identification of the trends in these three factors and the utilization of the trends in making forecasts represent the primary distinction between this model and the previous model.

The last factor in the decomposition, i.e., the hourly index H, should be trend-free. If significant trends are detected in this index, it means that the choice of factors is not adequate and the data and results should be re-examined. (Appropriate factors can always be detected by examining the frequency content of the data.) Assuming that variations in H from year to year are random in nature, corresponding values of H for each year in the data base are simply averaged to eliminate the random component and determine representative hourly indices.

In the current version of the model, trends in the four factors, LF, W, D and HD are assumed to be linear. That is, it is assumed that

$$LF = A + B * YR$$

$$W_k = A_k + B_k * YR$$

$$D_{jk} = A_{jk} + B_{jk} * YR$$

$$HD_{ijk} = A_{ijk} + B_{ijk} * YR$$

where the subscripts refer to the following quantities and range over the following values:

k	week	1 through 52
j	day	1 through 7
i	half-day	1 (1 a.m. to 12 midnight) or 2 (1 p.m. to 12 midnight)

and YR refers to year.

A least-squares procedure is used to determine the parameters in these regression equations. Whether or not the slopes, B, B_k, B_{jk}, and B_{ijk} differ significantly from zero is determined at a specified level of confidence. If it is found that a given slope does not differ significantly from zero, the average value of the corresponding factor is computed and used in the forecast rather than the extrapolated trend.

An hourly demand forecast for a given year is obtained by recomposing factors in the following way:

$$DH_{hijk} = PD \overset{FORECAST}{*}_{LF} \overset{FORECAST}{*}_{W_k} \overset{FORECAST}{*}_{D_{jk}} \overset{FORECAST}{*} HD_{ijk} \overset{FORECAST}{*}_{\overline{H}_{hijk}}$$

where, either average values or extrapolated trends are utilized for the factors LF, W_k, D_{jk} and HD_{ijk}. The forecasted peak yearly demand factor,

$PD^{FORECAST}$, is obtained by a least-squares exponential extrapolation of observed yearly peak demands unless a value has been published by the utility under investigation. The utility-supplied value is always used when it is available. The subscript h denotes "hour" (ranging from 1 through 12) and $\overline{H}_{hijk}$ denotes the average hourly index discussed above.

As with all forecast models the newly developed model has its limitations. Specifically, while the trends for the four factors in the recomposition model may exhibit a high degree of mathematical significance (measured in terms of the ratio of the sum of squares due to regression and the sum of squares about the mean), there may be a limited (if any) physical basis for anticipating that these trends will continue 15 to 25 years into the future. Conversely, some trends may exhibit little mathematical significance and yet have a meaningful basis in terms of projected technological developments or demographic characteristics of a particular area. In short, the trends determined by the model need to be carefully evaluated for practical as well as statistical significance for each utility before the credibility of the forecast can be assessed.

For the decomposition model discussed above, up to 11,027 parameters are required to obtain a continuous hourly forecast for a hypothetical year consisting of 8,736 hours (52 weeks * 7 days/week * 24 hours/day). Of this total, up to 2,290 of the parameters are used to define one "load factor" trend, 52 weekly trends, 364 daily trends, and 728 half-day trends. While this may appear to be an exorbitant number of parameters, it is significantly less than the number (approximately 17,500) required by the previous model to provide a static forecast.

An informative way of assessing the value of the model for a given utility is to compare forecasts predicted by the model with observed behavior for those years included in the data base. If it is found that there are large differences between predicted and observed demand values (due to a large, apparently random component in the data induced by variable weather

conditions, nonlinear trends in the data, etc.), there is little justification for performing forecasts with the model until these differences are reduced by modifying the decomposition, using nonlinear trend equations or modeling the weather component. Computation of the differences between predicted hourly demand and observed hourly demand (referred to as the "residual") is an integral part of the new forecast methodology, however.

Portions of the hourly demand forecasts which were obtained with the new forecasting procedure are illustrated in Figures 2-7 through 2-17. Corresponding historical (i.e., measured demand) data for the year 1972 are shown on the same figures for comparison.

All utilities except FPL (Fig. 2-9 a/b) show a noticeable Saturday and Sunday drop in demand while FPL shows only a Sunday drop. The reason for this is unclear. The PPL forecast (Figure 2-12(a)) exhibits very pronounced mid-day peaks due to statistically significant trends in the half-day indices for those days. These peaks are not observed in the 1972 data (Figure 2-12(b)). Also the midweek peak demands for PJM in 1972 (Figure 2-6(b)) were generally about 70 percent of the annual peak demand for that year, while they are forecast to increase to approximately 80 percent of the annual peak demand in 1990 (Figure 2-6(a)) due to statistically significant trends in the weekly indices. The CPSB forecast (Figure 2-17(a)) and observed demand (Figure 2-17(b)) are considerably different in character for CPSB, April and May for the transition period between a stable winter demand pattern and a highly variable summer pattern. Throughout most of the 15-year data base which was used (1959-1973), April was a relatively stable demand period as reflected in the forecast. The observed demand patterns for April 1972 are exceptionally variable.

An examination of the full year's demand profiles for the six utilities indicates that 1990 peak demands will occur in the same months as 1972 demands. Both CPC and PPL are winter peaking utilities while FPL, CPSB, PJM, and SCE are summer peaking utilities. In general, the shapes of the

load profiles are not expected to change significantly between 1972 and 1990 unless significant and unforeseen socio-economic changes take place in the service area of these utilities.

Load durations for the forecasted 1990 load profiles are plotted in Figures 2-7, 2-9, 2-11, 2-13, 2-15, and 2-17 and are compared with 1972 demand data. The six utilities are bounded at the upper limit by PJM (load factor = 0.675) and by CPSB (load factor = 0.466) as a lower limit. Base loads forecast for these utilities varies between 18 percent of the annual peak for CPSB up to 40 percent of the annual peak for PJM and SCE.

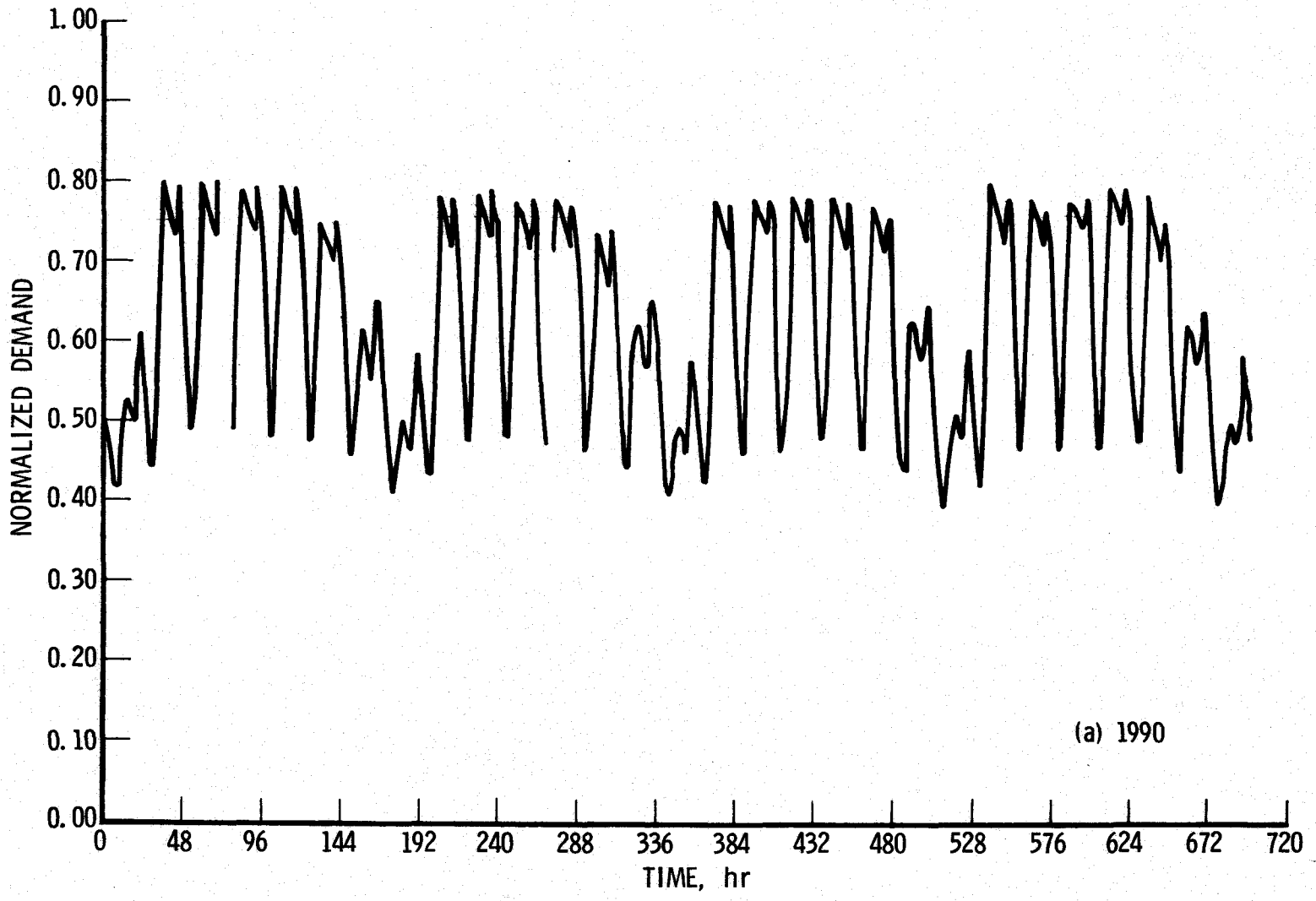


Figure 2-7(a). PJM Demand Forecast for April, 1990

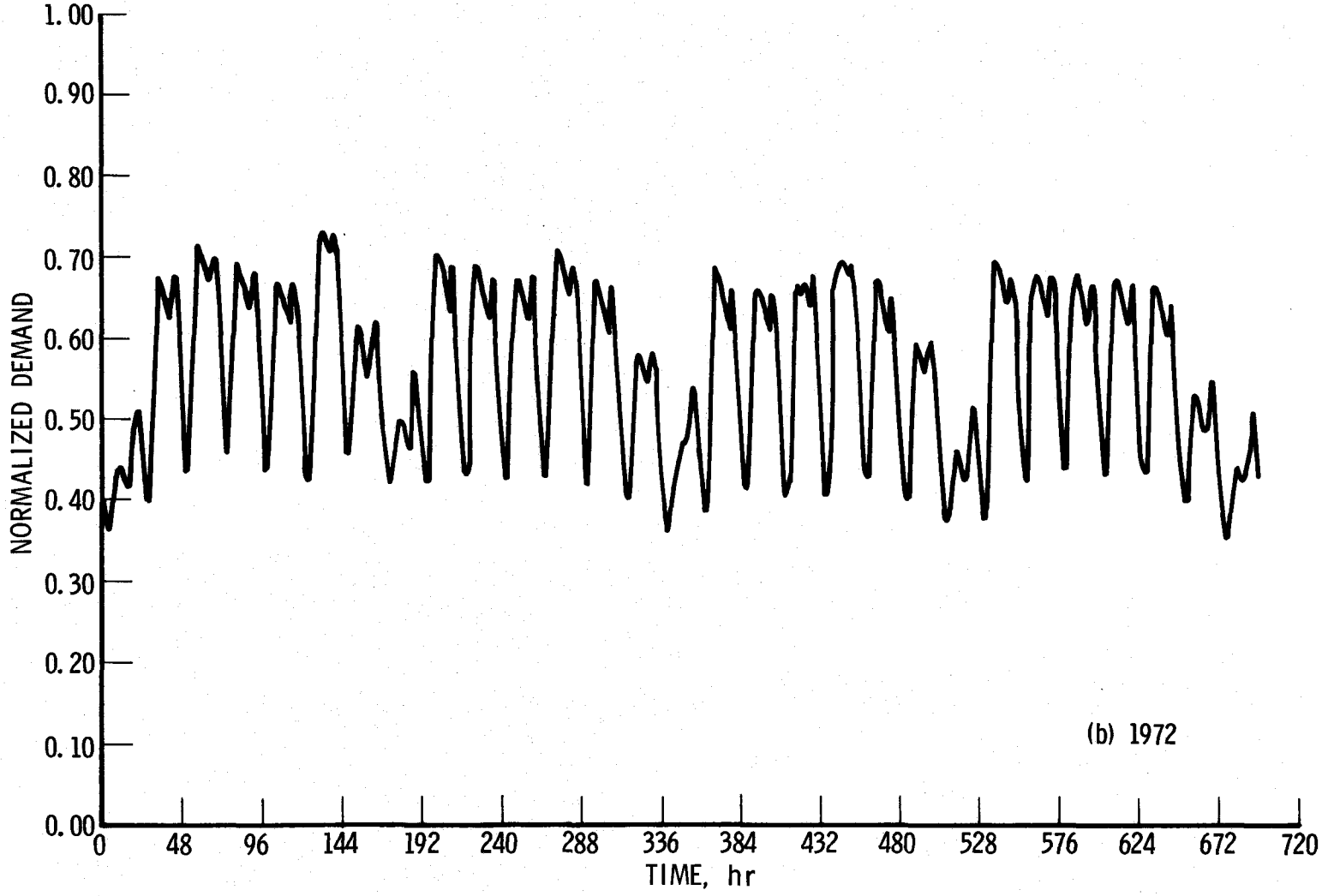


Figure 2-7(b). PJM Demand Data for April, 1972

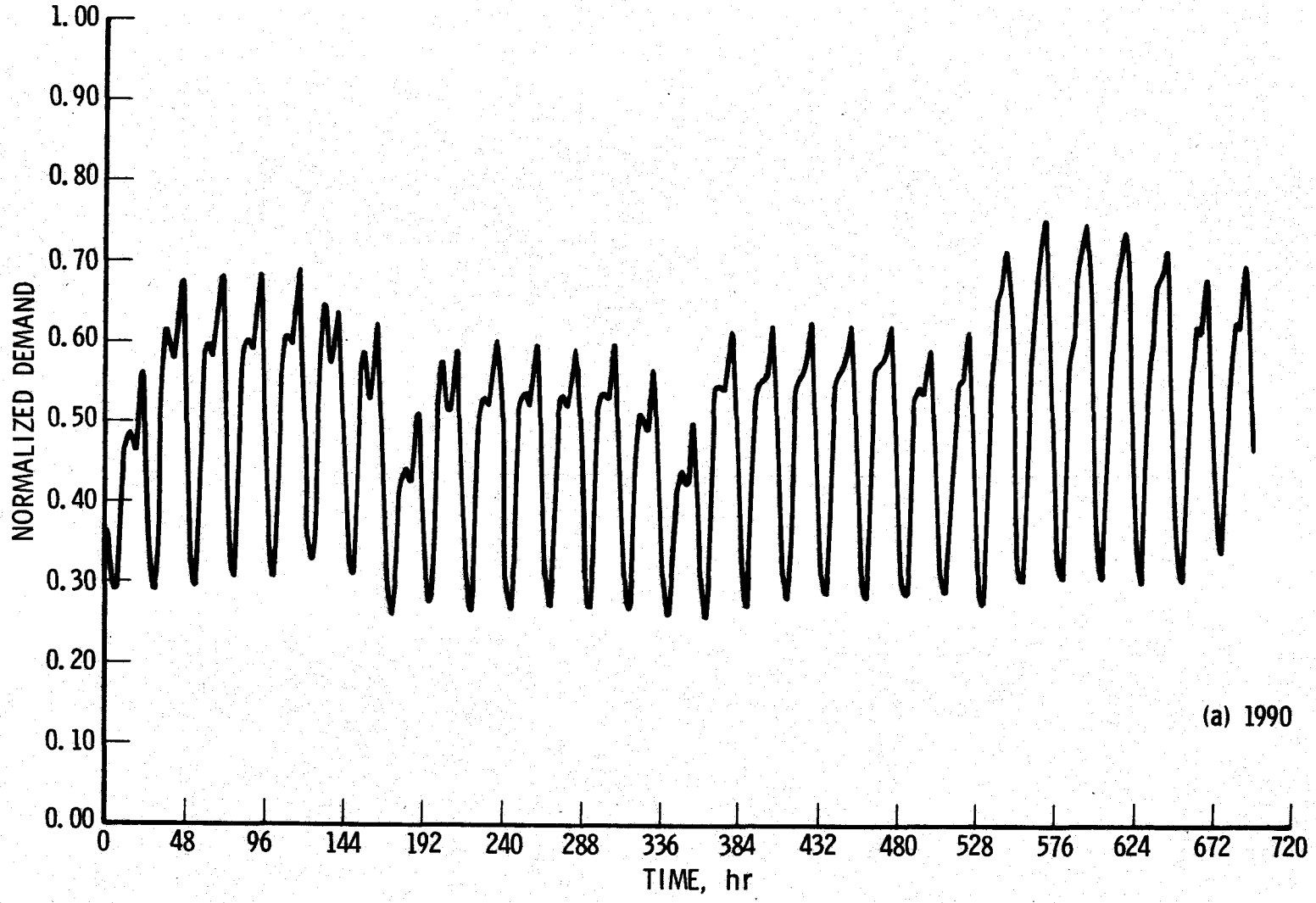


Figure 2-9(a). FPL Demand Forecast for April, 1990

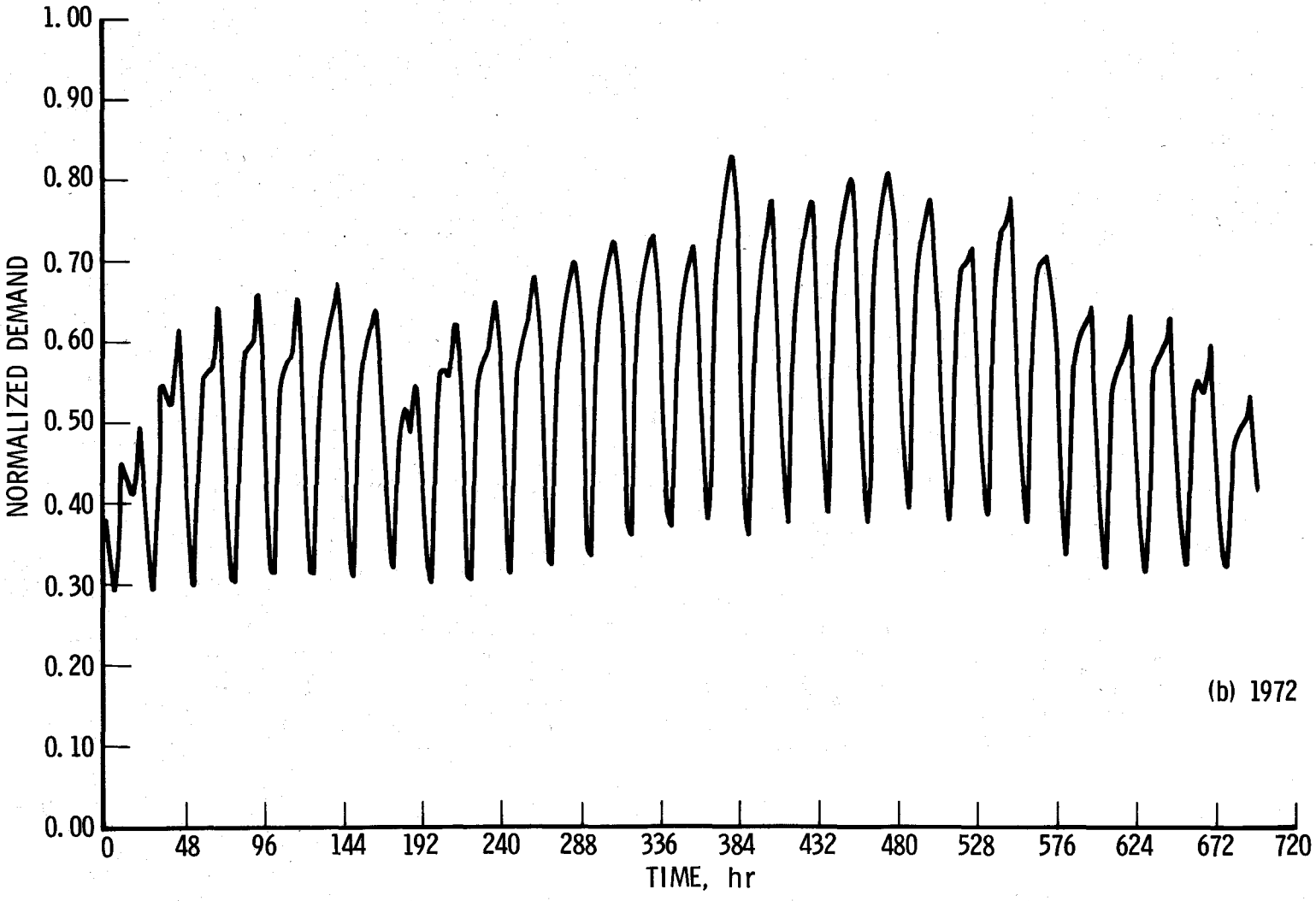


Figure 2-9(b). FPL Demand Data for April, 1972

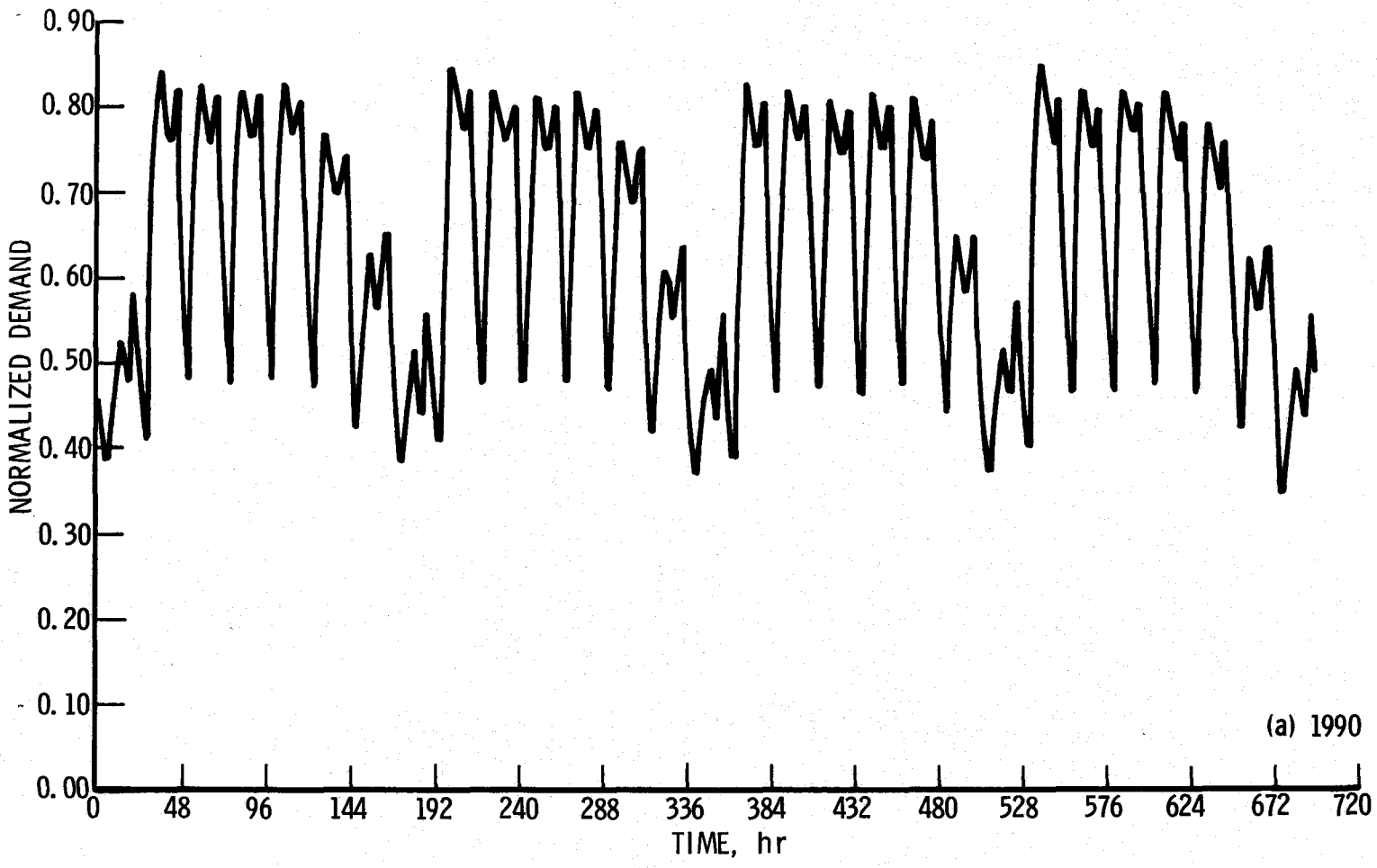


Figure 2-11(a). CPC Demand Forecast for April, 1990

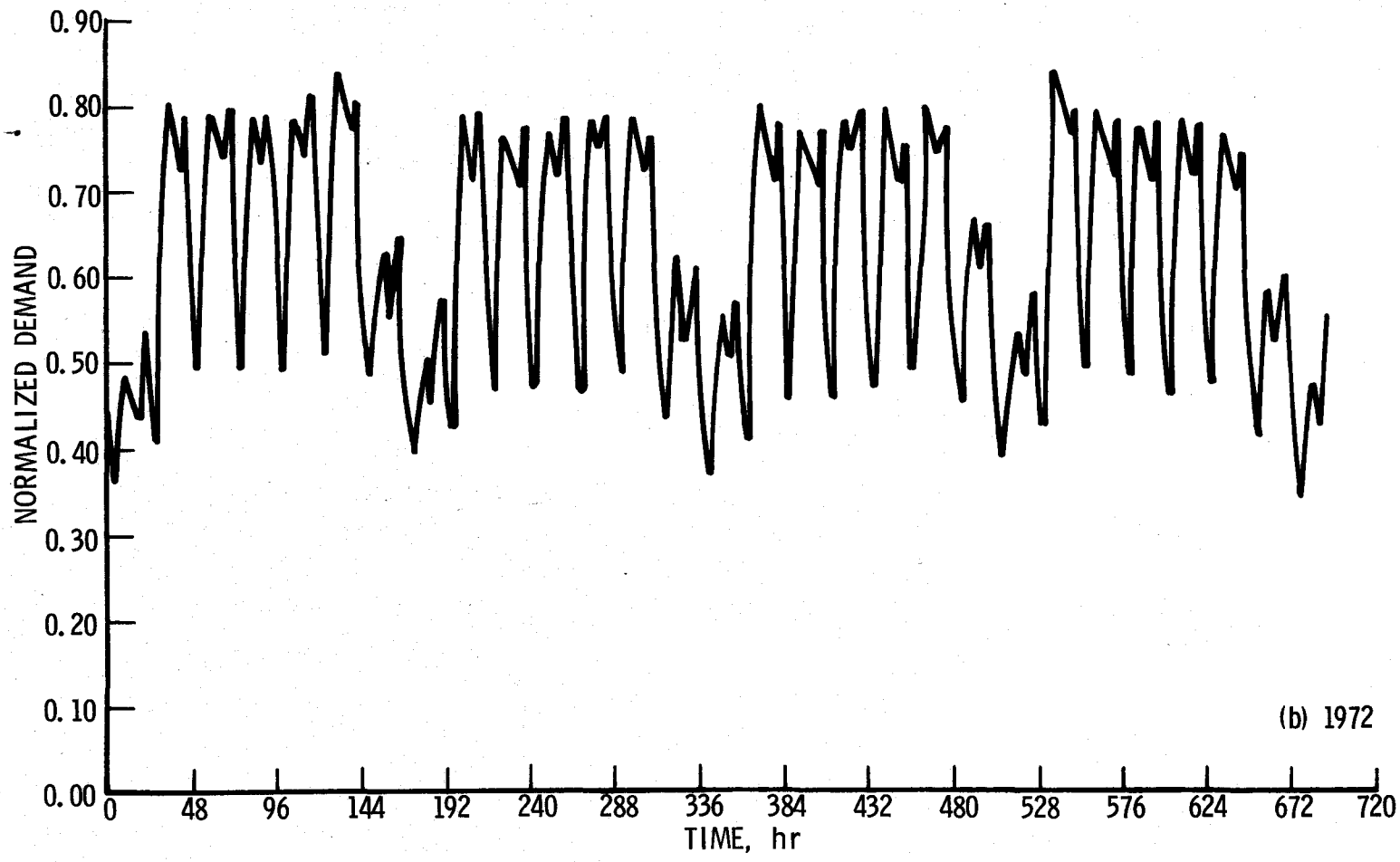


Figure 2-11(b). CPC Demand Data for April, 1972

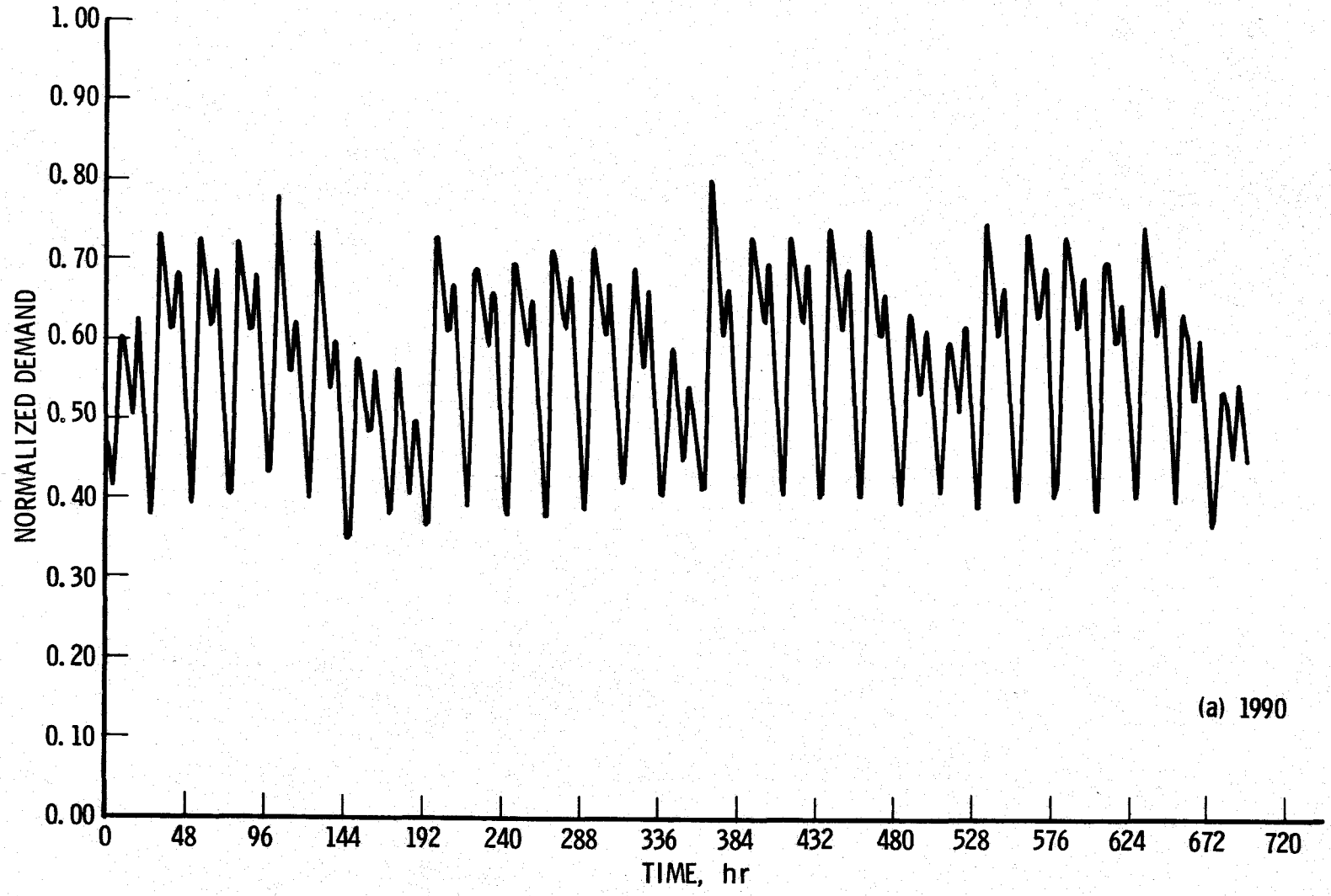


Figure 2-13(a). PPL Demand Forecast for April, 1990

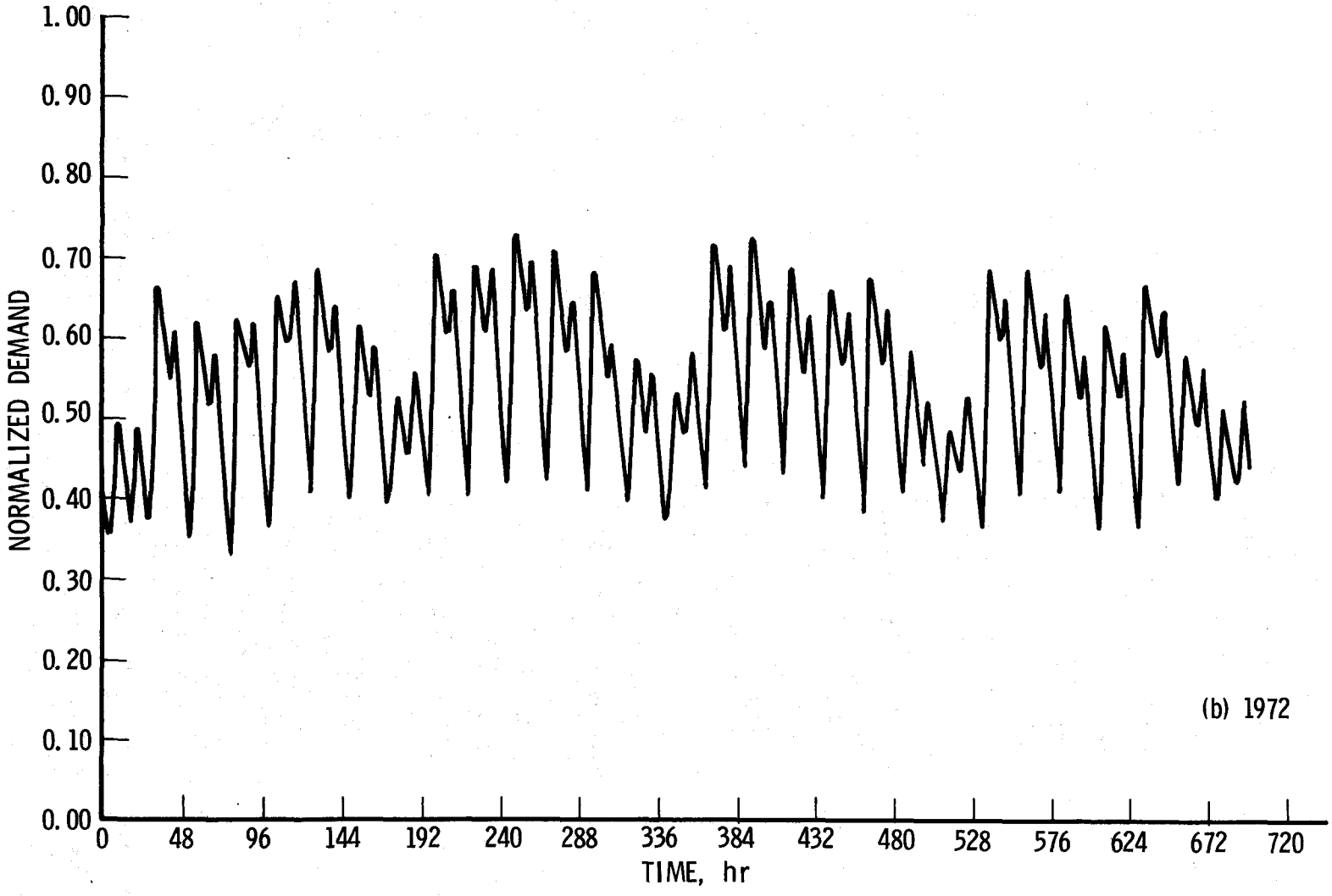


Figure 2-13(b). PPL Demand Data for April, 1972

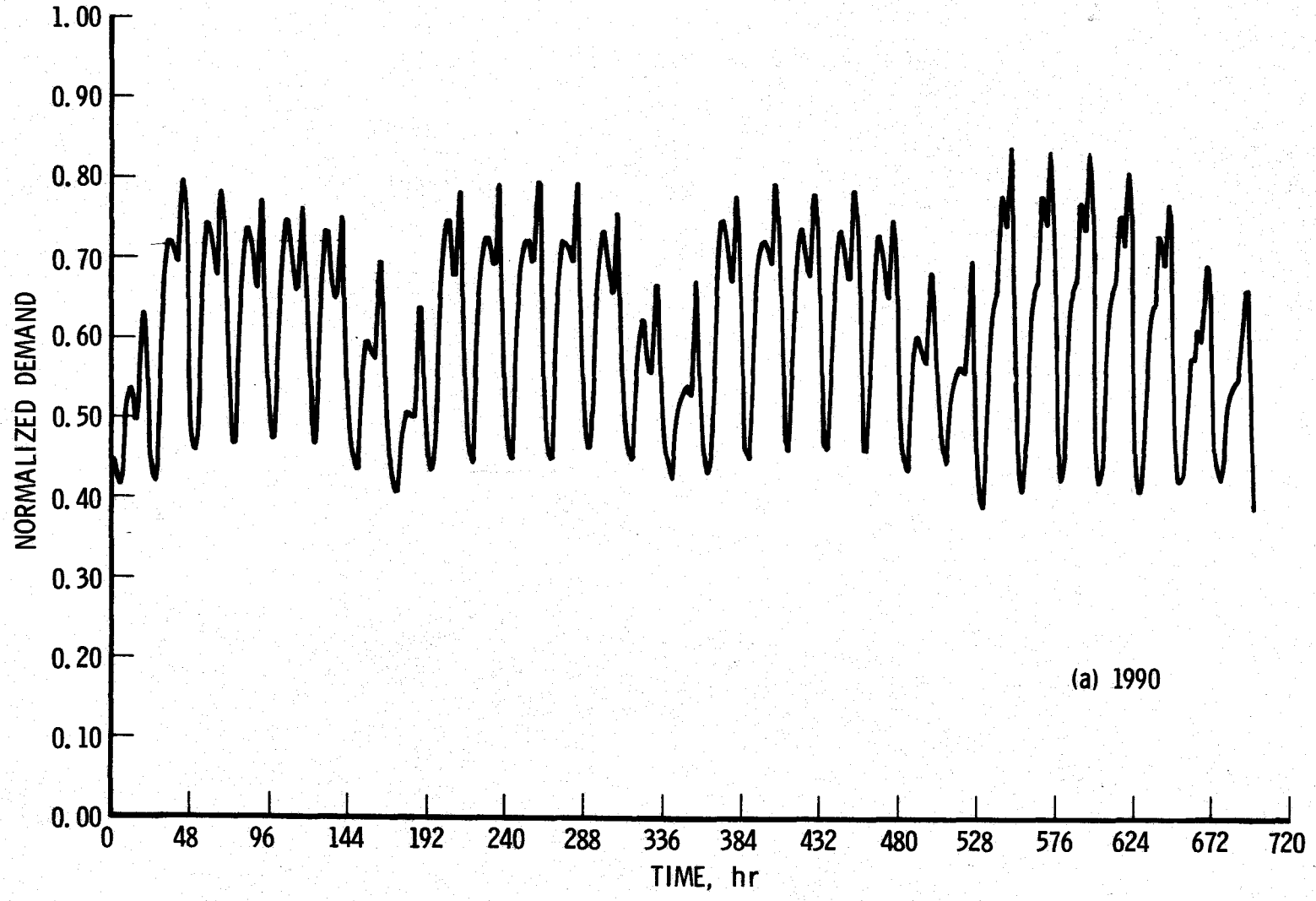


Figure 2-15(a). SCE Demand Forecast for April, 1990

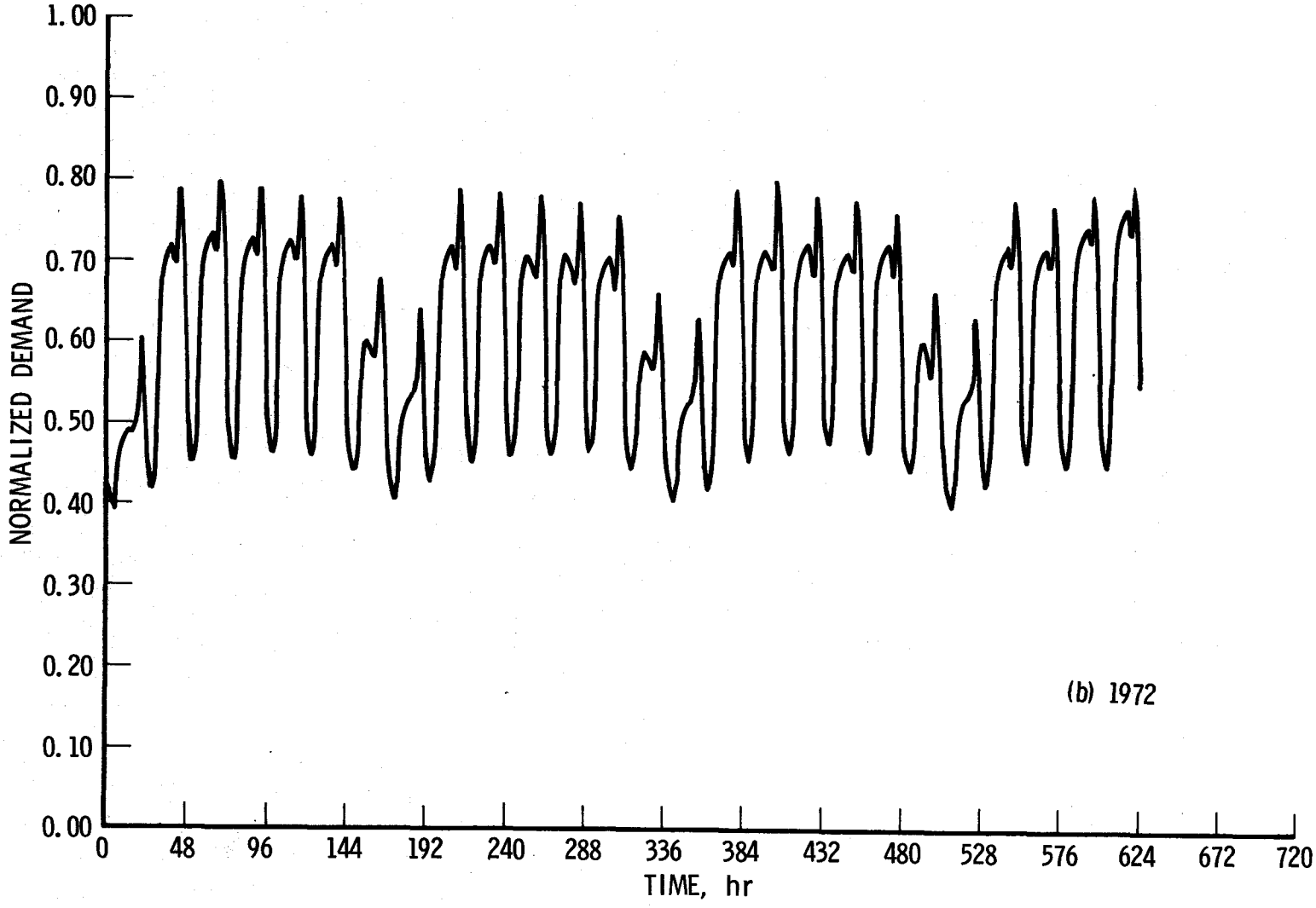


Figure 2-15(b). SCE Demand Data for April, 1972.

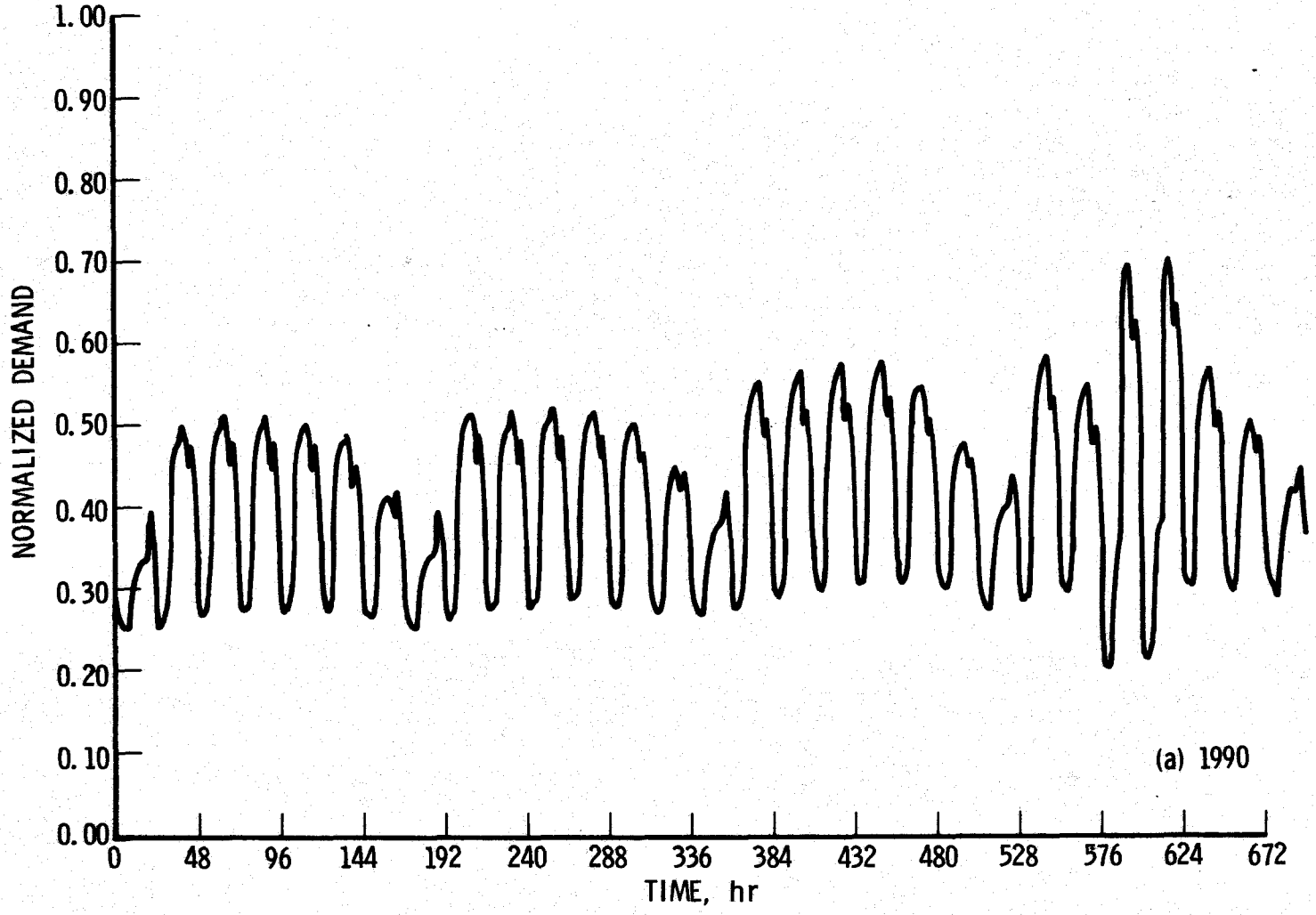


Figure 2-17(a). CPSB Demand Forecast for April, 1990

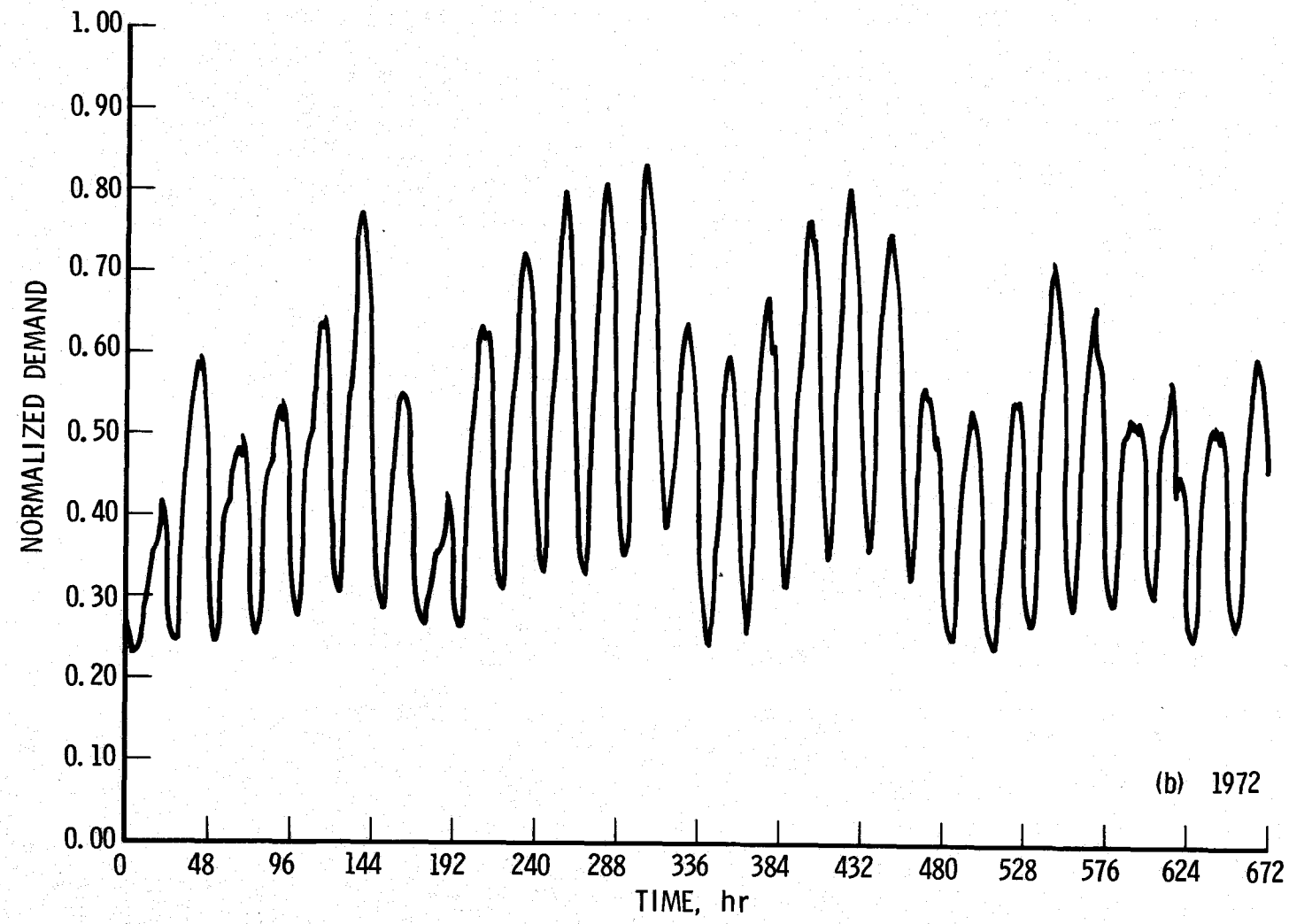


Figure 2-17(b). CPSB Demand Data for April, 1972

III. INSOLATION AND CLIMATOLOGY STUDIES

A. INTRODUCTION AND BACKGROUND

Since the earliest studies of solar thermal conversion concepts were initiated, the importance of an adequate insolation and climatology data base covering all areas of interest within the United States has been recognized. Design and cost comparisons of various competitive system concepts require information descriptive of the average seasonal and annual insolation values in various regions of interest, as well as statistics describing the fluctuations of insolation levels over various time intervals. Substantial efforts have therefore been devoted during this study as well as the preceding ones (References 3 and 9) to providing adequate characterization of the insolation throughout the continental United States. This work has involved both the development and refinement of analytical methods for processing and correlating measured data, and the preparation of standard data bases which could be used by all contractors performing studies under the Solar Thermal Program. Both of these tasks are discussed below.

Also presented in this section is an analysis of the dynamics of cloud shadowing of a solar collector field. Cloud shadowing can rapidly modulate the level of solar energy focussed on the receiver of a solar thermal system. This modulation affects the design of the control system associated with the receiver, the storage subsystem and the turbine, and it has implications for the fatigue lifetime of the receiver and the rate of wear of control system components. A study was therefore performed to relate the statistics of cloud size and shape for various cloud types to the resulting shadow motions and collected insolation histories.

The earlier Aerospace Corporation studies of insolation and climatology within the continental U. S. were addressed primarily to nine midwestern and southwestern states: California, Arizona, New Mexico, Nevada, Utah, Colorado, Texas, Nebraska and Kansas. A total of 20 sites, the majority

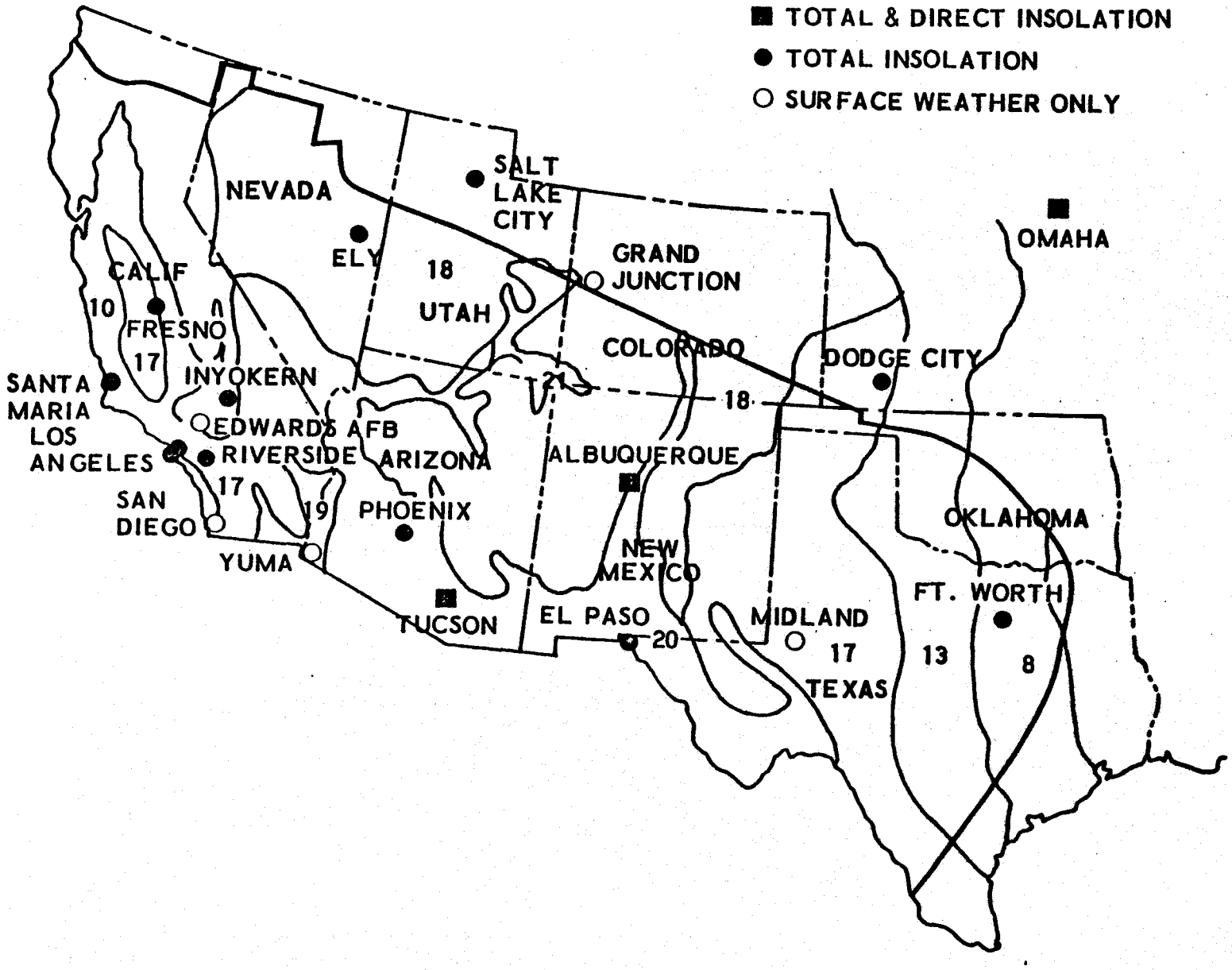


Figure 3-1. Southwestern United States Climatic Zones

in California, Texas and Arizona, were examined (Figure 3-1). Hourly values of insolation and other climatological parameters were prepared covering the years 1962 and 1963. These earlier studies also included studies of the correlation of insolation with various meteorological parameters, such as wind.

During the present study the hourly insolation data base has been extended spatially to include 12 additional locations within the contiguous United States outside the southwestern portion of the country. It has also been extended temporally by providing an hourly data base for climatologically significant time periods. Another daily insolation data base including information from 90 locations and periods up to 22 years has also been formatted.

Analysis of these data for the purpose of obtaining information of significance to solar energy systems has also continued during the present study. These include an evaluation of the ability to forecast insolation (Reference 6), attempts to divide the nation into similar regions for the purpose of solar energy system analysis (Reference 10), and preparation of reasonable cloud motion models for the analysis of system performance under varying conditions (Reference 10).

Within this report the types of information available from the various data bases are summarized, and the monthly insolation levels obtained from the hourly insolation data base listed. Various sections of the country are compared with respect to the estimated direct insolation available in the hourly data base. For detailed results of the other studies mentioned above the reader is directed to the referenced periodic progress reports.

B. INSOLATION DATA BASES

A number of collections of insolation and meteorological data in computer-compatible format have been assembled by The Aerospace Corporation in connection with various solar energy system mission analysis studies. These data collections are available to other groups on the basis of reimbursement for the cost of tape duplication. It is the purpose of this section to describe the available data and the procedures for obtaining such data.

A climatic description of the United States for the purpose of solar energy systems must be based on a data base of adequate length and geographical coverage. It must include as many relevant meteorological parameters as possible. The number of locations at which insolation is measured limits the resolution of the geographic coverage to about 90 locations in the contiguous 48 states, which has been the principal area of interest to date. Hourly data are available for periods of up to 20 years for about one-third of these stations. Hourly data bases have been prepared at Aerospace for the 34 locations listed in Table 3-1 and shown in Figure 3-2. These data bases cover the two-year time period 1962-63, except at Columbia, Mo. where the time period is 1952 to 1969. The procedures employed in generating these are described in References 3 and 9 and summarized below.

Another data collection, of daily total-hemispheric insolation and extreme meteorological parameters, has also been assembled covering a time period of up to 20 years. This data base can be used to form climatological inferences on a statistical basis for a longer period than the presently available hourly data bases. The original daily total insolation data tapes from the National Climatic Center contain, in addition to continental U.S. data, data for some stations in Canada as well as some island locations. Only the data for the contiguous 48 U.S. have been processed. Table 3-2 is a list of all of the stations for which at least 730 insolation measurements were available. Those station numbers which have asterisks indicate that the data from nearby stations were combined into one data set. The location of these stations is shown in Figure 3-3.

Table 3-1. Hourly Data Base Locations

Station Number	Station Name	Data Source*
03927	Fort Worth, Texas	2
03937	Lake Charles, Louisiana	2
23066	Grand Junction, Colorado	3
12839	Miami, Florida	2
13880	Charleston, South Carolina	2
13897	Nashville, Tennessee	2
13985	Dodge City, Kansas	2
14837	Madison, Wisconsin	3
14753	Blue Hill, Massachusetts	1
14820	Cleveland, Ohio	3
23023	Midland, Texas	3
23044	El Paso, Texas	2
23050	Albuquerque, New Mexico	1
23114	Edwards AFB, California	3
23119	Riverside, California	2
24131	Boise, Idaho	3
23154	Ely, Nevada	2
23160	Tucson, Arizona	2
23174	Los Angeles Airport, California	2
23183	Phoenix, Arizona	2
23188	San Diego, California	3
23195	Yuma, Arizona	3
23273	Santa Maria, California	2
24011	Bismarck, North Dakota	2
24127	Salt Lake City, Utah	2
24143	Great Falls, Montana	2
24225	Medford, Oregon	2
24233	Seattle, Washington	2
93104	Inyokern, California	2
93134	Los Angeles Civic Center, California	2
93193	Fresno, California	2
93734	Sterling, Virginia	2
94918	Omaha, Nebraska	1
13983	Columbia, Missouri	2, 4

*Data Source Key:

1 Observed values of Direct and Hemispheric Insolation available.
2 Observed values of Hemispheric Insolation only. Direct estimated.
3 Observed values of cloud cover only. Both Direct and Hemispheric Insolation estimated.
4 Covers 1952 through 1969.

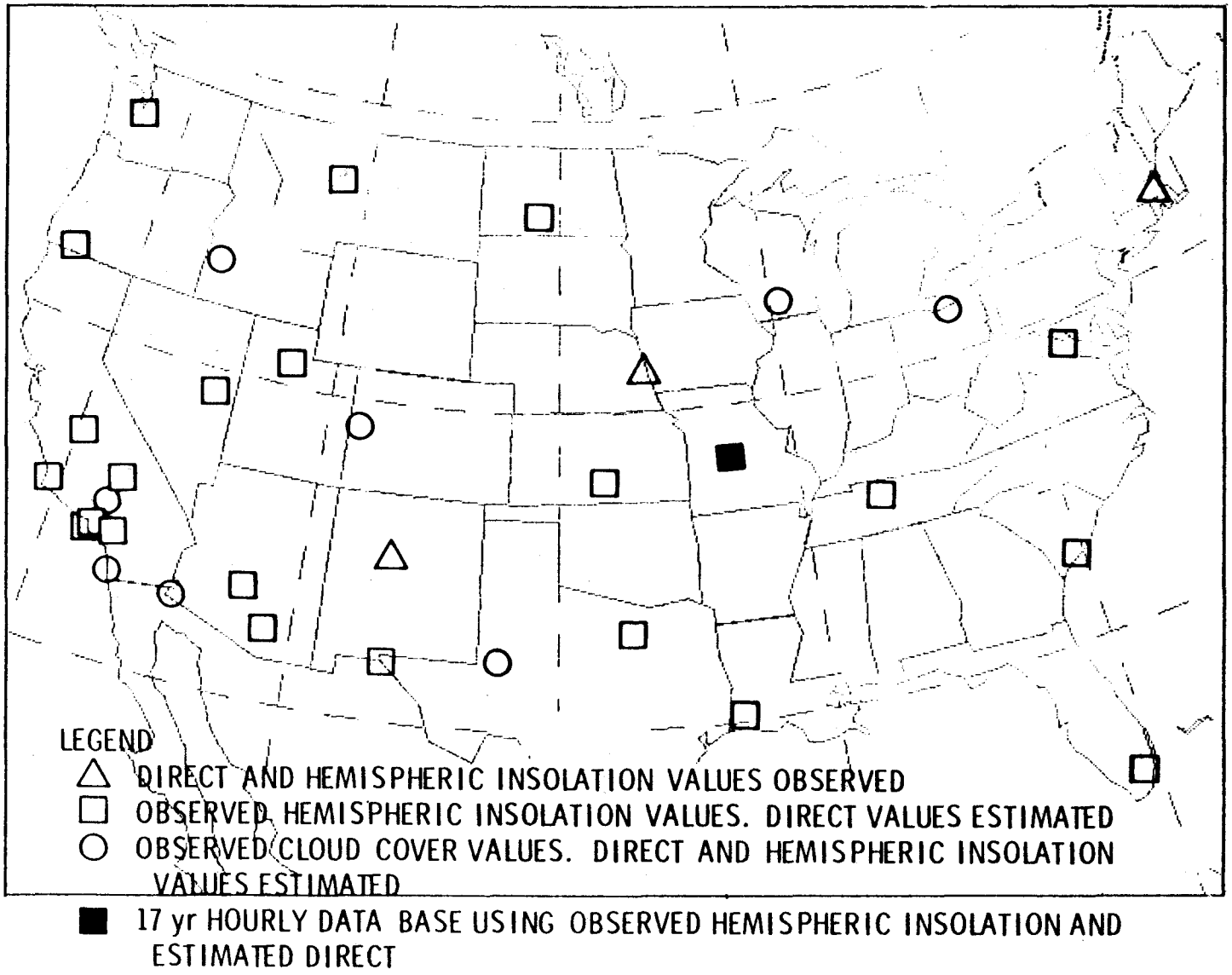


Figure 3-2. Hourly Insolation Data Base Locations

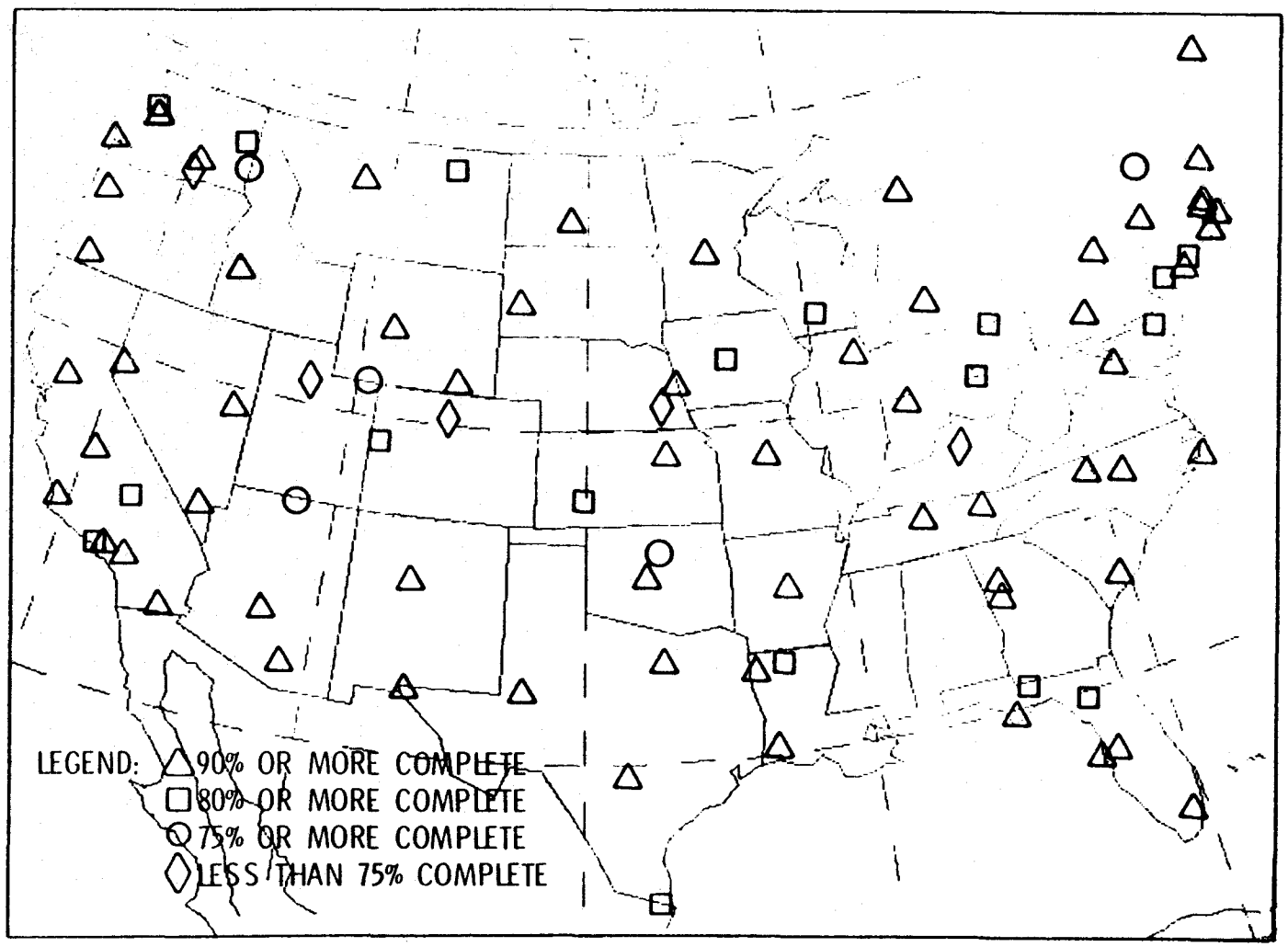


Figure 3-3. Daily Hemispheric Insolation Data Base Locations for Which at Least 730 Values of Insolation are Available

Table 3-2. Stations Included in Daily Hemispherical Insolation Data Base Arranged by Station Name

NUMBER	STATION NAME	LOCATION LAT	LOCATION LONG	INSOLATION DATA PERIOD START DATE	START MJD	END DATE	END MJD	PERIOD LENGTH DAYS	INSOL VALUES	PRCNT	CLOUD VALUES	SUNS PRCNT VALUES
23050	ALBUQUERQ.,NM-MUN.AP	35.05	106.62	52/ 7/ 1	34195	73/ 4/28	41801	7607	6986	92	6993	6925
-0201	AMES,IOWA-STATE UNIV	42.03	93.63	59/ 7/ 1	36751	72/ 8/31	41561	4811	4253	88	0	0
12832	APALACHICOLA,FLA-WBC	29.73	84.98	52/ 7/ 1	34195	73/ 4/30	41803	7609	6869	90	6871	6466
*94224	ASTORIA,ORE-WBAS	46.15	123.88	52/ 7/ 1	34195	73/ 4/30	41803	7609	7013	92	7152	148
13874	ATLANTA,GA-WBAS	33.65	84.42	52/ 7/ 1	34195	73/ 4/30	41803	7609	6974	92	6971	6317
24011	BISMARK,N.DAK-WBAS	46.77	100.75	52/ 7/ 1	34195	73/ 4/30	41803	7609	7203	95	7234	6633
14753	BLUE HILL/MILTON MAS	42.22	71.12	52/ 7/ 1	34195	73/ 4/30	41803	7609	7379	97	2439	5980
24131	BOISE,IDAHO-WBAS	43.57	116.22	52/ 7/ 1	34195	73/ 4/30	41803	7609	7090	93	7094	6697
94701	BOSTON,MASS-WBC	42.35	71.07	52/ 7/ 1	34195	68/11/12	40173	5979	5377	90	5215	4649
12919	BROWNSVILLE,TEX-WBAS	25.90	97.43	52/ 7/ 1	34195	73/ 4/30	41803	7609	6800	89	6831	6386
14742	BURLINGTON,VER-WBAS	44.47	73.15	63/ 1/ 1	38031	73/ 4/30	41803	3773	2945	78	2976	2652
*93729	CAPE HATTERAS,NC-WBC	35.27	75.55	52/ 7/ 1	34195	73/ 4/30	41803	7609	7205	95	7209	6256
14607	CARIBOU,MAINE-WBAS	46.87	68.02	52/ 7/ 1	34195	73/ 4/30	41803	7609	7243	95	7271	1
13880	CHARLESTON,SC-WBAS	32.90	80.03	52/ 7/ 1	34195	73/ 4/30	41803	7609	7282	96	7286	4725
14820	CLEVELAND,OHIO-WBAS	41.40	81.85	52/ 7/ 1	34195	73/ 4/29	41802	7608	6351	83	6434	5689
13983	COLUMBIA,MO-WBAS	38.97	92.37	52/ 7/ 1	34195	70/12/31	40952	6758	6600	98	6600	5975
-1788	COLUMBUS,OH-STA UNIV	40.00	83.02	52/ 7/ 1	34195	57/ 9/30	36112	1918	1542	80	0	0
-1860	CORVALLIS,ORE-ST COL	44.55	123.22	57/ 7/ 2	36022	64/ 7/31	38608	2587	2389	92	0	0
-2294	DAVIS,CALIFORNIA	38.53	121.75	52/ 7/ 1	34195	73/ 4/30	41803	7609	7132	94	0	0
13985	DODGE CITY,KANS-WBAS	37.77	99.97	52/ 7/ 1	34195	73/ 4/29	41802	7608	6699	88	6728	6307
*-2395	E.LANSING,MICHIGAN	42.75	84.47	53/ 1/ 1	34379	71/ 6/30	41133	6755	6466	96	0	0
-2456	E.WAREHAM,MASS	41.77	70.67	52/ 7/ 1	34195	56/12/ 2	35810	1616	1501	93	0	0
-2718	EL CENTRO,CALIF	32.80	115.67	63/ 2/ 2	38063	73/ 4/30	41803	3741	3462	93	0	0
23044	EL PASO,TX-WBAS	31.80	106.40	52/ 7/ 1	34195	73/ 4/30	41803	7609	7262	95	7274	7219
23154	ELY,NEVADA-WBAS	39.28	114.85	52/ 1/ 1	34013	73/ 4/30	41803	7791	7118	91	7229	7107
-2864	FLAMING GORGE,UTAH	40.93	109.42	59/ 6/17	36737	73/ 4/30	41803	5067	3891	77	0	0
*03927	FORT WORTH,TEXAS	32.83	97.05	52/ 7/ 1	34195	73/ 4/30	41803	7609	7102	93	7180	0
93193	FRESNO,CA-WBAS	36.77	119.72	52/ 7/ 1	34195	73/ 4/30	41803	7609	7141	94	7141	6806
-3311	GAINESVILLE,FLORIDA	29.65	82.35	57/ 3/ 1	35899	73/ 4/30	41803	5905	4905	83	0	0
*94008	GLASGOW,MONT-WBAS	48.22	106.62	52/ 7/ 1	34195	73/ 4/30	41803	7609	6617	87	6624	0
-3492	GRANBY,COLO-GRAND LK	40.23	105.85	52/ 7/ 1	34195	58/ 3/13	36276	2082	871	42	0	0
23066	GRAND JUNCT.COLO-WBC	39.12	108.53	52/ 7/ 1	34195	73/ 4/30	41803	7609	6641	87	6656	6447
13723	GREENSBORO,NC-WBAS	36.08	79.95	52/ 7/ 1	34195	73/ 4/30	41803	7609	7385	97	7384	6754
-3941	GRIFFIN,GA-EXP.STA.	33.23	84.42	52/ 7/ 1	34195	66/ 2/28	39185	4991	4584	92	0	0
24143	GRT FALLS,MONT-WBAS	47.48	111.35	52/ 7/ 1	34195	73/ 4/30	41803	7609	7281	96	7294	6874
93819	INDIANAPLIS,IND-WBAS	39.73	86.28	52/ 7/ 1	34195	73/ 4/30	41803	7609	7195	95	7210	6436
-4279	INYOKERN,CA-CHINA LK	35.65	117.67	52/ 7/ 1	34195	71/ 9/30	41225	7031	6029	86	0	0
-4177	ITHACA,NEW YORK	42.45	76.47	52/ 7/ 1	34195	73/ 4/30	41803	7609	6889	91	0	0
*03937	LAKE CHARLES,LA-WBAS	30.12	93.22	52/ 7/ 1	34195	73/ 4/30	41803	7609	6913	91	6914	0
12883	LAKELAND,FLA	28.03	81.95	63/10/ 1	38304	73/ 4/30	41803	3500	3305	94	3314	3257
24021	LANDER,WYOMING-WBAS	42.82	108.73	52/ 7/ 1	34195	73/ 4/30	41803	7609	7090	93	7095	6844
-5410	LARAMIE,WYO-STA UNIV	41.30	105.57	57/12/ 8	36181	73/ 4/30	41803	5623	5487	98	0	0
23169	LAS VEGAS,NEV-WBAS	36.08	115.16	52/ 7/ 1	34195	73/ 4/30	41803	7609	7262	95	7363	7286
-5023	LEMNT ILL-ARGONNE LB	41.70	87.98	57/ 1/ 7	35846	73/ 4/30	41803	5958	5785	97	0	0
*93820	LEXINGTON,KY-ST UNIV	38.03	84.50	57/ 7/31	36051	73/ 4/30	41803	5753	2886	50	0	0

Table 3-2. Stations Included in Daily Hemispherical Insolation Data Base Arranged by Station Name (Continued)

NUMBER	STATION NAME	LOCATION LAT	LOCATION LONG	INSOLATION DATA PERIOD START DATE	START MJD	END DATE	END MJD	PERIOD LENGTH DAYS	INSOL VALUES	PRCNT VALUES	CLOUD VALUES	SUNS PRCNT VALUES
*14971	LINCOLN,NEBRASK-WBO	40.82	96.70	52/ 8/15	34240	59/12/ 1	36904	2665	1718	64	1718	1578
13963	LITTLE ROCK,ARK-WBAS	34.73	92.23	52/11/ 5	34322	73/ 4/30	41803	7482	6964	93	6968	6288
23174	LOS ANGELES,CA-WBAS	33.93	118.38	52/ 1/ 1	34013	73/ 4/30	41803	7791	6912	89	6952	0
93134	LOS ANGELES,CA-WBO	34.05	118.23	52/ 7/ 1	34195	73/ 4/30	41803	7609	6903	91	4585	4442
14837	MADISON,WISC-WBAS	43.13	89.33	52/ 7/ 1	34195	73/ 4/30	41803	7609	6182	81	6189	5406
-4972	MANHATTAN,KANSAS	39.20	96.58	57/ 4/16	35945	73/ 4/30	41803	5859	5819	99	0	0
24225	MEDFORD,ORE-WBAS	42.37	122.87	52/ 1/ 1	34013	73/ 4/30	41803	7791	7357	94	7359	0
12839	MIAMI,FLA-WBAS	25.80	80.27	52/ 7/ 1	34195	73/ 4/29	41802	7608	7038	93	7059	26
23023	MIDLAND,TX,SLOAN FLD	31.93	102.20	53/11/19	34701	73/ 4/30	41803	7105	6422	90	6444	0
94918	N.OMAHA,NEB-WBA	41.37	96.02	57/ 6/ 1	35991	73/ 4/29	41802	5812	5242	90	5330	1
13897	NASHVILLE,TENN-WBAS	36.12	86.68	52/ 7/ 1	34195	73/ 4/30	41803	7609	7208	95	7197	6459
-5230	NEWPORT,RI-EPPLEY LB	41.50	71.32	52/ 7/ 1	34195	73/ 4/30	41803	7609	7365	97	0	0
94706	NY,NY-CENTRAL PARK	40.70	74.02	52/ 7/ 2	34196	70/12/31	40952	6757	5829	86	4380	5216
03841	OAK RIDGE,TENN-WBO	36.02	84.23	52/ 7/ 1	34195	73/ 4/30	41803	7609	7393	97	3730	1
13967	OKLA.CITY,OKLA-WBAS	35.40	97.60	52/ 7/ 1	34195	73/ 4/30	41803	7609	6986	92	7000	6432
-6180	PAGE,ARIZONA	36.93	111.45	59/ 1/31	36600	73/ 4/30	41803	5204	4131	79	0	0
23183	PHOENIX,ARIZ-WBAS	33.43	112.02	52/ 7/ 1	34195	73/ 4/30	41803	7609	7336	96	7335	6846
14764	PORTLAND,MAINE-WBAS	43.65	70.32	52/ 7/ 1	34195	73/ 4/30	41803	7609	7089	93	7078	6111
-6768	PROSSER,WASH	46.25	119.75	53/ 4/ 2	34470	73/ 3/31	41773	7304	4657	64	0	0
-6784	PULLMAN,WASH	46.73	117.16	55/ 5/ 7	35235	70/ 4/30	40707	5473	4212	77	0	0
-7079	RALEIGH,NC	35.78	78.63	57/ 1/11	35850	59/ 5/ 6	36695	846	777	92	0	0
24090	RAPID CTY,S.DAK-WBAS	44.05	103.07	52/ 7/ 1	34195	73/ 4/30	41803	7609	7155	94	7157	6600
23185	RENO,NEVADA	39.50	119.78	65/12/ 1	39096	73/ 4/30	41803	2708	2631	97	2693	2653
-7018	RICHLAND,WASH	46.57	119.58	65/ 7/ 1	38943	73/ 4/30	41803	2861	2812	98	0	0
-7473	RIVERSIDE,CALIF	33.96	117.33	52/ 7/ 1	34195	73/ 4/30	41803	7609	7300	96	0	0
-8067	RUSTON,LA	32.53	92.65	65/ 5/ 1	38882	73/ 4/30	41803	2922	2500	86	0	0
14926	SAINT CLOUD,MINN	45.58	94.18	54/ 7/ 2	34926	73/ 5/19	41822	6897	6443	93	6462	1
*24127	SALT LK CTY,UT-WBAS	40.77	111.97	52/ 7/ 2	34196	73/ 4/30	41803	7608	4982	65	3304	3099
12921	SAN ANTONIO,TEX-WBAS	29.53	98.47	52/ 7/ 1	34195	73/ 4/30	41803	7609	7228	95	7314	6765
*23273	SANTA MARIA,CA-WBAS	34.90	120.45	52/ 7/ 1	34195	73/ 4/30	41803	7609	6895	91	6906	0
14847	SAULT STE MARIE,MICH	46.47	84.37	52/ 7/ 1	34195	73/ 4/30	41803	7609	7017	92	7174	6035
-7493	SAYVILLE,NY	40.77	73.08	52/ 7/ 1	34195	63/11/30	38364	4170	3822	92	0	0
-7518	SCHENECTADY,NY	42.83	73.88	52/ 7/ 1	34195	59/ 5/26	36714	2521	2503	99	0	0
-7941	SEABROOK,NJ	39.50	75.23	52/ 7/ 1	34195	57/ 9/22	36104	1910	1658	87	0	0
24233	SEATL,WASH-T.AP-WBAS	47.45	122.30	52/ 1/ 1	34013	73/ 4/30	41803	7791	7424	95	7427	2474
-7478	SEATTLE,WASH- U OF W	47.65	122.30	52/ 7/ 1	34195	73/ 4/29	41802	7608	6732	88	439	1624
-8445	SHREVEPORT,LA	32.42	93.75	57/ 4/ 4	35933	65/ 4/30	38881	2949	2803	95	0	0
24157	SPOKANE,WASH-WBAS	47.63	117.53	52/ 7/ 1	34195	73/ 4/29	41802	7608	6520	86	6537	5685
-8454	STATE COLLEGE,PA	40.80	77.86	52/ 7/ 1	34195	73/ 4/30	41803	7609	7226	95	3	0
*93734	STERLNG,VA-DULLES AP	38.98	77.47	52/ 7/ 1	34195	73/ 4/30	41803	7609	7136	94	1977	27
-8501	STILLWATER,OKLA	36.13	97.08	52/ 7/ 1	34195	67/12/ 7	39803	5638	4477	79	0	0
-8753	TALLAHASSEE,FL-ST UV	30.43	84.28	54/ 3/ 5	34807	56/11/20	35758	992	800	81	0	0
12842	TAMPA,FLA-WBAS	27.97	82.53	52/ 7/ 1	34195	73/ 4/30	41803	7609	7324	96	7332	7120
-8815	TUCSON,ARIZ-STA UNIV	32.02	110.95	55/ 7/ 2	35291	73/ 4/30	41803	6513	5843	90	1830	1820
04729	UPTON,NY	40.87	72.88	52/ 7/ 1	34195	57/ 6/30	36020	1826	1506	82	0	0

These two data collections are described in more detail in the following paragraphs.

a, Daily Total-Hemispheric Insolation Data Base

The measured insolation data used for the preparation of the daily total hemispheric insolation data base are all derived from the Solar Radiation Summary of Day, Deck 480, prepared by the National Climatic Center at Asheville, N. C. No corrections have been applied to the measured insolation values for possible sensor errors, since that information is only now being assembled by the National Weather Service, and since even the assembled historical station records may be inadequate to correct for all problems. Conclusions based on these insolation data should therefore be used with appropriate caution. The cloudiness and minutes of sunshine available for some stations are copied directly from the Deck 480 data tapes.

