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INTEGRATION OF
Solar Thermal Power Plants
INTO
Electric Utility Systems

Southern California Edison Company

Volume II

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INTEGRATION OF SOLAR THERMAL POWER PLANTS INTO ELECTRIC UTILITY SYSTEMS

VOLUME II. TECHNICAL AND ECONOMIC STUDIES

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EXECUTIVE SUMMARY

The operation of solar power plants as a part of a large electric utility system has been studied using Southern California Edison Company loss of load probability and production cost simulation computer programs. Solar generation has been evaluated in the context of an electric system having high percentages of baseload type generation, represented by nuclear. The present Southern California Edison system, which is heavily dependent on oil fired generation, was not used because its resource mix is not typical of economically preferred future systems into which solar may be introduced.

A solar generation model has been developed which includes effects of hourly solar input variations, cloud induced forced outages, use of energy storage, and peak shaving dispatch. The contribution of solar generation to the system's ability to serve forecast loads has been determined for varying amounts of installed solar capacity and for varying thermal energy storage capabilities associated with the solar units.

Breakeven costs for solar generation have been calculated based on financial assumptions consistent with those Edison presently uses in generation resource planning. Sensitivities to assumed rates of escalation of fuel and capital costs have been investigated by applying a specific alternative set of assumptions provided by ERDA, to a mixture of conventional resources that is not optimum for these assumptions. The effect of solar on the optimum mix of conventional resources has also been studied.

It was found that stored solar derived thermal energy can be used to effect a peak shaving dispatch strategy. Used in this way, the effect of thermal energy storage is significant and greatly enhances the

Executive Summary Cont'd.

economic value of the solar units. Storage also accommodates the output of additional collection capability, which adds to the units' economic value by increasing the annual energy production. In an electric system containing relatively little solar generation, small amounts of storage, allowing one or two extra hours of operation, will allow a solar unit to achieve most of the potential economic value. As the solar percentage is increased, system reserve margin requirements are also increased. This can be partially offset by increasing the amount of storage.

Based on Edison financial assumptions, and for various combinations of solar unit storage capacities and solar percentages, the current-dollar economic value of solar units to a utility in 1986 dollars ranged from \$533/kw to a maximum of nearly \$1470/kw. The equivalent range in current dollars is \$250/kw to \$700/kw. Applying ERDA financial assumptions to a case involving an electric system totally fueled by oil, resulted in significantly higher solar unit economic values.

The addition of solar generation would be accompanied by adjustments in the mix of non-solar resources to both optimize economics and maintain acceptable levels of service reliability. Despite its usefulness, solar generation will not directly replace any single resource type. In present electric systems, solar would primarily reduce the amount of intermediate generation additions needed. As the system resource mix approaches optimum levels, increased amounts of solar would begin to displace small amounts of base load generation. However, additional peaking capacity is required to maintain acceptable levels of system reliability as the level of solar gener-

(or solar hybrid)

ation is increased. The amount of peaking required for this purpose can be significantly reduced by adding thermal energy storage to the solar units.

Proper dispatch and maintenance strategies can allow significant percentages of solar generation to be integrated into a system. Electric system operating practices will have to be modified to reflect the unique characteristics of solar generation, and to accomplish successful integration of their operation with the remainder of the system.

The cost to build a solar unit today, without the benefit of further technological development, would be well above the "breakeven" costs indicated above. Reducing the cost of concentrating mirrors (e.g. heliostats in the central receiver concept), their support structure and aiming gear to an absolute minimum is the key to economic feasibility. It appears that these costs must be reduced to no more than one half of the overall plant cost. Accordingly, there are incentives to reduce the cost of the storage subsystem and the balance of plant to allow higher mirror costs and to increase the efficiency of the storage and balance of plant so as to require fewer mirrors. Such competing objectives will require cost trade-offs based on integration study results, while the major development thrust should thus be toward components, e.g. heliostats, that can be cheaply maintained as well as cheaply fabricated.

Additional study is needed in several areas. One key area is the modeling and optimization of solar unit design with respect to preferred dispatch strategies. In addition, different solar unit sites, electric system characteristics, solar unit configurations, Executive Summary Cont'd.

subsystem efficiencies, dispatch strategies, fossil fuel cost and availability scenarios should be considered.

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Introduction

I. INTRODUCTION

Need For Solar Integration Study

This report summarizes the findings of a study designed to fill the need for an electric utility to evaluate solar thermal power power plants as they would be evaluated if they were commercially available and could be put to immediate use. The study was motivated by a mutual recognition of this need by the Energy Research and Development Administration and the Southern California Edison Company.

This report consists of two volumes: Volume I is a summary report which provides an overview of the study. Volume II is a complete technical report, which includes detailed discussions of data, models assumptions and results.

The Energy Research and Development Administration is currently involved in a major effort to develop solar thermal power generation systems. The solar thermal power plants under development will involve the concentration of solar radiation onto heat exchange surfaces, in order to produce steam for turbine generator systems similar to those of present fossil and nuclear power plants. Solar thermal power plants are recognized to have the potential of becoming a technically and economically viable generation resource for electric utilities as a result of these efforts. If successfully developed, they will be used, along with nuclear, fossil and other large scale electric generation facilities to supply electrical energy to utility customers.

Solar plant design optimization will require an understanding of the factors affecting the value of solar power plants to utilities. Their value is not simple to assess, since it depends upon their effect on the investment and operating cost of the whole electric system of which they are a part. Accordingly, solar generation

Need For Solar Integration Study Cont'd.

can best be analyzed and assessed in the context of a specific electric system, based on the particular characteristics of solar plants as they are presently envisioned.

Applicability

As proposed, the study was to be a case study using the Southern California Edison electric system as the basis for analysis. Instead, it was decided to study solar in the context of an electric system having an economically "optimum" mixture of conventional resources. Such a system, while unlike that of most present southwestern utilities, including SCE, is representative of systems that are likely to exist when solar generation is commercially feasible, if the assumptions made regarding fuel cost and availiability remain valid.

The study is considered to have significant general applicability. Although southwestern utilities differ greatly in terms of size, it is the relative amount of solar in any system that is the major variable, and therefore the study results are expressed in terms of relative amount. Because there are substantial similarities in the load patterns of most southwestern utilities, this study's results, which were derived using SCE load patterns, should be indicative of the situation over the broader region.

Study Objectives

The primary objective of the study was to define the value of solar thermal power plants operating in a large electric system, as it is affected by the major variables discussed below. Doing so provides insight regarding how solar units might best be designed, operated, and configured to be of most value to an

Study Objectives Cont'd.

electric utility company in meeting its customers' electrical power requirements.

A second objective was to understand how the electric system would be modified to accommodate and make best use of solar. In an electric system to which solar units have been added, the mix of resources in the non-solar part of the system will be shifted to accommodate and make best use of the solar units.

Major Variables

The value of solar generation integrated into a large electric system depends on:

1) The coincidence between the solar generation pattern (sun-fall pattern) and the electric system load shape.

2) The percentage of the electric system capacity that is solar, i.e. the "solar penetration" (5, 10, and 20 percent penetrations were assumed.)

3) The mix of conventional (non-solar) resources in the system.

4) The energy storage capability associated with the solar units measured in megawatt-hours (MWh) of energy stored per megawatt (MW) of peak unit output; (0,1,2 and 6 MWh/MW capabilities were assumed.)

5) The way in which the solar units are dispatched, i.e. the way thermal energy storage is used to modify the output profile of the solar unit.

The effect of solar heating and cooling systems installed on individual buildings was not a consideration in this study.

To evaluate the effect of varying the amount of solar capacity in the total system, systems involving 5, 10, and 20 percent solar

Major Variables Cont'd.

(compared to total capacity) were analyzed. To evaluate the benefits of storage, four levels of storage were studied at each level of solar penetration; no storage, and one, two, and six MWh of storage per MW of rated electrical generating capacity were studied.

Substudies

The study was organized around two major substudies dealing with reliability and economics. These substudies were parallel and interactive and based on the same idealized solar unit and electric system characteristics. The reliability substudy (Section III) dealt with the question of how solar generating capacity affects electric system reliability. The reliability analyses optimized the operation of solar as a part of the total generating system in order to minimize the total system installed capacity requirements.

The economic substudy (Section III) dealt with the question of how much solar generating capacity is worth, i.e. what can a utility afford to pay for solar generation. The economic evaluation minimized the total cost of generating electricity by optimizing the mix of conventional resources.

In the reliability and economics substudies, solar unit characteristics were quantified where possible and idealized as necessary to limit the computational complexity. There are other user points of view which also had to be considered in parallel. Section IV examines the question of how solar power plants would actually be operated subject to the constraints of the electric system. Section V reflects the fact that utilities will need to evaluate "real" solar units based on their costs, and attempts to identify critical cost engineering concerns. Similarly, Section VI discusses utility concerns regarding

Substudies Cont'd.

the design of "real" solar power plants. Finally, Section VII discusses how the results of the present study might be used for evaluation of alternative design concepts and for design optimization and subsystem sizing, and where the results may need to be extended by future work.

EVALUATION STRATEGY

Analytical Tools

The key to our ability to deal with the reliability and economic questions raised above is that the questions posed are similar to those which must be answered in the conventional process of utility generation resource planning. Thus, the overall strategy was to use the analytical tools of this process to evaluate solar. A brief discussion of electric utility generation resource planning is provided in Appendix A as an introduction to the major terms and concepts used in the discussion of this study.

The study used existing production costing and reliability analysis computer programs that had been developed by Southern California Edison for its own use in analyzing future generation resource plans. Both programs were modified to appropriately model the solar generation, as though the solar power plants were a fully proven commercially available generation resource. Dispatch models were developed which effectively used solar generation to help carry the system load during high demand periods and thus effect a peak shaving dispatch strategy. The assumed dispatch strategy is one that is capable of implementation.

The reliability analysis program was used to evaluate the likelihood of successfully serving the forecast load for each hour of the year without requiring emergency interconnection support from other

Analytical Tools Cont'd.

utilities. The production costing program simulates the daily operation of the electric system and was used to evaluate the annual system fuel requirements, total operating costs, plant capacity factors, etc.

From a utility's viewpoint, each generating unit has two key properties: its operational reliability or capacity contribution to the system, and the total annual or lifetime costs to own and operate the unit in the system. Each different size and type of unit has its own unique levels of these two properties. Characteristically, hydroelectric generation is the most reliable type of generation, while base load generation (such as nuclear and base load hydro) has the lowest total lifecycle cost (capital, fuel, and O & M) per kilowatt-hour of energy produced. The utility attempts to meet the system design reliability criterion (for these studies, a loss of load probability [LOLP] index of one hour of outage in twenty years) at the lowest possible total cost, by adjusting the amounts of each type of alternative generation resource utilized. It should be noted that the level of the system LOLP design criterion is not critical, as all the systems were designed to meet the same LOLP index.

The generation resource planning process is normally approached by electric utilities by first determining the required annual capacity additions over the planning horizon (e.g. 20 years). Specific resource types to be added to the system are then selected for each year, based on the results of comparative economic evaluations of the viable resource alternatives and planning constraints.

In the 1976-1990 timeframe, the resource alternatives avail-

Analytical Tools Cont'd.

able to utilities for large scale implementation are:

1. Nuclear (fission)
2. Conventional coal
3. Conventional oil and gas
4. Conventional hydroelectric
5. Pumped storage hydroelectric
6. Combined cycle
7. Combustion turbine

Other resource types that are available or could potentially be available for implementation to a lesser degree are geothermal, fuel cell, solar and wind energy systems.

For solar generation study purposes and, specifically, to facilitate economic comparisons, hypothetical systems were developed which contained only conventional hydroelectric, nuclear, combined cycle, combustion turbine and solar thermal generating units.

For this investigation it was determined that each generating system evaluated would be adjusted to nearly exactly meet the Edison design LOLP criterion of one hour of outage in 20 years. Furthermore, each generating system would be optimized such that the total present worth of the capital and annual operating costs of the aggregate of non-solar resources would be the lowest total cost achievable at each level of solar penetration and storage.

The primary reasons for choosing to evaluate a set of optimum systems are as follows. First, in the absence of external constraints such as financial and regulatory considerations, most utilities would plan resources so as to achieve an optimum resource mix at some time in the future, as it represents the lowest cost system attainable.

Analytical Tools Cont'd.

Second, the break-even costs of solar generation derived from comparing optimum systems (described in Chapter III) represent the lowest threshold cost for solar (i.e. if solar costs are less than the threshold cost, solar is certainly economic.) Lastly, the optimum case is most nearly representative of the type of resource mix that most utilities expect to be approaching when solar generation becomes commercially feasible.

In order to establish a basis for comparison, a base case resource system comprised of presently available conventional generating units, with no solar generation, was developed. As with all the systems that were optimized around specified percentages of solar generation, the base system was developed to meet an annual LOLP index of one hour of outage in twenty years, and was optimized to achieve the lowest present worth total of capital and annual operating costs. For this optimum sytem, an installed generation reserve margin of 15.4% of peak demand was required to meet the reliability criterion.

Optimization

The optimum generating system at each solar percentage and level of storage was determined by an iterative process. First, the reliability analysis program was used to determine the approximate total amount of conventional generating capacity needed, including the assumed amount of solar to meet the Edison's reliability requirements. The annual operating costs were then determined using the production costing program.

Then, the present worth of the capital costs and annual operating costs of an assumed mix of conventional generation units comprising

Optimization Cont'd.

the system was evaluated. These last two steps were repeated until the mix with the lowest present worth total cost for that solar percentage and level of storage had been identified. The installed capacity of each system was then adjusted as necessary to meet the reliability criterion. The procedure for selecting the optimum resource plan described above is identical to the procedure Edison normally uses to select the most appropriate future generation resource program, with the exception that in the development of utility resource plans, other factors, such as the existing resource mix, financial constraints, and regulatory requirements must be considered.

To effect this strategy involving iterative optimization of resource plans, hundreds of runs using the two computer programs had to be completed to analyze the cases involving different combinations of storage level and solar percentage.

Non-Solar Resource Plan

To establish a basis for economic comparison, a generation resource plan containing no solar generation was developed. Standard unit sizes and reliability characteristics were assumed for each resource type. These standard units were a 1000 MW nuclear unit assuming 50% SCE ownership (base), a 250 MW combined cycle unit (intermediate) and a 100 MW combustion turbine (peaking).

To simplify the present worth economic analysis, it was assumed that the optimum mix of resources would remain constant throughout the studies. Furthermore, because the load pattern, carrying charge rates, and escalation rates were assumed to be long term averages which would remain constant throughout the 1986-2015 study period, it was necesary to determine the total capital and operating costs

Non-Solar Resource Plan Cont'd.

for one year only.

Solar Unit Assumptions

The central receiver concept was used as the design baseline, because it is receiving more attention in the ERDA program than other concepts. The central receiver concept involves a large number of individually steerable flat mirrors (heliostats) directing concentrated solar radiation to a tower mounted heat exchanger.

A 100 MW solar unit size was assumed, with the 100 MW rating defined as the output capability of the unit at noon on the summer solstice (6/21). The basis for assumptions on solar unit output at other times and for assumptions on solar unit insolation outages are discussed in Appendix B.

The 100 MW solar unit was assumed to include a thermal energy storage system and a single turbine which could accept steam from the receiver, from storage, or from both in parallel. This reflects the specified capabilities of ERDA central receiver designs. It was further assumed that the turbine could produce 70 MW when operating solely from storage, with no loss in conversion efficiency relative to operation using heat directly from the receiver. The size of the collector field was assumed to be matched to the storage capability being modeled, such that sufficient collector was provided to both operate the unit at full output during all sunlight hours, and totally charge the storage unit on the summer solstice, without losing any energy due to the storage system being fully charged and unable to absorb excess collector production.

Section II
Reliability Analysis

II. RELIABILITY ANALYSIS

INTRODUCTION

The primary objective of any electric utility is to meet its customers' needs for electrical energy. Because of uncertainties in future loads, and because generating units which produce the electrical energy are subject to both planned and random outages, it is necessary for the utility to provide reserve generating capacity in excess of expected peak demand in order to serve the load with any degree of reliability.

Historically, electric utility customers' have enjoyed high levels of service reliability. In order to ensure the ability to continue to successfully meet the customers' expectations of service reliability, utilities have established minimum criteria for use in planning facility expansion to meet forecast load growth. Southern California Edison requires that future generation resource plans meet or exceed each of the following three criteria in each year of a forecast period:

1) Installed capacity margin (difference between installed generating capacity and peak demand, expressed as percent of peak demand) must be 18%, plus or minus 2%, of the annual estimated peak demand.

2) Installed capacity margin, after deducting scheduled maintenance, must be sufficient to allow the loss of the larger of a) the two largest risks (generating unit or interconnection), or b) 7% of system demand plus the largest risk, without loss of load.

3) A reliability criterion based on probability calculations. The criterion requires that the resource plan have at least a 95% certainty of being able to serve the forecast loads every hour of the year, allowing for planned generation maintenance and random forced outages, without requiring delivery of capacity via Edison's interconnections in excess of amounts assumed normally available. A reliability index of 95% indicates that inter-

Introduction Cont'd.

connection assistance in excess of that assumed normally available will be required for approximately one hour every twenty years.

The first two criteria are based upon providing sufficient reserve generating capacity to allow for the more common contingency outages without shedding load. The third criterion is based upon probabilistic modeling techniques which reduce the various factors which affect generating system reliability to a single measurement of reliability.

The amount of generating capacity required to serve any load pattern is dependent upon many factors, including the characteristics of the load pattern, the planned and random outage rates of the generating units, and the operational characteristics of the generating units. Each of the various resource types available for utility use has its own unique outage and operating characteristics, and hence has a unique impact on overall system reliability. This will be particularly true of solar generation, both with and without storage, as compared to conventional fossil-fired generation.

For example, considering the limitations on solar unit operation resulting from the limited direct availability of energy input (i.e. energy is collected during sunlight hours only) and the dispatching of limited amounts of energy from storage, it is known that a solar generating unit capable of 100 MW peak output would not be able to directly replace a 100 MW conventional generating unit. A solar unit's capability (i.e. capacity and energy production) is dependent upon the sunfall during the day; on a cloudy day sunfall might not be sufficient to operate the unit. Prior to the present

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INTEGRATION OF SOLAR GENERATION INTO ELECTRIC UTILITY SYSTEMS

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Abstract - The value of solar thermal power plants to an electric utility system has been determined. The relationship between solar power plant values and solar thermal storage levels, mix of other resources, and the level of solar generation in the system are described. The operating characteristics of solar generation are discussed, and strategies for optimizing the value of solar generation are described. Current maximum cost levels (in dollars) for solar generation are presented, and target levels for component costs are discussed.

INTRODUCTION

Conventional generation, such as fossil-fired generation, can be utilized at anytime during the day or night. In contrast, solar generation is dependent upon sunlight for its input energy. Because the solar input energy varies both hourly and seasonally, reaching a peak level for only a few hours in each year, solar generation is unique relative to conventional generation currently in use by most electric utilities. These special characteristics necessitated an analysis of the effects of integrating solar generation into an electric utility system.

This report summarizes an electric utility's evaluation of the role of solar thermal power plants in a utility system under the assumption they were commercially available and could be put to immediate use. The study was performed under a contract with the Energy Research and Development Administration.

STUDY OBJECTIVES

The principal objective of this study was to define the nature of the economic interaction between system generation requirements and solar generation characteristics and thus identify the economic value of solar generation to an electric utility. Specifically, this involved identifying how the electric system resource mix and operation would be modified to accommodate and make best use of varying amounts of solar generating capacity and associated storage capability. The effect of solar heating and cooling systems installed on individual buildings was not a consideration in this study.

MAJOR VARIABLES

The value of solar thermal power plants to a utility system is comprised of two components: energy and capacity. The energy produced is valuable because it reduces the net fuel consumption of conventional (non-solar) power plants in the system. In addition, the ability of the solar plants to serve part of the load demand has value (i.e., "capacity value") to the utility.

The value of solar generation integrated into a large electric system depends on:

1) The coincidence between the solar generation pattern (sunfall pattern) and the electric system load shape.

2) The percentage of the electric system capacity that is solar, i.e., the "solar penetration" (5, 10, and 20 percent penetrations were studied.)

3) The mix of conventional (non-solar) resources in the system.

4) The energy storage capability associated with the solar units measured in megawatthours (MWh) of energy stored per megawatt (MW) of peak unit output (0,1,2 and 6 MWh/MW capabilities were studied).

5) The way in which the solar units are dispatched, i.e., the way thermal energy storage is used to modify the output profile of the solar unit.

SUBSTUDIES

The study was organized around two major substudies dealing with reliability and economics. These parallel and interactive substudies were based on idealized solar unit and electric system characteristics.

The reliability substudy addressed the effect of solar generating capacity on generating system reliability. This analysis involved optimizing the operation of the solar units as a part of the total generating system in order to minimize the total system installed capacity requirements while maintaining a preset reliability criterion.

The economics substudy dealt with the question of how much solar generating capacity is worth. The economic evaluation was based on hypothetical "optimum" resource plans that minimized the total cost of producing electricity.

In both the reliability and economics substudies, the characteristics of the solar unit were quantified where possible and idealized as necessary to limit the computational complexity.

In addition, four other substudies interfaced with the reliability and economics substudies and addressed the following corollary questions.

Operation - What would be the impact of operational considerations that were not modeled?

Design - What are the utility concerns regarding the design of "real" solar units?

Cost - What are likely to be the critical cost engineering concerns with "real" solar units?

Alternatives - What would be the impact on the cost and value of solar units if they had design features other than those assumed in the models?

METHOD OF ANALYSIS

Analytical Tools

The reliability and economic questions posed regarding the value of solar generation are similar to those which must be answered in the conventional process of utility generation resource planning. Thus, the overall study strategy was to use the analytical tools of this process to evaluate solar thermal power plants.

The existing production costing and reliability analysis computer programs that had been developed by Southern California Edison for its own use in analyzing future generation resource plans were the principal evaluation tools used in the study. Both programs were modified to appropriately model the solar generation, as though the solar power plants were a fully proven commercially available generation resource. Dispatch models were developed which effectively used solar generation to help carry the system load during high demand periods and thus effect a peak shaving dispatch strategy. The assumed peak shaving dispatch strategy is one that is capable of implementation.

The reliability analysis program was used to evaluate the probability of failing to serve the forecast load during each hour of the year. The production costing program simulates the daily operation of the electric system and was used to evaluate the annual system fuel requirements, total operating costs, plant capacity factors, etc.

From a utility's viewpoint, each generating unit has two key properties: the operational reliability or capacity contribution of the unit to the system (capacity value), and the total annual or lifetime costs to own and operate the unit in the system. Each different size and type of unit has its own unique levels of these two properties. Characteristically, hydroelectric generation is the most reliable type of generation, while base load generation (such as nuclear and coal) has the lowest total lifecycle cost (capital, fuel, and O&M) per kilowatthour of energy produced. The utility designs its resource plans to meet the system design reliability criterion (for these studies, a loss of load probability [LOLP] index of one cumulative hour of outage in twenty years) at the lowest possible total cost, by adjusting the amounts of each type of alternative generation resource utilized. It should be noted that the various system configurations were compared at the same design LOLP index. However, varying the design LOLP index has only a small effect on the assessed economic and capacity value of solar generation.

The generation resource planning process is normally approached by electric utilities by first determining the required annual capacity additions over the planning horizon (e.g., 20 years). Specific resource types to be added to the system are then selected for each year, based on the results of comparative economic evaluations of the viable resource alternatives and planning constraints such as lead time and budgeting constraints.

In the 1976-1990 timeframe, the resource alternatives available to utilities for large scale implementation are:

1) Nuclear (fission)
2) Conventional coal
3) Conventional oil and gas
4) Conventional hydroelectric
5) Pumped storage hydroelectric
6) Combined cycle
7) Combustion turbine

Other resource types that are available or could potentially be available for implementation to a lesser degree are geothermal, fuel cell, solar and wind energy systems.

For solar generation study purposes and, specifically, to facilitate economic comparisons, hypothetical systems were developed which contained only conventional hydroelectric, nuclear, combined cycle, combustion turbine and solar thermal generating units.

For this investigation it was determined that each generating system evaluated would be adjusted to nearly exactly meet the Edison design LOLP criterion of one cumulative hour of outage in 20 years. Furthermore, each generating system would be optimized such that the total present worth of the capital and annual operating costs (revenue requirements) of the aggregate of non-solar resources would be the lowest total cost achievable at each level of solar penetration and thermal storage.

The primary reasons for choosing to evaluate a set of optimum systems are as follows. First, in the absence of external constraints such as financial and regulatory considerations, most utilities would plan resources so as to achieve an optimum resource mix at some time in the future, as it represents the system with the lowest long-term revenue requirements. Second, the breakeven costs of solar generation derived from comparing optimum systems represent the lowest threshold cost for solar (i.e., if solar costs are less than the threshold cost, solar is certainly economic.) Lastly, the optimum system is representative of the type of system that utilities expect to be approaching when solar generation becomes commercially feasible.

Strategy

To assess the value of solar generation integrated into a utility system, generation resource plans were developed for each assumed level of solar penetration and storage. The total amount of installed capacity, and the relative mix of each of the various non-solar resource types were adjusted so that each plan would meet the SCE generation system reliability criterion while serving the same SCE forecast load pattern, at the lowest possible total present worth cost (including capital related, fuel, and operating costs). Each of the resulting plans represented the ideal mix of resources to achieve the lowest total cost at the specified level of solar penetration and storage. Each of these plans was then compared to an optimum base plan which contained no solar generation. It should be noted that the level of intermediate generation was not permitted to drop below 750 MW, in spite of the results of the economic analysis. As a result, the addition of large amounts of solar generation caused a small reduction in the amount of base load generation. However, without the constraint on the minimum amount of intermediate load generation, the addition of solar generation would normally displace a mix of intermediate and peaking generation.

To reduce the complexity of the evaluation, all the resource plans were developed using three basic types of conventional generating capacity (nuclear, combined cycle, and combustion turbine) as well as a fixed amount of hydroelectric generation. Standard unit sizes and reliability characteristics were assumed for each resource type. These standard units were a 1000 MW nuclear unit assuming 50% SCE ownership (base), a 250 MW combined cycle unit (intermediate) and a 100 MW combustion turbine (peaking). Unit reliability and maintenance assumptions for these conventional resource types and for the solar units are summarized in Table 1, and the cost characteristics for each conventional resource type used are summarized in Table 2.

To simplify the economic analysis, it was assumed that the optimum mix of resources would remain constant throughout each year of the studies. Furthermore, because the load pattern, carrying charge rates, and escalation rates were assumed to be long term averages which would remain constant throughout the 1986-2015 study period, it was necessary to determine the total capital and operating costs for one year only.

Solar Unit Assumptions

The central receiver concept was used as the baseline design, because it is receiving more attention in the ERDA program than other concepts. The central receiver concept involves a large number of individually steerable flat mirrors (heliostats) directing concentrated solar radiation to a tower-mounted heat exchanger (receiver).

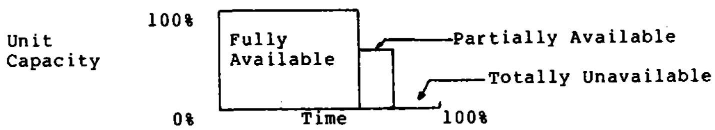
A 100 MW solar unit size was assumed, with the 100 MW rating defined as the output capability of the unit at noon on the summer solstice (June 21). The 100 MW solar unit was assumed to include a thermal energy storage system and a single turbine which could accept steam from the receiver, from storage, or from both in parallel. This reflects the specified capabilities of ERDA central receiver designs. It was further assumed that the turbine could produce 70 MW when operating solely from storage, with the same conversion efficiency as when using heat directly from the receiver. The size of the collector field was matched to the

TABLE 1

RELIABILITY & MAINTENANCE ASSUMPTIONS

UNIT TYPE	CAPACITY (MW)	FORCED OUTAGE DATA: Total Forced Outage Rate (%)	FORCED OUTAGE DATA: Capacity Lost During Partial Forced Outage	FORCED OUTAGE DATA: Partial Forced Outage Rate (%)	FREQUENCY OF OVERHAUL: Major (1) Interval & Tolerance	FREQUENCY OF OVERHAUL: Major Duration	FREQUENCY OF OVERHAUL: Minor (1) Interval & Tolerance	FREQUENCY OF OVERHAUL: Minor Duration
Hydro Variable	847-907							
Hydro Base	500	1.59	250MW	14.8%				
Nuclear - 1st Year	500	4.47	53	11.47	1yr±7wks	6wks		
Nuclear - Mature	500	3.89	53	9.42	1yr±7wks	6wks		
Combined Cycle - 1st Year	250	.61	121	11.52	2yr±13wks	6wks	24wks±4wks	2wks
Combined Cycle - Mature	250	.53	121	9.51	2yr±13wks	6wks	24wks±4wks	2wks
Combustion Turbine - 1st Yr	100	10.			10yr±13wks	3wks	2yrs±13wks	1wk
Combustion Turbine - Mature	100	5.			10yr±13wks	3wks	2yrs±13wks	1wk
Solar - 1st Year	100	7.5	50	2.5	2yr46wk±1wk	(2) 6wks	25wks±4wks	1wk
Solar - Mature	100	5.0	50	1.5	2yr46wk±1wk	6wks	25wks±4wks	1wk

Illustration of Outage States



Routine Maintenance - 10,250 GWH, or 1170 MW Average each hour

Notes
(1) Interval from end of last overhaul to beginning of next overhaul.
(2) Close tolerance selected to prevent solar unit overhaul pattern from migrating into summer months.

storage capability being modeled, such that sufficient collector area was provided to both operate the unit at full output during all sunlight hours, and totally charge the storage unit on the summer solstice without losing any energy due to the storage system being fully charged and unable to absorb excess energy from the collector. A pictorial illustration of the solar model used in both the reliability and economic evaluations is shown in Figure 1.

TABLE 2

FINANCIAL ASSUMPTIONS

	Nuclear	Combined Cycle	Combustion Turbine
Capital cost* (1986) - $/kW	1,570	702	401
Cost of money - % economic	11.7	11.7	11.7
Economic life - years	30	30	30
Fixed charge rate %	18.5	18.5	18.5
1986 O&M cost - $/kW	7.0	8.0	2.5
1986 fuel cost - $/$10^6$ BTU	0.59	3.42	3.42
1986 - 2015 annual escalation rates:			
O&M	4.67	4.67	4.67
Fuel	5.00	5.00	5.00
Unit full load heat rate - BTU/kWh	10,200	8,387	11,900
Capacity factor - %	75	60	4

RESULTING DELIVERED POWER COSTS
(Levelized Annual Cost - $/kW-Yr)

	Nuclear	Combined Cycle	Combustion Turbine
Capital	290.00	129.90	74.20
O&M	10.90	12.50	3.90
Fuel	63.90	243.60	23.00
Total	365.30	386.00	101.10

*Includes the cost for transmission, related facilities, overheads and nuclear unit first core costs.

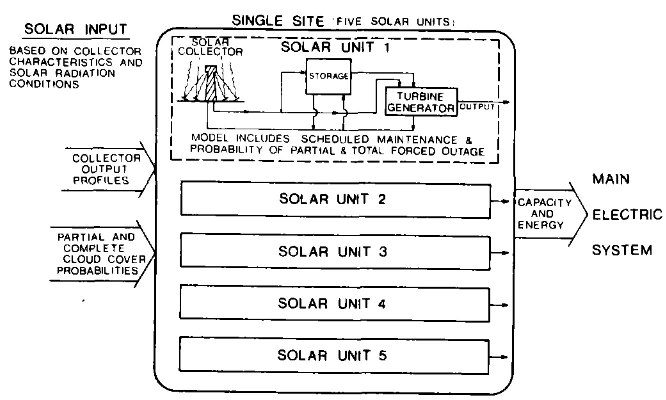
The assumed derate to 70% capacity when operating from storage permits an evaluation of the capacity value of the single turbine central receiver designs specified by ERDA. Although neglecting the efficiency losses when operating from storage causes a small over-optimism regarding the economic value of solar, it permits an unambiguous definition of storage capacity and yields results that can easily be adjusted to reflect the efficiency of specific storage configurations.

Solar Input/Output Assumptions

The available output of the solar unit was assumed to be proportional to the heat absorbed by the

FIGURE 1

SOLAR GENERATION MODEL



receiver. This parameter was established for each hour of a typical day in 13 four week seasons, using curves developed by the University of Houston based on predicted levels of solar radiation.

The solar unit output was normalized to 100 MW at the hour of peak solar input. Corrections were made to reflect measured sunfall in areas of interest. Five years worth of solar data was averaged to provide a basis for assumptions on sunfall-related total and partial forced outages.

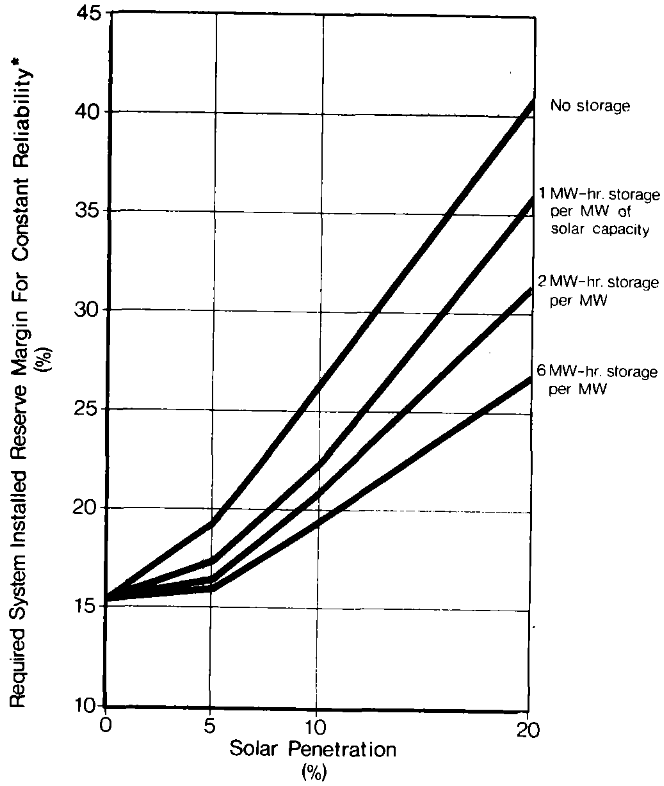
RELIABILITY EVALUATION

Both the amount of solar generation included in the electric utility's aggregate resources, and the amount of thermal energy storage associated with solar generating units have significant effects on the value of solar generating units to a utility. The results of reliability studies, which evaluated the effect of varying both of these parameters on the total system installed reserve margin requirements, are summarized in Table 3. The relative collector size and electric system installed capacity for the various levels of storage and solar generation are indicated, along with electric system installed reserve margins required in each of the cases considered. The effective load carrying capability of the solar units, which is a probabilistic measure of the amount of load the units could carry at the specified reliability, is also presented.

Figure 2 illustrates the variation in system installed reserve margin requirements as a function of solar penetration in the system. It shows that at any fixed amount of storage, system installed reserve margin requirements increase as the level of solar generation is increased. Figure 2 also indicates that for a given level of solar penetration, margin requirements are reduced by an increase in the amount of thermal energy storage and the attendant increase in collector area. Figure 3 shows that the effective load carrying capability of the solar generation is reduced as the solar penetration increases.

FIGURE 2

REQUIRED INSTALLED RESERVE MARGIN vs. SOLAR PENETRATION



*Loss Of Load Probability Held Constant At 1 Hour Of Outage (Total) In 20 Years

TABLE 3

SUMMARY OF RELIABILITY RESULTS
(For Constant Loss of Load Probability Index Of Approximately One Hour Of Outage In 20 Years)

Case Identification	Solar Penetration (%)	Storage MW-Hr/MW of Solar Capacity	Solar Collector Size (Per Unit Of Solar Electrical Capacity)	Total Installed Capacity MW	Installed Reserve Margin (%)	System Effective Load Carrying Capability (%)	Solar Generation Effective Load Carrying Capability (%)
00/0	0	-	-	20608	15.4	86.6	-
05/0	5.16	0	1.0	21338	19.3	83.8	32.3
05/1	5.23	1	1.18	20938	17.1	85.4	63.7
05/2	5.28	2	1.29	20838	16.5	85.8	71.5
05/6	5.30	6	1.71	20738	16.0	86.2	79.4
10/0	9.76	0	1.0	22538	26.1	79.3	12.1
10/1	10.03	1	1.18	21938	22.7	81.5	35.8
10/2	10.17	2	1.29	21638	21.0	82.6	47.6
10/6	10.31	6	1.71	21338	19.3	83.8	59.4
20/0	19.81	0	1.0	25238	41.2	70.8	7.1
20/1	19.80	1	1.18	24238	35.6	73.8	21.8
20/2	19.63	2	1.29	23438	31.1	76.3	34.1
20/6	19.35	6	1.71	22738	27.2	78.6	45.2

From Figure 3, it is apparent that the solar units can have significant load carrying capability under certain conditions, but in all cases it is less than that of the average conventional unit. This is because, with no storage, the solar generator can only be operated when the sun is shining. With modest amounts of storage, solar units have significant capacity value at low solar penetrations. With substantial amounts of storage the same is true at higher penetrations. This suggests that the first solar units may require relatively little extended operation capability to achieve close to their full potential usefulness in a generating system.

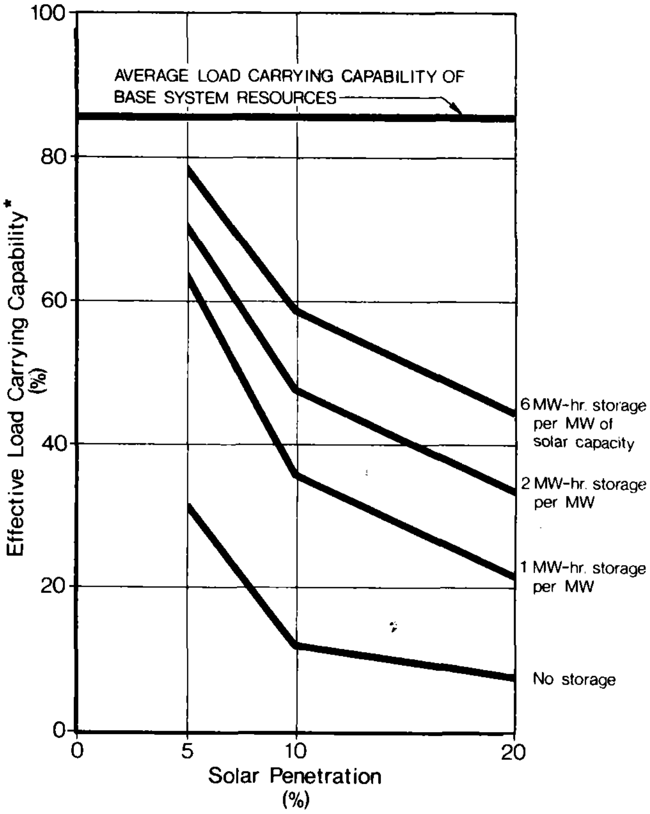
ECONOMIC EVALUATION

The results of the economic evaluation of solar generation are summarized in Table 4. The 1986 present worth total of the lifetime capital-related, fuel and operating costs of various systems (excluding costs for solar generation) for all combinations of assumptions on storage and penetration are presented. Calculations were based on operation over the 1986-2015 period. The equivalent value of solar generation (capital equivalent of total lifetime capital and O&M costs) to the utility, expressed in 1986 investment dollars, is presented in Table 4 and plotted in Figure 4. (To convert 1986 values to 1976 dollars, divide by 2.16.) The value of solar generation varies from $533/kW to $1470/kW in 1986 dollars. The equivalent range in 1976 dollars is $247/kW to $681/kW. These values were developed by deducting the total lifecycle cost of the conventional resources in each solar resource plan from the total cost of a totally conventional base plan. These values represent the "breakeven" cost, or the cost below which solar units would certainly be economically attractive to a utility. For example, the amount that a utility would be willing to pay for solar units having 6 MWh of storage per MW of capacity and making up 10% of its system installed capacity would be $1370/kW, expressed in 1986 dollars.

The combined economic value of solar capacity and energy is seen to decrease as the solar percentage increases, but not as sharply as the capacity value

FIGURE 3

EFFECTIVE LOAD CARRYING CAPABILITY OF SOLAR GENERATION vs. SOLAR PENETRATION



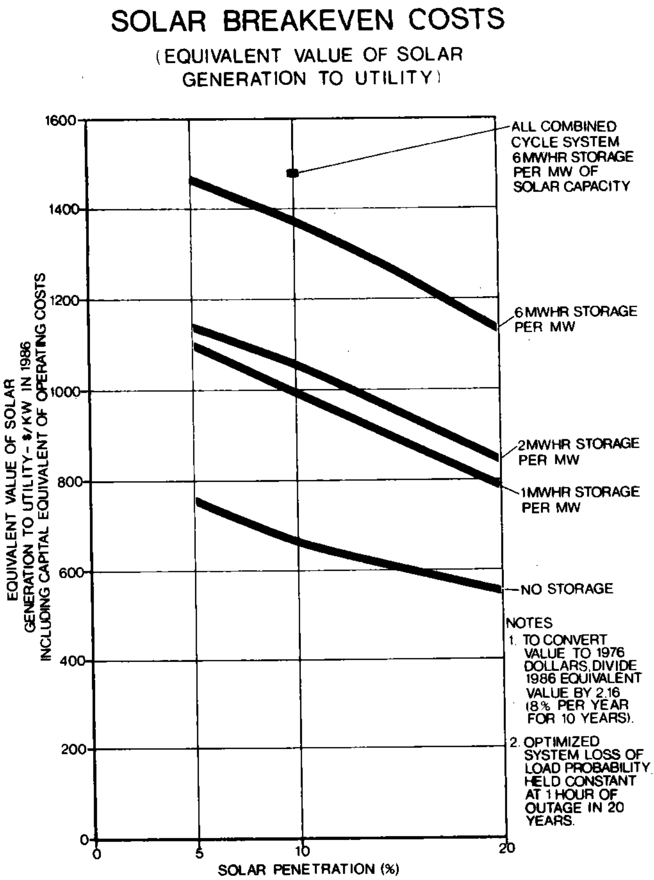
*Loss Of Load Probability Held Constant At 1 Hour Of Outage (Total) In 20 Years

TABLE 4

SUMMARY OF ECONOMIC COMPARISONS

Solar Penetration (%)	Solar Penetration (MW)	Storage (MWh/MW)	Total Installed Capacity (MW)	1986 Present Worth Costs-Billions of Dollars: Capital & O&M	Fuel	Total	Value Of Solar Capacity: 1986 Differential Present Worth (Nonsolar Minus Solar) Billions Of Dollars	Equivalent 1986 Investment $/kW	Equivalent 1976 Investment $/kW
0	BASE		20638	36.92	10.82	47.74	BASE		
5	1100	0	21338	34.55	11.93	46.48	1.26	753	349
5	1100	1	20938	34.36	11.55	45.91	1.83	1093	506
5	1100	2	20838	34.23	11.60	45.83	1.91	1141	528
5	1100	6	20738	34.17	11.13	45.30	2.44	1457	675
10	2200	0	22538	34.62	10.92	45.54	2.20	657	304
10	2200	1	21938	34.23	10.18	44.41	3.33	995	401
10	2200	2	21638	34.04	10.18	44.22	3.52	1051	487
10	2200	6	21338	32.93	10.23	43.16	4.58	1370	634
20	5000	0	25238	30.91	12.78	43.69	4.05	533	247
20	4800	1	24238	30.27	11.66	41.93	5.81	795	368
20	4600	2	23438	29.75	12.11	41.86	5.88	840	389
20	4400	6	22788	29.69	10.44	40.13	7.61	1136	526
All Combined Cycle Base System									
0	BASE		20138	22.02	34.69	56.71	BASE		
10	2000	6	20638	20.25	31.98	52.23	4.48	1470	681

FIGURE 4



decreases, since the energy value of solar is relatively unaffected by penetration. The value of solar generation is increased by providing storage, but it appears, as might be expected, that beyond a certain point, each additional increment of storage and associated collector area becomes less valuable. In a system containing relatively little solar generation, small amounts of storage, allowing one or two extra hours of operation, will suffice to achieve most of the solar units' maximum potential economic value.