Most of the measured daily meteorological parameters come from the TD3005 or TD3016 Summary of Day Observations prepared by the National Climatic Center for the station which is the source of the insolation data or for a nearby station. The TD series of meteorological tapes includes only extreme values for the day. For some parameters mean values are more significant. Therefore, for the period from 1961 through the present, the mean values of the parameters shown in Table 3-3 have been included in the daily data base from a third National Climatic Center data compilation known as Deck 937 for the period 1961 through 1964, and in slightly different format (Deck 939) from 1965 through the present. The stations selected for the 937/939 data sources were either the same as the TD3000 series data stations or nearby stations. Except for conversion to metric units, no corrections or estimations have been applied to any parameters in the daily total insolation data base.

Table 3-2 gives the dates of the first and last insolation measurements as well as the number of measurements actually present between these dates. The ratio of the number of observations to the length of the period is a measure

Table 3-3. Meteorological Observables for Which Daily Mean Hourly Values Are Available, 1961 to Daily Data Base End

	Character Locations	
	Deck 937 (1961 - 1964)	Deck 939 (1965 - Present)
Sky Cover	43, 44	Not available
Station Pressure	45 - 48	40 - 44
Dry Bulb Temperature	49 - 51	Not available
Relative Humidity	55 - 57	64 - 66
Dew Point Temperature	58 - 60	45 - 47
Wet Bulb Temperature	52 - 54	Not available
Mean Wind Speed	63 - 64	48 - 51
Resultant Wind Direction	73 - 74	52 - 53
Mean Resultant Wind Magnitude	79 - 80	54 - 57

of the completeness of the insolation data and is also included in this table. The number of cloud and sunshine observations is also provided.

The insolation data for the majority of stations are more than 90 percent complete. Those 62 stations appearing in Table 3-2 which are more than 90 percent complete are indicated by triangles on Figure 3-3. Those 18 which are 80-90 percent complete are indicated by squares. Those five which are 75-80 percent complete are indicated by circles, and those five which are less than 75 percent complete are indicated by parallelograms.

Most of the data bases in Table 3-2 were listed under a single station number in the insolation data obtained from the National Climatic Center. In some cases, longer data periods could be obtained by combining data provided

under two different station numbers. These are indicated by asterisks in Table 3-2. In some cases when the instrument was moved a short distance a new station number was assigned. These cases were identified by overlaying maps of station locations and then examining in detail the periods of record for each location where symbols were overlayed. The format of this data base is provided in Appendix A. A number of computed parameters are also included in this data base and are discussed below.

Date. Within both data bases the date is specified both by the year, month and day and by the modified Julian Day number, D, during which noon occurs at the longitude of the station. D is related to the Julian Day (J) defined by the astronomical community, and provides a convenient running day number count and a convenient entry into other computer subroutines used by Aerospace to compute the position of the sun.

$$J = D + 2400000.5 \tag{3-1}$$

A table relating modified Julian Day numbers with calendar dates is provided in Appendix D.

Solar Declination. The solar declination, δ, and distance from the earth, R, are computed from J by use of a computer subroutine which employs an analytic formula fit to ephemeris data during this century to interpolate the required values for any given day.

Minutes of Sunshine Possible. Zenith angle is the basic quantity required for computing radiation related quantities at a specific location from the known position of the sun on a specific date. This angle, Z, is the angular distance from the observer's zenith to the sun and can be shown, as an application of the spherical law of cosines, to be related to δ; the hour angle, H, of the sun; and the latitude of the observer, L.

$$\cos Z = \sin L \sin \delta + \cos L \cos t \delta \cos H \tag{3-2}$$

For present purposes, the hour angle of the sun is the angle which the meridian on which the sun lies makes with the observer's zenith meridian. Thus, at solar

noon H = O. Since the sun moves uniformly in hour angle during the day, the length of the day may be determined by finding the hour angle corresponding to sunset and sunrise and then deriving the difference. The National Weather Service uses the astronomical definitions of sunrise and sunset which refer to the upper edge of the sun, and include the effects of atmospheric refraction. Therefore, the zenith angle corresponding to sunrise (sunset) is defined as $Z_s = 90.833$ deg. Equation 3-2 is then solved for the hour angle corresponding to Z_s. The calculation of M, the minutes of sunshine, is simplified by assuming the sun remains fixed in the celestial sphere during any given day.

$$M = 2K \cos^{-1}[\cos(Z_s)/(\cos(L)\cos(\delta)) - \tan(L)\tan(\delta)] \qquad (3\text{-}3)$$

K is a constant which relates the angular measure provided by the arc consine to angular measure in minutes of time. $K_o = 4$ min/deg, if the result of the arc cosine is in degrees. $K_r = 229.183$ min/rad, if the result of the arc cosine is in radians. $K_t = 1$, if the result of the arc cosine is already in minutes of time.

Extraterrestrial Radiation. The total hemispherical radiation is defined in terms of a horizontal flat plate, so the flux depends on the projection of this flat plate normal to the sun. The instantaneous flux, I, also depends on the departure of the sun from the mean distance, $\bar{R}$, between the earth and the sun for which the solar constant, S, is defined.

$$I = S(\bar{R}/R)^2 \operatorname{coz} Z \qquad (3\text{-}4)$$

The solar position subroutine is based on a value of $R = 1.496 \times 10^8$ km. The solar constant is assumed to be

$$S = 1.9398 \text{ cal cm}^{-2} \text{ min}^{-1} \ (1.353 \text{ W/m}^2) \qquad (3\text{-}5)$$

based on recommendations of Reference 11. The total energy, E, during any time period from $H_o - \Delta$ to $H_o + \Delta$ can then be found under the assumption that the sun does not move in the celestial space during the period 2Δ, by substituting Eq. 3-2 into Eq. 3-4 and integrating.

$$E = 2S\,(\bar{R}/R)^2\,\Delta[\sin(L)\sin(\delta) + (K_r \sin(\Delta/K_r)/\Delta) \cos(L)\cos(\delta)\cos(H_o)] \quad (3\text{-}6)$$

The units of Δ are assumed to be minutes. If the integrated value for one hour is desired, $\Delta = 30$ min, $(K_r \sin(\Delta/K_r)/\Delta) = 0.9972$, and H_o should correspond to the midpoint of the hour. For an entire day, Δ depends on the length of the day. The value of M/2 from Eq. 3-3 is inappropriate, since it includes the time that part of the sun is below the horizon. In that instance, the hour angle for which the zenith angle of the sun is exactly 90 deg was chosen instead. Then Eq. 3-2 may be solved for Δ:

$$\Delta = K \cos^{-1}(-\tan\delta \tan L) \quad (3\text{-}7)$$

The resulting Δ is then used in Eq. 3-6 to determine the extraterrestrial energy for the day.

Percent of Possible Radiation. This is 100 times the ratio of the observed total hemispherical radiation to the extraterrestrial radiation computed by means of Eq. 3-6 and 3-7.

Percent of Possibe Sunshine. This is 100 times the ratio of the observed minutes of sunshine to the possible minutes of sunshine computed by means of Eq. 3-3.

b. Hourly Data Base

This insolation climatology is designed to provide direct that total insolation and associated weather data for solar power studied. Since insolation is of prime importance, data have been drawn from a number of

sources which were in several different formats. The data have all been converted into a single format described in Appendix B.

Every record corresponds to a day and contains, as a minimum, the information listed in Table 3-4. Included, if the sun is above the horizon, are values for the total and normal incidence (direct) insolation. These latter quantities are estimated if measured values are unavailable. Except for insolation data, and for some stations a few values of missing temperature, there are no estimated or interpolated values in the data base.

Table 3-4. Quantities Which Are Included for Every Hour for All Stations

Item	Character Location	Notes
Station Number	1-5	
Year	6, 7	
Month	8, 9	
Day	10, 11	
Hour Local Standard Time	12, 13	
Total Insolation	14-17	1, 3
Solar Elevation	18, 19	2
Extra-Terrestrial Radiation	20-22	1
Normal-Incidence Radiation	30-32	1
Solar Hour	38, 39	1
Percent of Possible Total Radiation	40, 41	4
Declination of the Sun	118-121	
Azimuth of the Sun	122-125	1
Modified Julian Day	126-130	

Notes

[1] Zero unless Solar Elevation >0.

[2] Set to -1 if Solar Elevation <0.

[3] During sunrise and sunset hours Total Insolation may be nonzero even if the tabulated solar elevation is less than zero.

[4] Blank unless Solar Elevation >0.

2. INSOLATION VALUES

Normal-incidence insolation is estimated by a linear relation from the percent of possible total extra-terrestrial insolation. The coefficients in this linear relation were obtained from a statistical study of measured data at Blue Hill, Massachusetts, and Albuquerque, New Mexico. All estimated values are flagged.

Most of the direct insolation values in the data base are estimated by a rather simple method. This method should produce reasonable mean insolation levels but will not reproduce the variations to be expected in real insolation data. The estimated nature of these direct insolation values should be kept in mind when drawing inferences from calculations based on them.

Measured total insolation values are used where available. When measured values are not available, values of the percent of extra-terrestrial radiation are estimated and, from this, the total insolation is calculated under the following conditions: (a) If opaque sky cover is available for that hour, this is used to estimate the percent of extra-terrestrial radiation. (b) If opaque sky cover is not available, total sky cover is used. (c) If total sky cover is not available, then the percent of possible total insolation from the following hour is used. (d) If this is not available, opaque or total sky cover from the hour following the unavailable missing data is used. (e) If none of these quantities are available for the following hour, a search for the same quantities during the hour preceding the missing data is used. (f) If no data are available for that hour, a mean value is used for the percent of extra-terrestrial radiation. It was unnecessary to use this arbitrary mean value for more than two percent of the possible observations for any location where total hemispheric insolation was available. If cloud cover is used, the percent of possible total insolation is estimated by a linear relation in air mass and a cubic relation in the sky cover. (See Reference 3 for details of the estimation procedures employed.)

3. TIME VALUES

The weather data are obtained approximately on the hour of local standard time. This is the time base on which the data base is organized. The insolation data are measured in terms of solar time, which will agree with local standard time only at one longitude per time zone and only two or four times per year. The solar-time-related quantities are labeled with the hour occurring at the end of an observation, e.g., the total insolation labeled 11 hours solar time is the integral of the radiation observed between 10 hours and 11 hours. Within the data base the tabulation of insolation-related quantities in terms of solar time has been retained, and thus the time dependence of these measurements are independent of the longitude of the particular site chosen to characterize the region. So that the solar time will be as close to the local standard time as possible in the data base, the solar time is associated with the local standard time which occurs within the solar hours. For example, for all locations east of the time meridian in a time zone, the solar time tag in the data base will be one hour later than the local time tag. All geometrical factors relating to the solar time are evaluated for the midpoint of the solar hour. The declination of the sun is computed once per day for noon at the longitude of the station.

4. RELIABILITY OF DATA

The data base has information (a) resulting from calculations outputed by a computer during the generation of the data base, (b) copied from external sources, and (c) computed from information copied from external sources. For quantities which were computed entirely by the computer, a sufficient check is to assure, by spot checks, that the computer coding is generating the correct numbers. All computer-generated quantities were checked by comparing samples of the numbers generated with the results of independent hand calculations. The copied quantities are unverified, except to ensure that they are being copied into the correct locations in the data records, and if units conversion is required, that the units conversion is being done

correctly. For calculated quantities based upon copied data, the calculation coding has been checked by comparison with independent hand computations, but the basic data are unverified. Table 3-5 indicates those quantities which were computer-generated and those which were copied from input data. Thus, the user can determine the relative reliability of the various data elements.

a. Data Availability

The hourly data base has been assembled with up to five stations per tape. The various tapes are listed in Table 3-6. Tapes are available to other users only as copies of one or more of these tapes.

The daily data base is contained on five tapes in order by station number. The range of station numbers on a given tape is given in Table 3-7.

b. Insolation Data Summaries

The average daily insolation has been computed by months for the stations included in the hourly data base. Tables 3-8 and 3-9 provide the monthly averages of daily total-hemispheric insolation for all stations except Columbia, Mo. Tables 3-10 and 3-11 provide the monthly averages of daily direct-normal insolation for all of the stations, with the exception of Columbia. Previously published values for other sites in the southwestern United States are reproduced here from Reference 9 for completeness. The values of daily average total hemispheric insolation for Columbia as computed from the hourly data base are provided in Table 3-12. The corresponding direct-normal averages for Columbia are provided in Table 3-13. Summaries of the climatic conditions, known as Local Climatological Data summaries, have been provided in References 3 and 9 for the southwestern United States sites as an aid to designers in obtaining a better understanding of the climatic conditions at these sites.

Table 3-5. Reliability of Quantities in the Hourly Data Base

Characters	Item	Reliability
1-5	Station Number	Computer-generated to be the same on all hourly records in a single run. The files for each station were generated on separate runs.
6-11	Date	Computed from the Julian Day.
12-13	Hour	Computer-generated.
14-17	Total Insolation	Copied if available, estimated if not available. See Table B-1. Estimation coding checked by spot checks. If available data were partially estimated, the flag used in Deck 280 was removed and the flag set in character 28.
18-19	Solar Elevation	Computer-generated.
20-22	Extra-terrestrial Radiation	Computer-generated.
23-25	Sunshine, Snow Cover	Copied from input data if available.
26-27	Blanks	Computer-generated.
28-29	Insolation Estimated Flags	Computer-generated. Spot checks were made to assure their being set for all appropriate conditions.
30-32	Normal-Incidence Insolation	If data were available, computer interpolated to appropriate airmass, otherwise estimated. See Table B-1.
33	Blank	Computer-generated.
34-35	Solar Week	Copied if available. No checks made.
36	Opaque Sky Cover	Copied if available. No checks made.

Table 3-5. Reliability of Quantities in the Hourly Data Base (Continued)

Characters	Item	Reliability
37	Blank	Computer-generated.
38-39	Solar Hour	Computer-generated. See Table B-1 and text for Relation to Local Standard Time.
40-41	Percent of Possible Total Insolation	Computer-generated.
42-54	Weather Data	Copied if available. No checks made.
55-57	Dew Point Temp.	Copied if available. No checks made. For Los Angeles Civic Center the dew point was computed from Relative Humidity Data actually available.
58-80	Clouds and Obscuring Phenomena	Copied if available. No checks made.
81-82	Wind Direction	Code converted to direction in degrees if data were available. No other checks made.
83-84	Wind Speed	Copied if available. No checks made.
85-88	Station Pressure	Copied if available. No checks made.
89-117	Blanks	Computer-generated.
118-121	Sun's Declination	Computer-generated.
122-125	Sun's Azimuth	Computer-generated.
126-130	Mod. Julian Day	Computer-generated to increment by one each day. This assures that all days will be included in the data base, since the date appearing in columns 6-11 is derived from the Julian date.

Table 3-6. Hourly Insolation Data Tape Catalog

Tape No.	Station	Station No.
1	Albuquerque, NM	23050
	Inyokern, CA	93104
	Yuma, AZ	23195
	Edwards AFB, CA	23114
	Riverside, CA	23119
2	L.A.C.C., CA	93134
	L.A.X., CA	23174
	San Diego, CA	23188
	Santa Maria, CA	23273
	Fresno, CA	93193
3	Tucson, AZ	23160
	Salt Lake City, UT	24127
	Phoenix, AZ	23183
	Ely, NV	23154
	Grand Junction, CO	23066
4	Omaha, NE	94918
	Fort Worth, TX	03927
	Dodge City, KS	13985
	Midland, TX	23023
	El Paso, TX	23044
5	Charleston, SC	13880
	Sterling, VA	93734
	Miami, FL	12839
	Nashville, TN	13897
	Lake Charles, LA	03937
6	Boise, ID	24131
	Great Falls, MT	24143
	Medford, OR	24225
	Seattle, WA	24233
7	Blue Hill, MA	14753
	Bismarck, ND	24011
	Madison, WS	14837
8	Phoenix, AZ	23183
	Cleveland, OH	14820
9	Columbia, MO (1952-1969)	13983

Table 3-7. Daily Total Insolation Data Tape Catalog

Tape Number	Station Number Range (see Table 3-2 for names)
1	-0201 to -6180
2	-6768 to 03937
3	04729 to 14753
4	14764 to 24021
5	24090 to 94918

Table 3-8. Average Daily Total-Hemispheric Insolation, 1962
(kWh/m^2)

Weather Station	CALIFORNIA								ARIZONA		
	Inyokern	Edwards AFB	Riverside	Fresno	San Diego	Santa Maria	LAX	LA Civic Center	Yuma	Phoenix	Tuscon
Jan	3.59	3.27	3.20	1.87	3.46	3.47	3.22	3.16	3.74	3.57	3.88
Feb	4.20	3.72	3.35	2.25	3.61	3.46	3.37	2.95	4.35	4.33	4.61
Mar	6.17	5.44	5.19	4.61	4.99	5.28	5.37	4.94	5.86	5.81	6.32
Apr	7.85	6.74	6.94	6.05	5.89	7.34	6.39	6.35	7.32	7.24	7.97
May	8.52	7.82	7.51	6.65	6.46	8.21	7.28	6.94	8.24	8.09	8.40
June	9.26	8.63	7.68	8.41	6.14	7.75	6.12	6.42	8.44	7.72	8.43
July	8.94	8.42	8.43	8.79	7.19	7.94	7.20	7.89	8.35	7.87	7.03
Aug	8.33	7.68	7.91	7.99	6.95	7.53	7.08	7.47	7.53	7.24	7.11
Sep	7.01	6.55	6.53	6.55	5.73	5.84	5.60	5.92	6.22	5.67	5.72
Oct	4.90	4.86	4.94	4.58	4.53	4.74	4.12	4.12	5.29	5.23	5.26
Nov	3.76	3.53	3.64	3.02	3.28	3.46	3.03	3.15	3.87	3.73	3.92
Dec	3.24	3.05	3.27	1.93	2.93	2.96	2.72	2.87	3.22	3.12	3.26
Annual	6.32	5.82	5.73	5.24	5.11	5.68	5.14	5.20	6.04	5.81	6.00

Table 3-8. Average Daily Total Hemispheric Insolation, 1962 (Continued)
(kWh/m^2)

	UTAH	NEVADA	N. M.	COLO.	TEXAS			KA.	NEB.
Weather Station	Salt Lake City	Ely	Albuquerque	Grand Junction	El Paso	Midland	Fort Worth	Dodge City	Omaha
Jan	2.16	3.10	3.59	2.65	4.01	3.22	3.13	2.87	2.59
Feb	2.53	3.16	4.59	3.06	5.24	4.47	4.13	3.60	2.67
Mar	5.42	5.53	5.87	4.90	6.22	5.24	4.99	5.21	4.25
Apr	6.90	6.92	7.35	6.51	7.74	6.45	5.08	5.89	5.70
May	7.55	6.46	8.82	6.82	8.93	7.41	7.25	6.60	6.09
June	8.40	8.49	8.86	7.90	8.70	7.61	6.81	7.01	6.61
July	8.01	8.00	7.44	7.65	7.46	7.01	7.10	7.34	6.88
Aug	7.60	7.80	7.73	7.00	7.75	7.38	7.09	7.11	6.20
Sep	6.12	6.50	5.64	5.63	5.71	5.70	5.27	4.48	4.87
Oct	4.62	4.81	5.43	4.38	5.52	4.64	4.24	4.07	3.43
Nov	2.65	3.34	3.74	3.01	3.96	3.44	2.82	2.78	2.09
Dec	2.07	2.79	3.29	2.44	3.45	2.98	2.67	2.63	1.96
Annual	5.35	5.59	6.04	5.17	6.23	5.47	5.06	4.97	4.45

Table 3-8. Average Daily Total Hemispheric Insolation, 1962 (Continued)
(kWh/m^2)

Weather Station	Lake Charles, La.	Miami, Fla.	Charleston, S.C.	Nashville, Tenn.	Blue Hill, Mass.	Madison, Wis.	Bismarck, N.D.
Jan	2.63	3.81	2.56	1.87	1.99	1.77	1.79
Feb	3.23	5.16	3.71	2.57	2.42	2.19	2.67
Mar	4.20	5.65	4.48	3.05	4.23	3.61	4.08
Apr	4.91	6.31	6.64	5.00	4.91	5.37	5.56
May	6.52	6.96	7.04	6.60	6.05	5.80	4.56
Jun	5.37	5.57	5.88	5.85	6.25	6.72	6.87
Jul	6.46	5.78	6.28	6.15	5.22	6.08	6.78
Aug	5.34	5.35	6.07	5.69	4.98	6.20	6.43
Sep	4.97	5.12	5.12	3.96	4.19	4.43	4.86
Oct	4.27	4.95	4.81	3.41	2.94	3.19	3.17
Nov	3.09	3.88	3.01	2.03	2.11	1.80	1.73
Dec	2.49	3.81	2.89	1.71	1.98	1.53	1.33
Annual	4.46	5.20	4.88	4.00	3.95	4.06	4.16

Table 3-8. Average Daily Total Hemispheric Insolation, 1962 (Continued)
(kWh/m^2)

Weather Station	Boise, Idaho	Great Falls, Mont.	Medford, Ore.	Seattle, Wash.	Sterling, Va.	Cleveland, Ohio
Jan	2.03	1.61	1.53	1.18	2.05	1.51
Feb	2.20	2.47	2.49	2.08	2.54	1.72
Mar	4.01	4.10	3.68	3.30	4.63	2.92
Apr	6.10	5.15	5.92	4.60	5.19	4.45
May	6.52	5.16	5.91	5.23	5.88	5.50
Jun	8.01	7.03	8.45	6.61	6.28	6.03
Jul	7.98	6.44	8.35	6.69	5.96	5.60
Aug	6.91	5.80	6.68	5.08	5.64	5.56
Sep	5.72	4.41	5.33	4.07	4.16	3.52
Oct	3.49	2.81	2.71	2.27	3.74	2.31
Nov	1.94	1.77	1.66	1.12	2.30	1.17
Dec	1.43	1.27	1.08	0.962	2.08	1.15
Annual	4.71	4.01	4.49	3.61	4.22	3.46

Table 3-9. Average Daily Total Hemispheric Insolation, 1963
(kWh/m^2)

Weather Station	Lake Charles La.	Miami, Fla.	Charleston, S.C.	Nashville, Tenn.	Blue Hill, Mass.	Madison Wis.	Bismarck, N.D.
Jan	2.20	3.81	2.94	2.08	1.82	1.79	2.01
Feb	4.18	4.45	3.45	3.22	2.99	2.78	2.29
Mar	4.91	6.19	5.23	4.39	3.90	3.73	4.01
Apr	5.52	7.05	5.83	5.15	5.26	5.57	4.41
May	6.45	6.40	5.93	5.69	6.14	6.24	5.84
Jun	6.37	6.40	5.65	5.70	6.49	7.55	6.81
Jul	6.03	7.06	6.32	5.67	6.21	7.37	6.79
Aug	6.00	6.12	5.76	5.52	5.49	6.17	6.12
Sep	5.05	4.50	4.77	4.76	4.16	4.59	4.17
Oct	4.74	4.88	4.25	4.35	3.82	3.42	3.29
Nov	3.28	3.76	3.55	1.97	1.46	1.83	1.95
Dec	2.53	3.54	2.89	1.97	1.86	1.58	1.54
Annual	4.77	5.35	4.72	4.21	4.14	4.39	4.11

Table 3-9. Average Daily Total Hemispheric Insolation, 1963 (Continued)
(kWh/m^2)

Weather Station	Boise, Idaho	Great Falls, Mont.	Medford, Ore.	Seattle, Wash.	Sterling, Va.	Cleveland, Ohio
Jan	1.86	1.47	1.83	1.25	2.47	1.59
Feb	2.74	2.37	2.28	1.87	3.25	2.27
Mar	4.10	3.87	4.03	2.88	4.25	3.08
Apr	4.86	4.80	4.60	3.81	5.88	4.64
May	6.75	6.08	6.37	6.65	6.50	5.75
Jun	6.72	5.98	7.01	5.38	6.70	6.52
Jul	8.58	7.15	7.83	5.75	6.80	5.83
Aug	6.98	6.16	7.04	5.21	6.04	4.67
Sep	5.10	4.28	5.35	4.04	4.67	4.12
Oct	3.19	2.85	2.77	2.11	4.21	3.08
Nov	1.74	1.60	1.47	1.13	2.35	1.16
Dec	1.39	1.27	1.17	0.74	1.81	1.35
Annual	4.51	4.00	4.33	3.41	4.59	3.68

Table 3-9. Average Daily Total Hemispheric Insolation, 1963 (Continued)
(kWh/m^2)

	UTAH	NEVADA	N. M.	COLO.	TEXAS			KA.	NEB.
Weather Station	Salt Lake City	Ely	Albuquerque	Grand Junction	El Paso	Midland	Fort Worth	Dodge City	Omaha
Jan	2.30	2.96	3.55	2.43	4.19	3.55	3.03	2.93	2.36
Feb	3.39	3.86	4.48	3.60	5.38	4.26	3.62	4.13	3.11
Mar	5.25	5.33	6.10	4.74	6.60	5.75	5.44	5.22	4.14
Apr	5.17	5.74	7.30	5.83	7.73	6.34	5.36	6.77	4.97
May	7.98	5.27	7.79	7.36	8.24	6.82	6.39	5.91	5.62
June	7.74	7.13	8.42	7.67	8.87	7.37	7.24	7.20	7.23
July	8.03	8.82	7.36	7.62	7.83	7.50	7.76	7.56	6.81
Aug	6.82	7.02	6.72	6.02	7.11	6.75	7.12	6.31	5.71
Sep	5.17	5.79	6.11	5.71	5.68	5.87	5.27	5.38	4.48
Oct	4.26	4.51	5.06	4.23	8.55	4.97	4.71	4.33	4.26
Nov	2.55	3.15	3.86	2.99	4.25	3.81	3.30	3.16	2.69
Dec	1.61	2.76	3.68	2.36	3.90	2.66	2.59	2.50	2.27
Annual	5.03	5.37	5.87	5.05	6.29	5.48	5.16	5.12	4.48

Table 3-10. Average Daily Direct Normal Insolation, 1962
(kWh/m^2)

Weather Station	CALIFORNIA								ARIZONA		
	Inyokern	Edwards AFB	Riverside	Fresno	San Diego	Santa Maria	LAX	LA Civic Center	Yuma	Phoenix	Tuscon
Jan	7.28	6.11	5.26	3.03	6.15	6.60	5.95	5.80	6.76	6.29	6.91
Feb	6.75	5.78	4.87	2.93	5.22	5.30	5.08	4.27	6.67	6.41	6.90
Mar	9.26	7.47	7.09	6.35	6.53	7.50	7.58	6.92	8.03	7.78	8.61
Apr	10.36	8.48	8.72	7.81	6.85	9.33	7.66	7.66	9.17	8.93	9.93
May	10.87	9.60	9.26	7.84	7.15	9.89	8.63	7.92	10.03	9.79	10.42
June	11.56	10.74	8.86	10.19	6.56	8.58	6.32	7.09	10.49	9.13	10.17
July	11.26	10.58	10.27	10.97	8.10	8.70	8.00	8.99	10.37	9.45	8.03
Aug	11.11	9.64	10.37	10.61	7.94	9.10	8.63	8.91	9.21	8.94	8.49
Sep	9.92	9.04	8.69	9.15	7.09	7.26	6.89	7.46	8.30	7.20	7.03
Oct	7.58	7.39	7.71	7.04	6.20	7.29	6.00	5.86	7.81	8.06	8.00
Nov	7.05	6.38	6.40	5.28	5.31	6.20	4.96	5.42	6.73	6.36	6.50
Dec	7.11	5.94	6.44	3.49	5.16	6.03	4.94	5.65	6.29	5.95	5.83
Annual	9.19	8.11	7.85	7.08	6.54	7.67	6.74	6.84	8.33	7.87	8.07

Table 3-10. Average Daily Direct Normal Insolation, 1962 (Continued)
(kWh/m^2)

	UTAH	NEVADA	N. M.	COLO.	TEXAS			KA.	NEB.
Weather Station	Salt Lake City	Ely	Albuquerque	Grand Junction	El Paso	Midland	Fort Worth	Dodge City	Omaha
Jan	4.73	6.64	6.90	5.21	7.07	5.45	5.20	6.00	5.92
Feb	3.72	5.07	7.60	4.90	8.14	6.62	6.00	5.90	4.25
Mar	8.10	7.99	8.70	6.93	8.41	6.71	6.41	7.37	6.07
Apr	8.58	8.96	9.49	8.20	9.58	7.75	5.54	7.33	7.36
May	8.57	7.69	10.98	8.35	11.05	8.63	8.24	7.90	7.06
June	10.00	10.37	10.79	9.78	10.24	9.03	7.51	7.96	7.60
July	9.77	9.72	8.78	9.59	8.13	8.30	8.27	8.64	8.01
Aug	10.55	10.35	10.22	8.95	9.53	8.93	8.66	9.08	7.80
Sep	9.07	9.21	6.94	7.88	7.27	7.36	6.56	5.60	6.59
Oct	8.16	8.08	8.77	7.06	8.28	6.47	6.00	6.47	5.62
Nov	5.54	6.76	7.25	5.78	6.37	5.53	4.34	5.15	4.17
Dec	4.94	6.82	6.82	5.17	6.25	5.24	4.66	6.57	4.33
Annual	7.67	8.16	8.61	7.33	8.36	7.17	6.46	7.01	6.25

Table 3-10. Average Daily Direct Normal Insolation, 1962 (Continued)
(kWh/m^2)

Weather Station	Lake Charles, La.	Miami, Fla.	Charleston, S. C.	Nashville, Tenn.	Blue Hill, Mass.	Madison, Wis.	Bismarck, N. D.
Jan	3.87	5.48	4.04	3.06	4.44	3.53	4.70
Feb	4.10	7.28	5.15	3.57	4.26	3.57	5.17
Mar	5.04	7.16	5.20	3.51	6.42	4.99	6.54
Apr	5.23	6.99	7.69	5.61	6.00	6.81	7.79
May	7.44	8.09	7.81	7.60	6.91	7.01	5.03
Jun	5.91	6.25	6.33	6.20	7.25	8.18	8.62
Jul	7.53	6.47	6.75	6.70	5.97	7.41	8.87
Aug	6.04	5.67	6.82	6.54	6.06	8.13	9.08
Sep	5.91	5.80	6.01	4.51	5.64	6.21	7.54
Oct	5.80	6.65	6.74	4.67	4.93	5.12	5.98
Nov	4.38	5.34	4.47	3.19	4.56	3.37	4.17
Dec	3.75	5.91	5.00	2.84	4.61	3.27	3.54
Annual	5.43	6.42	6.01	4.84	5.60	5.64	6.42

Table 3-10. Average Daily Direct Normal Insolation, 1962 (Continued)
(kWh/m^2)

Weather Station	Boise, Idaho	Great Falls, Mont.	Medford, Ore.	Settle, Wash.	Sterling, Va.	Cleveland, Ohio
Jan	4.29	4.08	2.94	2.74	3.94	2.67
Feb	3.20	4.87	3.88	3.84	3.72	2.13
Mar	5.71	6.83	4.91	4.93	6.57	3.51
Apr	8.17	7.05	7.51	5.91	6.39	4.97
May	7.90	6.04	6.57	5.93	6.52	6.25
Jun	10.02	9.26	10.65	8.21	6.96	6.88
Jul	10.25	8.15	10.48	8.34	6.68	6.29
Aug	9.16	7.78	8.68	6.41	6.86	6.83
Sep	8.50	6.76	7.46	5.72	5.26	4.25
Oct	5.91	5.15	4.02	3.78	5.85	3.02
Nov	3.75	4.23	2.87	2.23	4.29	1.68
Dec	3.09	3.61	1.85	2.37	4.64	2.00
Annual	6.68	6.15	5.99	5.02	5.65	4.22

Table 3-11. Average Daily Direct Normal Insolation, 1963
(kWh/m^2)

Weather Station	CALIFORNIA								ARIZONA		
	Inyokern	Edwards AFB	Riverside	Fresno	San Diego	Santa Maria	LAX	LA Civic Center	Yuma	Phoenix	Tuscon
Jan	7.18	6.20	5.53	4.57	5.17	5.41	4.97	4.93	6.41	6.64	6.39
Feb	7.57	6.25	6.42	3.78	5.80	5.85	5.50	5.49	7.28	7.40	7.42
Mar	9.21	7.48	8.35	6.71	7.26	8.19	8.13	7.85	8.05	8.63	8.31
Apr	9.76	8.39	8.61	7.60	8.13	8.42	8.48	8.43	8.73	9.12	9.01
May	10.39	9.37	7.85	8.71	6.77	6.26	6.51	6.23	9.60	9.60	9.65
June	10.51	10.38	8.57	9.83	6.68	7.98	6.61	6.52	10.72	10.33	10.73
July	11.24	10.54	10.79	10.49	8.13	8.99	8.84	9.77	10.07	9.04	8.45
Aug	9.90	9.18	9.86	9.49	7.74	8.36	8.25	8.92	8.88	7.70	7.06
Sep	8.11	8.21	8.38	7.19	7.25	7.39	6.93	7.64	8.60	8.12	8.20
Oct	7.31	6.83	7.38	6.11	6.20	6.19	6.29	6.68	7.36	7.68	7.21
Nov	6.79	6.09	6.72	3.50	6.05	5.69	5.70	5.91	6.84	6.93	6.32
Dec	7.30	6.06	8.22	1.39	6.55	7.00	6.50	6.48	6.97	7.42	7.00
Annual	8.78	7.93	8.07	6.63	6.82	7.15	6.90	7.08	8.30	8.22	7.98

Table 3-11. Average Daily Direct Normal Insolation, 1963 (Continued)
(kWh/m^2)

	UTAH	NEVADA	N. M.	COLO.	TEXAS			KA.	NEB.
Weather Station	Salt Lake City	Ely	Albuquerque	Grand Junction	El Paso	Midland	Fort Worth	Dodge City	Omaha
Jan	5.23	6.30	6.91	4.56	7.35	6.16	5.06	6.05	5.33
Feb	5.78	6.44	7.01	6.09	8.24	6.23	5.30	6.76	5.21
Mar	8.04	7.79	8.92	6.62	9.18	7.57	7.08	7.75	5.84
Apr	6.47	7.06	9.20	7.25	9.47	7.49	5.85	8.65	5.96
May	9.36	8.95	9.27	9.28	10.07	7.68	6.99	6.85	6.15
June	8.84	8.37	10.08	9.43	10.65	8.78	8.25	9.18	8.16
July	9.86	11.38	8.21	9.45	9.09	9.04	9.15	8.95	7.88
Aug	9.23	9.16	7.82	7.34	8.23	8.03	8.92	8.11	6.99
Sep	7.46	8.09	7.94	8.04	7.72	7.56	6.44	7.19	6.05
Oct	7.24	7.34	8.12	6.66	8.55	7.01	6.92	6.93	7.06
Nov	5.20	6.28	7.19	5.68	7.03	6.39	5.24	6.23	5.78
Dec	3.37	6.48	7.75	4.90	7.35	4.48	4.50	5.65	5.34
Annual	7.19	7.82	8.21	7.11	8.58	7.21	6.66	7.36	6.32

Table 3-11. Average Daily Direct Normal Insolation, 1963 (Continued)
(kWh/m^2)

Weather Station	Lake Charles La.	Miami, Fla.	Charleston, S. C.	Nashville, Tenn.	Blue Hill, Mass.	Madison, Wis.	Bismarck, N. D.
Jan	2.90	5.66	4.67	3.51	3.83	3.57	5.39
Feb	5.79	6.02	4.67	4.54	5.37	4.89	4.22
Mar	5.93	7.78	6.70	5.54	5.56	5.29	6.47
Apr	5.99	8.06	6.75	5.77	6.75	7.10	5.66
May	7.24	7.18	6.54	5.86	7.27	7.69	7.16
Jun	7.06	7.13	5.74	5.68	7.40	9.31	8.35
Jul	6.80	8.03	6.94	5.78	7.07	9.14	8.53
Aug	7.49	6.71	6.45	6.01	6.90	7.94	8.15
Sep	5.88	4.82	5.41	5.67	5.64	6.53	6.14
Oct	6.23	6.44	5.82	6.24	6.23	5.48	6.10
Nov	4.70	5.28	5.64	2.86	2.53	3.53	4.60
Dec	4.03	5.33	5.11	3.38	4.04	3.51	4.42
Annual	5.84	6.54	5.88	5.08	5.72	6.17	6.28

Table 3-11. Average Daily Direct Normal Insolation, 1963 (Continued)
(kWh/m^2)

Weather Station	Boise, Idaho	Great Falls, Mont.	Medford, Ore.	Seattle, Wash.	Sterling, Va.	Cleveland, Ohio
Jan	3.84	3.64	3.96	2.71	5.02	2.74
Feb	4.77	4.77	3.42	3.14	5.22	3.35
Mar	5.95	6.20	5.56	4.19	5.83	3.73
Apr	6.02	6.30	5.30	4.45	7.33	5.63
May	8.25	7.76	7.22	8.32	7.48	6.74
Jun	7.89	7.15	8.62	5.82	7.46	7.56
Jul	11.20	9.44	9.58	6.81	7.80	6.83
Aug	9.31	8.27	9.23	6.59	7.31	5.42
Sep	7.35	6.44	7.49	5.87	6.04	5.43
Oct	5.20	5.19	4.27	3.32	6.93	4.72
Nov	3.23	3.73	2.44	2.26	4.46	1.66
Dec	2.93	3.49	2.13	1.51	3.82	2.45
Annual	6.34	6.04	5.79	4.59	6.23	4.70

Table 3-12. Average Total-Hemispherical Insolation for Columbia, Mo.
(kW hr/m^2)

	Month	1952	1953	1954	1955	1956	1957	1958	1959	1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	Average
1	January	2.121	2.304	2.396	2.032	1.864	1.707	2.175	2.149	1.903	2.726	2.512	2.056	2.299	2.028	2.278	2.673	1.824	1.718	2.154
2	February	3.043	3.723	3.573	2.942	2.610	2.600	3.449	2.961	2.982	2.771	2.843	3.130	3.278	3.346	3.075	3.510	3.271	2.405	3.084
3	March	4.010	4.508	4.538	4.726	4.728	3.662	2.729	3.943	4.807	3.123	4.101	4.142	3.908	3.916	3.998	3.797	4.406	4.443	4.083
4	April	5.475	5.144	5.663	5.964	5.307	4.038	4.682	5.062	5.195	4.668	5.564	5.662	4.946	4.838	4.183	5.097	5.478	5.287	5.125
5	May	6.213	6.373	6.777	5.889	5.934	5.922	6.458	6.053	6.888	5.841	6.723	6.394	6.124	6.480	6.093	5.745	5.615	5.290	6.130
6	June	7.736	7.608	7.197	6.271	7.107	6.398	6.270	6.700	6.492	6.872	6.574	7.284	6.330	6.162	6.089	6.250	7.051	6.253	6.702
7	July	6.987	7.427	7.583	6.913	7.143	6.391	5.391	6.798	6.500	6.628	6.923	6.997	6.762	6.163	6.357	7.412	6.430	6.795	6.756
8	August	5.905	6.781	5.853	6.466	6.146	6.354	6.436	5.996	6.261	6.496	6.785	5.993	6.129	5.363	5.591	6.660	5.403	5.992	6.145
9	September	5.812	6.531	5.496	5.170	5.885	4.844	4.248	4.889	5.427	4.733	4.393	5.171	4.753	4.210	4.303	4.875	4.702	4.689	5.007
10	October	4.793	4.349	3.375	3.788	3.874	3.484	4.066	3.013	3.623	4.038	3.472	3.980	3.955	3.552	3.871	3.261	3.750	3.118	3.742
11	November	2.701	3.381	2.758	2.824	2.259	2.161	2.552	2.453	2.773	2.239	2.305	2.405	2.313	2.249	2.414	2.551	1.735	2.555	2.479
12	December	1.747	2.484	1.778	2.114	1.573	1.726	2.049	1.514	2.213	1.950	2.123	2.434	1.740	1.683	1.775	1.651	1.767	1.755	1.893
	Annual	4.713	5.055	4.753	4.600	4.540	4.117	4.145	4.300	4.594	4.350	4.538	4.644	4.382	4.171	4.177	4.462	4.287	4.201	4.446

Table 3-13. Average Daily Direct Normal Insolation for Columbia, Mo.
(kW hr/m^2)

	Month	1952	1953	1954	1955	1956	1957	1958	1959	1960	1961	1962	1963	1964	1965	1966	1967	1968	1969	Average
1	January	3.769	4.680	4.926	3.740	3.277	2.995	4.096	4.188	3.598	5.511	5.021	3.867	4.223	3.698	4.500	5.688	3.313	3.098	4.122
2	February	4.779	6.162	6.081	4.482	3.855	3.723	5.539	4.570	4.561	4.040	4.441	4.944	5.020	5.264	4.922	5.751	5.305	3.510	4.831
3	March	5.289	6.315	6.114	6.589	6.291	4.737	3.065	5.203	6.533	3.790	5.564	5.562	4.930	5.040	5.392	5.144	6.111	6.370	5.447
4	April	6.699	6.066	6.683	7.305	6.232	4.379	5.121	5.970	6.245	5.355	6.921	7.035	5.773	5.497	4.606	6.259	6.710	6.468	6.074
5	May	7.419	7.337	7.903	6.708	6.676	6.669	7.338	6.787	8.134	6.753	7.913	7.502	7.035	7.565	7.167	6.599	6.363	5.898	7.098
6	June	9.432	8.907	8.230	6.945	8.117	7.148	6.957	7.730	7.181	8.204	7.633	8.506	7.202	6.908	6.855	7.037	8.089	7.198	7.682
7	July	8.242	8.762	8.714	7.887	8.346	7.393	5.697	7.867	7.555	7.645	8.204	8.291	7.855	7.050	7.347	8.888	7.371	7.765	7.827
8	August	7.376	8.670	6.734	7.773	7.216	7.571	7.589	7.321	7.725	8.537	8.980	7.520	7.502	6.255	6.908	8.675	6.615	7.348	7.983
9	September	8.082	9.362	7.172	6.720	7.911	6.452	5.311	6.245	7.261	6.351	5.596	6.968	6.146	5.083	5.521	6.524	6.332	6.228	6.626
10	October	8.167	7.123	4.923	5.801	5.826	5.154	6.202	4.318	5.555	6.388	5.255	6.229	6.049	5.437	6.074	4.928	5.993	4.601	5.779
11	November	5.228	6.766	5.109	5.312	3.980	3.814	4.575	4.620	5.390	3.968	4.176	4.507	4.049	3.792	4.466	4.772	2.885	4.892	4.572
12	December	3.637	5.832	3.637	4.286	3.138	3.535	4.145	2.891	4.833	4.012	4.528	5.528	3.494	3.274	3.798	3.374	3.614	3.525	3.949
	Annual	6.510	7.167	6.349	6.138	5.910	5.309	5.469	5.646	6.220	5.894	6.202	6.379	5.777	5.407	5.638	6.140	5.724	5.585	5.970

C. REGIONAL COMPARISONS OF DIRECT-NORMAL INSOLATION

1. INTRODUCTION

Direct (normal incidence) insolation values are required by the solar energy engineering community for the performance comparison of solar energy collectors installed in different regions of the United States. These values are required not only to predict the performance of concentrating collectors, but also to predict the effect of tilting and/or tracking on the performance of non-concentrating collectors. Unfortunately, direct-normal measurements have been made on a routine basis for a long time period only at Albuquerque, New Mexico. However, there exist hourly measurements of total-hemispheric insolation on a horizontal surface for about 30 locations in the United States. By themselves, these data are of limited value in estimating collector performance since most collector designs involve some tipping of the collector. However, these data do provide the best available basis for estimating the direct-normal insolation at locations where measurements are unavailable.

This section provides a direct-normal insolation comparison of regions in the United States based on hourly direct-normal insolation values estimated from hourly total-hemispheric insolation values at 33 locations in the United States for the years 1962 and 1963. The estimation procedures have been discussed in detail elsewhere (References 3, 9 and 12) and so will be only briefly reviewed here. The comparison summaries of these data follow the discussion of estimation procedures.

2. ESTIMATION PROCEDURES

The hourly data bases used in this comparison were originally prepared under rather stringent time constraints for use in solar energy systems simulations. The locations of the 33 stations finally included in those studies are shown in Figure 3-1. For 25 of these locations, hourly total-hemispheric

insolation values are available. To provide increased geographic coverage, hourly total-hemispheric values were estimated from observed sky cover for an additional eight locations. The data source at each location is indicated by the symbol in Figure 3-1. A more detailed discussion of the estimating procedures summarized in the following paragraphs is available in Reference 3.

The direct-normal insolation values are estimated by a linear relation between direct-normal insolation and percent of possible total-hemispheric insolation. The coefficients in the relation were derived from data for Albuquerque, New Mexico and Blue Hill, Massachusetts. The estimated total-hemispheric insolation values required to fill in missing data at all stations are related to opaque sky cover observations by a cubic polynomial which also includes a linear term in the relative atmospheric path length.

The procedure is limited in several ways. The mean value of direct-normal insolation values is reproduced correctly by this procedure but the distribution of values about the mean is not. Values at the beginning and end of the day may be severely distorted by small absolute errors in the total insolation measurements. Recent data from other locations indicate the estimated hourly direct-normal insolation may be too high on partly cloudy days.

3. DIRECT INSOLATION COMPARISONS

The direct-normal insolation values derived for the 33 stations of Figure 3-1 have been compared in two ways. The direct-normal insolation values were first compared by computation of average daily insolation by months and annually. The results of this study are shown as a part of Table 3-14. The values listed in the right column of Table 3-14 were obtained by taking the

Table 3-14

AVERAGE NUMBER OF CASES WITH INSOLATION GREATER THAN - N - KW. PER SQ. METER FOR GREATER THAN - M - CONSECUTIVE HOURS.

ALBUQUE., STATION: 23050

MONTH	.60 KW./SQR.M. GRTR THAN OR EQL 4	5	6	.70 KW./SQR.M. 4	5	6	HOURS	AVERAGE DIRECT INSOLATION KW./SQR.M.
1	26.5	22.5	20.5	23.5	20.5	19.0		6.91
2	22.5	20.5	20.5	20.0	19.5	18.5		7.30
3	27.5	25.5	23.5	26.5	23.0	21.5		8.81
4	29.5	26.5	25.5	27.5	24.5	20.5		9.30
5	30.5	29.0	28.5	29.5	28.0	27.5		10.13
6	30.5	29.5	27.5	28.5	27.5	26.5		10.44
7	28.5	26.5	24.5	25.5	24.5	21.5		8.50
8	30.5	26.5	23.5	28.5	25.0	22.5		9.02
9	25.5	24.5	22.5	24.5	24.5	22.5		7.44
10	27.5	26.5	25.5	26.0	24.5	23.5		8.45
11	24.5	23.0	22.5	22.0	20.5	20.5		7.22
12	28.5	27.5	25.5	26.5	25.5	23.5		7.29
YEAR TOTAL	329.5	306.5	289.5	308.5	286.5	264.5		8.41

BISMARK, STATION: 24011

MONTH	.60 KW./SQR.M. GRTR THAN OR EQL 4	5	6	.70 KW./SQR.M. 4	5	6	HOURS	AVERAGE DIRECT INSOLATION KW./SQR.M.
1	16.5	14.0	12.5	16.0	12.5	10.0		5.05
2	13.5	11.5	11.0	12.0	9.5	8.0		4.70
3	21.5	19.5	18.5	17.0	15.0	12.5		6.51
4	18.5	16.5	15.5	16.5	15.5	13.5		6.73
5	13.5	12.5	11.0	13.0	11.5	10.0		6.10
6	23.5	19.5	18.5	19.5	18.5	17.0		8.49
7	26.5	22.5	20.5	21.5	18.0	15.5		8.70
8	27.5	25.5	24.5	24.5	23.0	22.5		8.62
9	23.5	22.5	19.5	21.5	17.0	15.0		6.84
10	23.5	21.5	19.5	18.5	15.0	12.5		6.04
11	15.5	13.5	11.5	12.0	10.0	7.5		4.39
12	13.5	11.5	9.5	10.5	6.5	5.5		3.98
YEAR TOTAL	235.5	208.5	190.5	202.5	172.0	149.5		6.35

BLUE HILLS, STATION: 14753

MONTH	.60 KW./SQR.M. GRTR THAN OR EQL 4	5	6	.70 KW./SQR.M. 4	5	6	HOURS	AVERAGE DIRECT INSOLATION KW./SQR.M.
1	15.5	12.5	10.0	11.0	7.5	6.5		4.14
2	15.5	14.5	12.5	12.5	11.5	10.5		4.82
3	18.0	17.0	16.5	17.0	16.0	16.5		5.99
4	19.5	16.5	14.0	15.5	12.5	10.5		6.38
5	20.5	18.5	15.5	18.0	14.5	13.5		7.09
6	21.5	19.5	17.5	16.5	15.5	14.5		7.33
7	21.5	16.5	13.0	14.0	11.5	9.5		6.52
8	19.5	18.5	14.5	16.5	11.0	7.5		6.48
9	17.5	15.5	13.5	13.0	11.5	9.5		5.64
10	22.5	19.5	16.5	17.5	14.5	13.0		5.58
11	10.5	8.0	8.0	8.0	7.5	6.5		3.55
12	16.5	14.5	13.5	13.5	11.5	10.5		4.33
YEAR TOTAL	218.0	187.5	164.0	172.5	144.5	126.5		5.66

Table 3-14 (Continued)

AVERAGE NUMBER OF CASES WITH INSOLATION GREATER THAN - N - KW. PER SQ. METER
FOR GREATER THAN - M - CONSECUTIVE HOURS.

BOISE , STATION: 24131

MONTH	.60 KW./SQR.M. GRTR THAN OR EQL 4	5	6	.70 KW./SQR.M. 4	5	6	HOURS	AVERAGE DIRECT INSOLATION KW./SQR.M.
1	16.5	14.0	13.0	13.5	11.0	9.5		4.07
2	12.0	10.0	9.5	9.0	8.5	7.0		3.99
3	17.0	16.5	14.5	15.0	14.0	11.0		5.83
4	20.0	19.0	16.5	18.5	16.5	14.0		7.10
5	23.0	21.5	19.5	21.5	18.5	17.0		8.08
6	25.0	23.0	22.0	22.0	20.0	18.5		8.96
7	29.5	29.0	27.5	28.5	28.5	27.0		10.73
8	29.0	28.0	27.0	27.0	26.0	25.5		9.24
9	25.5	24.0	24.0	23.5	22.0	22.0		7.93
10	20.5	19.5	18.0	18.0	16.5	15.0		5.56
11	12.5	10.0	7.0	8.5	6.5	5.5		3.49
12	11.0	10.5	8.0	9.5	7.5	5.5		3.01
YEAR TOTAL	239.5	225.0	206.5	214.5	195.5	177.0		6.51

CHRLSTN SC, STATION: 13880

MONTH	.60 KW./SQR.M. GRTR THAN OR EQL 4	5	6	.70 KW./SQR.M. 4	5	6	HOURS	AVERAGE DIRECT INSOLATION KW./SQR.M.
1	15.0	13.0	12.5	13.5	12.0	10.5		4.36
2	15.0	11.5	9.5	12.0	10.5	8.5		4.91
3	20.0	17.0	16.0	16.5	15.5	12.5		5.95
4	24.0	20.5	17.5	21.5	19.0	16.0		7.22
5	23.5	21.0	20.0	19.5	18.5	14.0		7.18
6	17.5	15.5	12.0	11.0	8.0	7.5		6.04
7	22.0	18.5	15.0	14.5	12.0	11.0		6.85
8	21.0	17.5	15.5	16.0	11.0	8.0		6.64
9	17.0	15.0	11.5	10.5	8.5	6.5		5.71
10	24.0	23.0	20.0	20.0	17.0	13.0		6.28
11	17.5	16.5	14.5	16.0	14.0	11.5		5.05
12	19.0	17.5	16.0	17.5	14.5	12.0		5.08
YEAR TOTAL	235.5	206.5	180.0	188.5	160.5	131.0		5.95

CLEVELAND , STATION: 14820

MONTH	.60 KW./SQR.M. GRTR THAN OR EQL 4	5	6	.70 KW./SQR.M. 4	5	6	HOURS	AVERAGE DIRECT INSOLATION KW./SQR.M.
1	8.0	6.0	4.5	2.5	2.5	2.0		2.70
2	7.0	5.5	5.0	1.0	.5	.5		2.74
3	10.5	9.5	9.0	4.5	4.0	3.5		3.62
4	16.5	13.5	11.0	8.5	7.5	6.5		5.30
5	18.5	16.0	14.0	9.0	7.0	5.0		6.50
6	20.0	20.0	19.0	11.0	10.0	10.0		7.22
7	16.0	13.5	11.5	7.5	7.0	4.5		6.56
8	16.5	16.0	15.0	8.5	8.5	8.0		6.13
9	12.5	11.0	9.5	5.5	5.0	4.0		4.84
10	10.0	8.0	7.0	0.0	0.0	0.0		3.87
11	3.0	1.5	1.0	0.0	0.0	0.0		1.67
12	5.0	3.5	2.0	2.0	.5	.5		2.27
YEAR TOTAL	144.0	124.0	109.0	61.0	53.0	45.0		4.60

Table 3-14 (Continued)

AVERAGE NUMBER OF CASES WITH INSOLATION GREATER THAN - N - KW. PER SQ. METER FOR GREATER THAN - M - CONSECUTIVE HOURS.

DODGE CITY, STATION: 13985

MONTH	.60 KW./SQR.M. GRTR THAN OR EQL 4	5	6	.70 KW./SQR.M. 4	5	6	HOURS	AVERAGE DIRECT INSOLATION KW./SQR.M.
1	23.5	19.0	18.0	19.0	17.0	16.5		6.03
2	22.5	20.0	18.5	20.5	17.0	15.5		6.33
3	25.5	23.0	23.0	22.5	19.5	18.5		7.56
4	24.0	24.0	23.0	23.0	22.0	19.5		7.99
5	23.0	21.0	17.5	14.5	13.0	12.5		7.38
6	27.0	25.5	25.0	10.5	8.5	8.0		8.57
7	27.5	27.0	25.5	26.0	24.0	22.0		8.80
8	27.0	25.5	23.5	19.0	16.5	16.0		8.60
9	22.5	20.5	20.0	19.0	16.0	13.0		6.40
10	25.5	25.0	23.0	24.0	21.5	18.5		6.70
11	22.0	19.5	18.0	19.0	16.0	14.0		5.69
12	26.5	25.0	25.0	10.0	10.0	9.5		6.11
YEAR TOTAL	293.5	275.0	260.0	227.0	201.0	183.0		7.19

EDWDS. AFB, STATION: 23114

MONTH	.60 KW./SQR.M. GRTR THAN OR EQL 4	5	6	.70 KW./SQR.M. 4	5	6	HOURS	AVERAGE DIRECT INSOLATION KW./SQR.M.
1	24.5	24.5	23.0	20.5	20.5	19.0		6.16
2	17.0	15.0	14.5	12.0	11.0	11.0		6.02
3	25.0	24.0	24.0	23.0	23.0	20.5		7.48
4	28.0	27.0	23.5	24.5	21.0	17.0		8.44
5	29.5	29.0	26.5	28.0	25.0	22.5		9.49
6	30.5	29.5	29.5	29.5	29.0	29.0		10.56
7	31.0	31.0	31.0	30.0	30.0	29.0		10.56
8	30.5	29.5	29.5	28.5	28.5	27.0		9.41
9	28.0	27.5	27.5	26.5	26.5	26.5		8.63
10	26.5	25.5	25.0	24.0	24.0	21.5		7.11
11	23.0	22.5	21.0	19.5	17.5	16.0		6.24
12	26.0	24.5	24.0	22.0	20.0	16.0		6.00
YEAR TOTAL	319.5	309.5	299.0	298.0	276.0	255.0		8.02

EL PASO , STATION: 23044

MONTH	.60 KW./SQR.M. GRTR THAN OR EQL 4	5	6	.70 KW./SQR.M. 4	5	6	HOURS	AVERAGE DIRECT INSOLATION KW./SQR.M.
1	26.0	25.0	22.0	24.5	22.0	20.5		7.21
2	24.5	24.0	23.5	25.0	22.5	22.5		8.19
3	26.0	25.0	24.0	25.0	23.0	22.0		8.80
4	28.5	27.0	26.0	25.5	25.0	24.0		9.53
5	30.0	29.5	29.0	30.5	28.5	26.5		10.56
6	29.5	29.0	29.0	29.5	28.5	28.5		10.45
7	29.0	26.5	24.5	27.5	23.5	21.0		8.61
8	30.0	28.5	27.0	28.5	26.0	23.0		8.88
9	27.5	27.5	26.5	11.5	11.0	9.5		7.50
10	28.0	26.0	24.5	26.0	24.5	22.5		8.42
11	24.0	22.0	20.0	22.5	20.0	17.0		6.70
12	25.5	23.5	21.5	23.5	22.0	20.5		6.80
YEAR TOTAL	330.5	313.5	297.5	299.5	276.0	257.5		8.47

Table 3-14 (Continued)

AVERAGE NUMBER OF CASES WITH INSOLATION GREATER THAN - N - KW. PER SQ. METER FOR GREATER THAN - M - CONSECUTIVE HOURS.

ELY, NEV., STATION: 23154

MONTH	.60 KW./SQR.M. GRTR THAN OR EQL 4	5	6	.70 KW./SQR.M. 4	5	6	HOURS	AVERAGE DIRECT INSOLATION KW./SQR.M.
1	24.5	23.0	20.5	22.0	21.5	20.0		6.47
2	15.0	13.5	12.0	13.0	11.0	9.5		5.76
3	23.5	22.0	19.0	21.5	20.0	16.5		7.89
4	22.5	18.5	18.0	20.0	15.5	15.5		8.01
5	24.5	21.5	16.0	20.5	16.5	11.5		8.32
6	24.0	23.0	21.5	23.0	22.0	20.0		9.37
7	29.0	27.5	27.0	28.5	27.0	25.0		10.55
8	29.0	28.5	25.0	27.5	26.5	23.5		9.76
9	27.0	25.0	23.0	25.0	23.5	22.0		8.65
10	28.0	26.5	22.5	25.5	24.5	22.0		7.71
11	24.5	22.5	18.0	20.5	17.5	15.0		6.52
12	27.0	24.5	24.5	20.5	20.5	19.0		6.65
YEAR TOTAL	298.5	274.0	247.0	268.0	246.0	219.5		7.99

FORT WORTH, STATION: 3927

MONTH	.60 KW./SQR.M. GRTR THAN OR EQL 4	5	6	.70 KW./SQR.M. 4	5	6	HOURS	AVERAGE DIRECT INSOLATION KW./SQR.M.
1	19.0	17.5	15.5	18.0	16.5	14.5		5.13
2	18.0	17.5	15.0	16.0	16.0	14.0		5.65
3	22.0	21.0	20.5	19.5	19.0	17.0		6.75
4	17.0	17.0	14.5	15.0	13.5	12.0		5.70
5	24.0	20.5	18.5	19.5	18.0	16.5		7.61
6	27.5	22.0	19.0	20.0	17.0	13.5		7.88
7	26.0	23.5	22.0	24.0	22.0	20.0		8.71
8	29.5	28.5	27.0	28.5	26.5	21.5		8.79
9	21.5	20.0	17.5	18.0	15.0	13.0		6.50
10	22.5	20.0	18.5	19.0	16.0	13.5		6.46
11	17.5	16.5	15.0	15.5	14.0	11.5		4.79
12	18.0	16.5	14.5	16.0	14.5	13.5		4.58
YEAR TOTAL	262.5	240.5	217.5	229.0	208.0	180.5		6.56

FRESNO, STATION: 93193

MONTH	.60 KW./SQR.M. GRTR THAN OR EQL 4	5	6	.70 KW./SQR.M. 4	5	6	HOURS	AVERAGE DIRECT INSOLATION KW./SQR.M.
1	13.5	11.5	10.0	8.0	6.5	6.0		3.80
2	7.0	7.0	6.0	6.0	5.0	2.5		3.36
3	22.0	19.5	17.0	17.5	12.5	10.5		6.53
4	27.0	26.0	26.0	9.5	8.0	8.0		7.71
5	25.5	25.0	23.5	23.0	19.5	17.5		8.28
6	29.0	28.0	27.0	27.0	26.0	25.0		10.01
7	31.0	31.0	31.0	31.0	31.0	31.0		10.73
8	30.5	30.0	30.0	30.0	30.0	30.0		10.05
9	27.0	26.5	26.5	24.5	24.5	24.5		8.17
10	25.5	23.5	22.0	22.5	21.5	17.5		6.58
11	16.0	14.0	10.0	11.0	6.5	3.0		4.39
12	8.5	6.0	3.0	2.5	.5	0.0		2.44
YEAR TOTAL	262.5	248.5	232.0	212.5	191.5	175.5		6.86

Table 3-14 (Continued)

AVERAGE NUMBER OF CASES WITH INSOLATION GREATER THAN - N - KW. PER SQ. METER FOR GREATER THAN - M - CONSECUTIVE HOURS.

MADISON , STATION: 14837

MONTH	.60 KW./SQR.M. GRTR THAN OR EQL 4	5	6	.70 KW./SQR.M. 4	5	6	HOURS	AVERAGE DIRECT INSOLATION KW./SQR.M.
1	14.0	13.0	11.5	10.5	8.5	4.0		3.55
2	12.5	11.5	8.0	8.5	8.0	7.0		4.20
3	15.5	13.0	12.0	12.5	11.5	9.5		5.14
4	21.0	21.0	19.5	21.0	19.5	18.0		6.96
5	19.0	18.0	15.0	17.0	16.5	13.5		7.35
6	28.5	24.0	20.5	23.0	19.5	18.5		8.75
7	25.5	23.5	22.0	24.0	22.0	19.0		8.28
8	25.0	23.5	23.0	23.5	21.5	19.0		8.04
9	19.0	16.5	16.0	15.0	12.5	10.5		6.37
10	20.0	19.0	16.5	16.5	14.0	12.0		5.30
11	13.0	10.5	8.5	8.5	6.0	3.0		3.45
12	15.0	14.0	10.5	10.5	7.5	4.0		3.39
YEAR TOTAL	228.0	206.5	183.0	191.0	167.0	138.0		5.91

MEDFORD , STATION: 24225

MONTH	.60 KW./SQR.M. GRTR THAN OR EQL 4	5	6	.70 KW./SQR.M. 4	5	6	HOURS	AVERAGE DIRECT INSOLATION KW./SQR.M.
1	11.0	10.0	7.5	6.5	6.0	5.0		3.45
2	10.0	8.0	5.0	7.0	3.5	2.0		3.65
3	16.0	12.5	9.5	11.5	9.5	7.5		5.24
4	18.0	15.0	12.0	13.5	11.5	10.5		6.41
5	16.5	16.0	15.0	15.0	13.0	11.0		6.90
6	27.5	24.5	23.5	23.5	22.0	21.0		9.64
7	30.0	29.0	28.0	30.5	27.5	27.0		10.03
8	28.0	27.5	26.5	27.0	25.0	25.0		8.96
9	25.0	24.0	22.5	23.0	21.5	18.0		7.48
10	14.0	10.0	7.0	11.5	8.0	3.5		4.15
11	6.0	4.0	1.5	3.5	1.5	0.0		2.66
12	5.0	4.0	3.0	3.5	3.0	2.0		1.99
YEAR TOTAL	207.0	184.5	161.0	176.0	152.0	132.5		5.89

MIAMI , STATION: 12839

MONTH	.60 KW./SQR.M. GRTR THAN OR EQL 4	5	6	.70 KW./SQR.M. 4	5	6	HOURS	AVERAGE DIRECT INSOLATION KW./SQR.M.
1	20.0	16.5	14.5	14.5	11.0	8.0		5.57
2	19.5	17.0	16.5	16.0	13.5	11.5		6.65
3	24.5	21.0	20.0	19.5	16.0	12.5		7.47
4	22.5	19.0	17.5	15.5	13.5	13.0		7.53
5	26.5	21.0	19.0	18.5	14.5	12.5		7.64
6	17.0	14.0	10.0	9.5	9.0	6.5		6.69
7	24.5	21.0	17.5	17.5	13.5	10.5		7.25
8	16.0	12.5	11.0	9.0	7.5	5.5		6.19
9	16.5	12.5	8.0	8.5	7.5	4.5		5.31
10	21.0	18.0	15.0	13.5	11.5	9.5		5.55
11	15.5	14.0	12.0	12.0	10.5	9.5		5.31
12	19.5	17.5	14.5	14.5	14.0	12.0		5.62
YEAR TOTAL	242.5	204.0	175.5	168.5	142.0	115.5		6.48

Table 3-14 (Continued)

AVERAGE NUMBER OF CASES WITH INSOLATION GREATER THAN - N - KW. PER SQ. METER FOR GREATER THAN - M - CONSECUTIVE HOURS.

LK CHARLES, STATION: 3937	.60 KW./SQR.M.			.70 KW./SQR.M.				
MONTH GRTR THAN OR EQL	4	5	6	4	5	6	HOURS	AVERAGE DIRECT INSOLATION KW./SQR.M.
1	10.5	10.0	9.5	10.0	9.5	7.5		3.39
2	15.0	12.5	11.0	11.5	10.5	9.5		4.95
3	18.0	16.5	14.5	15.5	13.5	11.0		5.49
4	16.0	14.5	13.0	10.0	9.5	8.0		5.61
5	23.5	21.0	18.0	13.5	11.0	9.5		7.54
6	17.5	15.0	13.5	11.5	9.0	5.5		6.49
7	24.5	20.5	14.5	11.0	9.5	7.0		7.17
8	22.0	21.0	18.0	6.0	3.5	2.0		6.77
9	20.5	17.0	14.0	9.5	6.5	5.0		5.90
10	23.5	20.0	17.0	15.0	11.5	7.5		6.02
11	14.0	13.0	12.0	11.5	9.5	9.5		4.54
12	13.5	13.0	11.0	11.5	9.5	7.5		3.89
YEAR TOTAL	218.5	194.0	166.0	136.5	113.0	89.5		5.64

LA. CONTR., STATION: 93134	.60 KW./SQR.M.			.70 KW./SQR.M.				
MONTH GRTR THAN OR EQL	4	5	6	4	5	6	HOURS	AVERAGE DIRECT INSOLATION KW./SQR.M.
1	22.0	22.0	21.5	15.0	12.0	9.0		5.37
2	15.0	13.5	13.0	12.0	10.0	7.5		4.88
3	25.0	23.0	20.5	21.0	20.0	19.0		7.39
4	24.5	24.0	22.0	24.0	23.5	21.0		8.05
5	21.0	20.5	17.5	19.5	17.5	16.0		7.08
6	20.0	19.5	18.0	18.5	17.0	15.5		6.81
7	31.0	30.5	30.5	30.0	29.5	29.0		9.38
8	30.0	30.0	29.5	28.5	28.5	27.0		8.92
9	26.5	25.5	24.0	24.5	24.5	23.5		7.55
10	22.5	20.5	19.0	18.5	18.0	13.5		6.27
11	20.5	18.0	16.0	18.0	14.0	12.0		5.67
12	25.0	24.5	22.0	17.5	14.5	12.0		6.07
YEAR TOTAL	283.0	271.5	253.5	247.0	229.0	205.0		6.96

LA AIRPORT, STATION: 23174	.60 KW./SQR.M.			.70 KW./SQR.M.				
MONTH GRTR THAN OR EQL	4	5	6	4	5	6	HOURS	AVERAGE DIRECT INSOLATION KW./SQR.M.
1	21.5	19.5	18.5	15.5	13.5	11.5		5.46
2	18.5	14.5	13.5	13.5	12.0	10.0		5.29
3	26.0	23.5	22.5	23.5	20.5	19.5		7.86
4	26.5	24.0	23.0	24.0	22.0	20.0		8.36
5	24.5	21.0	19.5	21.0	19.0	17.0		7.57
6	22.5	20.0	16.5	16.0	15.0	13.0		6.47
7	29.5	29.0	28.0	29.0	28.0	25.0		8.42
8	30.0	30.0	27.5	29.0	28.0	27.0		8.44
9	26.0	24.5	22.5	24.0	23.0	20.0		8.91
10	21.5	18.5	15.5	16.5	14.0	11.0		6.15
11	19.0	18.0	15.5	15.5	13.0	9.0		5.33
12	21.5	18.5	15.5	16.0	13.0	10.5		5.72
YEAR TOTAL	285.0	261.5	238.0	247.5	221.0	193.5		6.82

Table 3-14 (Continued)

AVERAGE NUMBER OF CASES WITH INSOLATION GREATER THAN - N - KW. PER SQ. METER FOR GREATER THAN - M - CONSECUTIVE HOURS.

MADISON, STATION: 14837

MONTH	.60 KW./SQR.M. GRTR THAN OR EQL 4	5	6	.70 KW./SQR.M. 4	5	6	HOURS	AVERAGE DIRECT INSOLATION KW./SQR.M.
1	14.0	13.0	11.5	10.5	8.5	4.0		3.55
2	12.5	10.5	8.0	8.5	8.0	7.0		4.20
3	15.5	13.0	12.0	12.5	11.5	9.5		5.14
4	21.0	21.0	19.5	21.0	19.5	18.0		6.96
5	19.0	18.0	15.0	17.5	16.5	13.5		7.35
6	28.5	24.0	20.5	23.0	19.5	18.5		8.75
7	25.5	23.5	22.0	24.0	22.0	19.0		8.28
8	25.0	23.5	23.0	23.5	21.5	19.0		8.04
9	19.0	16.5	16.0	15.0	12.5	10.5		6.37
10	20.0	19.0	16.5	16.5	14.0	12.0		5.30
11	13.0	10.5	8.5	8.5	6.0	3.0		3.45
12	15.0	14.0	10.5	10.5	7.5	4.0		3.39
YEAR TOTAL	228.0	206.5	183.0	191.0	167.0	138.0		5.91

MEDFORD, STATION: 24225

MONTH	.60 KW./SQR.M. GRTR THAN OR EQL 4	5	6	.70 KW./SQR.M. 4	5	6	HOURS	AVERAGE DIRECT INSOLATION KW./SQR.M.
1	11.0	10.0	7.5	6.5	6.0	5.0		3.45
2	10.0	8.0	5.0	7.0	3.5	2.0		3.65
3	16.0	12.5	9.5	11.5	9.5	7.5		5.24
4	18.0	15.0	12.0	13.5	11.5	10.5		6.41
5	16.5	16.0	15.0	15.0	13.0	11.0		6.90
6	27.5	24.5	23.5	23.5	22.0	21.0		9.64
7	30.0	29.0	28.0	30.5	27.5	27.0		10.03
8	28.0	27.5	26.5	27.0	25.0	25.0		8.96
9	25.0	24.0	22.5	23.0	21.5	18.0		7.48
10	14.0	10.0	7.0	11.5	8.0	3.5		4.15
11	6.0	4.0	1.5	3.5	1.5	0.0		2.66
12	5.0	4.0	3.0	3.5	3.0	2.0		1.99
YEAR TOTAL	207.0	184.5	161.0	176.0	152.0	132.5		5.89

MIAMI, STATION: 12839

MONTH	.60 KW./SQR.M. GRTR THAN OR EQL 4	5	6	.70 KW./SQR.M. 4	5	6	HOURS	AVERAGE DIRECT INSOLATION KW./SQR.M.
1	20.0	16.5	14.5	14.5	11.0	8.0		5.57
2	19.5	17.0	16.5	16.0	13.5	11.5		6.65
3	24.5	21.0	20.0	19.5	16.0	12.5		7.47
4	22.0	19.0	17.5	15.5	13.5	13.0		7.53
5	26.5	21.0	19.0	18.5	14.5	12.5		7.64
6	17.0	14.0	10.0	9.5	9.0	6.5		6.69
7	24.5	21.0	17.5	17.5	13.5	10.5		7.25
8	16.0	12.5	11.0	9.0	7.5	5.5		6.19
9	16.5	12.5	8.0	8.5	7.5	4.5		5.31
10	21.0	18.0	15.0	13.5	11.5	9.5		6.55
11	15.5	14.0	12.0	12.0	10.5	9.5		5.31
12	19.5	17.5	14.5	14.5	14.0	12.0		5.62
YEAR TOTAL	242.5	204.0	175.5	168.5	142.0	115.5		6.48

Table 3-14 (Continued)

AVERAGE NUMBER OF CASES WITH INSOLATION GREATER THAN - N - KW. PER SQ. METER
FOR GREATER THAN - M - CONSECUTIVE HOURS.

MIDLAND TX, STATION: 23023

MONTH	.60 KW./SQR.M. GRTR THAN OR EQL 4	5	6	.70 KW./SQR.M. 4	5	6	HOURS	AVERAGE DIRECT INSOLATION KW./SQR.M.
1	22.5	21.5	21.0	18.5	17.5	16.0		5.81
2	20.5	19.5	19.0	18.0	18.0	16.5		6.43
3	26.5	23.5	22.5	24.0	22.0	21.5		7.14
4	24.5	23.5	23.0	22.0	21.5	20.5		7.62
5	26.5	26.5	25.5	24.5	23.5	22.5		8.16
6	26.5	25.0	22.5	24.0	21.5	20.5		8.91
7	26.5	25.5	24.5	23.0	21.5	19.0		8.67
8	28.0	26.5	26.0	25.5	25.0	24.0		8.43
9	24.5	22.0	21.0	21.5	20.0	17.5		7.46
10	26.0	24.0	21.5	21.0	19.0	18.0		6.74
11	22.5	20.5	19.5	19.0	18.0	15.5		5.96
12	20.0	19.0	16.0	16.0	14.5	11.5		4.86
YEAR TOTAL	293.0	277.0	262.0	257.0	242.0	222.5		7.19

NASHVILLE , STATION: 13897

MONTH	.60 KW./SQR.M. GRTR THAN OR EQL 4	5	6	.70 KW./SQR.M. 4	5	6	HOURS	AVERAGE DIRECT INSOLATION KW./SQR.M.
1	11.0	10.5	9.5	10.5	10.0	8.5		3.29
2	15.0	14.5	11.0	12.5	8.5	5.0		4.05
3	15.5	14.0	13.0	13.5	12.5	10.5		4.53
4	18.5	17.0	14.0	16.0	13.5	11.0		5.69
5	22.5	20.5	17.5	17.5	15.0	13.5		6.73
6	15.0	13.0	11.5	9.0	7.5	6.0		5.94
7	18.0	14.5	13.0	11.0	8.0	6.0		6.24
8	20.5	16.5	14.0	9.5	7.0	6.5		6.28
9	16.5	15.0	13.5	12.5	10.0	9.0		5.09
10	22.0	17.5	14.5	14.5	9.5	8.5		5.46
11	10.5	9.5	8.0	7.5	4.0	2.0		3.03
12	11.5	9.5	7.5	1.5	1.0	0.0		3.11
YEAR TOTAL	196.5	171.5	147.0	135.5	107.5	86.5		4.96

OMAHA , STATION: 94918

MONTH	.60 KW./SQR.M. GRTR THAN OR EQL 4	5	6	.70 KW./SQR.M. 4	5	6	HOURS	AVERAGE DIRECT INSOLATION KW./SQR.M.
1	20.5	17.0	15.5	20.0	13.5	12.0		5.63
2	14.5	14.0	11.5	12.0	11.5	9.5		4.73
3	18.5	16.5	15.0	16.0	13.5	12.0		5.96
4	19.5	18.5	17.0	18.0	16.0	15.0		6.66
5	19.0	18.0	15.0	16.5	13.5	11.5		6.61
6	25.0	23.0	19.5	23.0	17.5	15.5		7.88
7	26.0	24.5	21.0	23.5	19.5	17.5		7.95
8	24.5	21.5	20.0	20.0	17.5	14.0		7.40
9	20.5	18.5	16.0	16.0	15.0	13.5		6.32
10	24.5	22.5	22.0	22.5	19.5	16.5		6.34
11	17.5	16.0	14.0	14.5	13.0	10.5		4.98
12	17.5	16.5	15.5	15.5	15.0	13.0		4.84
YEAR TOTAL	247.5	226.5	202.0	217.5	185.0	160.5		6.29

Table 3-14 (Continued)

AVERAGE NUMBER OF CASES WITH INSOLATION GREATER THAN - N - KW. PER SQ. METER FOR GREATER THAN - M - CONSECUTIVE HOURS.

PHOENIX, STATION: 23183	.60 KW./SQR.M.			.70 KW./SQR.M.				AVERAGE DIRECT
MONTH	GRTR THAN OR EQL 4	5	6	4	5	6	HOURS	INSOLATION KW./SQR.M.
1	26.0	25.0	23.5	23.5	21.0	19.5		6.47
2	21.5	20.0	18.0	20.5	18.0	17.0		6.91
3	27.0	25.5	23.5	26.5	24.0	21.5		8.21
4	29.5	27.5	26.5	26.0	23.5	23.0		9.03
5	29.0	28.5	27.5	28.0	27.5	26.5		9.70
6	30.0	29.5	29.0	24.0	22.5	22.5		9.73
7	29.0	28.0	27.5	27.5	27.5	26.0		9.25
8	28.0	27.0	26.5	24.5	24.0	21.5		8.32
9	26.5	25.5	23.0	24.0	22.5	22.5		7.66
10	29.0	28.5	25.5	26.5	26.0	22.0		7.87
11	26.0	25.5	23.0	23.5	22.5	20.0		6.65
12	27.0	26.5	26.0	25.5	24.5	22.0		6.69
YEAR TOTAL	328.5	317.0	299.5	300.0	283.5	264.0		8.05

RIVERSIDE, STATION: 23119	.60 KW./SQR.M.			.70 KW./SQR.M.				AVERAGE DIRECT
MONTH	GRTR THAN OR EQL 4	5	6	4	5	6	HOURS	INSOLATION KW./SQR.M.
1	22.5	20.0	17.5	18.5	17.0	13.5		5.40
2	17.5	16.0	14.5	15.0	15.0	12.5		5.65
3	24.0	22.0	19.5	21.0	19.0	17.0		7.72
4	26.0	25.0	22.5	25.0	23.0	20.5		8.67
5	25.5	24.5	23.0	23.0	22.0	20.0		8.56
6	27.5	25.5	23.0	25.5	23.5	22.0		8.72
7	30.5	30.5	30.5	30.0	30.0	29.5		10.53
8	30.0	29.5	29.5	29.5	27.5	27.5		10.12
9	28.5	28.0	26.5	28.5	27.0	24.5		8.54
10	26.5	24.5	22.5	24.5	22.5	21.0		7.55
11	23.5	22.0	20.0	20.5	18.0	17.5		6.56
12	27.5	26.5	25.0	27.0	23.0	22.0		7.33
YEAR TOTAL	309.5	294.0	274.0	288.0	267.5	247.5		7.96

SALT LAKE, STATION: 24127	.60 KW./SQR.M.			.70 KW./SQR.M.				AVERAGE DIRECT
MONTH	GRTR THAN OR EQL 4	5	6	4	5	6	HOURS	INSOLATION KW./SQR.M.
1	16.0	14.5	13.5	14.5	13.0	11.0		4.98
2	12.0	11.0	10.5	10.0	9.5	9.0		4.75
3	26.5	24.5	23.0	25.0	22.5	20.5		8.07
4	21.0	18.0	17.0	19.5	16.5	15.5		7.53
5	26.5	22.0	20.0	22.5	20.5	18.5		8.97
6	25.5	24.0	23.5	24.5	23.0	22.0		9.42
7	27.5	26.0	25.5	26.0	25.5	24.5		9.82
8	31.5	26.5	24.5	27.5	23.0	20.0		9.89
9	25.0	25.0	22.5	24.5	24.5	22.5		8.27
10	27.5	25.5	25.0	24.5	24.0	23.0		7.70
11	18.5	16.5	13.5	15.0	13.5	11.0		5.37
12	16.5	13.5	11.0	13.5	11.5	10.5		4.16
YEAR TOTAL	273.5	247.0	229.5	247.0	227.0	208.0		7.43

Table 3-14 (Continued)

AVERAGE NUMBER OF CASES WITH INSOLATION GREATER THAN - N - KW. PER SQ. METER FOR GREATER THAN - M - CONSECUTIVE HOURS.