The economic evaluation was performed on hypothetical "optimum" resource plans containing a maximum desirable amount of nuclear generation, therefore differing significantly from the predominantly oil based systems of present-day southwestern electric utilities. The value of solar generation in a non-optimum electric system may exceed these "breakeven" levels. To indicate roughly how great a difference this might make, two resource plans were studied in which the conventional resources were entirely comprised of oil fired generating units. As indicated in Figure 4, the value of a 10% penetration of solar with 6 MWh/MW storage in such a system would be approximately $1470 kW, expressed in 1986 dollars, which is 7% higher than in the "optimum" resource plan.

It should be noted that, because the economic value of the solar units was derived parametrically as the cost difference between two resource plans (one with solar, one without), the values are very sensitive to the input parameters. Because of this and a similar sensitivity to other cost and modeling assumptions, they should not be considered exact.

STORAGE

Based on the discussion in the preceeding paragraphs, a key finding of the study is that thermal energy storage has a major impact on the value of solar power plants in a utility electric system. Storage increases the capacity value of solar units by allowing them to be operated during the evening peak load periods when the sun is not shining. The additional collector area associated with storage increases the annual energy production capability of solar units.

In the analysis, an "ideal" storage system was assumed. The amount of storage was characterized as the ratio of the number of MWh of electrical energy which could be stored, to the turbine generator rated output, expressed in MW. In order to provide "reserve energy" with which to heat the turbine plant in preparation for operation after an overnight or cloud-related interruption in solar input, it may be necessary to provide an additional one or two MWh/MW of storage capability, and to maintain "heatup" energy in storage. This additional storage was not accounted for parametrically in the reliability and economic evaluations.

RESOURCE MIX

The addition of solar generation would be accompanied by adjustments in the mix of conventional generation resources to both optimize economics and maintain acceptable levels of service reliability. As indicated by the study results, solar generation will not directly replace any single resource type.

In most present electric systems, solar would reduce the need for intermediate generation additions. As the system resource mix approaches optimum levels, the addition of solar begins to displace small amounts of base load generation. However, additional peaking capacity is required to maintain acceptable levels of system reliability as the level of solar generation is increased.

Figure 5 illustrates the variation in an optimum resource mix due to the addition of solar. As illustrated, the amount of peaking required to maintain acceptable reliability when solar is added can be significantly reduced by adding thermal energy storage to the solar units.

SYSTEM OPERATION CONSIDERATIONS

Solar units having storage are likely to be subjected to spinning reserve performance standards now applied to energy limited hydroelectric units. Such standards require that in order for a unit to be considered as on-line operating capacity during any hour, it must have at least two hours of energy production capability in storage. The dispatch of the solar units, as modeled in this study, is likely to be modified to reflect this standard.

The introduction of solar generation into electric utility systems will affect several aspects of electric system operation. Implementing a peak shaving dispatch strategy using solar complicates daily capacity planning and suggests that increased use of weather forecasts and telemetered sunfall data may be required. Similarly, computer programs to optimize combined solar and thermal generation may be necessary to assist operating personnel in optimizing the use of solar generation.

More complicated automatic generation control algorithms than are presently used by utilities will be required to handle solar unit output variations that cannot be buffered effectively with storage. Optimal maintenance strategies for large solar penetrations will require a departure from present practice, and solar unit designs will need to reflect a desire to defer outages until non-critical hours. In summary, as the amount of solar generation in an electric system increases, additional sophistication in system operation will be essential to fully benefit from its capabilities. In most cases, system operation computer programs and algorithms currently available or in effect can be adjusted and/or expanded to properly integrate solar generation.

COST AND DESIGN CONSIDERATIONS

The cost to build a solar unit today, without the benefit of further technological development, would be well above the breakeven costs indicated in Table 4 and Figure 4. Reducing the cost of concentrating mirrors (e.g., heliostats in the central receiver concept) and their support structure and aiming gear to an absolute minimum is the key to economic feasibility. It appears that these costs must be reduced to no more than one half of the overall plant cost.

Accordingly, there are incentives to reduce the cost of the storage subsystem and the balance of plant to allow higher mirror costs, and to increase the efficiency of the storage and balance of plant to require fewer mirrors. These competing objectives will require cost trade-offs based on integration study results. Another important area of optimization is to balance the value of the cycling capabilities that are needed to fully utilize the varying solar input against the associated costs. Demonstration of cost optimum design features should be a major objective for pilot scale units.

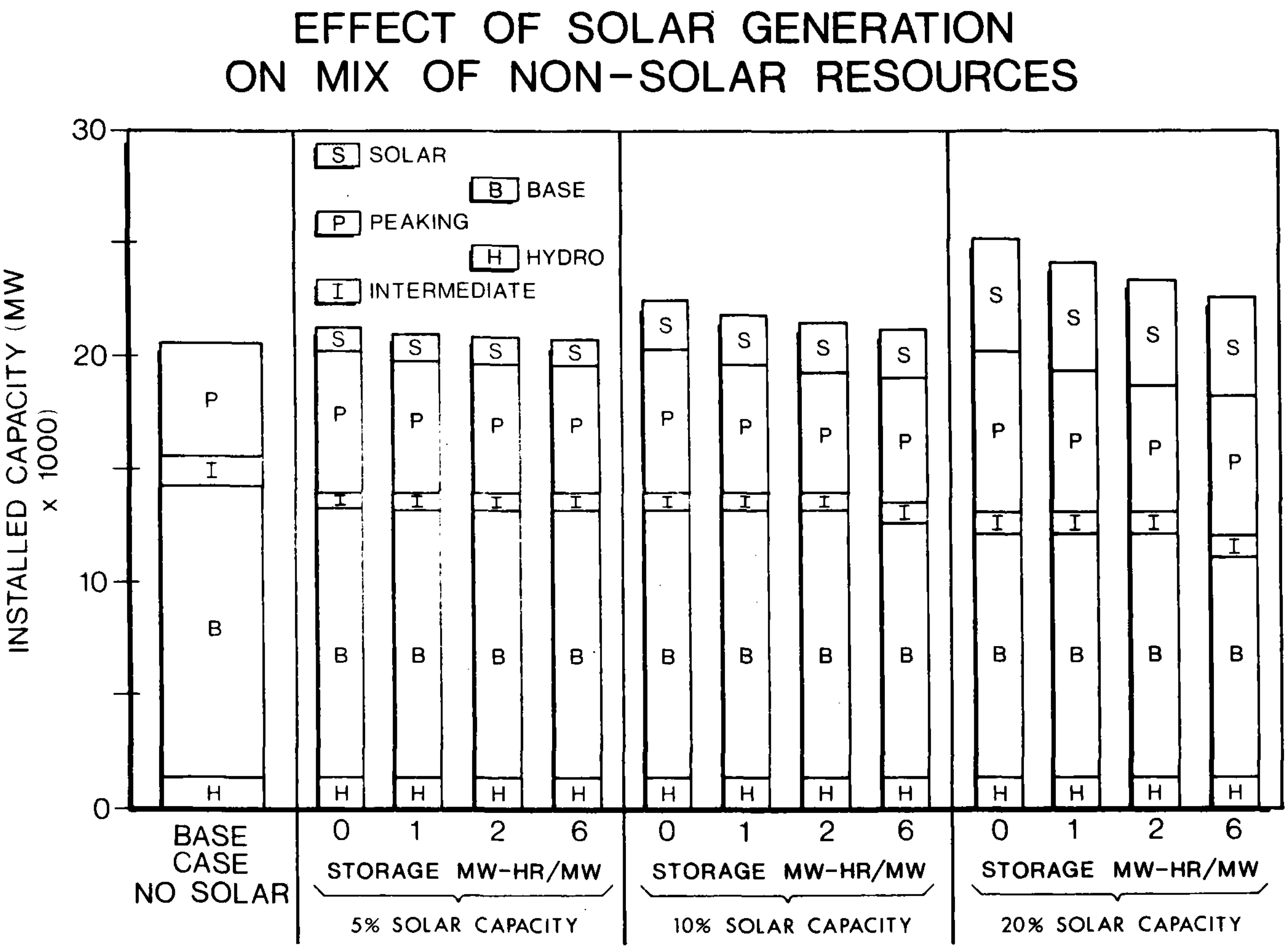
It is essential to recognize that the breakeven costs discussed in this report include lifecycle operation and maintenance costs. The major development thrust should thus be toward components, e.g., heliostats, that can be cheaply maintained as well as cheaply fabricated and installed in the field.

ADDITIONAL STUDY

The integration study discussed in this report was intended to fit into a design optimization process that, it is hoped, will culminate in a technically successful, economically feasible solar thermal power generation technology. The process has just begun, and this report is but a first step.

Additional study is needed in several areas, particularly as the designs for solar power plants become firmed up, field tested and verified. One key area is the modeling and optimization of solar unit design with respect to the value and cost of storage and cycling requirements associated with preferred dispatch strategies. Once this has been done, additional integration studies should evaluate the effect of making different assumptions than for the present study. Different solar unit sites, electric systems, solar unit configurations, subsystem efficiencies, dispatch strategies, and fossil fuel cost and availability scenarios should be considered in order to

FIGURE 5



refine the basic results which have been achieved in this first study.

CONCLUSIONS

Conventional generation, such as fossil-fired generation, can be utilized at any time during the day or night. In contrast, solar generation is dependent upon sunlight for its input energy. The extent to which solar generation can be effectively utilized in a utility system depends on both the coincidence between the solar input (sunfall) pattern and the electric system load shape, and the amount of energy storage capability in the solar generating unit or the utility system. In spite of its operational limitations, solar generation has been shown to have economic value to an electric utility. Without storage, solar generation is shown to have an economic value ranging from $533/kW to $753/kW (1986 investment dollar capital equivalent of total lifetime capital and O&M costs). The addition of thermal storage, with its attendant increase in collector area, permits limited evening peaking operation, increases total energy production, and thus increases the economic value of solar to as much as $1470/kW.

Nothing in the study results would preclude the integration of solar thermal power plants into an electric utility system. Existing control strategies can be modified and adapted to solar generation. The integration of solar generation into utility systems will only be limited by the economics of solar relative to other types of generation. The costs of solar generation today would be well above the breakeven costs shown. Consequently, solar generation costs must drop substantially in order for solar to achieve parity with other resource alternatives and to begin to penetrate into utility markets.

Because solar generation has operating characteristics unlike any conventional type of generation, the integration of solar generation would displace a combination of resource types. Furthermore, because of its unique operating characteristics, solar generation has less load carrying capability than conventional generation. This study has shown that solar generation has between 8% and 92% of the capacity value of conventional generation. Therefore, to maintain the same level of generating system reliability, the addition of solar generation will require a net increase in generating system reserve margin compared to a system with no solar generation. These considerations suggest that the extent to which solar generation can be applied will be controlled by its relative cost, rather than by its operating characteristics and limitations.

References

Integration of Solar Thermal Power Plants into Electric Utility Systems, Volumes I and II, Southern California Edison Company, prepared for U.S. Energy Research and Development Administration under Contract No. E(04-3)-1117, September 1976.

Introduction Cont'd.

study, it was not clear how much non-solar generating capacity, and of what type, solar units could economically and reliably replace.

In order to properly consider all of the various factors which will influence the amount of generating capacity (including solar generation) required to reliably serve the system load, it was determined that probabilistic modeling was the appropriate principal measurement tool. Each hypothetical generating system considered for evaluation was studied using Edison's Probability of Loss of Load (POLL) computer program. The amount of generating capacity in each system was adjusted such that the resulting generating system would have a constant Loss of Load Probability (LOLP) index of one hour of outage in twenty years, with no restriction on reserve margin levels. Therefore, for each system studied, the load would be served with the same degree of reliability.

The LOLP calculation measures the expected total amount of time that the generating system capability is less than the system load. An LOLP index of one hour of outage in twenty years means that on the average, the generating system will fail to serve the load for a total of one hour in a twenty year period.

Comparison of the total generating capacities of two systems with different levels of solar generation (but with identical reliabilities) yielded an approximate measure of the capacity value of solar generation.

The capacity value of the solar generation was evaluated as a function of the relative proportion of solar generation (solar penetration) and amount of storage associated with it. Examination of these results provides insight into the optimal design and use of

Introduction Cont'd.

solar generation.

The remainder of this section is devoted to a discussion of reliability analysis assumptions, models, procedures, and results.

ASSUMPTIONS AND MODELS

Five basic resource types were assumed to be available for the purpose of constructing optimum systems. Each system was assumed to have 1388 MW of hydro capacity available at the time of the system peak, corresponding to present Edison hydro capability. Peaking capacity was provided by combustion turbines, combined cycle generation provided intermediate capacity factor generation, nuclear generation provided base load energy, and solar generation with high temperature thermal energy storage was assumed to be available.

Unit Reliability and Maintenance

The reliability data and overhaul criteria for each of the five basic resource types are summarized in Table II-1. Each generating unit is represented in the reliability program using a six capacity state model. These six states are: A fully available state, a partial random forced outage state, a partial scheduled outage state, a total random forced outage state, a long-term scheduled outage state, and a deferred short-term routine outage state. The partial scheduled outage state and the deferred short-term routine outage state are combined to develop an equivalent routine maintenance outage state.

Each new generating unit was assumed to undergo a two step maturity cycle, with the immature (less reliable) first step lasting one full year. All generating units were assumed to be stan-

Unit Reliability and Maintenance Cont'd.

dard sizes, as indicated in Table II-1. The effects of economies of scale and variations in reliability as a function of unit size were considered of second order importance, and were therefore neglected.

The random forced outage data, and scheduled and routine maintenance assumptions for the conventional generating units (non-solar) were based on Southern California Edison's current estimates for these data items. The random forced outage data and scheduled maintenance assumptions for the solar units were based upon outage and maintenance data for a conventional 100 MW oil-and-gas fired boiler and turbine/generator, with additional assumptions for forced outage of the solar energy collection system resulting from random storm damage. As discussed in a later paragraph, the reliability of the solar units was further modified by the availability of incident sunlight.

Long term scheduled generation maintenance (overhauls lasting at least one week) was scheduled weekly, in accordance with the long term scheduled maintenance assumptions provided for each unit. The total system maintenance program was developed by scheduling the maintenance for each generating unit, beginning with the largest unit, such that the system reserve margin (expressed as a percentage of weekly peak demand), after deducting scheduled maintenance, was approximately levelized throughout each year. The scheduled overhauls of the solar units were constrained to occur during the winter (low sunlight) months, when the solar units had the least impact on system reliability. The resulting planned maintenance program

Unit Reliability and Maintenance Cont'd.

was then used in the reliability analysis. A plot of a typical maintenance program is included as Figure II-1.

Routine day-to-day maintenance (including short-term routine and partial scheduled outages) for the conventional generation was modeled by reducing the calculated hourly margin (after deducting long term scheduled maintenance) by the amount of expected routine maintenance during that hour. The expected routine maintenance for each hour is developed from the total annual system routine maintenance requirements (input data) and the hourly reserve margin, such that the reserve margin after deducting both long-term scheduled and routine maintenance is approximately levelized. This algorithm results in most of the routine maintenance being scheduled during the offpeak (late evening and early morning) hours of each day. Routine maintenance for the solar units was assumed to occur during the hours the units were not operating each day.

Solar Unit Output Variations

The reliability model for solar generation includes: 1) a representation of the reliability of the solar collector-turbine generator system, including forced outage and planned maintenance data as presented in Table II-1; 2) representation of hourly variations in solar unit output as a result of variations in sunfall; 3) representation of an energy storage system with a model to dispatch the energy from storage; and 4) representation of the probability of random degraded sunfall levels resulting from a single cloud formation simultaneously shielding one or more solar generating units. Figure II-2 pictorially illustrates the solar generation

Solar Unit Output Variations Cont'd.

capacity model used in the reliability study.

As noted in Chapter I and Appendix B, the sunfall data base was developed for three sites. For the reliability and economic evaluation, all the solar units were assumed to be sited in areas having the sunfall characteristics of Inyokern, California (within the SCE service territory.) Data for sites outside of California, although available, were not used. Table II-2 presents the sunfall data used for the studies, expressed as the equivalent electrical output of a solar unit sited at Inyokern. As required by the SCE computer programs, it was assumed that the year was comprised of thirteen four-week seasons, and that there were thirteen seasonal sunfall patterns, each of which was constant for the whole season.

The likelihood of a loss of solar input (due to cloud cover, etc.) was modeled probabilistically using a three state model. The three outage states were: the fully available state, a partial random forced outage state, and a total random forced outage state. The percent of average sunfall and the number of days of less than 50% sunfall were used to develop the appropriate total and partial forced outage rates and the partial forced outage state. The resulting outage rates and states are also summarized in Table II-2.

Storage

Figure II-3 illustrates the peak day load shape for the electric system and coincident sunfall patterns for August (the summer peak month) and December (the winter peak month). The daily peak load and the sunfall, or solar energy input to the solar unit, are nearly coincident during the summertime. However, the sunfall is

Storage Cont'd.

ended before the daily peak load occurs during the wintertime.

Since maintenance scheduling attempts to levelize margin over the year, and since margin affects the reliability of the system at any time, each day can potentially affect the overall annual reliability. For this reason, the effect of solar generation on reserve requirements is not adequately understood by considering solar unit performance only during the day of the annual system peak.

In general, in order to have significant capacity value to a utility, generation must be capable of operating when the utility most needs generating capacity, generally at the time of the daily peak load. The integration of an energy storage device into a solar generating unit would allow the production of electrical energy to be deferred until the time of the daily peak load. A solar unit with energy storage capability would therefore have greater "capacity value" to the system than a solar unit with no energy storage capability. To evaluate the benefits of storage, four levels of storage were studied at each level of solar penetration; no storage, and one, two, and six MW-hours of storage per MW of rated electrical generating capacity. The rated capacity is the turbine generator rating, i.e. 100 MW.

As indicated in Figure II-2, the solar powered turbine generators were assumed to be able to operate from collector output, storage, or simultaneously from both. The storage unit was assumed to have an energy loss rate of .08% per hour, which is equivalent to 2% loss from a full storage unit in a twenty-four hour period. It was further assumed that energy could be removed from storage

Storage Cont'd.

at a rate of 70% of the nominal turbine-generator rating, with no loss in conversion efficiency compared to operation directly from collector output. Although the latter assumption results in slightly overestimating the value of solar generation, it is a simple matter to recalculate the optimum storage and collector sizes to match other specified efficiency assumptions using the results of this study.

It should be noted that a fully charged 6 MW-hour per MW storage unit could produce energy for 8.6 hours at a 70% maximum rate of energy removal from storage (.7 MW-hour per hour). Because the combination of eleven hours of operation from direct sunfall during the summer plus an additional 8.6 hours of operation from a fully charged 6 MW-hour per MW storage unit results in nearly twenty hours of daily operation, increasing the amount of storage beyond 6 MWh per MW was not expected to yield sufficiently increased capacity value to merit detailed evaluation.

Because the effectiveness of the solar unit is directly related to the size of the solar collector, various collector sizes were studied. The "optimum" collector size for each storage configuration was defined to be that collector size which would, on the day of maximum solar energy input, completely charge the storage unit and simultaneously operate the solar unit at rated capacity during all sunlight hours, without losing any energy due to the storage system being fully charged and unable to accept excess collector production. In the absence of storage, the collector was sized to operate the plant at full output at noon on the summer

Storage Cont'd.

solstice. These sizing criteria are expected to be optimum or close to optimum. Figure II-4 illustrates the charging of a two hour storage unit on the summer solstice, and the dispatch of the energy from storage after the input has ceased. Note that the storage is completely charged at 5:00 p.m., the latest time at which there is sufficient input energy to both operate the unit and charge the storage.

Dispatch

It is obvious that, without storage capability, the solar generating unit would be operated at maximum capability whenever solar energy input was available. This mode of operation, so-called "run-of-the-sun", is identical to the operation of "run-of-the-river" stream flow hydro units, whose output is solely dependent upon the rate of water flow in the river.

With the addition of storage capability, it becomes possible to dispatch the solar units to operate at those times that generating capacity is most valuable, generally at the time of the daily peak load. There are many sophisticated dispatch strategies which could be theorized, each of which would attempt to maximize the capacity value of the solar generation. However, it was determined that the study results would be most meaningful if the dispatch strategy used was similar to the strategy which would be used in actual operation. The most practical dispatch strategy for use in actual operation would be peak shaving, where the solar unit is operated primarily during the peak load hours. This strategy has the advantages of being reasonably simple to implement, of

Dispatch Cont'd.

minimizing the amount of energy retained in storage, and therefore minimizing storage losses.

This peak shaving dispatch strategy was implemented in both the reliability and economic analyses by ranking the loads for each hour of the peak day in each four-week season in order, from the highest to lowest load. The ranking is presented in Table II-3. The solar units were then operated as much as possible during the highest load hours, subject to the constraints of the total amount of energy in storage and the total daily solar energy input. Energy collected during low load sunlight hours was stored for use during a higher load hour. The energy collected during a day was assumed to be fully utilized during that day, and solar operation was assumed to occur every day, including weekends and holidays. As noted earlier, Figure II-4 illustrates operation of a typical 100 MW solar generating unit with 2 MW-hours per MW of storage capability, during the summer solstice. On this day the highest load occurs in the afternoon, with a secondary peak occurring during the evening. Notice that the storage unit is completely filled at 5:00 p.m., and then energy is withdrawn from storage at varying rates in order to shave the evening peak load.

Multiple Units At A Site

The development of large amounts of solar generating capacity will necessitate the siting of multiple units at each favorable solar site. Recognizing that a single cloud formation could then block the insolation incident upon a number of solar units simultaneously, it was necessary to include this consideration in the

Multiple Units at a Site Cont'd.

solar model. For each case, it was assumed that 5 independent sites would be developed. This limited the maximum capacity at any site to 300 MW, 500 MW, and 1000 MW for the 5%, 10%, and 20% solar penetration cases, respectively. For each case, the reliability of all the solar generation at a site was modified by the probability of simultaneously losing all the capacity due to cloud cover.

Load Pattern

The load pattern used for the reliability analysis is an hourly pattern comprised of thirteen typical weekly load patterns (7 days/week x 24 hours/day = 168 hours in each week pattern) and fifty-two weekly peak factors for each study year. Each typical weekly load pattern is assumed to be in effect for four weeks in sequence. There are thirteen four week "seasons" per year. The thirteen season hourly load pattern and the weekly peak factors are a composite of Edison's historical load pattern for the 1971-1974 period, modified by expectations of future load patterns based on forecasts. Firm on-peak and off-peak sales are then added to this pattern to develop the load for the Edison area. The resulting composite load duration curve is presented in Figure II-5.

Load forecast uncertainty is included in the reliability evaluation. For this study the load forecast uncertainty was modeled using 5 discrete loads, with associated probabilities of occurance. The probability of the load being exactly the mean forecast load was 38.292%, of being either 2.15% above or below the mean forecast load was 24.173%, and of being either 4.3% above or below the mean

Load Pattern Cont'd.

forecast load was 6.681%.

Electric System Reliability Model

The probability of loss of load (POLL) analysis involves the determination of the expected total amount of time in each study year that the forecast load cannot be served by the generating units available for service, after deducting long-term scheduled and routine maintenance, as a result of the random failure of some of these generating units. Because long-term scheduled maintenance is assumed to be scheduled on a weekly basis, the resources available to serve load during any day of a study week are assumed to remain constantly available (excluding forced outages) for every day of the week. Within the program, a capacity outage table is developed for each week which relates specific amounts of reserve margin (difference between available capacity and system load) to the associated probabilities that this margin will be reduced to zero during a given hour as a result of unit outages. Because random forced outages of generating units are assumed to be independent of the hour, and scheduled outages are constant during each day of the week, only one capacity outage table need be developed for each week. The annual LOLP index is equal to the sum of the hourly probabilities that the actual generating system margin in each hour is lost.

With the inclusion of solar generation, it was necessary to vary hourly both the total amount of generating capacity available to serve the load, and the reliability of that generating capacity. The variations in hourly total capacity and reliability were accomplished by including in the development of the weekly capacity outage table the amount of solar capacity which would be available at the time of the peak load in the week. Then, the apparent hourly system margin was modified by the probabilistic difference between the amount of solar capacity included in the system capacity calculation and the actual output of the solar units during that hour.

Although the above calculation does not yield results identical to those which could be obtained if the capacity outage table was developed every hour rather than once each week, the approximation is expected to yield valid results. It was not considered practical to develop the capacity outage table hourly, considering the marginal benefits in terms of increased accuracy. Furthermore, the error introduced in this approximation is expected to be insignificant compared to the uncertainties in the design and operating characteristics of the solar generating units.

RESULTS

Discussion

Because the need for generating capacity is greatest during peak load periods, when the reserve margins are the smallest, most of the annual probability of loss of load is accumulated during these periods. If a generating unit can produce power at its rated capacity during the peak periods, then the unit can be expected to have high capacity value to the sytem. If on the other hand, the unit cannot produce power, or produces power at less than rated capacity, during peak periods, then the unit will have a lesser capacity value to the system. Because the highest peak load periods in the Southwest occur during daylight hours in the summer, small amounts of solar generation will have substantial capacity

Discussion Cont'd.

value as a peak shaving generation resource.

As noted earlier, the purpose of a peak shaving dispatch is to levelize the system load which remains to be served, after deducting operation of the solar unit being dispatched. A simple illustration of an ideal peak shaving dispatch is included in Figure II-6. Notice that as units, e.g., solar units, are added, the additional units must operate for longer periods of time to achieve the desired reduction in remaining load. For small levels of solar penetration, the solar units, either with or without storage, need operate only a few hours to effectively shave the peak. Increasing the amount of solar capacity in the system requires the units to operate longer and longer periods of time in order to effectively shave peak loads. Because the solar unit can operate only a limited number of hours each day, even with storage, each additional increment of solar capacity has a lower capacity value than each of the preceding increments. Evidence of this will be presented later in terms of the need to provide increased amounts of installed reserve margin as the solar penetration increases.

Results Summary

The major results of the reliability evaluation are presented graphically in Figures II-7, 8, and 9, and are tabulated in Table II-4.

Effect on Margin Requirements

Figure II-7 summarizes the reserve margin required to maintain a constant loss of load probability of one hour in twenty years, as a function of the level of solar penetration in the resource mix, Effect On Margin Requirements Cont'd.

for various levels of storage. As discussed earlier, increasing the amount of storage capability (with the attendant increase in collector size) enables the solar units to operate for longer periods, and therefore increases the capacity value of the solar units, and decreases the installed reserve margin requirements. The figure illustrates this.

To further illustrate this point, consider a system comprised entirely of solar generating units. If the system had no storage, it would have no ability to serve load during the nighttime hours. To reliably serve the load pattern used in this study, our example system would need sufficient storage to allow operation of at least a portion of the capacity every hour of the year. Given sufficient storage to meet the daily energy requirements, the solar units must still be dispatched such that sufficient capacity is available to meet the load every hour.

Figure II-8 presents the effective load carrying capability of solar generation as a function of solar penetration, for various levels of storage. Load carrying capability (LCC) is an approximate measure of the amount of load which can be served by a generating resource or system at a given level of system reliability. The load carrying capability of the base system for an LOLP index of one hour in twenty years was approximately 86.6%. This may be interpreted as meaning a system with a total of 100 MW of generating capability could serve 86.6 MW of load (with the same load pattern as the base system) with a reliability of one hour of outage in twenty years. This is equivalent to requiring

Effect on Margin Requirements Cont'd.

installed generating capacity equal to 115.4% of system peak demand (15.4% installed reserve margin). The LCC of the solar generation presented in Figure II-8 was derived by deducting the LCC of the conventional generation in the system (assumed to be constant at 86.6%) from the LCC of the total system.

Because variations in the amount and mix of the conventional generation will affect the LCC of that generation, the curves presented in Figure II-8 are only approximate. However, they are descriptive of the relationship between load carrying capability and solar penetration. Note that this figure illustrates the same effects presented in Figure II-7, namely that increasing the solar penetration reduces the capacity value (or LCC) of the solar generation at any level of storage, and that increasing the storage increases the capacity value of the solar generation.

Effect on Resource Mix

Figure II-9 presents the optimum resource mix by loading category as a function of solar penetration and storage level. Note that as the level of storage increases, for a fixed penetration, the total capacity required decreases. Furthermore, as the level of solar penetration increases, the amount of intermediate and base load generating capacity required in the optimum system decreases. This further demonstrates that as the level of solar penetration increases, the solar generation must operate at higher load factors, replacing base and intermediate load units, in order to achieve higher capacity values.

Note that increasing solar penetration will reduce the amount

Effect on Resource Mix Cont'd.

of base load generation in the system only if the level of base load generation was nearly optimum. In reality, there are very few utilities which have near optimum levels of base load, so in the foreseeable future, the addition of solar generation will primarily reduce the need for intermediate and, to some extent, peaking generation additions.

Effect on Load

To illustrate the operation of the solar generation, plots of the system load, and the load minus the hourly solar output, are included in Figures II-10 through II-13.

Figures II-10A and II-10B illustrate the effect of solar operation on a peak summer day in August and a peak winter day in December, for a 5% level of solar penetration and no storage. Note that although the solar unit operates at nearly full capacity during the summer peak, during the evening winter peaks there is no sunfall and hence no generation output (because of no storage). Therefore, in this case the unit has little capacity value.

Figures II-11A and II-11B illustrate the effect of operation of a 5% solar penetration with one MW-hr of storage per MW of capacity during the same peak days. Notice that although the storage has practically no additional benefit during the summer peak, it does allow operation of the solar unit for about two hours at reduced output during the winter evening peak. Because of this, the addition of storage has a significant impact upon the load carrying capability of the solar generation, as illustrated in Figures II-7 and II-8.

Effect on Load Cont'd.

Figures II-12A and II-12B and Figures II-13A and II-13B illustrate the operation of a 20% solar penetration with one MW-hr and six MW-hrs of storage per MW of capacity, respectively. Comparison of Figures II-12B and II-13B clearly demonstrate that when solar becomes a significant portion of the resource mix, high levels of storage allow more versatile operation and therefore result in higher capacity values than can be achieved with low levels of storage.

Figure II-14 illustrates the effect of the dispatch strategy by plotting the dispatch of a typical solar unit with six MW-hrs of storage per MW of capacity on a December peak day. Because the daily peak load in December occurs during the evening, the solar unit is not operated during the lower priority hours of 12 noon, 2:00 and 3:00 p.m. so that sufficient energy may be stored to allow operation during the evening peak. Figure II-13B illustrates the composite operation of all the solar generation in the 20% penetration case (with six MW-hr of storage per MW) overlayed on the system load during the December peak. To maximize the capacity value of the solar generation, the units were dispatched so as to levelize the margin in each hour to the maximum extent practical. The success of this strategy is clearly illustrated in Figure II-13B. Although it would have been possible to obtain a more levelized margin pattern during the daylight hours, that effort would have had little impact on overall system reliability in as much as the margins during the critical peak hours of 5:00 p.m. through 9:00 p.m. were increased by the maximum possible increment.

Effect on Load Cont'd.

This increase was dependent upon the rate at which energy could be removed from storage, and the units were already operating at the maximum discharge rate of 70%.

Application of Results

As noted earlier, all the results presented in this section are based upon serving the load with an annual loss of load probability of one hour of outage in twenty years. Figure II-15 illustrates the variation in the installed generation reserve margin required to meet various levels of LOLP. As the required reserve margin varies, so also will the effective LCC of the solar generation, as presented in Figure II-7. For a design LOLP of one hour of outage in four years, the LCC of the base system would be increased from 86.6% to 89.4%, and the LCC of the solar generation at 10% penetration with 6 MW-hours of storage per MW would increase from about 59.4% to about 60.6%.

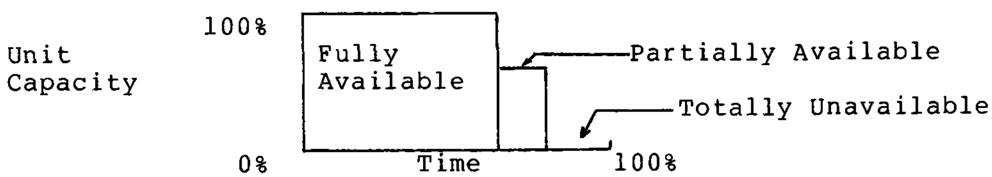
Using the results presented in Figures II-7 and II-8, modified as necessary to adjust for a different LOLP design criterion (using Figure II-15), it is possible to make a preliminary assessment of the value of solar generating capacity to a utility system having a reliability criterion that differs from that used by SCE.

TABLE II-1

RELIABILITY & MAINTENANCE ASSUMPTIONS

UNIT TYPE	CAPACITY (MW)	FORCED OUTAGE DATA: Total Forced Outage Rate (%)	Capacity Lost During Partial Forced Outage	Partial Forced Outage Rate (%)	FREQUENCY OF OVERHAUL: Major (1) Interval & Tolerance	Major Duration	Minor (1) Interval & Tolerance	Minor Duration
Hydro Variable	847-907	0	0	0				
Hydro Base	500	1.59	250MW	14.8%				
Nuclear - 1st Year	500	4.47	53	11.47	1yr±7wks	6wks		
Nuclear - Mature	500	3.89	53	9.42	1yr±7wks	6wks		
Combined Cycle - 1st Year	250	.61	121	11.52	2yr±13wks	6wks	24wks±4wks	2wks
Combined Cycle - Mature	250	.53	121	9.51	2yr±13wks	6wks	24wks±4wks	2wks
Combustion Turbine - 1st Yr	100	10.			10yr±13wks	3wks	2yrs±13wks	1wk
Combustion Turbine - Mature	100	5.			10yr±13wks	3wks	2yrs±13wks	1wk
Solar - 1st Year	100	7.5	50	2.5	2yr46wk±1wk	(2) 6wks	25wks±4wks	1wk
Solar - Mature	100	5.0	50	1.5	2yr46wk±1wk	6wks	25wks±4wks	1wk

Illustration of Outage States



Routine Maintenance - 10,250 GWH, or 1170 MW Average each hour

Notes
(1) Interval from end of last overhaul to beginning of next overhaul.
(2) Close tolerance selected to prevent solar unit overhaul pattern from migrating into summer months.

TABLE II-2

SOLAR HEAT SOURCE DATA

Equivalent Electrical Output of 100MW Collector in (MW)

Season (4 weeks each)

Hour	1	2	3	4	5	6	7	8	9	10	11	12	13
6													
7				47									
8		50	57	67	58	78	73	73	59				
9	69	71	78	82	73	88	86	86	79	66	67	67	61
10	72	77	83	87	84	95	94	94	92	88	81	72	67
11	71	78	86	89	87	100	99	99	98	94	81	71	66
12	70	78	85	89	90	99	98	98	98	93	79	70	65
13	69	78	85	89	89	100	99	99	98	94	79	69	64
14	67	77	83	87	89	99	98	98	98	93	77	67	63
15	56	71	77	81	87	97	96	96	95	91	76	56	51
16	43	47	53	54	83	93	92	92	90	85	68	43	
17			29	41	69	82	80	80	74	62	61		
18					51	66	62	62	49	35			
Avg. % Sun	75%	79%	81%	85%	90%	94%	86%	86%	88%	93%	84%	84%	77%
Days < 50% Sun	5.9	4.8	4.3	3.2	1.8	.7	2.9	2.9	2.3	1.0	3.4	3.2	5.4
Total Forced Outage %	19.0	17.17	13.87	10.67	5.81	2.3	9.4	9.4	7.4	3.3	11.0	10.7	17.4
Partial Forced Outage %	23.9	18.2	27.0	10.3	41.9	61.7	32.9	32.9	38.3	52.9	31.3	33.1	24.4
Partial Derate %	25	21	19	15	10	6	14	14	12	7	16	16	23

TABLE II - 3

DISPATCH PRIORITY*

Season (4 weeks each)

Priority	1	2	3	4	5	6	7	8	9	10	11	12	13
1	18	19	19	19	20	15	15	15	15	20	19	18	18
2	19	18	20	20	21	14	14	16	14	15	20	19	19
3	20	20	18	21	14	13	16	14	16	14	18	20	20
4	21	21	21	14	15	16	17	17	13	16	15	17	17
5	10	10	11	13	13	21	13	13	17	19	14	21	21
6	17	11	10	18	11	17	18	18	20	13	21	11	10
7	9	9	14	11	16	12	12	12	18	17	17	14	11
8	11	13	13	15	12	11	21	21	12	18	13	13	9
9	12	12	15	12	19	18	11	11	11	21	16	10	13
10	13	14	9	10	10	20	19	19	21	12	11	15	12
11	14	17	12	16	17	10	20	20	19	11	12	9	14
12	15	15	17	17	18	19	10	10	10	10	10	16	22
13	16	16	16	9	9	9	22	22	22	9	9	12	15
14	8	8	8	22	22	22	9	9	9	22	22	8	16
15	22	22	22	8	8	8	23	23	23	8	8	22	8
16	7	7	23	23	23	23	8	8	8	23	23	23	23
17	23	23	7	7	7	7	24	24	24	7	7	7	7
18	24	24	24	24	24	24	7	7	7	24	24	24	24
19	6	6	6	6	6	6	1	1	1	6	6	6	6
20	1	1	1	1	1	1	6	6	6	1	1	5	1
21	5	5	5	5	2	2	2	2	2	2	2	1	5
22	2	2	2	2	5	5	5	3	3	5	5	2	2
23	3	4	3	4	4	3	3	5	5	3	3	4	3
24	4	3	4	3	3	4	4	4	4	4	4	3	4

* For example in the 8th season (mid-summer) the 15th hour is assigned the highest priority (i.e. it is the hour with the highest load) it ends at 3 p.m., while the hour with the lowest priority begins at 4 a.m.

TABLE II-4

SUMMARY OF RELIABILITY RESULTS
(For Constant Loss of Load Probability Index of Approximately
1 Hour of Outage in 20 Years)
Installed Generation Resources (a)

Case Identification	Solar Penetration (%)	Storage Mw-Hr/Mw of Solar Capacity	Solar Collector Size (Per Unit of Solar Electrical Capacity)	Nuclear Mw	Combined Cycle Mw	Combustion Turbine Mw	Hydro Mw	Solar Mw	Total Installed Capacity Mw	Installed Reserve Margin (%) (a,b)	System Effective Load Carrying Capability (%) (a,c)	Solar Generation Effective Load Carrying Capability (%) (a,d)
00/0	0	-		13000	1250	5000	1388	-	20638	15.4	86.6	-
05/0	5.16	0	1.0	12000	750	6100	1388	1100	21338	19.3	83.8	32.3
05/1	5.23	1	1.18	12000	750	5700	1388	1100	20938	17.1	85.4	63.7
05/2	5.28	2	1.29	12000	750	5600	1388	1100	20838	16.5	85.8	71.5
05/6	5.30	6	1.71	12000	750	5500	1388	1100	20738	16.0	86.2	79.4
10/0	9.76	0	1.0	12000	750	~~6200~~ 6100	1388	2200	22538	26.1	79.3	12.1
10/1	10.03	1	1.18	12000	750	5600	1388	2200	21938	22.7	81.5	35.8
10/2	10.17	2	1.29	12000	750	5300	1388	2200	21638	21.0	82.6	47.6
10/6	10.31	6	1.71	11500	750	5500	1388	2200	21338	19.3	83.8	59.4
20/0	19.81	0	1.0	11000	750	7100	1388	5000	25238	41.2	70.8	7.1
20/1	19.80	1	1.18	11000	750	6300	1388	4800	24238	35.6	73.8	21.8
20/2	19.63	2	1.29	11000	750	5700	1388	4600	23438	31.1	76.3	34.1
20/6	19.35	6	1.71	10000	750	6200	1388	4400	22738	27.2	78.6	45.2

Notes:

a. Resources adjusted to achieve annual LOLP index of 1 hour of outage in 20 years.
b. Installed reserve margin = ((Total installed capacity/peak demand) - 1.0)x100, where peak demand = 17880 MW
c. System effective load carrying capability (LCC) = (1./(1.0 + (installed reserve margin/100))) x 100
d. Solar generation effective load carrying capability = ((System effective LCC - (86.6X(1.0 - solar penetration/100)))/ solar penetration) x 100.