SAN DIEGO , STATION: 23188 MONTH	.60 KW./SQR.M. GRTR THAN OR EQL 4	5	6	.70 KW./SQR.M. 4	5	6	HOURS	AVERAGE DIRECT INSOLATION KW./SQR.M.
1	22.5	20.5	19.0	19.5	18.5	16.5		5.66
2	17.5	16.0	14.0	15.0	12.5	10.0		5.51
3	24.5	22.5	22.0	22.0	21.5	20.5		6.90
4	25.0	23.5	22.5	23.5	23.0	19.5		7.49
5	24.0	22.0	20.0	22.0	20.0	16.5		6.96
6	19.0	17.0	15.5	19.0	16.0	12.5		6.62
7	29.0	28.0	27.5	28.5	26.5	25.0		8.12
8	30.5	29.0	27.5	29.0	27.0	26.0		7.84
9	27.0	25.0	23.0	26.0	24.0	21.5		7.17
10	25.5	24.5	22.0	24.0	21.5	18.5		6.20
11	23.0	21.0	16.5	18.5	15.5	12.5		5.68
12	24.0	24.0	21.0	23.5	21.0	18.5		5.86
YEAR TOTAL	291.5	273.0	250.5	270.5	247.0	217.5		6.68

STA MARIA , STATION: 23273 MONTH	.60 KW./SQR.M. GRTR THAN OR EQL 4	5	6	.70 KW./SQR.M. 4	5	6	HOURS	AVERAGE DIRECT INSOLATION KW./SQR.M.
1	24.0	23.0	22.5	20.0	20.0	19.0		6.01
2	16.0	15.5	12.5	14.5	13.0	10.0		5.58
3	23.0	21.5	21.0	23.0	21.0	19.0		7.85
4	27.5	25.0	24.0	26.0	24.5	23.0		8.88
5	22.0	21.0	20.5	20.5	19.5	19.0		8.08
6	26.5	26.0	25.0	26.0	24.0	22.5		8.28
7	31.0	30.5	30.0	31.0	30.5	30.0		8.85
8	30.0	29.5	29.5	29.5	29.0	29.0		8.73
9	26.0	24.0	24.0	25.0	23.5	21.5		7.33
10	25.0	23.5	21.5	24.0	22.5	20.0		6.74
11	22.0	20.0	19.5	19.0	18.0	15.5		5.95
12	25.0	23.5	23.5	23.0	21.0	18.5		6.52
YEAR TOTAL	298.0	283.0	273.5	281.5	267.0	247.0		7.41

SEATTLE , STATION: 24233 MONTH	.60 KW./SQR.M. GRTR THAN OR EQL 4	5	6	.70 KW./SQR.M. 4	5	6	HOURS	AVERAGE DIRECT INSOLATION KW./SQR.M.
1	10.0	9.5	7.0	8.5	7.5	4.0		2.73
2	9.0	8.5	7.5	7.5	5.0	4.5		3.49
3	12.0	10.0	8.5	9.5	8.0	8.0		4.56
4	11.0	9.5	7.5	8.5	6.0	4.5		5.18
5	20.5	18.0	15.0	16.5	14.0	11.5		7.13
6	17.5	16.0	14.0	15.5	14.0	12.5		7.22
7	21.0	17.5	16.5	15.5	14.5	14.0		7.58
8	19.5	16.5	13.5	14.5	13.0	11.5		6.50
9	17.5	17.5	16.0	17.0	15.0	13.5		5.80
10	7.5	6.5	4.0	5.0	4.0	2.0		3.35
11	5.5	5.0	4.0	3.0	1.0	.5		2.25
12	4.5	2.5	2.5	3.0	1.5	1.5		1.94
YEAR TOTAL	155.0	137.0	116.0	124.0	103.5	88.0		4.82

Table 3-14 (Concluded)

AVERAGE NUMBER OF CASES WITH INSOLATION GREATER THAN - N - KW. PER SQ. METER FOR GREATER THAN - M - CONSECUTIVE HOURS.

STERLNG VA, STATION: 93734

MONTH	.60 KW./SQR.M. GRTR THAN OR EQL 4	5	6	.70 KW./SQR.M. 4	5	6	HOURS	AVERAGE DIRECT INSOLATION KW./SQR.M.
1	16.5	16.0	13.0	13.5	11.5	10.5		4.48
2	15.0	13.5	12.0	13.0	12.0	10.5		4.47
3	22.0	20.0	18.0	17.0	16.0	15.0		6.20
4	21.0	19.0	17.0	17.0	15.5	13.5		6.86
5	23.0	20.5	19.0	19.5	16.5	15.5		7.00
6	21.0	18.5	16.5	17.5	14.0	13.0		7.21
7	22.5	19.5	17.0	16.5	11.5	10.0		7.24
8	19.5	17.0	15.0	14.5	11.0	8.5		7.09
9	17.5	16.5	15.5	14.5	12.5	9.5		5.65
10	24.0	21.5	20.5	19.0	17.5	14.0		6.39
11	15.5	12.5	10.0	11.5	9.5	7.5		4.38
12	15.5	13.5	11.0	11.0	9.0	6.0		4.23
YEAR TOTAL	233.0	208.0	184.5	184.5	156.5	133.5		5.94

TUCSON , STATION: 23160

MONTH	.60 KW./SQR.M. GRTR THAN OR EQL 4	5	6	.70 KW./SQR.M. 4	5	6	HOURS	AVERAGE DIRECT INSOLATION KW./SQR.M.
1	24.5	24.0	22.5	23.0	21.0	18.5		6.65
2	22.5	21.0	21.0	20.5	20.0	19.5		7.16
3	29.0	27.5	24.5	26.5	22.5	21.5		8.46
4	27.5	27.5	27.5	27.5	26.5	25.5		9.47
5	30.5	29.0	27.5	30.0	27.5	26.5		10.04
6	30.0	29.5	28.5	29.0	28.0	27.5		10.45
7	26.0	24.5	22.5	23.5	22.0	18.0		8.24
8	27.0	25.0	22.5	25.5	23.5	21.0		7.78
9	27.0	25.0	24.0	24.0	23.0	21.5		7.62
10	28.5	26.5	24.0	26.0	23.5	22.5		7.61
11	23.5	22.0	20.5	22.0	20.0	19.5		6.41
12	26.0	24.5	23.5	26.0	23.5	21.5		6.42
YEAR TOTAL	322.0	306.0	288.5	303.0	281.0	262.0		8.03

YUMA ARIZ, STATION: 23195

MONTH	.60 KW./SQR.M. GRTR THAN OR EQL 4	5	6	.70 KW./SQR.M. 4	5	6	HOURS	AVERAGE DIRECT INSOLATION KW./SQR.M.
1	27.5	27.0	26.0	27.0	25.0	23.5		6.59
2	25.5	24.0	23.5	24.0	22.5	20.5		6.98
3	29.0	28.5	28.0	28.0	27.5	25.5		8.04
4	29.5	28.5	27.5	27.5	27.0	26.0		8.95
5	30.5	30.5	30.5	31.0	30.0	29.0		9.82
6	30.0	30.0	30.0	29.5	29.0	28.5		10.61
7	30.5	30.5	30.5	30.5	30.0	30.0		10.22
8	29.5	28.5	28.0	28.5	27.0	26.5		9.05
9	27.5	27.0	26.0	26.0	26.0	25.0		8.45
10	29.5	29.5	29.0	29.0	28.5	27.5		7.59
11	27.5	27.0	26.0	24.5	22.0	21.0		6.79
12	31.0	30.0	30.0	22.0	22.0	21.0		6.63
YEAR TOTAL	348.5	342.5	335.0	327.0	317.0	304.0		8.32

mean value by station and month of the values presented in Tables 3-10 and 3-11. Free-hand isopleths are shown in Figures 3-4 through 3-6. These maps are quite different from the average daily total-hemispheric insolation maps prepared by other investigators (Reference 13). For comparison the total-hemispheric insolation isopleths of Bennett (Reference 13) are shown as dotted lines on Figures 3-5 and 3-6. This difference in the isopleths, particularly in winter, suggests that, for solar energy applications with tilted collectors, the total-hemispheric insolation maps imply too great a penalty at northern latitudes. For example, the total-hemispheric maps would imply for the Southwest an average daily December insolation three times that of the northern Great Plains states. The direct insolation values indicate, on the other hand, that the Southwest has only approximately 50 percent greater daily average insolation.

Direct-normal insolation values were next compared on the basis of persistence. For many applications, such as a central power plant, the power must be available for periods of several consecutive hours to make a region attractive. This comparison consisted of counting for each month the number of cases for which the insolation exceeded a given value (N_g) for <u>exactly</u> M_g hours. Results are presented here for the values of $N_g = 0.6$ and $0.7\ KWm^{-2}$. The values for the same months at a given station were combined to provide an average number of cases for each month. The average number of cases for the year was also computed. An example of the results of this computation for $N_g = 0.6\ kWm^{-2}$ are shown in Table 3-15. In Table 3-15 the persistence values have been summed to indicate the number of cases when the direct-normal insolation is greater than N_g for M_g, <u>or more</u> hours.

The persistence data from Table 3-15 for the conditions of (a) $0.6\,kWm^{-2}$ for four or more hours and (b) $0.7\ kWm^{-2}$ for five or more hours are extracted in visual form on the maps shown in Figures 3-7 through 3-11. The number of cases for a given month for insolation level and time period are listed in Figures 3-12 and isopleths are sketched in.

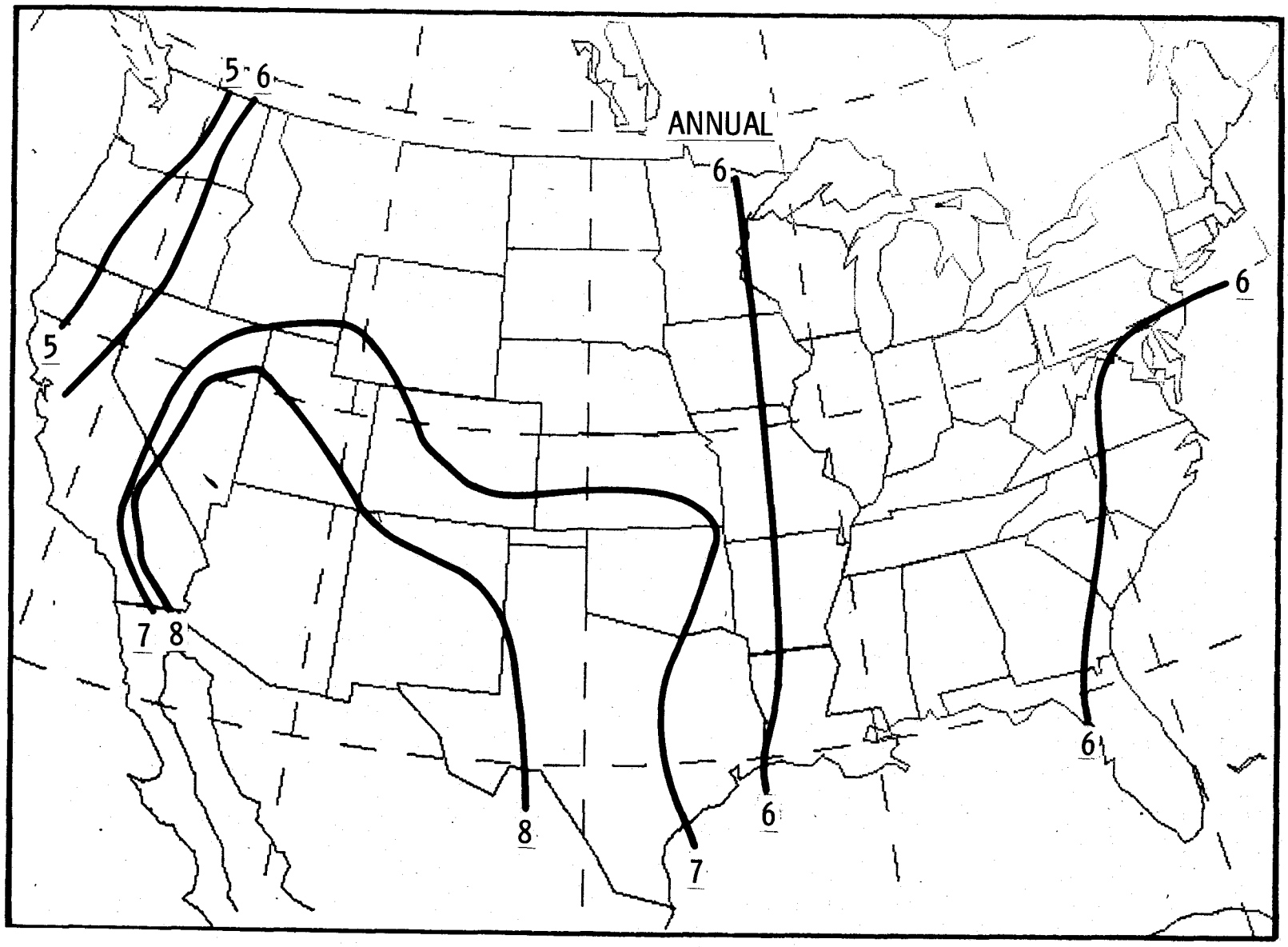


Figure 3-4. Isopleths of Annual Daily Average Direct-Normal Insolation (kWh m^{-2})

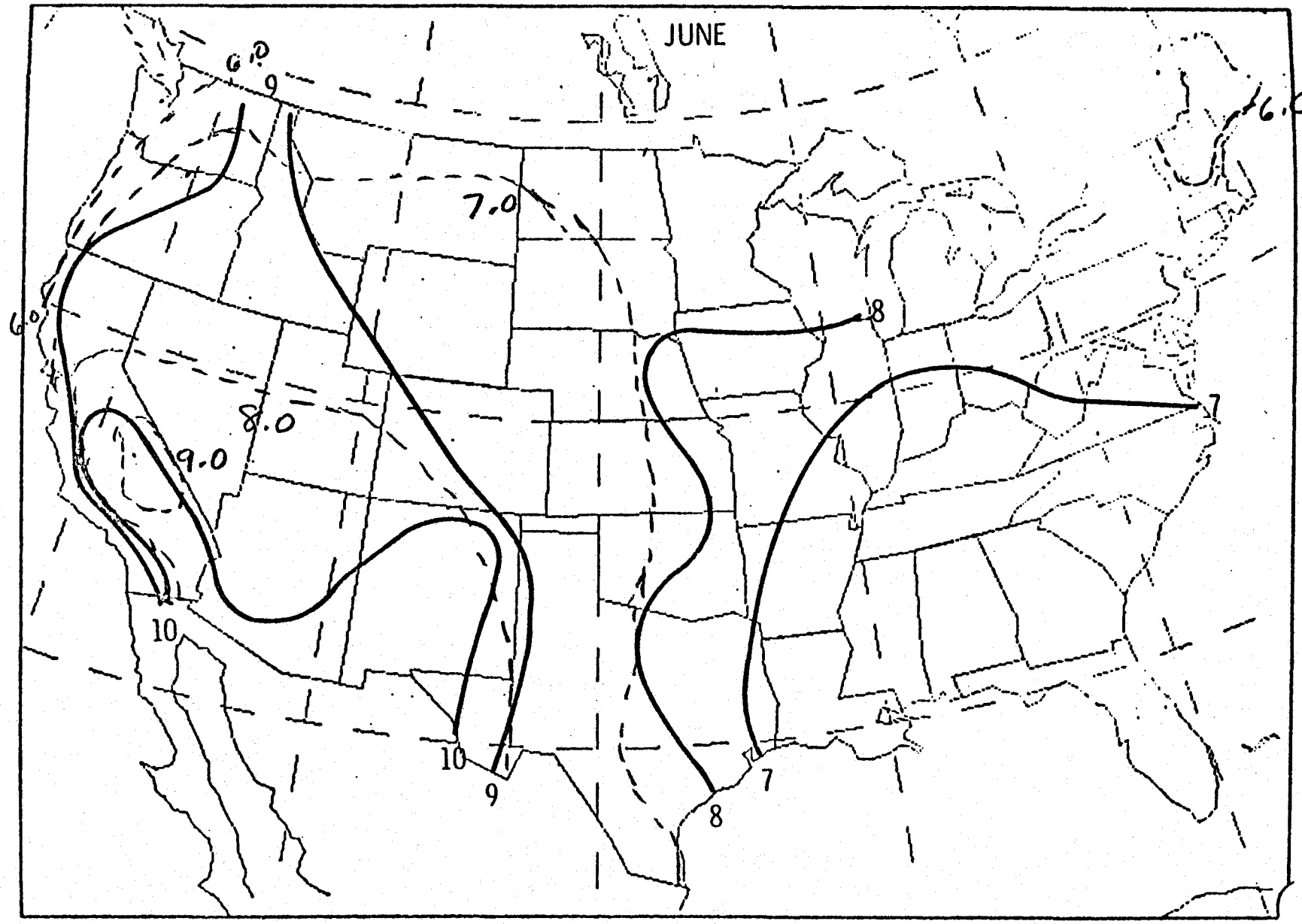


Figure 3-5. Isopleths of Average Daily Insolation for the Month of June (kWh m^{-2}) (The solid curves are from the estimated direct-normal data. The dashed curves are for total hemispheric insolation and are taken from Reference 3.)

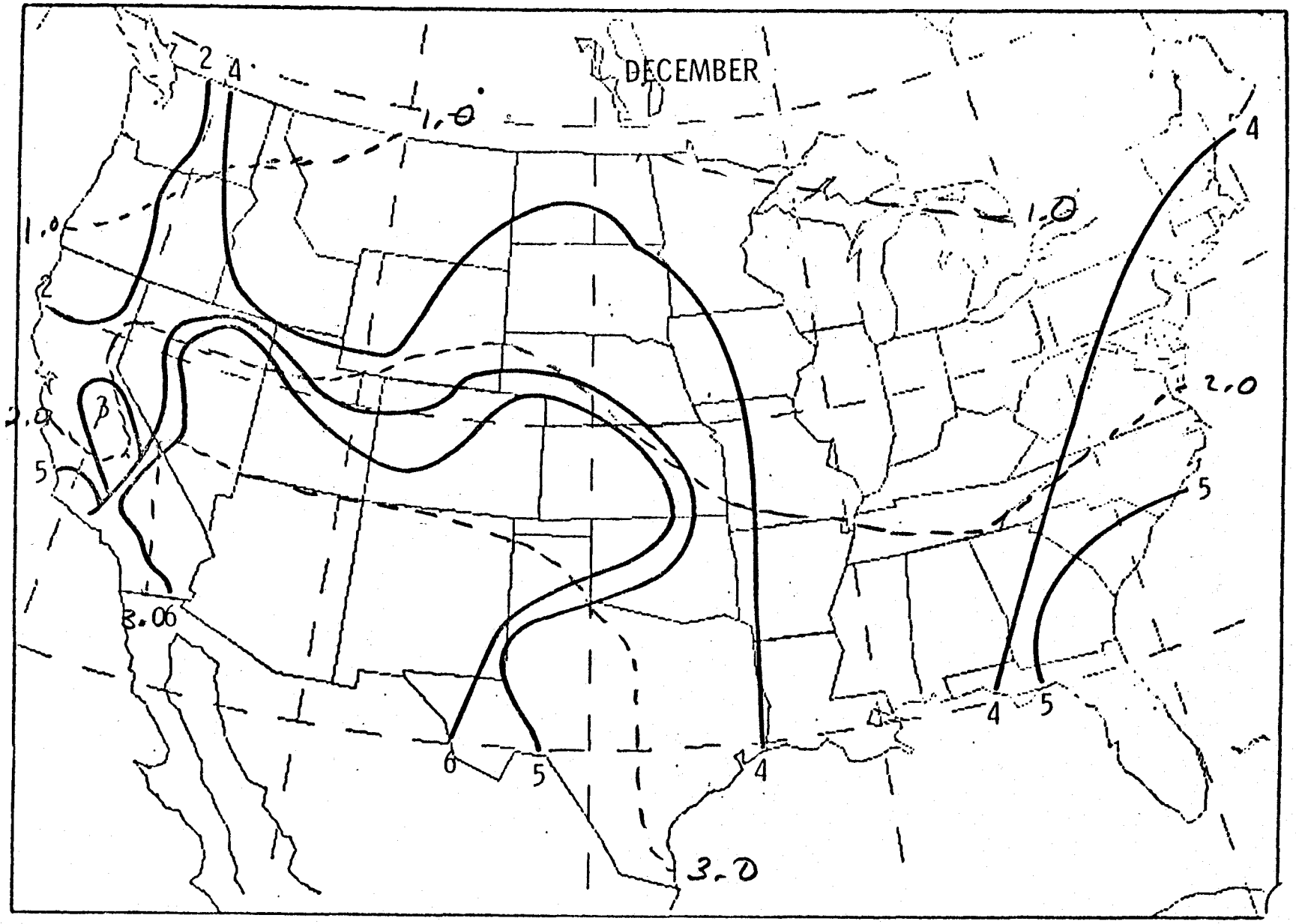


Figure 3-6. Isopleths of Average Daily Insolation for the Month of December (kWh m^{-2}) (The solid curves are from the estimated direct-normal data. The dashed curves are for total-hemispheric insolation and are taken from Reference 3.)

Table 3-15
Average Number of Cases of Continuous Insolation Greater Than .60 kW/m^2

ALBUQUE. , STATION: 23050

MONTH	CONSECUTIVE HOURS 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
1	3.0	2.0	1.5	3.0	2.0	1.0	1.0	1.0	0.5	0.0	0.0	0.0	0.0	0.0	0.0
2	3.0	2.0	2.0	2.0	2.0	2.0	2.0	1.0	0.5	0.0	0.0	0.0	0.0	0.0	0.0
3	3.0	3.0	2.0	3.0	2.0	2.0	2.0	2.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0
4	3.0	2.0	2.0	2.0	1.0	2.0	3.0	2.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0
5	3.0	3.0	2.0	3.0	2.0	3.0	3.0	3.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0
6	2.0	2.0	2.0	2.0	1.0	2.0	2.0	2.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0
7	2.0	2.0	2.0	2.0	1.0	2.0	3.0	4.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0
8	2.0	2.0	2.0	3.0	2.0	2.0	3.0	4.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0
9	2.0	2.0	2.0	3.0	2.0	2.0	3.0	4.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0
10	2.0	2.0	2.0	3.0	2.0	2.0	3.0	4.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0
11	2.0	2.0	2.0	3.0	2.0	2.0	3.0	4.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0
12	2.0	2.0	2.0	3.0	2.0	2.0	3.0	4.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0
YEAR TOTAL	30.0	33.0	20.0	23.5	17.0	20.0	24.5	46.5	48.5	6.2	26.0	50.0	7.0	4.0	0.0

BISMARK , STATION: 24011

MONTH	CONSECUTIVE HOURS 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
1	3.0	2.0	2.0	2.0	1.5	2.0	4.0	4.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0
2	3.0	3.0	2.0	2.0	1.0	3.0	3.0	2.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0
3	4.0	3.0	3.0	2.0	1.0	3.0	3.0	2.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0
4	11.0	4.0	4.0	3.0	1.0	3.0	2.0	2.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0
5	3.0	3.0	4.0	4.0	1.0	3.0	2.0	2.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0
6	3.0	2.0	4.0	4.0	1.0	3.0	2.0	2.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0
7	3.0	3.0	4.0	4.0	1.0	3.0	2.0	2.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0
8	3.0	2.0	4.0	4.0	1.0	3.0	2.0	2.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0
9	3.0	2.0	4.0	4.0	1.0	3.0	2.0	2.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0
10	3.0	2.0	4.0	4.0	1.0	3.0	2.0	2.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0
11	3.0	2.0	4.0	4.0	1.0	3.0	2.0	2.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0
12	3.0	2.0	4.0	4.0	1.0	3.0	2.0	2.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0
YEAR TOTAL	71.0	45.0	43.0	28.5	18.5	27.0	33.5	30.0	23.5	21.5	23.0	15.5	10.0	4.0	0.5

BLUE HILLS, STATION: 14753

MONTH	CONSECUTIVE HOURS 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
1	3.0	2.0	1.5	3.0	2.0	3.0	3.5	1.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0
2	3.0	3.0	2.0	2.0	1.0	2.0	2.0	2.0	1.0	0.0	0.0	0.0	0.0	0.0	0.0
3	4.0	3.0	2.0	2.0	1.0	3.0	2.0	3.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0
4	7.0	3.0	2.0	2.0	1.0	3.0	2.0	3.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0
5	3.0	3.0	2.0	2.0	1.0	3.0	2.0	3.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0
6	3.0	3.0	2.0	2.0	1.0	3.0	2.0	3.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0
7	3.0	3.0	2.0	2.0	1.0	3.0	2.0	3.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0
8	3.0	3.0	2.0	2.0	1.0	3.0	2.0	3.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0
9	3.0	3.0	2.0	2.0	1.0	3.0	2.0	3.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0
10	3.0	3.0	2.0	2.0	1.0	3.0	2.0	3.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0
11	3.0	3.0	2.0	2.0	1.0	3.0	2.0	3.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0
12	3.0	3.0	2.0	2.0	1.0	3.0	2.0	3.0	2.0	0.0	0.0	0.0	0.0	0.0	0.0
YEAR TOTAL	63.0	42.0	28.5	30.5	23.5	28.0	22.5	32.5	20.5	29.5	18.5	13.5	9.0	0.0	0.0

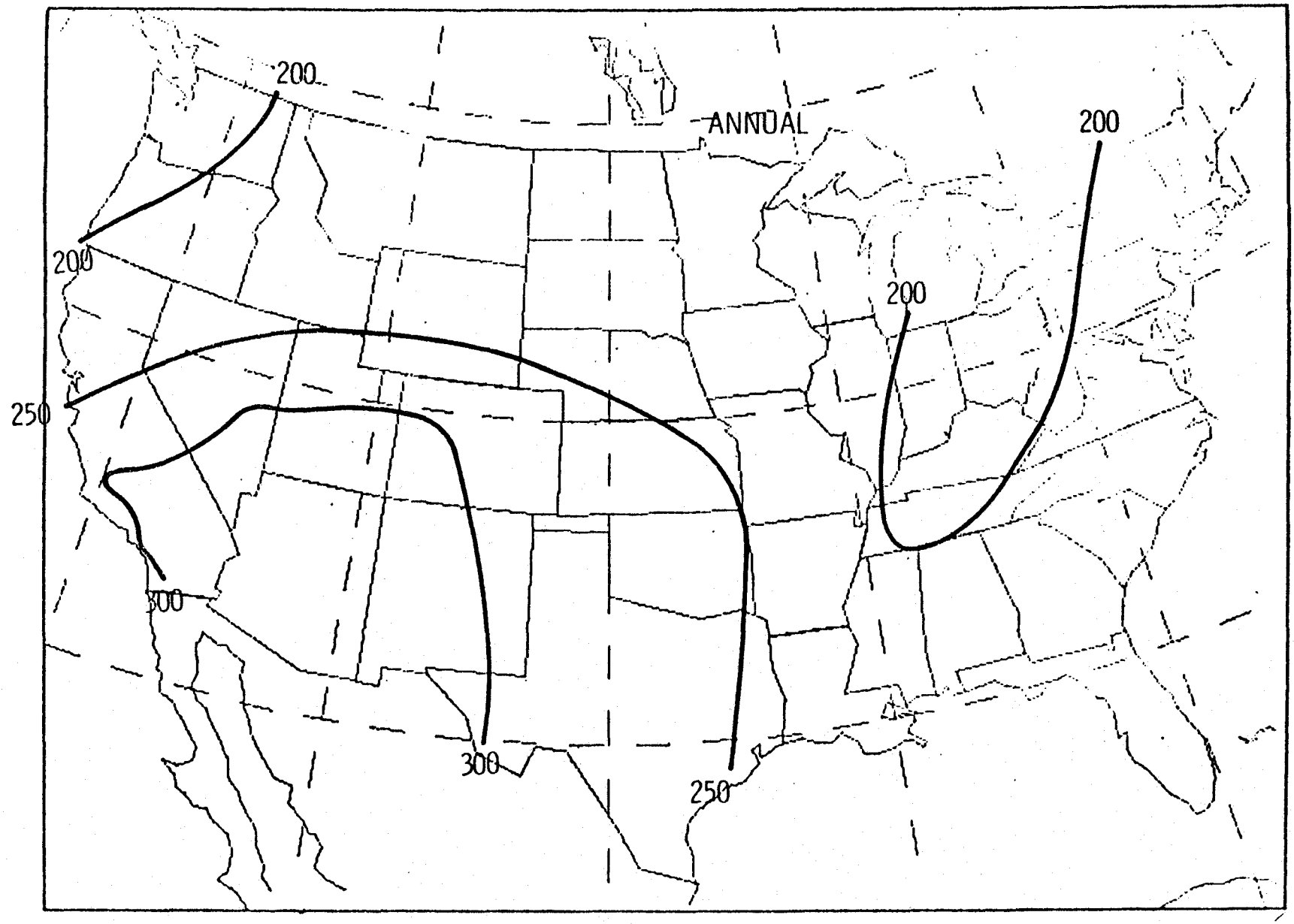


Figure 3-7. Cases of Direct Insolation ≥0.6 kWm^{-2} for Four or More Hours

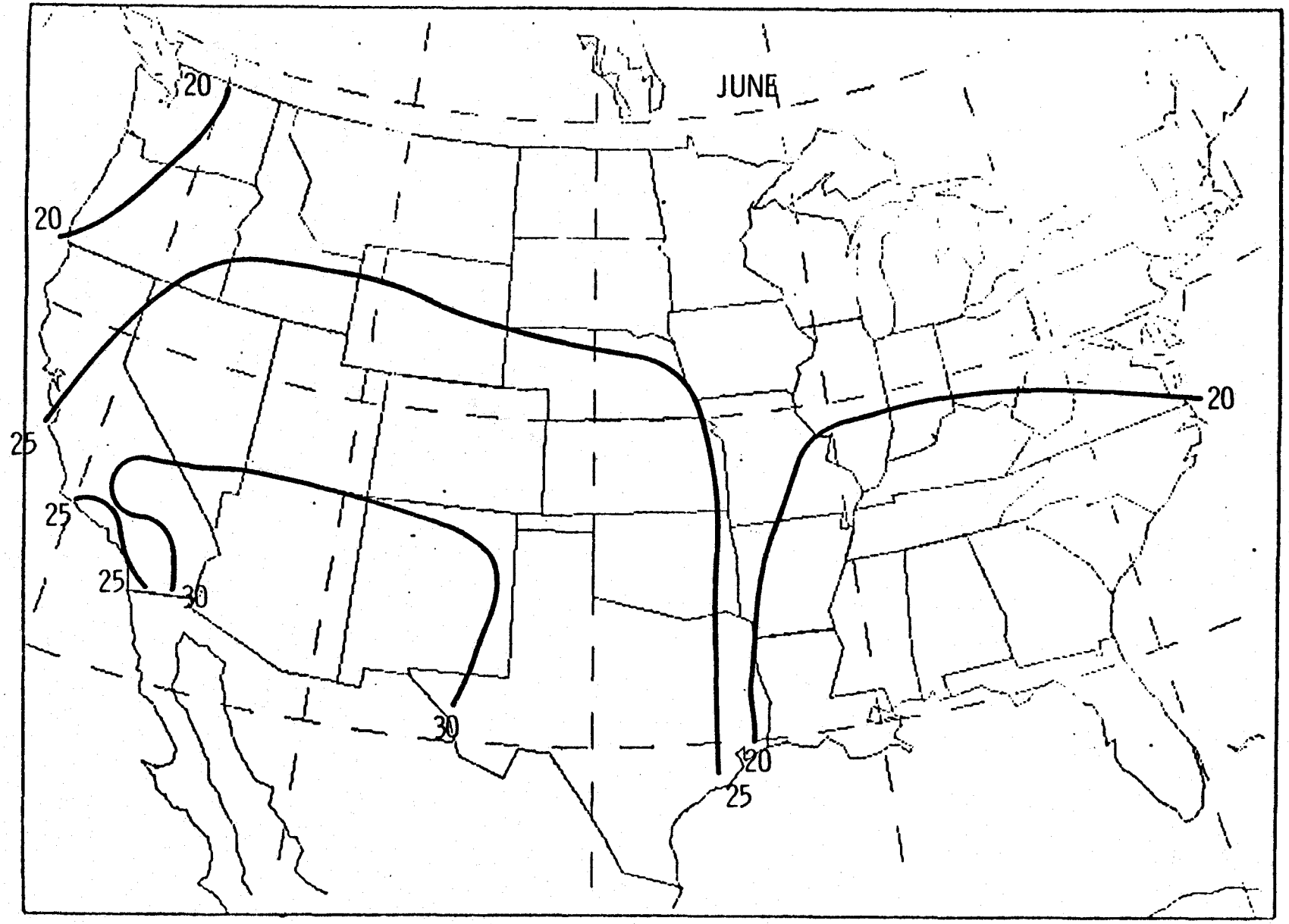


Figure 3-8. Cases of Direct Insolation ≥0.6 kWm^{-2} for Four or More Hours

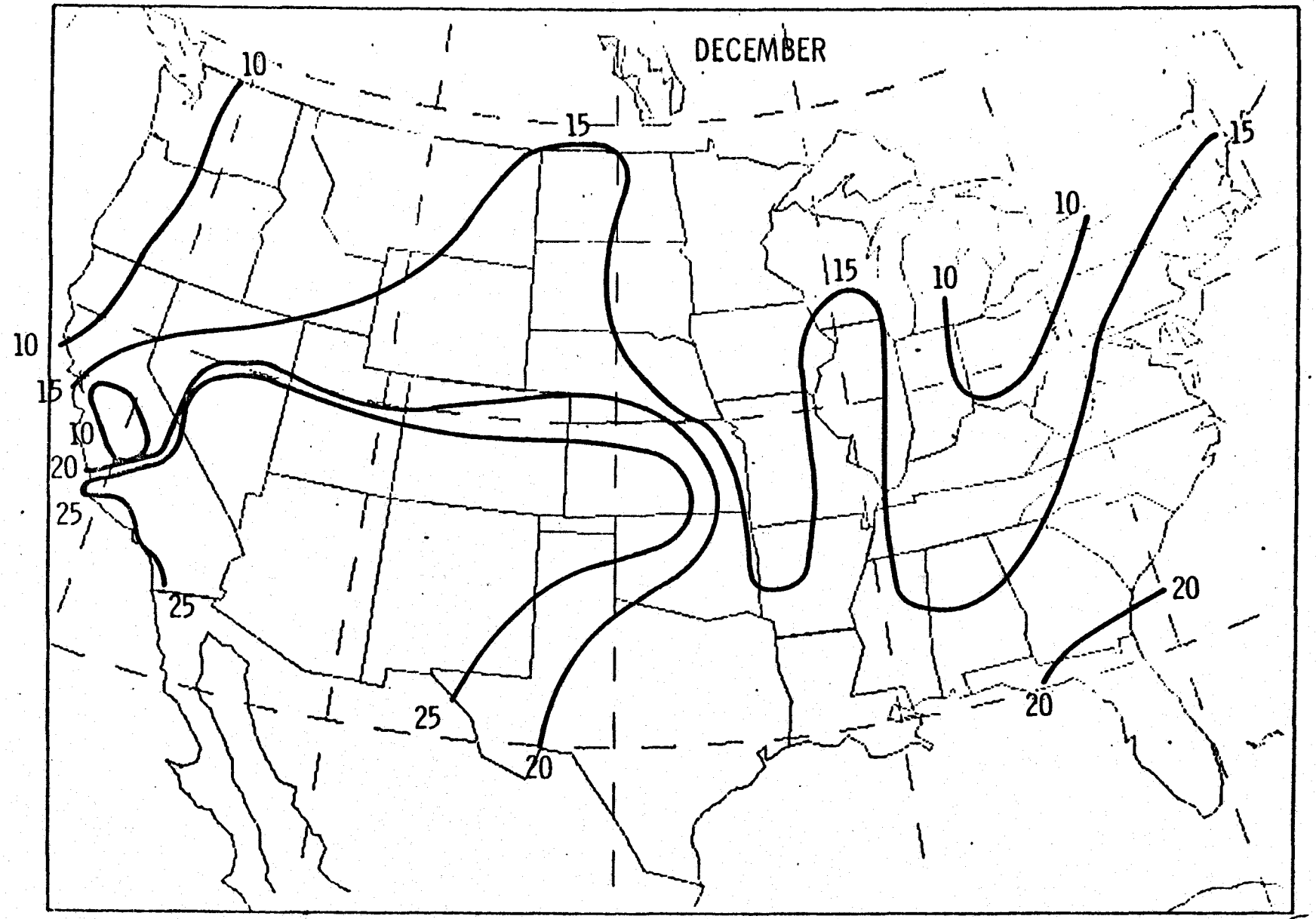


Figure 3-9. Cases of Direct Insolation ≥0.6 kWm^{-2} for Four or More Hours

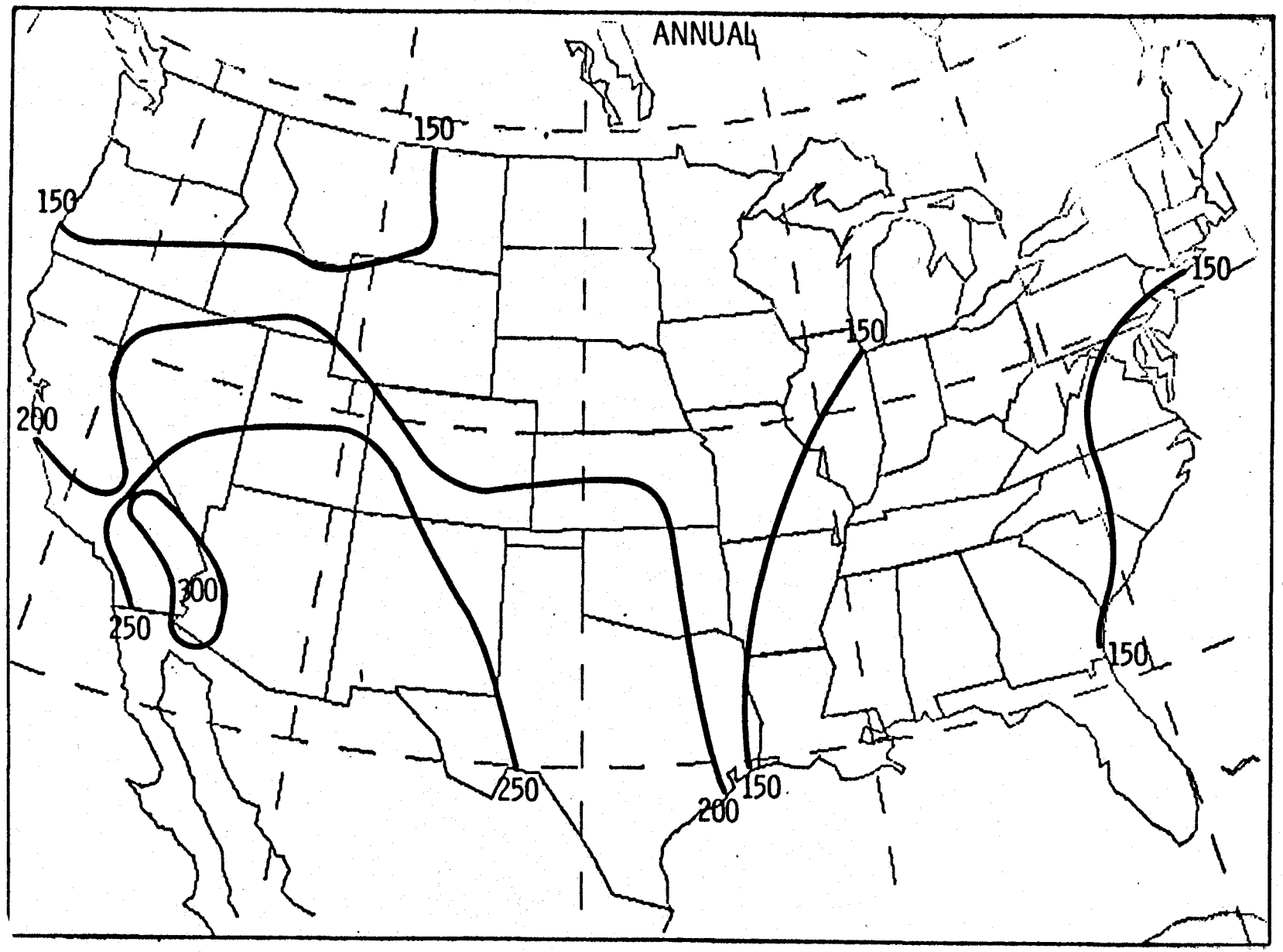


Figure 3-10. Cases of Direct Insolation ≥0.7 kWm^{-2} for Five or More Hours

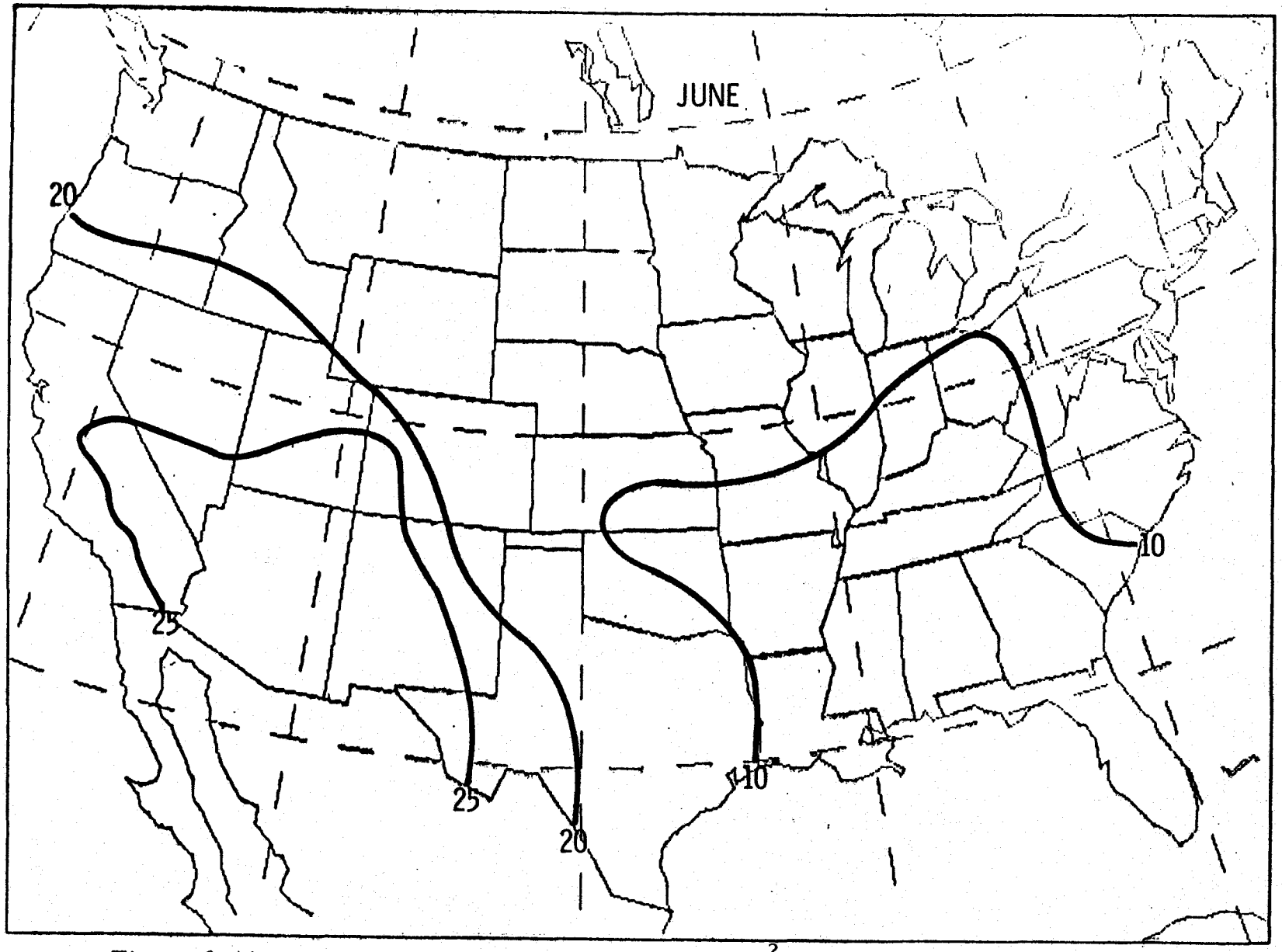


Figure 3-11. Cases of Direct Insolation ≥0.7 kWm^{-2} for Five or More Hours

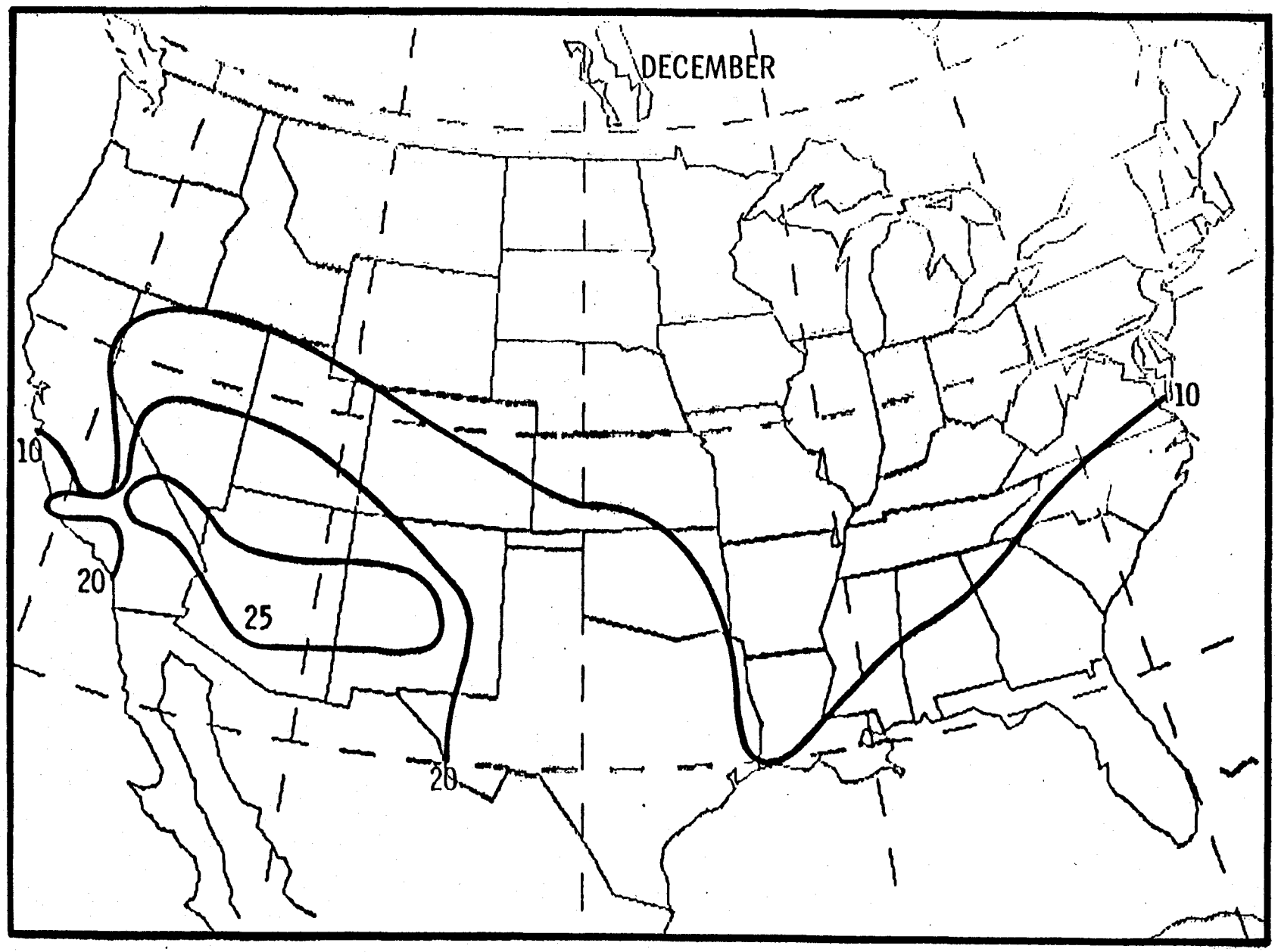


Figure 3-12. Cases of Direct Insolation ≥ 0.7 kWm^{-2} for Five or More Hours

4. DISCUSSION

Based on the direct-normal insolation data presented here, the southwestern United States, consisting of western Texas, New Mexico, Arizona, southwestern Colorado, and the southern portion of Utah, Nevada and interior California are the most attractive regions for solar energy applications. This is particularly true for those applications requiring uninterrupted direct-normal insolation for several hours, as indicated by the persistence data.

In the Southeast there appears to be relatively less difference between summer and winter, with more cases of sustained sunshine during the winter than the summer at Miami and Charleston. This is consistent with the weather patterns for the Southeast, which result in tropical rainy weather in the summer and relatively drier weather in the winter.

Note that, during December while the southwestern region defined above had more than 20 occurrences of five hours or longer, the entire northern half of the country and most of the Mississippi Valley extending to the Gulf of Mexico had less than 10 occurrences.

While the comparisons presented here are valuable because they are based on an internally consistent direct-normal estimating procedure, the limitations should also be remembered when applying the results. First, the direct-normal values are all estimated. Second, the estimating procedures do not reproduce short-term fluctuations in the data. This becomes particularly evident when higher insolation values, such as 0.8 kWm^{-2}, are studied. The results are not included here however because of the bias introduced by the estimating procedure. Third, only two years of data are available in a form suitable for this analysis. While studies of the southwestern United States (Reference 9) indicate 1962 and 1963 were not unusual in terms of long-term climatology, that conclusion may not be valid for the entire country. Clearly, a data base covering a longer time period would

be preferable. Finally the geographic resolution is very low. In drawing isopleths, large known features, such as the Rocky Mountains, were considered to some extent but great detail is not available from the data. For this reason it must be remembered that some locations in the Southwest will not be as good as the values indicated for this region on the maps.

D. CLOUD SHADOWING

1. Introduction

This section summarizes work performed in the study relative to the transient behavior of a central receiver solar collector due to cloud movement across the field of collecting mirrors. Computer software has been developed which simulates various cloud models and calculates the effects of cloud motion on the energy output of a specific central receiver model. A FORTRAN coded computer program (CLDSIM) is used to compute the redirected power level as a function of time and determine probability statistics of the rate of change of received power. This program has been exercised to provide statistical information on the power levels and rates of change of power level as a function of various parameters such as sky cover, cloud drift velocity, cloud type, and solar elevation. The results of these simulations are presented in Section D. 3.

2. Computer Simulation

The simulation consists of two parts: the formation of cloud shadow and solar collector fields and the simulation of the passage of the cloud shadows across the collector field. The cloud shadow field is rectangular and has a direction of motion parallel to its long dimension. The shape of each cloud shadow within the field is approximated by a rectangle with the appropriate area. The number, area, length and width of the rectangles are computed from cloud statistics and solar elevation. The rectangle was chosen for ease of use within the computer program. This simplification should be sufficiently realistic as long as the cloud statistics are correctly represented. The ratio of cloud length to width is approximately a constant as determined from cloud data (Reference 14). To maintain a rectangular shadow from a rectangular cloud, the width of the shadow is taken to be the same as the width of the cloud, and the length of the shadow is proportional to the cloud length and inversely proportional to the solar elevation. The dependence on solar elevation comes from cloud thickness. The exact relationships are given in Section D. 2. 1.

The analyses and simulations of this study are concerned only with cloud types that produce sharp shadows on the ground. These are assumed to represent worst-case conditions for a collector field. High-altitude clouds move at high velocities but do not produce sharp shadows. Limited extent water clouds with bases generally below 5000 feet cast sharp shadows. These usually fall into three categories:

Type 1: cumulus humilis (fractus)
Type 2: cumulus mediocris (congestus)
Type 3: cumulonimbus calvus

These cloud types will not be discussed here. Details on these clouds and their characteristics may be obtained from Reference 14.

Statistics of cloud sizes, shapes, and spacings were obtained from photographs made of cumulus and cumulonimbus clouds from several U-2 flights across the United States (References 15 through 17). The probability of being in shadow can be estimated from cloud-free lines-of-sight studies (References 18 and 19). This probability has been studied as a function of elevation angle, cloud type, and cloud cover. The probability of a cloud-free line-of-sight may be interpreted as the fractional area of the shadow field not shadowed. Factors from these studies have been combined to formulate the cloud model used for the simulations.

The frequency distribution of cloud sizes in a given total cloud area is shown in Figure 3-13 for three cumuliform cloud types. The percentage of small clouds is greater for Type 1 and least for Type 3. Type 3 cloud formations contain a small percentage of very large clouds. The area of the mirror field for a 100 MW central receiver plant is about 1 km^2. Clouds with areas which are equal to or smaller than the size of the mirror field will produce the largest variations and most rapid rates of change in output energy levels. Therefore, the Type 1 clouds are of greatest importance due to the high frequency of smaller clouds.

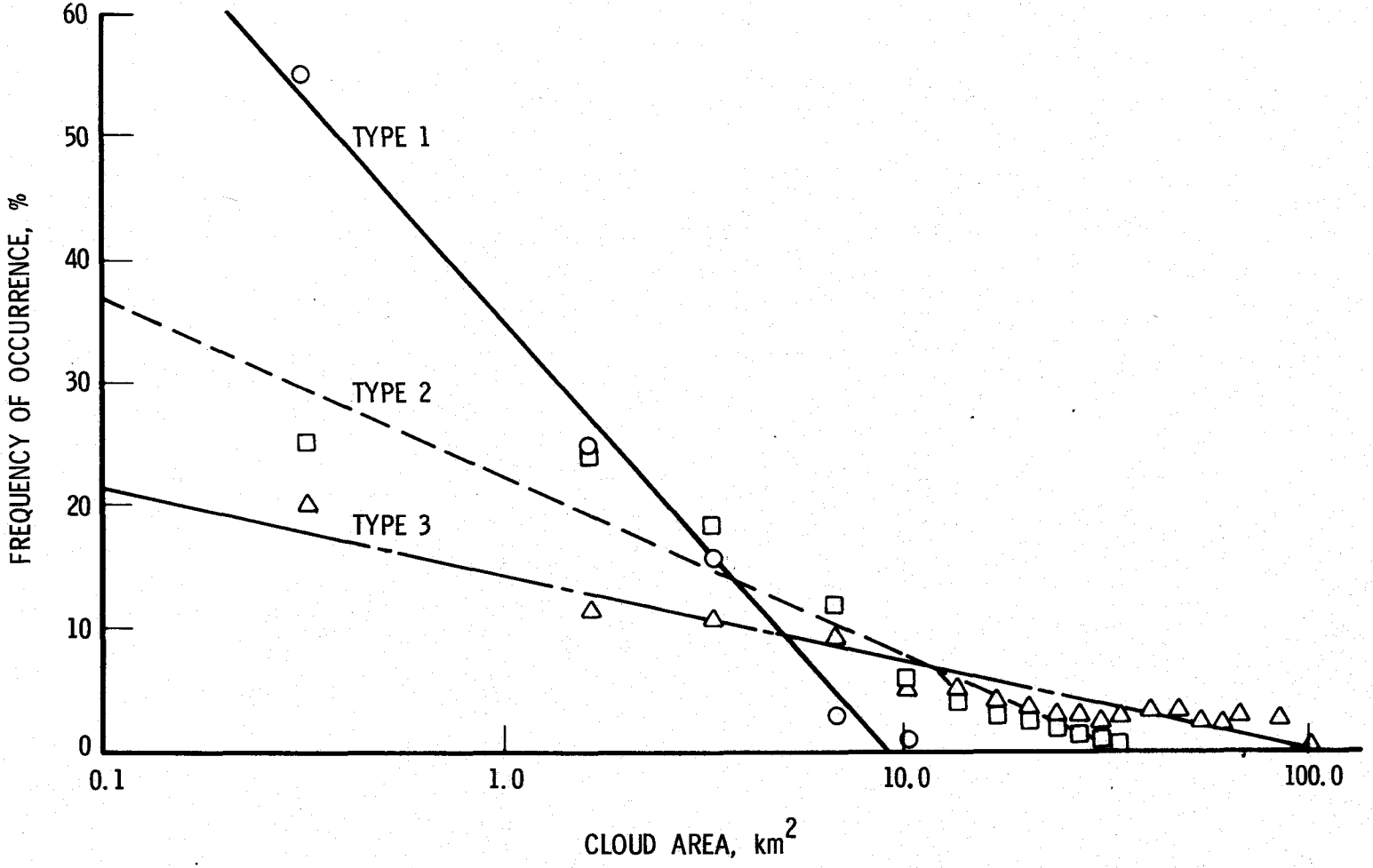


Figure 3-13. Frequencies of Cloud Areas for Three Cumuliform Cloud Types

The mirror field is square and divided into 121 equal cells (Figure 3-14). Each cell consists of several hundred individual heliostats. An average efficiency is given for all of the collectors in a cell. The efficiencies of the cells are symmetric about a north-south line. Due to the southern position of the sun in the sky, the mirrors in the northern end of the collecting field are oriented such that their normals are more nearly in the sun's direction, while those in the southern end of the field are not as aligned with the sun in order to redirect the energy to the receiver. Due to the differences in projection factor, the mirror density is greater in the southern portions of the field and,therefore, the efficiencies of the cells about an east-west line are asymmetric.

The geometric and efficiency characteristics of the central receiver were obtained from detailed simulations (Reference 20) of a model optimized for winter operation. The efficiency as a function of position in the collector field was determined by a detailed modeling of the various losses (i.e., shading, blocking, projection factor) as a function of solar position. It was found possible to represent the collector efficiencies as a function of only solar elevation. The use of these models in the simulation of the transient behavior is described in detail in Section D.2.1.

The geometry of the simulation is shown in Figure 3-14. The shadow field begins at the edge of the collector field and its position is incremented in such a way that the mid point of the cloud grid front moves over the geometric center of the mirror field. If the center of a cell is covered by a cloud shadow, the entire cell is assumed to be in shadow. This is a valid approximation due to the small size of the cells. The efficiency of a covered cell is set to zero. For each time increment, the redirected power P is calculated as:

$$P = \sum_{i=1}^{n} \epsilon_i A_i S = AS \sum_{i=1}^{n} \epsilon_i$$

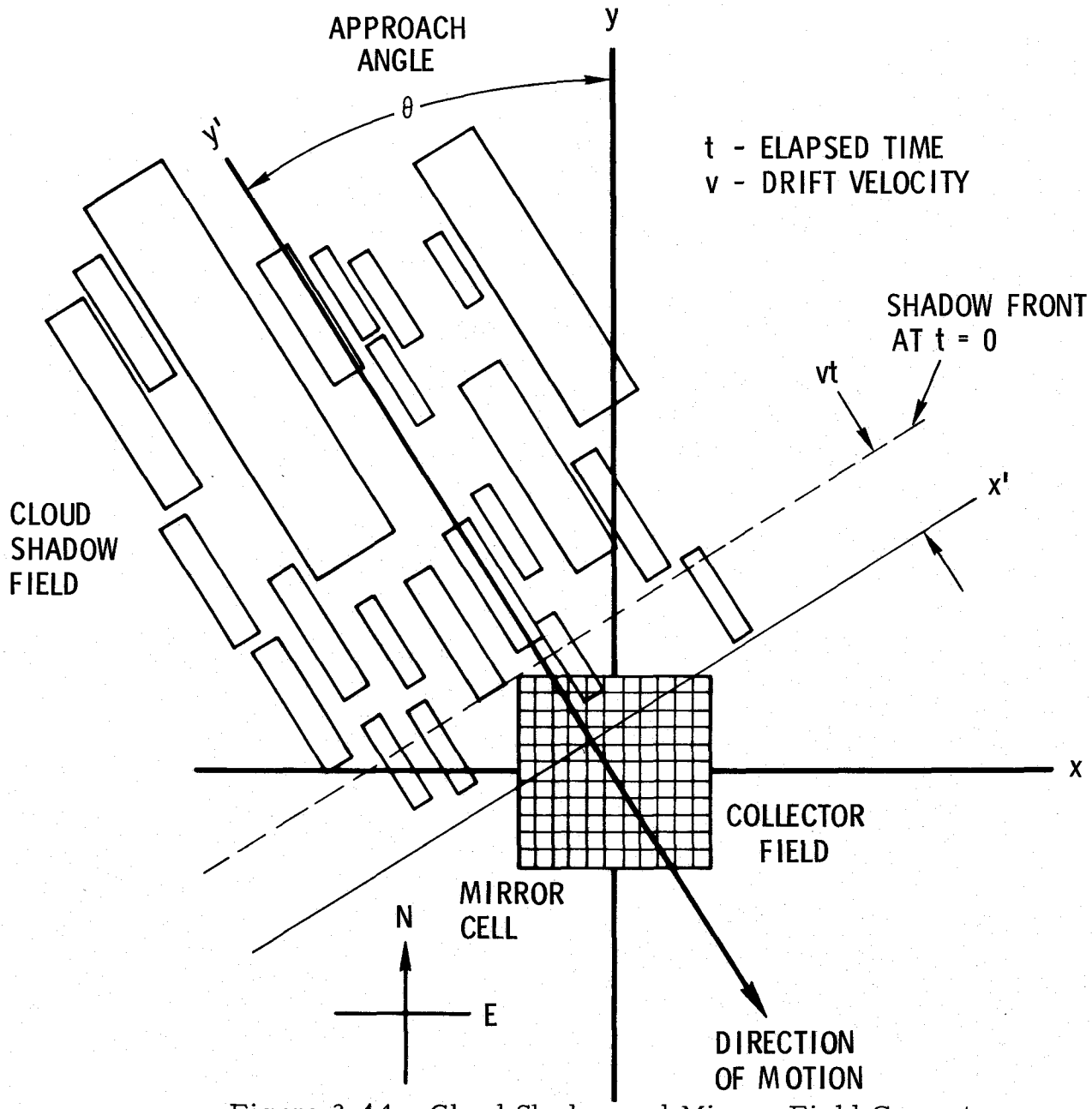


Figure 3-14. Cloud Shadow and Mirror Field Geometry

where

ϵ_i = efficiency of ith cell

A_i = area of ith cell = A (all cells are identical)

S = terrestrial value of solar constant ≈ 1.0 kW/m^2

n = number of cells

The azimuthal approach angle of the cloud field (Figure 3-14) may range from 0-360 deg. The solar elevation may vary from 0-80 deg.

The cloud shadow field position is incremented until the entire field transits the collector field. At this point the simulation is complete and analysis and plotting of the data begins.

a. Cloud Shadow Field Formation

The shadow field is formed utilizing the following data: solar elevation, sky coverage fraction, cloud type, cloud field dimensions, and a set of cloud areas. The cloud areas are a pre-selected set covering the range of possible cloud areas from 0.2 to 35 km^2. This range is compatible with all the cloud types used in the simulations. These areas represent a discrete set necessary for the simulation which approximates the continuous set existing in nature.

The length (L) and width (W) of the clouds are related by

$$W = 0.582\ L$$

The length and width of a shadow are related by

$$W = \frac{0.582\ L}{1 + 0.963 \cot \theta}$$

where θ is the solar elevation.

The lengths and widths of the cloud shadows are computed from the set of cloud areas (A) and are given by

$$W = \sqrt{0.582\ A}$$

$$L = \frac{\sqrt{0.582\ A}}{0.582\ (1 + 0.963\ \cot\theta)}$$

Details and background on these equations are given in Reference 14.

The length and width of the entire shadow field can be input or calculated by the program. If calculated, the program uses a field width wide enough to cover the collector field and adds twice the width of the largest shadow. The length is computed as the longest dimension of the collector field plus twice the length of the longest shadow.

The fractional area of the cloud shadow field which must be in shadow is determined from the field area and the shadow fraction. The shadow fractions are derived from cloud-free line-of-sight studies and are a function of sky cover and solar elevation (Table 3-16).

The number of shadows of each size to be put in the shadow field is derived from the frequency of occurrence in total cloud area (Figure 3-13). The straight line approximations to this data for each cloud type are given by:

Cloud Type 1	$P = 36.144 - 16.256 \ln(A)$
Cloud Type 2	$P = 22.605 - 6.363 \ln(A)$
Cloud Type 3	$P = 14.277 - 3.061 \ln(A)$

where P is the percent of the total cloud area to be represented by a cloud of area A, where A is in square kilometers. P and A are used to calculate the number of shadows of each area to be put in the shadow field. Some errors may occur at this point due to round-off to form an integer number

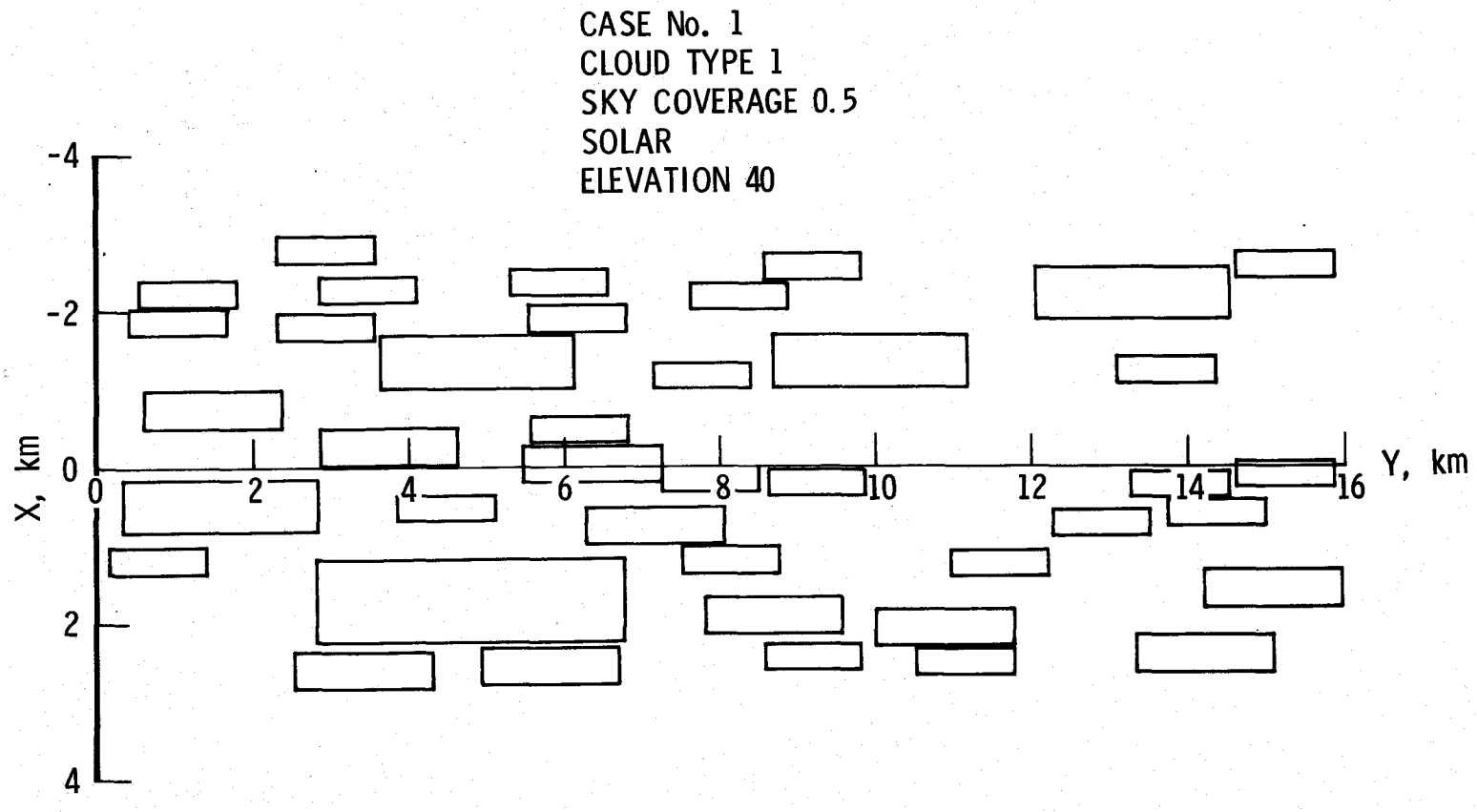


Figure 3-15. Cloud Shadow Field

Table 3-16. Total Fractional Shadow Area for Cumuliform Clouds

SOLAR ELEVATION ANGLE	SKY COVER (tenths)								
	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9
90	0.06	0.12	0.17	0.22	0.26	0.32	0.44	0.59	0.75
80	0.06	0.12	0.17	0.22	0.26	0.33	0.44	0.59	0.75
70	0.06	0.12	0.17	0.22	0.26	0.33	0.45	0.59	0.75
60	0.06	0.12	0.17	0.22	0.27	0.33	0.45	0.61	0.76
50	0.06	0.13	0.17	0.23	0.28	0.34	0.46	0.63	0.78
40	0.07	0.14	0.19	0.25	0.31	0.37	0.50	0.66	0.81
30	0.08	0.16	0.22	0.29	0.35	0.43	0.55	0.71	0.84
20	0.11	0.20	0.27	0.36	0.43	0.50	0.63	0.76	0.88
10	0.15	0.27	0.34	0.46	0.53	0.61	0.72	0.83	0.92

of clouds. The total shadow area is re-calculated using the integer number of clouds and compared to the original total shadow area. If they differ by more than one percent, all shadow areas are uniformly adjusted (multiplied by the ratio of old area to new area) so the total shadow area is unaltered.

The simulation program has now determined the number and sizes of cloud shadows required to comprise a shadow field of the given size which conforms to the specified cloud statistics, solar elevation, and cloud type.

The shadow field is formed by compiling a table of four sets of entries. Each set consists of the coordinates of the boundaries of a cloud shadow. The shadows are randomly placed in the field. The program uses a random number generator to form a set of coordinates for the center of a cloud. The coordinates are evenly distributed over the shadow field region. The boundaries of the shadow are formed and then checked to see if they exceed the boundary of the field or overlap with another previously placed cloud. If overlap occurs, a new set of coordinates is generated until the shadow falls in the field without overlap. If overlap doesn't occur, the coordinates for that shadow's boundaries are placed in the table. The program places shadows in the order of decreasing shadow size to minimize chances that a cloud will not fit in the field. If the program cannot place a shadow after generating coordinates 1000 times, it ignores the shadow. Experience has shown that shadows are always placed without problem until sky coverage fractions of 0.8 or higher are attempted and in this case usually only a few of the smallest shadows have to be omitted. Examples of cloud shadow fields with various sky coverages are given in Figures 3-15 and 3-16.

The shadow boundary table is sorted in the order of increasing coordinate of the shadow's leading edge. This increases the efficiency of the simulation by limiting the extent of searches within the shadow table.

b. Simulation Technique

Input data for the simulation includes the cloud drift velocity, drift direction with respect to the collector field, collector field size, and

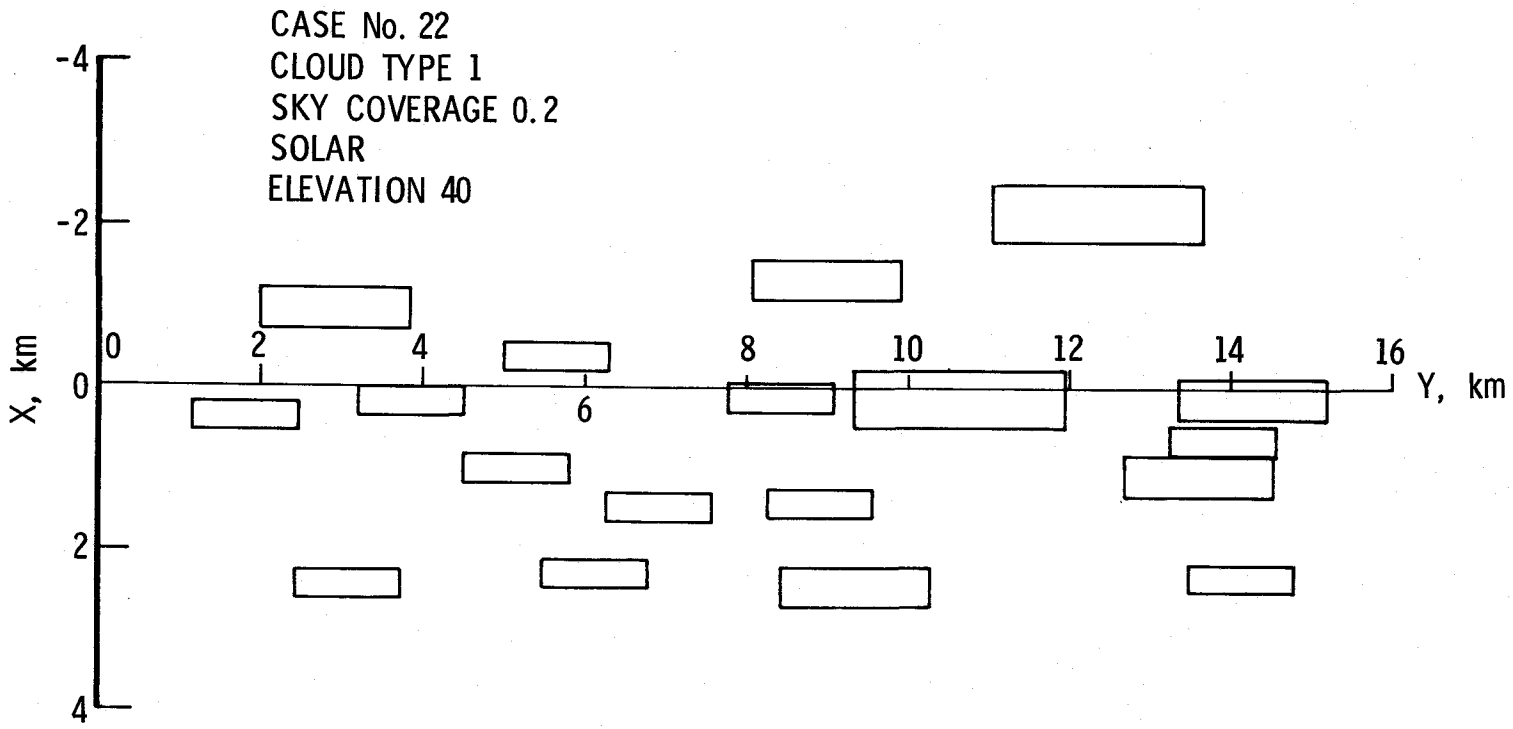


Figure 3-16. Cloud Shadow Field

terrestrial solar constant. The collector cell efficiencies as a function of solar elevation are stored in the program. The simulation requires as input the sorted cloud shadow table prepared in the shadow field formation section of the program.

Using the drift velocity, the program computes the time required for the shadow field to completely traverse the collector field. The position of the shadow field is incremented in time and for each increment, the cells obscured by shadow are determined. The time increment is either input to the program or an optimum value is computed. The optimum value is taken to be the time required for a shadow to move the length of one cell. As shown in Figure 3-14, the shadows lie in the prime coordinate system which moves at a velocity v and angle θ with respect to the collector field coordinate system. For convenience, the y' axis of the shadow always moves through the center of the collector field coordinate system.

At each time increment, the following computations take place. A data array is initialized with the appropriate cell efficiencies for the specified solar elevation and a search of the cells is conducted to determine whether or not the cell is covered by a shadow. It is assumed that a cell is not receiving any power if its center is covered by a shadow. The errors introduced by this can be kept small as long as the cells are small. These errors will be random and should average out. The coordinates of the cell center are converted to the coordinates of the shadow field. The table of shadow boundaries is searched until the cell center is found to lie within a shadow. If this occurs, that cell's efficiency is set to zero. After all cells are searched, the efficiencies are summed and multiplied by the terrestrial solar constant to get the received power for the current time increment. The rate of change of received power is computed by taking the difference between the current value and last value and dividing by the time increment.

After the shadow field has been incremented a sufficient number of times to complete the simulation, the received power and rate of change of power data is analyzed.

c. Data Analysis

Besides developing data on the received power and rate of change of power as a function of time, the program analyzes the power change data to determine the number of times that power changes occurred. For this purpose the power changes have been divided into 25 MW/min intervals. Experience has shown that for most cases this is a reasonable value. The power change data are searched to count the number of occurrences during the simulation of power changes falling in each 25 MW/min interval. These can be plotted as percent of occurrence as a function of power change. These data are used in the statistics routine described in the next paragraph.

Since the placement of cloud shadows is random, it is sometimes necessary to repeat simulations until mean values with meaningful standard deviations are developed for the data. Thus, the program has a routine which will cause it to re-form the shadow field and re-run the simulation any number of times. The mean and standard deviation are computed from these simulations. Thus, it is possible to develop data on the variations which may occur due to cloud placement. For example, in the results given in another section of this report a data point for 0.3 sky coverage means that a 0.3 sky was reformed and passed over the collector field 15 times, and the result shown is the mean value and its standard deviation. The mean maximum rate of change of power, and the mean percent of occurrence of power change found for each 25 MW/min interval are also obtained from this routine.

When statistics data are requested, the program goes through the first case in the usual fashion, and then it repeats only shadow placement and simulation for the required number of times. When this operation is complete, the means and standard deviations of the data are computed and printed. The program then proceeds to the next case.

d. Program Graphical Output

Optional graphical outputs for the program consist of CALCOMP plots of any of the following data for each case:

a. The cloud shadow field
b. Received power vs time
c. Power change vs time
d. Percent of occurrences as a function of power change.