Figure II-1

MAINTENANCE SCHEDULE

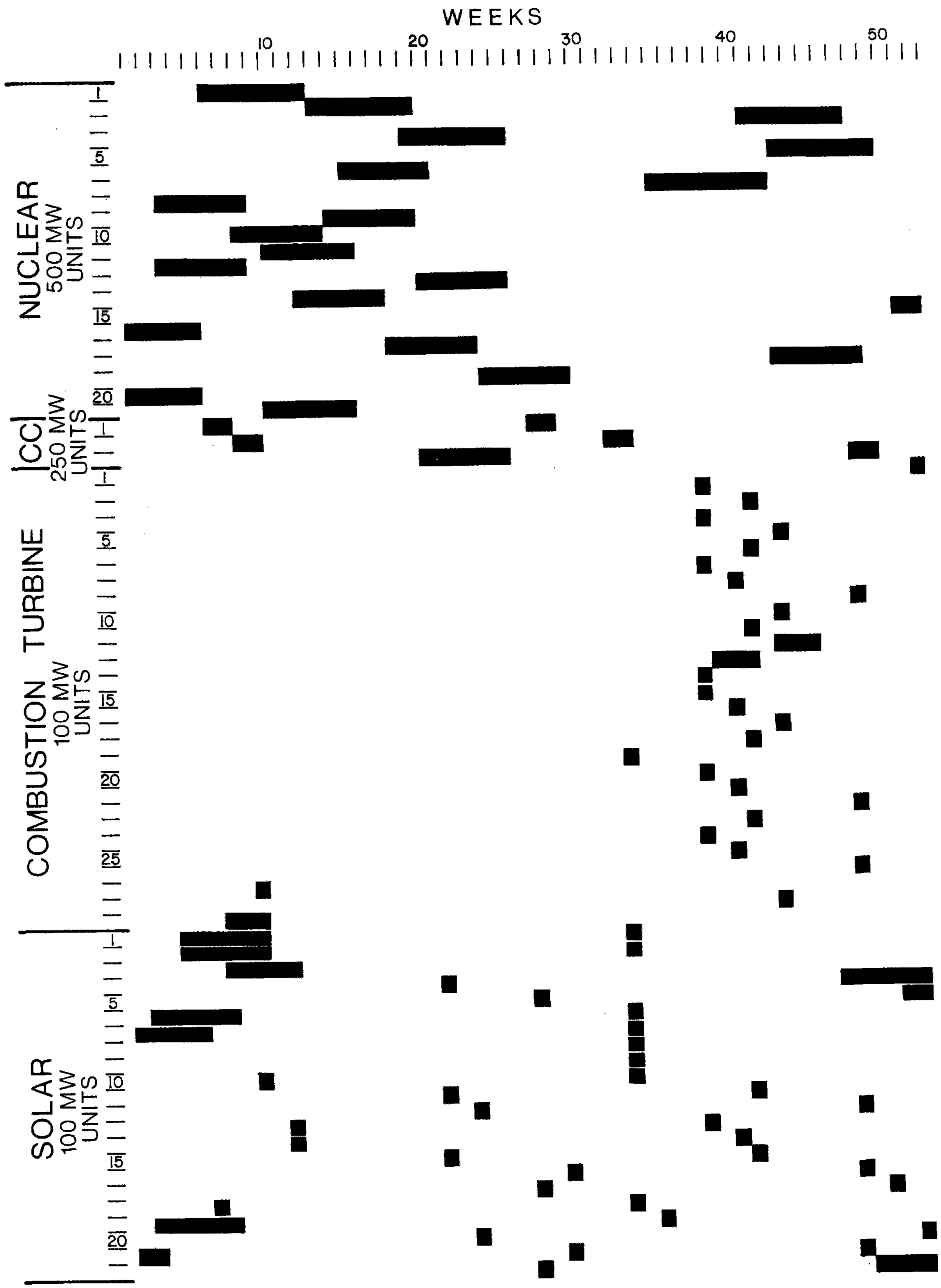


Figure II-2

SOLAR GENERATION MODEL

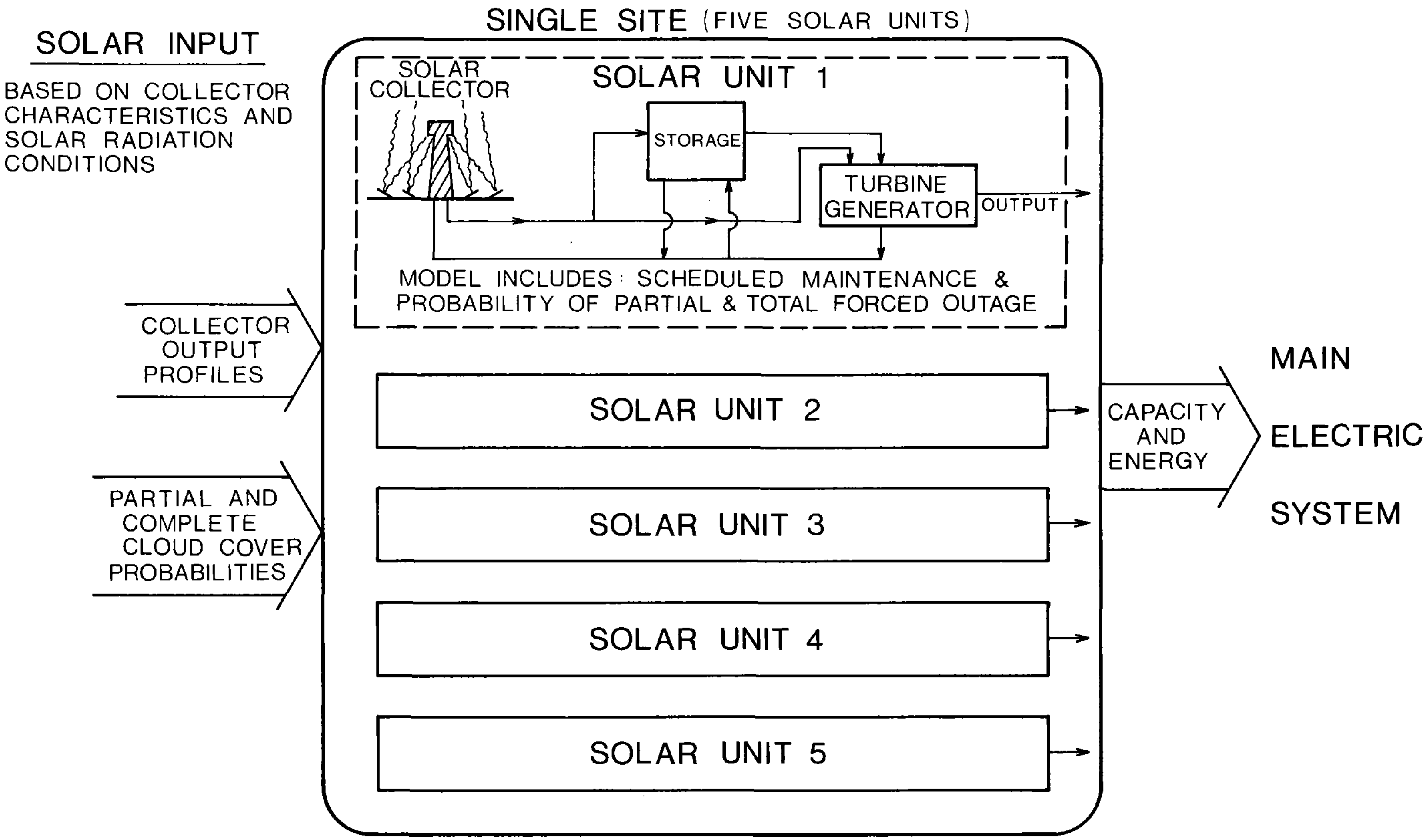


Figure II-3

DAILY LOAD SHAPE VS. SUNFALL

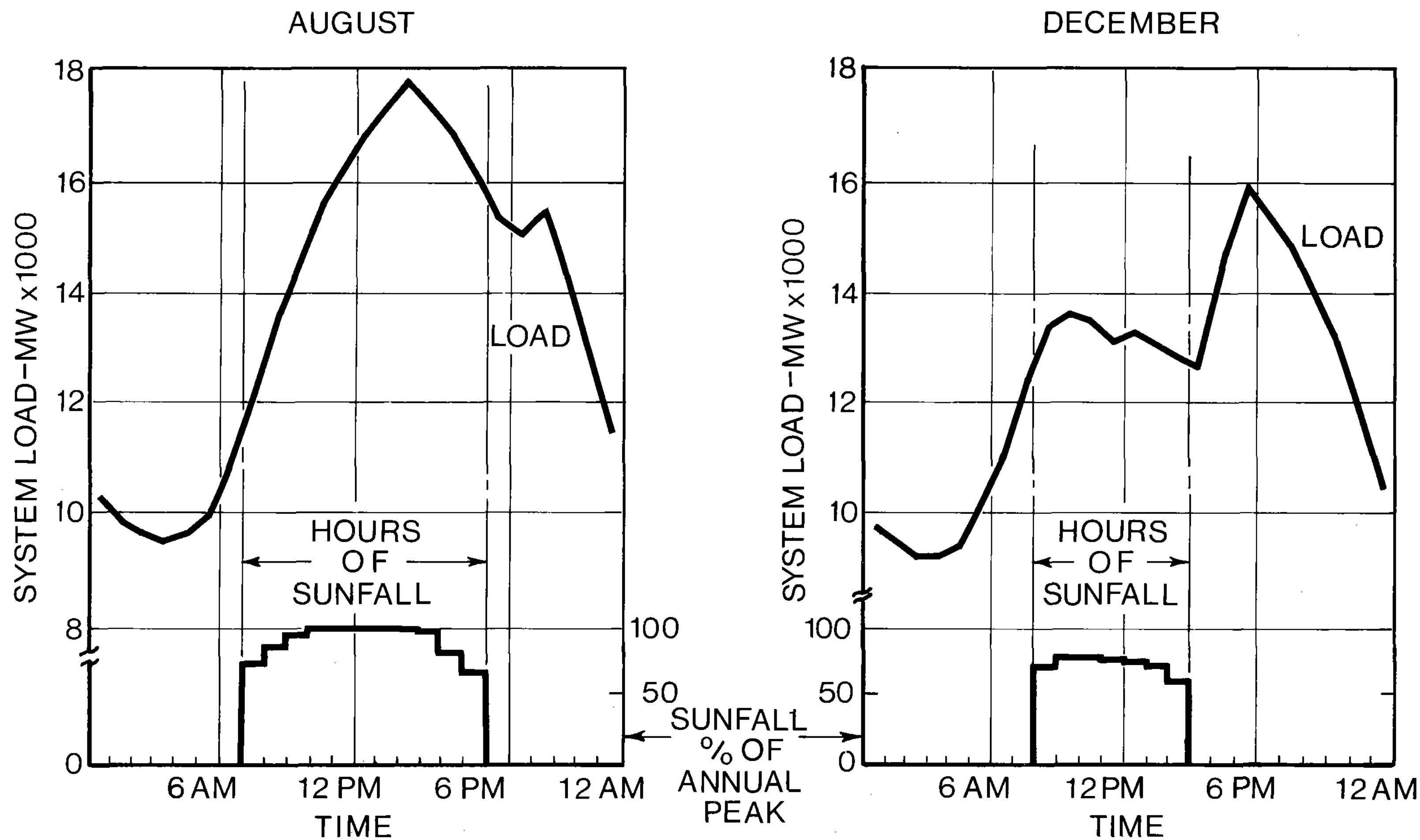


Figure II-4

TYPICAL SOLAR DISPATCH - JUNE
100 MW UNIT, 2 HOURS OF STORAGE
129 MW COLLECTOR

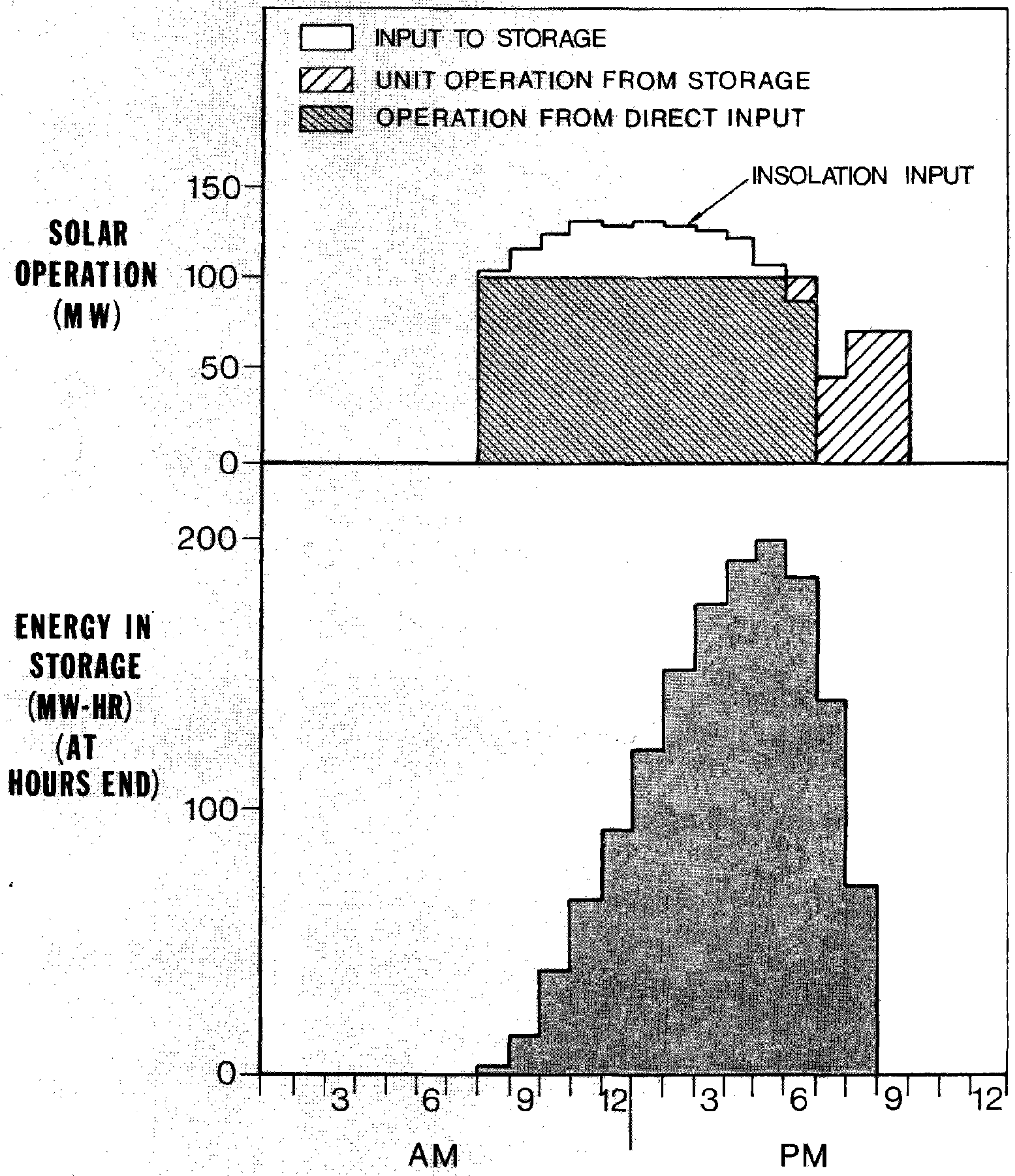
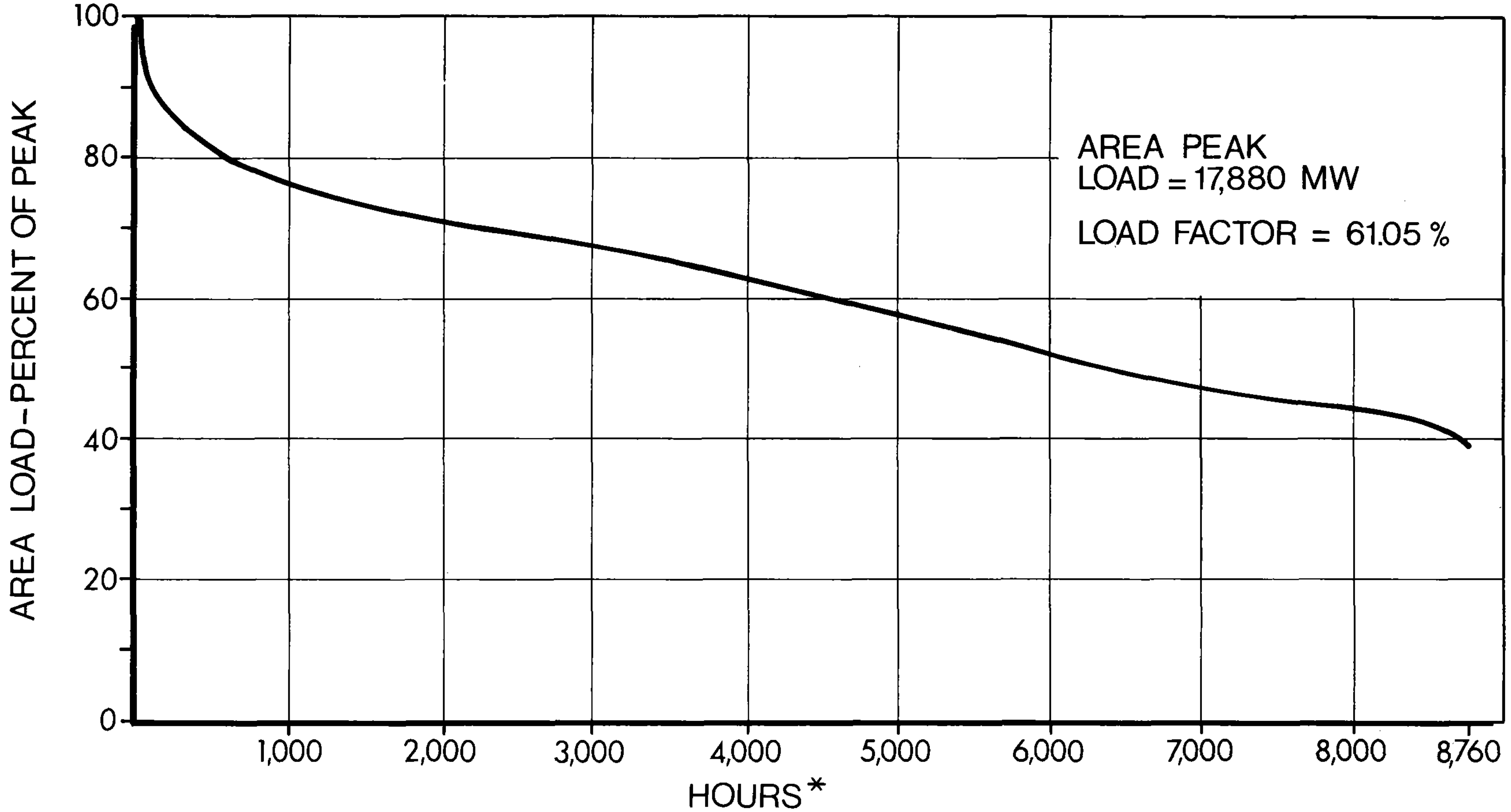


Figure II-5

SCE LOAD DURATION CURVE



* NUMBER OF HOURS PER YEAR DURING WHICH SYSTEM LOAD EXCEEDS INDICATED PERCENT OF AREA PEAK LOAD

Figure II–6

IDEAL PEAK SHAVING DISPATCH

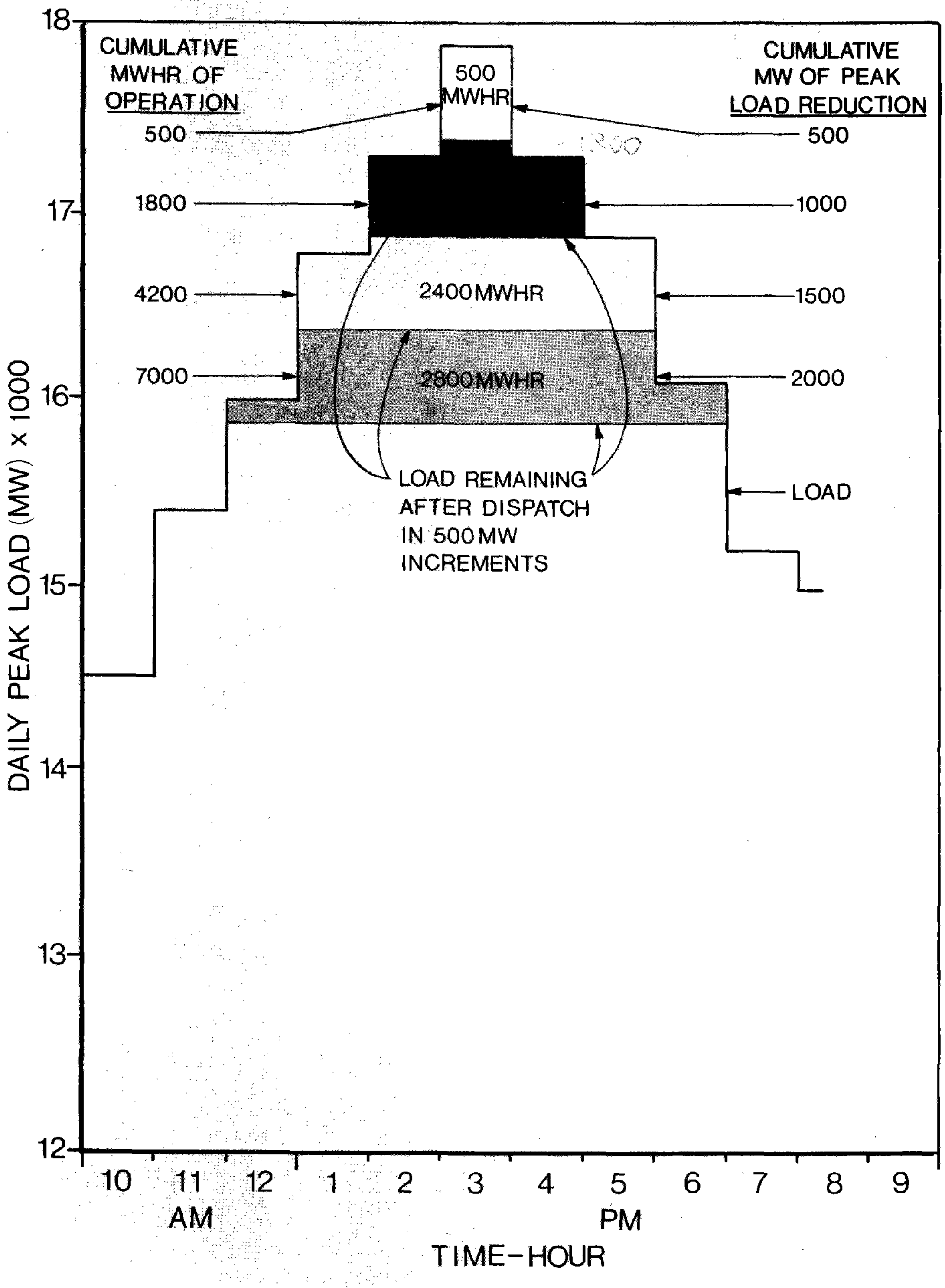
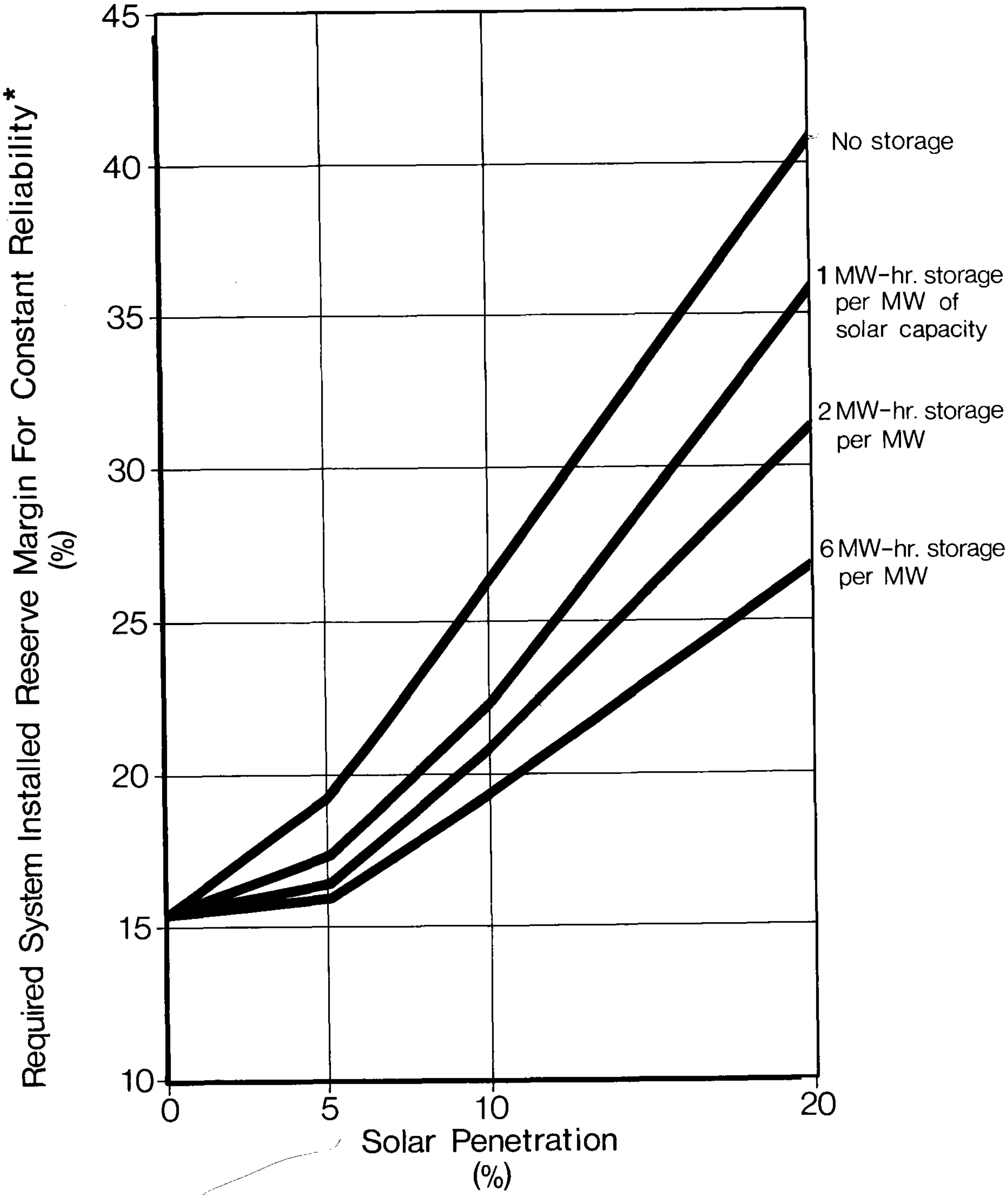


Figure II-7

REQUIRED INSTALLED RESERVE MARGIN vs. SOLAR PENETRATION



*Loss Of Load Probability Held Constant At 1 Hour Of Outage (Total) In 20 Years

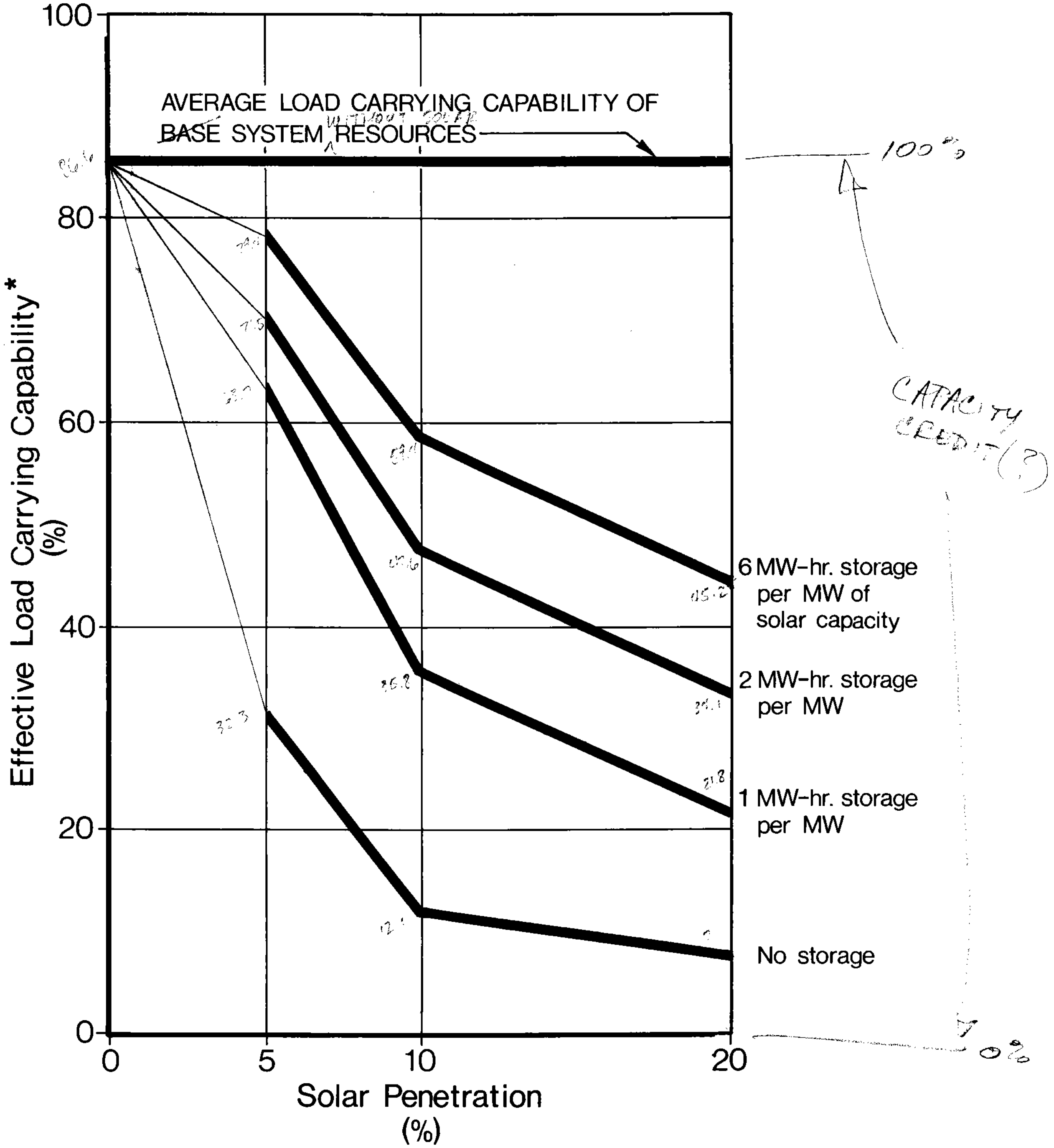
MW solar

MW solar + MW ...

Table 2-4

Figure II-8

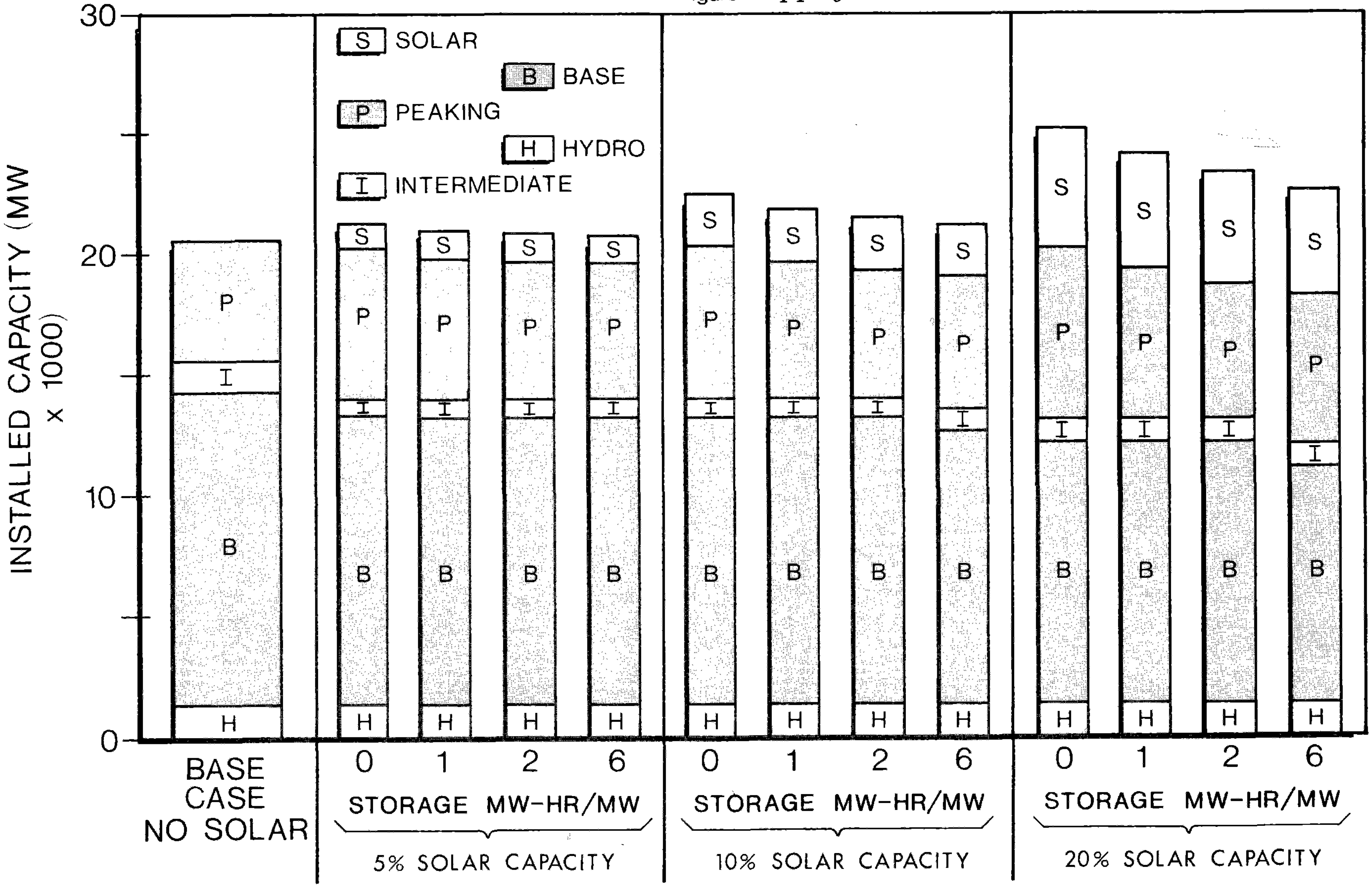
EFFECTIVE LOAD CARRYING CAPABILITY OF SOLAR GENERATION vs. SOLAR PENETRATION



*Loss Of Load Probability Held Constant At 1 Hour Of Outage (Total) In 20 Years

EFFECT OF SOLAR GENERATION ON MIX OF NON-SOLAR RESOURCES

Figure II-9



EFFECT OF SOLAR GENERATION ON SYSTEM LOAD
5% SOLAR 0 MWH/MH

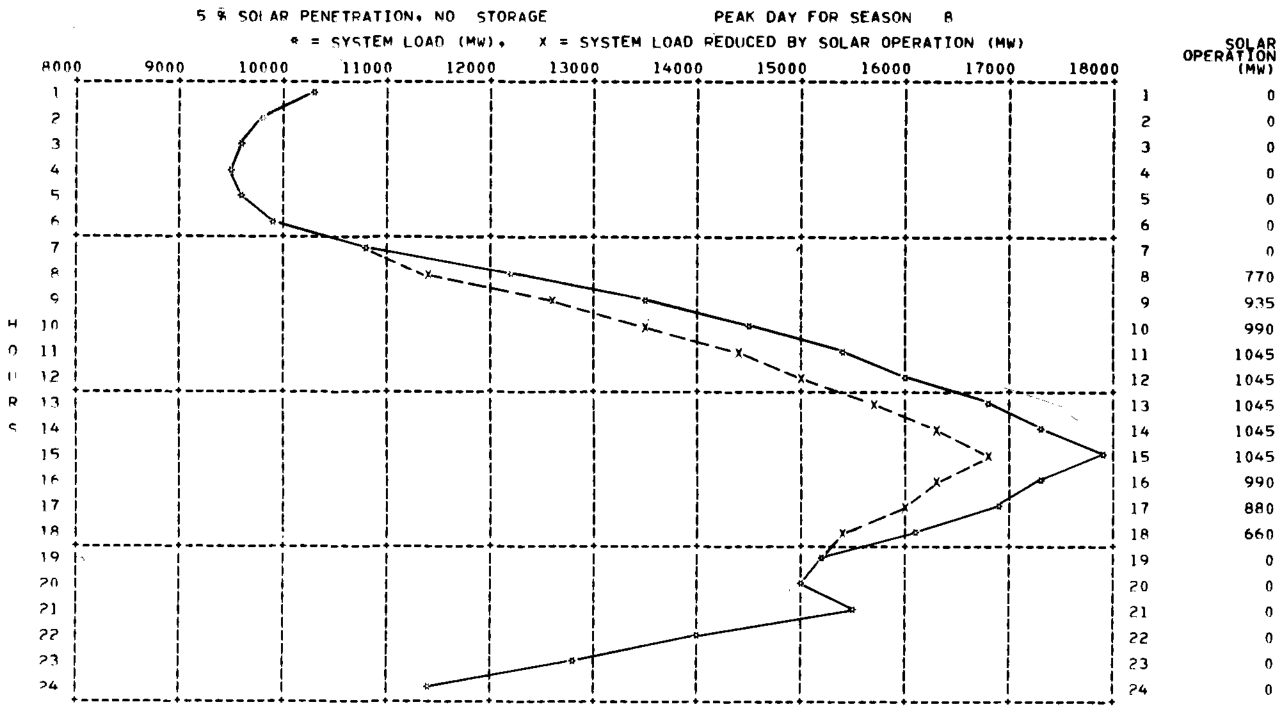


Figure II-10A
SUMMER

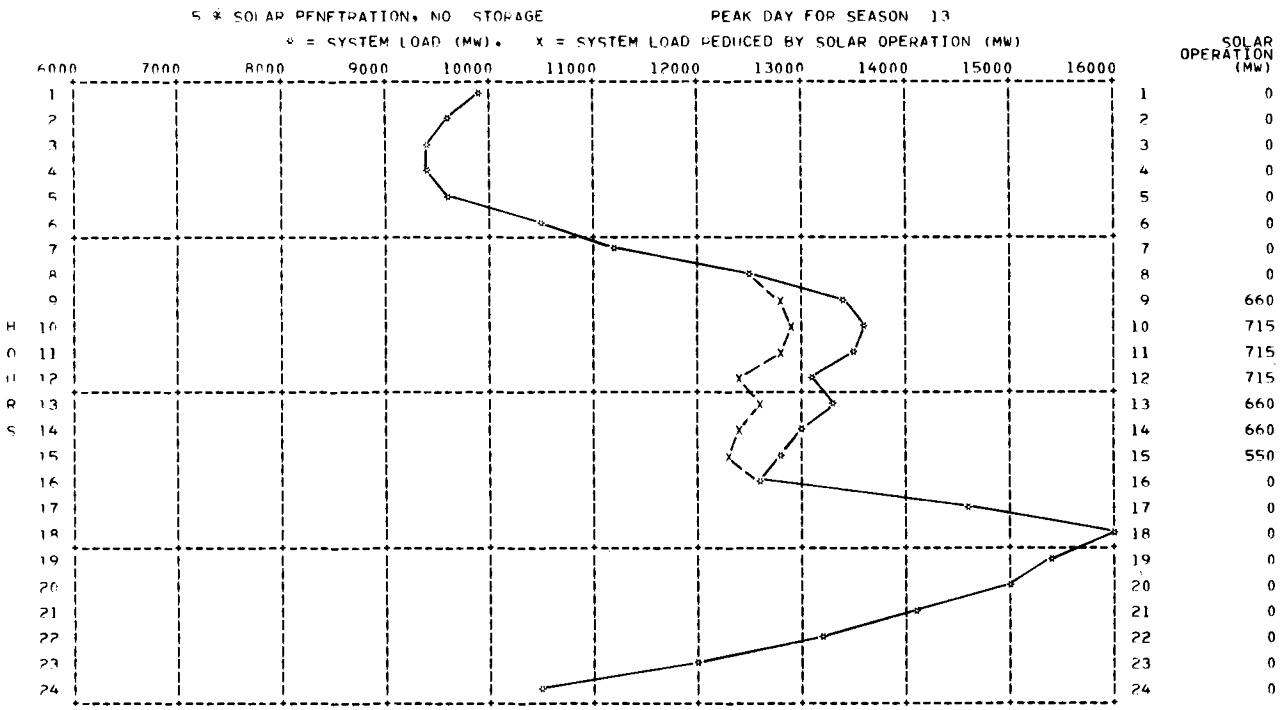


Figure II-10B
WINTER

EFFECT OF SOLAR GENERATION ON SYSTEM LOAD
5% SOLAR 1MWH/MW

Figure II-11A

SUMMER

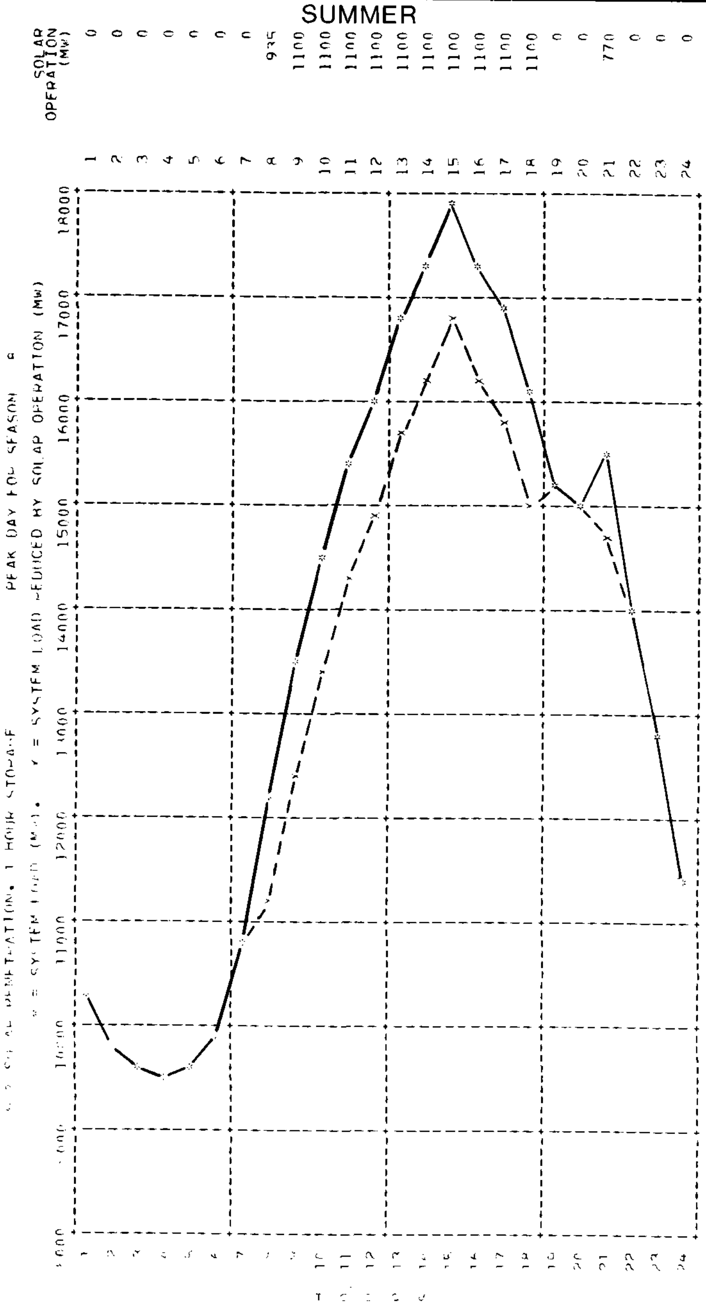
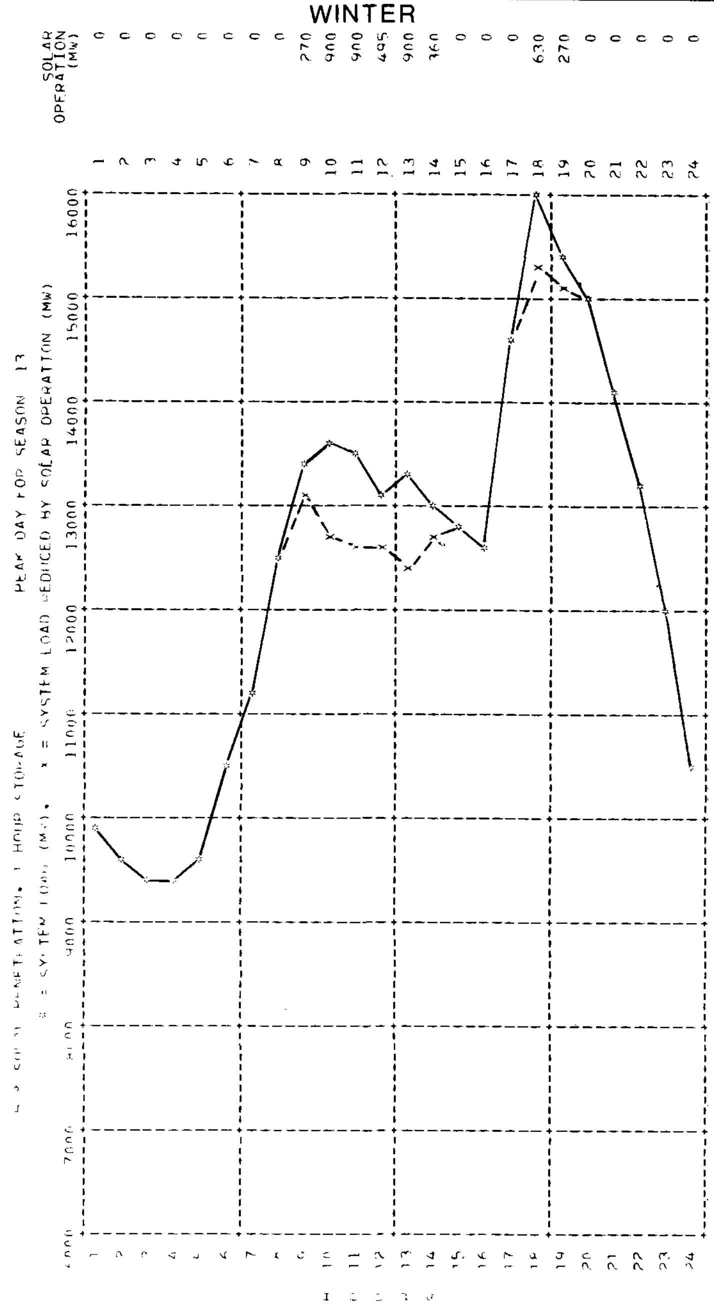