Examples of these plots are shown in Figures 3-15 to 3-19.

e. Program Options

The following options are available when running the program:

a. Use of the same shadow field

The program can re-use the same shadow field for the next case. This eliminates shadow placement variations when examining the effects of drift velocity and direction.

b. Print options

The program will print the efficiency array of the collector cells during simulation.

c. Scaling option

For easy comparison of graphical output, the same plotting scales can be used for several cases.

d. Statistics option

The program repeats shadow field formation and simulation a requested number of times and prints out the mean and standard deviation of maximum rate of power change and percent of occurrence as a function of power change.

f. Simulation Input Data

In order to develop data on the probability of power changes and maximum power changes as a function of solar elevation, sky coverage fraction, cloud drift velocity, and cloud type, typical values were adopted for these parameters as well as ranges for which they would be studied. Whenever the effects of a particular parameter are being investigated, all

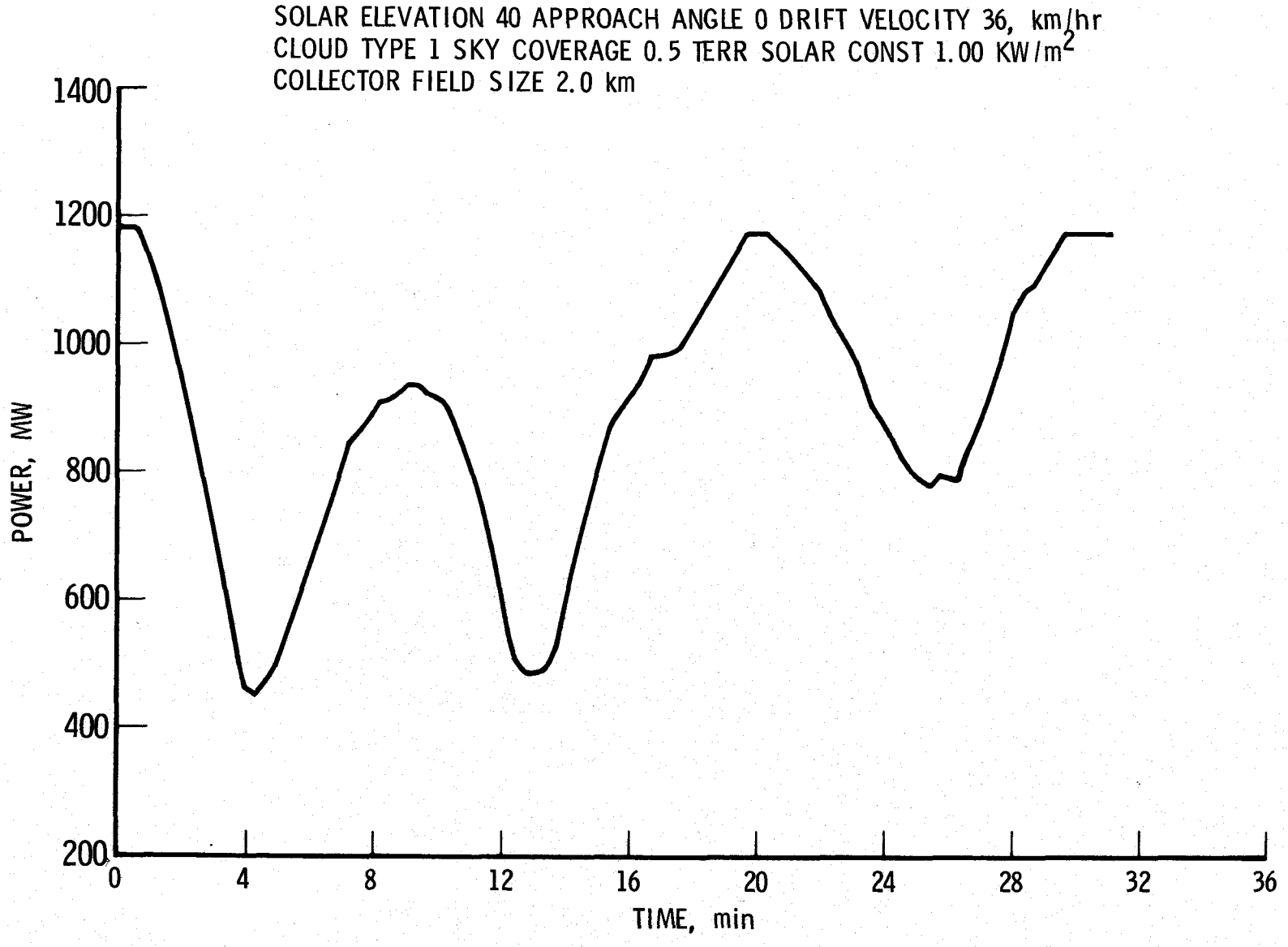


Figure 3-17. Power Curve

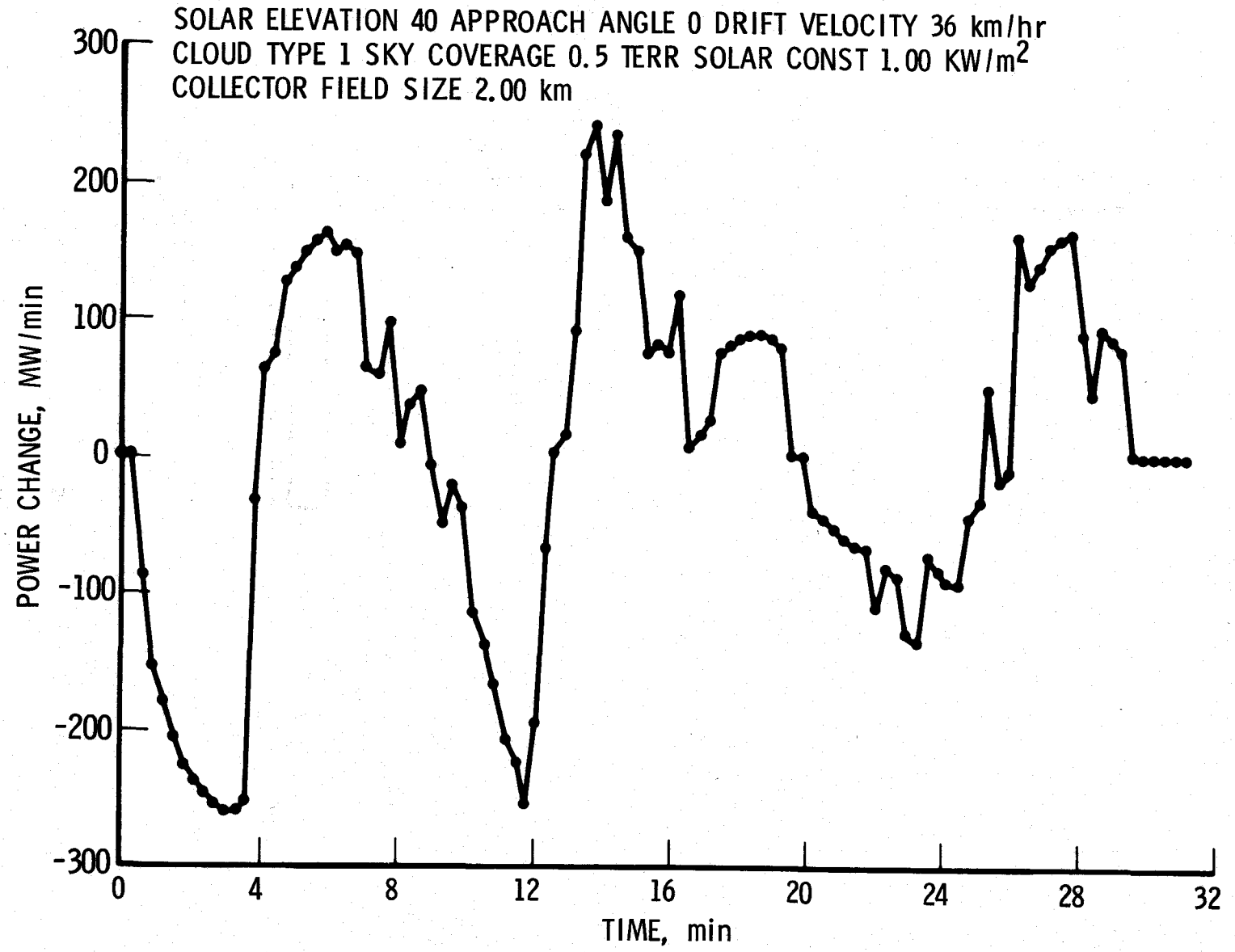


Figure 3-18. Power Change Curve

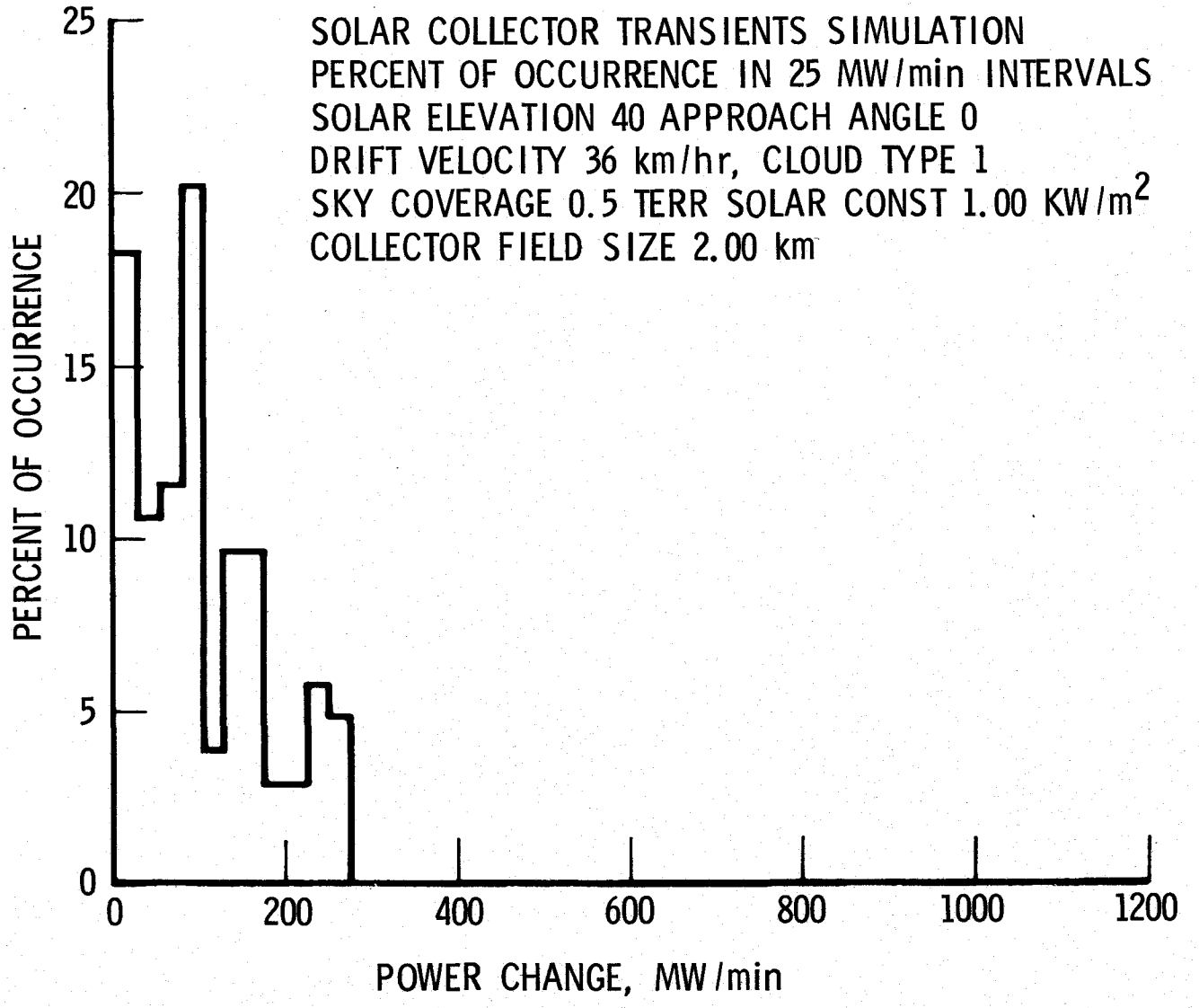


Figure 3-19. Percent of Occurrence Curve

other parameters are held at typical values. No attempt has been made to select values applicable to specific solar-collector sites or take into account probabilities of occurrence of given conditions. The range of values used here should be sufficient to cover most site conditions. However, only a limited number of values within the ranges have been investigated. These are discussed below.

Solar Elevation

Solar elevation was varied from 20 to 80 deg in 20 deg increments; 40 deg was taken as a typical value.

Sky Coverage Fraction

Cloud shadow fields were generated with sky coverages from 0.1 to 0.8 with 0.5 taken as a typical value. Due to the algorithms used in forming the placement of the clouds, it is more difficult to form cloud shadow fields with sky covers greater than 0.9 and also requires greater amounts of computer time.

Drift Velocity

Two sources of data were examined for information on moving velocity of clouds with bases around 5000 ft. One study reported data on wind velocities at White Sands, N. M. (Reference 21), and the other examined cloud drift velocities at Sapporo, Japan (Reference 22). For the purposes of this report, the wind velocities were assumed to represent probable cloud drift velocities. These sources led to the selection of 36 km/hr as an average expected velocity with 18 and 54 km/hr as the minimum and maximum expected velocities.

Cloud Type

There are only three types of clouds which are expected to cast sharp shadows. The program can form shadow fields for all three. Most runs were done with Type 1 clouds which have a greater number of small clouds and are thought to represent a worst case.

Solar Collector Cell Efficiencies

The efficiencies incorporated in the simulation are from a specific model of a collector field optimized for winter operation. They arise from detailed modeling of various loss factors. As new data become available or other models are developed, these may be easily incorporated into the simulations.

Terrestrial Solar Constant

A typical value of 1.0 kW/m^2 was used for all simulations.

Solar Collector Field Size

All of the data in this study are for a collector field 2 km on a side, 4 km in area. This size was chosen to obtain data for a field as large as possible with respect to the cloud formation. This minimizes the variations which can occur due to random cloud placement thus reducing the number of runs required to get good statistical data.

3. Results

Probability statistics of the rate of change of power with those parameters which characterize the geometry and dynamics of the cloud model were developed. The parameters included:

a. Sky cover
b. Cloud type
c. Cloud velocity
d. Solar elevation.

Two functional relationships were determined which best illustrate the dependence of the rate of change of power on these parameters:

a. Maximum rate of change of power (MRCP) vs parameter
b. Percent probability of occurrence vs rate of change of power as a function of the parameter (PRCP).

Due to the finite sample considered (15 cases), the standard deviation was calculated in all cases. However, a larger sample should not substantially alter the results.

a. Maximum Rate of Change of Power (MRCP)

The MRCP varies from 130 to 350 MW/min for sky covers of 0.1 to 0.8, respectively (Figure 3-20). The standard deviations are shown as vertical bars about each average. There is little change in MRCP for sky covers of 0.3-0.6. Sky covers greater than 0.8 are difficult to simulate. As explained in Section D.2, a sky cover equal to 1.0 would be analogous to a single cloud whose dimensions exceeded that of the collector field. The MRCP is also dependent on the collector efficiencies and angle of approach of the cloud front. These dependencies were not investigated in this analysis.

The MRCP is essentially independent of the cloud type as shown in Figure 3-21. It ranges from 250 to 295 MW/min for cloud Types 1 and 3, respectively.

The MRCP is linearly dependent on cloud velocity. The velocity range investigated was 18 to 54 km/hr; the average value was 36 km/hr. The MRCP ranges from 130 to 390 MW/min for this velocity range, as shown in Figure 3-22.

The dependence of the MRCP on solar elevation is minor and approximately monotonic. It ranges from 220 to 295 MW/min for solar elevations of 20 to 80 deg, respectively (Figure 3-23).

b. Probability of Rate of Change of Power

The probability of occurrence of rate of change of power (PRCP) for various sky covers shows significant variations at small values of rates of change of power (Figure 3-24). The 0.1 sky cover example shows a very high PRCP at 25 MW/min, but it decreases more rapidly than for larger values of sky cover. There is an initial plateau of the PRCP of about

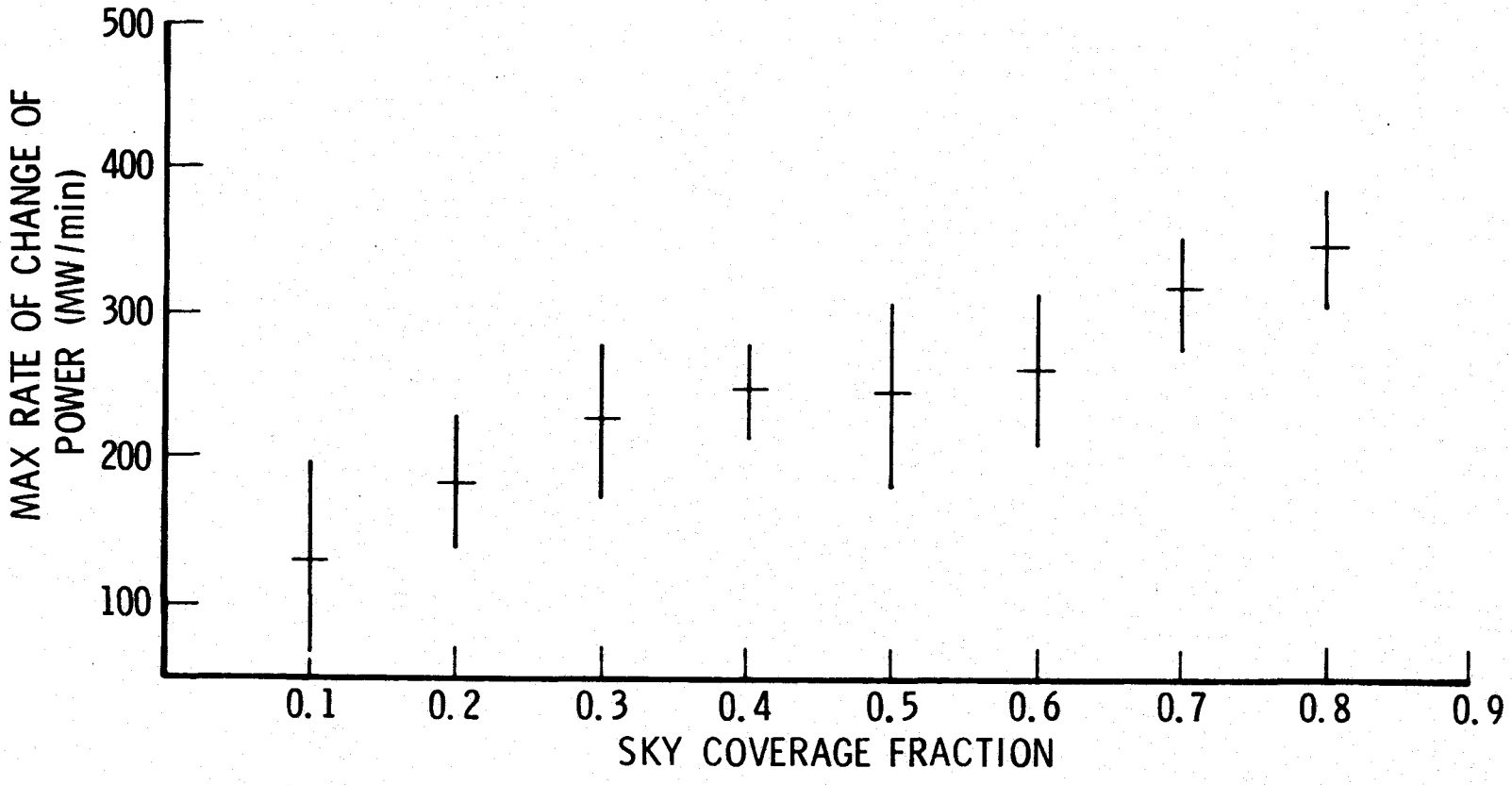


Figure 3-20. Maximum Power Change vs Sky Cover

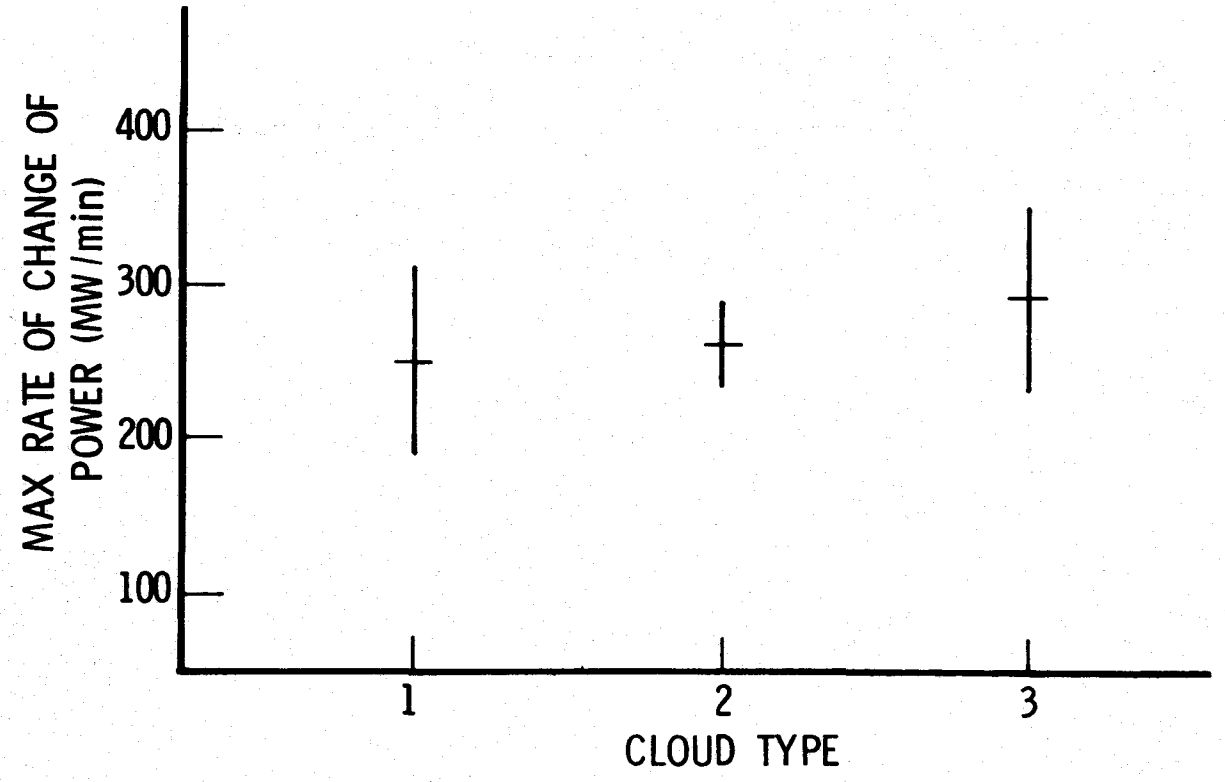


Figure 3-21. Maximum Power Change vs Cloud Type

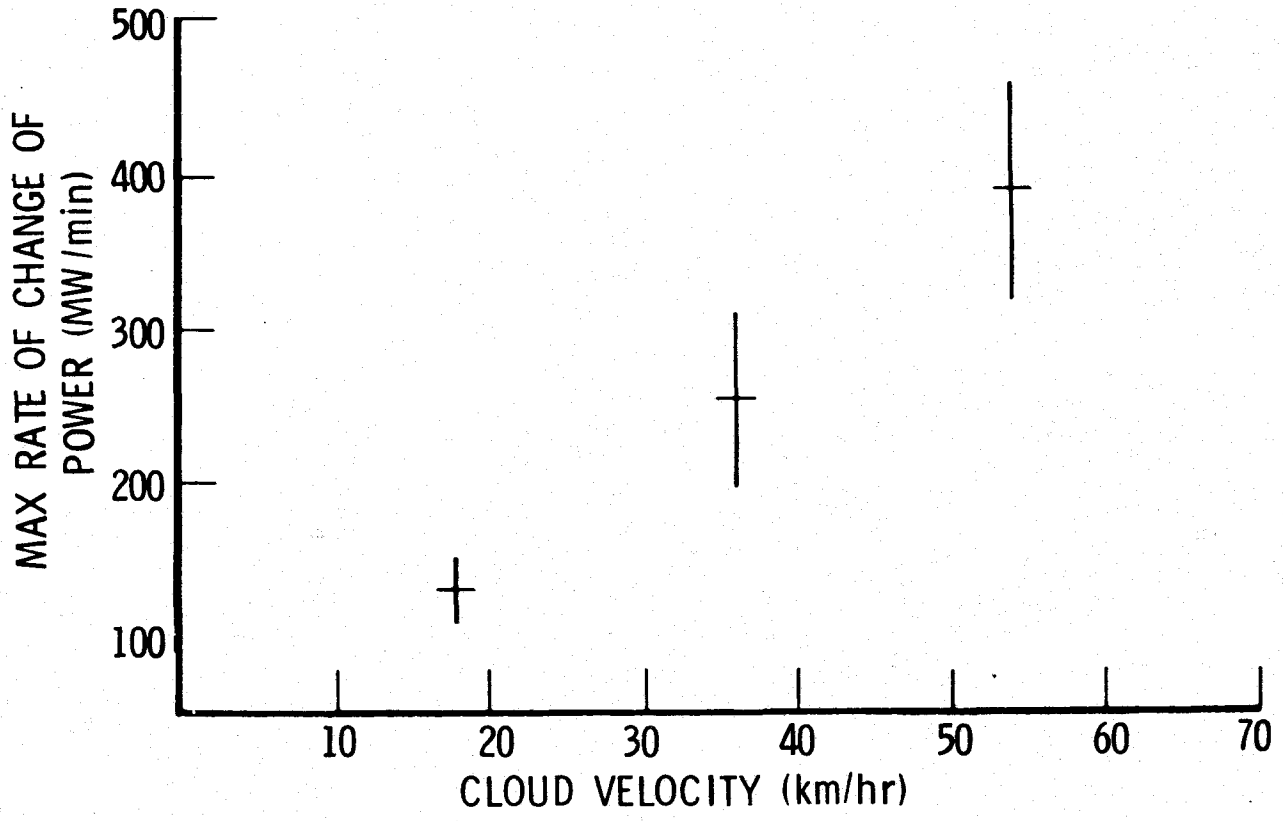


Figure 3-22. Maximum Power Change vs Cloud Velocity

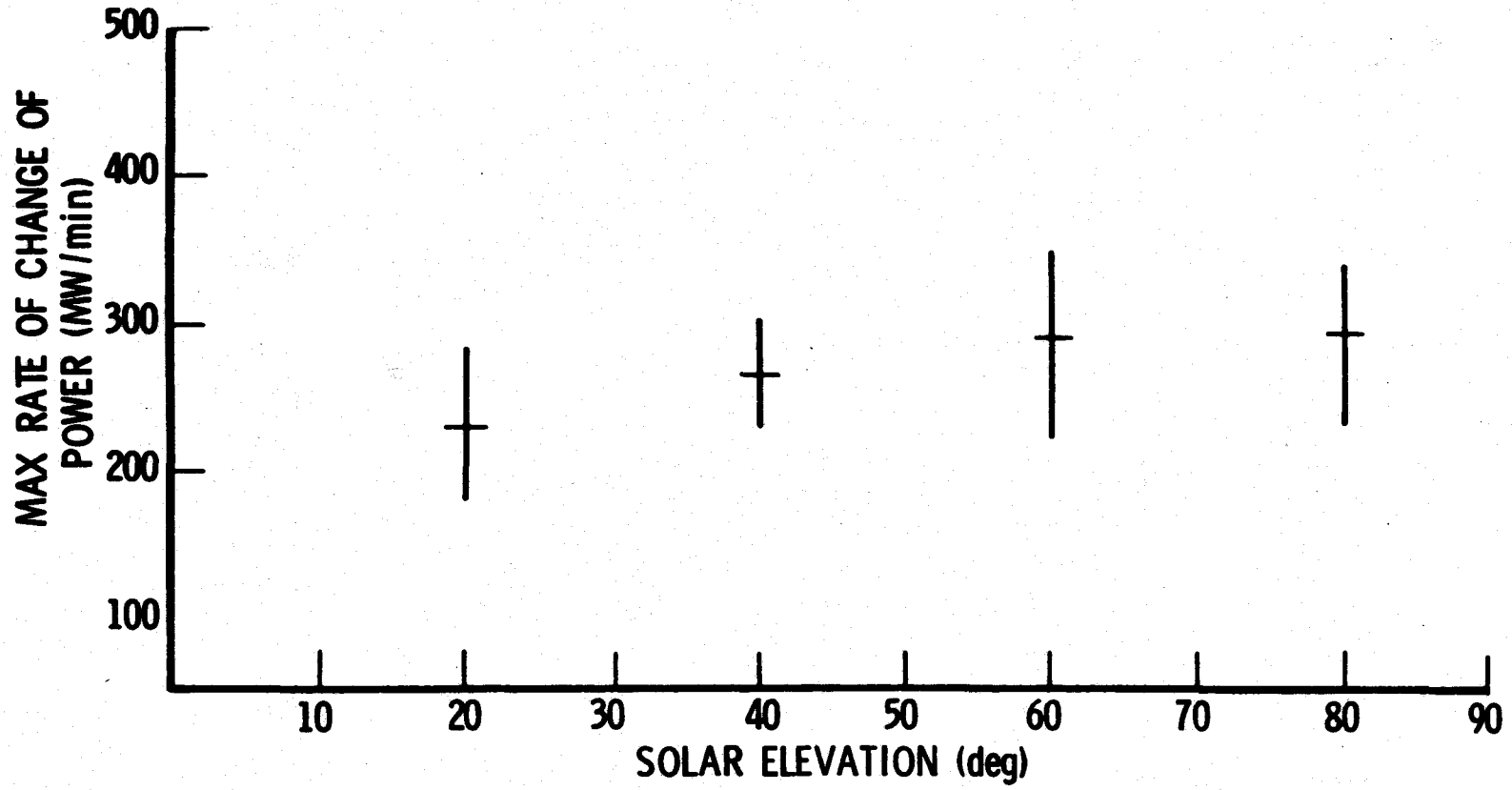


Figure 3-23. Maximum Power Change vs Solar Elevation

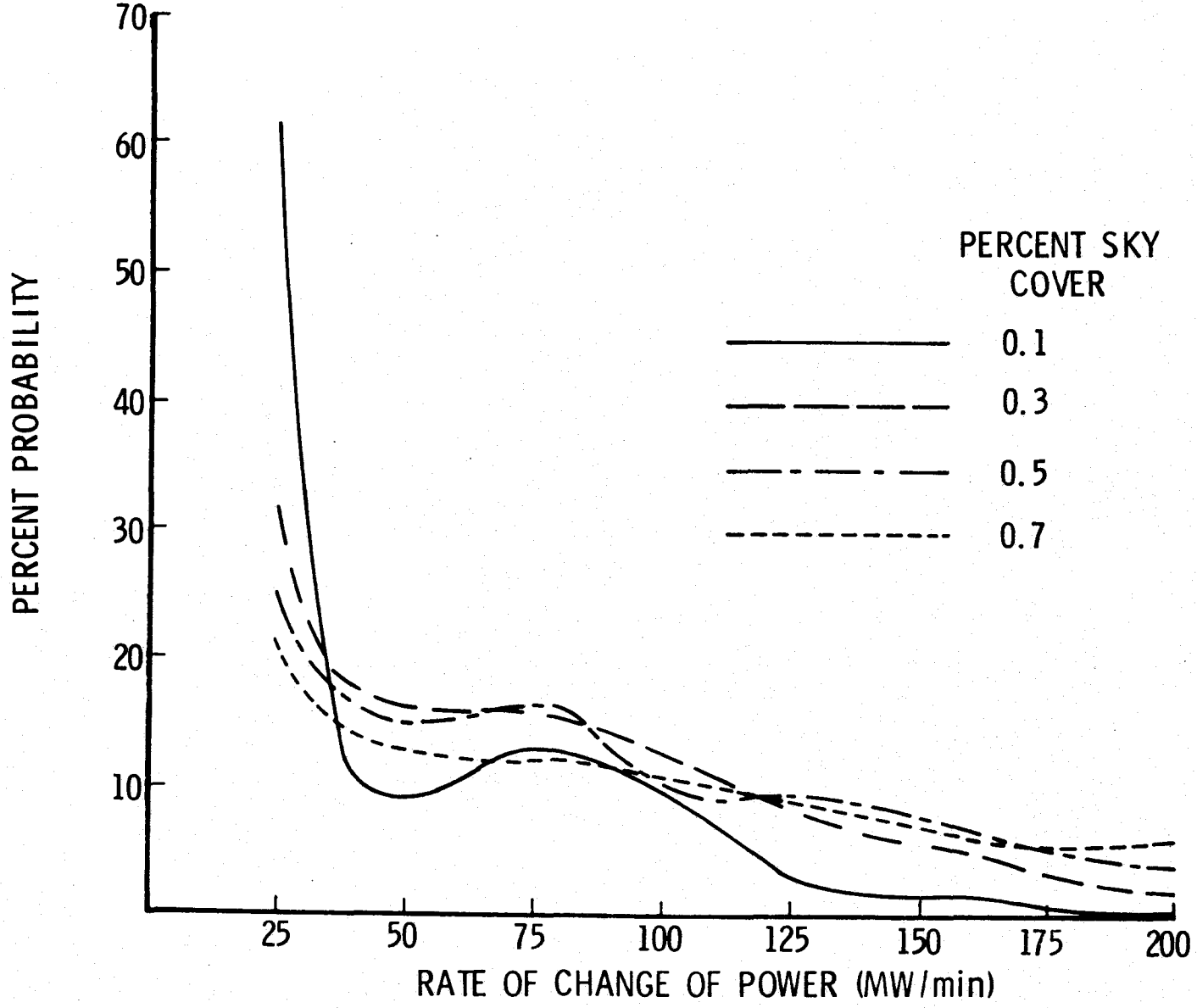


Figure 3-24. Probability of Occurrence of Rate of Change of Power vs Sky Cover

15 percent in the 50 to 100 MW/min range. It then falls steadily to values of 5 percent or less near 200 MW/min.

There is no significant dependence of the PRCP on cloud type (Figure 3-25). The relationship is monotonically decreasing from 25 percent to 5 percent over a range of 25 to 200 MW/min.

The PRCP is highly dependent on cloud velocity as shown in Figure 3-26. The lower velocities (18 km/hr) have high PRCP's (35 to 15 percent) at 25 to 75 MW/min which rapidly fall to zero near 150 MW/min. The PRCP of the higher cloud velocities (54 km/hr) is more nearly uniform at 10 percent decreasing to 5 percent at 200 MW/min. The expected higher PRCP at the higher velocities is clearly evident due to the rapid obscuration of collector cells.

There is little dependence of the PRCP on solar elevation (Figure 3-27). The relationship is nearly linear decreasing from 25 to 5 percent over the range 25 to 200 MW/min.

A summary of the standard deviations associated with each of the PRCP calculations is presented in Table 3-17. The standard deviations for the MRCP calculations are included on their respective graphs. Since the deviations represent cloud placement variations, it appears that no significant improvement of the relationships would be obtained by processing larger numbers of samples.

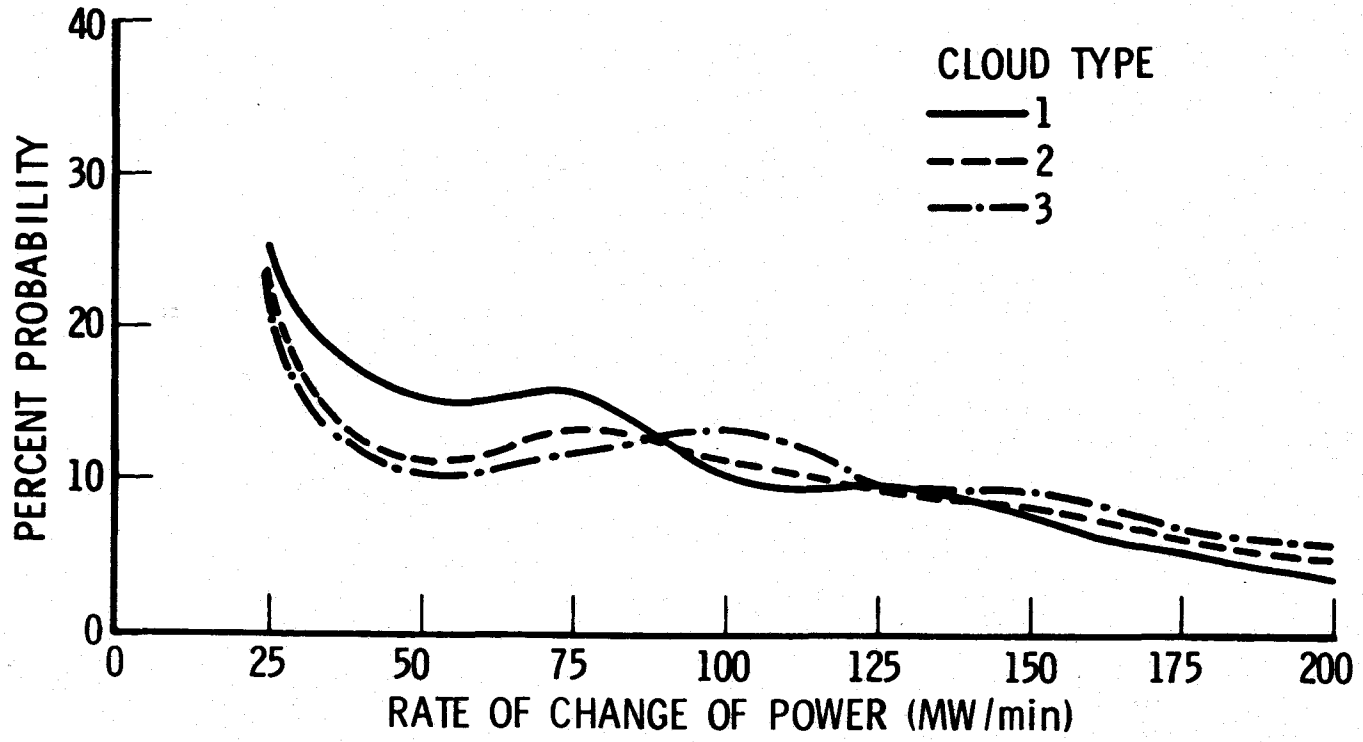


Figure 3-25. Probability of Occurrence of Rate of Change of Power vs Cloud Type

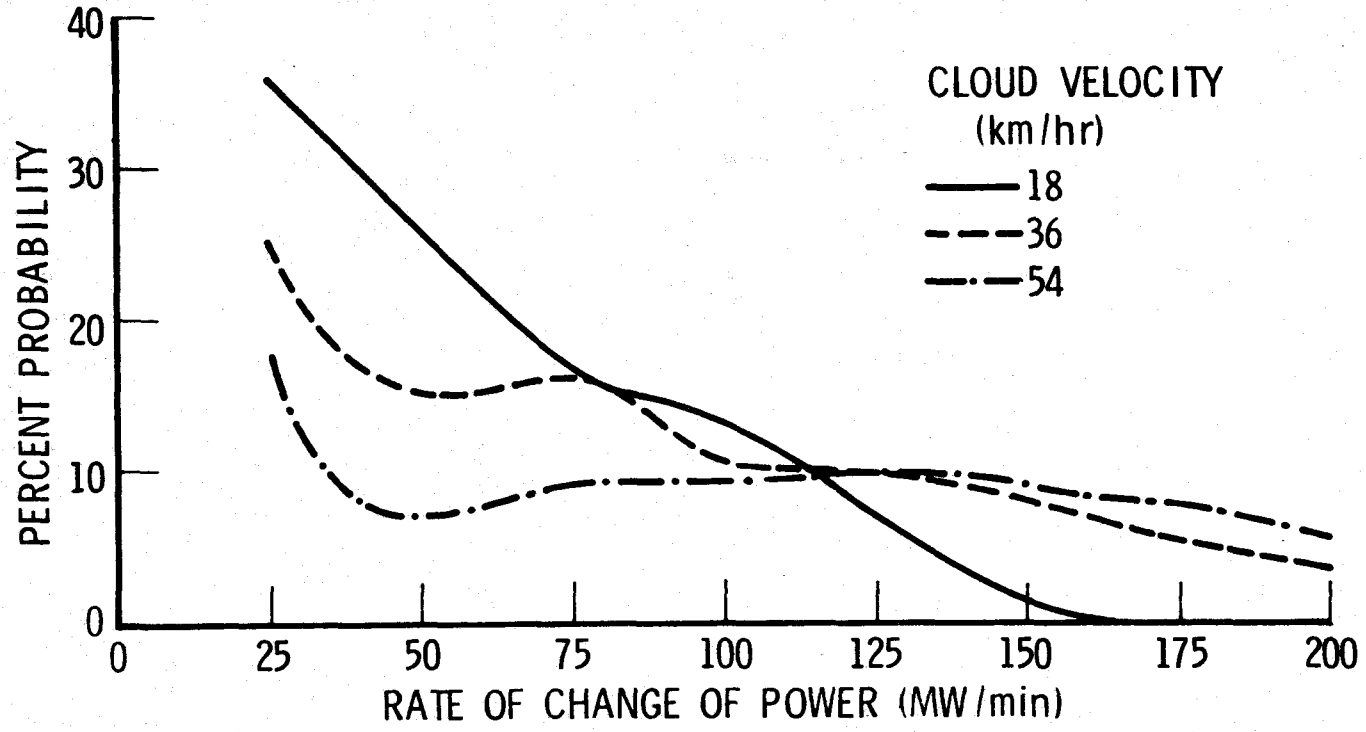


Figure 3-26. Probability of Occurrence of Rate of Change of Power vs Cloud Velocity

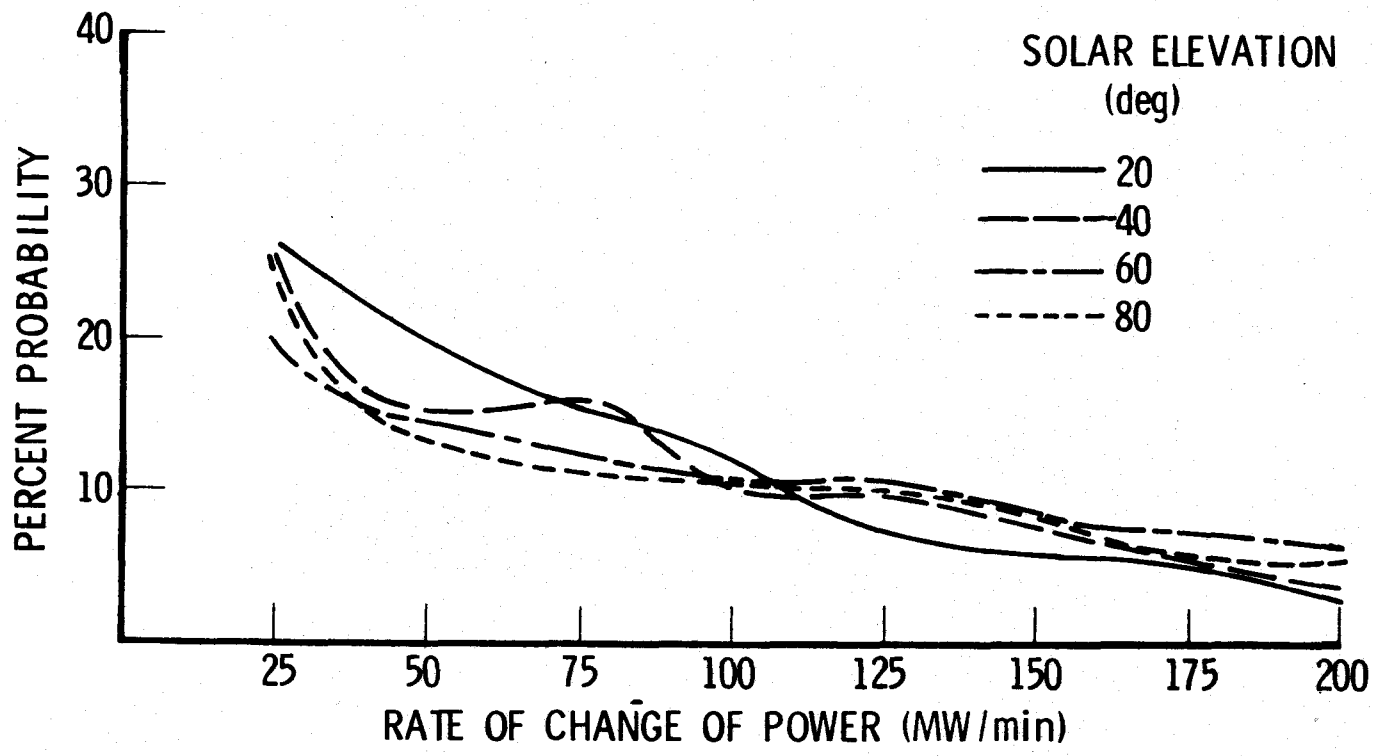


Figure 3-27. Probability of Occurrence of Rate of Change of Power vs Solar Elevation

Table 3-17. Probability of Rate of Change of Power (PRCP)

Cloud Velocity

Parameter (km/hr)	PRCP ± Standard Deviation
18	36 ± 6 / 26 ± 6 / 16 ± 7 / 13 ± 3 /
36	25 ± 6 / 15 ± 5 / 16 ± 6 / 10 ± 3 /
54	18 ± 4 / 7 ± 4 / 9 ± 4 / 9 ± 5 /

Solar Elevation

Parameter (deg)	PRCP ± Standard Deviation
20	26 ± 8 / 20 ± 7 / 15 ± 6 / 12 ± 7 /
40	25 ± 6 / 15 ± 5 / 16 ± 6 / 10 ± 3 /
60	20 ± 6 / 15 ± 4 / 12 ± 5 / 10 ± 3 /
80	24 ± 6 / 13 ± 4 / 12 ± 5 / 12 ± 3 /

Cloud Cover

Parameter (fraction)	PRCP ± Standard Deviation
0.1	61 ± 16 / 9 ± 7 / 13 ± 8 / 10 ± 6 /
0.3	33 ± 11 / 16 ± 6 / 16 ± 5 / 13 ± 5 /
0.5	25 ± 6 / 15 ± 5 / 16 ± 6 / 10 ± 3 /
0.7	22 ± 5 / 13 ± 5 / 13 ± 4 / 10 ± 5 /

Cloud Type

Parameter	PRCP ± Standard Deviation
1	25 ± 6 / 15 ± 5 / 16 ± 6 / 10 ± 3 /
2	24 ± 4 / 11 ± 4 / 13 ± 5 / 11 ± 4 /
3	23 ± 5 / 10 ± 4 / 12 ± 5 / 14 ± 6 /

Key 25 MW/min/50MW/min/75 MW/min/100 MW/min

IV. CENTRAL POWER SYSTEMS ANALYSIS

A. INTRODUCTION

This section describes the development and use of three computer simulation models employed during the study as tools for assessing the performance and operating economics of solar systems operating in different sections of the U.S. The models were also used for determining the additional capacity margin (backup) required by solar plants at various penetrations to meet conventional standards for network reliability. The first of these models determines plant performance under various operating strategies. It uses as inputs for a one-year period the hourly demand assumed or derived (as in Section II) for a selected electric utility plus the hourly direct normal insolation for some nearby location. Outputs of this model include the solar plant annual capacity factor, based on solar energy delivered within a selected "demand band," and also the solar energy delivered outside this band.

The second computer simulation model is a margin analysis program (MAP) and is described in Subsection C. It computes on a probabilistic basis the additional capacity margin required when solar plants are substituted for conventional (fossil) plants in a utility network. Assumptions are made in this model as to the forced outage rates to be expected for both solar and conventional plants and the required scheduled maintenance periods.

The outputs of the margin analysis program and the performance analysis program are inputs to a third computer simulation model, the public utility financial analysis planning program (PUFAP). This model, developed using internal (corporate)funds, calculates in an extremely detailed way the yearly operating costs and associated cash flows for a utility plant, either conventional or solar. PUFAP has recently supplanted both the power plant economic model (PPEM) used in earlier studies (Refs. 1 and 4) and the ERDA/EPRI levelized fixed charge model described in Ref. 8 for calculating

and comparing costs of service for various electric plant configurations and operating conditions. A description of PUFAP and comparisons of solar and conventional plant service costs based on PUFAP, PPEM, and the ERDA/EPRI model are presented in Subsection D of this report.

B. PERFORMANCE SIMULATION MODELING

The modifications recently made to the performance simulation model provided the basis for the solar plant performance projections presented in Ref. 6 for the Southwestern U.S. These modifications reflect a more realistic assessment of the probable energy losses associated with thermal storage and a recognition of the importance of an appropriate method for dispatching solar energy. Dispatching is here taken to mean the decision processes (or algorithms) whereby collected solar energy is either put into thermal storage or used immediately to supply network demand. Given that the solar system overall performance, insolation input, and hourly demand have been specified, the objective of an optimum dispatch algorithm is to provide the highest possible annual solar plant capacity factor while simultaneously providing as much load leveling as possible for that part of the load supplied by the conventional plants in the network. Annual plant capacity factor is an important parameter in plant operating economics since cost-of-service is approximately inversely proportional to the capacity factor. Load leveling for the remainder of the network does not, to first order, affect solar plant cost of service. However, the effect of solar plant inclusion on network load profiles is of great interest to the electric utilities, on whom the commercialization prospects for solar central power systems will ultimately depend. The resulting load profiles also affect capacity backup requirements, on which the solar plant economics depend to a small but not insignificant degree.

1. Model Improvements

A recently developed power plant dispatching procedure schedules solar plants such that the daily requirement for solar derived electrical energy is more uniform from day to day than the daily requirement associated with the

previous procedure (see Ref. 4). This new dispatching procedure utilizes an hourly forecast of the total system demand for an entire year. Insolation forecasts are not required.

The new procedure is illustrated schematically in Figure 4-1. As indicated in this figure, during the time interval (T_1, T_2), those solar plants not scheduled for maintenance are required to supply a "band" of energy in the daily demand profile. (It is conservatively estimated that 10 percent of the installed solar capacity (ISC) is scheduled for maintenance on a continuous basis.) This assigned portion of the total system demand is chosen such that two criteria are satisfied:

a. The upper bound of the band scheduled for the solar plants is a fixed percentage (PMULT) of the maximum daily demand D_{max}

b. The solar capacity factor for the combined system of solar plants will be equal to 0.5 provided that all the demand scheduled for these plants can, in fact, be supplied. (The latter criterion implies that the solar plants are scheduled to operate as intermediate power plants.)

This method of dispatching solar plants not only provides for energy displacement during "on-peak" hours of the day, but it also provides for substantial capacity displacement since it theoretically reduces the maximum daily demands on the conventional plants in the system by an amount equal to 90 percent of the rated output of the combined system of solar plants (Figure 4-1). Of course, limited insolation and limited stored thermal energy may prevent the solar plants from supplying the scheduled demand.

The dispatching procedure illustrated in Figure 4-1 can be altered when it results in an excessive amount of surplus energy. For example, the daily insolation profile generally attains its maximum value prior to the time at which the maximum daily demand occurs. To provide a significant amount of electrical energy at or near the time corresponding to this maximum

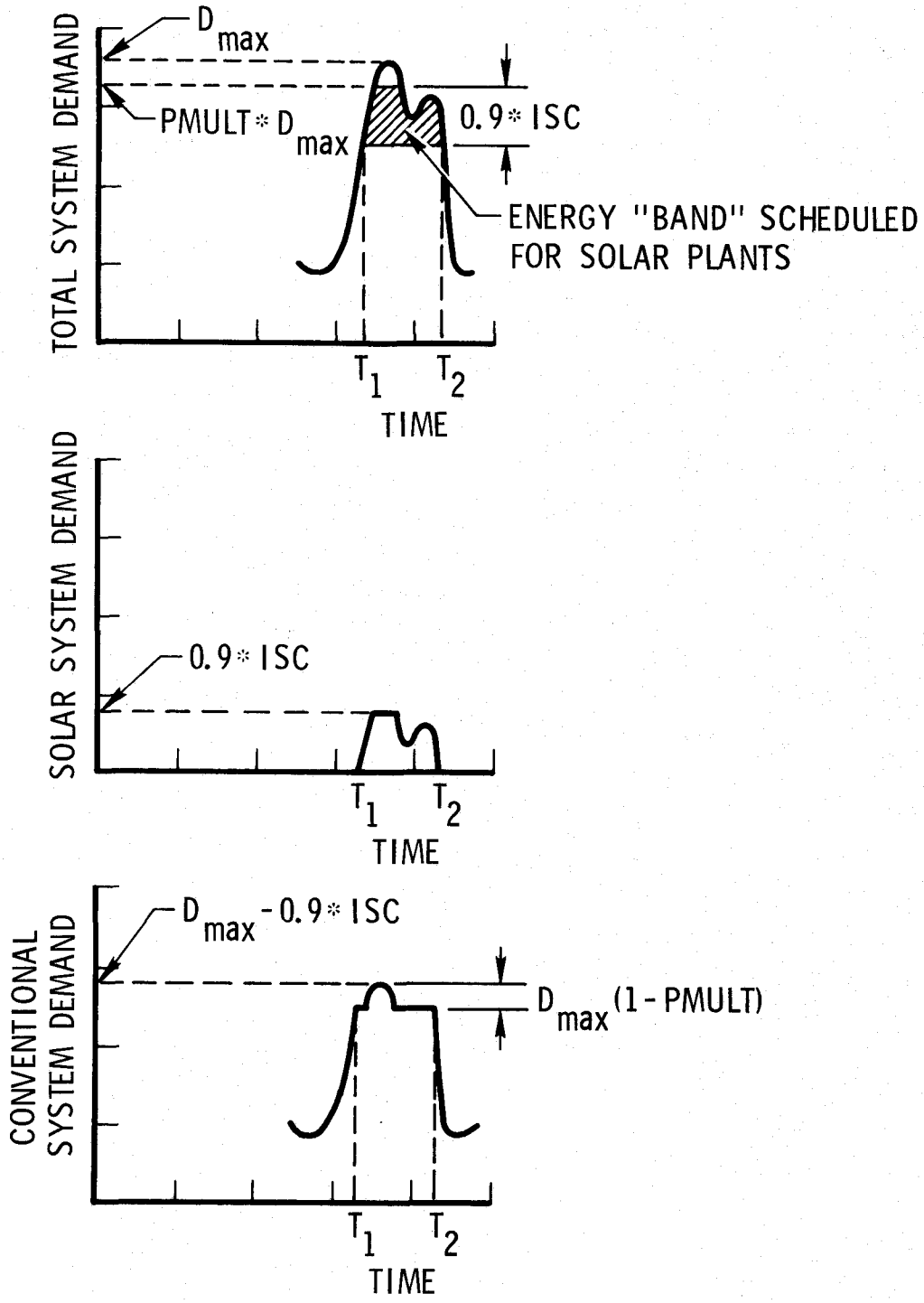


Figure 4-1. Daily Scheduling of Solar Power Plants

demand, it is normally necessary to store a substantial amount of thermal energy. If the solar plant storage facilities are filled to capacity prior to the time the solar plants are scheduled to provide electrical energy, time T_1 (Figure 4-1), any additional thermal energy collected prior to this time should be converted into electrical energy rather than discarded as surplus energy, provided of course, that the energy rate falls within the operating range of the turbine/generators. The electrical energy generated under these circumstances is referred to as "base load" energy (SPBASE) in the dispatching procedure, since it is unscheduled electrical energy which generally would be supplied by conventional base load plants. This energy is not included in the computation of the capacity factor of the solar plants; however, a credit is taken for an equivalent amount of conventional fuel in the economic analysis.

To further increase the amount of electrical energy generated by the solar plants, it may even be desirable to utilize stored thermal energy to augment SPBASE. This could be the case, for example, after the time (T_2) at which the solar plants are no longer scheduled to supply any additional electrical energy and a significant amount of thermal energy remains in storage. Rather than incur additional losses from storage overnight, it may be more desirable to convert this thermal energy into electrical energy and evacuate storage. Of course, if the insolation during the following day is below average, stored thermal energy left over from the previous day could be effectively utilized to provide scheduled energy during that day. Because of this uncertainty in the utilization of stored thermal energy for providing unscheduled electrical energy (SPBASE), a new parameter was added to the dispatching procedure. This parameter (STBASE) ranging in value from zero and one, controls the amount of stored energy that can be used for generating unscheduled electrical energy. When the amount of stored energy falls below a value equal to STBASE times the capacity of storage, the new dispatching procedure does not allow the conversion of any additional stored energy into unscheduled electrical energy.

A schematic diagram of the simulation model for the Central Receiver Solar Power Plant is shown in Figure 4-2. All losses accounted for in the

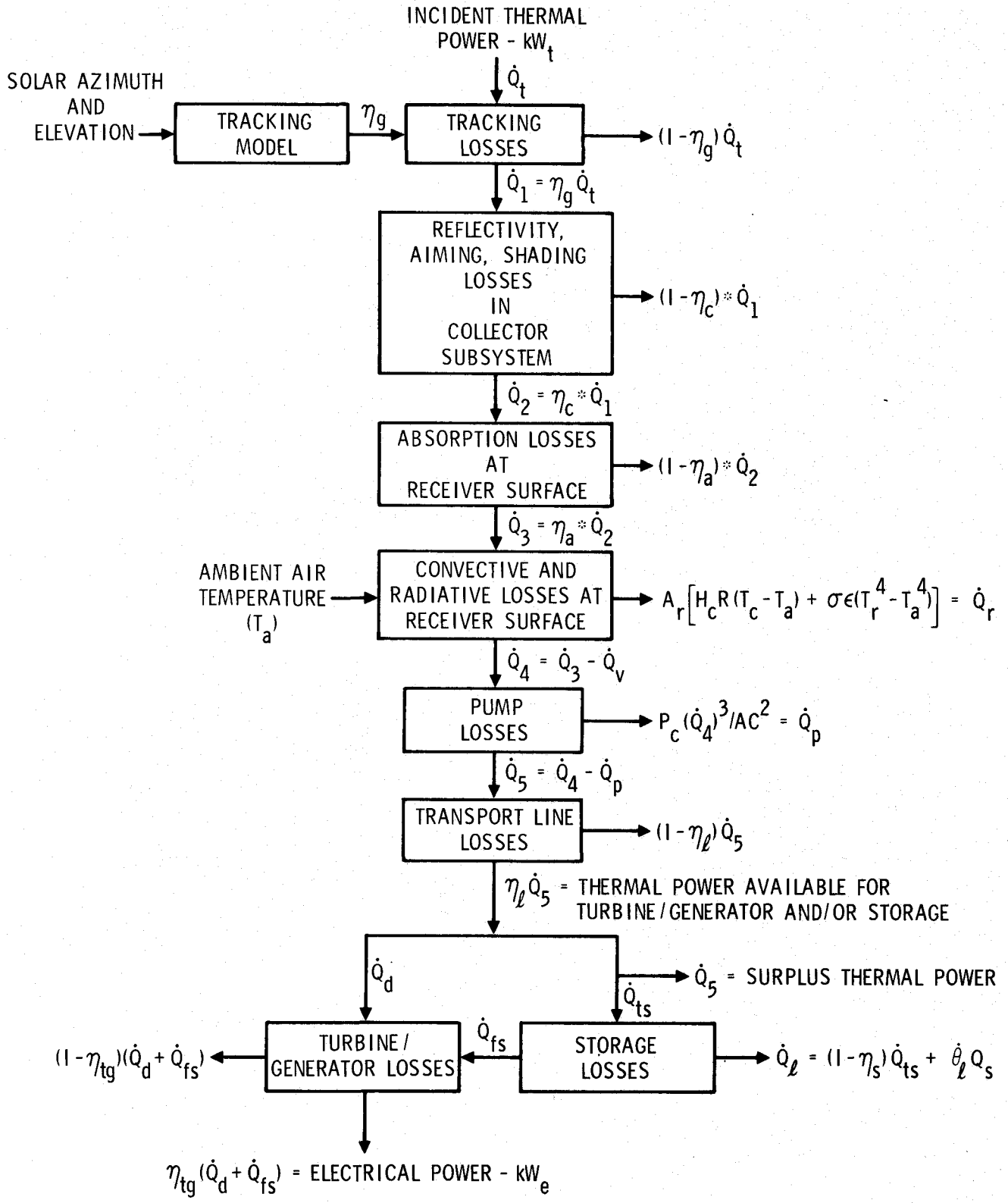


Figure 4-2. Central Receiver Simulation Model

model are explicitly defined in this figure. Given hourly values of normal incidence radiation (kW_t/m^2), the incident thermal power is computed by multiplying this radiation by the combined surface area of all heliostats in the solar plant system (AC). A time-dependent tracking efficiency η_g is computed given hourly values of solar azimuth and elevation. Reflectivity, aiming and shading losses in the collector subsystem, and absorption losses at the receiver surface are accounted for by the constant efficiencies η_c and η_a, respectively. The time-dependent convective and radiative losses at the receiver surface illustrated in Figure 4-2 are computed given hourly values of the ambient air temperature where A_r = receiver surface area, H_c = convective coefficient, R = convective surface-receiver surface area ratio, T_c = receiver or glass envelope surface temperature, σ = Steffan-Boltzman constant, ϵ = receiver surface emissivity, and T_r = receiver surface temperature. Time-dependent pumping power losses are computed using the formula given in Figure 4-2 (P_c = pumping constant; see the Solar Thermal Mission Analysis, Volume IV). Losses in the transport lines are accounted for by a constant efficiency η_ℓ. Surplus thermal power refers to that amount of excess available power which must be discarded when the storage facility is filled to capacity and both scheduled and unscheduled energy are being supplied at a rate equal to the capacity of the solar plants. The losses from storage are accounted for by a constant efficiency η_s and a constant loss rate $\dot{\theta}_\ell$ (Q_s refers to the energy in storage). Losses in the conversion from thermal to electrical power are accounted for by a turbine/generator efficiency η_{tg}. Because the pressures and temperatures of steam originating in the receiver and storage facility differ, this efficiency varies continuously between two extreme values depending on the origin of the steam. When the plants operate simultaneously from receiver and storage steam, the effective turbine/generator efficiency has a value between these two extremes. This value is determined by the specific design of the turbine/generator. Accounting for this variation in turbine/generator efficiency is a new feature of the simulation model. The net electrical power generated by the solar plant is denoted $\eta_{tg}(\dot{Q}_d + \dot{Q}_{fs})$ in Figure 4-2. The overall plant efficiency is equal to the ratio of this quantity and the incident thermal power, $\dot{Q}_t$.

2. Results

Solar plant performance as measured by capacity factor or energy displacement is sensitive to two key design parameters: thermal storage capacity* and collector area. Consequently, a series of parametric studies using the improved simulation model were conducted to determine the impact on plant performance of changes in these parameters. These studies were performed for PJM (Pennsylvania-New Jersey-Maryland interconnection) using Sterling, Virginia insolation data; FPL (Florida Power and Light Co.) using Miami, Florida insolation data; CPC (Consumers Power Co.) using Madison, Wisconsin insolation data; PPL (Pacific Power and Light Co.) using Seattle, Washington insolation data; CPSB (San Antonio City Public Service Board) using Fort Worth, Texas insolation data; and SCE (Southern California Edison Co.) using Inyokern, California insolation data. The service areas for these utilities and the insolation sites are illustrated in Figure 4-3. The choice of the insolation data was determined primarily by the availability of sites in The Aerospace data base which were in the vicinity of the utility service areas. In two cases (PJM and CPC), parametric studies were also performed using Blue Hill, Massachusetts and Cleveland, Ohio insolation data, respectively. However, for the sake of brevity, these results are not discussed.

Typical thermal energy balances predicted by the simulation model are summarized in Table 4-1. The values shown in this table denote percentages of the available thermal power $\eta_\ell \dot{Q}_5$ (see Figure 4-2) integrated over a year which are dispatched as follows:

a. directly to the turbine/generators from the solar receivers,

b. indirectly to the turbine/generator from the storage facilities,

*The units of storage capacity are hours at 65 percent of the rated capacity of the turbine/generators.

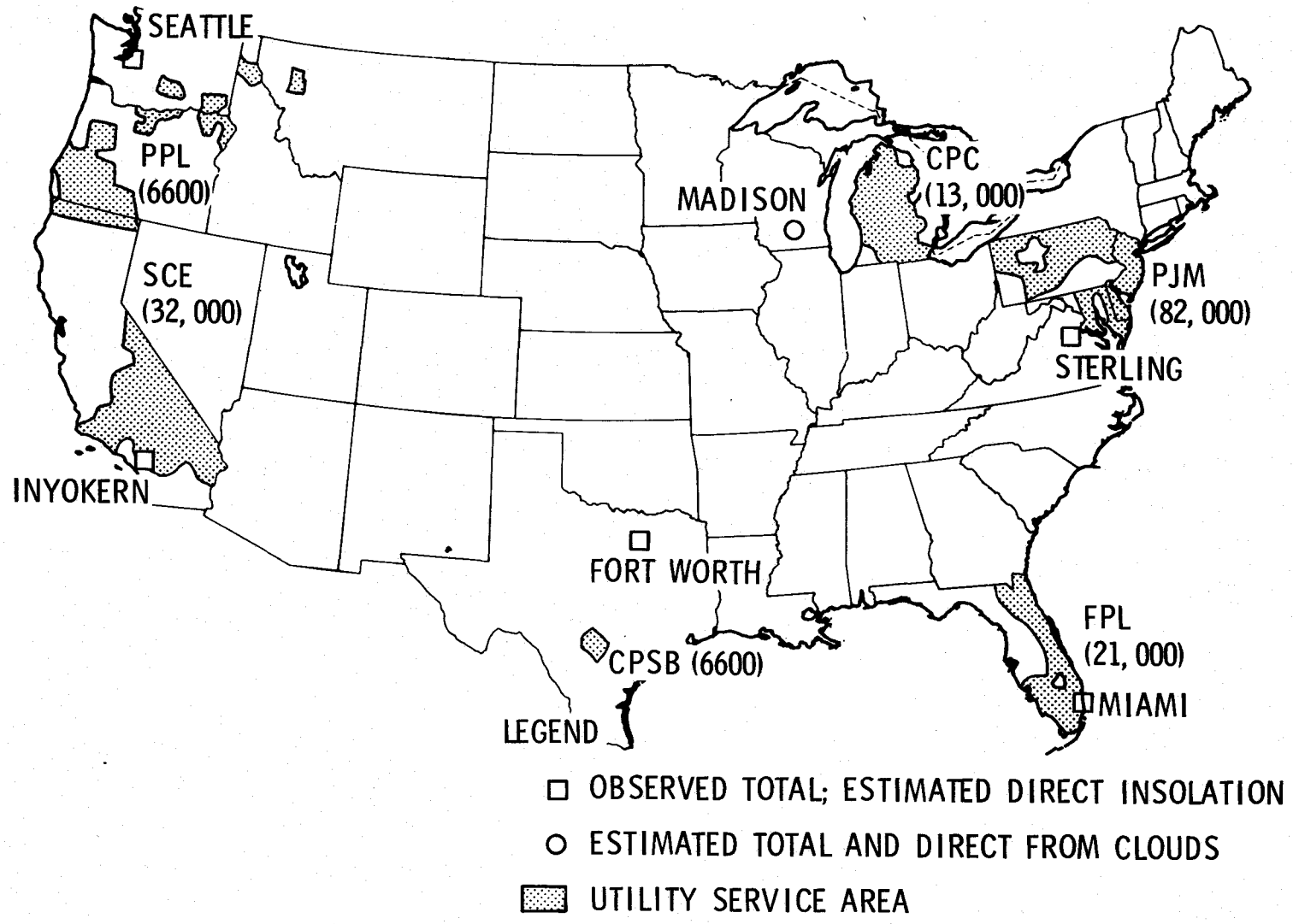
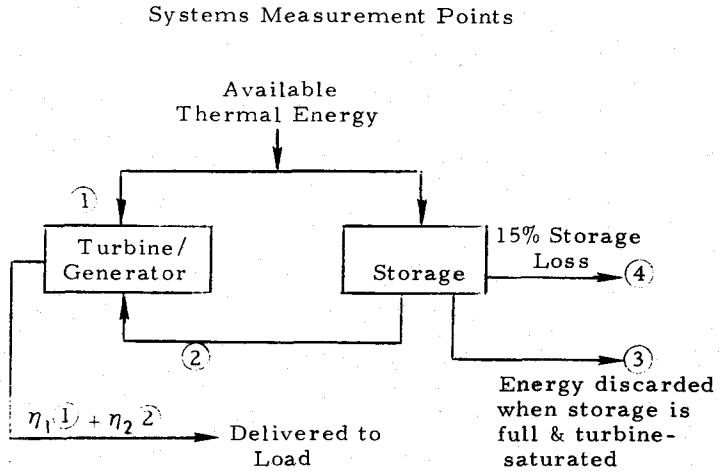


Figure 4-3. Central Receiver Regional Analysis

Table 4-1. Normalized Thermal Energy Balance for CPSB 1990 Demand and Fort Worth Insolation

Storage Hours	Measurement Point in System	Annual Average Fractional Energy Distribution in System		
		Collector Area Km^2/100 MWe		
		0.5	1.0	1.5
3	①	.897	.623	.455
	②	.087	.167	.117
	③	0	.178	.405
	④	.016	.032	.023
6	①	.881	.625	.458
	②	.100	.235	.188
	③	0	.094	.317
	④	.019	.046	.037
9	①	.877	.621	.459
	②	.103	.263	.228
	③	0	.062	.265
	④	.020	.054	.048



Notes

- 1500 MWe (18.1%) solar penetration
- η_1 (turbine efficiency for direct steam) ≈0.36
- η_2 (turbine efficiency for steam from storage) ≈0.27
- Storage hours are at 65 MWe system output
- Thermal balance requires 2 + 3 + 4 = 1.00 - 1

c. as surplus energy, and

d. as losses from the storage facilities.

As shown in Table 4-1, as storage capacity increases for collector areas of 1.0 and 1.5 $km^2/100\ MW_e$, increasing amounts of surplus energy can be stored and used for generating electrical energy after sundown. With the collectors sized at 0.5 $km^2/100\ MW_e$, there is no surplus energy since the storage facilities are never filled to capacity. For a given storage capacity, much of the additional energy which can be made available by increasing the size of the collector systems is wasted because of periods during the day, especially during the summer months, when the storage facilities are filled to capacity. The absolute amounts of energy which are dispatched to the turbine/generators both directly from the receivers and indirectly from the storage facilities increase monotonically with increasing collector area. However, relative to the increasing amounts of energy available, the direct receiver energy decreases and the indirect stored energy attains a maximum value for a collector area of 1.0 $km^2/100\ MW_e$.

For each of the six utilities enumerated above, solar capacity factor and energy displacement are shown as a function of storage capacity and collector area for two solar penetrations in "carpet plot" format in Figures 4-4 through 4-15. (Solar capacity factor is defined to be equal to the total scheduled electrical energy generated by the solar plants for a year divided by the total electrical energy that could be generated continuously at rated capacity of those plants not scheduled for maintenance. Energy displacement is equal to the total scheduled electrical energy generated by the solar plants for a year divided by the total scheduled demand.) The results shown in these plots were obtained from 108 hourly simulations of solar plants located at the sites mentioned above supplying portions of the electrical demand forecasted for the year 1990 (Section II) for the utilities associated with these sites. For all solar power plant simulations, thermal energy from storage was not utilized to supply unscheduled electrical energy unless the energy in storage

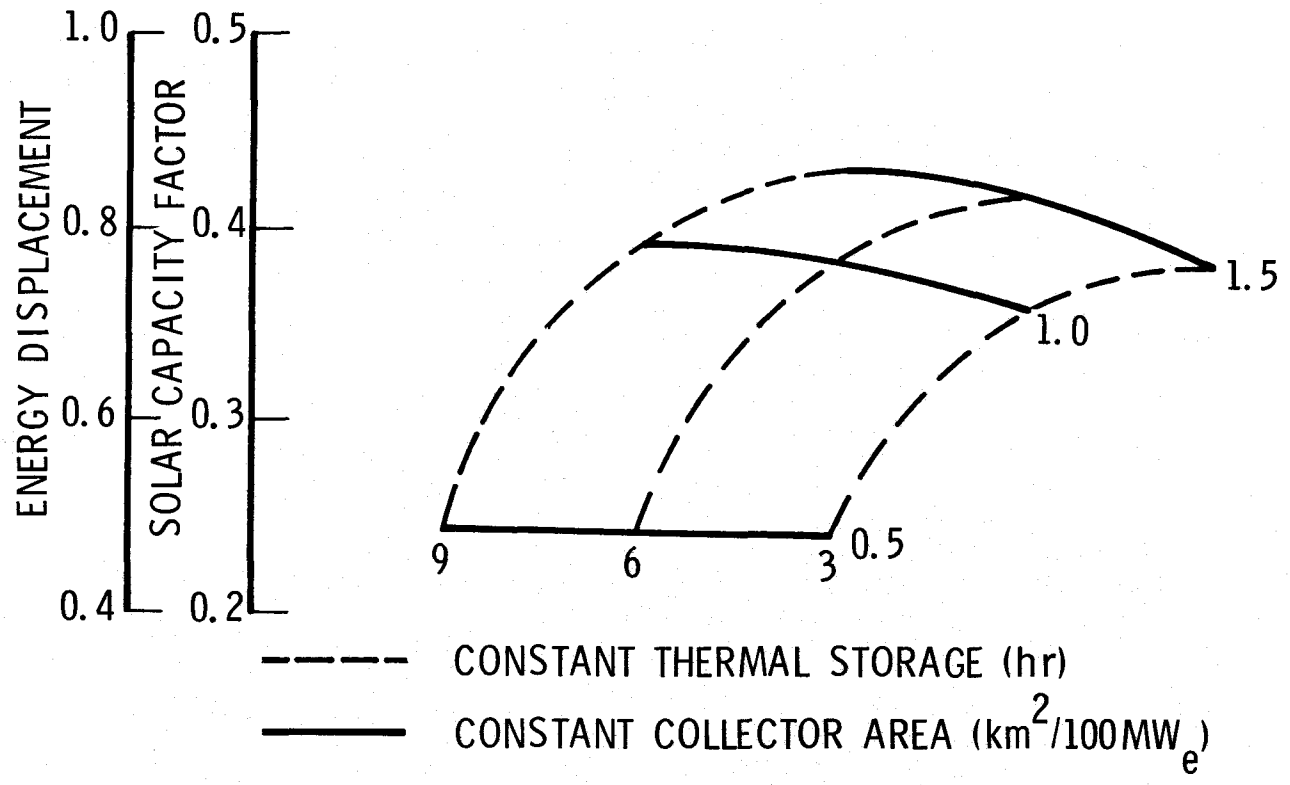


Figure 4-4. PJM (1990) - Sterling, Vermont, Simulation Results, 8000 MW_e Solar Penetration (8.8%)

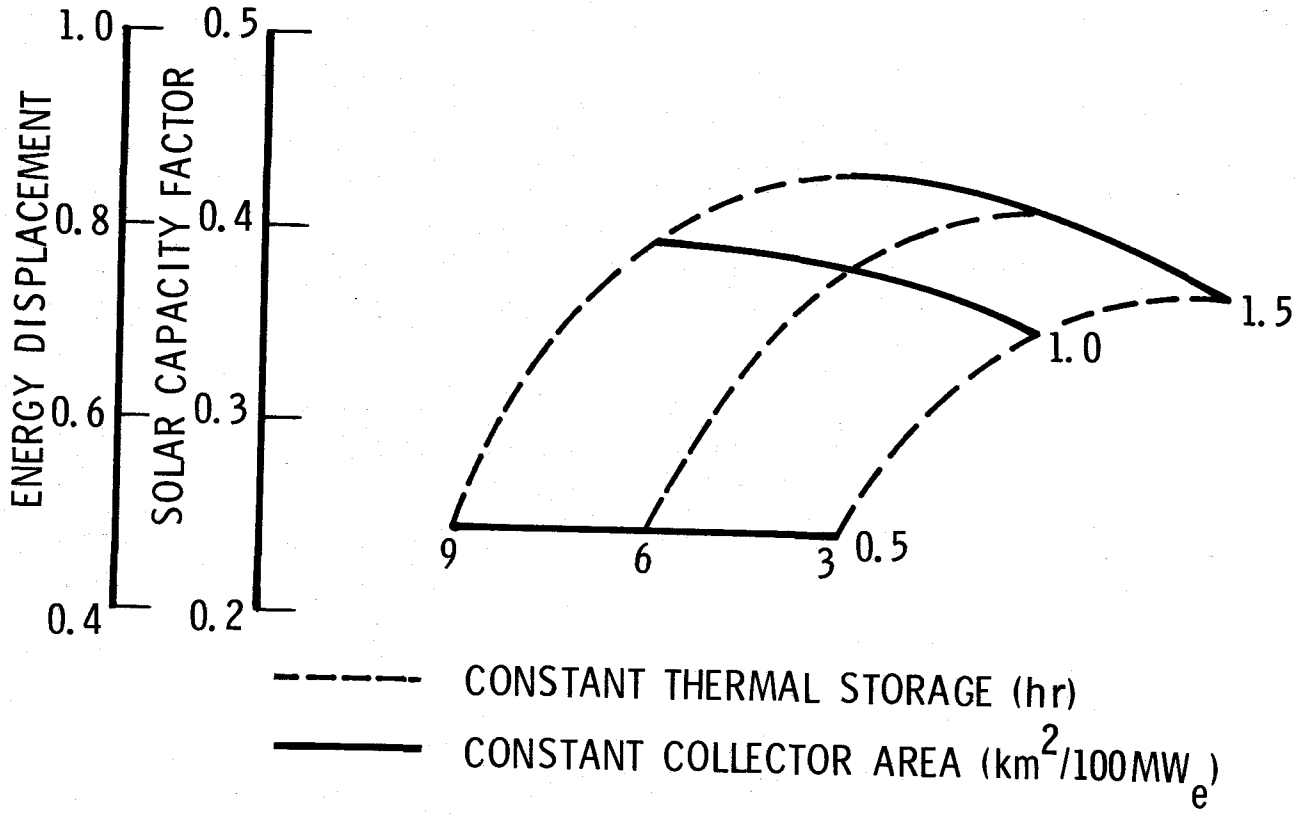


Figure 4-5. PJM (1990) - Sterling, Vermont, Simulation Results, 18,000 MW$_e$ Solar Penetration (19.8%)

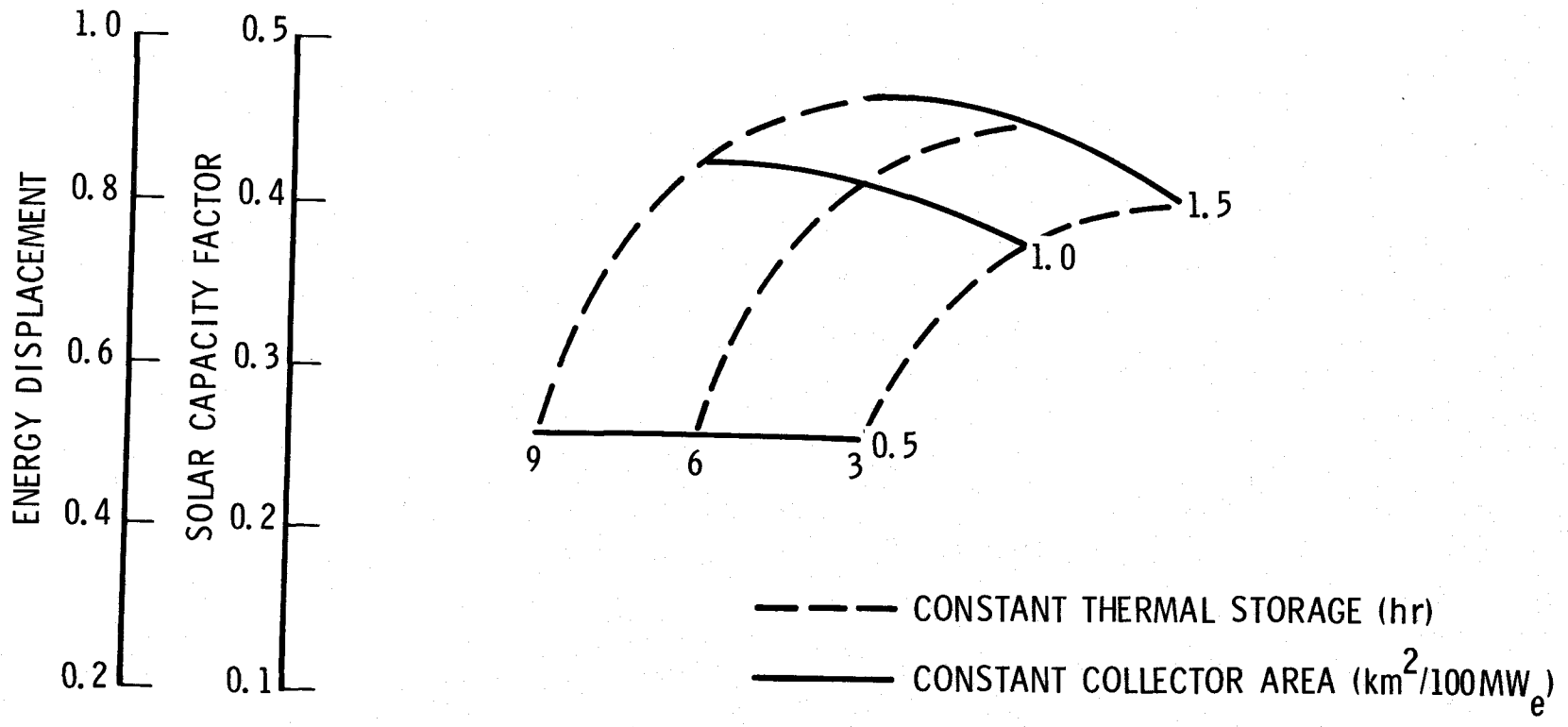


Figure 4-6. FPL (1990) - Miami, Florida, Simulation Results, 2000 MW_e Solar Penetration (8.2%)

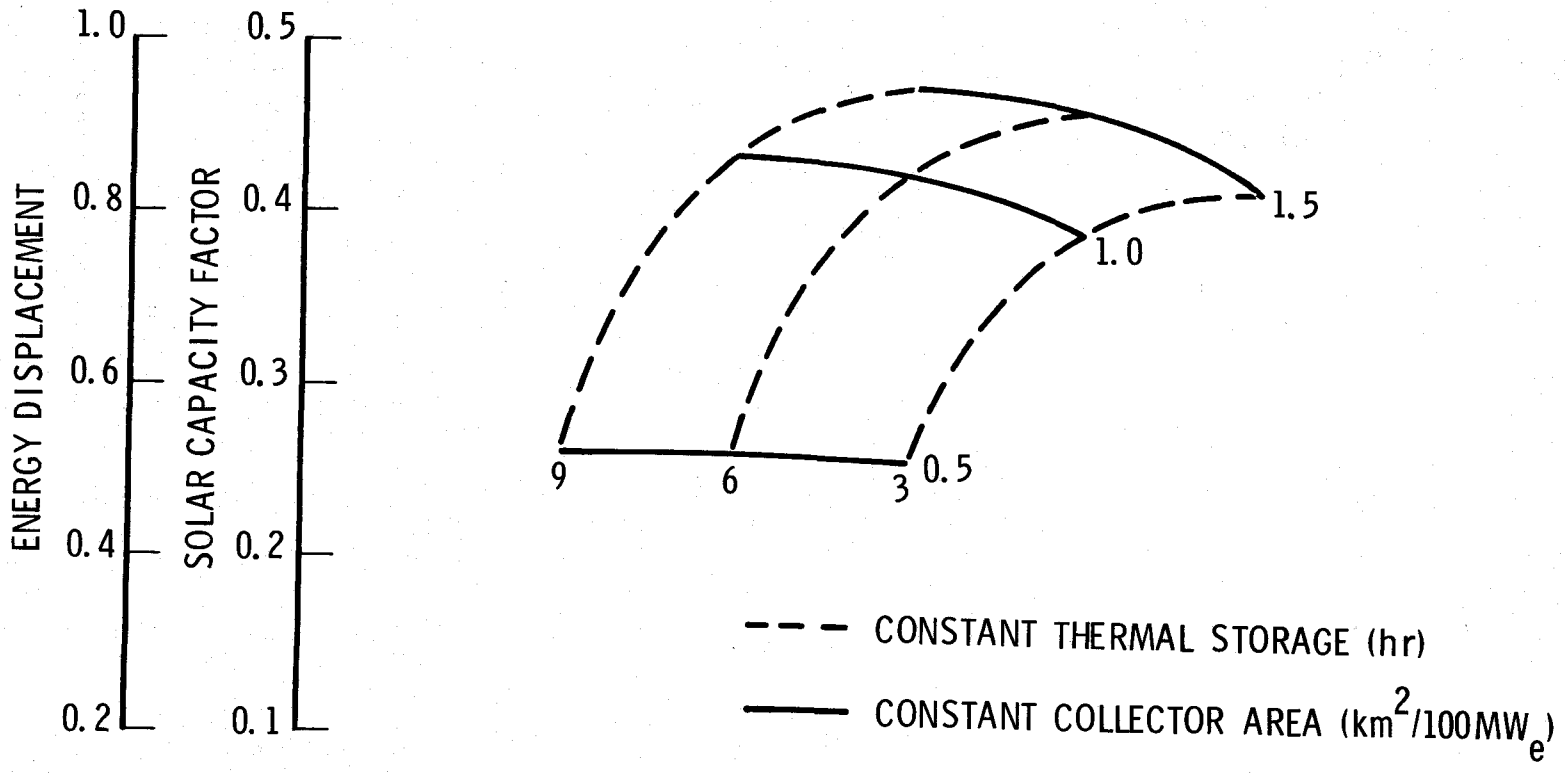


Figure 4-7. FPL (1990) - Miami, Florida, Simulation Results, 6000 MW_e Solar Penetration (24.7%)

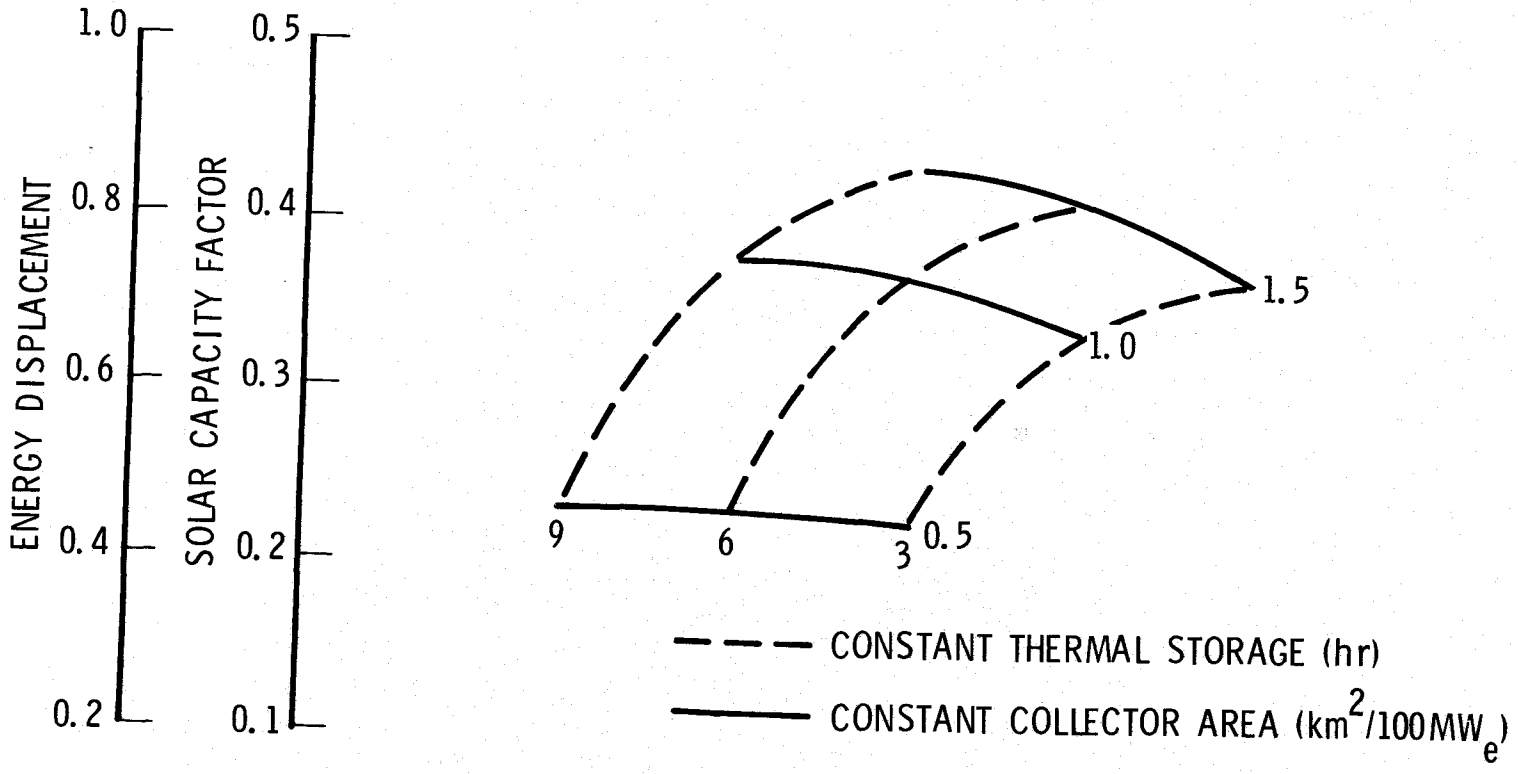


Figure 4-8. CPC (1990) - Madison, Wisconsin, Simulation Results, 1000 MW_e Solar Penetration (5.8%)

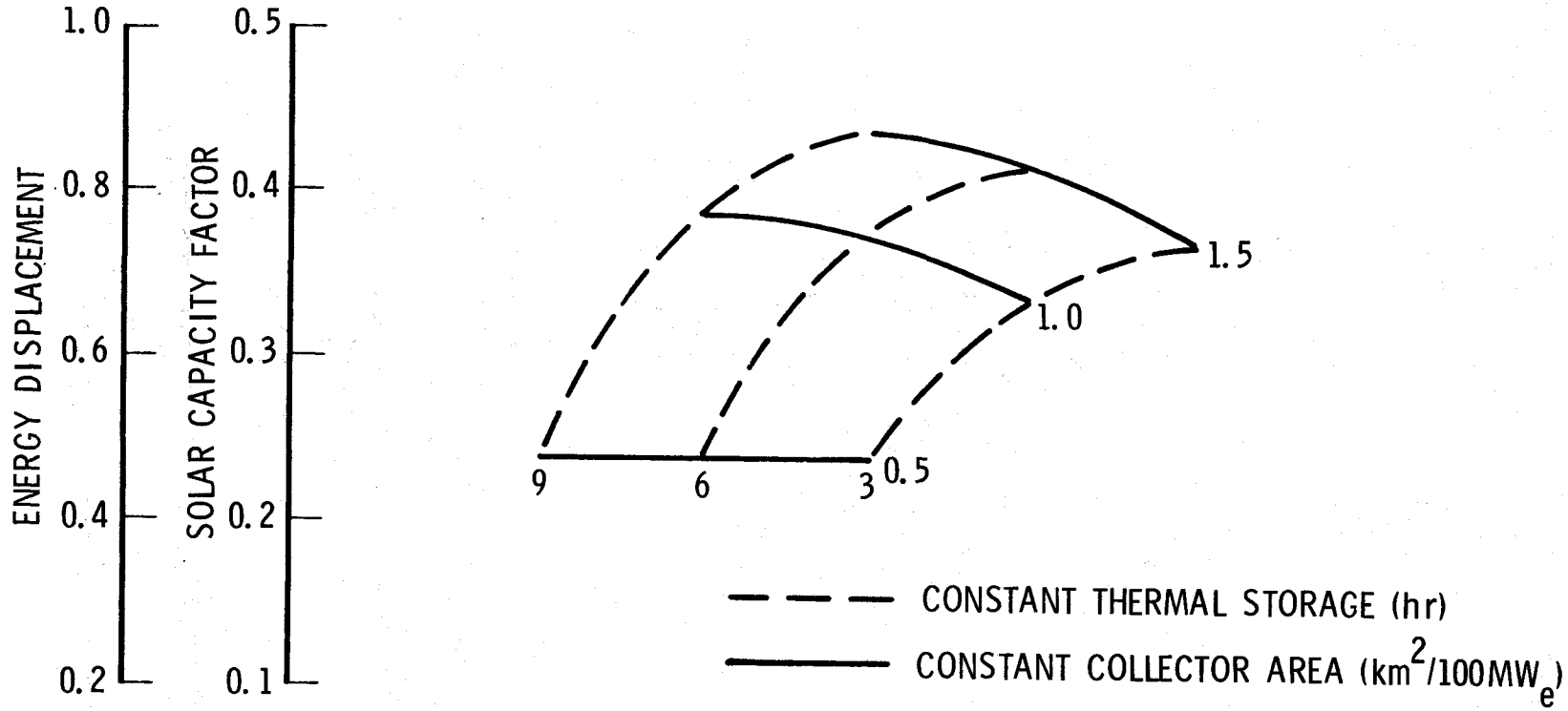


Figure 4-9. CPC (1990) - Madison, Wisconsin, Simulation Results, 3000 MW$_e$ Solar Penetration (17.3%)

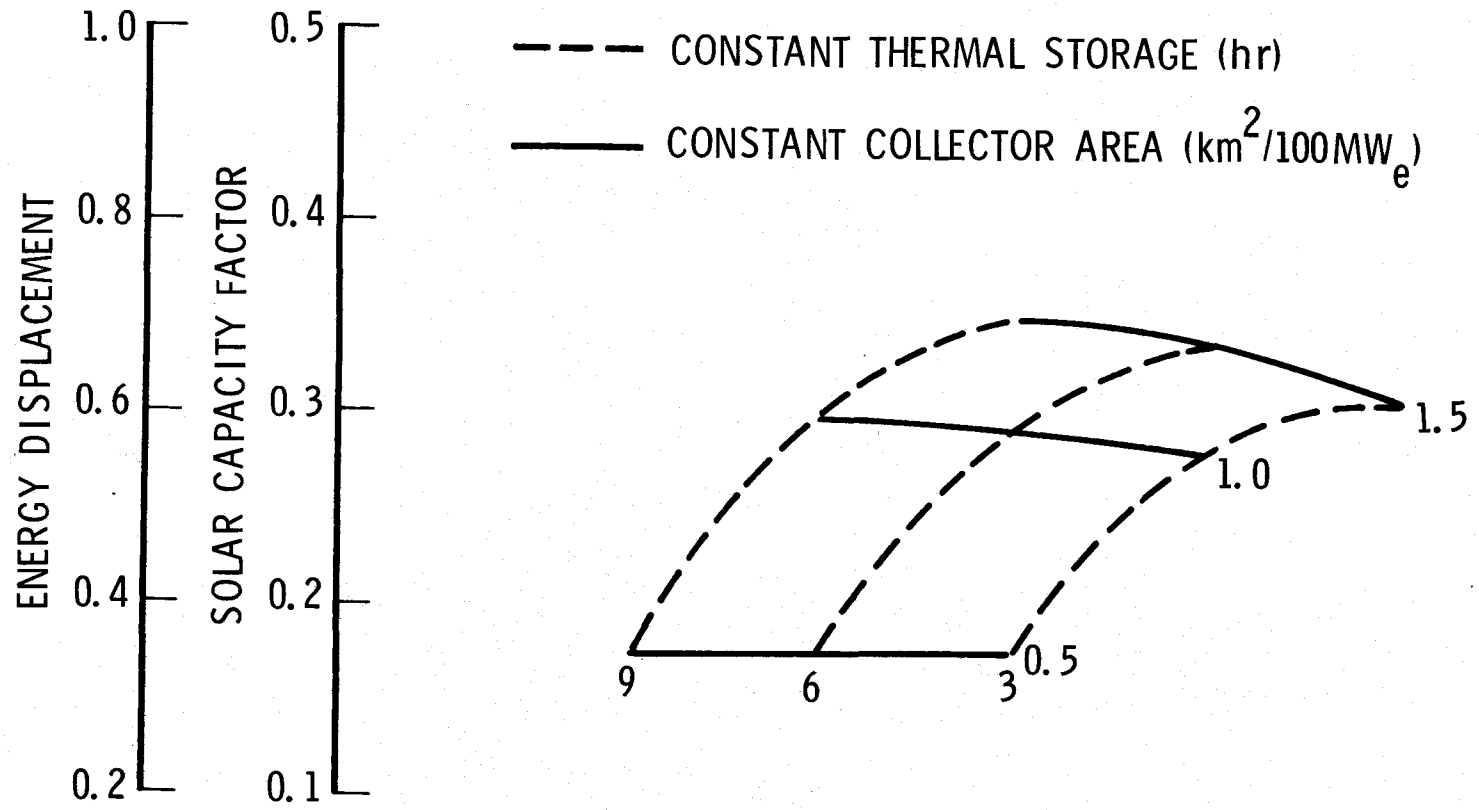


Figure 4-10. PPL (1990) - Seattle, Washington, Simulation Results, 1000 MW_e Solar Penetration (11.8%)

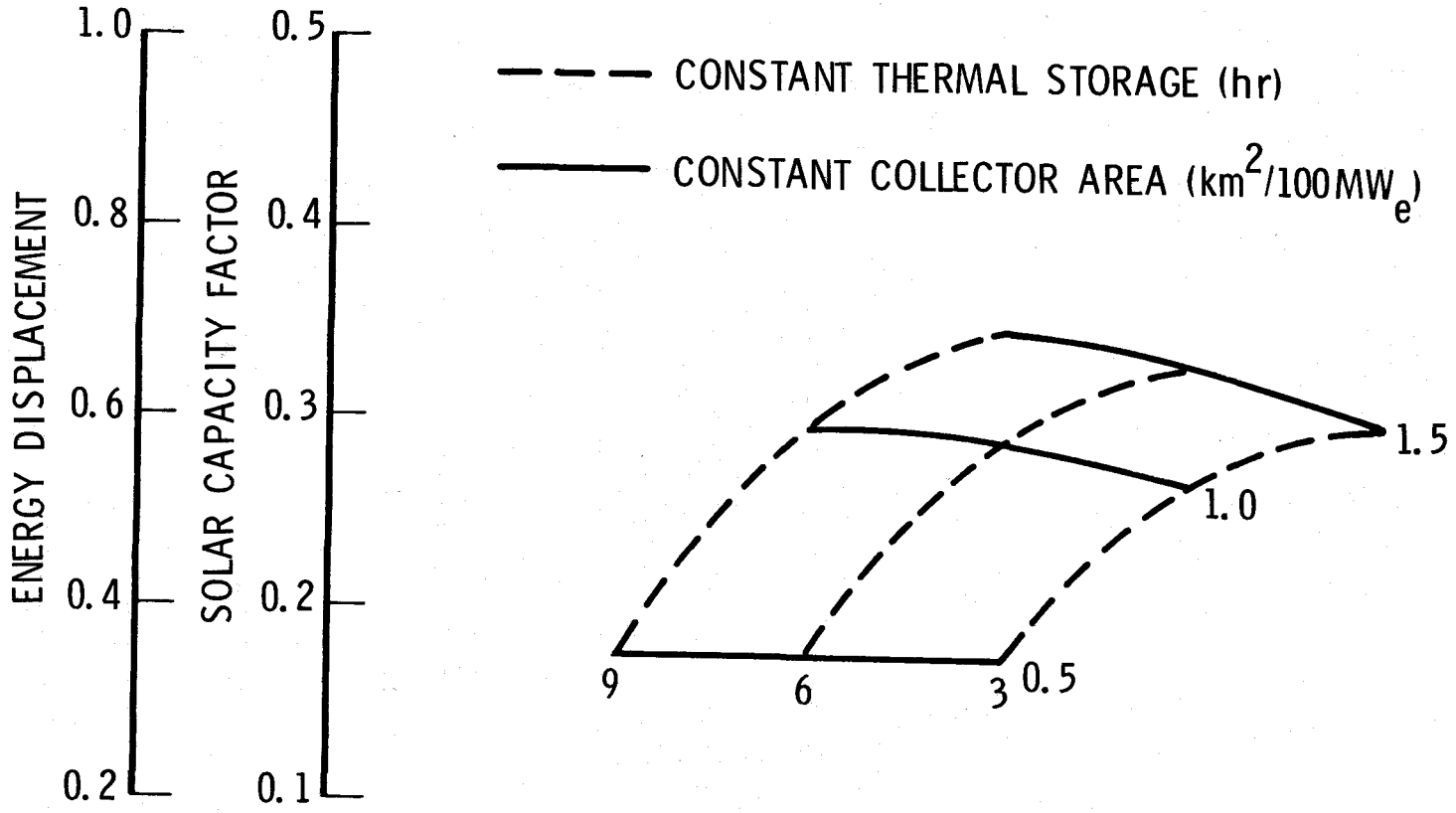


Figure 4-11. PPL (1990) - Seattle, Washington, Simulation Results, 1500 MW_e Solar Penetration (17.6%)

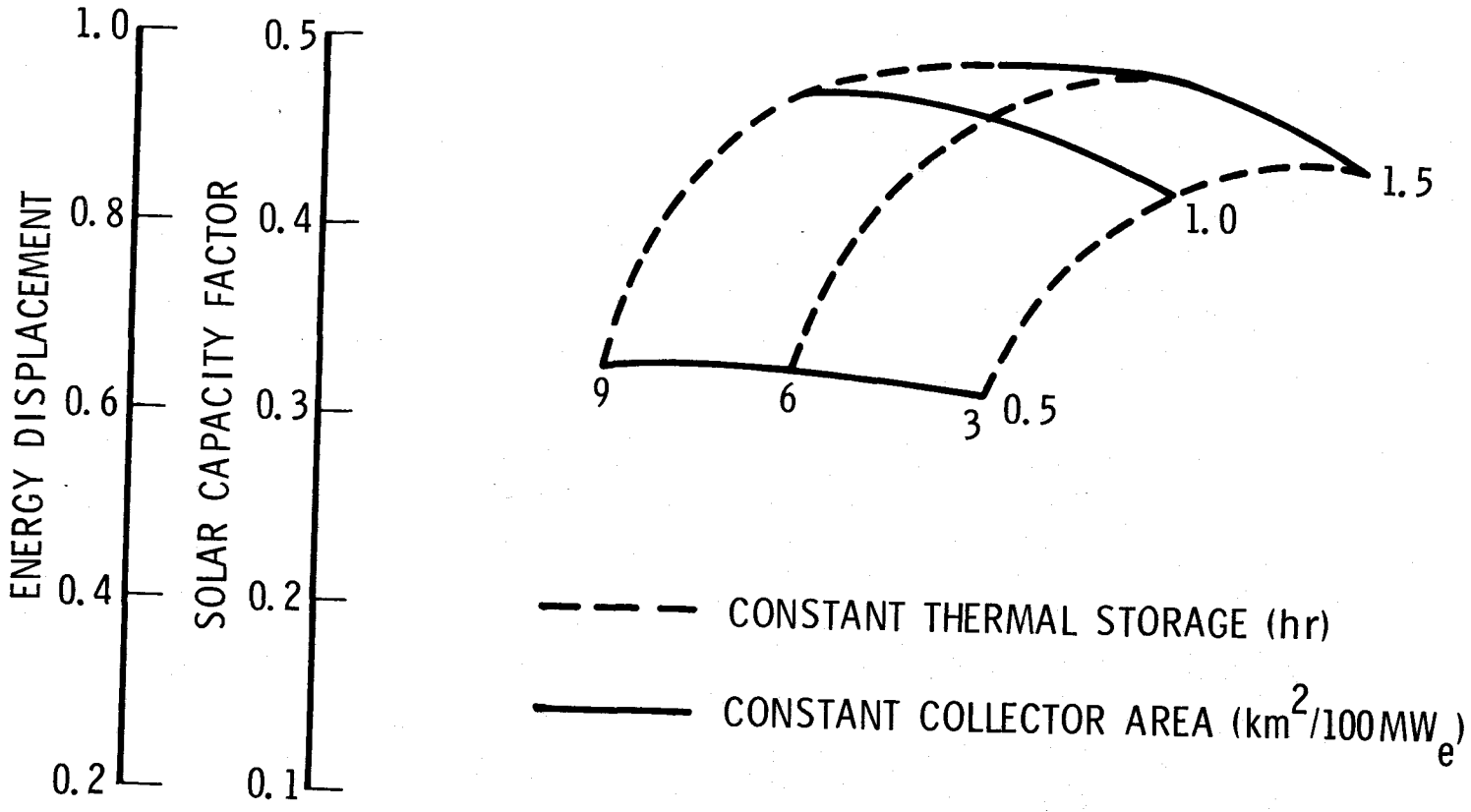


Figure 4-12. SCE (1990) - Inyokern, California, Simulation Results, 3000 MW$_e$ Solar Penetration (8.2%)

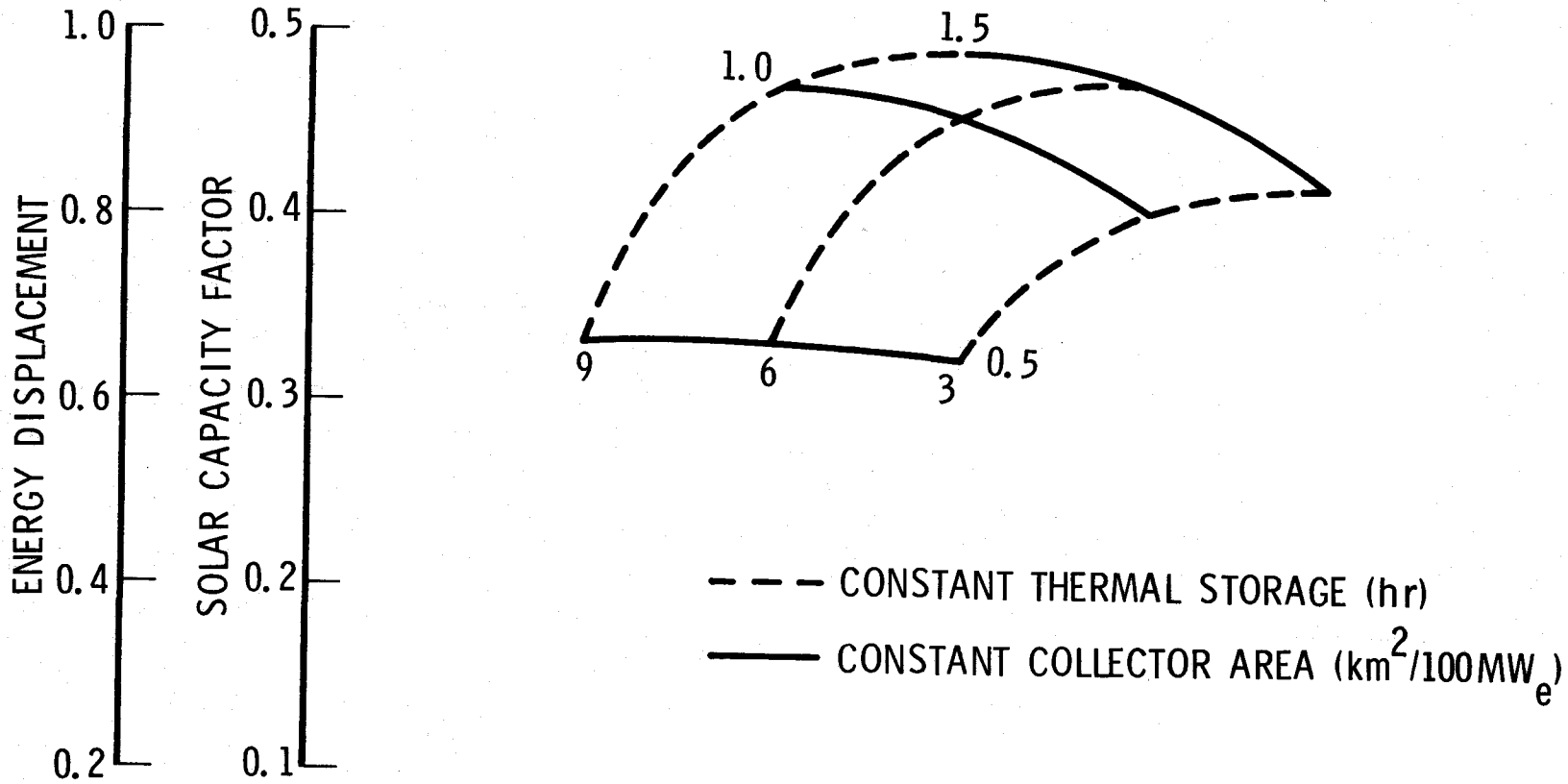


Figure 4-13. SCE (1990) - Inyokern, California, Simulation Results, 10,000 MW$_e$ Solar Penetration (27.5%)

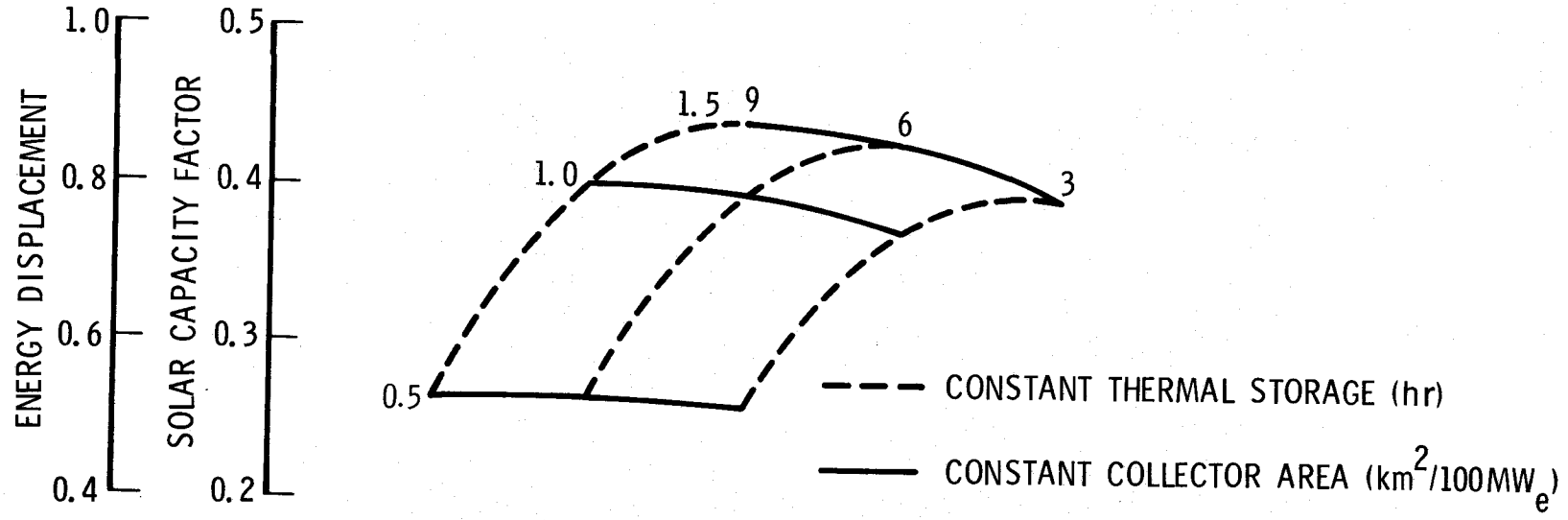


Figure 4-14. CPSB (1990) - Fort Worth, Texas, Simulation Results, 500 MW_e Solar Penetration (7.5%)

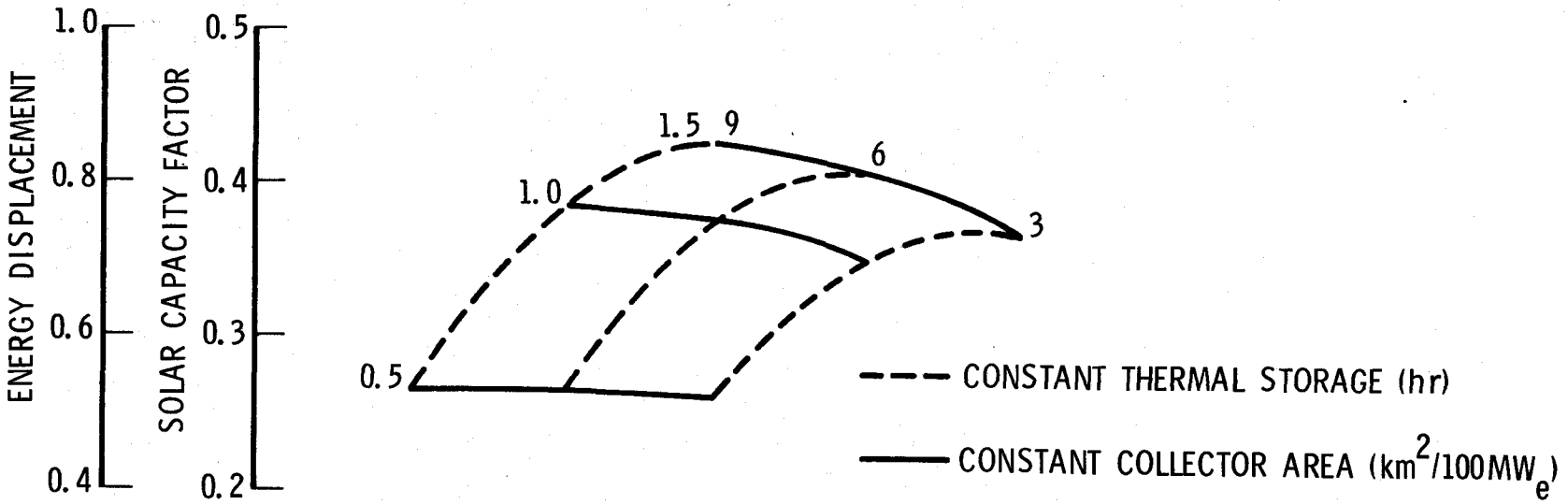


Figure 4-15. CPSB (1990) - Fort Worth, Texas, Simulation Results, 1500 MW_e Solar Penetration (22.7%)

exceeded 60 percent (STBASE = 0.6) of the thermal storage capacity. The term, "penetration," referred to in Figures 4-4 through 4-15 is defined as the ratio of gross solar capacity to the total utility generation capacity (including reserve capacity).

Several general observations can be made with respect to these figures. The solar capacity factor is insensitive to solar penetration. This, of course, would be expected, since the daily scheduled demands for the solar plants are chosen in the simulations such that the solar capacity factor will be 0.5 regardless of penetration, provided there is sufficient insolation and stored energy. For a collector size of 0.5 $km^2/100\ MW_e$, increasing the storage capacity has little effect on the solar capacity factor. This results from the fact that there is insufficient collector area available, and the amount of energy collected rarely exceeds the capacity of the turbine/generator so that available storage is not utilized. The rate of increase of capacity factor with increasing collector area (for a fixed storage capacity) or with increasing storage capacity (for a fixed collector area) decreases substantially for collector areas greater than 1 $km^2/100\ MW_e$ and storage capacities greater than six hours. For example, consider the carpet plot for the City Public Service Board of San Antonio (Figure 4-15). As the collector area is increased from 0.5 to 1.0 $km^2/100\ MW_e$, the amounts of surplus energy in the simulated plant performance relative to the additional thermal energy available for generating electricity or for storage are 36, 19, and 12 percent for storage capacities of three, six, and nine hours, respectively. That is, for a storage capacity of three hours, over one-third of the incremental amount of energy available due to the addition of 0.5 km^2 of collector area is wasted because of insufficient storage capacity. The amount of surplus energy decreases substantially with respect to increasing storage capacity above this value. The remaining amounts of the additional collected thermal energy available for generating electricity are 64, 81, and 88 percent of this energy for storage capacities of three, six, and nine hours, respectively. The increases in solar capacity factor are, in fact, proportional to these values. That is,

for a storage capacity of three hours, the solar capacity factor increases by an amount equal to 0.09 (from 0.260 to 0.350) as the collector area increases from 0.5 to 1.0 $km^2/100\ MW_e$. The incremental increases in solar capacity factor for six and nine hours of storage capacity are equal to (81/64)(0.09) $\simeq$ 0.11 and (88/64)(0.09) $\simeq$ 0.12, respectively, as indicated in Figure 4-15.

As the collector area is increased from 1.0 to 1.5 $km^2/100\ MW_e$, the amounts of surplus energy in the simulated plant performance relative to the additional available energy are 86, 76, and 67 percent for storage capacities of three, six, and nine hours, respectively. That is, the collectors are oversized relative to the capacity of the plants. The remaining amounts of additional thermal energy available for generating electricity are 14, 24, and 33 percent of this energy. Again, the increases in solar capacity factor are proportional to these values. That is, for a storage capacity of three hours, the solar capacity increases by an amount equal to 0.017 (from 0.350 to 0.367) as the collector area increases from 1.0 to 1.5 $km^2/100\ MW_e$. The incremental increases in solar capacity factor for six and nine hours of storage capacity are equal to (24/14)(0.17) $\simeq$ 0.03 and (33/14)(0.017 $\simeq$ 0.04, respectively, as indicated in Figure 4-15.

The dependence of solar capacity factor on geographical location is illustrated in Figure 4-16. Note that the correlation between the capacity factor and mean daily insolation is initially linear and, for large enough values of mean daily insolation, is asymptotic to a capacity factor of 0.5 since only scheduled demand is accounted for in the definition of this capacity factor.

The method of utilizing stored energy in the simulation model was also investigated in this study. While it may seem reasonable to operate the solar plants at rated capacity whenever possible, there is a priority associated with the time interval during the day when the solar plants are scheduled to operate. If stored energy is never used to supply unscheduled electrical demand, i.e., energy outside of the demand band of Figure 4-1, the solar capacity factor increases at the expense of an increase in surplus energy.

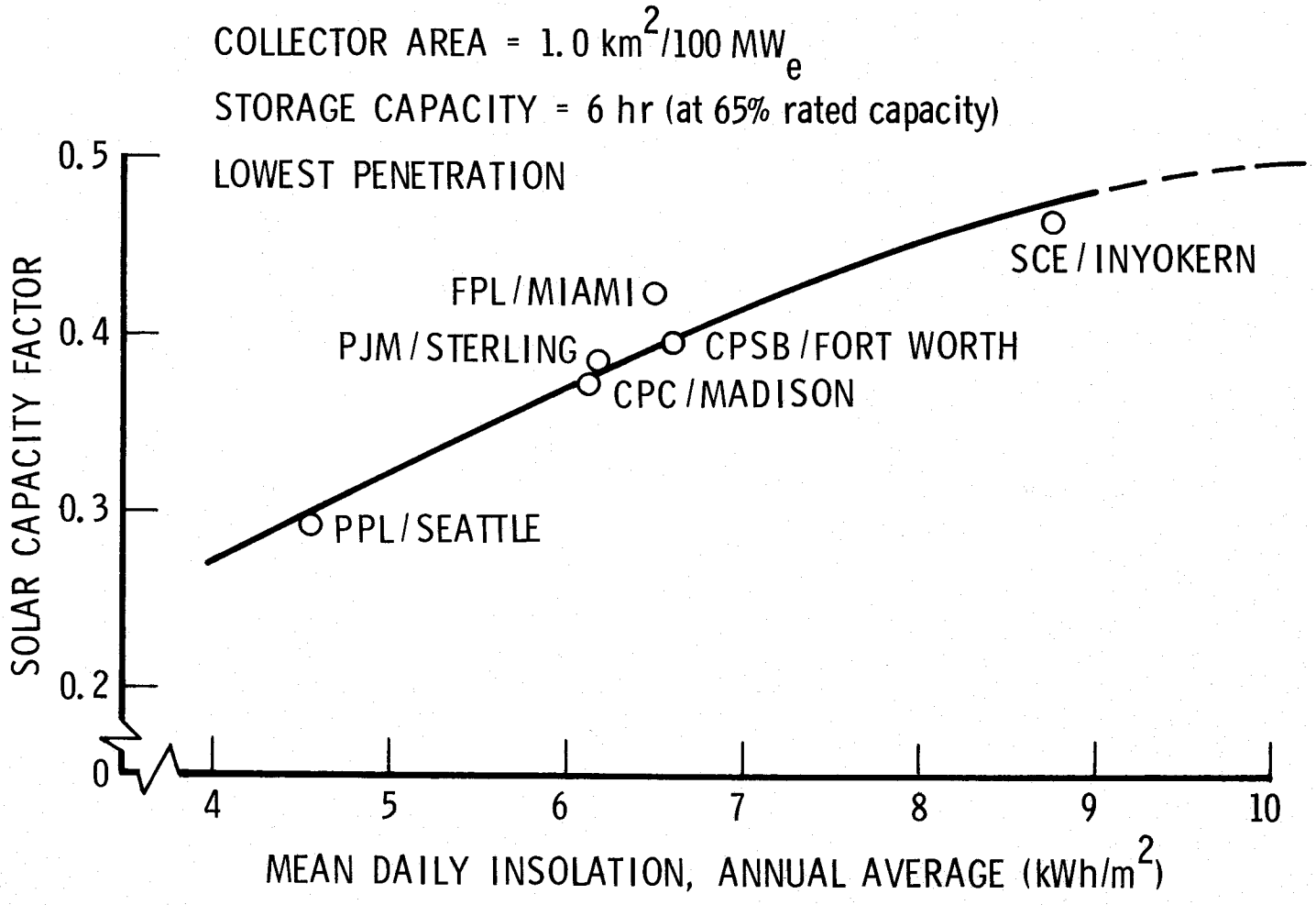


Figure 4-16. Correlation Between Solar Capacity Factor and Insolation

The change in solar capacity factor with increasing values of STBASE (the fraction of storage capacity below which stored energy is not used to supply unscheduled electrical demand) is illustrated in Figure 4-17. Values of the change in solar capacity factor for all six utility/site combinations are contained within the band shown in the figure. Since the gain in capacity factor above a value of STBASE = 0.6 is small and is offset to a certain extent by increasing surplus energy and decreasing fuel credit, STBASE was set equal to this value for all 108 solar power plant simulations performed in this study.

C. MARGIN ANALYSIS

The results described in this section were obtained utilizing the revised margin analysis methodology described in the Midterm Report (Reference 6). Briefly, the method first obtains a margin value for the conventional baseline system (i.e., no solar plants). This is the least amount of margin consistent with a specified loss of load requirement and scheduled maintenance requirements for baseload, intermediate, and peaking plants. Details of this optimization procedure are described in Reference 23. When solar plants are used, an equivalent amount of intermediate conventional capacity is removed from the baseline system. Because of insolation outages, this "penetrated" baseline system generally requires backup conventional capacity to satisfy the loss of load criterion. This backup capacity is again determined using the above optimization procedure. However, the maintenance schedule for the conventional plants in the penetrated system will normally differ from the baseline maintenance schedule because of insolation variations throughout the year. Hourly values of solar power determined from the solar plant simulation studies (Section B) and hourly demand data forecast for the utility under investigation are used in the margin analysis to provide a large enough sample to improve the stability of the analysis. The optimization procedure ensures a unique solution in the sense that no lower margin value can be obtained based

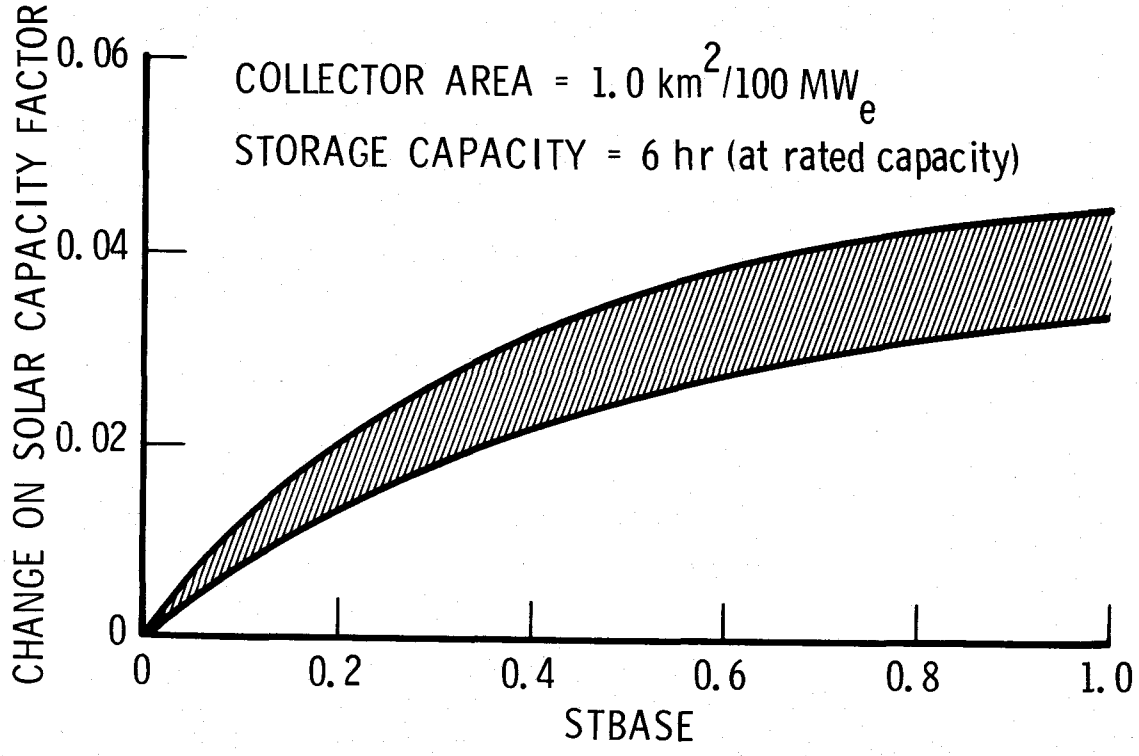


Figure 4-17. Relationship Between Solar Capacity Factor and STBASE

on the demand and solar power data, the loss of load criterion, and the scheduled maintenance requirements.

Although simplified into the categories of base, intermediate, and peaking plants, the generation models given in Table 4-1 are based on projected demand estimates for the year 1990. As shown in this table, it is assumed that the base plants are of size 1000 MW; the intermediate plants of size 500 MW; and the peaking plants of size 200, 100, or 50 MW, depending on the utility under investigation. The forced outage rates shown in the table are based on actual data, taking into consideration the size, type, and age of the plants. The loss of load criterion is taken to be 2.4 hr in one year. The conventional baseline margin results for the six utilities considered in this study are also shown in Table 4-2. In general, the large utilities tend to have lower margins simply due to the fact that having more plants, they are more flexible in scheduling maintenance to reduce the required margin. However, the variability of demand and the combination of plant sizes in the utility are also factors that influence margin. In the case of CPC, the relatively large number of baseload plants (58 percent) is the primary reason for the high margin of 31 percent. The larger plants have higher forced outage rates, and each outage means a capacity reduction of 1000 MW. As an example, if all ten baseload plants in CPC were replaced by twenty 500-MW plants, the required margin would be reduced to 22.7 percent.

When solar plants are used in the utility and an insolation outage coincides with a period of high demand, the loss of load probability for that period will be correspondingly high. The annual loss of load is equal to the sum of the hourly loss of load probabilities. This sum, expressed in units of time, is kept below the required value (namely, 2.4 hr) by adding conventional backup capacity to the system. Required backup capacities are plotted in the form of carpet plots for the six utilities considered in this study (Figures 4-18 through 4-23). Two penetrations are analyzed for each utility. The carpet plots are given for three values of thermal storage capacity and

Table 4-2. Margin Analysis Assumptions

Baseline Conventional Generation Models

Plant Size (MW)	Number of Plants in Generation Mix						Assumed Forced Outage Rate
	PJM	SCE	FPL	CPC	PPL	CPSB	
1000 (Baseload)	44	18	13	10	4	4	7
500 (Intermediate)	40	20	14	8	5	4	5
200 (Peaking)	135	42	--	--	--	--	3
100 (Peaking)	---	--	43	33	--	23	3
50 (Peaking)	--	--	--	--	40	--	3
Total Capacity	91,000	36,400	24,300	17,300	8,500	8,300	
Baseline Margin, %	10.9	13.8	13.1	31.0	28.2	25.3	

Scheduled Maintenance

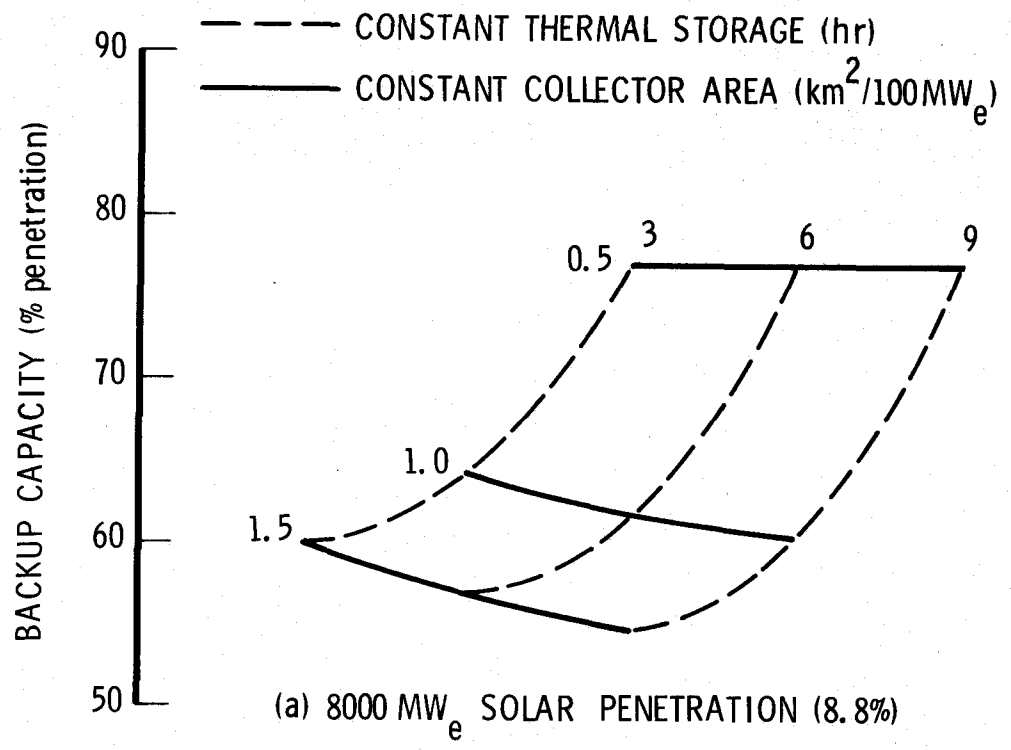
10% - All types

Solar Plants

Size 100 MW with 5% forced outage rate
(network penetration is by replacement of 500-MW_e conventional plants)

Loss of Load Criterion

1.4 hr/yr.



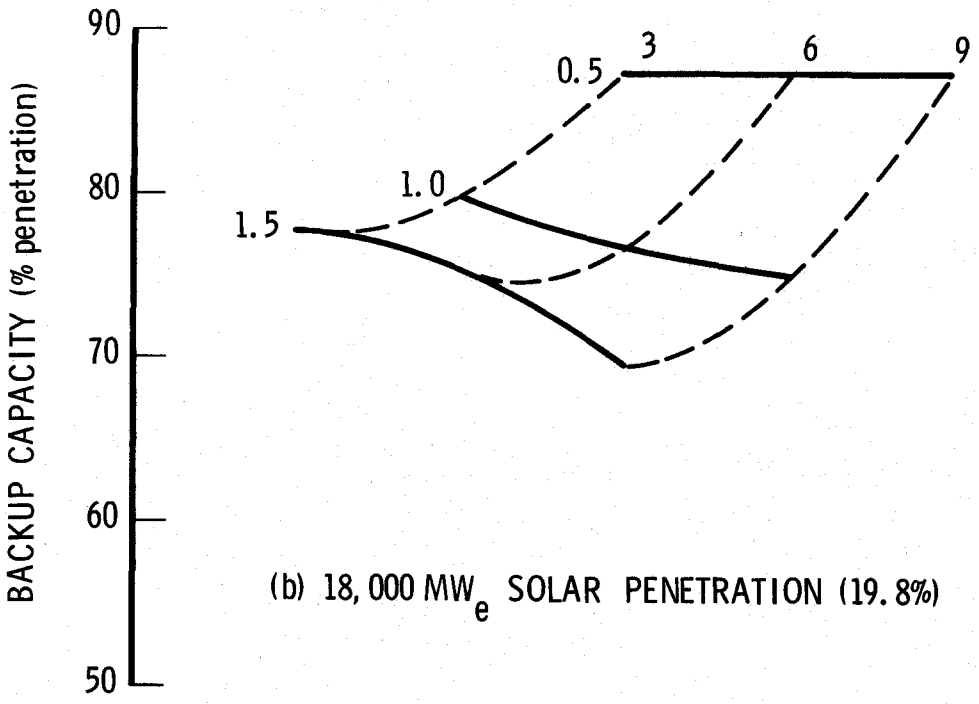


Figure 4-18. PJM (1990) - Sterling, Vermont, Margin Analysis Results, 8000 MW_e Solar Penetration (8.8%)

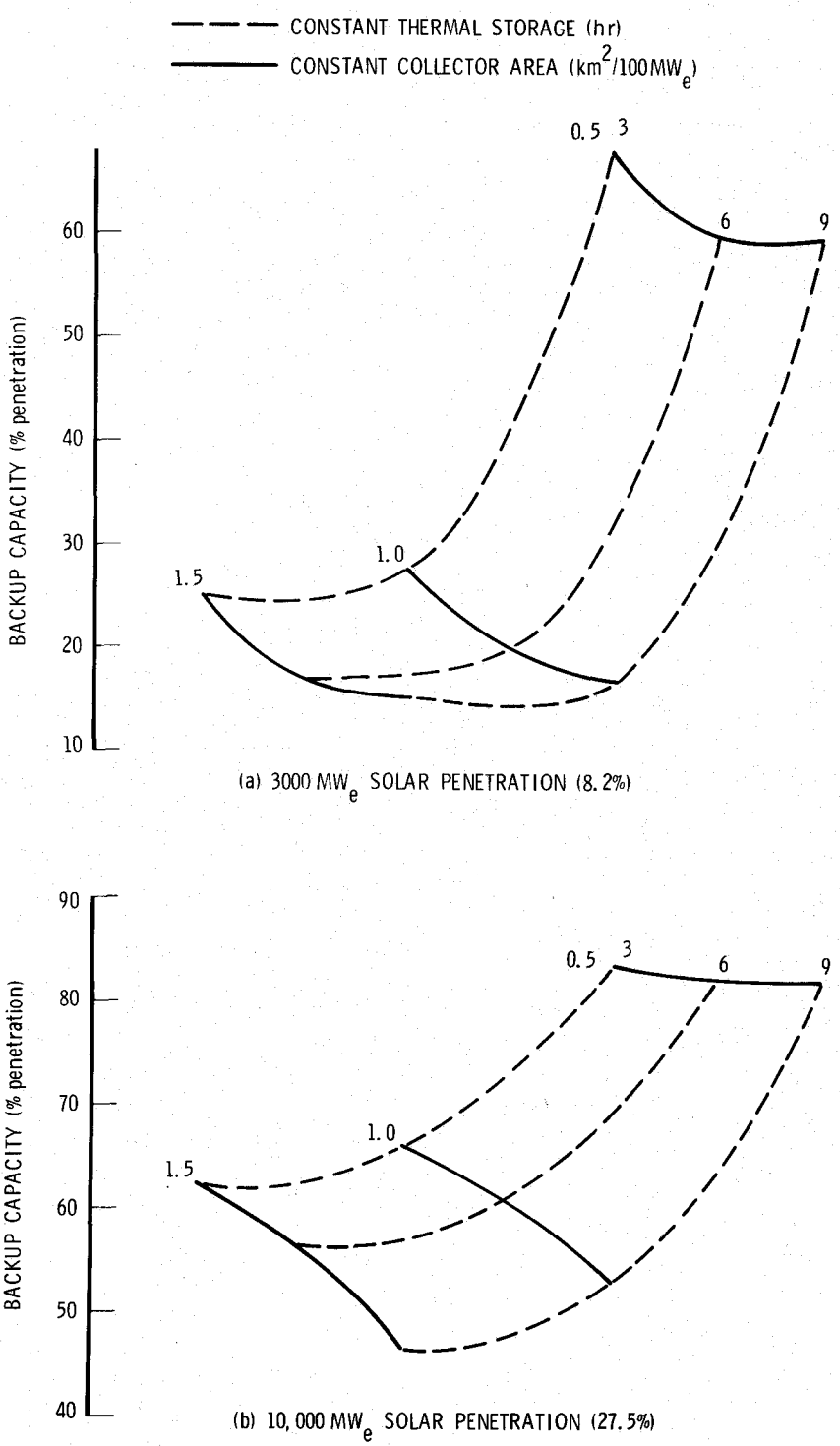


Figure 4-19. SCE (1990) - Inyokern, California, Margin Analysis Results

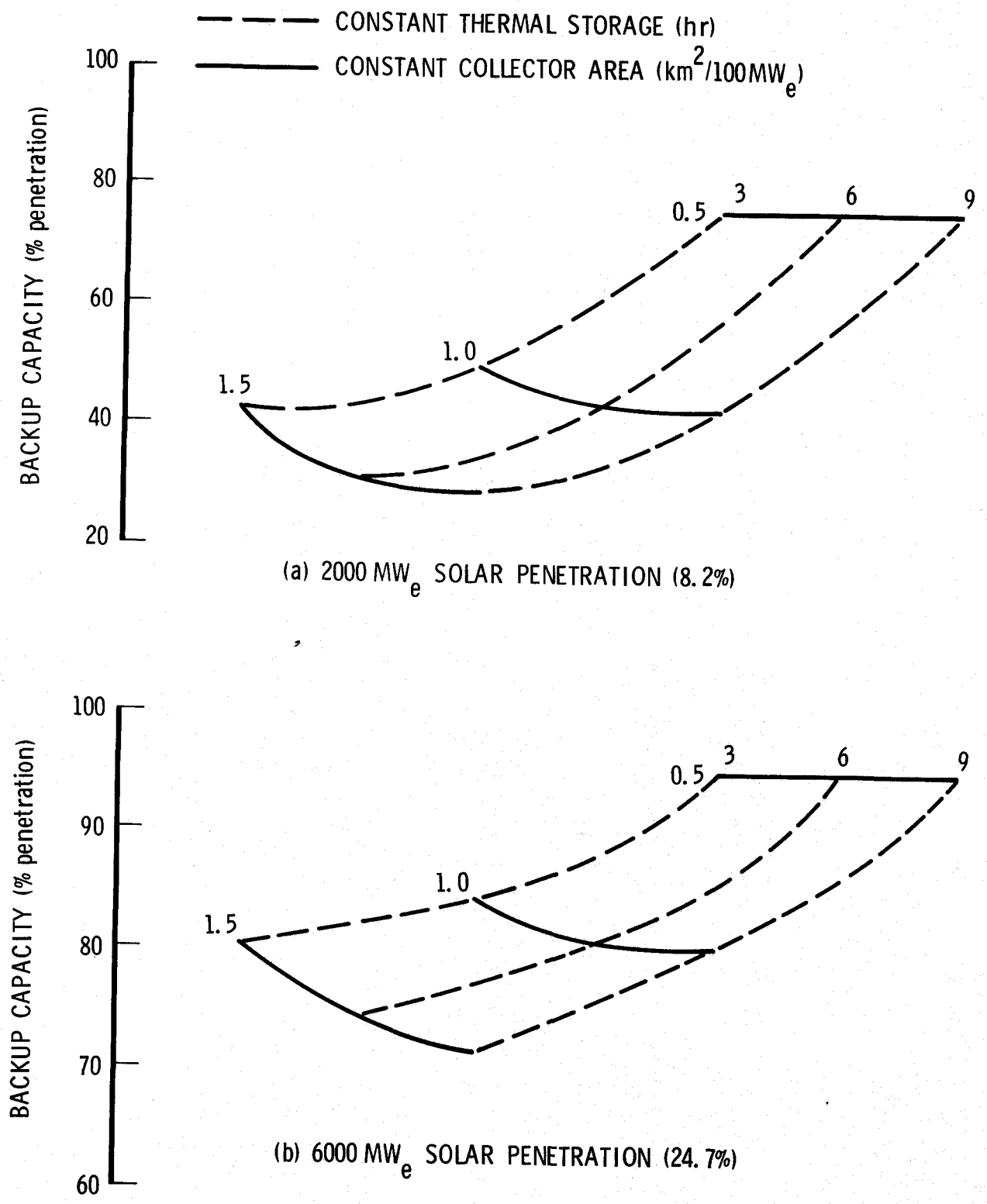


Figure 4-20. FPL (1990) - Miami, Florida, Margin Analysis Results

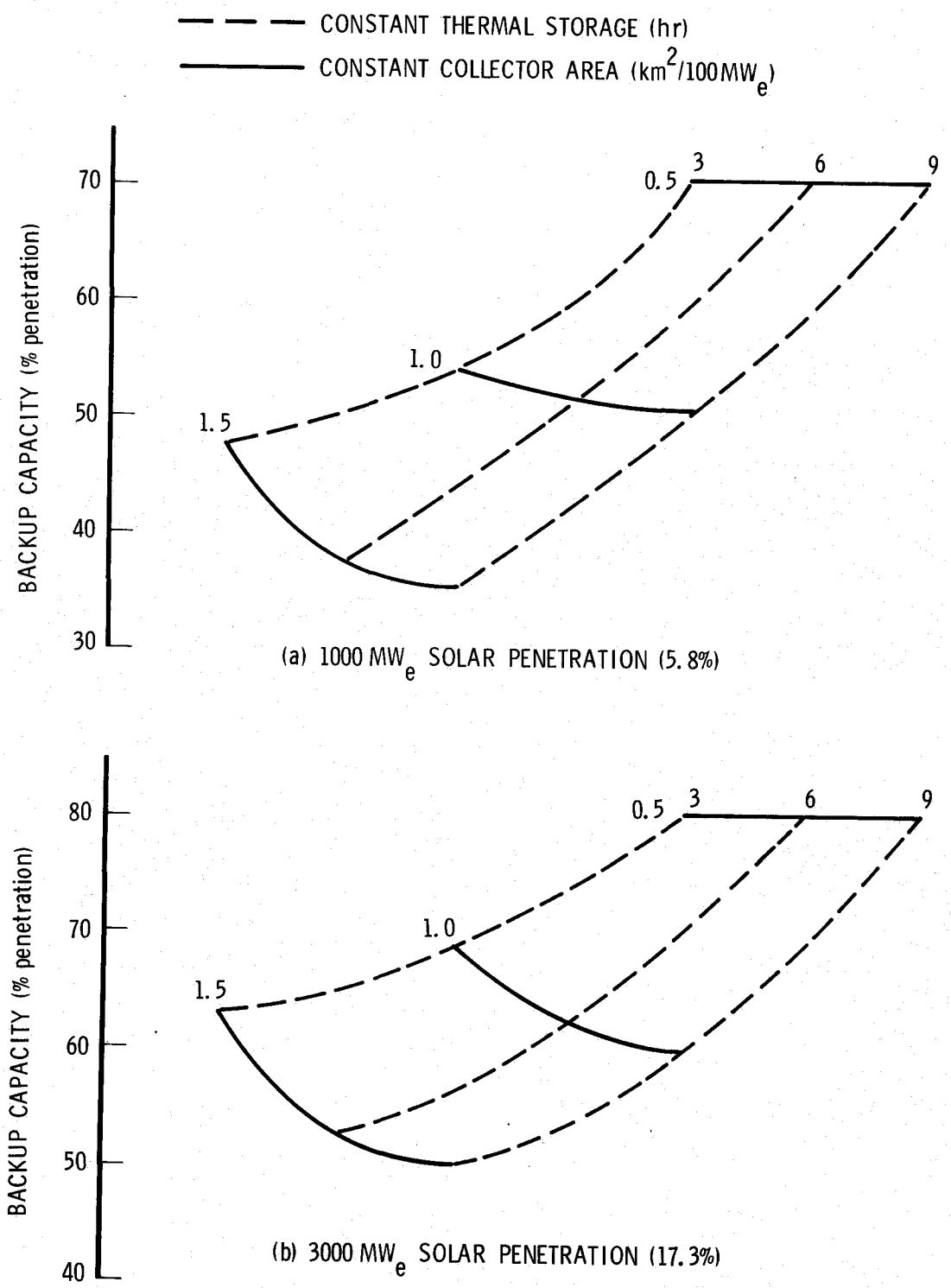
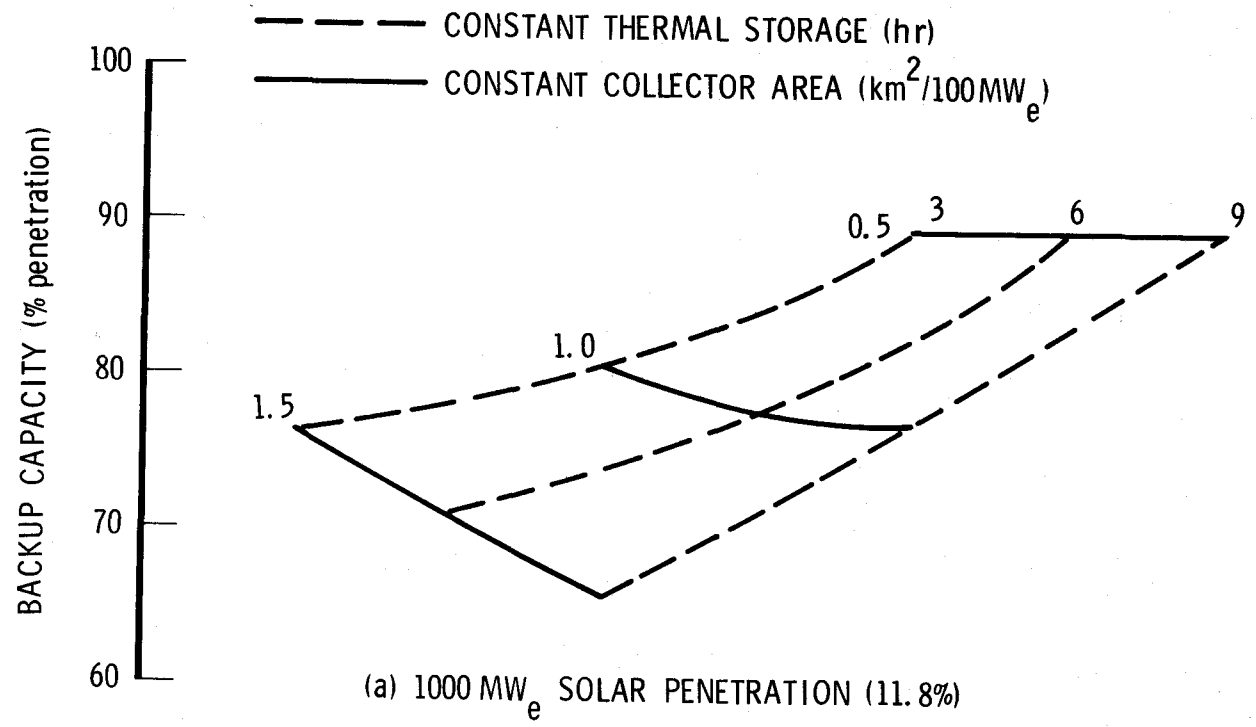
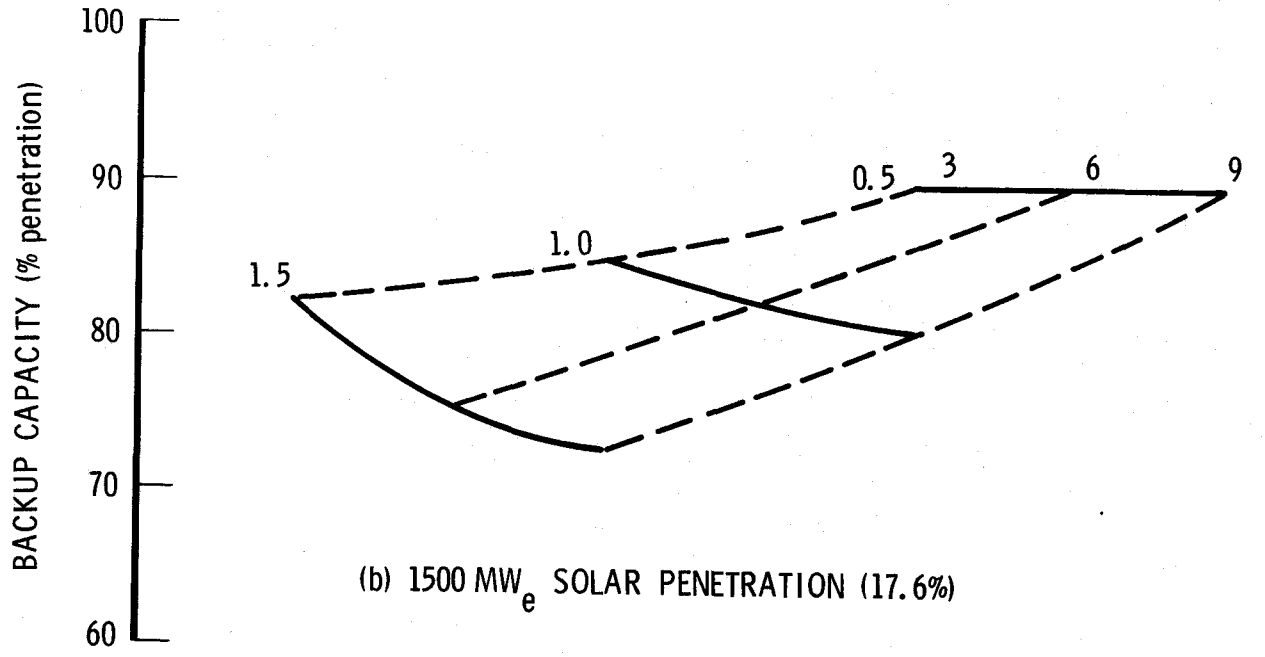


Figure 4-21. CPL (1990) - Madison, Wisconsin, Margin Analysis Results



(a) 1000 MW_e SOLAR PENETRATION (11.8%)



(b) 1500 MW_e SOLAR PENETRATION (17.6%)

Figure 4-22. PPL (1990) - Seattle, Washington, Margin Analysis Results

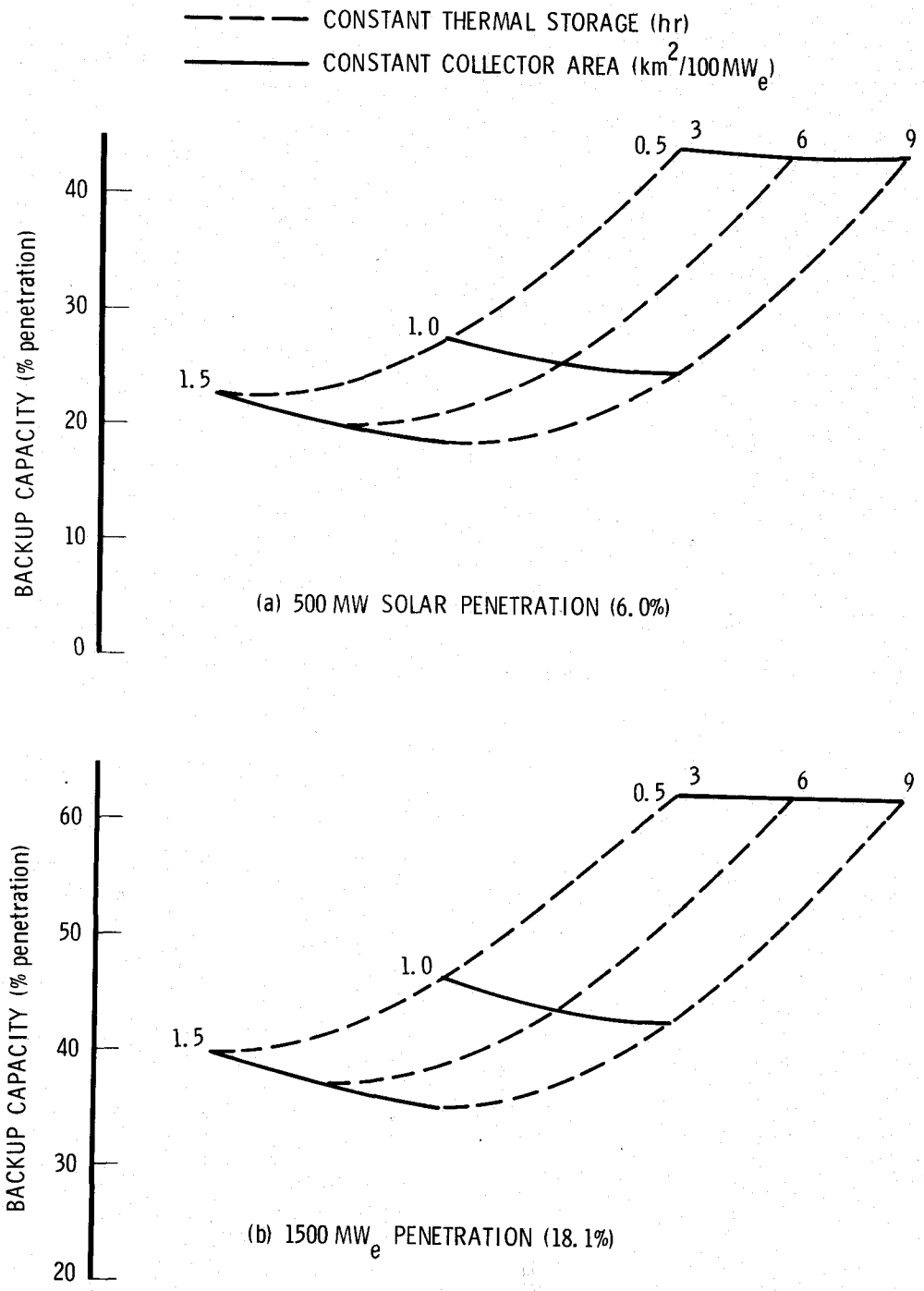


Figure 4-23. CPSB (1990) - San Antonio, Texas, Margin Analysis Results

solar collector area. At a collector area of 0.5 km^2/100 MW and storage capacity of three hours, full power is not being generated by the solar plants during many high demand periods (even though there is adequate insolation to provide this power) because these two subsystems are undersized with respect to turbine/generator capacity. Consequently, a major decrease in backup capacity is obtained when the collector area is increased from 0.5 to 1.0 km^2/ 100 MW and when storage capacity is increased from three to six hours. Further increases in collector area and storage capacity have a secondary effect on required backup capacity because the prolonged duration of the insolation outages becomes the limiting factor.

A plot of backup capacity versus penetration for a collector area of 1.0 km^2/100 MW and storage capacity of six hours given in Figure 4-24. As shown in this figure, backup capacity increases rapidly with penetration. This is due to the fact that increasing the amount of solar penetration does not result in a proportional increase in solar energy on days when there is little or no insolation. Even though there may only be a few days when solar outages occur, they are the predominant influence when the analysis is constrained by the stringent loss of load requirement. This figure also shows the wide variation in backup capacity required for the various utilities. The most significant factor here is the average insolation level, which tends to be low in the East and higher in the Southwest.

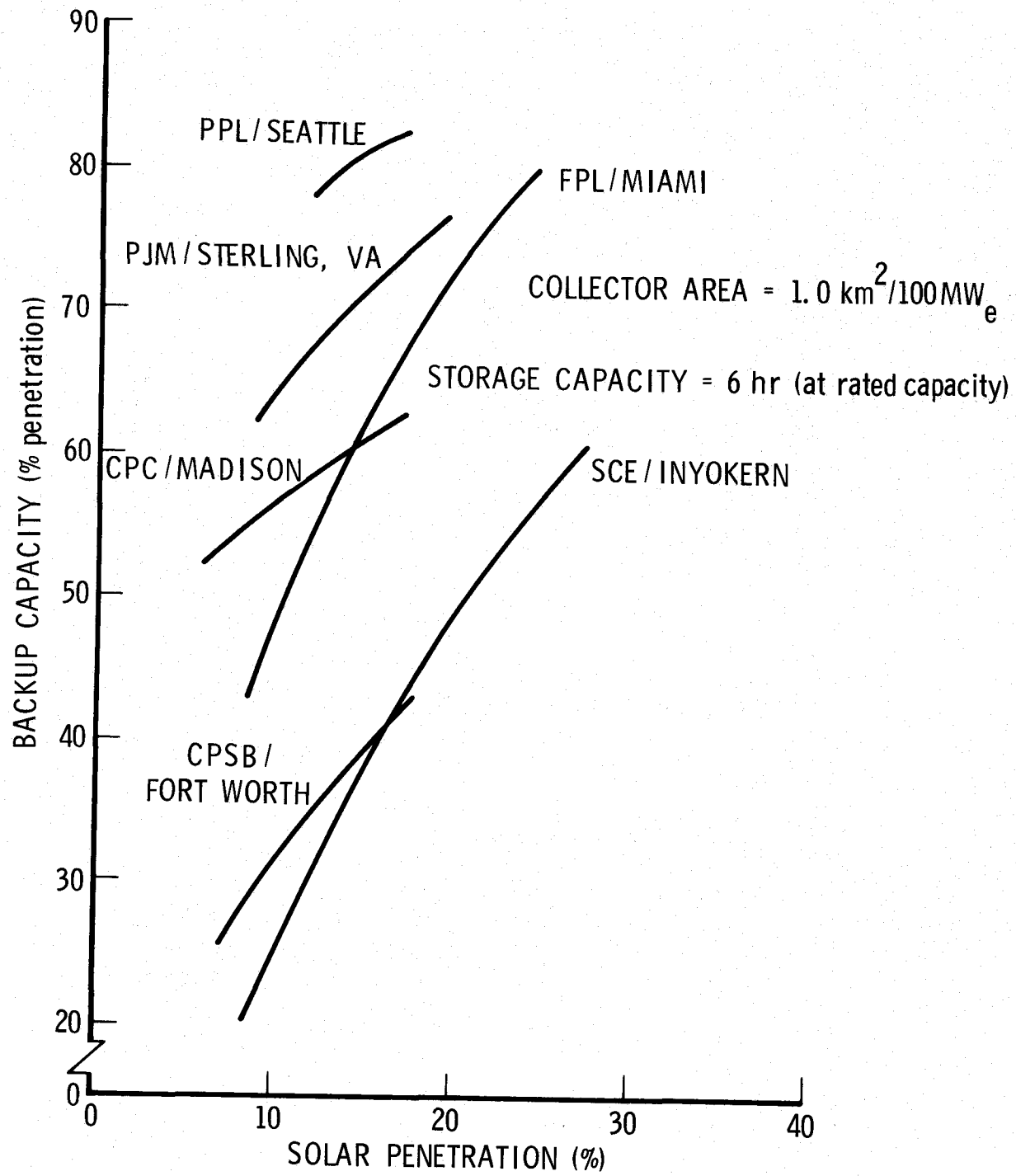


Figure 4-24. Dependence of Backup Capacity on Solar Penetration

D. SOLAR PLANT ECONOMIC ANALYSIS

1. INTRODUCTION

In support of this and previous mission analysis studies, The Aerospace Corporation has performed studies of the investment costs and operating economics of various solar plant concepts. These solar plants, with various assumptions regarding configuration and geographic location, have been compared with each other and with various kinds and sizes of fossil fueled electric plants to determine the conditions under which solar plants will be economically competitive. The outputs of these economic studies consist typically of two figures for each specific case. These are the plant capital investment cost (dollars/per kilowatt) referred to a selected year; and the busbar energy cost (mills per kilowatt hour, or dollars per megawatt hour) based on the capital investment costs and on various sets of assumed economic parameters. Inputs to these calculations are plant construction costs, assumed plant lifetime, and construction period; annual plant capacity factor; and assumed economic parameters including interest rates, cost escalation rates and costs of taxes, insurance, etc. Also required for fossil plants are assumed fuel costs and escalation rates; and for the solar plants, the expected backup capacity (additional margin) requirements. The performance simulation studies previously described in Section IV provide the plant capacity factor and (for solar plants) the backup requirements.

2. ECONOMICS METHODOLOGY

A variety of economic models and computational algorithms have been used by various organizations to estimate busbar energy costs. The early Aerospace Corporation studies (Ref. 4) utilized a computerized technique called The Power Plant Economic Model (PPEM) whose formulation is described in Ref. 7. This model was also the basis of the busbar energy cost estimates presented in November 1975 at the Solar Thermal Projects Semiannual Review in Las Vegas. Beginning in early 1976, however, Aerospace undertook the development of a new and more comprehensive

economic model, the Public Utility Financial Analysis and Planning Model, PUFAP. The Aerospace PUFAP program was utilized for this report for calculating busbar energy costs.

A third modeling technique, which is of interest, is the ERDA/EPRI Revenue Methodology described in Ref. 8. The use of this technique, hereafter referred to as the ERDA/EPRI method, has been encouraged by ERDA in order to assure that economic calculations by different agencies are done on a common basis to facilitate comparison. The ERDA/EPRI method is a levelized fixed charge method which provides constant busbar energy costs over the assumed plant lifetime. It is useful for preliminary cost comparisons, but provides limited insight into the effects of various economic assumptions on the annual cash flows and working capital of a utility.

3. METHODOLOGY APPLICATION

This section of the report discusses the details of application of the various economics methodologies referred to above and provides general comparisons of their operation. Despite the apparent differences in computational approach, all cost of energy analyses address similar cash flows that are incurred in the generation of electrical energy. Each analysis determines the necessary price of electrical energy in order to provide for the cost of operating the system over its lifetime, and provide a return on the investments of its stockholders and creditors.

An illustration of the representative costs incurred by a power plant over its lifetime is shown in Figure 4-25. The economic analysis must first determine the cash outlays required to finance the construction of the power plant. This construction cost is developed by estimating the cost in current dollars, and then determining the additional costs incurred by excalation from current dollars through the construction period. The interest expenses incurred from the start of construction through the

completion of the power plant must also be calculated. This combination of construction and escalation costs, and interest expense during the building of the power plant is referred to as the total capital investment cost at the year of commercial operation and is illustrated in Figure 4-25.

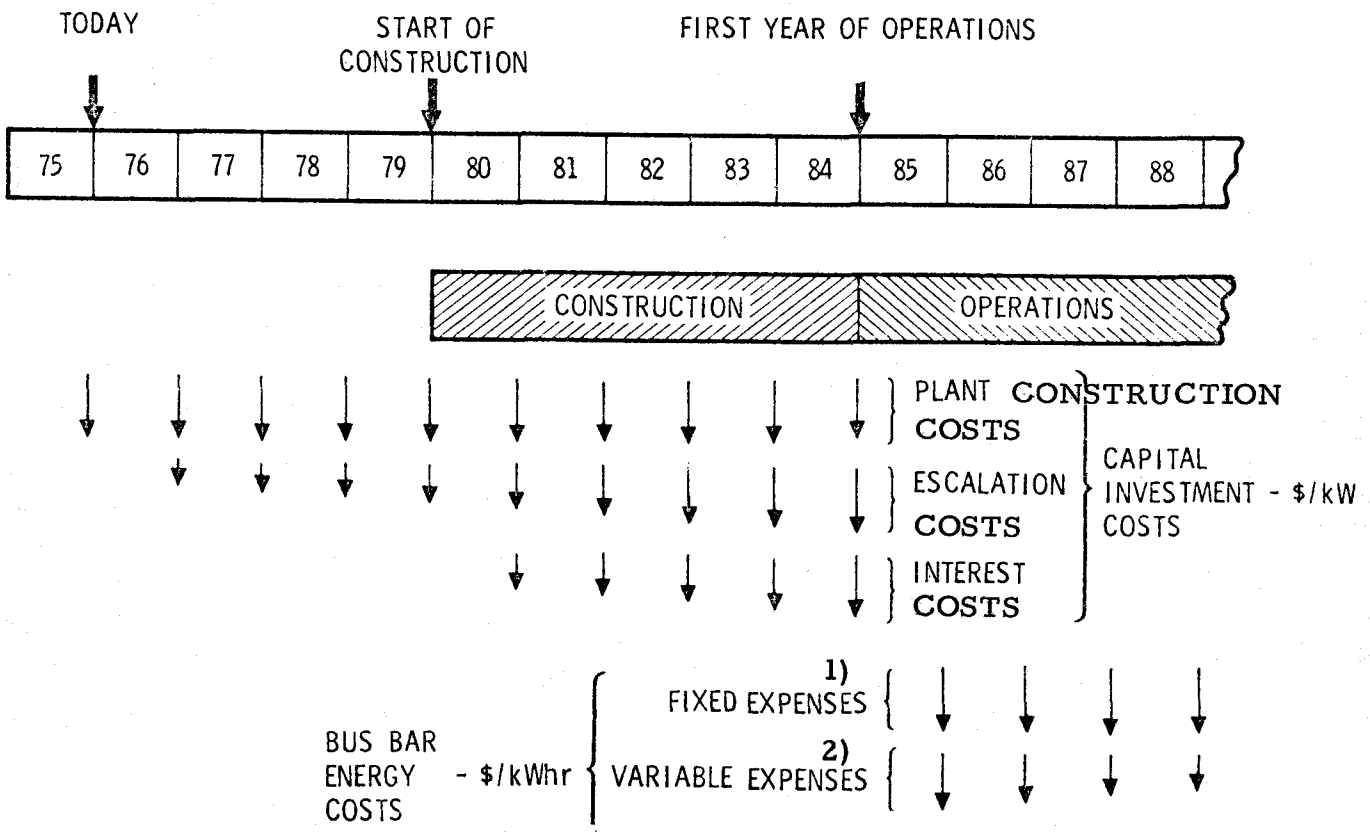
The power plant busbar energy cost (mills per kWh) is then determined by considering the capital investment and all operating expenses incurred during the plant operational period. These expenses can be classified as fixed (e.g., interest, dividends, debt, depreciation, and taxes) or variable (e.g., operations, maintenance, and fuel) expenses.

The effective cost of capital is the weighted average cost of interest, dividends, and yield on bonds, and is based on the debt/equity ratio and the individual rates of return associated with these methods of raising capital. All of the economic models discussed here take these factors into account. The primary differences between models is in the level of complexity and details which either simplifies the lifetime cash flows into an average value, or performs year by year plant cash flow analyses. Also, final results may be presented in either selected year dollars or in current (actual year incurred) dollars. Care must be used when comparing results for similar power plants having substantially different construction schedules since some of the cash flows will be discounted over different periods.

Aerospace Power Plant Economic Model

The Aerospace PPEM has been fully described in Ref. 7. This model consists of a comprehensive computer program which was developed in 1973 for conducting comparative economic analyses of power plants.

PPEM operates by estimating the construction costs for each plant subsystem account (for a given size power plant) in terms of base year dollars. Included in this routine is a cost scaling relationship which adjust for different plant sizes. The model then calculates the plant escalation costs until the start of construction. During construction, interest during construction expenses and additional plant excalation costs are accounted for.