Figure II-11B

WINTER



EFFECT OF SOLAR GENERATION ON SYSTEM LOAD
20% SOLAR 1MWH/MH

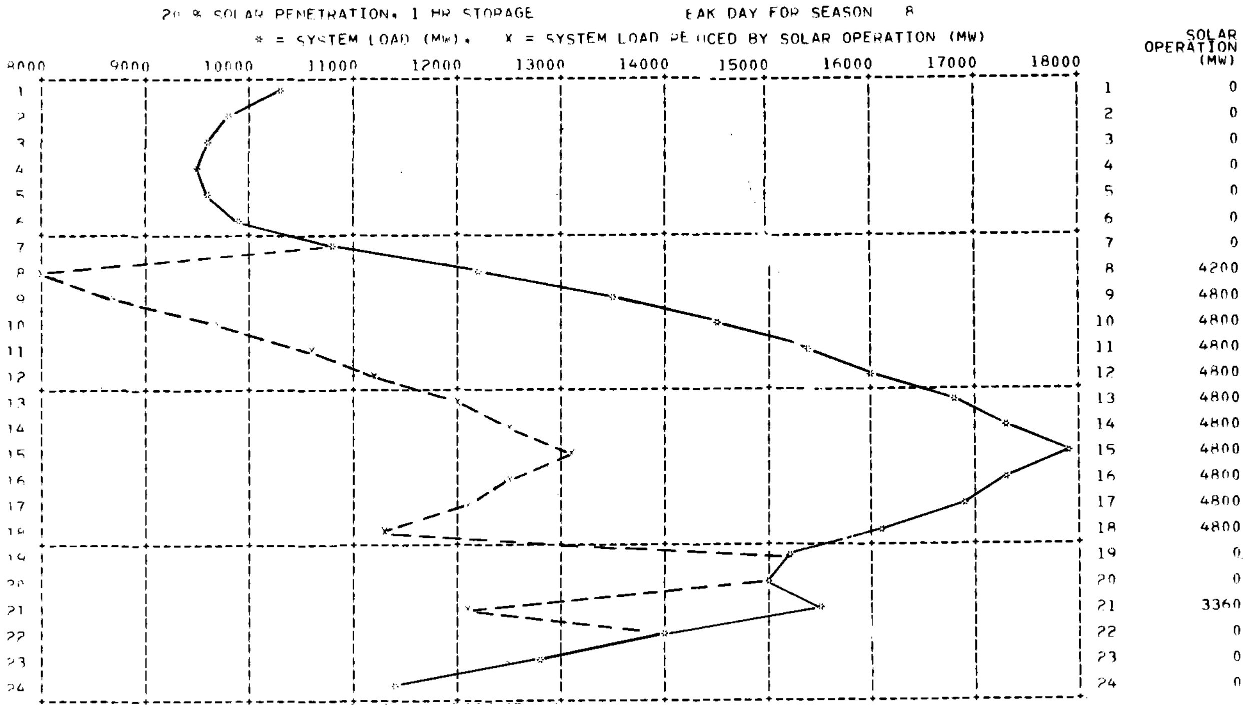


Figure II-12A
SUMMER

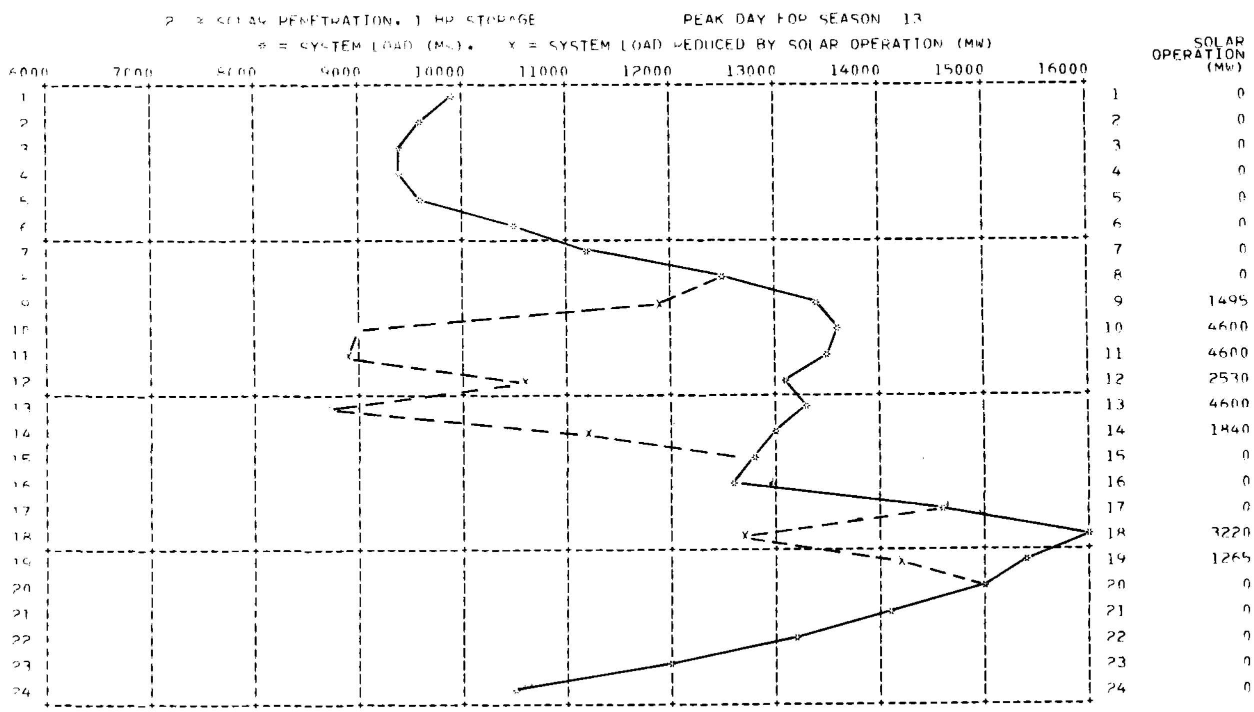


Figure II-12B
WINTER

EFFECT OF SOLAR GENERATION ON SYSTEM LOAD
20% SOLAR 6 MWH/MW

Figure II-13A
SUMMER

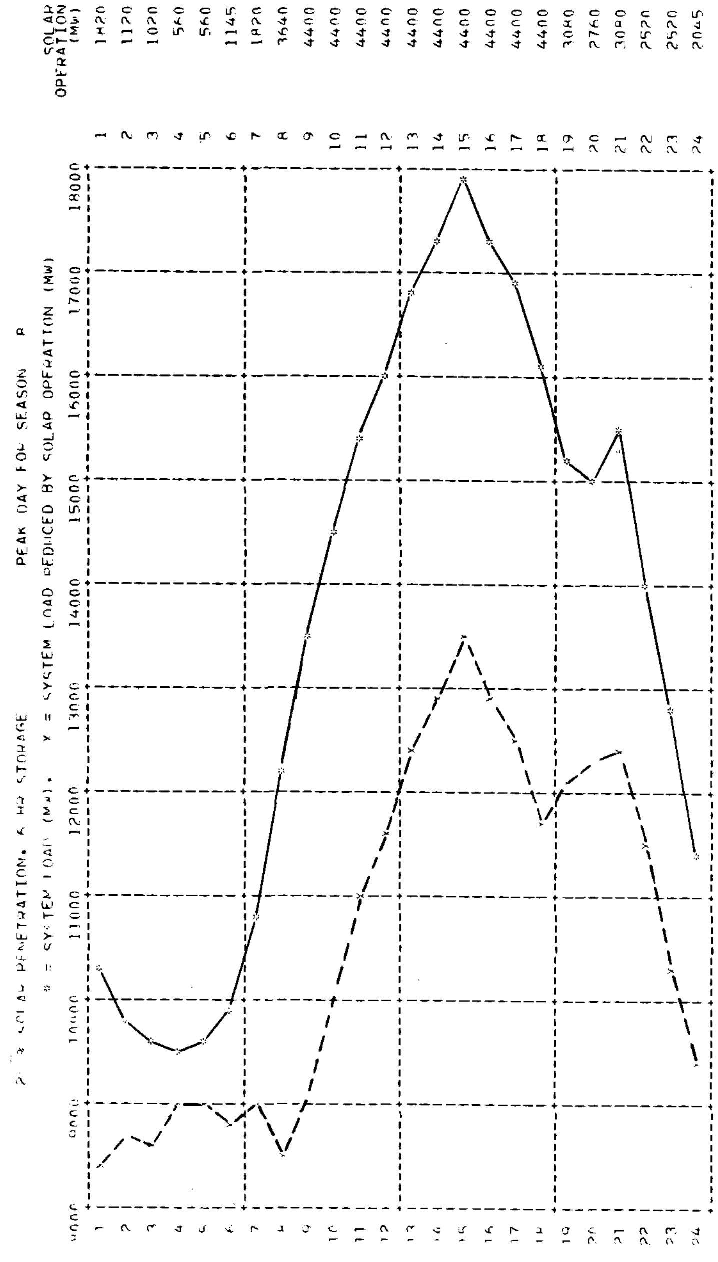


Figure II-13B
WINTER

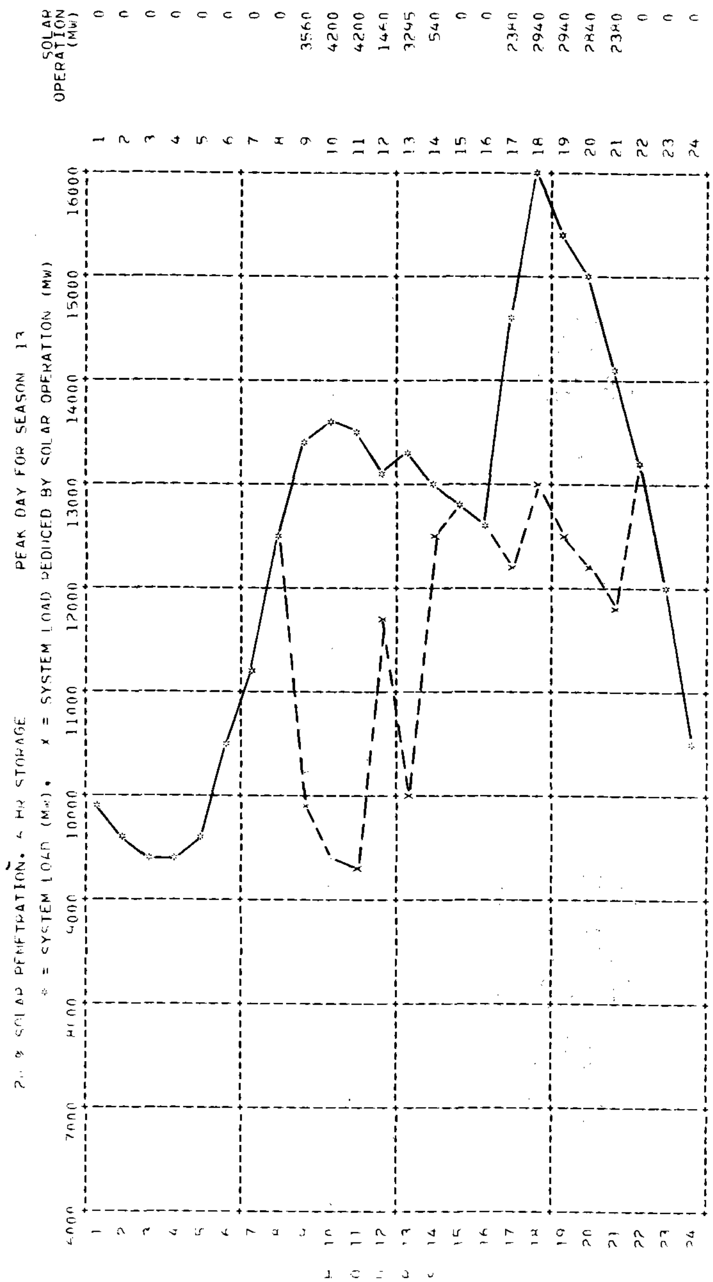


Figure II-14

TYPICAL SOLAR DISPATCH - DECEMBER 100 MW UNIT, 6 MW-HOURS OF STORAGE PER MW, 171 MW COLLECTOR

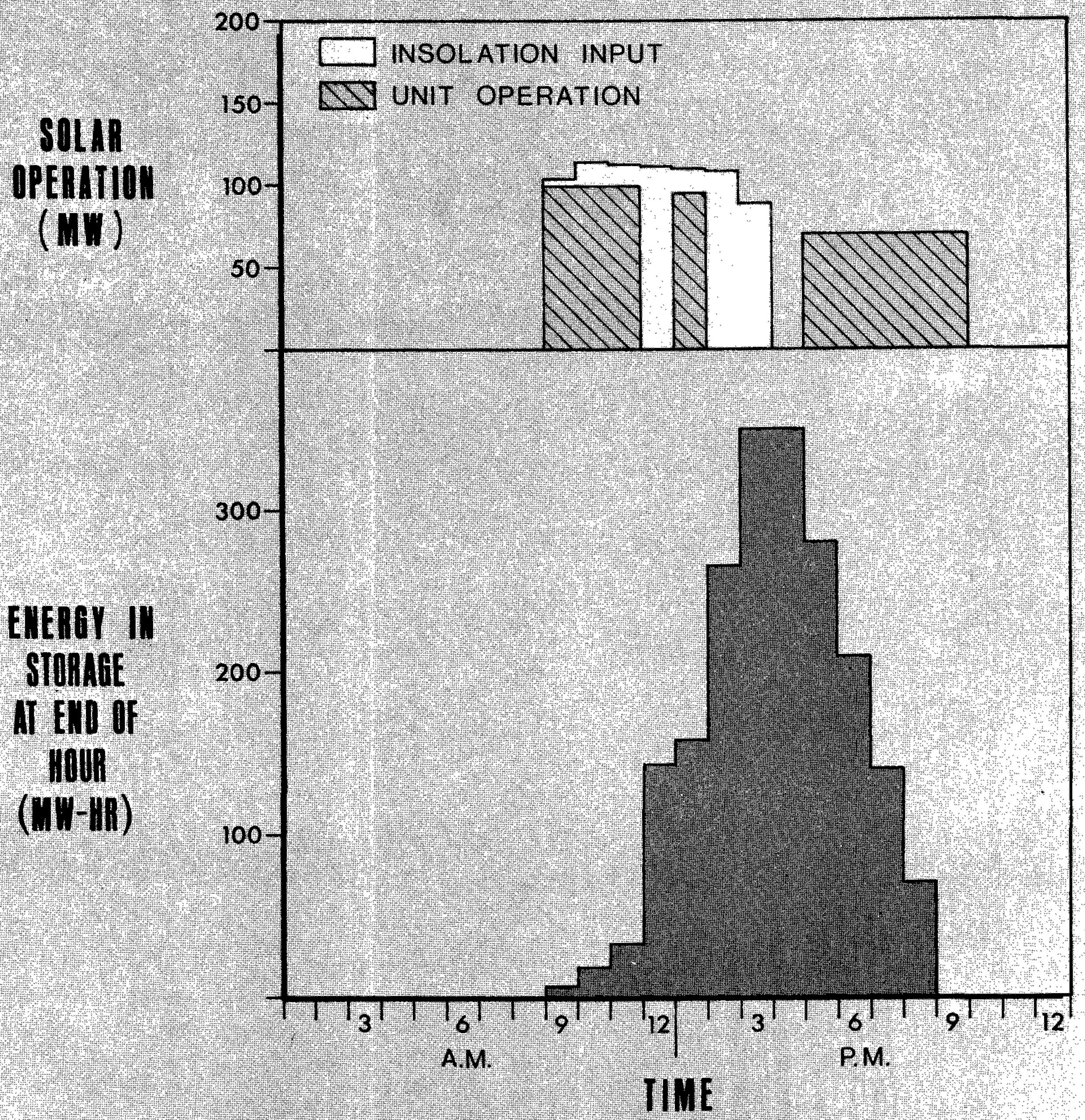
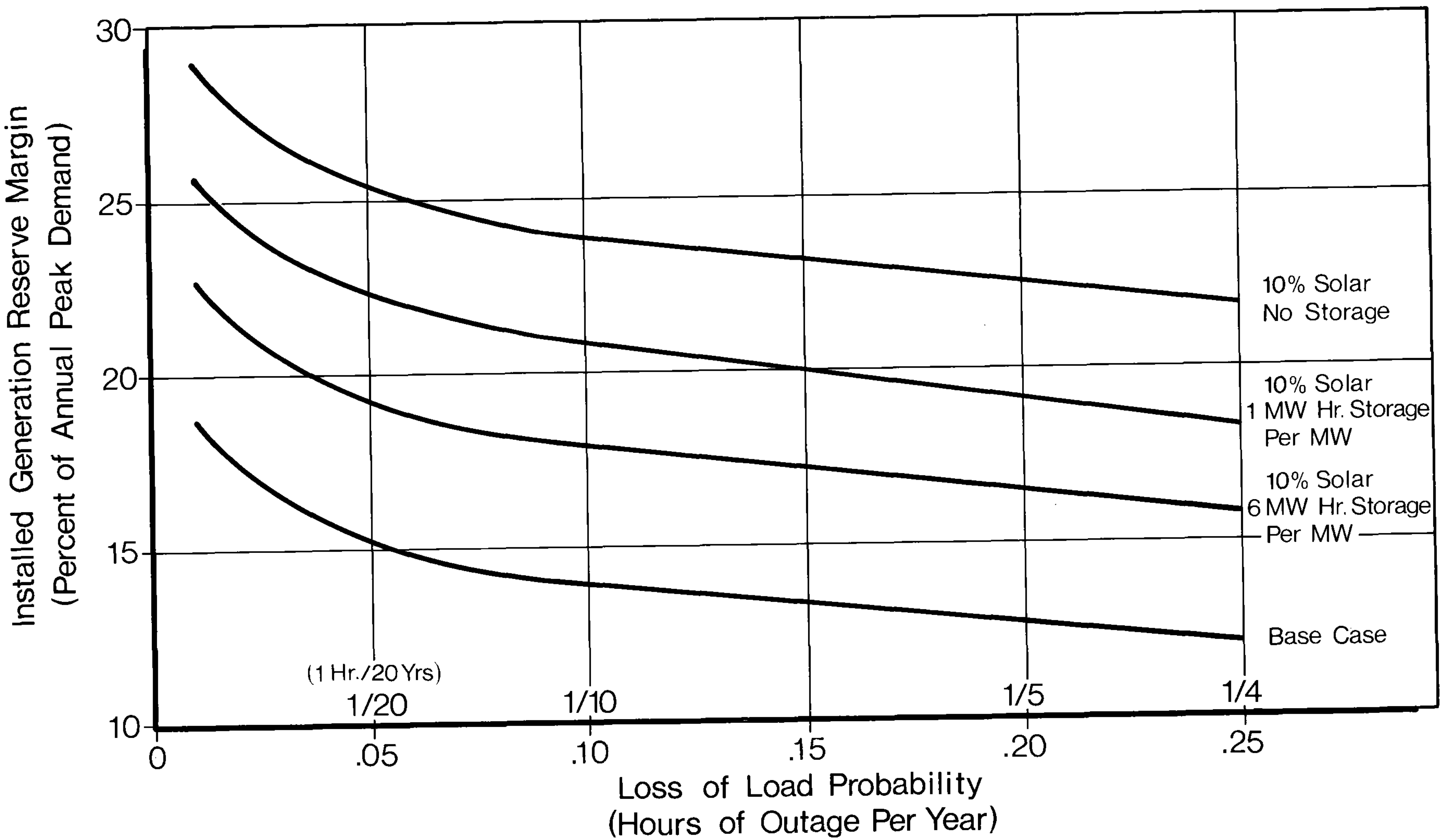


Figure II-15

REQUIRED RESERVE MARGIN VS LOSS OF LOAD PROBABILITY CRITERION



Section III
Economic Evaluation

III. ECONOMIC EVALUATION

INTRODUCTION

For study purposes, solar generation costs were treated as a system variable; that is, competitive costs for solar generation systems (plant, transmission, storage, O&M, land and water) were derived based on the results of economic comparisons between resource plans containing solar capacity and a "non-solar" resource plan. It may be helpful to the reader to consult Appendix A for a detailed discussion of the methodology employed by Southern California Edison in the economic evaluation of alternative resource plans.