1) Interest, dividends, taxes, depreciation, debt
2) Operations, maintenance, fuel

Figure 4-25. Economic Analysis Methodology

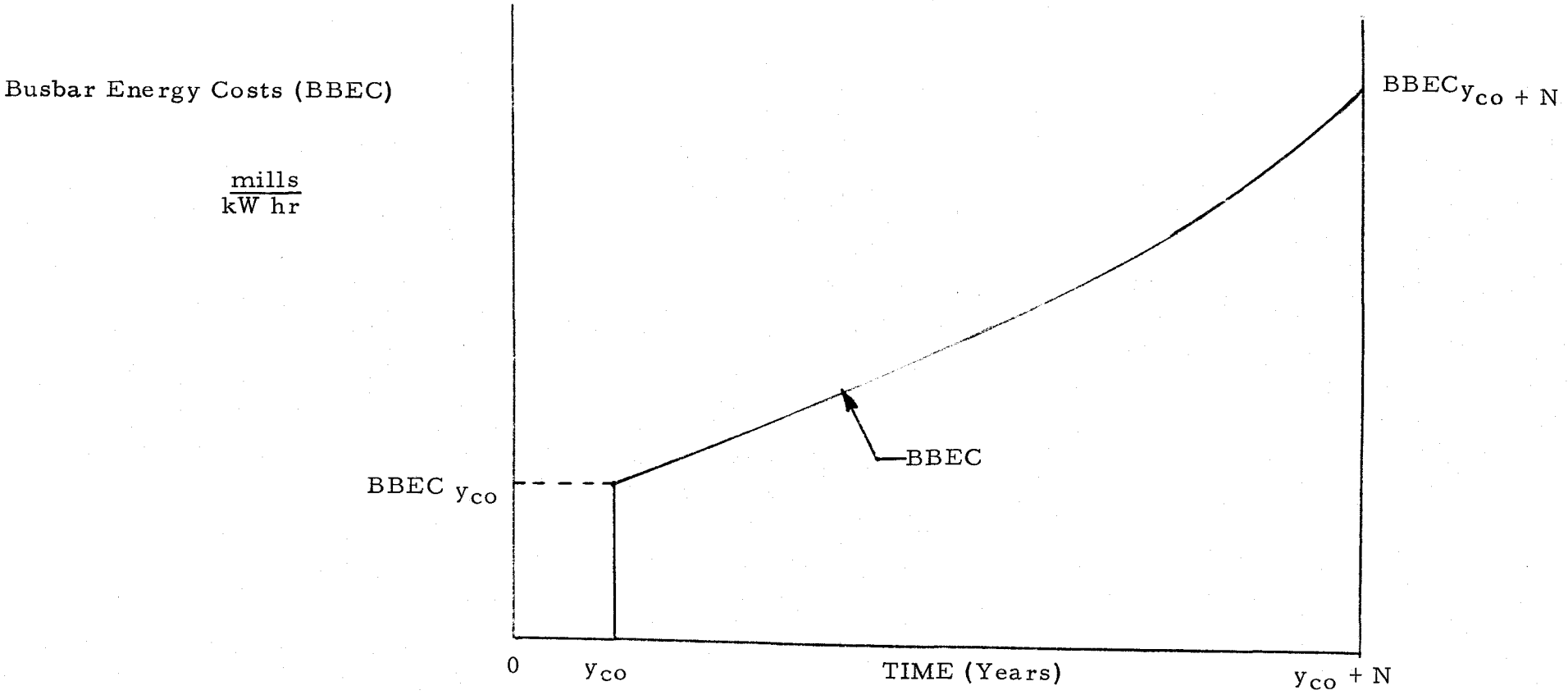
The base year plant construction costs combined with cost escalation and interest during construction determine the total capital investment at the first year of commercial operation, Yco. Using the discounted cash flow method, the capital investment cost at the year of commercial operation together with other annual charges (such as insurance and taxes) are used to determine the fixed and variable plant expenses, and cash flows are then determined from pro-forma income statements. The rate of discount used in this model is calculated from a weighted average rate of return on common and preferred equity and long-term debt. The busbar energy costs are then determined in either current or constant dollars.

An illustration of the results of PPEM is shown in Figure 4-26. The calculated busbar energy cost is a minimum at Yco, and increases monotonically thereafter until the assumed end of plant lifetime. This behavior is in contradiction to the busbar energy costs normally observed, which decrease beyond Yco due to debt retirement. It is because of this behavior that PPEM is no longer used, although it has proved adequate for relative comparison of different systems at a single selected time, usually the first year of commercial operation.

ERDA/EPRI Model

The ERDA/EPRI Model (Ref. 8) is a levelized cost method of computing busbar energy costs in that it computes a constant cost over the life of the plant. This is illustrated on the right side of Figure 4-27, which compares the levelized energy cost with exemplary starting (Yco) and ending (Yco + N) year costs.

This levelized cost method is widely used in the utility industry for quick calculations of busbar energy costs. The key input parameters are the plant construction cost estimates, the fixed charge rate (FCR), and the capital recovery factor (CRF). Ref. 8 provides a methodology for calculating CRF and FCR, based on assumed values for the other economic parameters which enter into the analysis of power plant economics.



BBEC = Busbar Energy Cost

y_{co} = First Year of Commercial Operation

N = System Lifetime

Figure 4-26. Aerospace Power Plant Economic Model (PPEM)

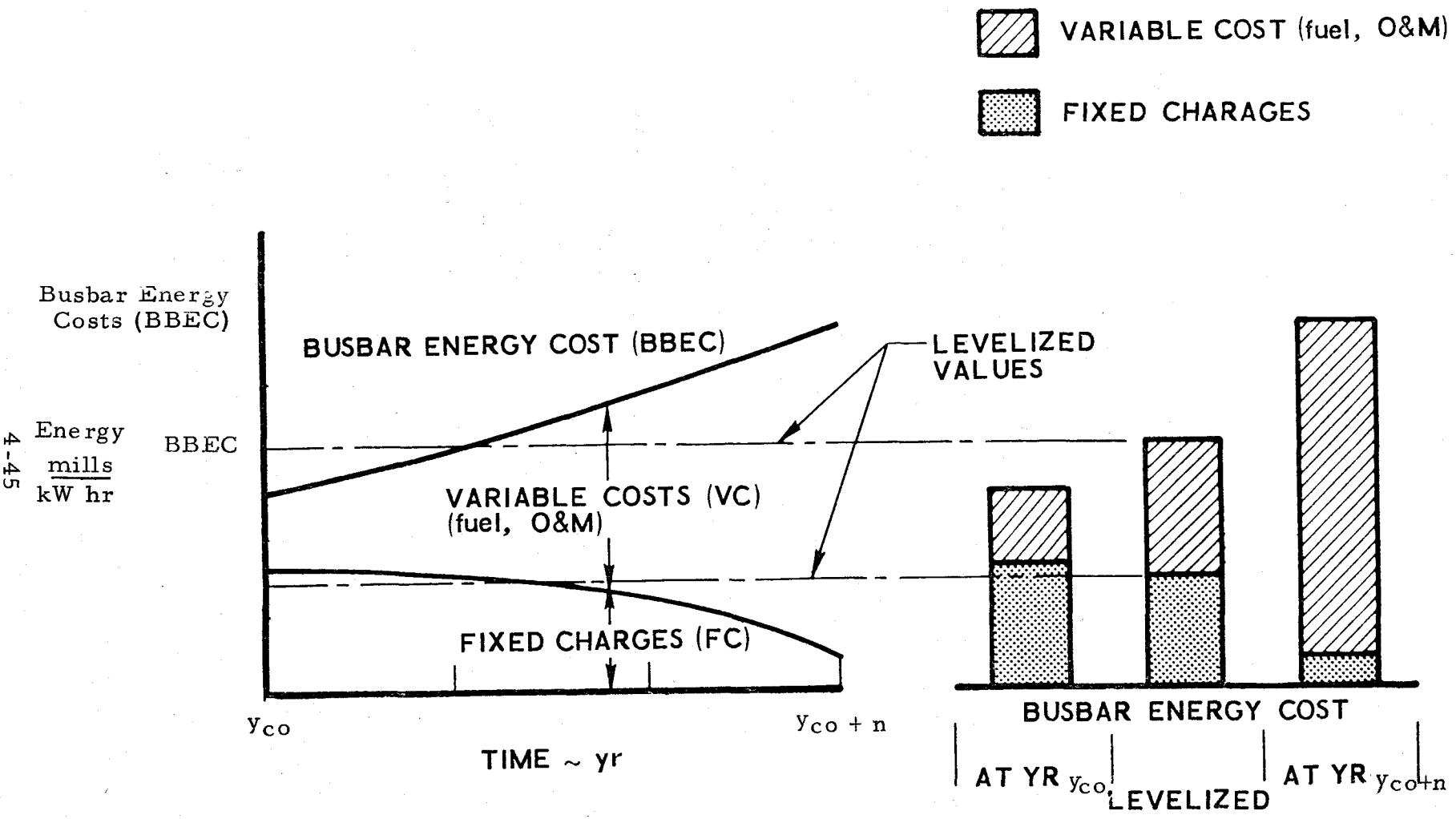


Figure 4-27. Levelized Cost of Service Model

Aerospace Public Utility Financial Analyses and Planning Model (PUFAP)

While many financial and economic models and techniques are currently used by industry to determine the economic feasibility of a power plant and to project the cost of service, few of these models show the detailed financial condition of a power plant over its economic life. In addition, since financial data submitted by power generation utilities to regulatory agencies may vary widely in format, it is often difficult to compare the relative financial prospects of different utilities in a consistent way. To adequately cope with these problems, the computerized Public Utility Financial Analysis and Planning Model (PUFAP) was developed by The Aerospace Corporation, and is described in Ref. 24.

The basic objective of this model is to insure that, based on the estimated cost of plant construction, annual operating costs, financial assumptions, and system performance, the annual plant revenues generated will be adequate to cover all lifetime power plant costs. Specific subroutines of the model provide for a) variable operating and maintenance costs, b) interest on outstanding indebtedness, c) depreciation and amortization of capital cost over the plant economic life, d) an adequate return on equity funds, e) an allowance for income taxes, including deferred income taxes, and f) accountability of all other taxes payable (state, local).

The Public Utility Financial Analysis and Planning Model provides busbar energy costs which vary with time as illustrated in Figure 4-28. A central element of the program is the calculation of annual revenues necessary to provide an adequate return on equity funds employed. This is accomplished through separate computations of total plant investment costs, rate base and rate of return on rate base, and income tax currently payable or deferred.

PUFAP Operation

The first step in operating PUFAP is to input the base year (unescalated) construction and annual operating costs, and other financial, economic, and performance assumptions. The program then escalates the base year construction costs to current dollars and computes each of the

components of the allowance for funds used during construction (AFUDC). Other taxes, materials, supplies, and working capital during construction are also included to determine the total construction cost and the depreciable cost at the first year of commercial operation.

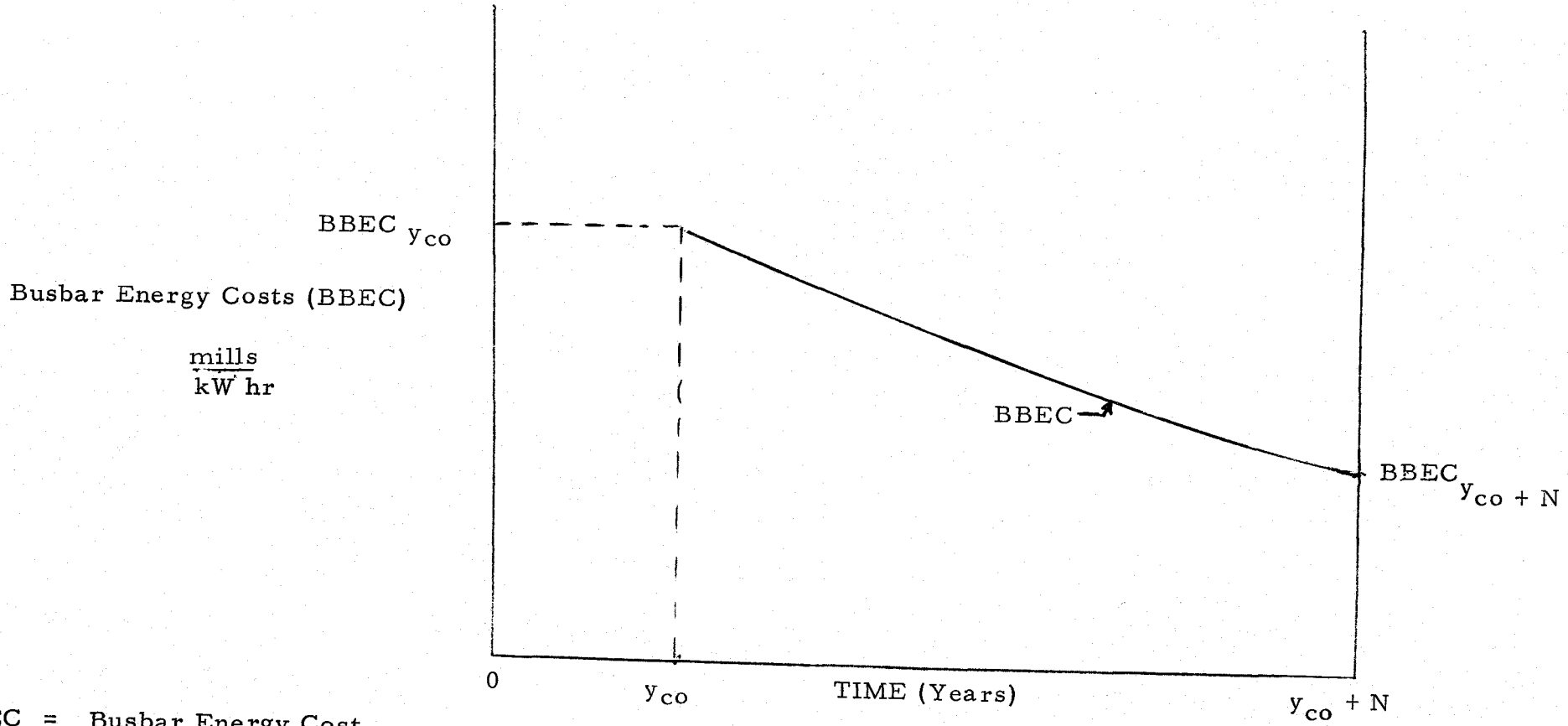
Annual amounts for depreciation are then computed for both initial and replacement facilities. Interest, debt retirement, financial cost and amortization of financing costs are computed next for both initial and replacement facilities.

The program then computes the annual rate of return based on average capitalization and cost of capital. It then computes the rate base which is composed of the average utility plant in service cost less average accumulated depreciation and deferred income taxes plus an allowance for working capital. The rate of return times the rate base provides the return on rate base.

Next, other taxes are computed based on the average depreciated value of plant facilities and the tax rate. Operating and maintenance costs are computed for fuel, other operating and maintenance costs, and insurance.

Federal and state income taxes are computed based on the return on rate base less interest expense plus the book depreciation of the equity return capitalized during construction. The tax adjustments resulting from differences between book and tax depreciation and tax losses from prior years determine those income taxes that are deferred or currently payable.

The program then computes annual cash flows to determine funds available for preferred and common dividends in accordance with dividend policy, and interest income and taxes on reinvested earnings. Annual operating expenses are then totaled and added to return on rate base to provide total operating revenues. Total operating revenues less operating expenses provide the net utility income after taxes. Net utility income is adjusted by other income and deductions to arrive at net income. Other income accounted for in the model, consists of interest income from invested earnings, investment tax credit, and AFUDC while other deductions comprise total interest charges and income taxes on interest income.



BBEC = Busbar Energy Cost

y_{co} = First Year of Commercial Operation

N = System Lifetime

Figure 4-28. Aerospace Public Utility Financial Analysis and Planning Model

The cash flow program then computes all cash sources and uses from the start of construction through each of the plant operational years. Dividends earned during the construction period are paid from available income as soon as the plant enters service -- dividends then are set equal to net income. A balance sheet is then computed showing the annual assets and other debits and liabilities and other credits. An annual cost of service im mills per kWh is also developed for each element of operating expenses and return on rate base.

A comprehensive Discounted Cash Flow (DCF) analysis is the last step in the calculations. The DCF program computes the discount rate, annualized fixed charge rate, capital recovery factor, and levelized energy costs in constant and current dollars. In addition, a present value analysis covering operating revenues, energy production, preferred and common dividends and operating and maintenance expenses is provided. A number of financial ratios covering the cumulative dividend payout rate for both preferred and common stock, effective tax rate, ratio of earnings to fixed charges, and tangible net worth are also provided.

4. ECONOMIC PARAMETER SELECTION

A number of key economic parameters are required as inputs to the various economic analysis models which have been discussed. Among these are the general inflation rate, the current costs of conventional fuels and power plant components, and the expected escalation rates for these costs. The previous economic analyses of Ref. 4 made use of economic parameters which were developed from a 1973 data base. Since 1973, however, these costs and escalation rates have increased significantly each year, and the values prevailing now are quite different from those for 1973.

A comparison of component cost escalation rates for conventional plants used for various phases of the study is shown in Table 4-3. These rates were obtained from Refs. 25, 26, and 27. The most recent rates (right-hand column of Table 3-2) are associated with a general inflation rate of 5.5% as measured by the G.N.P. implicit price deflation, Ref. 27. This value of general inflation rate is assumed to prevail beyond 1975.

Based on the conventional plant component cost escalation rates of Table 4-3 cost escalation rates for the major plant subsystems are presented in Table 4-4. These were estimated partly from the data of Table 4-3, and for the final calculations of this report, were replaced by a composite rate of 6.5%. It should be noted, however, that these values vary significantly over different regions of the U.S., and that for some areas the data underlying Table 4-4 represented a statistically small sample.

Escalation rates have also been developed for solar thermal plant components and major subsystems. Plant component escalation rates used for the study are shown in Table 4-5. For both the current and prior phases the indicated rates were developed from Ref. 26. A composite escalation rate of 6.5 percent per year was projected for solar plants during the final phase of the study. This value was developed by weighting labor at 40 percent and material allocations as 20 percent concrete, 15 percent steel, purchased equipment of 15 percent boilers, and 5 percent pumps and pipes. By comparison, the escalation rate used for the central receiver in the initial studies (Ref. 4) was 2.8 percent.

Fuel escalation rates used in economic modeling are shown in Table 4-6. The initial values of fuel escalation rates were obtained from Ref. 4, and initial study results were developed using data from Ref. 28. The escalation values used for the final study results were obtained from an ERDA report, Ref. 29.

A summary comparison of the economic parameters used in the Aerospace studies is shown in Table 4-7. As noted, the escalation factors increased in all cases between the initial phases of the Mission Analysis Study and the current study. Major increases occurred in the cost of money used in the economic model (7.4% to 11.5%), the plant cost escalation factors (2.8% to 6.5%) and the fuel escalation rate (3.5% to 7.5%). All of these parameters influence the cost of service calculations, resulting in much larger busbar energy costs for the current study compared with those of the earlier analysis. This impact is discussed further in the Busbar Energy Cost Section.

Table 4-3. Cost Escalation Rates

System Component	Projected Escalation Rates Used for Various Phases of the Mission Analysis	
	Initial Study Inputs (%) (11/74)	Interim & Final Parameter Selection (%)
Industrial and Commercial Construction Labor and Materials (Boeckh Index of Construction Costs)	4.7	6.7
Electrical Machinery and Equipment (Wholesale Price Index)	1.0	4.1
All Machinery and Equipment (Wholesale Price Index)	1.8	5.2
Iron and Steel Products (Wholesale Price Index)	3.6	6.3
Rural Land (Department of Agriculture Index)	6.1	8.6
GNP Implicit Price Deflator (Ref 13)	3.0	5.5
Turbine/Generators (Handy-Whitman Index)	1.1	5.4
Boilers (Handy-Whitman Index)	3.0	7.4
Fuel Handling Equipment (Handy-Whitman Index)	1.6	6.7

Data Source - Refs. 16, 17, 18

Table 4-4. Conventional Power Plant Escalation Rates

Conventional Plant Subsystems	Projected Escalation Rates Used for the Mission Analysis		
	Initial Study Inputs (11/75)	Interim Parameter Selection (11/75)	Final Parameter Selection
LAND	6.1%	8.6%	
BOILER	3.4%	6.9%	
PLANT STRUCTURES	4.7%	6.7%	
TURBINE/GENERATOR EQUIPMENT	2.3%	7.1%	6.5%
REACTOR EQUIPMENT	4.2%	6.5%	
ELECTRIC PLANT EQUIPMENT	3.6%	5.9%	
MISCELLANEOUS PLANT EQUIPMENT	3.9%	5.2%	

Table 4-5. Solar Thermal Power Plant Escalation Rates

Category	Description	Projected Escalation Rates Used for the Mission Analysis		
		Initial Study Inputs (2) (11/74)	Interim Parameter Selection (%) (1) (11/75)	Final Parameter Selection
Labor	Construction & Installation	2.8%	7.6	6.5%
Material(s)	Concrete		4.9	
	Steel		6.9	
	Lumber		6.9	
	Wiring & Cables		4.4	
	Plastic		9.2	
	Glass		2.6	
Purchased Equipment	Boilers		6.9	
	Pumps		6.5	
	Steam Pipes		5.0	
	Steel Pipes		5.8	

(1) Data Source - Ref. 26
(2) Data Source - Ref. 4

Table 4-6. Projected Fuel Escalation Rates

Time Period	Projected Fuel Escalation Rates [1] Mission Analysis Study Phase		
	Initial Study Inputs (11/74)[3]	Interim Parameter[4] Selection	Final[2] Parameter Selection
1980 - 1990	3.5%	10.0%	Coal-6.5%
1990 - 2000	3.5%	8.0%	Oil-7.5%
2000 - 2010	3.5%	6.0%	

(1) For both coal and oil, except as noted
(2) Escalation rates are for the period 1980-2010 - Data Source - Ref. 29
(3) Data Source - Ref. 4
(4) Data Source - Ref. 28

Table 4-7. Summary Comparison of Mission Analysis Economic Parameters

Parameter	Mission Analysis Study Phases		
	Initial Study Inputs (11/74)	Interim Parameter Selection (11/75)	Final Parameter Selection
General Inflation Rate	3.0%	5.2%	5.5%
Conventional Plant Escalation Rate	2.3 - 6.1%	5.2 - 8.6%	6.5%
Solar Collector/Receiver/Thermal Storage Escalation Rate	2.8%	2.6 - 7.6%	6.5%
Fuel Escalation Rate	3.5%	6.0 - 10.0%	6.5 - 7.5%
Revenue Escalation Rate	2.0%	4.0%	0%
Applicable Data Year	1973	1975	1976
Base Year for Costs	1975	1975	1975
Cost of Money	7.4%	8.35%	11.5%

5. PLANT CONSTRUCTION COSTS

During the course of the study, power plant capital investment cost accounts have been developed at the system and subsystem level of detail. For each of these cost accounts, composite escalation rates (shown previously in Tables 4-4 and 4-6) have been applied to determine the total capital investment costs at the year of commercial plant operation (including interest during construction and escalation costs). The investment cost accounts generally follow the structure previously introduced by the Atomic Energy Commission and currently used by the Federal Power Commission. Additional accounts have been introduced during this study to accommodate the solar equipment portions of electric power plants. Figure 4-29 illustrates the central receiver power plant investment cost account structure to the level of detail used in the current study. A brief description of the central receiver system and subsystem elements included in each cost account is presented below:

Cost Account Structure

a) Land Acquisition Account

This account includes the cost of locating the utilities and buildings on the proposed site, and includes land purchase, surveys, clearing costs, etc. Not included in this account are the costs for site preparation for various plant subsystems (e.g., site preparation for the collector foundation will be allocated to that particular subsystem element).

b) Structures Account

This account includes all structures and facilities required for the conventional portion of power plants, including turbine generator building, administration building, etc. The costs for structures required for the central receiver tower and collectors are not included.

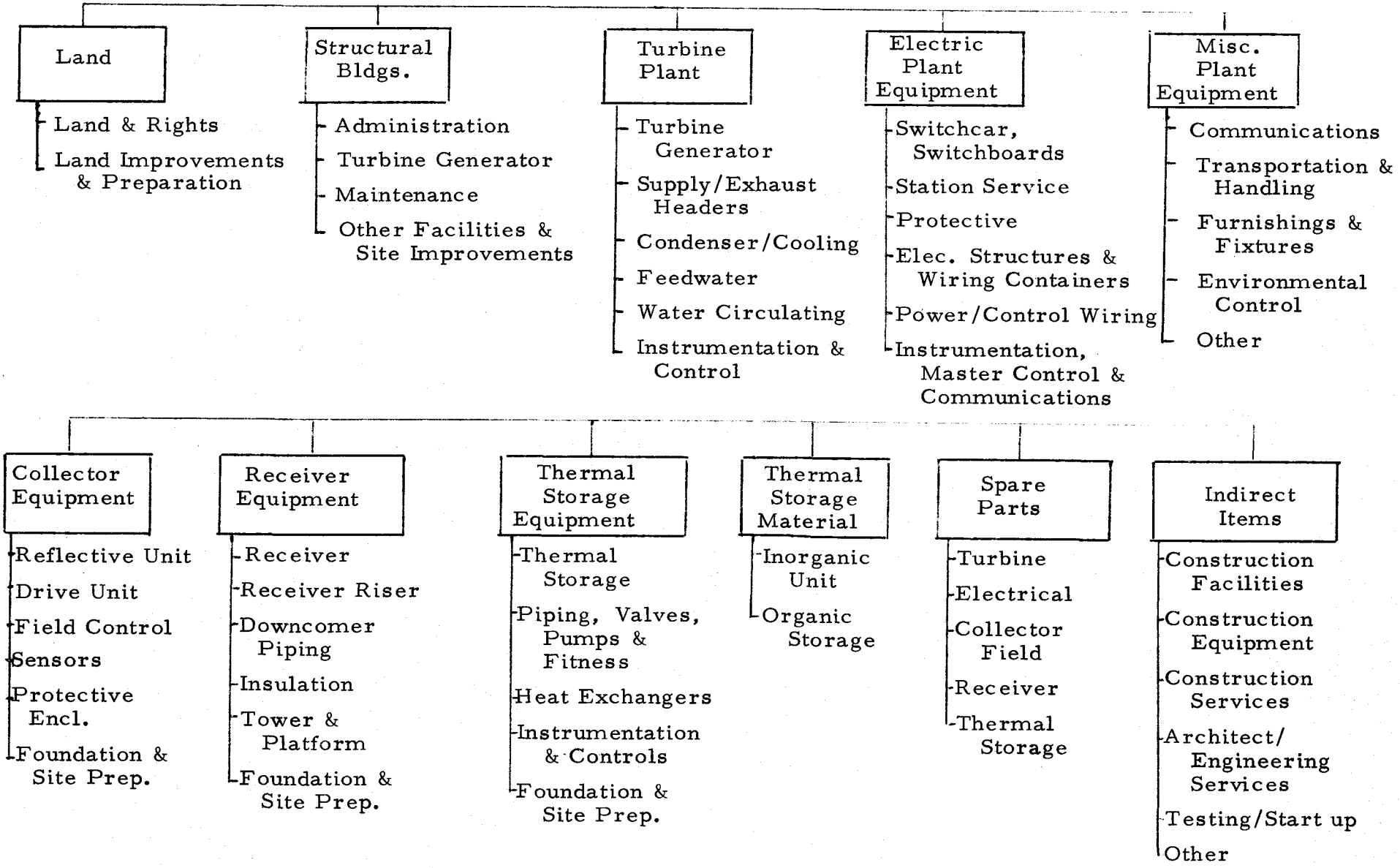


Figure 4-29. Central Receiver Power Plant Costing Work Breakdown Structure

c) Turbine Plant Equipment Account

This account includes generator equipment, turbine equipment, control instrumentation, condensing systems, cooling towers, and water circulating systems.

d) Accessory Electrical Plant Equipment Account

This account includes power conditioning, switch gear, station service equipment, wiring conditioning, power distribution, control system computer equipment and software.

e) Miscellaneous Plant Equipment Account

This account includes transportation, communications, furnishings and fixtures, and environmental control systems.

f) Collector Equipment Account

This account includes all items related to the central receiver heliostats and includes reflective surfaces, insulation, structural and foundation supports, heliostat drive units, and any control units which are required.

g) Receiver Equipment Account

This account includes all items related to the receiver, including the tower. Included in this account are the receiver units, receiver support structure, downcomer, riser, control units, and the tower structure and foundations.

h) Thermal Storage Equipment Account

This account includes the thermal storage equipment which is part of the central receiver plant and includes the thermal storage structural unit, heat exchangers, piping, valves, fittings, pumps and control units. Excluded from this account is the heat transport material.

i) Thermal Storage Materials Account

This account applies only to the cost of the heat transport material.

j) Spare Parts Account

This account includes all spares utilized for the central receiver power plant during its operational lifetime.

k) Contingency Account

This account applies to all direct material and labor costs associated with construction and checkout.

l) Indirect Costs Account

This account contains all cost elements exclusive of the fabrication, assembly and checkout of a power plant. It includes any special construction facilities, architect/engineering services, special professional services, training, and plant start-up costs.

Solar Plant Construction Cost Estimates

Utilizing the investment cost accounts shown in Figure 4-29, plant construction costs have been developed for both the solar central receiver plant and for various conventional power plants. A detailed breakdown of the construction cost estimates for 100 MW central receiver solar plants is shown by subsystem in Table 4-8. A comparison between cost estimates used in the initial Mission Analysis Study and those used in the current study is shown in Table 4-9. The initial study cost estimates are given in 1974 dollars, while the most recent estimates are in 1975 dollars. These costs exclude interest during construction and escalation costs incurred up to the year of commercial operation. The initial cost estimates to be associated with each account were obtained from Ref. 4. The most recent cost estimates were developed by Aerospace from preliminary data provided by the ERDA contractors engaged in the 10 MW Central Receiver Pilot Plant Study.*

*In late 1977 much more detailed cost data became available based on well understood design concepts and including estimates of the early plants rather than assuming large volume production for the "Nth" plant. These costs are presently under review.

Table 4-8. Capital Costs of Alternate 100 MW Central Receiver Configuration

Collector Area (km^2)	.5	.5	.5	1.0	1.0	1.0	1.5	1.5	1.5
Storage Time (hr)	3	6	9	3	6	9	3	6	9
Solar Plant Element Costs - $\$/kW_e$									
Land	1.8	1.8	1.8	3.5	3.5	3.5	5.3	5.3	5.3
Structures	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9	52.9
Turbine Plant	107.8	107.8	107.8	107.8	107.8	107.8	107.8	107.8	107.8
Electric Plant	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9	25.9
Miscellaneous	28.7	28.7	28.7	28.7	28.7	28.7	28.7	28.7	28.7
Collector (1)	324.0	324.0	324.0	613.0	613.0	613.0	937.0	937.0	937.0
Receiver	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0	96.0
Therm Storage (3)	50.0	100.0	150.0	50.0	100.0	150.0	50.0	100.0	150.0
Spare Parts	4.3	4.3	4.3	6.4	6.4	6.4	8.9	8.9	8.9
Contingency	42.7	43.2	43.7	60.8	61.3	61.8	81.0	81.5	82.0
Indirect Costs	185.3	188.3	191.2	225.9	228.8	231.8	271.3	274.3	277.2
Plant Construction Costs (2) - $\$/kW$	919.4	972.8	1026.3	1271.9	1324.4	1377.8	1664.8	1718.3	1771.7

(1) **Collector and receiver costs - 61 $\$/m^2$**

(2) Excludes interest during construction and inflation costs - All estimates are in 1975 dollars

(3) Storage costs assumed to be $\$17/kW_e h$

Table 4-9. Comparison of 100 MW Central Receiver Capital Investment Costs

Solar Plant Element[1]	Capital Costs ($/kW)		
	Initial Cost Estimates (1974 Dollars)	Interim and Final Cost Estimates From Table 3-7 (1975 Dollars)	% Increase
Land	2.0	3.5	75%
Structure	43.8	52.9	21
Miscellaneous	23.6	28.7	22
Turbine Plant	80.0	107.8	35
Electrical	21.0	25.9	23
Collector Receiver	354.0[2]	709.0[3]	100
Thermal Storage	90.0	100.0	11
Direct Plant Costs	614.4	1027.8	
Indirect Costs, Contingencies, and Spares	161.7	296.2	83
Total Plant Construction Costs[4]	776.1	1324.0	

1) Collector Area = 1 km^2, Thermal Storage = 6 hr
2) 35 $/m^2$
3) 71 $/m^2$
4) Excludes interest during construction and inflation costs
5) Data developed in late 1977 indicate higher costs than shown here for early plants.

As shown in Table 4-8, the central receiver power plant cost estimate approximately doubled during the course of the study from 776 to 1324 $/kW. This was due to the change in the estimated heliostat cost from 30 $/m^2 to 61 $/m^2, coupled with sudden large increases in the costs of most of the other plant components. The capital costs of alternate 100 MW central receiver configurations evaluated in the current study are shown in Table 4-8. These estimates are for a family of power plants having the same capacity (100 MW), but with the collector field area varying from 0.5 to 1.5 square kilometers, and thermal storage time varying from 3 to 6 hours.

The plant construction cost estimates presented in Table 4-8 and 4-9 apply to commercial solar plants operational in the 1990 time period and are based on discussions held with ERDA contractors and on Refs 35, 36, 37, and 38. These estimates assume large production quantities of all plant components and manufacturing facilities in which high production rate jigs, fixtures and tooling have been installed.

Conventional Plant Cost Estimate

Construction cost estimates for conventional fossil fuel plants and for nuclear plants are shown for comparison in Tables 4-10 and 4-11. The data in Table 4-10 were utilized in earlier phases of the Mission Analysis and are now outdated. Table 4-10 has, however, been included here for comparison with the most recent cost estimates which are given in Table 4-12. Most of the data in the references on which these tables were based are for 1000 MWe plants. The data for smaller sizes (100 MWe and 400 MWe) were obtained by use of a scaling relationship: $C/_{Co} = (S/_{So})^k$ where C is cost per kilowatt, S is size (kilowatts), and the subscript denotes values for a 1000 MWe plant. The exponent k is found to be about 0.9 in order to fit the available data.

On comparing these two tables, substantial increases in cost are evident between 1974, when the figures of Table 4-10 were applicable, and late 1976, the date of applicability of Table 4-11. All plants represented in Tables 4-10 and 4-11 include provisions for the flue gas desulfurization

Table 4-10. Conventional Power Plant Construction Costs
(Data Used in Earlier Studies)

Plant Construction Cost Elements[1] ($/kW)	Power Plant Construction Costs ($/kW)[2]			
		Coal Fired Steam Plants		
	Nuclear (1000 MW)	1000 MW	400 MW	100 MW
Direct Costs	287	252	299	386
Indirect Costs	117	83	89	223
Contingency and Spares	23	20	24	32
Total Capital Investment	427	355	412	641

(1) Excludes interest during construction and inflation costs. All estimates are in 1975 dollars, and are provided for comparison purposes only. See Table 4-11 for current estimates.

(2) Data Source - Ref. 30 and 31.

Table 4-11. Conventional Power Plant Construction and Fuel Costs - Final Parameter Selection

Plant Type	Plant Location	Fuel Costs[2] ¢/$/MBtu	Power Plant Construction Costs[1] - $/kW		
			100 MW	400 MW	1000 MW
Coal Fired Steam[3]	Pacific	.76	885	735	671
	North Central	.63	690	602	549
	South Atlantic	.98	708	615	562
Oil Fired Steam[4]	Pacific	2.14	537	447	339
	North Central	2.09			
	South Atlantic	1.68			
Nuclear[4] (Light water)	Within U.S.	-	-	-	550[3]

(1) Excludes interest during construction and inflation costs. All estimates are in 1975 dollars

(2) Data Source - Ref. 34

(3) Data Source - Ref. 32

(4) Data Source - Ref. 33

Table 4-12.

Comparison of Conventional and Solar Power Plant Construction Costs

Plant Type	Construction Cost Parameters[1] Utilized During Various Phases of the Mission Analysis		
	Initial Study Inputs (1974 Dollars)	Interim Study Inputs (1975 Dollars)	Final Parameter Selection (1975 Dollars)
Coal Plant			
100 MW_e	522 $/kW	640 $/kW	690-885 $/kW
400 MW_e	382 $/kW	412 $/kW	602-735 $/kW
1000 MW_e	310 $/kW	356 $/kW	562-671 $/kW
Fuel Costs	$0.35/MBtu (1980 $)	$0.57/MBtu (1980 $)	$0.76/MBtu to $0.98/MBtu
Oil Plant	N/A	N/A	
100 MW_e			537
400 MW_e			447
1000 MW_e			339
Fuel Costs	N/A	N/A	$167/MBtu to $214/MBtu
100 MW_e Central Receiver (1.0 sq km, 6 hrs)	776 $/kW	1324 $/kW	1324 $/kW
Heliostat Unit Cost	30 $/$m^2$	61 $/$m^2$	61 $/$m^2$

(1) Excludes interest during construction and inflation costs

and mechanical draft cooling towers, but exclude costs due to escalation and interest during construction. Also, it should be noted that there are substantial regional differences in power plant costs. Table 4-11 illustrates this point and shows that construction costs have generally been higher in the Pacific States than in the South Atlantic or North Central States.

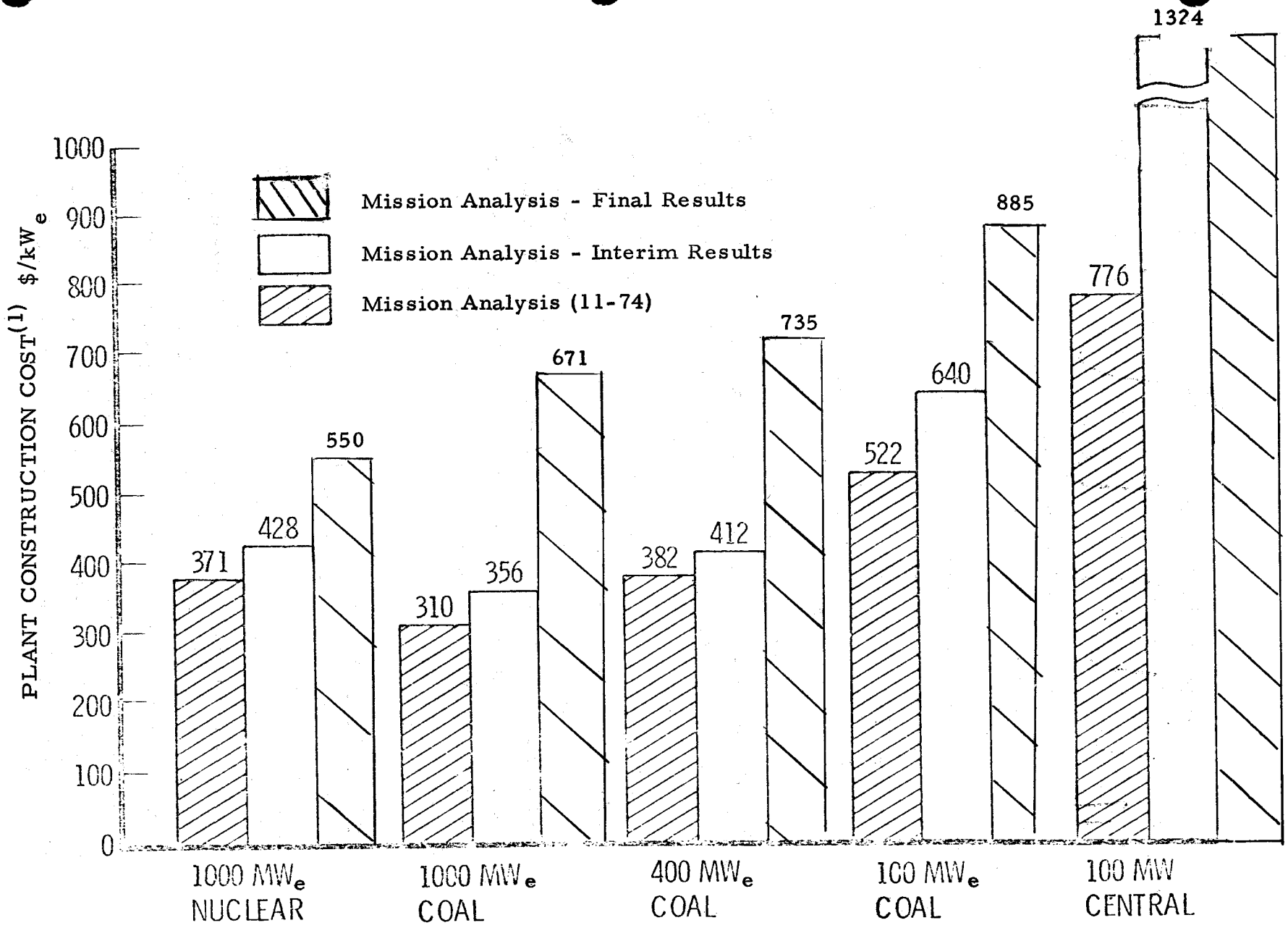
Table 4-12 summarizes the cost parameters used during the initial, interim, and final phases of the Aerospace Mission Analysis. Both fossil (coal and oil) plants and solar plants are addressed. Nuclear plant costs are omitted from this final comparison because they are invariably operated as baseload plants. Solar plants have been found economically unattractive when operated as baseload plants because of the large amount of storage required and the relatively low conventional energy costs with which the solar plant must compete. The data in Table 4-12 are also presented in graphical form in Figure 4-30.

6. BUSBAR ENERGY COSTS

a) Analysis Methodology

Comparative cost of service analyses were conducted for electrical generating systems consisting of either conventional power plants, or combined conventional and solar thermal power plants. These evaluations were for power plants utilized in an intermediate (load following) mode. Nuclear and coal baseload power plant costs of service were also calculated for comparative purposes. The final economic analyses for this study have also been compared with the initial and the interim Mission Analyses study results, and these comparisons are presented in this section.

The comparative economic analysis procedure first estimates the plant construction costs in 1975 dollars, and then calculates the additional funds (i.e., escalation and interest during construction) required prior to the first year of commercial operation. Then, using the fixed charge rate (FCR) and capital



- Excludes interest during construction and inflation costs
- Mission Analysis Interim and Final Results estimates are in 1975 dollars.
- Mission Analysis study in 11/74 is in 1974 dollars.

Figure 4-30. Summary Comparison of Aerospace Power Plant Construction Costs

recovery factor (CRF) calculated by the Aerospace financial model (PUFAP), the annual levelized fixed and variable expenses of the plant operations are determined using the ERDA/EPRI methodology. The sum of these fixed and variable costs is the levelized plant busbar energy cost (mills per kWh) on an annual basis in current dollars.

Two additional cost items must be determined for the solar plants. These are the backup capacity (additional margin) costs required by the addition of the solar plants and the fuel credit for displacement of baseload fuel.

The solar backup capacity costs are the costs of those additional (fossil) peaking units required to provide an increase in the total reserve capacity to maintain the same overall system reliability as that of the conventional only system. The fuel displacement is a credit to the solar plant, and is due on the additional energy available from thermal storage (in excess of scheduled intermediate demand), to be used in place of power supplied by other baseload conventional plants. This excess energy can result in a reduction of the fuel used in other conventional plants, and the savings in the fuel cost is credited to the solar thermal plant.

b) Interim Study Results

During the ERDA Semiannual Review held in Las Vegas in November 1975, some interim results of the Mission Analysis were presented, and are briefly repeated here for information purposes. The computational methodology utilized was the Aerospace PPEM Program described earlier. The busbar energy costs for nuclear and coal plants and for a 100 MW central receiver plant, operational in the 1990 time period, and assumed located in Inyokern, California, as calculated by this program are presented in Table 4-13.

Table 4-13. Allocation of Power Plant Busbar Energy Costs - Interim Results
(Semi Annual Review Presented in November 1975)

	BUSBAR ENERGY COSTS - $\frac{\text{MILLS}}{\text{kW HR}}$ (1975 DOLLARS)				
Plant	Nuclear	Coal	Coal	Coal	Central Receiver
Plant Rating	1000 MW	1000 MW	400 MW	100 MW	100 MW
Utility/Insolation	---	SCE/	SCE/—	SCE/—	SCE/Inyokern
Annual Capacity Factor Assumed	.8	.8	.46	.46	.46
Fuel	2.65	9.68	11.95	12.51	0
O & M	1.47	1.80	3.17	3.49	3.97
Taxes	1.80	2.87	4.38	5.56	6.07
Cost of Money	5.85	6.95	11.84	16.50	25.01
Depreciation	2.47	2.06	4.12	6.39	11.82
Back Up Capacity	0	0	0	0	.98
Fuel Credit	0	0	0	0	(1.73)
Busbar Costs	14.24	23.37	35.47	44.46	46.11

The busbar energy cost for the central receiver is 46 mills per kWh, and for a 100 MW coal plant, 45 mills per kWh. A breakdown of these energy costs for the fixed and variable elements are presented in bar graph format in Figure 4-31.

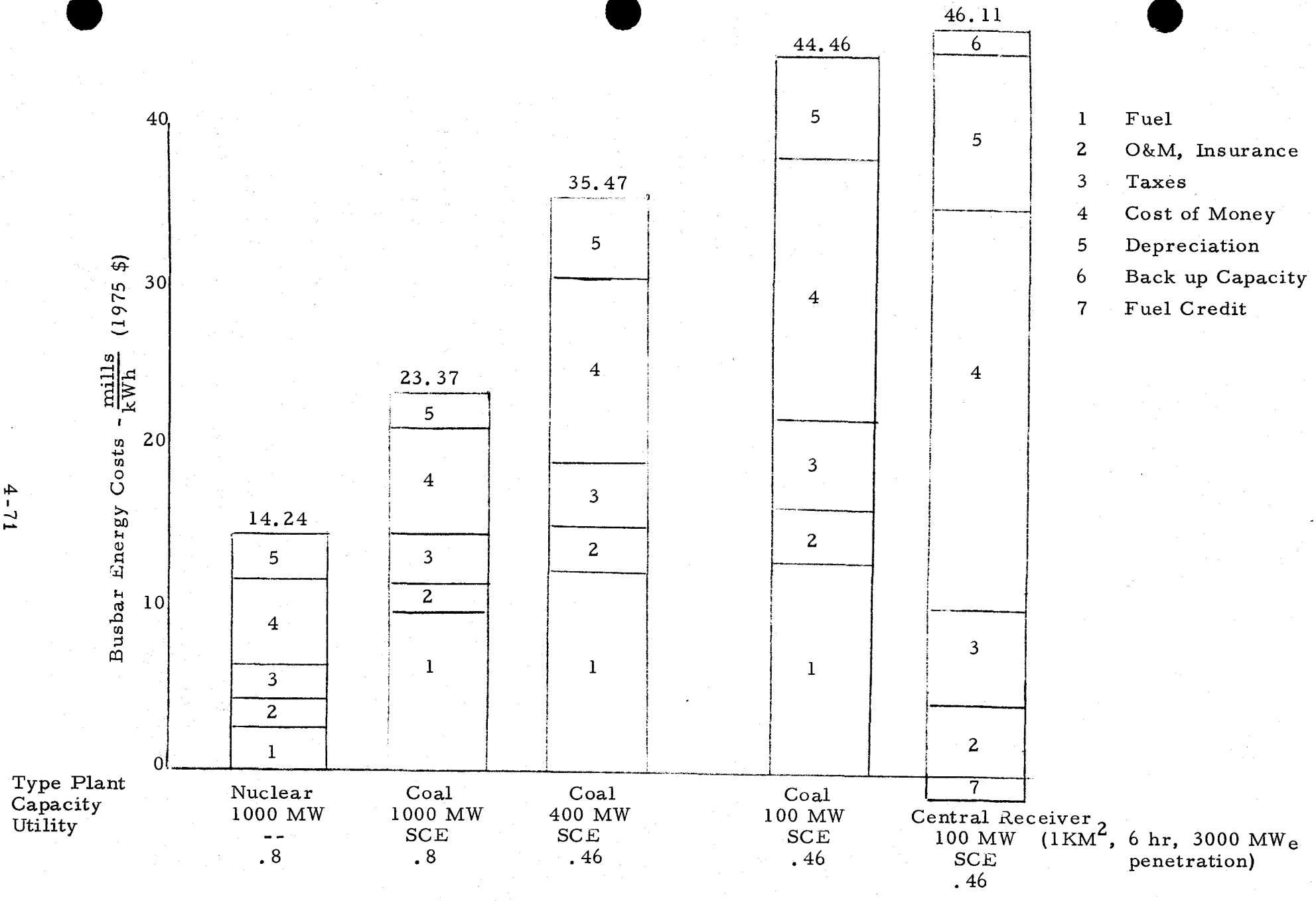


Figure 4-31. Comparative Busbar Energy Costs of Representative Power Plants Interim Results (Semi Annual Review Presented in November 1975)

c) Final Study Results

For the final results of the Mission Analysis, solar central receiver plant economics were evaluated for several geographically dispersed regions within the United States. Fossil fuel plant economics were also calculated for purposes of comparison using the latest available cost data. Table 4-14 presents the geographical location of the six sites where solar plants were compared with conventional power plants relative to busbar energy costs.

The fuel costs for the fossil fired power plants are determined by the unit nameplate capacity rating (MW) and the net heat rate (BTU per kWh). Typical heat rates for plants in the early 1980's operating at 100 percent output are shown in Table 4-15, and were obtained from Reference 39.

The operations and maintenance (O&M) costs are based on data reported to the Federal Power Commission (Reference 40). These costs (in terms of $ per kW) were found to be correlated with plant capacity (MW), as shown in Figure 4-32 which was drawn for power plants in California but is assumed to be generally applicable throughout the country. For the purposes of this study, O&M costs for a given plant size were assumed equal for solar and fossil plants.

From the values of plant capital costs presented in Section 2, levelized bus bar energy costs were calculated for both conventional power plants of varying size, and for a 100 MW central receiver solar plant. The busbar energy costs for coal and oil fired plants and for nuclear plants are tabulated in Table 4-16. These costs are presented as fixed costs (interest, dividends, taxes), O&M (operations and maintenance) costs, fuel costs, and the total busbar energy costs. The costs are based on a conventional plant capacity factor of 0.5. Conventional oil plant capacities selected for comparison purposes with the solar plant are 100 MW and 400 MW. The coal plant capacities selected were 400 MW and 1000 MW, although it is realized that few coal plants in the 400 MW size range are likely to be constructed during the time period of interest because of their less attractive operating economics relative to larger (800-1000 MW) coal plants.

Table 4-14. Geographical Location of Conventional and Solar Power Plants

100 MW Central Receiver Plant		Fossil Fuel Plants
Insolation Data Base	Utility	U.S. Regional Location
Inyokern, California	Southern California Edison	Western
Seattle, Washington	Public Power & Light	Western
Fort Worth, Texas	City Public Service Board	Western
Madison, Wisconsin	Consumer Power	North Central
Sterling, Virginia	PJM	South Atlantic
Miami, Florida	FPL	South Atlantic

Table 4-15. Fossil Generation Unit Net Heat Rates

Type Power Plant	Capacity (MW)	Heat Rate[1] Btu/kWh
Coal Fired	100	9,600
	100	9,000
	1000	8,750
Oil Fired	100	10,000
	400	9,400
	1000	9,100

(1) Date Source - Ref. 39

OPERATION AND MAINTENANCE COSTS

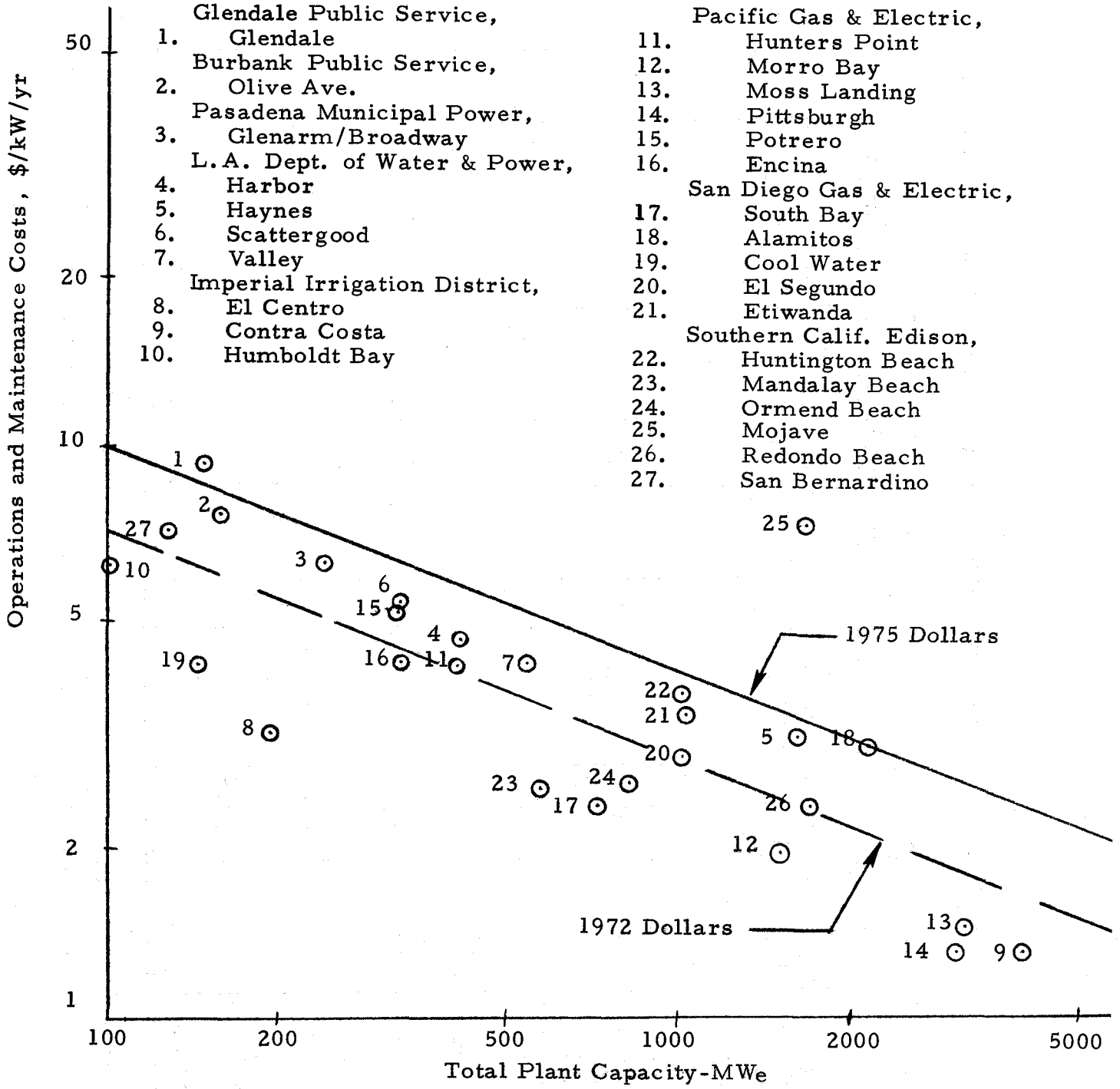


Figure 4-32. Operation and Maintenance Costs - (1975 Dollars)
Source: Ref. 40

Table 4-16. Conventional Power Plant Busbar Energy Costs - Final Result

Type Plant	Plant Location	Plant Capacity Factor	Busbar Energy Costs -- Mills/kWh (1975 Dollars)											
			100 MW				400 MW				1000 MW			
			Fixed	O&M	Fuel	Total	Fixed	O&M	Fuel	Total	Fixed	O&M	Fuel	Total
Coal Fired	Pacific	.5	38.5	1.8	19.1	59.4	32.0	1.8	17.9	51.7	-	-	-	-
	North Central	.5	30.0	3.2	12.7	45.9	26.2	3.2	11.9	41.3	-	-	-	-
	South Central	.5	30.8	1.3	20.2	52.3	26.8	1.3	19.1	47.2	-	-	-	-
	Pacific	.80	-	-	-	-	-	-	-	-	18.2	.7	20.8	39.7
Oil Fired	Pacific	.5	23.4	1.8	56.3	81.5	19.5	1.8	53.5	74.8	-	-	-	-
	North Central	.5	23.4	3.2	43.7	70.3	19.5	3.2	41.6	64.3	-	-	-	-
	South Central	.5	23.4	1.3	36.4	61.1	17.6	1.3	34.6	53.5	-	-	-	-
	Pacific	.80	-	-	-	-	-	-	-	-	9.2	.7	61.3	71.2
Nuclear	Pacific	.80	-	-	-	-	-	-	-	-	15.0	.7	3.0	18.7

The energy costs for various 100 MW central receiver solar plant sites were developed for a series of design parameter variations (e.g., collector area, thermal storage time) utilizing different utility/insolation data, as described earlier in this report. The busbar energy costs and related plant technical characteristics are presented in Tables 4-17 through 4-23, for SCE/Inyokern, PPL/Seattle, CPSB/Forth Worth, CP/Madison, PJM/Sterling and FPL/Miami, respectively. Tables 4-17 and 4-18 represent data for penetrations of 10 and 33 percent for SCE/Inyokern.

The results of the economic comparison between the conventional and solar power plants are also presented in graphic form in Figures 4-33 through 4-39 for the various combinations of utility demand and insolation selected. The energy cost data contained within Tables 4-17 through 4-23 were utilized to generate these figures.

The energy costs for two conceptual SCE/Inyokern solar plants are graphically presented in Figures 4-33 and 3-34, for solar penetrations of 3000 MW and 10,000 MW, respectively. As can be seen in these figures, the solar plant configuration having the lowest energy cost has a collector area of 1.0 square kilometers, and a thermal storage capacity of 6 hours independent of penetration. The energy cost for the smaller solar plant penetration is 69 mills per kWh, which is below the band of costs representative of oil fired plants in the 400 MW size range. The cost penalty for increasing the solar penetration to 10,000 MW is an increase of 3 mills/kWh due to the requirement for increased (conventional) backup capacity as shown in Figure 4-34.

The energy costs for a PPL/Seattle solar plant are graphically presented in Figure 4-35, for a solar penetration of 1000 MW. The minimum cost solar plant configuration continues to have a collector area of 1.0 square kilometer and a storage capacity of 6 hours. The corresponding energy cost, however, is 124 mills per kWh, significantly higher than the energy costs of either coal or oil fired conventional plants. These high solar energy costs are directly the result of the poorer insolation in the Seattle region which results in a lower plant capacity factor and larger backup requirement.

Table 4-17. SCE/Inyokern - Central Receiver Solar Plant Technical Characteristics and Operating Economics

PLANT TECHNICAL CHARACTERISTICS[1]				FINAL RESULTS-ECONOMIC ANALYSIS(1975 DOLLARS)					
Collector Area (km^2)	Thermal Storage (hr)	Plant Capacity Factor	Solar Back-up % of Penetration	Capital Investment ($/kW) (1975 $)	Busbar Energy Costs - Mills/kWh				
					Investment	C & M	Back Up	Fuel Credit	Total
0.5	3	.284	68	919	70.5	3.3	7.3	1.7	79.4
0.5	6	.294	61	973	72.1	3.2	6.3	0.5	81.1
0.5	9	.296	61	1026	75.5	3.2	6.3	0.1	84.9
1.0	3	.382	28	1271	72.4	2.5	2.2	4.2	72.9
1.0	6	.418	20	1324	68.6	2.0	1.5	3.7	69.0
1.0	9	.428	17	1378	70.1	2.2	1.2	3.8	69.7
1.5	3	.394	25	1665	92.0	2.4	1.9	4.8	91.5
1.5	6	.437	18	1718	85.6	2.1	1.3	5.2	83.8
1.5	9	.441	16	1772	87.5	2.1	1.1	5.3	85.4

[1] Peak Demand 32,000 MW
Reserve (Baseline) 13.8%
Penetration 3,000 MW

Table 4-18. SCE/Inyokern - Central Receiver Solar Plant Technical Characteristics and Operating Economics

PLANT TECHNICAL CHARACTERISTICS[1]				FINAL RESULTS-ECONOMIC ANALYSIS (1975 DOLLARS)					
Collector Area (km^2)	Thermal Storage (hr)	Plant Capacity Factor	Solar Back-up % of Penetration	Capital Investment ($/kW)	Busbar Energy Costs - Mills/kWh				
					Investment	C & M	Back Up	Fuel Credit	Total
0.5	3	.292	84	919	68.5	2.0	8.7	0.7	78.5
0.5	6	.298	82	973	71.1	1.9	8.4	0.0	81.4
0.5	9	.298	82	1026	75.0	1.9	8.4	0.0	85.3
1.0	3	.365	66	1271	75.8	1.6	5.5	5.5	77.4
1.0	6	.410	61	1324	70.3	1.4	4.5	4.4	71.8
1.0	9	.422	53	1378	71.1	1.4	3.8	4.2	72.1
1.5	3	.375	63	1665	96.7	1.5	5.1	6.2	97.1
1.5	6	.427	57	1718	87.6	1.4	4.1	5.5	87.6
1.5	9	.439	47	1772	87.9	1.3	3.3	5.9	86.6

[1] Peak Demand 32,000 MW
Reserve (Baseline) 13.8%
Penetration 10,000 MW

Table 4-19. PPL/Seattle - Central Receiver Solar Plant Technical Characteristics and Operating Economics

PLANT TECHNICAL CHARACTERISTICS[1]					FINAL RESULTS-ECONOMIC ANALYSIS (1975 DOLLARS)				
Collector Area (km^2)	Thermal Storage (hr)	Plant Capacity Factor	Solar Back-up % of Penetration	Capital Investment ($/kW)	Busbar Energy Costs - $\frac{Mills}{KWh}$				
					Investment	C & M	Back Up	Fuel Credit	Total
0.5	3	.158	89	919	126.6	10.0	17.2	0.0	153.8
0.5	6	.158	89	973	134.1	10.0	17.2	0.0	161.3
0.5	9	.158	89	1026	141.4	10.0	17.2	0.0	168.6
1.0	3	.247	81	1271	112.0	6.4	10.0	2.3	126.1
1.0	6	.261	78	1324	110.4	6.1	9.1	1.6	124.0
1.0	9	.267	77	1378	112.4	5.9	8.8	1.2	125.9
1.5	3	.277	77	1665	130.9	5.7	8.5	3.2	141.9
1.5	6	.303	71	1718	123.4	5.2	7.1	2.8	132.9
1.5	9	.315	66	1772	122.5	5.0	6.4	2.5	131.4

[1] Peak Demand 6,632 MW
Reserve (Baseline) 28.2%
Penetration 1000

Table 4-20. CPSB Fort Worth - Central Receiver Solar Plant Technical Characteristics and Operating Economics

PLANT TECHNICAL CHARACTERISTICS[1]				ECONOMIC ANALYSIS (1975 Dollars)					
Collector Area (km^2)	Thermal Storage (hr)	Plant Capacity Factor (%)	(Solar Back Up (% of Penetration Estimated)	Capital Investment ($/kW)	Busbar Energy Costs - Mills/kWh				
					Investment	C & M	Back Up	Fuel Credit	Total
0.5	3	.236	31	919	84.8	8.1	4.0	0.4	96.5
0.5	6	.236	31	973	89.8	8.1	4.0	0.1	101.8
0.5	9	.236	31	1026	94.6	8.1	4.0	0	106.7
1.0	3	.335	21	1271	82.6	5.7	1.9	2.8	87.4
1.0	6	.356	18	1324	81.0	5.4	1.5	2.9	85.0
1.0	9	.361	17	1378	83.1	5.3	1.4	3.2	86.6
1.5	3	.354	18	1665	102.4	5.4	1.6	3.4	106.0
1.5	6	.385	11	1718	97.2	5.0	0.9	3.5	99.6
1.5	9	.396	9	1772	97.4	4.8	0.7	3.9	99.0

[1] Peak Demand 6625 MW
Reserve (Baseline) 13.0%
Penetration 500 MW

Table 4-21. Consumers Power/Madison - Central Receiver Solar Plant Technical Characteristics and Operating Economics

PLANT TECHNICAL CHARACTERISTICS[1]				FINAL RESULTS-ECONOMIC ANALYSIS(1975 DOLLARS)					
Collector Area (km^2)	Thermal Storage (hr)	Plant Capacity Factor	Solar Back-up % of Penetration	Capital Investment ($/kW)	Busbar Energy Costs - Mills/kWh				
					Investment	C & M	Back Up	Fuel Credit	Total
0.5	3	.203	71	919	98.6	7.8	10.7	0.9	116.2
0.5	6	.208	71	973	101.8	7.6	10.4	0.2	119.6
0.5	9	.209	71	1026	106.9	7.6	10.4	0.1	124.8
1.0	3	.302	54	1271	91.6	5.3	5.5	2.9	99.5
1.0	6	.333	52	1324	86.6	4.8	4.8	1.9	94.3
1.0	9	.341	51	1378	88.0	4.7	4.6	1.9	95.4
1.5	3	.331	47	1665	109.5	4.8	4.3	3.6	115.0
1.5	6	.374	37	1718	100.0	4.2	3.1	2.9	104.4
1.5	9	.302	36	1772	127.7	5.3	3.6	2.3	134.3

[1] Peak Demand 13,203 MW
Reserve (Baseline) 31.0%
Penetration 1000 MW

Table 4-22. PJM/Sterling - Central Receiver Solar Plant Technical Characteristics and Operating Economics

PLANT TECHNICAL CHARACTERISTICS[1]				FINAL RESULTS-ECONOMIC ANALYSIS(1975 DOLLARS)					
Collector Area (km^2)	Thermal Storage (hr)	Plant Capacity Factor	Solar Back-up % of Penetration	Capital Investment ($/kW)	Busbar Energy Costs - Mills/kWh				
					Investment	O & M	Back Up	Fuel Credit	Total
0.5	3	.215	77	919	93.1	3.0	10.9	0.8	106.2
0.5	6	.218	77	973	97.2	3.0	10.8	0.2	110.8
0.5	9	.219	77	1026	102.0	3.0	10.7	0.0	115.7
1.0	3	.321	64	1271	86.2	2.0	6.1	3.1	91.2
1.0	6	.345	62	1324	83.6	1.9	5.5	2.6	88.4
1.0	9	.354	61	1378	84.7	1.8	5.3	2.4	89.4
1.5	3	.342	60	1665	106.0	1.9	5.3	3.8	109.4
1.5	6	.374	57	1718	100.0	1.7	4.7	3.7	102.7
1.5	9	.387	55	1772	99.7	1.5	3.9	3.6	108.7

[1] • Peak Demand 82,035 MW
Reserve (Baseline) 10.9%
Penetration 8000 MW

Table 4-23. FPL/Miami - Central Receiver Solar Plant Technical Characteristics and Operating Economics

PLANT TECHNICAL CHARACTERISTICS[1]				FINAL RESULTS-ECONOMIC ANALYSIS(1975 DOLLARS)					
Collector Area (km^2)	Thermal Storage (hr)	Plant Capacity Factor	Solar Back-up % of Penetration	Capital Investment ($/kW)	Busbar Energy Costs - Mills/kWh				
					Investment	C & M	Back Up	Fuel Credit	Total
0.5	3	.232	31	919	86.2	4.8	4.1	0.6	94.5
0.5	6	.235	31	973	90.1	4.8	4.0	0.0	98.9
0.5	9	.235	31	1026	95.1	4.8	4.0	0.3	103.6
1.0	3	.352	19	1271	78.6	3.2	1.7	2.8	80.7
1.0	6	.382	17	1324	75.5	2.9	1.4	2.1	77.7
1.0	9	.390	17	1378	76.9	2.9	1.3	1.9	79.2
1.5	3	.376	17	1665	96.4	3.0	1.4	3.4	97.4
1.5	6	.415	12	1718	90.1	2.7	0.9	3.2	90.5
1.5	9	.425	11	1772	90.8	2.6	0.8	3.7	90.5

[1] Peak Demand 21,479 MW
Reserve (Baseline) 13.1%
Penetration 2,000 MW

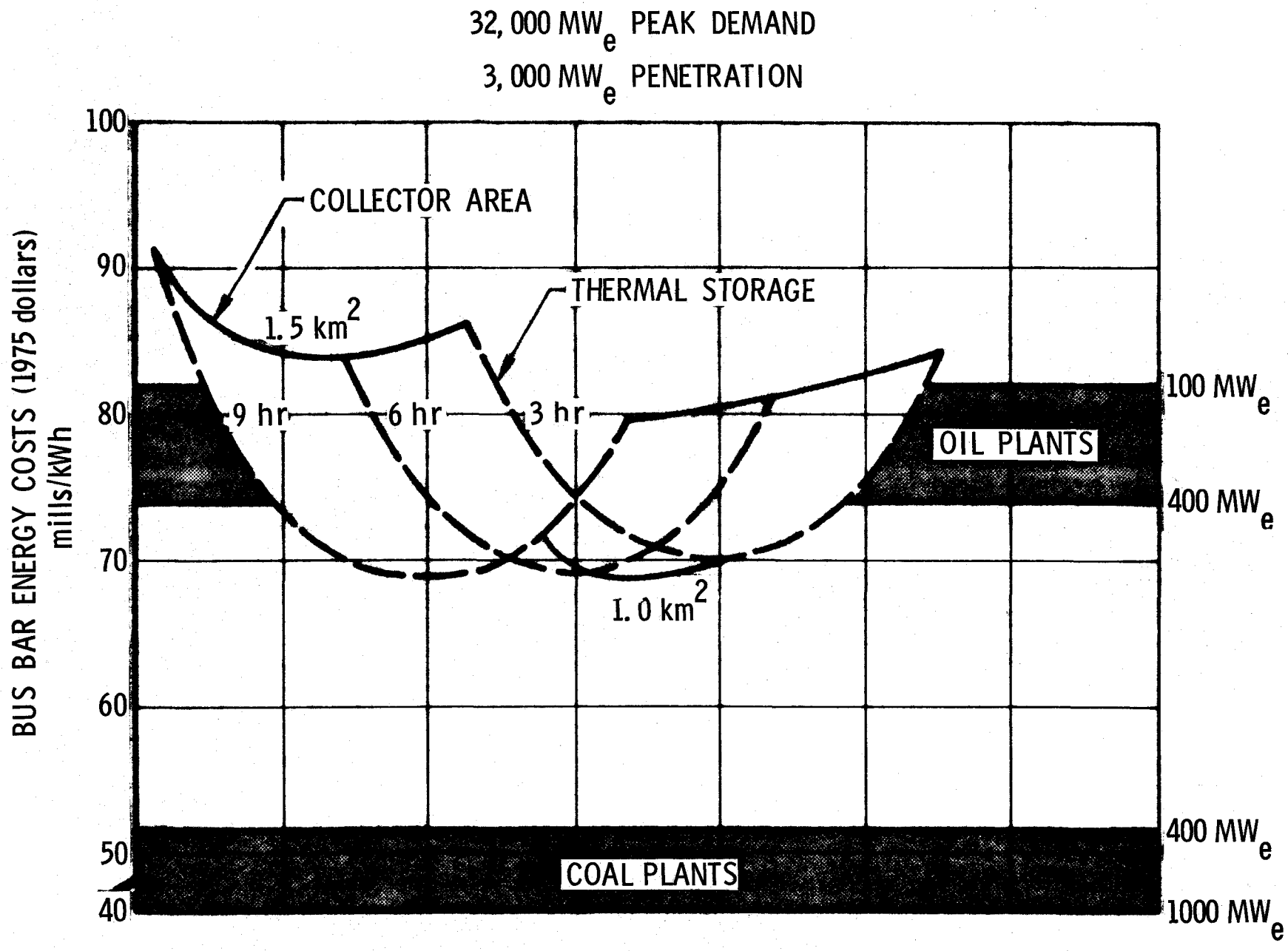


Figure 4-33. SCE/Inyokern Central Receiver Power Plant Busbar Costs

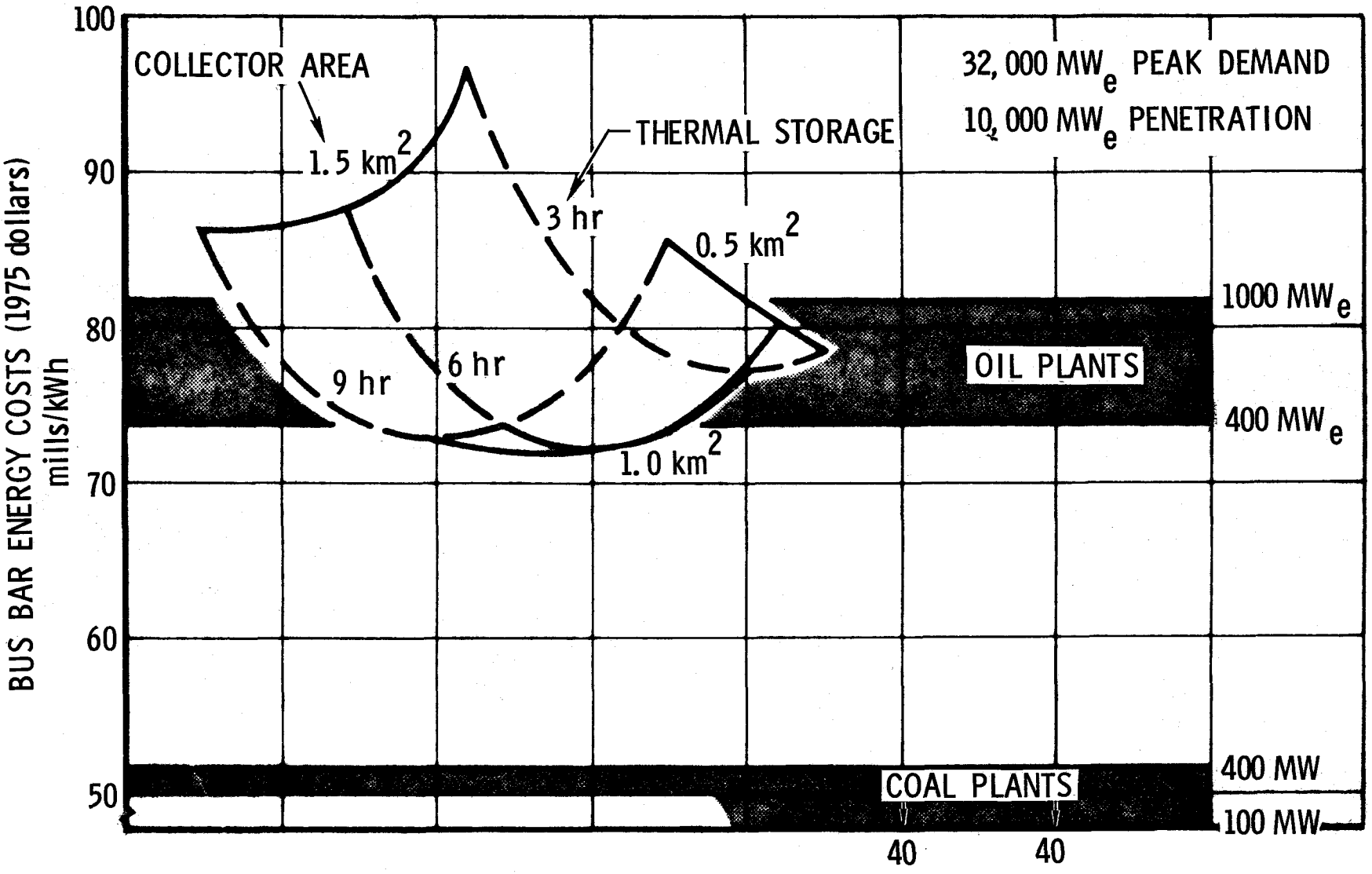


Figure 4-34. SCE/Inyokern Central Receiver Power Plant Busbar Costs

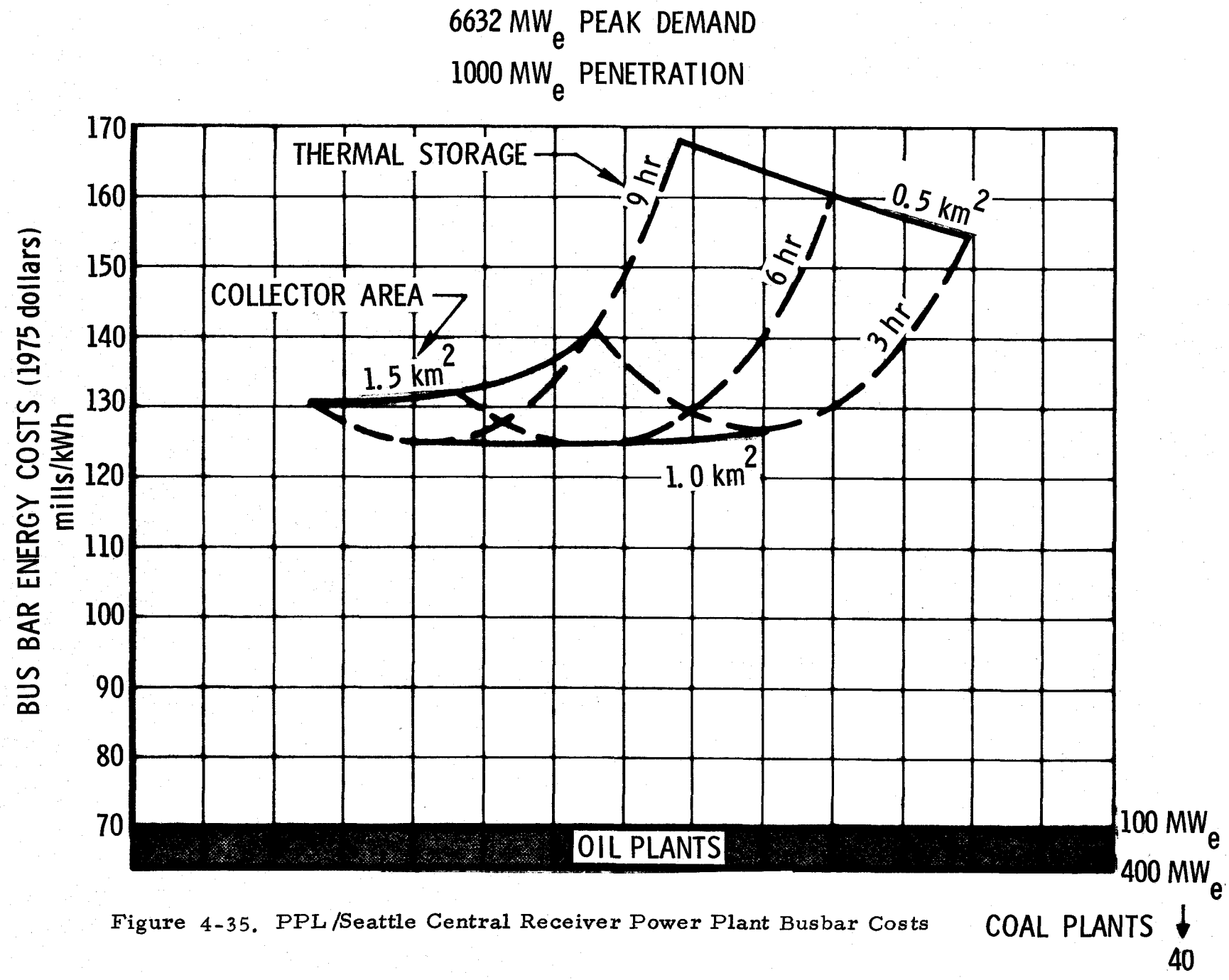


Figure 4-35. PPL/Seattle Central Receiver Power Plant Busbar Costs

Energy costs for a CPSB/Fort Worth solar plant are graphically presented in Figure 4-36 for a system penetration of 500 MW. As with the other locations, the solar plant configuration having lowest bus bar energy costs has 1.0 square kilometer collector area, and a storage capacity of 6 hours. The minimum energy cost (85 mills per kWh), is slightly higher than the energy costs for an oil fired plant and substantially higher than energy from coal.

The energy costs for CP/Madison, PJM/Sterling, and FPL/Miami are graphically presented in Figures 4-37, 4-38, and 4-39, respectively. In all of these cases, the optimum configuration has a collector area of 1.0 square kilometer and thermal storage of 6 hours. The FPL/Miami case shown in Figure 4-39 has the lowest projected solar energy cost of the three, at 78 mills per kWh.

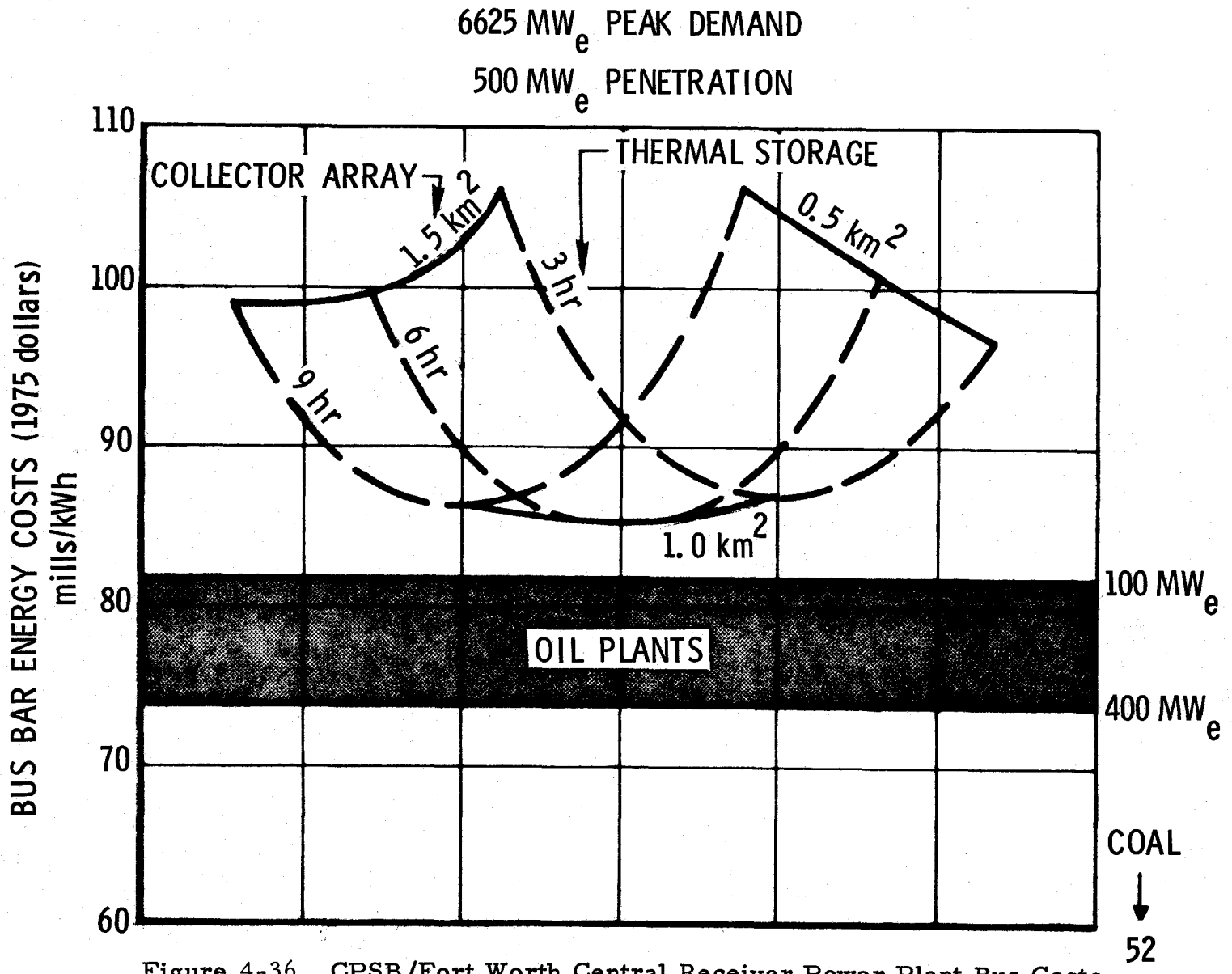


Figure 4-36. CPSB/Fort Worth Central Receiver Power Plant Bus Costs

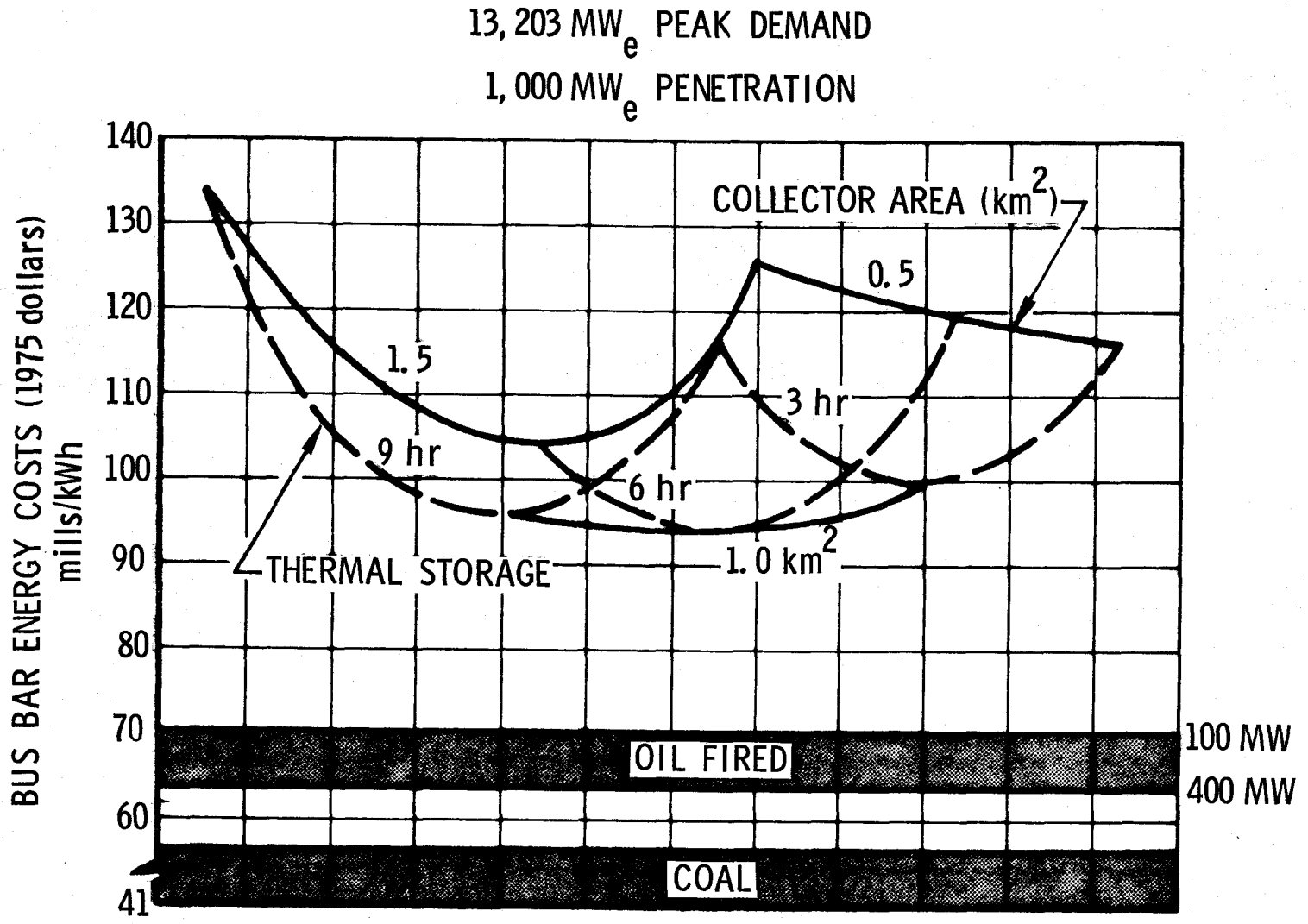


Figure 4-37. Consumers Power/Madison Central Receiver Busbar Costs

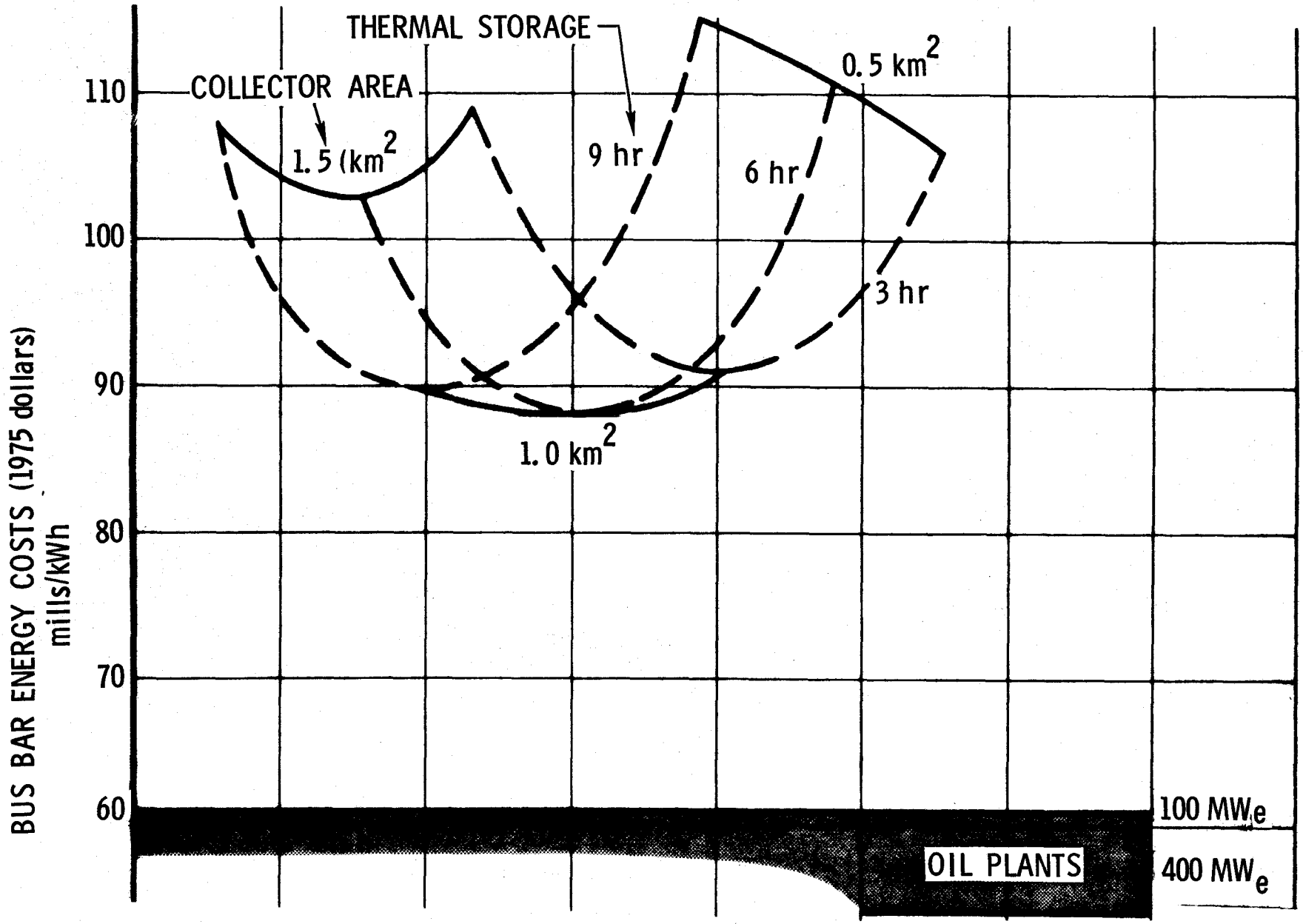


Figure 4-38. PJM/Sterling-Central Receiver Power Plant Busbar Costs

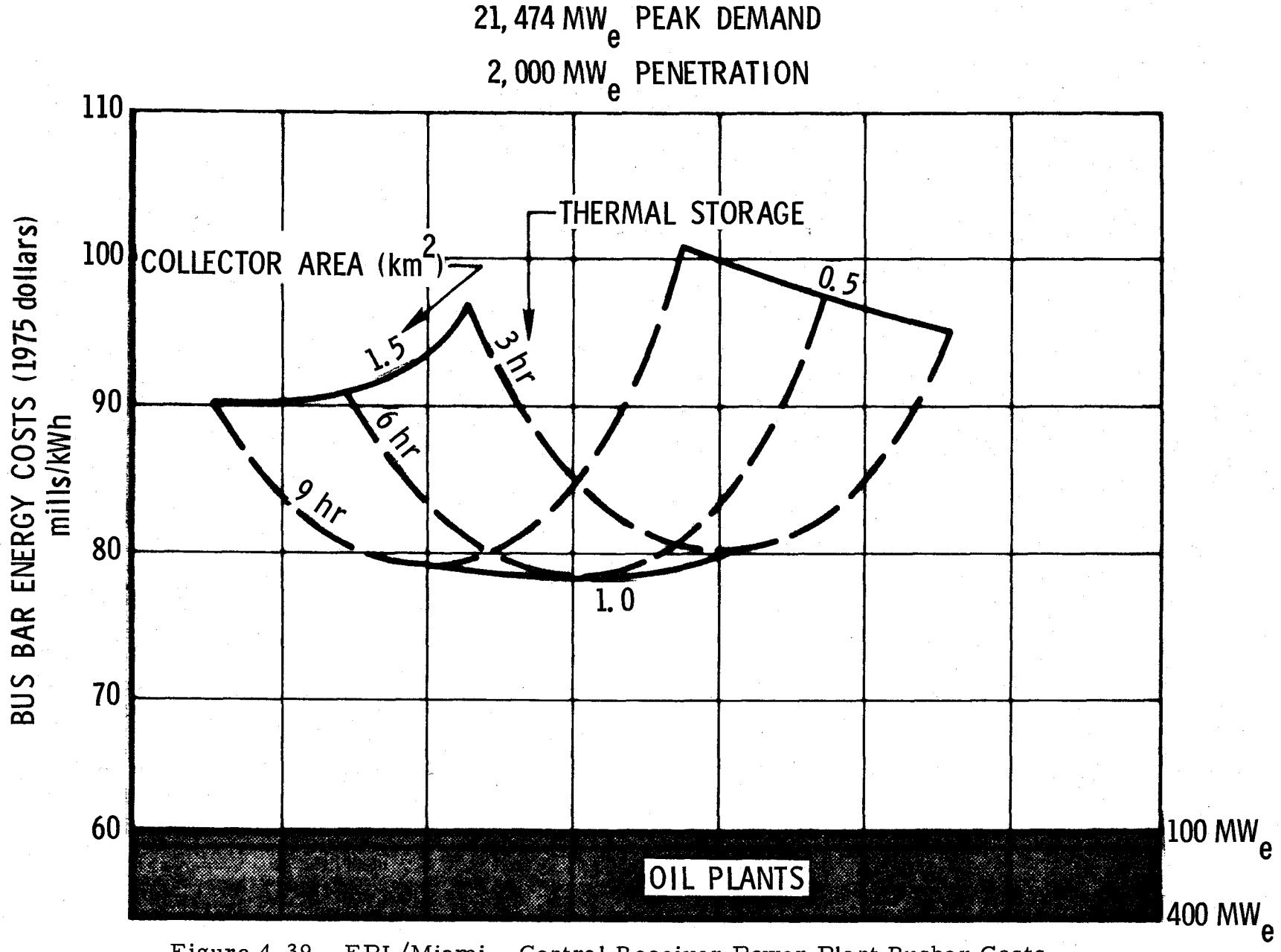


Figure 4-39. FPL/Miami - Central Receiver Power Plant Busbar Costs

V. SOLAR PLANT IMPLEMENTATION IMPACT ON RESOURCES

A. INTRODUCTION

The U.S. economy is based upon the three key interdependent factors of technology, materials and energy resources. The long term success of solar power plants as alternative energy sources depends in part upon the required materials and energy investments and the corresponding payback periods which in turn are dependent upon the technology of solar plant designs. Currently available solar thermal plant designs are preliminary in nature and detailed designs for commercial solar plants are not available. Nevertheless sufficient information is available to permit some approximate calculations to be made of the energy required to produce solar systems and of the time required to recoup that energy.

To initiate this assessment of solar plant impacts on resources, a review of the current designs of solar central power plants was made. The results of this review are described briefly in Section B. Based upon this review and on communications with potential design contractors, estimates were developed for material types and their weight requirements for a 10 MW_e solar power plant. These estimates were then scaled to represent two alternate 100 MW_e commercial systems. The estimated ranges of energy requirement, energy payback period and energy return ratio for commercial solar power plants are developed in Section C. Materials and energy resource impacts by solar central power plants were then estimated for different implementation scenarios. These impacts are discussed in Section D.

B. CURRENT DESIGNS OF SOLAR CENTRAL POWER PLANTS

Designs for solar central power plants have undergone extensive development during the past year. At present there are four separate designs available for a 10 MW_e solar central power plant. These designs were developed by the following contractor-teams:

- Martin Marietta Aerospace, Denver, Colo. (Prime)
  - Bechtel Corp., Scientific Development Div., San Francisco, California (Architectural and Engineering Assistance)
  - Foster Wheeler Corp., Livingston, N.J. (Receiver Subsystem)
  - Georgia Institute of Technology, Engineering Institute (Thermal Storage Subsystem)
- McDonnell Douglas Astronautics Co., Huntington Beach, Calif. (Prime)
  - Rocketdyne Co., Canoga Park, Calif - a subsidiary of Rockwell International Corp. (Thermal Storage Subsystem)
  - Stearns & Roger, Denver, Colo. (Thermal Storage Subsystem)
  - Sheldahl Inc., Northfield, Minn. (Collector Subsystem: Mirror Surfaces)
  - University of Houston (Collector Subsystem: Field Optimization)
- Honeywell, Systems and Research Center, Minneapolis, Minn. (Prime)
  - Black & Veatch, Kansas City, Mo. (General Assistance)
  - Babcock & Wilcox Co., N.T., N.Y. (Receiver Subsystem)
  - Research Inc., Minnea polis, Minn. (Receiver Subsystem: Radiant Heat Testing Device)
  - Honeywell, Aerospace, St. Petersburg, Fla. (Collector Subsystem: Heliostat Fabrication)
  - Kenney Boiler, Minneapolis, Minn. (Thermal Storage Subsystem)
- The Boeing Co., Seattle, Wash. (Prime)

The early design concepts developed by the above contractor-teams are briefly described below. It should be pointed out that these are preliminary designs (References 41 through 44) and will undoubtedly undergo many changes before they become final. For some subsystems, the associated components are only in the conceptual stages and hence detailed subsystems are not available.

1. Martin Marietta System Design

The Martin Marietta collector subsystem consists of second surface silver mirrors that are warped to provide concentration of the sunlight through a minimum aperture. Each heliostat contains 25 mirrors that are arranged in 5 rows of 5 mirrors (Figure 5-1). The warping is obtained by distorting the flat mirrors with mechanical frames. The heliostats face south with the receiver located on a tower at the south edge of the field. The image from each heliostat strikes the cavity walls of the receiver at a predetermined location to provide a known flux pattern. To provide maximum solar energy to the receiver, each heliostat is tracked independently by a reflected beam sensor. In addition to this independent tracking, heliostats can also be controlled in either individual or group mode by an executive computer control.

The receiver subsystem located on top of a tower is a cavity type with its aperture tilted downwards facing the collector field. Boiler and super-heater tubes lined the cavity walls that receive the solar energy. A steam drum receiver distributes feedwater to the boiler section for the generation of steam using gravity feed. The steam is separated in the steam drum and provided to the superheater for further heating. The superheated steam is then sent down to the base of the tower and dispatched to the turbine or thermal storage subsystem. In addition, the receiver subsystem provides the necessary controls for feedwater flow, steam temperature and heliostat operational requirements.

The thermal storage subsystem consists of insulated tanks where energy extracted from the steam is stored as sensible heat in either Hitec (a molten salt) or a hydrocarbon oil. Hitec is used for high temperature storage, and hydrocarbon oil for the low temperature storage. The thermal storage subsystem consists of three stages, each capable of serving opposite functions associated with the charge and discharge modes of the storage subsystem. When the subsystem is being charged, the first stage removes the superheat from the steam. The steam is then sent to a desuperheater to assure that the condenser receives saturated steam. In the second

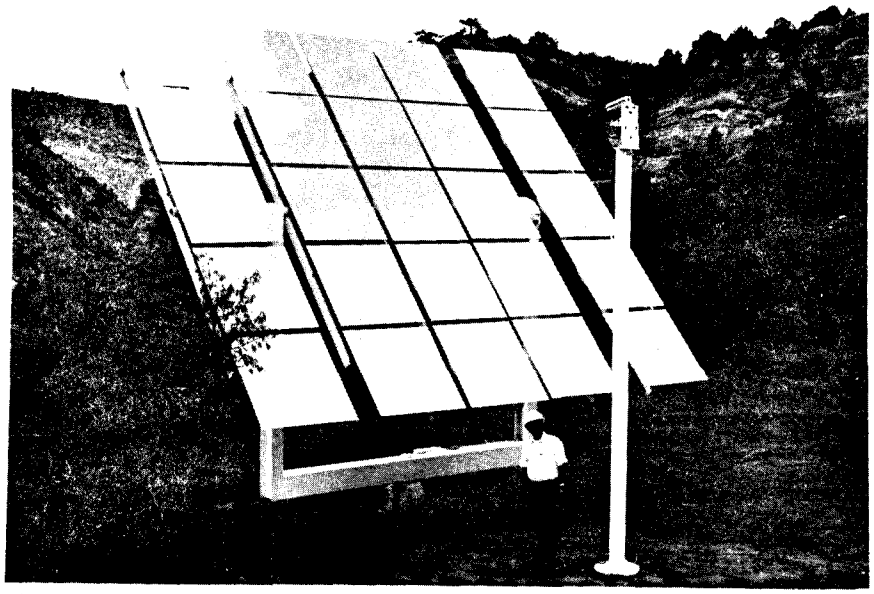


Figure 5-1. Martin Marietta 25-Mirrored Warped Heliostat

stage, water is removed from the condenser slightly subcooled and is further subcooled in the last stage. This feedwater is then supplied to the receiver for further generation of steam. When the subsystem is being discharged, each stage function is reversed, that is, the subcooler now preheats the water, the condenser functions as a boiler, and the last stage superheats the steam which is then sent to the electrical power generation subsystem.

The electrical power generation subsystem consists of conventional power plant components with dry cooling system design. The turbine is capable of operation from the receiver alone, the thermal storage alone, or from both simultaneously. Control modes are provided to either track the output of the receiver or to provide a required load. If more steam is available from the receiver than required for electrical power generation, the extra steam is diverted to the thermal storage subsystem. Similarly, if more steam is required than available from the receiver, additional steam can be withdrawn from thermal storage. Further details of the Martin-Marietta system design are given in Table 5-1.

2. McDonnell Douglas (MDAC) System Design

The MDAC collector subsystem consists of first surface silver float glass mirrors with Sheldahl acrylic overlays. The heliostat mirrors are octagonal disks that are assembled from eight segments (Figure 5-2). This segmented approach provides a focusing ratio of 4 to 1. The canted focus heliostats are pedestal-mounted and feature a tracking-control system operated by reflected-beam sensors tied to a field controller. Each field controller is connected directly to the master control unit and serves separate groups of approximately 25 heliostats. Closed loop beam sensing is used for normal tracking, and position potentiometers and computer override are used for off-nominal conditions. The heliostat field is based on a University of Houston optimum configuration.

The receiver subsystem consists of a jump-formed concrete tower that supports a cylindrical boiler-superheater of several panels, each with individual flow controls. Each panel is made up of numerous tubes that

Table 5-1. Martin Marietta Solar Central Power Plant Preliminary Design Characteristics

Collector Subsystem

Field length	619 m (N-S)
Field width	595 m (E-W)
No. of heliostats	1718
Individual heliostat area	37.2 m^2, 25 mirrors of 1.2 x 1.2 m^2
Total heliostat reflective area	63,910 m^2
Heliostat mirror reflectance	91%
Mirror reflective surface	3 mm, second surface white glass with honeycomb substrate
Weight of heliostat	2041 kg
Weight of sensor	352 kg
Weight of yoke assembly	159 kg
Heliostat availability	99.4 %

Thermal Storage Subsystem

Thermal storage capacity	180 MWH_t
Charge rate	88.8 BAR/510°C, 61,364 kg/hr
Discharge rate	44.4 BAR/399°C, 57,500 kg/hr
Net electrical output	7 MW_e
Discharge time	6 hr
Thermal storage media:	
Stage 1	HITEC (molten salt)
State 2, 3	Hydrocarbon oil (e.g., Therminol 55)
Total quantity of HITEC	1.6 - 6.4 x 10^6 kg
Total quantity of oil	5.685 x 10^6 liters

Receiver Subsystem

Tower height	137 m
Cavity height	23 m
Cavity width	15.2 m
Cavity depth	18.3 m
Tilt of receiver centerline	20±5 deg
Aperture area	56.3 m^2
Peak absorbed thermal power	52 MW
Feedwater flow rate	69545 kg/hr
Inlet conditions	108.6 BAR/ 206°C
Outlet conditions	91.4 BAR/ 516°C

Electrical Generation Subsystem

Turbine name-plate capacity	12.5 MW_e
Turbine generator cyclic conditions:	
From receiver	88.2 BAR/511°C (10 MW_e)
From thermal storage	41.7 BAR/398°C (7 MW_e)
Availability of electric power (excluding weather + planned maintenance)	90%
Net annual electric power	3.4 x 10^4 MWH
Turbine efficiency	27.5%
Turbine efficiency for 100 MW_e:	
Wet cooling	37.6%
Dry cooling	35.8%
Dry cooling + plant aux. equipment	32.5%

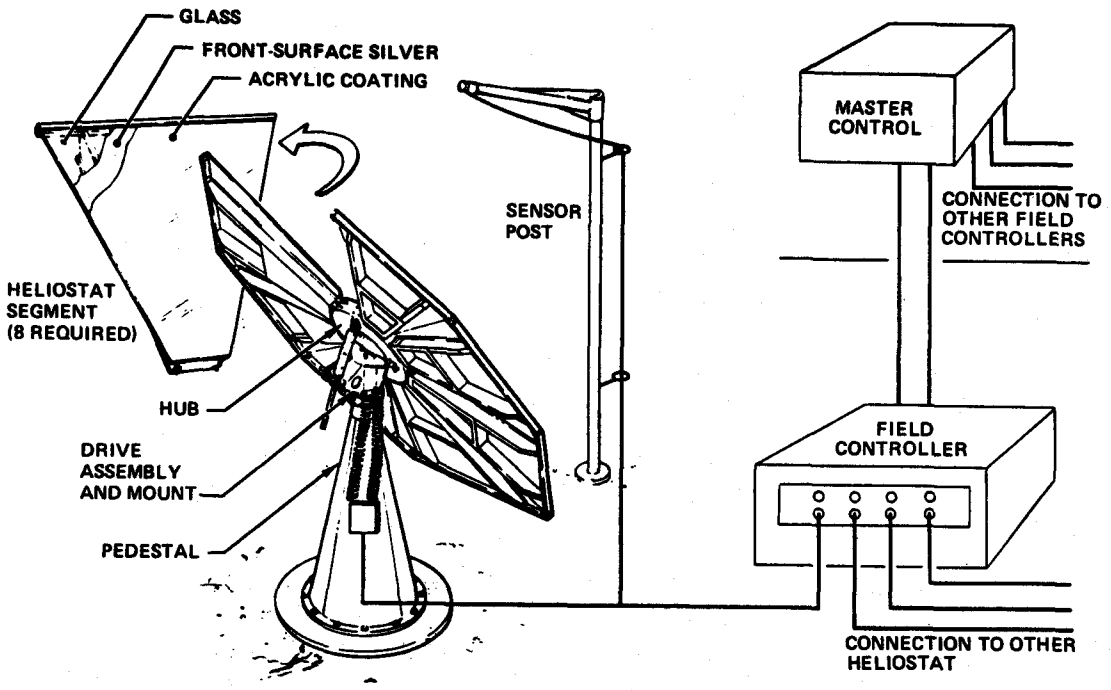


Figure 5-2. MDAC Canted Octagonal-Disks Heliostat

have constant outside diameter and coats of absorptivity-enhancing paint. The other major components of the receiver subsystem consists of distribution, collection and control subassemblies. The steam from the receiver subsystem is sent to the electrical power generation subsystem and any excess steam is diverted to the thermal storage subsystem. However, if weather conditions make it impossible to generate enough steam to operate the turbine or if it is desirable to charge the thermal storage subsystem, all steam can be fed directly to thermal storage.

The thermal storage subsystem uses crushed granite as the storage medium and caloria HT43 heat-transfer oil for heat transport. The system is contained in an underground mild steel cylindrical tank, which is welded at the plant site. The roof of the tank is at grade level. Heat is stored in a thermocline with a 83°C temperature differential. Counterflow shell-and-tube exchangers are used for the thermal storage heater, steam generator, and alternate feedwater heater. Thermal storage can be charged and discharged simultaneously.

As with other contractors' designs, a two-port steam turbine was selected to drive the electric power generator. Steam may be introduced either directly from the receiver or from the thermal storage discharge. The revised MDAC system uses a dry-cooling system design for heat rejection. The entire operation including choice of operating mode is governed by a master control unit operated by a dispatcher. Further details of the MDAC system design are given in Table 5-2.

3. Honeywell System Design

The Honeywell collector subsystem is a tower-centered collector field which is based on a tilt-tilt 2-axis gimbal configuration (Figure 5-3). The reflective surface consists of a 3 mm second surfaced, float glass silver mirror that is bonded to a honeycomb support (Figure 5-4). Each heliostat consists of four mirror modules, mounted and aligned to a tubular axle and operated by two motors that are continuously commanded by a central receiver. Multi-faceted, low-profile focusing heliostats are designed

Table 5-2. MDAC Solar Central Power Plant
Preliminary Design Characteristics

Collector Subsystem

Field length	526 m (N-S)
Field width	526 m (E-W)
No. of heliostats	2350
Individual heliostat area	29 m^2, 8 octagonal segments of 6.1 m dia.
Total heliostat reflective area	68,150 m^2
Heliostat mirror reflectance	90-95%
Mirror reflective surface	First surface silver with acrylic cover
Glass thickness	6 mm
Acrylic thickness	3 mm
Weight of heliostat (excluding pedestal support)	1000 kg

Thermal Storage Subsystem

Thermal storage capacity	195 MWH_t
Maximum charge rate	42.3 MW
Maximum discharge rate	34.3 MW
Charging steam conditions	4.7 BAR/ 302°C
Net electrical output	7 MW_e
Discharge time	6 hr
Thermal efficiency	26.6%
Dimensions of storage tank	18 m x 19 m dia
Total quantity of crushed granite	8.7 x 10^6 kg
Total quantity of Caloria HT 43 oil	965,000 liters

Receiver Subsystem

Tower height	95 m
Boiler-superheater height	17 m
Boiler-superheater diameter	7 m
Panel dimensions	1 m x 17 m
No. of panels	24
Panels absorption area	408 m^2
Absorption coefficient	0.9
No. tubes/panel	106
Feedwater inlet temp	205°C
Superheated steam outlet conditions	104 BAR/ 516°C
Boiler-superheater weight	100,000 kg
Individual panel weight	1450 kg

Electrical Generation Subsystem

Turbine name-plate capacity	15 MW_e
Turbine generator cyclic conditions	
From receiver:	101 BAR/510°C
From thermal storage:	26.6 BAR/275°C
Availability of electric power (excluding weather + planned maintenance)	90%
Net plant efficiency during daytime	26.7%
Net plant efficiency during nighttime	23.4%

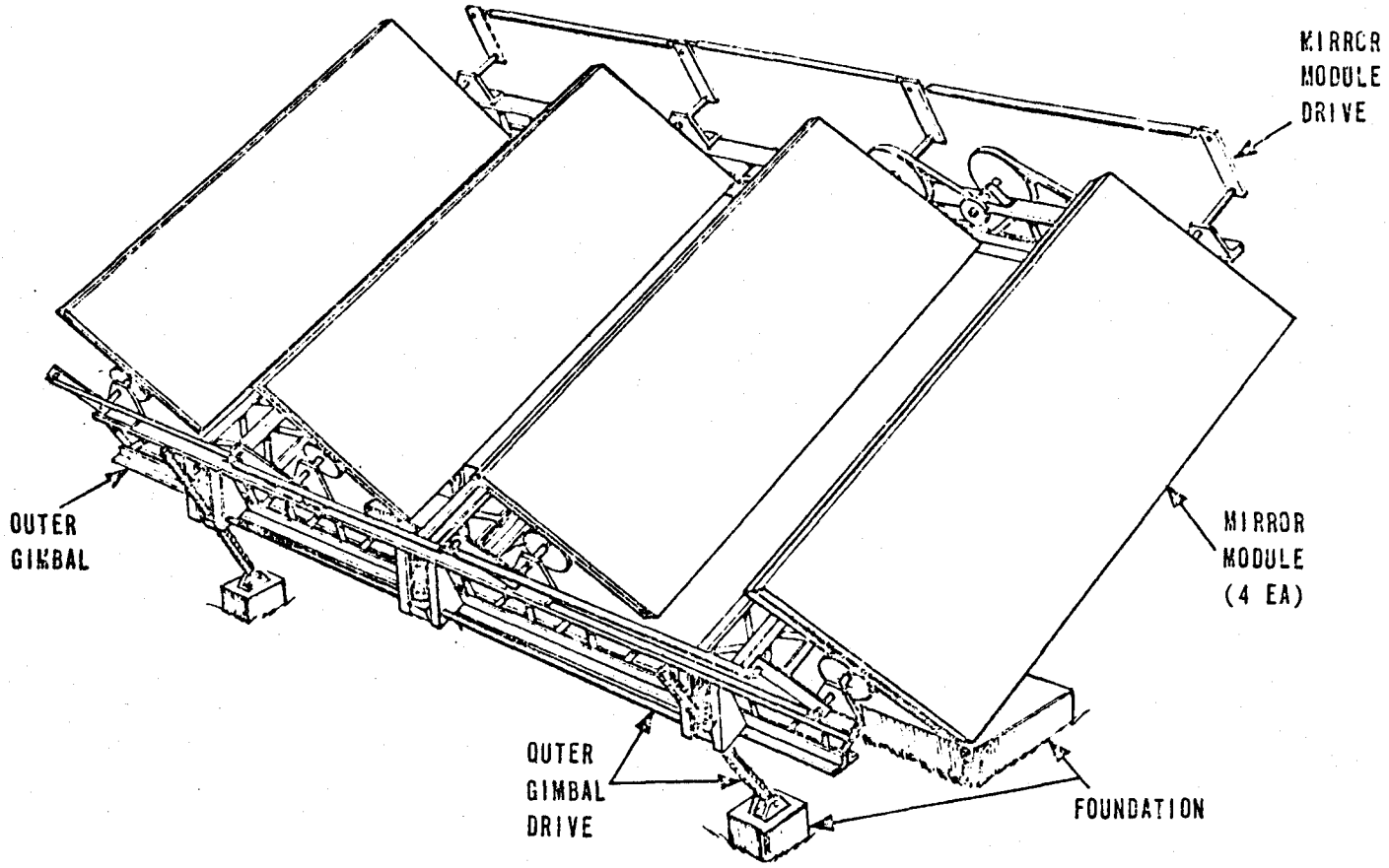


Figure 5-3. Tilt-Tilt Configuration Heliostat

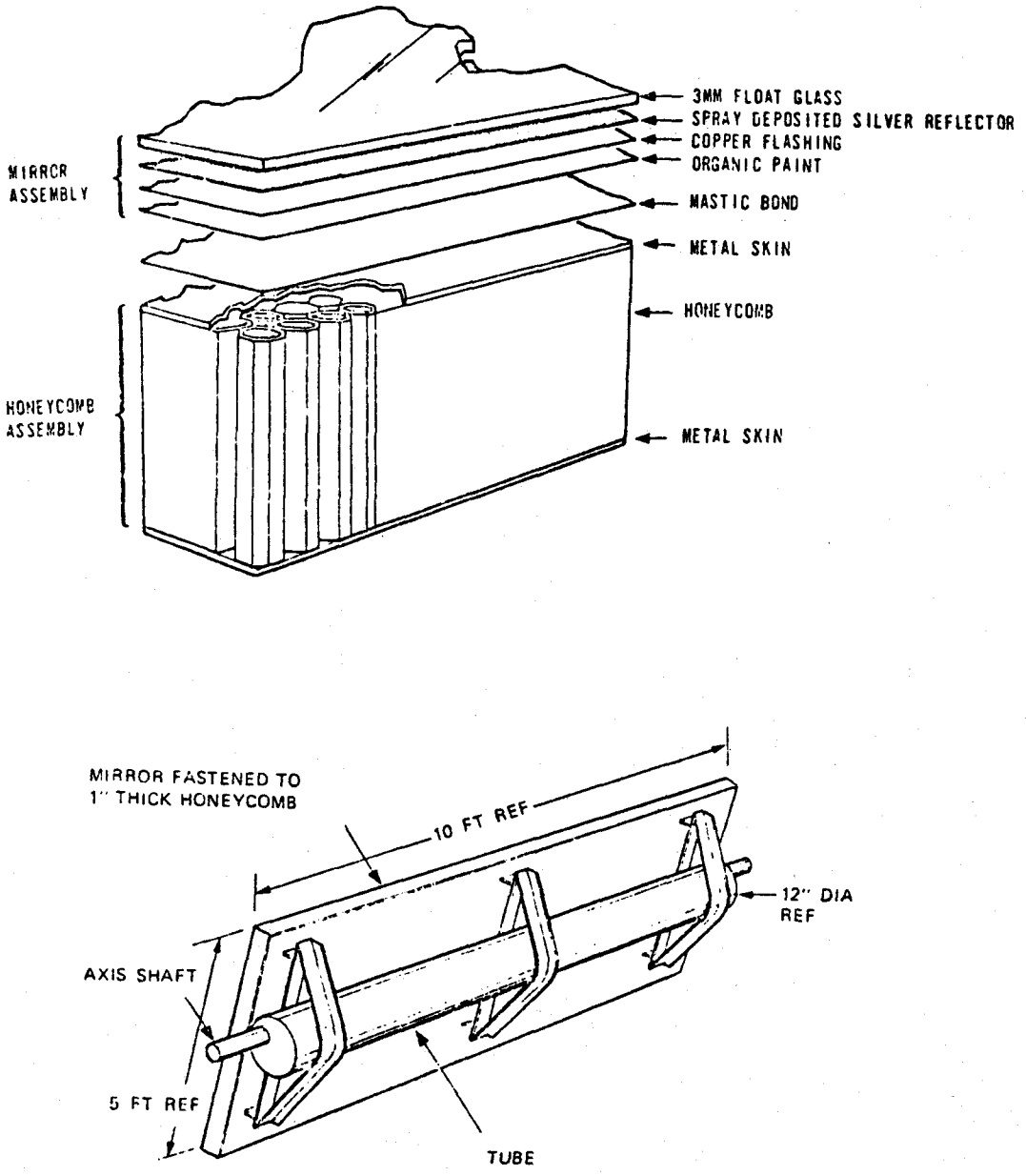


Figure 5-4. Details of Honeywell Mirror Module Configuration

to minimize wind loading effects. There is a local battery at each heliostat that guarantees failsafe operation in the event of power failure. The support of the heliostat consists of two steel posts mounted on a concrete foundation.

The receiver subsystem consists of a tower-mounted cylindrical cavity with an annulus type aperture. The tower structure is designed as a circular-tapered column, fabricated with reinforced concrete. The receiver cavity encloses boiler, drum, and superheater tubes. Feedwater and high pressure steam pipings provide the necessary links between the steam generator at the top of the tower and other subsystems at grade elevation. The steam generator housing is made up of structural steel.

The thermal storage subsystem uses the heat of fusion of an eutectic salt (sodium hydroxide-sodium nitrate) to store thermal energy. The energy to charge the salt is obtained as heat of condensation from the steam supplied by the receiver subsystem. The storage tanks are installed below ground to grade level on a foundation of 3 to 4 layers of heavy duty fireclay-firebrick and spaced approximately three feet apart. A combination of castable-block insulation is used over the entire field to maintain an acceptable field heat loss. The thermal storage subsystem is divided into two units, one for saturated steam and the other for supersaturated steam. Each storage unit contains a charge and discharge cycle heat exchanger.

The electrical power generation subsystem is based on a dry-cooling system design and uses a water-steam cycle with thermal energy being supplied either from the receiver subsystem or from the thermal storage subsystem. A dual-pressure admission turbine is used to generate electricity using either high pressure receiver steam or low pressure steam from thermal storage. The turbine area plant arrangements consist of three floors comprising various sections for the turbine generator, control room, computer room, water treatment facility, machine shop, general offices, relay room and other miscellaneous facilities. Further details of the Honeywell system design are given in Table 5-3.

Table 5-3. Honeywell Solar Central Power Plant Preliminary Design Characteristics

Collector Subsystem

Field outer radius	578 m
Field inner radiums	488 m
No. of heliostats	1680
Individual heliostat area	40 m^2
Total heliostat reflective area	67,280 m^2
Heliostat mirror reflectance	83%
Mirror reflective surface	3 mm, second surface float glass with honeycomb substrate
Annual thermal energy into cavity aperture	1.77×10^5 MWH
Peak thermal power to aperture	55 MW
Net annual thermal energy per unit mirror area	1.8 MWH/m^2
Net peak thermal power per unit mirror area	0.6 kW/m^2

Thermal Storage Subsystem

Thermal storage capacity	196 MWH_t
Maximum thermal power input to-storage	49 MW
Maximum thermal output from storage	29.8 MW
Net annual electrical energy produced if storage is charged and discharged daily	4.15×10^4 MWH
Net annual electrical energy produced if storage is not used	4.4×10^4 MHW
Storage input steam conditions	128.6 BAR/327°C
Weight flow from storage	50,455 kg/hr
Net electrical output	7 MW_e
Discharge time	6 hr
Thermal efficiency	26.4%
Dimensions of main storage tanks	3.66 m x 4.58 m x 12.81 m (9.5 mm thick)
No. & individual weight of main storage tanks	12, 46,818 kg.

Receiver Subsystem

Tower height	130 m
Cavity height	14 m
Cavity diameter	10 m
Steam generator housing height	20 m
Steam generator housing diameter	12 m
Annulus aperture area	80 m^2
Annual thermal energy absorbed by the cavity working fluid	1.59×10^5 MWH
Peak absorbed thermal power	49 MW

Electrical Generation Subsystem

Turbine name-plate capacity	15 MW_e
Turbine type	dual-pressure admission
High-pressure steam turbine inlet conditions	128.6 BAR/510°C
Low-pressure steam turbine inlet conditions	63.4 BAR/308°C
Peak steam flow rate to turbine inlet	80,100 kg/hr
Net busbar efficiency when running from receiver	27.7%
Net busbar efficiency when running from storage	23.2%

Dimensions of superheated storage tank	3.66m x 3.66m x 5.19m
Weight of superheated storage tank	45,455 kg
Total quantity of phase charge materials ($NaOH$-$NaNO_3$)	4.5×10^6 kg

4. Boeing System Design

The Boeing study effort addresses only a Collector Subsystem design. However, for purposes of overall system analyses, Boeing was provided with data for all three study team concepts. Boeing utilized the McDonnell Douglas receiver concept for the Boeing collector subsystem analysis.

The Boeing collector subsystem preliminary design consists of a reflective assembly, a transparent enclosure assembly, and a drive and control assembly. Figure 5-5 shows the reflective and transparent enclosure assemblies. Details of the Boeing collector subsystem are given in Table 5-4. The reflective assembly does not use glass or silver material. Instead, it utilizes a mylar film coated with vacuum-deposited aluminum. A toroidal aluminum ring supports the membrane reflector in the required planar configuration. A transparent air-supported Tedlar dome isolates the reflector and its support and control apparatus from outside objects. The transparent dome is supported on a concrete ring foundation which is contoured to allow the lower portion of the membrane reflector to extend below the base-plane of the dome, when oriented near vertical. The transparent dome is tethered and sealed to a curb on the concrete foundation by use of a segmented clamping ring. A three-point support is used to interface the toroidal ring with the orientation gimbal and base. The heliostat control command configuration consists of a central controller which commands operational modes and provides other functions of system clock synchronization, power control and heliostat failure information. A microcomputer would control the individual pointing of each heliostat in a set of 64 in an open-loop command mode.

C. MATERIALS AND ENERGY REQUIREMENTS

Materials and energy requirements for solar power plants are expected to be an important consideration in formulating future U.S. energy policies. Material requirements for a future 100 MW_e solar power plant can be estimated from the various current designs of 10 MW_e solar plants.

HELIOSTAT FEATURES

- TEDLAR DOME
  - 0.15 MM THICK
  - 7 METER DIAMETER
- ALUMINIZED MYLAR REFLECTOR
  - 6.09 METER DIAMETER
  - 0.05 MM THICK
- OPEN-LOOP AUTOMATED CONTROL
  - MINICOMPUTER CONTROL
  - AUTOMATED RE-ALIGNMENT

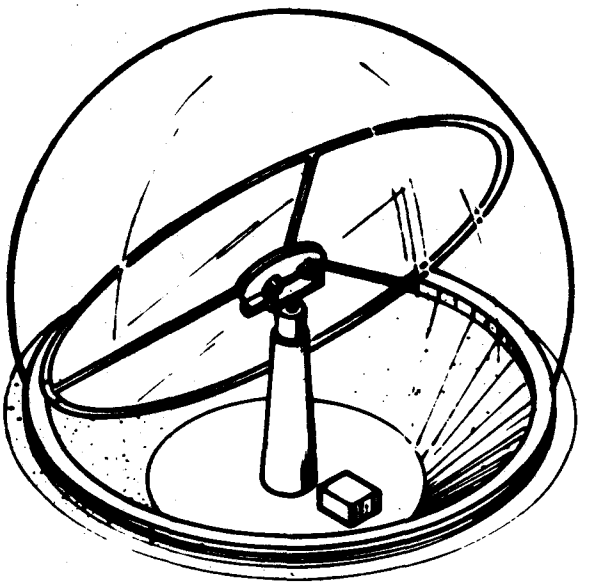


Figure 5-5. Boeing Heliostat with Aluminized Mylar Reflector and Transparent Dome Enclosure

Table 5-4. Boeing Solar Central Power Plant Preliminary Design Characteristics

Collector Subsystem

Field length		793 m (N-S)
Field width	=	680 m (E-W)
No. of heliostats	=	4900
Membrane reflectors dimension	=	6.48 m dia, 0.05 mm thick
Total heliostat reflective area	=	161,500 m^2
Tedlar domes dimensions	=	7.0 m dia, 0.15 mm thick

An analysis of the solar power plant designs given in Section B shows that compared to other plant subsystems, the collector subsystem involves the greatest number of design variations as well as the maximum expected requirement for materials and energy. Some of the collector subsystems make use of second surface silvered float glass mirrors. These require relatively thin glass mirror panels for minimizing absorption and the panels are typically bonded to a substrate such as honeycomb paper for adequate structural support. Other design alternatives make use of first surface silvered glass with a plastic coating for protection. These use relatively thick glass surfaces with no honeycomb paper structure.

Another collector subsystem design which has been proposed does not use any glass or silver materials. Instead it uses plastic and aluminum for its reflective assembly which is enclosed in a plastic dome. This design, although it involves less initial materials investment, may require more frequent replacement of components to maintain the desired reflectance during its system lifetime.

Figure 5-6 gives the materials and energy requirements for these alternate collector subsystem designs for a 100 MW_e solar power plant. The energy requirements for these systems are based upon the materials used and their weights.

There are several methods of estimating energy requirements for the production of different materials. The fundamental principle of estimating energy requirements is that for a given material the total energy requirement of the material inputs should equal the total energy requirements of all the outputs. Some of the possible methods for calculating energy requirements are process analysis, input-output table analysis and statistical analysis. The process analysis technique (Reference 45) tends to underestimate the energy requirement of a material, since it includes only part of the energy which is utilized and does not include the maximum energy (calorific value) which is potentially available from a fuel. Moreover it is not sufficient to consider simply the calorific value of the used fuels.

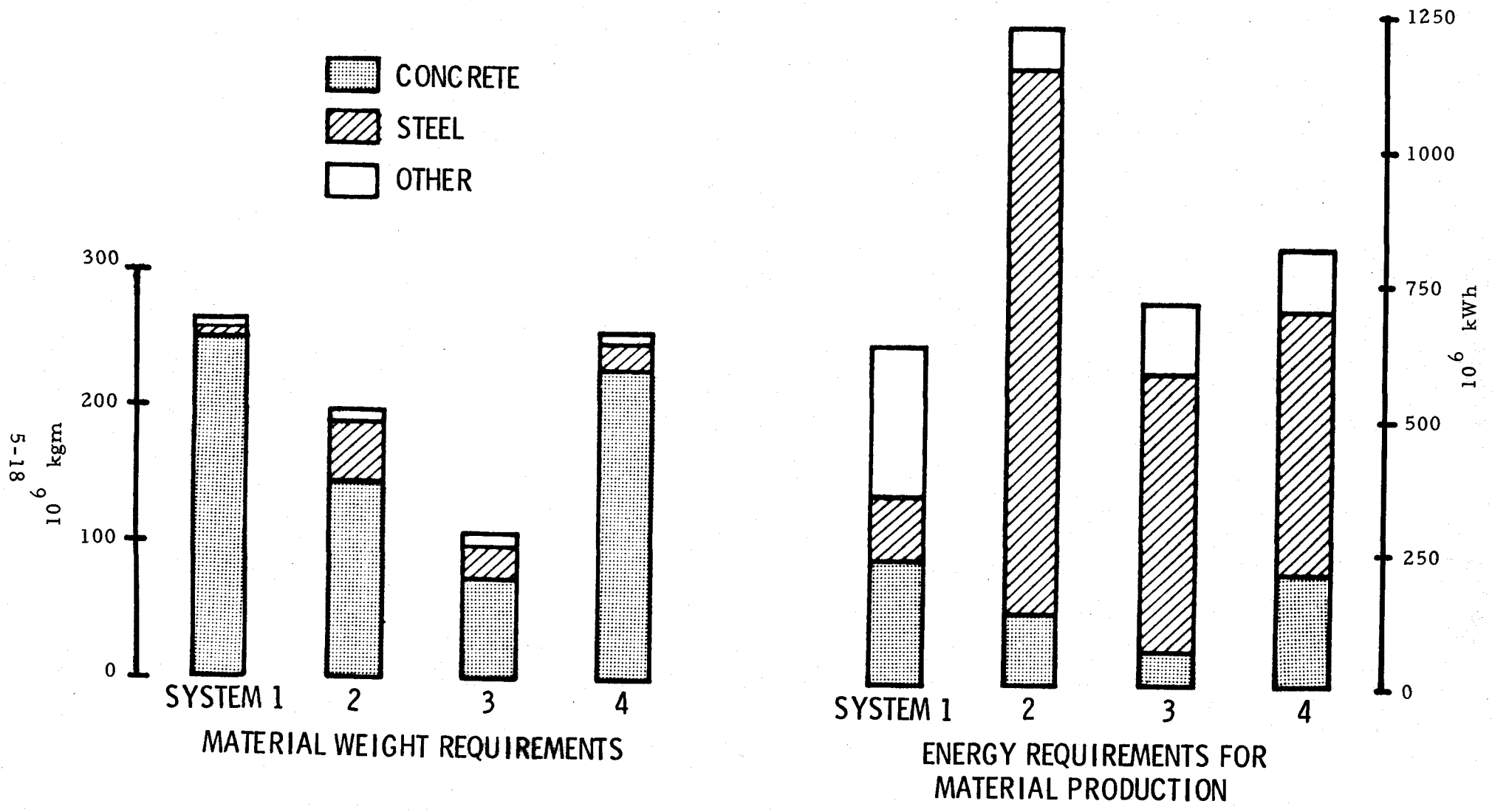


Figure 5-6. Materials and Energy Requirements for 100 MW_e Solar Power Plant Collector Subsystems

Account must also be taken of the energy expended in making the fuel available for use. For example, the mining and transport of coal involves the consumption of fuel, so that the total energy cost associated with the consumption of a ton of coal is the sum of its calorific value and the energy expended in producing the coal. The main disadvantage of the input-output table analysis technique (References 46, 47) is that it deals with the transactions in financial terms, not in terms of physical weights.

The technique of statistical analysis (Reference 48) is based upon the information of energy supply and product output for different industries, which is available in various data sources (e.g., U.S. statistical abstract, annual survey of manufacturers, mineral yearbook, census of manufactures, survey of current business, current industrial reports, etc). Based upon this technique, energy requirements for the production of different materials are given in Table 5-5. This information was used to estimate the energy requirements for constructing the 100 MW_e solar plant collector subsystems illustrated in Figure 5-6. For some of the industrial products, the estimates of energy requirements need further review of the published statistics, especially where more than one byproduct results from a given production system and where different production subsystems are linked together. This is taken care of by the simple analysis shown in Figure 5-7.

Energy requirement values are likely to change in the future when a larger fraction of raw materials will be recycled. For metals, the energy requirement (Reference 49) for recycling is generally an order of magnitude less than the energy requirement for production from primary ores. For example, the energy requirements for aluminum are 90 and 3 kWh_t/kgM from primary ore and recycled scrap. Thus, the future energy requirement for a given metal is estimated by the following relationship:

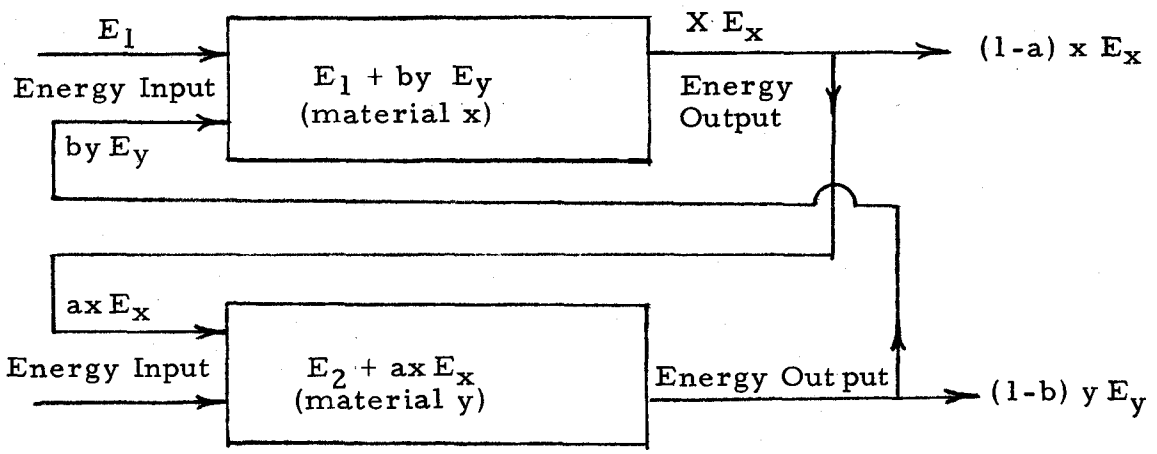
$$E_{av} = \frac{aE_a + bE_b}{(a + b)}$$

where a, b are the quantities produced from primary and scrap material sources and E_a, E_b are the corresponding energy requirements.

Table 5-5. Energy Requirement for Production of Different Materials

MATERIALS	ENERGY REQUIREMENT* kWH_t/kgm
STEEL (industrial & structural finished components)	22.0
COPPER (electrical)	32.0
MIRROR (3-6 mm float glass)	8.8
PAPER (honeycomb)	8.8
CONCRETE (finished structures)	0.9
ALUMINUM (structural & elecrical finished components)	77.0
PLASTICS (includes raw materials combustion energy)	50.0
LEAD (batteries & industrial components)	16.6
SALT ($NaCl$-$NaNO_3$ - Na_2SO_4)	3.0
FIRE BRICK	1.1

*Data are for 1973-1974 period and include energy requirements for unit production machinery depreciation and transportation.



$$E_x = \frac{E_1 + b E_2}{x\,(1 - ab)} \qquad E_y = \frac{E_2 + a E_1}{y\,(1 - ab)}$$

Figure 5-7. Energy Requirement Calculations for Two Interlinked Material Industries

Reduction in the current requirements of industrial process heat and further improvements in the technical efficiency of manufacturing processes will also bring down the energy requirements. However, these energy economies may be diluted by the increased energy requirement associated with the use of lower grades of ore as rich sources of materials are gradually exhausted. Also, the future increased energy requirement to produce the raw energy fuels will increase the energy requirement of materials, since material production consumes large quantities of these fuels. Thus, the energy requirements given in Table 5-5 are considered to have the accuracy limits of approximately ±20% (Reference 50).

Based upon the analysis of various current 10 MW_e solar power plant system designs and the energy requirements for manufacturing associated plant materials (Table 5-5), total energy investments were estimated for two possible 100 MW_e solar systems. Since there are no actual detailed available system designs for a 100 MW_e commercial solar plant, the energy investments for the two solar plant systems given in Figure 5-8 merely correspond to upper and lower limits that are anticipated in some future time period. The power plant energy investments are given in terms of both subsystem and material divisions. Anticipated different material types in future commercial solar plants have also been accounted for in the two systems. Figure 5-8 shows that by far the largest energy investment in solar power plants is for steel. This is followed by concrete, energy storage materials and reflective surface components.

The energy investment for a 100 MW_e fossil power plant was also estimated by subsystem and material divisions and is given in Figure 5-8 for comparison purposes. It should be pointed out that there are inherent differences between a solar and fossil-fired power plant. A solar power plant is both a primary energy producer (collector subsystem) and an electrical energy converter (receiver, thermal storage and electrical generation subsystems), whereas a conventional fossil-fired power plant is only an electrical energy converter. Thus in order to make a proper comparison, the energy investment for producing primary fossil

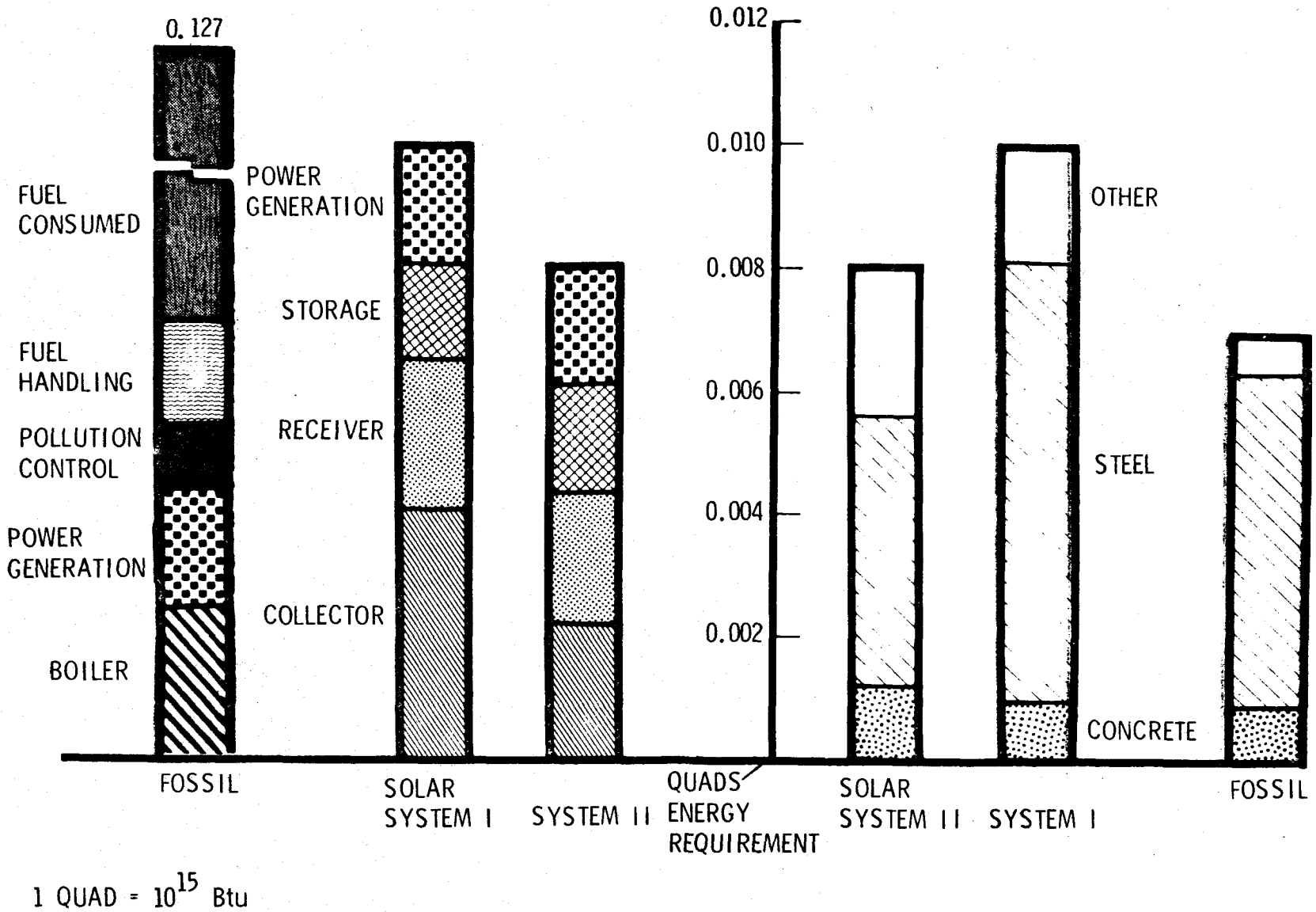


Figure 5-8. 100 MW_e Power Plant Energy Investment

fuel (fuel handling subsystem) should be added to the investments for the other conventional plant subsystems (boiler, electrical generation and pollution control subsystems) that are physically located at the plant site. The energy investment for producing primary fossil fuel includes such items as explorations, production, transportation, land withdrawal and land environmental restoration. The fuel handling energy investment given in Figure 5-8 does not include the associated calorific value of fuel. Neglecting this quantity is acceptable as long as there is no material fuel shortage during the power plant lifetime and no foreseeable significant energy impacts in the subsequent time frame. This assumption is valid for coal-fired, power plants. However, for oil and gas-fired power plants, the U.S. is currently importing large quantities of primary fuel feedstocks. Here the fuel handling energy investments can be substantially greater than those given in Figure 5-8. Where foreign imports of a primary fuel are involved, the energy investment, ϵ_t, to consume a unit quantity of such fuel in the U.S. is given by

$$\epsilon_t = \frac{\epsilon_d E_d + \epsilon_f E_f + \Sigma_j \epsilon_j X_j}{E_t}$$

where, $$\Sigma_j X_j C_j = E_f C_f$$

and E_t, E_d and E_f are the fuel quantities for total U.S. demand, domestic production and foreign imports, respectively.

ϵ_d = energy investment to produce and transport a unit quantity of fuel in the U.S.

ϵ_f = energy investment to transport a unit quantity of imported fuel to the U.S.

ϵ_j - energy investment to produce a unit quantity of material j for foreign exports

X_j = quantity of material j for foreign exports with associated unit sale price C_j

C_j = unit sale price of foreign fuel imports

The above estimates of energy investments for consuming a unit quantity of fossil fuel are based on three implicit assumptions: (1) there is no worldwide fuel shortage, (2) the supply of fuel to the U.S. is guaranteed and, (3) the U.S. exports equivalent-valued goods and services with no national shortage of raw materials necessary for their production.

Thus, as the resources of non-renewable raw materials and energy fuels are depleted, there will be greater requirements for conservation and recycling of raw materials, and for the use of renewable energy sources (Reference 51). There are two important factors that can be used in evaluating different energy sources. These are, "return ratio," which is the energy output to energy input ratio, and "payback period" which is the time to produce equivalent invested energy. In the past, the payback period played an important role when there was no shortage of the energy source, since this factor is significantly correlated with the economics of energy production. The role of this factor becomes more important as the interest rate or cost of money rises. The other factor (energy return ratio) is closely related to energy conservation and will play a significant role in future energy sources development.

Table 5-6 gives the estimated values for energy return ratio and energy payback period for various energy sources. It can be seen from this table that the energy return ratio for solar power is comparable with synthetic coal fuels and middle eastern oil when the energy investment for its transportation is included. The energy return ratio for solar power also compares favorably with oil shale, bio-conversion and North Sea oil when it arrives in England. The energy payback period for solar power plants is not very favorable since energy is produced in approximately half the available time when compared to other energy sources.

Table 5-6. Energy Source, Payback Period, and Return Ratio

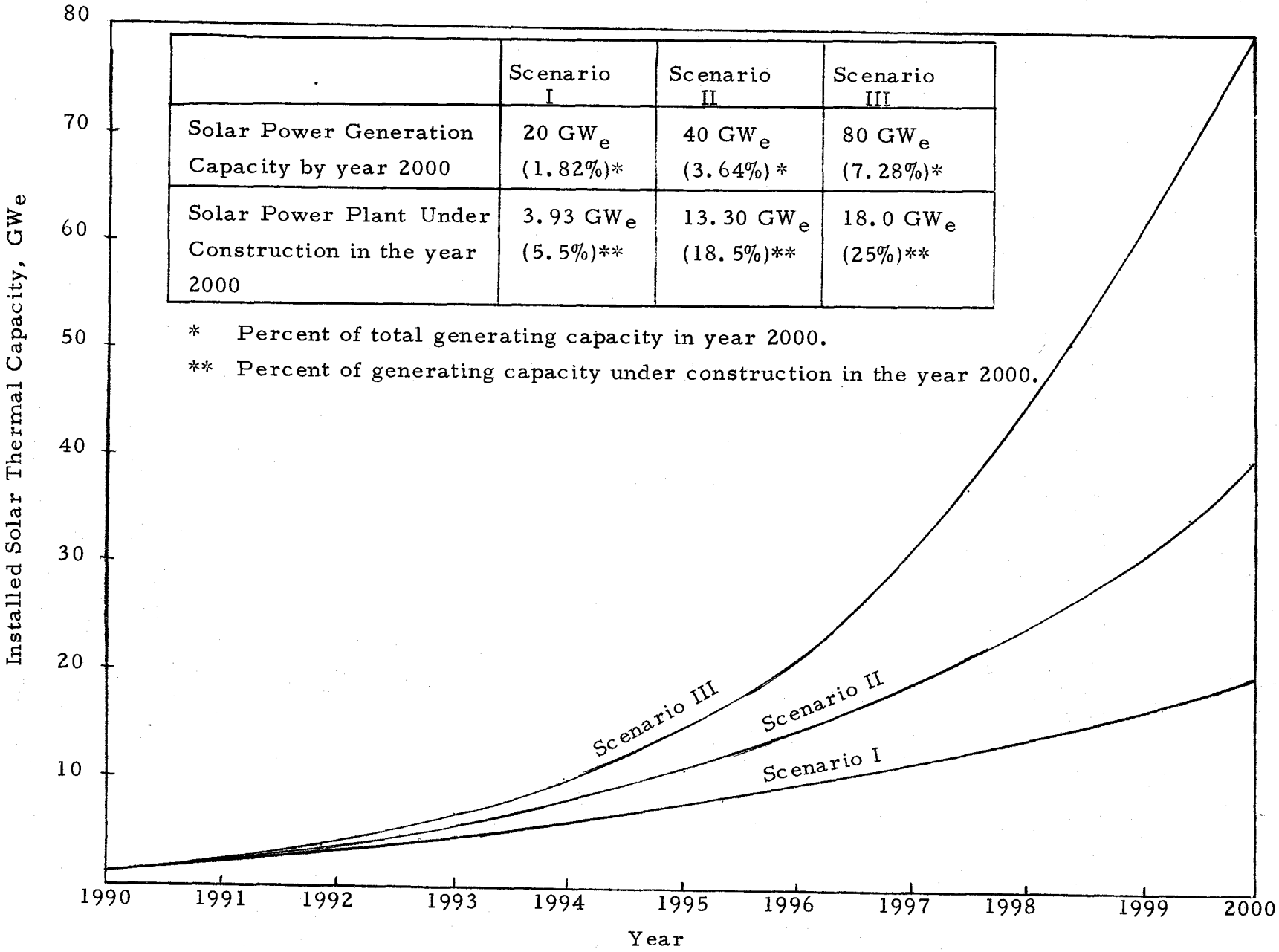
ENERGY SOURCE	RETURN RATIO $\left(\frac{\text{energy output}}{\text{energy input}}\right)$	PAYBACK PERIOD (time to produce equivalent invested energy)
MIDDLE EAST OIL WELL	25	2 months
MIDDLE EAST OIL WELL PLUS TRANSPORTATION TO U. S.	11	4 months
U. S. COAL	20	4 months
SYNTHETIC COAL FUELS	10-14	8 months
NORTH SEA OIL WELL	10	5 months
NORTH SEA OIL WELL PLUS TRANSPORTATION TO ENGLAND	7	8 months
OIL SHALE	5-6	1 year
BIOCONVERSION	3	6 months
SOLAR THERMAL POWER PLANT	11-14	2.2 - 2.7 years
NUCLEAR POWER PLANT*	20	1.1 - 1.4 years
CONVENTIONAL FOSSIL FIRED POWER PLANT*	8-18	1.2 - 1.9 years
OIL SHALE FIRED POWER PLANT*	5	2.0 - 2.5 years
SYNTHETIC COAL FIRED POWER PLANT*	10-14	1.6 - 2.3 years

*Energy conversion not an energy source

D. MATERIALS AND ENERGY IMPACTS UNDER DIFFERENT SCENARIOS

Materials and energy impacts by solar central power plants are directly proportional to their market penetration. It is not possible to predict the exact size of such future market penetration as it largely depends upon the availability of conventional energy sources, technical and economic success in developing new energy sources, and the balance of trade and political relationships between the U.S. and the energy producing nations. However, estimates of the various possible ranges of market penetrations can be made that may be in concert with the various ranges of future uncertainties. Figure 5-9 gives the three growth scenarios for solar power plants, with installed solar thermal capacities of 20, 40 and 80 GW_e by the year 2000. Scenarios II and III correspond to the projected scenarios of business-as-usual and accelerated-development as outlined in Project Independence (Reference 52), and Scenario I refers to a limited-development situation. Based upon ERDA estimates (Reference 41), Figure 5-9 also gives for each of the three scenarios, installed solar plants generating capacity in units of percent of total generating capacity in the year 2000, and solar power plant generating capacity under construction in units of percent of total electric capacity under construction in the year 2000.

Table 5-7 gives estimates of the impact of solar plant penetration on current U.S. materials and manufacturing facilities for each of the three scenarios. It gives the projected material and manufacturing requirements in the year 2000 as the percent of 1974 production rates. Such percent requirements would be substantially less when represented as percent of the year 2000 production and manufacturing outputs. The materials requirements for mirror production and float glass and silver are based upon the assumption that all the installed plant reflective surfaces are made up of silver-float-glass mirrors. The requirements for plastics and aluminum metalizing on plastics are based upon the assumption that all the reflective surfaces will be made up of plastics and aluminum. Thus, the above mentioned requirements of these materials will be reduced depending upon the design of installed reflective surfaces. The corresponding materials requirements for constructing fossil power plants of equivalent generating capacities are also given in Table 5-7 for comparison purposes.



	Scenario I	Scenario II	Scenario III
Solar Power Generation Capacity by year 2000	20 GW_e (1.82%)*	40 GW_e (3.64%)*	80 GW_e (7.28%)*
Solar Power Plant Under Construction in the year 2000	3.93 GW_e (5.5%)**	13.30 GW_e (18.5%)**	18.0 GW_e (25%)**

* Percent of total generating capacity in year 2000.

** Percent of generating capacity under construction in the year 2000.

Figure 5-9. Growth Scenarios for Solar Power Plants

Table 5-7. Solar Plant Penetration Impacts on Current U.S. Materials/Manufacturing Facilities

MATERIALS/MANUFACTURING ITEMS	PROJECTED ANNUAL REQUIREMENTS IN YEAR 2000 AS PERCENT OF 1974 PRODUCTION RATES					
	SCENARIO I		SCENARIO II		SCENARIO III	
	FOSSIL	SOLAR	FOSSIL	SOLAR	FOSSIL	SOLAR
MIRROR PRODUCTION	--	200%	--	670%	--	900%
FLOAT GLASS	--	11-21%	--	37-72%	--	50-97%
STEEL	2.4%	1.8-3.2%	8.3%	6.0-10.8%	11.2%	8.2-14.7%
SILVER	--	2.0%	--	6.7%	--	9.1%
CEMENT	1.5%	1.4-2.6%	5.0%	4.9-8.8%	6.7%	6.6-11.6%
ALUMINUM METALIZING ON PLASTICS	--	11%	--	36%	--	49%
ALUMINUM	--	0.6%	--	2.0%	--	2.6%
PLASTICS	--	0.5%	--	1.7%	--	2.3%

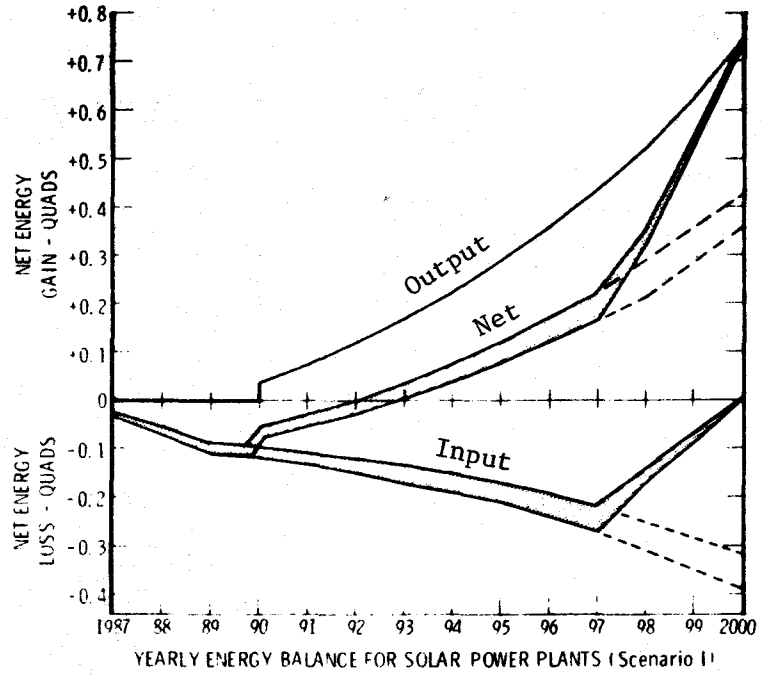
Scenario I, II and III corresponds to power plant capacities of 3930 mW_e, 13300 mW_e and 18000 mW_e under construction during the year 2000

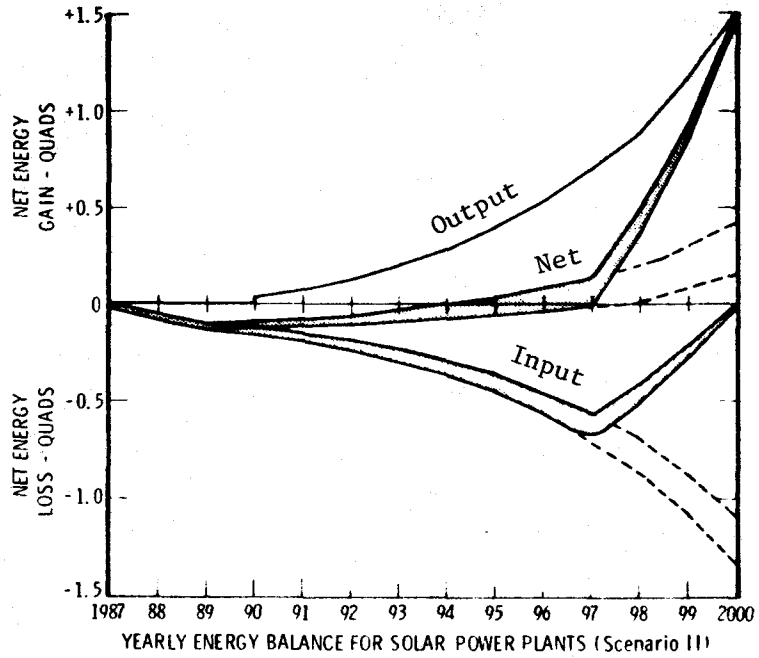
Sources: (1) Minerals yearbook
(2) Annual survey of manufacturers
(3) U. S. statistical abstracts

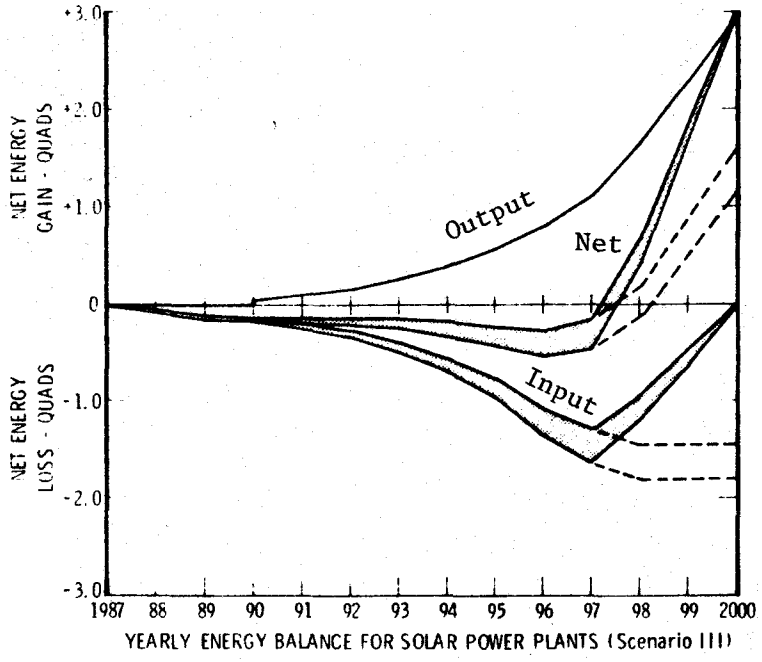
Figure 5-10 gives the yearly energy balance for solar power plants for each of the three scenarios of Figures 5-9. Energy input for constructing solar power plants, energy output from electrical power generation and the net energy difference for each of the three scenarios are plotted in this figure. The energy input is based upon the requirements of the two possible systems of Figure 5-8 and a 3-year energy investment period for constructing solar power plants. The shaded area in the energy input curve represents the uncertainty range of the invested energy in constructing solar power plants. The energy output is based upon the assumption that yearly energy displacement is equal to 0.037 quad for every 1000 MW_e installed generating capacity of solar central power plants. The net energy curve is simply the difference between the energy input and energy output. The dotted lines near the energy input curves represent energy investments for those plants which are being constructed and would be completed after the year 2000 and for which no energy displacement credit is obtained in the time frame under consideration. The dotted lines near the net energy curve represent the case in which the above mentioned energy investment is included. Figures 5-10 also illustrates the total U.S. energy consumption and energy for power generation for the 1970-2000 time period. These data are based upon ERDA estimates (Reference 53).

Figures 5-11, 5-12 and 5-13 give the cumulative net energy balance for solar power plants according to the three implementation scenarios given in Figure 5-9. This cumulative net energy balance represents the total energy accumulation that is obtained by summing the net energy balance given in Figure 5-10 for all previous years. The shaded areas shown in Figures 5-11, 5-12 and 5-13 represent the uncertainty range associated with the two solar power plant systems of Figure 5-8. The dotted lines in these figures represent the energy accumulations which are obtained when energy investments are included for power plants that become operational in the years 2001, 2002 and 2003.

Figures 5-14 and 5-15 illustrate the yearly and cumulative net energy balances for materials enrichment and construction of nuclear power plants for the time period 1945-1970. The data are compiled from several







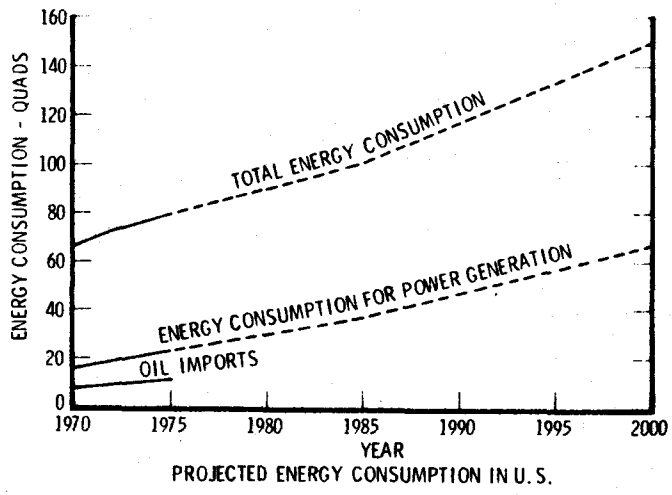


Figure 5-10. Yearly Energy Balance

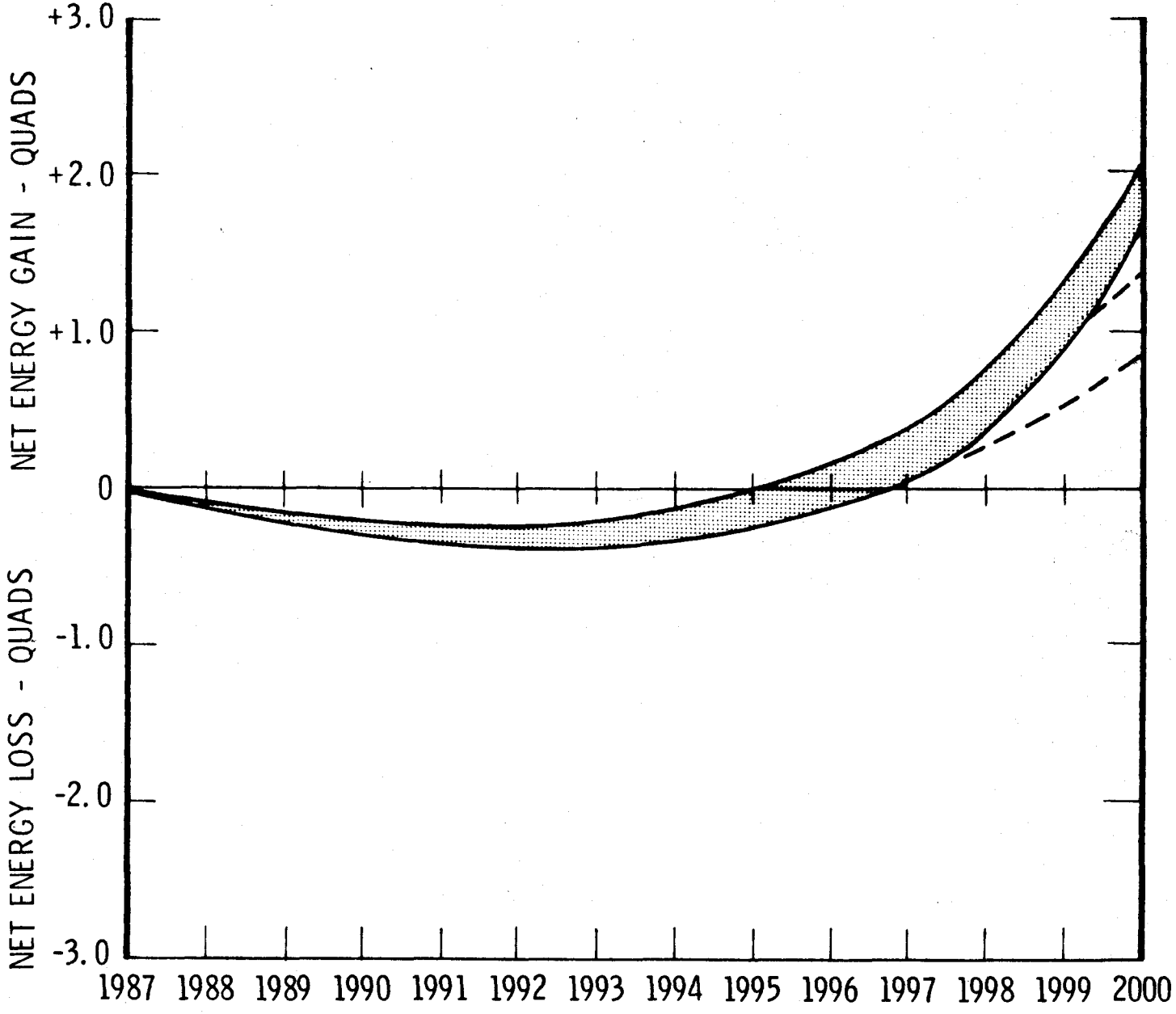


Figure 5-11. Cumulative Net Energy Balance
Scenario I

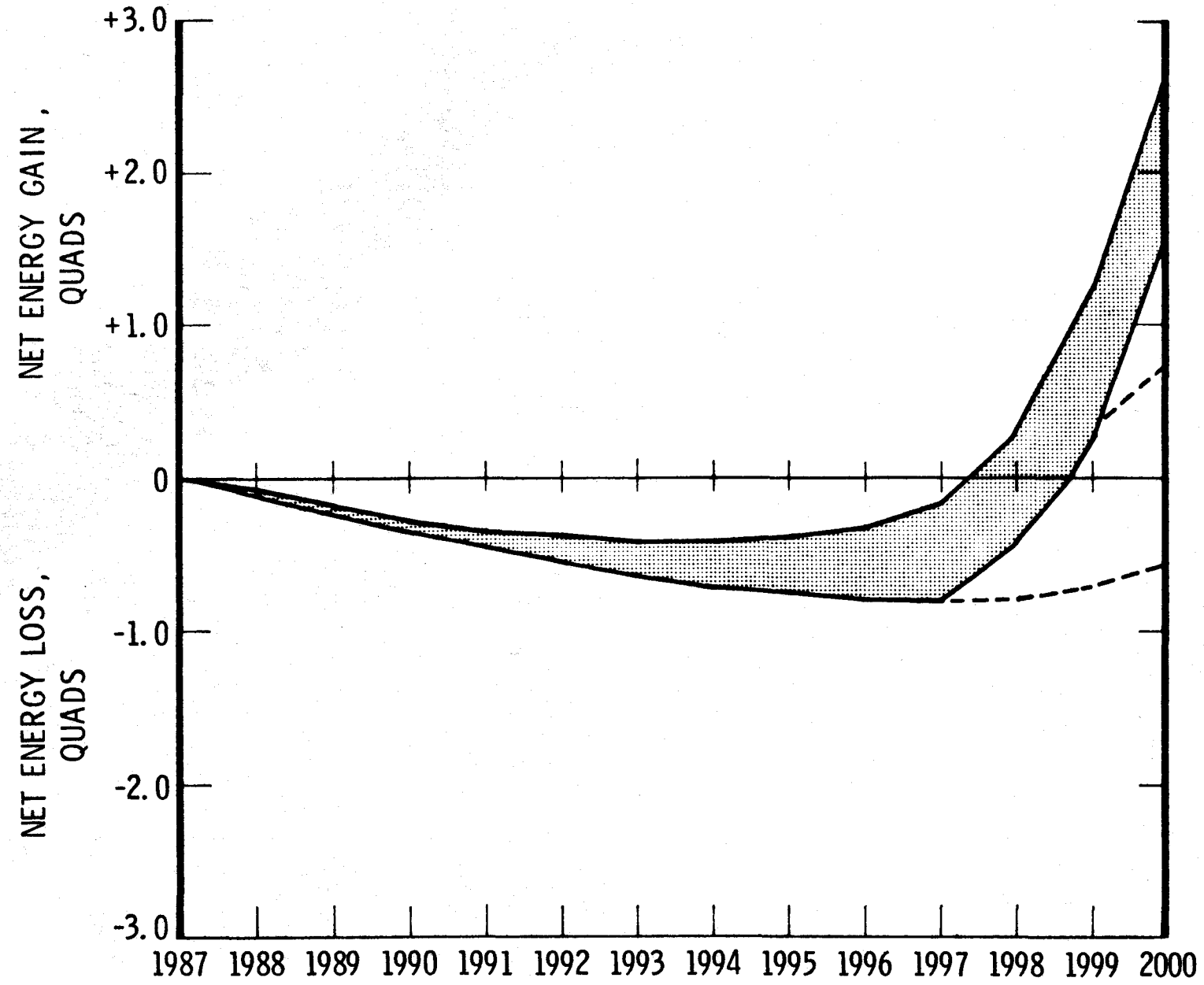


Figure 5-12. Cumulative Net Energy Balance
Scenario II

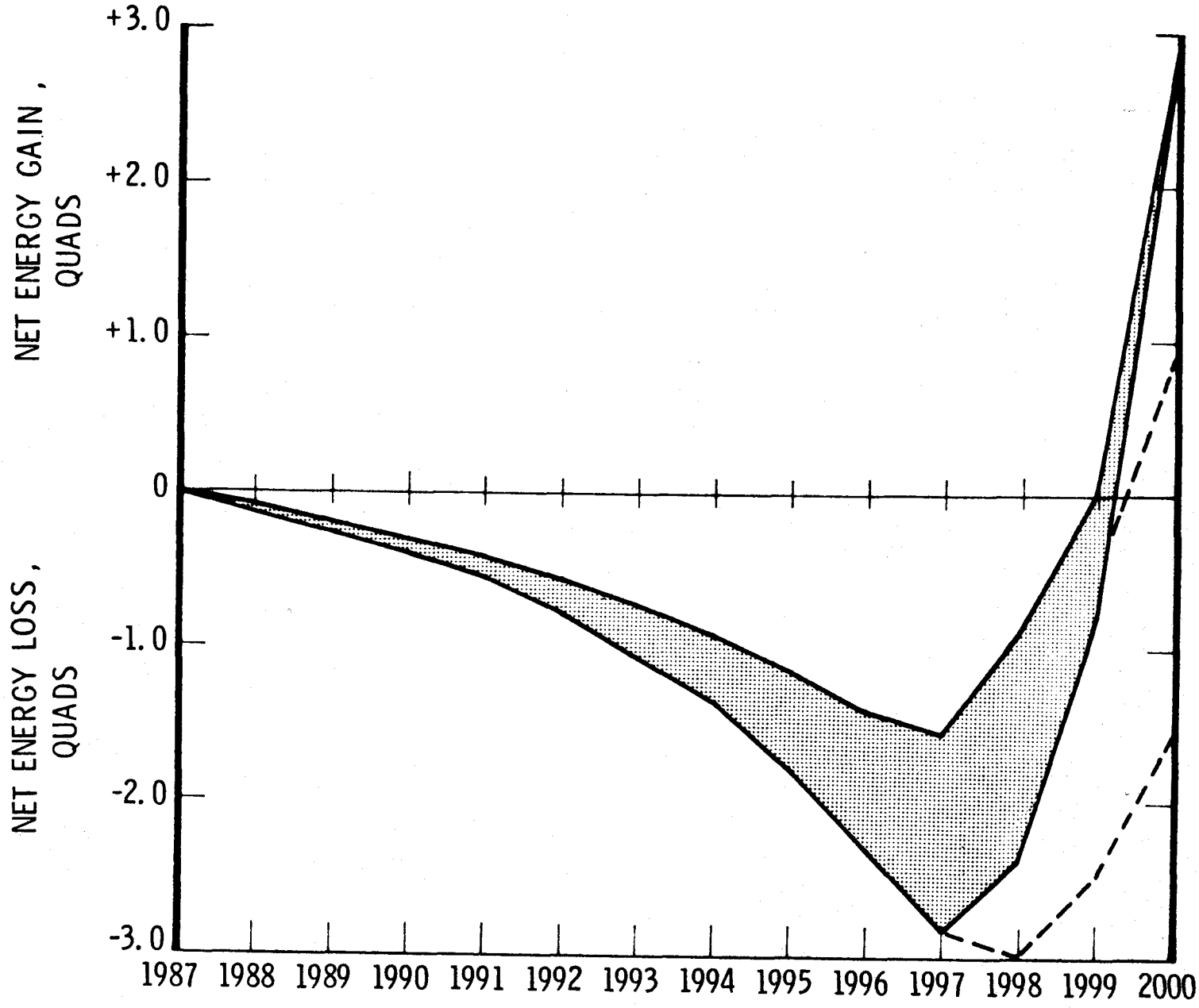


Figure 5-13. Cumulative Net Energy Balance
Scenario III

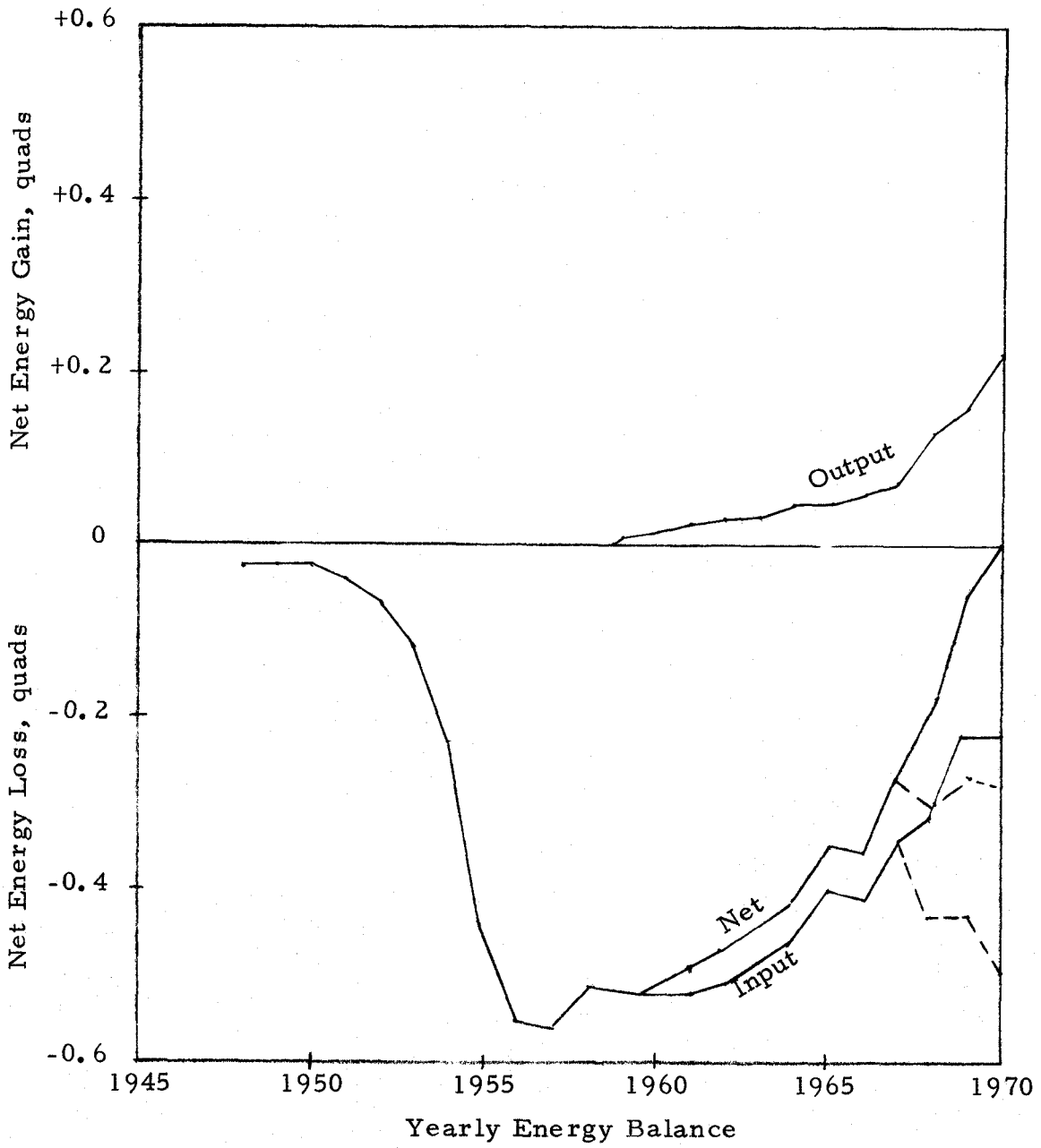


Figure 5-14. Yearly Net Energy Balance
for Materials Enrichment and Nuclear Power Plant

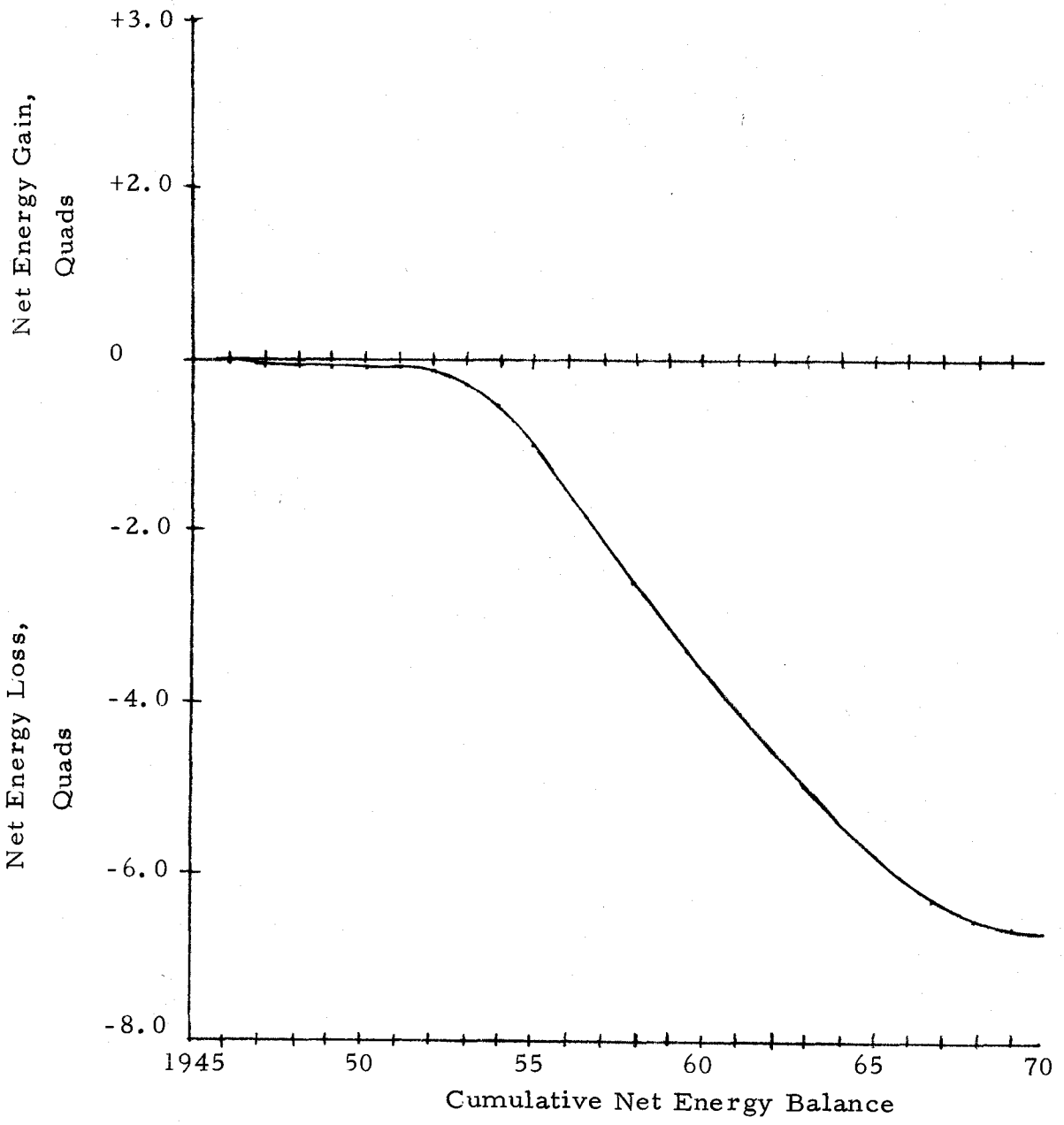
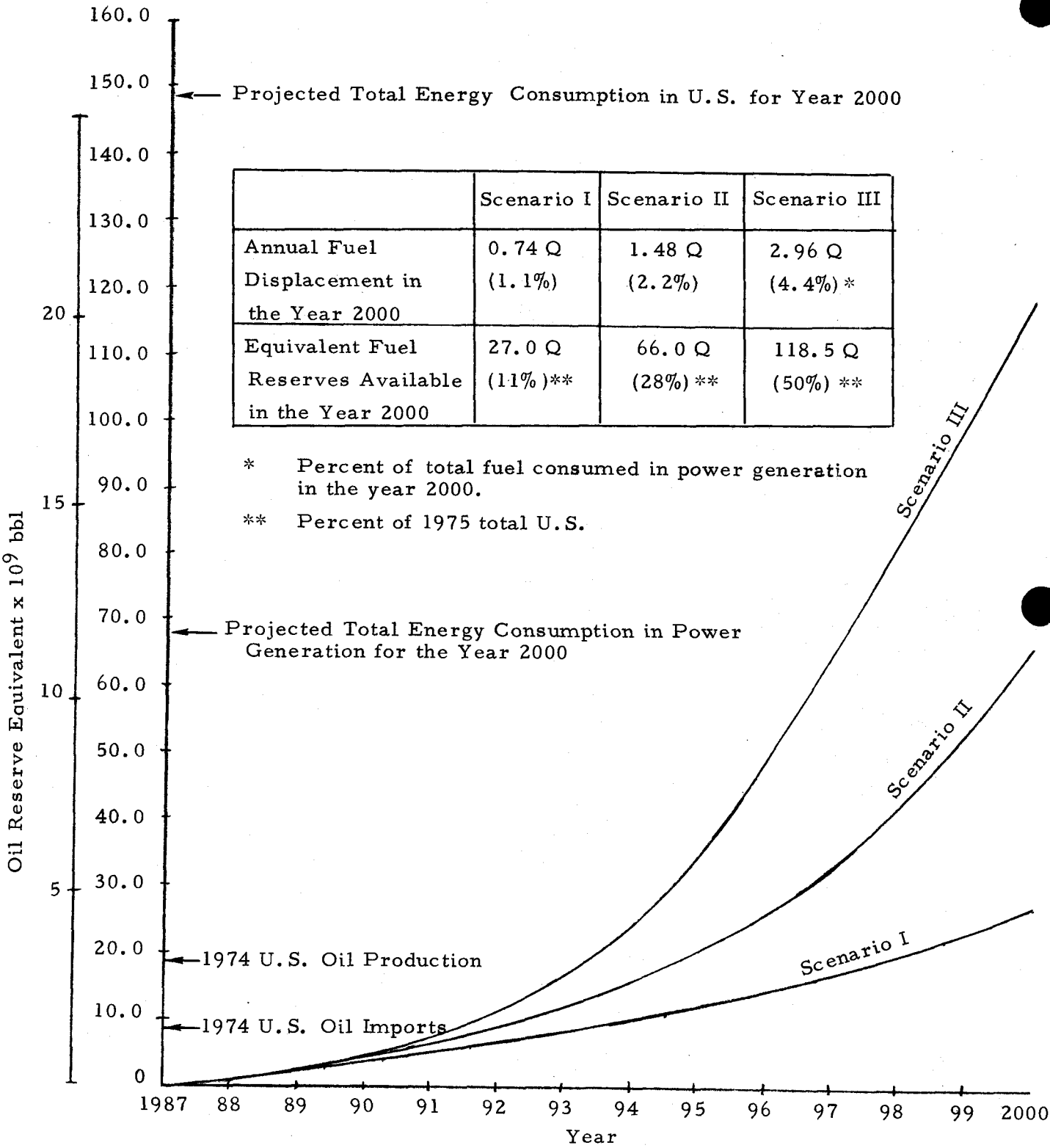


Figure 5-15. Cumulative Net Energy Balance for Materials Enrichment and Nuclear Power Plants

documents (References 54, 55, 56). The energy investment curve includes a total energy expenditure in materials enrichment and construction for a nuclear plant capacity of 6.87 MW_e in 1970. Materials enrichment and its associated R&D efforts for national security are the major energy consuming elements in the energy input curve. Nuclear power plant energy investment started around 1955 and represents only one-tenth of the total energy input. The dotted curve corresponds to the case when energy investment is included for nuclear plants that become operational after 1970.

Figure 5-16 gives the energy reserve equivalent of installed solar thermal power plants according to the three implementation scenarios given in Figure 5-9. It can be seen from Figure 5-16 that very significant energy reserves can be made available by installing solar central power plants. For example, energy reserve equivalent under Scenario III is approximately 50% of the total current U.S. oil reserves or one-fifth of the total cumulative oil production through (1975) in the U.S. This high energy reserve equivalent is primarily due to the efficient energy return ratio for solar central power plants. The relatively high energy payback period is primarily responsible for the somewhat lower yearly fuel displacement rate. However, in the long run, it is the energy return ratio and not the energy payback period that is responsible for improving the energy balance of a nation.



	Scenario I	Scenario II	Scenario III
Annual Fuel Displacement in the Year 2000	0.74 Q (1.1%)	1.48 Q (2.2%)	2.96 Q (4.4%) *
Equivalent Fuel Reserves Available in the Year 2000	27.0 Q (11%)**	66.0 Q (28%) **	118.5 Q (50%) **

* Percent of total fuel consumed in power generation in the year 2000.

** Percent of 1975 total U.S.

Figure 5-16. Available Energy Reserve Equivalent of Installed Solar Thermal Power Plants

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APPENDIX A

DAILY INSOLATION/CLIMATOLOGY DATA BASE FORMAT

This Appendix and the following one (Appendix B) describe the format and contents of standard insolation/climatology data tapes which are obtainable from The Aerospace Corporation for use in solar energy system studies. The procedures for procuring these tapes are described in Appendix C.

The data for each station form a separate file. The data for each month form a separate block on the file. The data for each day are contained as coded information in a 130-character record. Each block consists of 31 records. For months with less than 31 days, all fields except the station number are filled with nines. There is a record on the file for every day of every year from 1 January 1952 through 30 December 1973, even if no measured data are presently available for that particular date. Missing data are indicated by blank fields. All values which can be calculated are included for every day. This includes solar declination, modified Julian day, extraterrestrial insolation and the possible minutes of sunshine. The location of the various data elements within the individual daily records is specified in Table A-1.

Table A-1. Daily Total Hemispheric Insolation Data

Record Format

Character Position	Item	Code	Code Definition
		Blank X X/	Missing or unknown data 11 punch on card 11 overpunch
1 - 5	Station Number	00000 - 99999 X0001-X9999	WBAN Number Cooperative Station Number
6, 7	Year	51 - 99	Last two digits of year
8, 9	Month	01 - 12	January - December
10, 11	Day	01 - 31	Day of month
12	None	Blank	
13 - 17	Observed Total Insolation	00000 - 99999	00000 - 99999 kilojoules/m^2 This is the measured energy received by a hemispheric collector during the entire day.
18	None	Blank	
19 - 23	Extra-terrestrial Insolation	00000 - 99999	00000 - 99999 kilojoules/m^2 This is the energy possible on a horizontal plate during the entire day.
24	None	Blank	
25 - 27	Percent of Possible Insolation	000 - 100	100 times the quotient obtained by dividing the observed insolation (characters 13 - 17) by the extraterrestrial insolation (characters 19 - 23).
28	None	Blank	

Table A-1. (Continued)

Character Position	Item	Code	Code Definition
29	Cloudiness	0 - 9	0 - 9 tenths of average cloudiness, sunrise to sunset.
		X	10 tenths average cloudiness, sunrise to sunset.
30	None	Blank	
31 - 34	Observed Minutes of Sunrise	0000 - 1440	Minutes of sunshine observed.
35	None	Blank	
36 - 39	Possible Minutes of Sunshine	0000 - 1440	Minutes of sunshine possible for date and latitude.
40	None	Blank	
41 - 43	Percent of Possible Sunshine	000 - 100	100 times the quotient obtained by dividing the observed minutes of sunshine (characters 31 - 34) by the possible minutes of sunshine (characters 36 - 39).
44 - 46	Mean Dew Point Temperature	X99 - X01 000 - 999	The sum of available hourly* dew point observations for the day divided by the number of observation. The units are whole Celsius degrees.
47 - 49	Mean Relative Humidity	000 - 100	The sum of available hourly* percent relative humidity observations for the day divided by the number of observations.
50 - 52	Maximum Temperature	X99 - X01 000 - 999	Maximum temperature in whole Celsius degrees.

Table A-1. (Continued)

Character Position	Item	Code	Code Definition
53 - 55	Minimum Temperature	X99 - X01 000 - 999	Minimum temperature in whole Celsius degrees.
56	24 Hour Precipitation Code	0	Trace
		1	Actual observed amount in characters 57 - 60.
		2	Estimated amount in characters 57 - 60.
		3	Accumulated value for period > 24 hour in characters 57 - 60.
		4	Precipitation amount not measured but included in subsequent day.
57 - 60	24 Hour Precipitation	0000 - 9999	Water equivalent of the precipitation for the period in millimeters.
61	24 Hour Snowfall Code	0	Trace
		1	Actual observed amount in characters 62 - 64.
		2	Estimated amount in characters 62 - 64.
		3	Accumulated value for period > 24 hours in characters 62 - 64.
		4	Amount not measured but included in subsequent day.
62 - 64	24 Hour Snowfall	000 - 999	Snowfall for the period in centimeters.
65	Snow Depth Code	0	Trace
		1	Actual observed amount in characters 66 - 68.
		2	Estimated amount in characters 66 - 68.
66 - 68	Snow Depth	000 - 999	Depth of snow on ground in centimeters.

Table A-1. (Continued)

Character Position	Item	Code	Code Definition
69 - 79	Occurrence of One or More Phenomena	0, 1, 9	0 No occurrence. 1 Day with occurrence. 9 Value not available.
69	Fog		
70	Heavy Fog		
71	Thunder		
72	Sleet		
73	Hail		
74	Rain		
75	Snow		
76	Glaze		
77	Dust or Sand		
78	Smoke or Haze		
79	Blowing Snow		
80 - 82	Peak Gust Speed	000 - 999	Wind speed in meters/second.
83 - 85	Peak Gust Direction	000 - 360 990	Wind direction in whole degrees: 000 = Calm 001 - 360 = 001° - 360° 990 = Light and variable
86 - 88	Peak Gust Time	000 - 239	Time of occurrence of peak gust to nearest hour and tenth, local standard time.
89 - 91	Mean Wind	000 - 999	The sum of the magnitudes of the available hourly* wind speeds in m/sec divided by the number of observations.
92 - 93	Resultant Wind Direction	00 - 36	The direction from north in tens of degrees of the vector sum of the available hourly wind velocity vectors.

Table A-1. (Continued)

Character Position	Item	Code	Code Definition
94 - 96	Resultant Wind	000 - 999	The magnitude of the resultant average wind in m/sec obtained by summing vectorially the available hourly* wind velocity observations and dividing by the number of observations.
97	Mean Sky Cover	0 - 9, X	The sum of the available hourly* sky cover observations in tenths divided by the number of observations.
98 - 100	Maximum Relative Humidity	000 - 100	Maximum relative humidity in whole percent.
100 - 103	Minimum Relative Humidity	000 - 100	Minimum relative humidity in whole percent.
104 - 108	Water Equivalent of Snow	00000 - 19999	Water equivalent of snow in millimeters: 00000 = Trace 10000 - 19999 = 0000 - 9999mm
109 - 111	Fastest Wind Speed	000 - 999	Fastest wind speed in m/sec. The source is indicated by the digit in character 112.
112	Fastest Wind Code	0 1 2 3	Fastest minute data Fastest mile speed data Highest instantaneous speed Fastest minute speed in knots
113 - 114	Fastest Wind Direction	00 - 36	Direction in tens of degrees.
115 - 117	Mean Temperature	X99 - X01 000 - 099	The sum of the available hourly* dry bulb temperature observations in whole degrees. Celsius divided by the number of observations.

Table A-1. (Continued)

Character Position	Item	Code	Code Definition
118 - 121	Mean Station Pressure	0000 - 9999	The sum of the available hourly* station pressure observations in millibars divided by the number of observations.
122 - 125	Solar Declination	X240 - 240	Solar declination at noon for the station longitude in tenths of a degree.
126 - 130	Modified Julian Day	00000 - 99999	The Julian day -2400000 during which the day in characters 6 - 11 begins at Greenwich.

*These fields are extracted from National Climatic Center decks 939 and 937. They exist only for 1961 and later. From 1961 through 1964 24 observations per day were normally archived and used to obtain the mean values. From 1965 on values were archived only every third hour, so that the averages are of eight values. Prior to 1961 the fields will be blank.

APPENDIX B

HOURLY INSOLATION CLIMATOLOGY DATA BASE FORMAT

The data for each year for each station form a separate file. The data for each day form a separate block on the file. The data for each hour are contained as coded information in a 130-character record. Each block consists of 24 records for the 24 hours of a day. There is a record on the file for every hour of every day for the two years covered, even if no data are presently available for entry into that record. The records are arranged in sequential time order from the first to the last of the file.

The format of the individual record is based on the Deck 280 - Hourly Record of Solar Radiation provided by the National Climatic Center of NOAA, except that the units are metric. The record length has been expanded from 80 characters to 130 characters to allow room for additional information. The locations of various data elements in the individual records are specified in Table B-1. In that table, the heading character should be interpreted as character position in the hourly record. Leading zeroes in a field may appear as either blanks or zeroes.

The insolation data files are preceded by two additional short files. The first of these files has general information about the data base and includes, in abbreviated form, the information provided in Table B-1 of this document. The second of these header files contains station peculiar data, such as the latitude and longitude of the station. Both of these header files consist of 80 character coded records blocked 20 records per block for a total of 1600 characters per block. On most computers, it should be possible to access this header information by simply listing these files.

Table B-1. Insolation Data Base
Hourly Record

August 1973

Character	Item	Symbol	Code	Code Definition	Remarks
	Missing Data		Blank	Missing or unknown data	
			X	11 punch	
			X/	X or 11 overpunch	
1-5	Station Number		00001-99999	WBAN Number	
			X0001-X9999	Cooperative Station Index Number	
6-7	Year		51-99	Last two digits of year	
8-9	Month		01-12	January - December	
10-11	Day		01-31	Day of month	
12-13	Hour LST		00-23	Hour, Local Standard Time	See TIME VALUES discussion in Preamble.
14-17	Total Solar Radiation		0000-9999	0.0 - 9.999 k watts/m^2	The radiation is Hemispheric Solar Radiation and is that received (direct and diffuse) on a horizontal surface. For some stations these data are estimated. See Character 28. Solar radiation data are recorded in solar time. The value is for the solar hour ending at the hour punched in Columns 38-39. The value is ascribed to the hour of observation (LST), Columns 12-13, that occurs within the solar hour (TST).
18-19	Solar Elevation		01-90	1 - 90 Whole Degrees	Computed for the midpoint of the solar hour listed in Characters 38-39 from the declination listed in Characters 118-121 and the latitude of the station listed in the Preamble to the tape.
			X1	Solar Elevation less than 0	

Table B-1 (Continued)

Character	Item	Symbol	Code	Code Definition	Remarks
20-22	Extra-Terrestrial Radiation		000-999	0 - 9.99 k watts/m^2	The integrated radiation computed for the solar hour listed in Characters 38-39 from the declination listed in Characters 118-121 and the latitude of the station listed in the Preamble. The solar constant is taken as 135.1 mW/cm^2 (1.936 Langleys/min).
23-24	Sunshine		00-60	0 - 60 Minutes	The value is for the hour ending at the hour punched in Columns 12-13. Where the sunshine record is maintained at a local but separate office, such as a downtown city office, the minutes of sunshine from that location will be used in the absence of data from the pyrheliometer site.
25	Snow Cover		0 or Blank	None or Trace of Snow	Some stations left this column blank to indicate none or trace. The snow cover is at the time of the nearest synoptic hour to the local standard hour in Columns 12-13.
			1	One inch or more	
26-27	None		Blank		
28	Estimated Total Insolation Flag		X	Estimated Value	This flag is set if the total insolation in Characters 14-17 is estimated from cloud data or indicated as estimated in the original Deck 280 data from which some of the present data are copied.
			Blank	Measured Value	
29	Estimated Normal Incidence Insolation Flag		X	Estimated Value	This flag is set if the normal incidence insolation is estimated. Interpolation of the data reported in the Climatological Data National Summary for different airmass is not counted as estimation.
			Blank	Measured Value	
30-32	Normal Incidence Radiation		000-999	0 - 9.99 k watts/m^2	For many stations these data are estimated, by means described in the Preamble, for the solar time indicated in Columns 38 and 39. See Character 29.
33	None		Blank		
34-35	Solar Week		01-52	Solar Week of Year	Punching of solar week was discontinued 1 Jan 63. Solar weeks are seven day periods with the first week beginning 1 Jan of each year, except that the last solar week of Dec is an eight day period. During leap year, the solar week beginning 24 Jun is an eight day period.

Table B-1 (Continued)

Character	Item	Symbol	Code	Code Definition	Remarks
36	Opaque Sky Cover		0	Less than 1 tenth	Tenths of sky hidden by clouds and/or obscuring phenomena. Sky cover through which the sky is visible is disregarded. 1 Jun 62, opaque was re-defined as follows: Those portions of cloud layers or obscurations which hide the sky and/or higher clouds. Translucent sky cover which hides the sky but through which the sun and moon (not stars) may be dimly visible is considered opaque. This column corresponds to Column 79 in Card Deck 144.
			1-9	1 - 9 tenths	
			X	10 tenths	
37	None		None		
38-39	Solar Hour		00-24	Solar Hour - True Solar Time	Solar radiation data are tabulated in True Solar Time (TST). The scheduled time of observation (LST) that occurs within the solar hour (TST) is punched in Columns 12-13.*
40-41	Percent of Possible Radiation		00-99	0 - 99%	Quotient is derived by division of radiation (Columns 14-17) by extra-terrestrial radiation (Columns 20-22). Values greater than 100% are set to 99%.
42-44	Visibility	VVV	000-970	kilometers in tenths	
			999	greater than 97 km	
45-51	Weather and/or Obstructions to Vision				These columns correspond to Columns 25-31 in Card Deck 144.
45	Liquid Precipitation		0	None	
		R-	1	Light rain	
		R	2	Moderate rain	
		R+	3	Heavy rain	
		RW-	4	Light rain showers	
		RW	5	Mod. rain showers	
		RW+	6	Heavy rain showers	
		ZR -	7	Light freezing rain	
		ZR	8	Mod. freezing drizzle	
		ZR+	9	Heavy freezing drizzle	

*Hour 24 is Hour 0 of the following day.

Table B-1 (Continued)

Character	Item	Symbol	Code	Code Definition	Remarks
46	Liquid Precipitation		0	None	
		L-	4	Light drizzle	
		L	5	Mod. drizzle	
		L+	6	Heavy drizzle	
		ZL-	7	Light freezing drizzle	
		ZL	8	Mod. freezing drizzle	
		ZL+	9	Heavy freezing drizzle	
47	Frozen Precipitation		0	None	
		S-	1	Light snow	
		S	2	Mod. snow	
		S+	3	Heavy snow	
		SP-	4	Light snow pellets	
		SP	5	Mod. snow pellets	
		SP+	6	Heavy snow pellets	
		IC-	7	Light ice crystals	Card code 7 was discontinued 1 Apr 63.
		IC	8	Ice crystals	Card code 8 was "Mod. Ice crystals" prior to 1 Apr 63.
		IC+	9	Heavy ice crystals	Card code 9 was discontinued 1 Apr 63.
48	Frozen Precipitation		0	None	
		SW-	1	Light snow showers	
		SW	2	Mod. snow showers	
		SW+	3	Heavy snow showers	
		SG-	7	Light snow grains	
		SG	8	Mod. snow grains	
		SG+	9	Heavy snow grains	
49	Frozen Precipitation		0	None	
		E-	1	Light sleet	Sleet showers is coded as sleet.
		E	2	Mod. sleet	
		E+	3	Heavy sleet	
		A-	4	Light hail	Card code 4 was discontinued 1 Sep 56.
		A	5	Hail	Card code 5 was "Mod. Hail" prior to 1 Sep 56.
		A+	6	Heavy hail	Card code 6 was discontinued 1 Sep 56.
		AP-	7	Light soft hail	Card code 7 was discontinued 1 Sep 56.
		AP	8	Small hail	Card code 8 was "Mod. soft hail" prior to 1 Sep 56.
		AP+	9	Heavy soft hail	Card code 9 was discontinued 1 Sep 56.

Table B-1 (Continued)

Character	Item	Symbol	Code	Code Definition	Remarks
50	Obstructions to vision		0	None	
		F	1	Fog	
		IF	2	Ice Fog	
		GF	3	Ground Fog	
		BD	4	Blowing dust	
		BN	5	Blowing sand	
51	Obstructions to vision		0	None	
		K	1	Smoke	
		H	2	Haze	
		KH	3	Smoke and haze	
		D	4	Dust	
		BS	5	Blowing snow	
		BY	6	Blowing spray	Card code 6 was effective 1 Jul 52.
52-54	Dry Bulb	TTT	000-099	0°C - 99°C whole degrees	Column 52 is punched X for values below zero.
			X01-X99	-1°C - -99°C	
55-57	Dew Point Temperature	T_dT_d	000-099	0°C - 99°C whole degrees	Column 55 is punched X for values below zero.
			X01-X99	-1°C - -99°C	
58-80	Clouds and Obscuring Penomena				These columns correspond to Columns 56-78 in Card Deck 144. Provision was made for as many as four layers of cloud and/or obscuring phenomena existing at one time. If more than four layers existed, the data for levels above the fourth were entered in the Remarks portion of WBAN 10B, and were not punched. Their presence is indicated by the entry for total sky cover. Layers were punched in ascending order of elevation. All fields above a layer which prevented observation were left blank. If two or more types of clouds were observed at the same height, only the predominating type was punched, their amounts being combined. For each layer, the amount, type and height were punched, and for the second and third layer, the summation amount at the level involved was punched, reflecting the total amount of sky covered by that layer and those below it. The summation total for the fourth layer is obviously the total sky cover. The summation total is not necessarily the sum of the individual layers.

Table B-1 (Continued)

Character	Item	Symbol	Code	Code Definition	Remarks
58	Total Amount		0, 1-9	Tenths	
			X	10 Tenths	
59	Amount of Lowest Layer		0, 1-9	Tenths	
			X	10 Tenths	
60	Type of Cloud Lowest Layer		0	None	
		F	1	Fog	
		St	2	Stratus	
		Sc	3	Stratocumulus	
		Cu	4	Cumulus	
		Cb	5	Cumulonimbus	
		As	6	Altostratus	
		Ac	7	Altocumulus	
		Ci	8	Cirrus	
		Cs	9	Cirrostratus	
		[illegible]	X/2	Stratus Fractus	Prior to 1 May 61, code X/2 was Fractostratus (Fs)
		Cf	X/4	Cumulus Fractus	Prior to 1 May 61, code X/4 was Fractocumulus (Fc)
		Cm	X/5	Cumulonimbus Mamma	
		Ns	X/6	Nimbostratus	
		Acc	X/7	Altocumulus Castellanus	
		Cc	X/9	Cirrocumulus	
			X	Obscuring phenomenon other than fog	
61-63	Height of Lowest Layer		000-990	kilometers to tenths	
			888	Unknown height of a cirroform layer	Effective 1 Sep 56.
			XXX	Unlimited vertical visibility.	

Table B-1 (Continued)

Character	Item	Symbol	Code	Code Definition	Remarks
64	Amount of Second Layer		0, 1-9 X	Tenths 10 Tenths	
65	Type of Second Layer		0, 1-9 X/	See Column 60	
66-68	Height of Second Layer		000-990 XXX	See Columns 61-63	
69	Summation Amount at Second Layer		0, 1-9 X	Tenths 10 Tenths	
70	Amount of Third Layer		0, 1-9 X	Tenths 10 Tenths	
71	Type of Third Layer		0, 1-9 X/	See Column 60	
72-74	Height of Third Layer		000-990 XXX	See Columns 61-63	
75	Summation Amount at Third Layer		0, 1-9 X	Tenths 10 Tenths	
76	Amount of Fourth Layer		0, 1-9 X	Tenths 10 Tenths	
77	Type of Third Layer		0, 1-9 X/	See Column 60	
78-80	Height of Fourth Layer		000-990 XXX	See Columns 61-63	

Table B-1 (Continued)

Character	Item	Symbol	Code	Code Definition	Remarks
81-82	Wind Direction	dd	00-36	True direction, in tens of degrees, from which wind is blowing	
83-84	Wind Speed	ff	00-99	Meters/sec	
85-88	Station Pressure	PPPP	0000-9999	Hundreds of Newtons/m^2 (millibars)	Station pressure is the pressure at the assigned station elevation.
89-117	Blanks				Allowed for further expansion of the data base.
118-121	Solar Declinations		-240 to 240	Solar declination in tenths of a degree	
122-125	Solar Azimuth		-180 to 180	The azimuth angle from south to the sun in whole degrees. Negative values are towards the east.	
126-130	Modified Julian Day		00000-99999	The Julian day - 2400000 during which the day in Characters 6-11 begins at Greenwich.	

APPENDIX C

DATA TAPE PROCUREMENT

The data tapes described in Appendices A and B can be obtained by requesting a price quotation on standard insolation data tapes as described above from -

The Aerospace Corporation
P. O. Box 92957
Los Angeles, California 90009
Att: Mr. J. D. Price - Contracts

The letter should state the number of the tapes desired, the density (bit/inch), the coding (BCD or EBCDIC), and whether 7-or 9-track tapes are desired. Daily tapes are available only as 9-track 1600 BPI tapes due to the amount of data. Information can be obtained from the following individuals relative to these tapes.

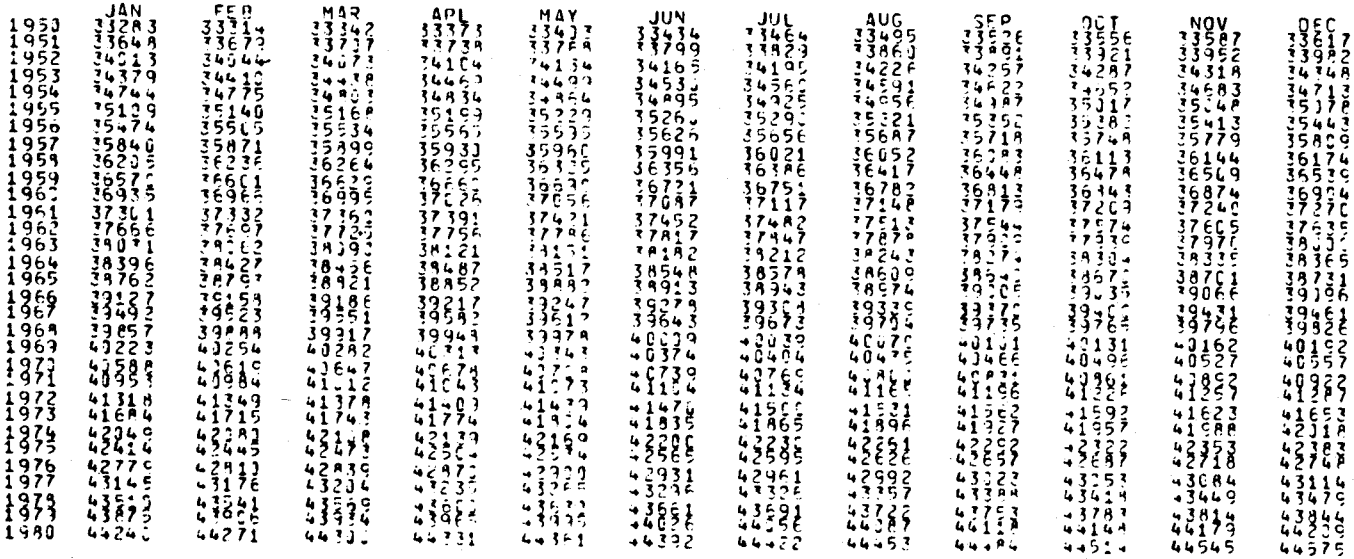
Contract Arrangements	Mr. D. Herman (213) 648-5757
Tape Reproduction Problems	Mr. R. Fasnacht (213) 648-6608
Insolation Data Base Contents	Dr. Charles Randall (213) 648-5977
Aerospace Solar Energy Studies	Dr. Mason Watson (213) 648-5615

APPENDIX D

MODIFIED JULIAN DAY NUMBERS

Table D-1 contains the Modified Julian Day number corresponding to the first day of each month of every year from 1950 through 1980.

Table D-1. Modified Julian Day Number



DOE F 1325.8
(7-79)

U.S. DEPARTMENT OF ENERGY

memorandum

DATE MAR 1 2 1984

REPLY TO ATTN OF Doug Elliott, DOE/Barstow

SUBJECT Search of TIC/NTIS Listings for Three Aerospace Corporation Reports.

TO: Don Holz, ISEA

In accordance with our discussions during my last trip to SAN, I would appreciate your assistance in determining whether certain of the reports associated with the 10-MWe Pilot Plant project are logged anywhere in the TIC or NTIS archives. Enclosed are covers, title pages and abstracts from three NSF- and ERDA-era reports by the Aerospace Corporation which provide background to the project. Project staff have been unable to locate these in the TIC Report Holdings File, and a contractor has tried to call them up on DIALOG without success. Unless you can verify through your resources that these are somewhere in the system, I shall have to initiate the process of entering them afresh.

The first, Aerospace ATR-75(7370)-3 (which we catalog as STMPO-13; this latter designation, however, is not in the TIC system), "Solar Thermal Conversion Central Receiver Pilot Plant Siting", 67pp plus 73pp of appendices, dated January 31, 1975, was done under National Science Foundation Contract C933. Other reports from NSF solar program contracts were incorporated into TIC's archives (with "PB-" numbers) and turned up on DIALOG, but this one has not, thus far.

Report ATR-77(7523-22)-3 (our STMPO-015), "Solar Thermal Conversion Mission Analysis", approx 300pp, dated May 1, 1976 but not issued until February 25, 1978, was done under an ERDA contract E(04-3)-1082. My ERDA-to-DOE contract crosswalk lists the DOE number as DE-AC03-76SF80064, but I come up with nothing under this number in the "Holdings" list, and it, too, failed to show up on DIALOG.

The third, ATR-76(7523-11)-6 (STMPO-018), "Highlights Report, Solar Thermal Conversion Program; Central Power Projects - Semiannual Review 3 June 1976", 49pp, and dated August, 1976, was one of a series of summaries of NSF, ERDA and DOE review meetings, others of which do appear in the "Holdings" list and DIALOG. It was done under Project Agreement No. 2 of ERDA Contract E(04-3)-1101, which translates as DE-AC03-76CS51101.

Please note that the "ATR" ("Aerospace Technical Report") numbers are "approved" numbers as employed by TIC, and these reports would be expected to be traceable under those numbers. They may, however, be "buried" in two lots of reports sent to TIC from SAN in 1980, in some cases without full identification. These appear in the "Holdings" list under contract CS51101 with a variety of non-ATR numbers, and also under Contract ET21060 (which was Project Agreement 14 of ERDA Contract E(04-3)-1101). If nothing else works, you might call up a printout of all the reports listed under these two contract numbers.

I am most appreciative of your offer of assistance in sorting out these reports; please let me know if there is any further information that might help locate them.

Encls.: 3, as stated

cc: Bob Hughey, DOE/SAN (FGS)
Mary Soderstrum, B&McD

S. D. Elliott, Jr., Director
DOE Project Office, Barstow

Department of Energy
San Francisco Operations Office
1333 Broadway
Oakland, California 94612

Reply to:
DOE Solar One Project Office
Post Office Box 366
Daggett, CA 92327
(619) 254-2672

Mr. Harry D. Eden
Energy Systems Directorate
Building D-5, Room 1110
The Aerospace Corporation
Post Office Box 92957
Los Angeles, CA 90009

MAR 13 1984

Subj.: Identification and CTearance for DOE Technical Information Center of Aerospace Documents Related to 10-MWe Solar Thermal Pilot Plant (Solar One)

Dear Harry:

We are finalizing the current edition (covering the period through mid-1982) of the Solar One Project Bibliography; a proof copy is provided for your reference (publication by the Electric Power Research Institute is expected at the end of March). While we are in the process of establishing a reference library at the Plant site, which will include all of the 555 documents identified in the Bibliography, we would like to be able to refer inquiries from recipients of this document for individual copies of reports cited to the DOE Technical Information Center (DOE contractors) or the National Technical Information Service. In order to do this, we must insure that proper TIC/NTIS stock numbers are provided, and that all reports in the Bibliography have been properly patent cleared and sent to TIC and NTIS for preparation of microfiche. Unfortunately, this is the case at present for only about 300 of the documents listed; specifically, those for which the "Other Recipients" (line 10 of the document identification block) includes these agencies. We propose to issue an update to the Bibliography following completion of the Experimental Testing and Evaluation phase of Plant Operation (currently scheduled for the end of July, 1984). This update, in addition to providing documents produced by the Project since mid-1982, will include proper TIC/NTIS citation for all documents listed; it will also include a small number of documents from the earlier period which are omitted from the initial edition, but may be of interest to users of the Bibliography.

STMPO-019, -021, -026, -027, -028, -034, -035, -038, -039 or will be included in the update
(NEW) -563, -564, -565

We have identified twelve Aerospace documents which are listed, but for which no TIC-approved citation has been located; most of these appear not to have been submitted in the first place, apparently having been treated as "working papers", while others are conference reports or journal articles. In addition, we have three NSF- and ERDA-era documents which, we feel sure, are "somewhere in the system", but which we have been unable to identify in the periodic reports lists issued by TIC, or - thus far - by inquiries to the data base. The latter three documents are described in the attached memorandum to Don Holz, the DOE/SAN Technical Information Officer; if, however, Aerospace records indicate the TIC/NTIS identifiers assigned (most likely "PB-" followed by six or eight digits), we would be most appreciative if you could pass them to us.

STMPO-013, -015, -018

For the twelve documents in the first group, I have provided copies for your reference; I have also prepared SAN Form 70 for completion by your staff for each of them (unless you have copies of previous patent clearances from SAN/OPC). While

I appreciate that Aerospace is no longer formally involved in the Project, and thus cannot assign a very high priority to dealing with these materials, I anticipate that you would be as eager as we are to get them cleaned up and on the way to TIC. (The "routine" on line 3 of the Form 70 is addressed to SAN/OPC.)

In preparing these documents and the Form 70's, I have assigned two identification numbers to each. The primary number is the normal TIC identifier: an ATR-series number, where such is provided on the document, or a number derived from the DOE contract number, where it is not. (Three Aerospace contracts are involved: DE-AT03-76CS51101 - formerly EY-76-C-03-1101/PA#2 -, DE-AT03-76ET21060 - formerly -1101/PA#14 - and the STMPO contract, DE-AC03-78ET20517; I have tried to assign the reports to the proper contract, where it is not cited in the document itself, using date or subject matter). If you know of appropriate ATR-nummer assignments, or if you wish to make such assignments, please do so and so advise me.

The secondary number (STMPO-xxx) is for convenience in filing and tracking Project documents; it will probably occur to you fairly promptly that it is connected with the Bibliography listing, and, in fact, it is the Bibliography page number. Aerospace documents comprise the first thirty-nine listings (STMPO-001 to STMPO-039), as well as the first three in the prospective update (STMPO-563 to STMPO-565) to the Bibliography. In any discussions with the Project Office, communication will be enhanced by using these numbers, and they should be preserved in the event your staff wishes to alter or re-type the relevant Form 70's.

I need, in order to track progress on a total of some 300 reports in processing, to have the Form 70's, together with the reference copies provided, <u>returned to me at the Project Office</u>, and <u>not</u> to SAN/OPC or TIC; I have made special arrangements with Roger Gaither at SAN and Bill Matheny at TIC, and the process seems to be working well at this point.

The advice of your patent/copyright staff on how best to deal with conference reports and journal articles (STMPO-28, -34, -38 and -39) and specifications including manufacturers' data sheets (STMPO-564, -565) would be welcomed. If copyright issues arise with these items, we can request TIC to limit further distribution as appropriate.

If you do wish copies of any of the documents provided, or cited in the Aerospace section of the Bibliography, I shall be happy to provide them. Thank you for your assistance.

Attch.: memo dtd. 3/12/84

Encls.: 12 Aerospace documents,
w/ SAN Form 70
Proof copy of Solar One
Project Bibliography

Sincerely yours,

Doug Elliott

S. D. Elliott, Jr., Director,
DOE Solar One Project Office

DOE F 1325.8
(7-79)

U.S. DEPARTMENT OF ENERGY

memorandum

DATE: March 20, 1984

REPLY TO ATTN OF: Norma DelGaudio/ISEA/X4428

SUBJECT: Search for Aerospace Corporation reports

TO: Doug Elliott

Reference your memo dated March 12, 1984 to Don Holz, I did a RECON search using the Aerospace report numbers. The information is as follows:

1) ATR-75(7370)-3
Solar Thermal Conversion Central Receiver Pilot Plant Siting
Page 154
Availability: NTIS - $16.00
31 Jan 75

2) ATR-77(7523-22)-3
Unable to locate any information. Checked contract number and report number.

3) ATR-76(7523-11)-6 "Highlights Report, Solar Thermal Conversion Program: Central Power Projects - Semiannual Review 3 June 1976"
Pages 54
Availability: NTIS - $10.00
Aug 76

If you have any questions, please give me a call.

Norma DelGaudio

APR 12 1984

Department of Energy
San Francisco Operations Office
1333 Broadway
Oakland, California 94612

Reply to:
DOE Solar One Project Office
Post Office Box 366
Daggett, CA 92327
(619) 254-2672

Mr. Harry D. Eden
Energy & Resources Division
Aerospace Corporation
Post Office Box 92957
Los Angeles, CA 90009

Subj.: Aerospace Documents for Solar One Project Archives

Dear Harry:

Your letter of April 9, inst., with enclosed documents arrived today. Thank you for taking the time to review and make suggestions regarding their disposition. With respect to the three documents (two experiment descriptions and the specification for the IR equipment) tentatively designated STMPO-563/4/5, I concur in your recommendation that they not be added to the Bibliography; as you have stated, they are adequately covered in other documents approved as Aerospace ATR's. With regard to the three conference papers (STMPO-028, -034 and -039), as well as the additional one you offered from the IEEE San Diego conference in December 1981, SAN/Patents and TIC do have a mechanism for dealing with these. I will work with them as to how to get them into the system.

The remaining six documents we definitely do want to send to TIC and list in the Bibliography (which was just published last week by EPRI; contact John Bigger if you wish a printed copy). I got a call from your Patents folks earlier this week, inquiring where to send the completed patent clearance forms, so it appears they are in processing. Again, your assistance is greatly appreciated.

I do have one more request to make of you (most likely, you will want to refer it to Mason Watson, since I believe it is related to work done by his group): as you will see from the enclosed note from Norma DelGaudio, she was able to locate two of the three NSF/ERDA-era reports I had asked about in the memo attached to my letter of March 13, from their ATR numbers; she was, however, unable to identify the third, which was the Final Report on "Mission Analysis III", either under the ATR number (ATR-77(7523-22)-3) or the contract number (ERDA E904-3)-1082). I am not particularly surprised, since completion of the third stage of the study was very much an off-again/on-again thing, and the report was not published until almost two years after ERDA had truncated the work. Nevertheless, it is useful information, and it is cited in our Bibliography; but a requester from outside would not be able to obtain a copy from TIC or NTIS using the information provided. I would, therefore, like to ask you (or Mason): first, to check your records for evidence of patent clearance by SAN, who held the contract, or, failing that, to fill out a SAN Form 70 and send it to me (I will forward it to SAN/Patents); and second, if there are any <u>extra</u> copies lying around, to send me one or two copies. On receipt, I will take action to enter it into the "system".

Thanks again for all your assistance, past and present.

Sincerely yours,

Jerry Elliott

DOE F 1325.8
(7-89)

U.S. DEPARTMENT OF ENERGY

memorandum

DATE: March 20, 1984

FROM: Norma DelGaudio/ISEA/X4428

SUBJECT: Search for Aerospace Corporation reports

TO: Doug Elliott

Reference your memo dated March 12, 1984 to Don Holz, I did a RECON search using the Aerospace report numbers. The information is as follows:

1) ATR-75(7370)-3
Solar Thermal Conversion Central Receiver Pilot Plant Siting
Page 154
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2) ATR-77(7523-22)-3
Unable to locate any information. Checked contract number and report number.

3) ATR-76(7523-11)-6 "Highlights Report, Solar Thermal Conversion Program: Central Power Projects - Semiannual Review 3 June 1976"
Pages 54
Availability: NTIS - $10.00
Aug 76

If you have any questions, please give me a call.

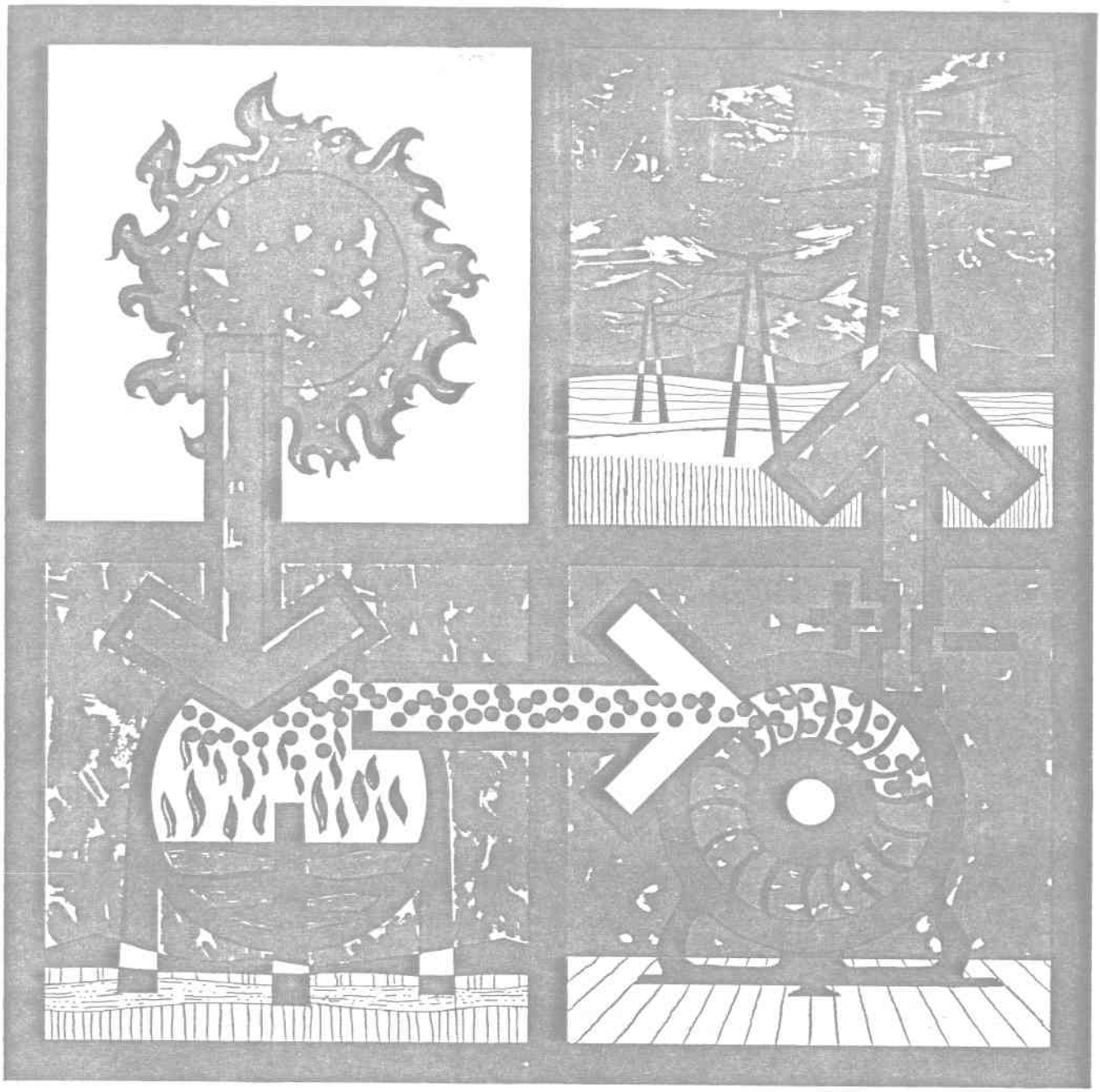
Norma DelGaudio

DOE FILE COPY

STMPO-015 FINAL

SOLAR THERMAL CONVERSION MISSION ANALYSIS

FINAL REPORT



THE AEROSPACE CORPORATION

Aerospace Report No.
ATR-77(7523-22)-3

SOLAR THERMAL CONVERSION MISSION ANALYSIS

FINAL REPORT

Contract E(04-3)-1082

1 May 1976
Issued 25 February 1978

Prepared by

THE AEROSPACE CORPORATION
Energy Systems Group
El Segundo, California
Telephone: (213) 648-7132

ABSTRACT

The Aerospace Corporation has performed, under ERDA sponsorship (Contract No. E(04-3)-1082), analyses of conceptual systems, missions, and economic factors governing the generation of electrical power by solar thermal conversion techniques. These analyses have focussed on large (greater than 100 MW) central solar power plants intended for electric power generation. Most of the methodology developed during these analyses and some of the analytical results were described in an earlier document*. This report extends those results and describes the application of previously developed methodologies to the determination of solar thermal power plant performance and operating economics for additional sites throughout the U.S. It represents a compilation of material which has been published previously in other forms.

*Solar Thermal Conversion Mission Analysis, Midterm Report. Aerospace Report No. ATR-76(7506-05)-1

THE AEROSPACE CORPORATION

Post Office Box 92957, Los Angeles, California 90009, Telephone: (213) 648-5000

1220-P-154
April 19, 1984

Mr. Roger S. Gaither
Assistant for Prosecution
Office of the Patent Counsel
P. O. Box 808 - L-376
Livermore, California 94550

SUBJECT: Patent Clearance Release Form

Dear Mr. Gaither:

We have been requested by your Daggett Project Office to execute the attached Patent Clearance Release form covering Contract No. DE-AT03-76S51101 (Report No. ATR-77(7523-22)-3) (STMPO-015).

Enclosed with the release form is a copy of the final report for your records.

Very truly yours,

THE AEROSPACE CORPORATION

Ronald L. Taylor
Patent Counsel

RLT/bt
encl.

cc: S. D. Elliott, Jr.
DOE Project Office
Daggett, Ca.

bcc: M. Watson
H. Eden

SAN FORM 70 10/80

DEPARTMENT OF ENERGY
SAN FRANCISCO OPERATIONS OFFICE

CONTRACTOR REQUEST FOR PATENT CLEARANCE
FOR RELEASE OF UNCLASSIFIED DOCUMENT

Roger S. Gaither, Asst. Chief for Prosecution
Office of Patent Counsel/Livermore Office
P.O. Box 808, L-376
Livermore, California 94550

Prime Contract No.	DE-AT03-76CS51101
Subcontract No.	
Report No.	ATR-77(7523-22)-3 (STMPO-015)
Date of Report	May 1, 1976
Name & Phone No. of DOE Technical Representative	S.D. Elliott, Jr. (619) 254-2672

FROM:
Mr. Ronald L. Taylor
Patent Counsel
The Aerospace Corporation
P. O. Box 92957
Los Angeles, Calif. 90009

1. Document Title:

Solar Thermal Conversion Mission Analysis

2. Type of Document: ☐ Technical Report, ☐ Conference Paper, ☐ Journal Article, ☐ Abstract or Summary, ☐ Copy of Oral Presentation, ☐ Other (please specify): _____

3. In order to meet a publication schedule or submission deadline, patent clearance by _____ would be desired.

SENDER IS TO CHECK BOX #4 OR #5 BELOW.

☒ 4. I have reviewed (or have had reviewed by technically knowledgeable personnel) this document for possible inventive subject matter (Subject Inventions) and that no inventions or discoveries (Subject Inventions) are deemed to be disclosed in this document except as stated below:

a. Attention should be directed to pages _____ of this document.

b. This document describes matter relating to an invention:

i. Contractor Invention Docket No. _____.
ii. A disclosure of the invention was submitted to DOE on _____ (date)
iii. A disclosure of the invention will be submitted shortly _____ (approximate date)
iv. A waiver of DOE's patent rights to the contractor:
☐ has been granted, ☐ has been applied for; or ☐ will be applied for _____ (date)

☐ 5. This document is being submitted, but no review has been made of this document for possible inventive subject matter.

6. Remarks:

Reviewing/Submitting Official: Name (Print/Type) Ronald L. Taylor
Title Patent Counsel
Signature _____ Date April 19, 1984

TO: INITIATOR OF REQUEST

FROM: ASSISTANT CHIEF FOR PROSECUTION
Office of Patent Counsel/Livermore Office

☐ No patent objection to above-identified release.

☐ Please defer release until advised by this office.

Signed _____ Date Mailed _____

DOE OFFICE OF PATENT COUNSEL (OPC)

DOE F 1325.8
(7-79)

ATTACHMENT 3 (5 pp)

U.S. DEPARTMENT OF ENERGY

memorandum

DATE APR 2 3 1984

REPLY TO ATTN OF S. D. Elliott, Jr., Director, DOE Solar One Project Office

SUBJECT Submission of Aerospace Corporation Report ATR-77(7523-22)-3, under Contract DE-AT03-76CS51101 for TIC Processing, Archiving and Announcement(STMPO-015)

TO William D. Matheny, DOE/TIC Document Control
Roger S. Gaither, SAN/OPC, Livermore

Although published in 1978, and describing work performed in 1976, the subject document does not appear ever to have been entered into the TIC/NTIS system. Inasmuch as it is a fundamental background document for the Solar One Project as well as other ongoing DOE and private-sector studies, we would like to do so at this time.

At our request, Aerospace (Attch. 1) has submitted one copy of this report directly to OPC, together with a completed SAN Form 70. I am herewith submitting one original plus one Xerox copy of the report:

ATR-77(7523-22)-3 (STMPO-015) "Solar Thermal Conversion Mission Analysis: Final Report"

to TIC, together with a completed DOE Form RA-426, for processing, archiving, announcement and forwarding to NTIS.

By copy of this memo, SAN/OPC is requested to:

- o Provide this office with a copy of the completed Form 70, once patent clearance is granted;
- o Forward the clearance copy of the Aerospace report to TIC, atten: W. D. Matheny, with the attached label placed on the upper right corner of the cover, as on the attached cover copy.

S. D. Elliott, Jr.

Attchs: Aerospace ltr. 1220-P-154, 4/19/84
Photocopy of report cover & label (OPC only)

Encl.: Aerospace Report ATR-77(7523-22)-3 (2 cc's), with DOE Form RA-426 (TIC only)

cc: Mike Lopez, DOE-SAN (FGS)
Don Holz, DOE/SAN (ISEA)
Mary Soderstrum, Burns & McDonnell

Encl 1

THE AEROSPACE CORPORATION

Post Office Box 92957, Los Angeles, California 90009, Telephone: (213) 648-5000

1220-P-154
April 19, 1984

Mr. Roger S. Gaither
Assistant for Prosecution
Office of the Patent Counsel
P. O. Box 808 - L-376
Livermore, California 94550

SUBJECT: Patent Clearance Release Form

Dear Mr. Gaither:

We have been requested by your Daggett Project Office to execute the attached Patent Clearance Release form covering Contract No. DE-AT03-76S51101 (Report No. ATR-77(7523-22)-3) (STMPO-015).

Enclosed with the release form is a copy of the final report for your records.

Very truly yours,

THE AEROSPACE CORPORATION

Ronald L. Taylor
Patent Counsel

RLT/bt
encl.

cc: S. D. Elliott, Jr.
DOE Project Office
Daggett, Ca.

bcc: M. Watson
H. Eden

SAN FORM 70 10/80

DEPARTMENT OF ENERGY
SAN FRANCISCO OPERATIONS OFFICE

CONTRACTOR REQUEST FOR PATENT CLEARANCE
FOR RELEASE OF UNCLASSIFIED DOCUMENT

Prime Contract No.	DE-AT03-76CS51101
Subcontract No.	
Report No.	ATR-77(7523-22)-3 (STMPO-015)
Date of Report	May 1, 1976
Name & Phone No. of DOE Technical Representative	S.D. Elliott, Jr. (619) 254-2672

Roger S. Gaither, Asst. Chief for Prosecution
Office of Patent Counsel/Livermore Office
P.O. Box 808, L-376
Livermore, California 94550

FROM:
Mr. Ronald L. Taylor
Patent Counsel
The Aerospace Corporation
P. O. Box 92957
Los Angeles, Calif. 90009

1. Document Title:

Solar Thermal Conversion Mission Analysis

2. Type of Document: ☐ Technical Report, ☐ Conference Paper, ☐ Journal Article, ☐ Abstract or Summary, ☐ Copy of Oral Presentation, ☐ Other (please specify): _____

3. In order to meet a publication schedule or submission deadline, patent clearance by _____ would be desired.

SENDER IS TO CHECK BOX #4 OR #5 BELOW.

☒ 4. I have reviewed (or have had reviewed by technically knowledgeable personnel) this document for possible inventive subject matter (Subject Inventions) and that no inventions or discoveries (Subject Inventions) are deemed to be disclosed in this document except as stated below:

a. Attention should be directed to pages _____ of this document.

b. This document describes matter relating to an invention:

i. Contractor Invention Docket No. _____.
ii. A disclosure of the invention was submitted to DOE on _____ (date)
iii. A disclosure of the invention will be submitted shortly _____ (approximate date)
iv. A waiver of DOE's patent rights to the contractor:
☐ has been granted, ☐ has been applied for; or ☐ will be applied for _____ (date)

☐ 5. This document is being submitted, but no review has been made of this document for possible inventive subject matter.

6. Remarks:

Reviewing/Submitting Official: Name (Print/Type) Ronald L. Taylor
Title Patent Counsel
Signature _____ Date April 19, 1984

TO: INITIATOR OF REQUEST

FROM: ASSISTANT CHIEF FOR PROSECUTION
Office of Patent Counsel/Livermore Office

☐ No patent objection to above-identified release.

☐ Please defer release until advised by this office.

Signed _____ Date Mailed _____

DOE OFFICE OF PATENT COUNSEL (OPC)

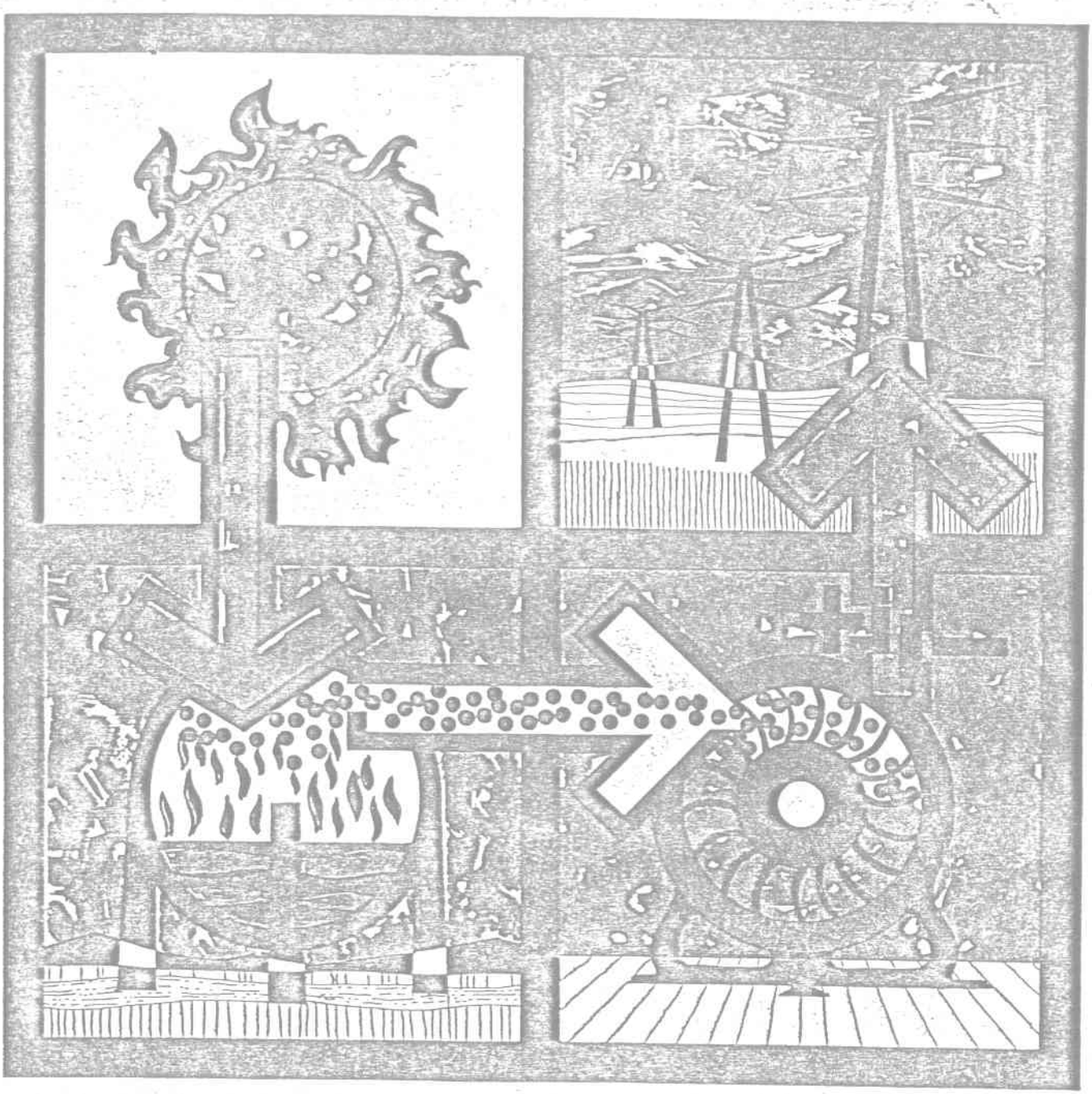
DOE FILE COPY

ATR-77(7523-22)-3
(STMPO-015)

SOLAR THERMAL CONVERSION MISSION ANALYSIS

Encl. 2

FINAL REPORT



THE AEROSPACE CORPORATION

DOE Form RA-426
(10/80)

U.S. DEPARTMENT OF ENERGY

OMB NO. 038-R0190

DOE AND MAJOR CONTRACTOR RECOMMENDATIONS FOR ANNOUNCEMENT AND DISTRIBUTION OF DOCUMENTS

See Instructions on Reverse Side

1. DOE Report No.	2. Contract No.	3. Subject Category No.
ATR-77(7523-22)-3 (STMPO-015)	DE-AT03-76CS51101	UC-62

4. Title
"SOLAR THERMAL CONVERSION MISSION ANALYSIS: FINAL REPORT"

5. Type of Document ("x" one)
- [X] a. Scientific and technical report
- [ ] b. Conference paper: Title of conference _____
  Date of conference _____
  Exact location of conference _____ Sponsoring organization _____
- [ ] c. Other (specify planning, educational, impact, market, social, economic, thesis, translations, journal article manuscript, etc.)

6. Copies Transmitted ("x" one or more)
- [ ] a. Copies being transmitted for standard distribution by DOE–TIC.
- [ ] b. Copies being transmitted for special distribution per attached complete address list.
- [X] c. Two completely legible, reproducible copies being transmitted to DOE–TIC. (Classified documents, see instructions) See #13 *
- [ ] d. Twenty-seven copies being transmitted to DOE–TIC for TIC processing and NTIS sales.

7. Recommended Distribution ("x" one)
- [ ] a. Normal handling (after patent clearance): no restraints on distribution except as may be required by the security classification.

Make available only [ ] b. To U.S. Government agencies and their contractors. [ ] c. within DOE and to DOE contractors. [ ] d. within DOE. [ ] e. to those listed in item 13 below.

- [X] f. Other (Specify) Archive/issue on request

8. Recommended Announcement ("x" one)
- [X] a. Normal procedure may be followed. [ ] b. Recommend the following announcement limitations:

9. Reason for Restrictions Recommended in 7 or 8 above.
- [ ] a. Preliminary information. [ ] b. Prepared primarily for internal use. [ ] c. Other (Explain)

10. Patent, Copyright and Proprietary Information

Does this information product disclose any new equipment, process or material? [XX] No [ ] Yes If so, identify page nos. _____

Has an invention disclosure been submitted to DOE covering any aspect of this information product? [XX] No [ ] Yes

If so, identify the DOE (or other) disclosure number and to whom the disclosure was submitted.

Are there any patent-related objections to the release of this information product? [XX] No [ ] Yes If so, state these objections.

Does this information product contain copyrighted material? [XX] No [ ] Yes

If so, identify the page number _____ and attach the license or other authority for the government to reproduce.

Does this information product contain proprietary information? [XX] No [ ] Yes If so, identify the page numbers _____.

("x" one [ ] a. DOE patent clearance has been granted by responsible DOE patent group.

[XX] b. Document has been sent to responsible DOE patent group for clearance.

11. National Security Information (For classified document only; "x" one)

Document [ ] a. does [ ] b. does not contain national security information

12. Copy Reproduction and Distribution

Total number of copies reproduced N/A Number of copies distributed outside originating organization N/A

13. Additional Information or Remarks (Continue on separate sheet, if necessary)

Substitute second original copy for Xerox, when forwarded by SAN/OPC

14. Submitted by (Name and Position) (Please print or type)

S. D. Elliott, Jr., Director, DOE Solar One Project Office

Organization

Post Office Box 366, Daggett, CA 92327 (619) 254-2672

Signature S. D. Elliott Date APR 2 3 1984

Department of Energy
San Francisco Operations Office
1333 Broadway
Oakland, California 94612

Reply to:
DOE Solar One Project Office
Post Office Box 366
Daggett, CA 92327
(619) 254-2672

Mr. William D. Matheny
Chief, Control Branch
Document Control & Evaluation Div.
DOE Office of Scientific
and Technical Information
Post Office Box 62
Oak Ridge, TN 37831

AUG 03 1984

Subj.: Submission of Two Reports by Aerospace Corporation in Support of Solar One Pilot Plant Project; Comments Concerning Three Additional Reports

Dear Mr. Matheny:

Enclosed are two copies each of two reports prepared by the Aerospace Corporation (under two separate contracts with ERDA/DOE) in support of the Solar One Ten-Megawatt (electric) Central Receiver Solar Thermal Pilot Plant project:

DOE Document No.	Secondary No.	Contract	Title
DOE/CS/51101-3	STMPO-027	DE-AT03-76CS51101	Barstow Daily Insolation Plots, Calendar Year 1976
ATR-80(7747)-2	STMPO-035	DE-AC03-78ET20517	Number of Thermal Cycles Estimated for the 10 MWatt Pilot Plant over its 30-Year Lifetime

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Encls.: 2 reports, w/DOE Forms RA-426

Attchs.: 3, as stated

Sincerely yours,

Doug Elliott

S. D. Elliott, Jr., Dorector,
DOE Solar One Project Office

cc: H. Eden/C. Randall, Aerospace
R. Gaither, DOE/SAN (OPC)
M. Lopez, DOE/SAN (ISEA)
D. Holz, DOE/SAN (ISEA)
M. Soderstrum, B&McD

DOE F 1325.8
(7-79)

U.S. DEPARTMENT OF ENERGY

memorandum

DATE [redacted] 1984

REPLY TO ATTN OF Doug Elliott, DOE/Barstow

SUBJECT Assorted Aerospace Reports; Closure

TO: Harry Eden, Aerospace

I think we've spent all the time on this topic any of us can afford. The only loose end I can think of is that you may want to get these two reports back into the Aerospace "system" as separate documents, which they were originally. I've got all I need at this end, and OSTI (nèe TIC) should be all set once Bill Matheny has digested my letter.

Please thank Dr. Randall for the rewrite on the "Thermal Cycles " paper; it's a most pertinent reference for future designers, and I'm also submitting the companion paper by John Raetz (Ref. 2) to OSTI/NTIS.

Please call me if you have any need for further follow-up; and let me know if you should have a cahance to come to (or past) Solar One before I leave in September.

Doug

S. D. Elliott, Jr.

OPC response ??

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RECEIVED BY DOE
AUG 8 1984
OFFICE OF PATENT COUNSEL
LIVERMORE-OFFICE

We do not & have not rec'd these reports for clearance. Please send them if you have them

Roger Gaither's office
8-10-84

heat (phase change) with tube-intensive heat exchange (HX). The results indicate that the all sodium 2-tank thermal storage concept is not cost-effective for storage in excess of 3 or 4 hours; the molten draw salt 2-tank storage concept provides significant cost savings over the reference sodium 2-tank concept; and the air/rock storage concept with pressurized sodium buffer tanks provides the lowest evaluated cost of all storage concepts considered above 6 hours of storage.

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A motor is described which contains a solar heater with switch and housing with spring attached to it by one end connected to the heater switch and outlet shaft and having a starter mechanism in the form of a thermal working element made of alloy which has thermomechanical shape memory. In order to expand the area of use, the motor is equipped with a sun-protected screen protected to the heater switch, and the thermal element is made in the form of a harmonic-shaped plate.

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The discussion traces the analysis leading to the original sensor specification for monitoring the temperature of the boiler tubes of the Barstow 10 MW Solar Pilot Plant and will hopefully prove useful to those faced with a similar application. Results of tests performed to date are discussed, as are the upgraded Pilot Plant model and the potential of the system for more sophisticated monitoring tasks.

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DOE F 1325.8
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U.S. DEPARTMENT OF ENERGY

memorandum

DATE: AUG 2 3 1984

REPLY TO ATTN OF: Doug Elliott, DOE/Barstow

SUBJECT: Aerospace Report ATR-77(7523-22)-3 (STMPO-015)

TO: Mary Soderstrum, Burns & McDonnell

As you will see by Attch. 1, STMPO-15 has been announced by OSTI as available through OSTI and NTIS. In spite of Roger Gaither's note (Attch. 2, p. 2) it must either (a) have gotten thru SAN/OPC unnoticed, and I just didn't get the Form 70 feedback copy; or (b) OSTI, noting that (as they say at the end of the abstract in STT-84/15), "It represents a compilation of material which has been published previously in other forms," cleared it themselves. I suspect the latter, and that that is why the statement just quoted was included. Any how, it's water under the dam (or is that "...over the bridge"); I've shelved it and checked it off in the "white book" and in the "working copy" of the bibliography.

Doug

cc: None (I won't even confuse Mike with this one)

bcc: Gaither

heat (phase change) with tube-intensive heat exchange (HX). The results indicate that the all sodium 2-tank thermal storage concept is not cost-effective for storage in excess of 3 or 4 hours; the molten draw salt 2-tank storage concept provides significant cost savings over the reference sodium 2-tank concept; and the air/rock storage concept with pressurized sodium buffer tanks provides the lowest evaluated cost of all storage concepts considered above 6 hours of storage.

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ATTCH 2

Department of Energy
San Francisco Operations Office
1333 Broadway
Oakland, California 94612

Reply to:
DOE Solar One Project Office
Post Office Box 366
Daggett, CA 92327
(619) 254-2672

Mr. William D. Matheny
Chief, Control Branch
Document Control & Evaluation Div.
DOE Office of Scientific
and Technical Information
Post Office Box 62
Oak Ridge, TN 37831

AUG 03 1984

Subj.: Submission of Two Reports by Aerospace Corporation in Support of Solar One Pilot Plant Project; Comments Concerning Three Additional Reports

Dear Mr. Matheny:

Enclosed are two copies each of two reports prepared by the Aerospace Corporation (under two separate contracts with ERDA/DOE) in support of the Solar One Ten-Megawatt (electric) Central Receiver Solar Thermal Pilot Plant project:

DOE Document No.	Secondary No.	Contract	Title
DOE/CS/51101-3	STMPO-027	DE-AT03-76CS51101	Barstow Daily Insolation Plots, Calendar Year 1976
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OPC INFO

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