Although "order of magnititude" cost estimates for solar generation systems are addressed in Section V of this report, such costs were not appropriate for use in this study for economic evaluation purposes for the following reasons:

1. The various penetrations of capacity studied were established independent of solar generation costs.
2. Basing economic studies on any specific cost estimate would severely limit the insight gained from study results.
3. Cost estimates for solar generation systems are, at present, highly speculative.

ASSUMPTIONS AND MODELS

As indicated in Sections I and II, resource plans were developed for a number of cases involving different solar percentages and levels of storage. These resource plans were then compared with a non solar resource plan serving the same load with the same reliability. In the solar resource plans, the total amount of

Assumptions And Models Cont'd.

installed capacity, and the relative mix of each of the various non-solar, i.e. conventional, resource types were adjusted so that each plan would meet the SCE system probabilistic reliability criterion, while serving the same load pattern, at the lowest possible total cost. Total cost is defined as the total present worth of the capital-related, fuel and operating costs over a 30 year period. Each of the resulting plans represented the ideal mix of non-solar resources to achieve the lowest total cost (not including solar costs) at the specified level of solar penetration and storage. The value of the solar generating portion of each plan was determined by subtracting the total present worth cost of each of the resource plans which included solar, from the total cost of a non-solar base plan.

Non-Solar Resource Plan:

To establish a basis for economic comparison, a generation resource plan containing no solar generation was developed based on the following assumptions:

1. Capacity requirements:
   a. 1986 forecast of SCE peak demand of 17,880 MW.
   b. Loss of load probability (LOLP) of one hour (total) of outage in a 20 year period. (see Section II for discussion.)
2. SCE load pattern.
3. 1,388 MW of hydro capacity installed prior to 1986.
4. Generation resource mix consisting of:
   a. Base load - nuclear
   b. Intermediate load - combined cycle

Non-Solar Resource Plan Cont'd.

c. Peaking - combustion turbine.

5. All alternative generating units constructed in 1986.

6. Optimal resource mix - defined to be that mix of conventional (non-solar) generating resources which results in the lowest present worth of capital and operating costs.

In order to develop the optimized non-solar resource plan, several optimization studies were performed. The initial non-solar plan was developed by evaluating and plotting the levelized annual total of capital costs, fuel costs and O&M costs of each resource alternative versus annual hours of operation. These levelized annual costs were based on a 30-year economic plant life using the cost estimates shown in Table III-1. The intersections of the least cost curves for all hours of operation were identified and relocated on the 1986 SCE system load duration curve, as shown in Figure III-1, to roughly determine proper amounts of each resource type. As a result of this preliminary optimization analysis, a resource mix consisting of approximately 56% nuclear capacity, 26% combustion turbine capacity and 12% combined cycle capacity was modeled in SCE's Production Costing computer program, along with the 1,388 MW of hydro capacity which was assumed to be installed prior to 1986, to determine total system fuel costs. By contrast, the present SCE resource mix is heavily reliant on oil and therefore has a higher percentage of intermediate type generation. It consists of approximately 17% baseload (i.e., coal, nuclear, and baseload hydro), 53% intermediate (i.e., primarily conventional oil and gas), and 30% peaking (i.e., purchases, hydroelectric, conventional oil and gas, and combustion turbine). The resulting fuel costs were then escalated each year of the 30-year study

Non-Resource Plan Cont'd.

period and then expressed in 1986 base dollars by present worth analysis. The sum of the 1986 present worth of the annual fuel costs and the 1986 present worth of the capital and O&M costs of the resources modeled became the reference for subsequent optimization of the non-solar plan. Through an iterative process of analyzing production-costing output data, adjusting the resource mix and recalculating fixed and variable system costs, a near optimum non-solar resource plan was identified. This resource plan contained the following proportion of resource types:

Nuclear	63%	
Combustion turbine	25%	26
Combined cycle	6%	17
Hydro	6%	

It should be noted that although the results of the economic analysis of the resource alternatives, illustrated in Figure III-1, indicate relative economic desirability, the extent to which any specific resource plan can be implemented depends on the planning constraints applicable to each utility. In the present study, such planning constraints as project lead times, financing and budgeting considerations, environmental considerations and fuel diversification were ignored.

Basis for Comparisons Involving Solar

For each assumed penetration of solar capacity, a resource plan was developed based on the same assumptions that were used to develop the nonsolar plan. The difference between the installed capacity required to meet the LOLP index of one hour of outage in 20 years (discussed in Section II) and the assumed amount of solar capacity, was provided by a combination of non-solar generation resources.

Basis For Comparisons Involving Solar Cont'd.

In each solar resource plan, the non-solar resources were optimized to achieve the lowest present worth cost by the same method used to develop the nonsolar plan. The total cost of the solar plans was then compared to the cost of the non-solar plan to determine what the cost of the solar generation facilities must be in order to be economically attractive.

For study purposes, all resource plans studied were developed for one arbitrary year, 1986, and evaluated over the 30-year period 1986-2015. The use of this method of evaluation is based on the following rationale: In all resource plans, the non-solar generating units were adjusted to achieve a near optimum resource mix in 1986. The escalation rates for power plant construction costs and fuel costs were assumed to be the same for each alternative generation resource. Therefore, if in all years after 1986, an optimum mix of resources is installed to serve the annual load growth, evaluating any one year in the study period results in the same value of solar capacity per unit as evaluating any other year of the study period. In the production costing simulation, the non-solar units are assumed to be loaded in accordance with a designated system dispatch philosophy. Although SCE's present generating unit load dispatch procedure is based on environmental considerations, for study purposes a dispatch procedure designed to minimize system fuel costs (economic dispatch) was used to allocate load on non-solar generating units. In order to maintain consistency between reliability and economic evaluations, the day-to-day operation of solar generating units was input to the Production Costing Program from the results of system reliability studies. The dispatch of the solar units is discussed in detail in Section II.

Results Presentation

A summary of the results of the economic comparisons between solar and non-solar resource plans is shown on Table III-2. The summary table contains the following information for each resource plan evaluated:

Column Number	Information
1	Solar penetration expressed as a percentage of total installed capacity*
2	Amount of installed solar capacity
3	Storage capability associated with the solar unit expressed in MWH of storage per MW of installed capacity
4	Total installed system capacity
5,6 and 7	1986 present worth of capital and operating costs
8	1986 present worth difference between the total cost of the non-solar resource plan and that of the solar plans
9	Value of solar facilities expressed as an equivalent investment in 1986 dollars. The dollar per kilowatt amount shown includes plant, storage, land, water and the 1986 value of lifetime operating and maintenance costs.
10	Value of solar facilities from column I expressed in 1976 dollars

* Exact values of lifetime solar percentages based on columns 2 and 3 differ slightly from the rounded off numbers in column 1 due to the use of discrete unit sizes.

Error Estimate

The values of the solar energy systems shown in Column 9 were calculated by first taking the difference between the 1986 total present worth cost of the non-solar resource plan and each solar

Error Estimate Cont'd.

plan, then dividing the resulting difference by the amount of installed solar capacity. The resulting quotient was then divided by a factor representing the present worth of the annual carrying charges to determine an equivalent investment value expressed in 1986 dollars. Because the method of calculation involved the subtraction of very large dollar amounts relative to the resultant values, a certain degree of error can be assumed to exist in the values. For example, a one percent error in the cost of the non-solar base case would result in up to a 40% change in the equivalent value of solar generation.

Sensitivity to Non-Solar Resource Mix

The study results represent the economic value of solar generation integrated into a hypothetical optimized system. Solar units have economic value in part because they contribute to the system's load carrying capability. In addition, because solar energy has no direct energy production cost, solar facilities derive value from their ability to replace energy which would otherwise be produced from nuclear and oil fired units, which have direct energy costs. Since nuclear plant operating costs are low, the benefits achieved by displacing their operation with solar would also be low. Results based on the assumption of solar operation in an optimum system relying heavily on nuclear units for energy production would, therefore, be different from results based on resource mixes of existing electric systems. In order to determine the impact on the value of solar capacity in a less than optimum system, the 10% solar penetration, 6 MWh/MW of storage resource plan, and the non-solar plan were reevaluated. In the reevaluation, combined

Sensitivity to Non-Solar Resource Mix Cont'd.

cycle generating units were the only non-solar units. The results of the reevaluation are also shown in Table III-2. They indicate that in a system fueled totally by oil, the value of solar capacity would be roughly 7% higher than in an optimized system containing a large proportion of nuclear generation. This may be viewed as a practical upper limit of the value of solar, under the assumptions of this study.

Sensitivity to Financial Assumptions

The study results represent the economic value of solar generation, based on financial assumptions substantially equivalent to those that would be used by Southern California Edison to evaluate alternative generation expansion plans for the 1986-2016 time period. As such, the assumptions are self-consistent and are considered to be realistic.

Since there is considerable uncertainty regarding economic parameters such as future fuel costs and rates of fuel cost escalation, inflation rates, etc., a cursory evaluation of the sensitivity of study results to varying financial assumptions was conducted. Table III-3 compares Edison's estimates of economic value with results obtained using two sets of assumptions provided by ERDA. The comparison is based on the production costing simulation results for the case involving 10% solar generation and storage equal to 6 MWh/MW and all non-solar generation involving combined cycle units. This case represents an extreme case of an undesirable resource mix, but produces the most optimistic economic value for solar generation, based on the extreme sensitivity to the cost of oil.

Computed economic values for both sets of ERDA assumptions

Sensitivity to Financial Assumptions Cont'd.

using the all combined cycle case were higher than the baseline Edison results. Use of ERDA's assumptions produced 1986 dollar breakeven costs in the range \$2220/kW - \$2840/kW, as compared to the \$1470/kW estimate based on Edison assumptions. In current dollars, the range is \$1370/kw - \$1740/kw, as compared to \$680/kw based on Edison assumptions. The differences between Edison and ERDA based numbers are due to ERDA's higher fuel and O&M costs and escalation rate assumptions.

As indicated in the table, the ERDA assumptions on capital cost, capital escalation rate, and cost of money are low relative to Edison's. The combination of high fuel costs and low cost of money and capital escalation rate assumed by ERDA would render an all combined cycle generating mix even less attractive than it appeared based on Edison's assumptions. Heavy reliance on oil fired generation would not be economically feasible. A different mix of conventional resources would be used, and calculations based on the more economical mix would result in lower solar breakeven costs than those presented in Table III-3 for the ERDA assumptions. Calculations based on the all combined cycle case and the ERDA assumptions are introduced only to provide a gross indication of the sensitivity of solar breakeven costs to the financial assumptions that can be made.

Accordingly, caution should be exercised in drawing inferences from the results presented in Table III-3. The sensitivity illustrated in Table III-3 is considered extreme. Solar breakeven costs computed based on the procedure employed in the study would be far less sensitive to financial assumptions, since economic optimization of the resource mix would tend to compensate for the effect of extreme variations of one financial parameter or another.

Discussion

The study results shown in Column 9 of the table are plotted in Figure III-2 and, as expected, indicate that:

1. As solar penetration for a specific storage capability increases, each additional increment of solar capacity will have less value than each of the preceding increments.

2. As the amount of storage capability for a specific solar penetration increases, the value of the solar facility will also increase.

While these observations are certainly important, they are by no means surprising, as they reflect the effects of penetration and storage on solar load carrying capability as discussed in the reliability portion of the study, Section II. Likewise, the second result reflects the effect on economic value resulting from increased energy production by a unit having a larger collector, sized for storage. The curves of Figure III-2 represent threshold costs, below which solar units would be economically attractive to the utility. The 1986 base dollars plotted in Figure III-2 are greater than equivalent 1976 base breakeven costs by a factor of about 2.16, based on an assumed 8% annual escalation rate.

For example, 1986 dollar breakeven costs range between $533/kW and $1470/kW, corresponding to a range of $240/kW to $681/kW when expressed in 1976 dollars. Notice that the effect of penetration and storage capability is substantial. Based on the discussions of error band and sensitivity to non-solar mix, it is possible that solar costs could be somewhat above these levels and still be acceptable. Likewise, there is the possibility of unforeseen con-

Discussion Cont'd.

straints such as conventional fuel or land availability acting to enhance or detract from the economic value of solar. It is not possible to infer optimal storage amounts or optimal relative collector sizes directly from the curves of Figure III-2 or the quantitative results on which they were based. To do so requires considerable insight regarding feasible subsystem costs. In effect, the results plotted represent the "benefit" half of the input information needed to evaluate benefits relative to associated costs in the solar plant design optimization process.

In summary, the economic evaluation results have significance to the on-going ERDA development effort in that:

1. They provide realistic cost targets for the overall solar generating system.
2. They provide a basis for cost trade-off studies to identify the most cost effective configuration and relative sizing of subsystems.

The potential use of the study results for these purposes is discussed further in Section VII, which also includes a discussion of suggestions for further study and a discussion of the model dependences of the present study.

TABLE III-1

FINANCIAL ASSUMPTIONS

	Nuclear	Combined Cycle	Combustion Turbine
Capital cost* (1986) - $/kW	1,570	702	401
Cost of money - % economic	11.7	11.7	11.7
Economic life - years	30	30	30
Fixed charge rate %	18.5	18.5	18.5
1986 O&M cost - $/kW	7.0	8.0	2.5
1986 fuel cost - $/$10^6$ BTU	0.59	3.42	3.42
1986 - 2015 annual escalation rates:			
O&M	4.67	4.67	4.67
Fuel	5.00	5.00	5.00
Unit full load heat rate - BTU/kWh	10,200	8,387	11,900
Capacity factor - %	75	60	4

RESULTING DELIVERED POWER COSTS
(Levelized Annual Cost - $/kW-Yr)

	Nuclear	Combined Cycle	Combustion Turbine
Capital	290.00	129.90	74.20
O&M	10.90	12.50	3.90
Fuel	63.90	243.60	23.00
Total	365.30	386.00	101.10

*Includes the cost for transmission, related facilities, overheads and nuclear unit first core costs.

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TABLE III-2

SUMMARY OF ECONOMIC COMPARISONS

1	2	3	4	5	6	7	8	9	10
				1986 Present Worth Costs-Billions of Dollars			Value Of Solar Capacity		
Solar Penetration (%)	(MW)	Storage (MWh/MW)	Total Installed Capacity (MW)	Capital & O&M	Fuel	Total	1986 Differential Present Worth (Nonsolar Minus Solar) Billions Of Dollars	Equivalent 1986 Investment $/kW	Equivalent 1976 Investment $/kW
0	BASE		20638	36.92	10.82	47.74	BASE		
5	1100	0	21338	34.55	11.93	46.48	1.26	753	349
5	1100	1	20938	34.36	11.55	45.91	1.83	1093	506
5	1100	2	20838	34.23	11.60	45.83	1.91	1141	528
5	1100	6	20738	34.17	11.13	45.30	2.44	1457	675
10	2200	0	22538	34.62	10.92	45.54	2.20	657	304
10	2200	1	21938	34.23	10.18	44.41	3.33	995	401
10	2200	2	21638	34.04	10.18	44.22	3.52	1051	487
10	2200	6	21338	32.93	10.23	43.16	4.58	1370	634
20	5000	0	25238	30.91	12.78	43.69	4.05	533	247
20	4800	1	24238	30.27	11.66	41.93	5.81	795	368
20	4600	2	23438	29.75	12.11	41.86	5.88	840	389
20	4400	6	22788	29.69	10.44	40.13	7.61	1136	526
All Combined Cycle Base System									
0	BASE		20138	22.02	34.69	56.71	BASE		
10	2000	6	20638	20.25	31.98	52.23	4.48	1470	681

TABLE III - 3

SENSITIVITY TO FINANCIAL ASSUMPTIONS
(All Combined Cycle Base System)

	SCE Assumptions	ERDA Assumptions Low	ERDA Assumptions High
Capital Cost (1986) $/kW	702	376	496
Capital Escalation Rate (%/year 1976-1986)	8%	5%	5%
Cost of Money - % Economic	11.7%	10.2%	10.2%
Economic Life - Years	30	30	30
Fixed Charge Rate - %	18.5	15	15
1986 O&M Cost - $/kW*	8	20.7	36.0
1986 Fuel Cost - $\$/10^6$ BTU	3.42	4.23	5.21
1986-2015 Annual Escalation rates:			
O&M - %	4.67	5.0	5.0
Fuel - %	5.00	7.3	7.3
Unit Full Load Heat Rate BTU/kWh	8,387	8,387	8,387
Capacity Factor - %	60	60	60

RESULTING DELIVERED POWER COSTS
(Levelized Annual Cost - $/kW - Yr)

	SCE Assumptions	ERDA Assumptions Low	ERDA Assumptions High
Capital	129.90	56.40	74.4
O&M	12.50	34.45	59.92
Fuel	243.60	401.30	493.91
Total	386.00	492.15	628.23
Mills/kWh	73.4	93.6	119.5
EQUIVALENT CAPITAL VALUE of Solar** (1986)-$/kW	1470	2220	2840
(1976)-$/kW	681	1370	1740

* SCE O&M relate to capacity, ERDA O&M relate to production (energy)
** For 10% penetration, 6 MWhr of storage per MW rated electrical capability, in all combined cycle system. Value includes capital cost of facilities and transmission, and capital equivalent of lifetime operating and maintenance expenses. Capacity value of solar - 76% of combined cycle unit. Capacity factor of solar - 40%.

Figure III-1

GENERATION MIX ANALYSIS

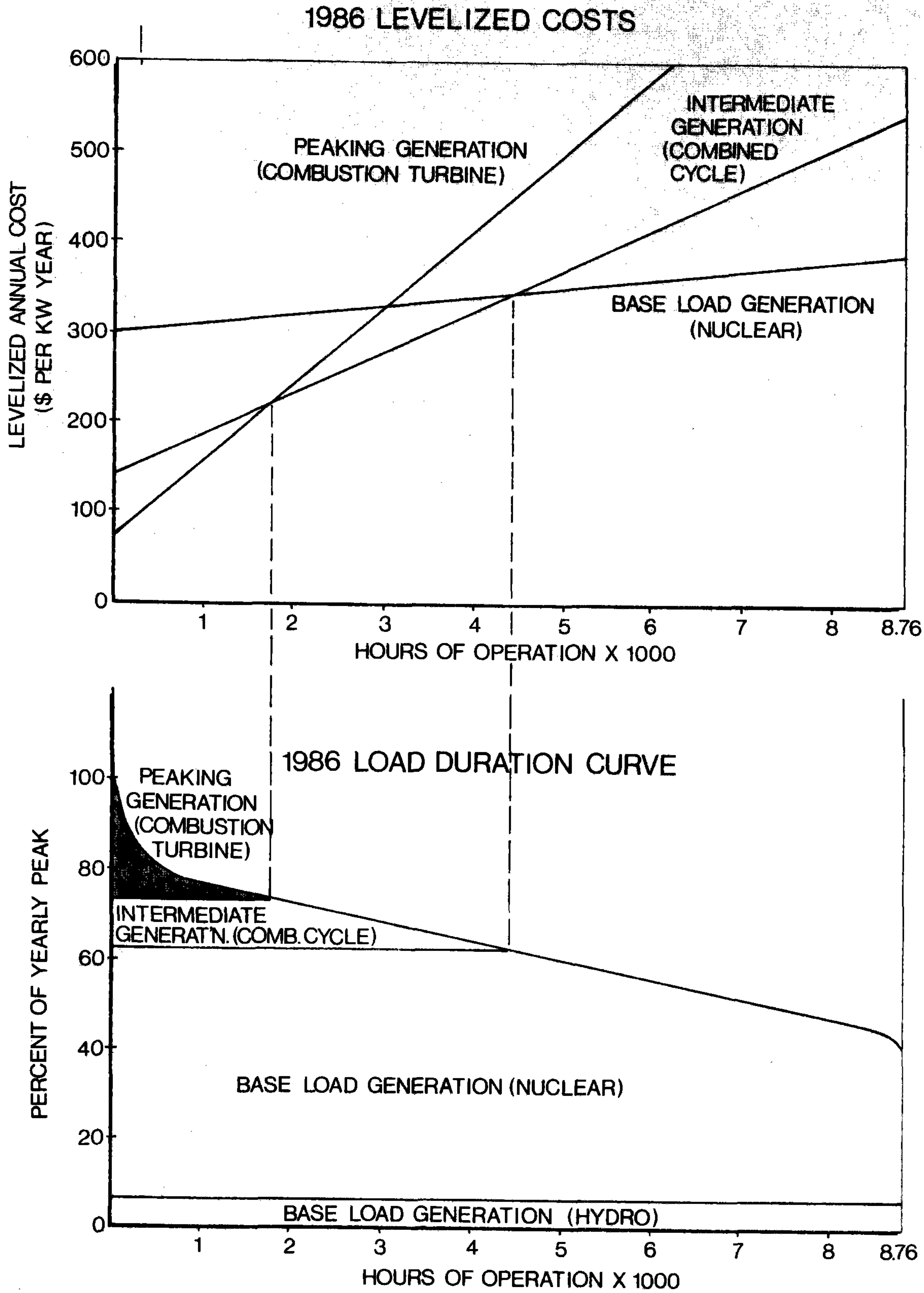
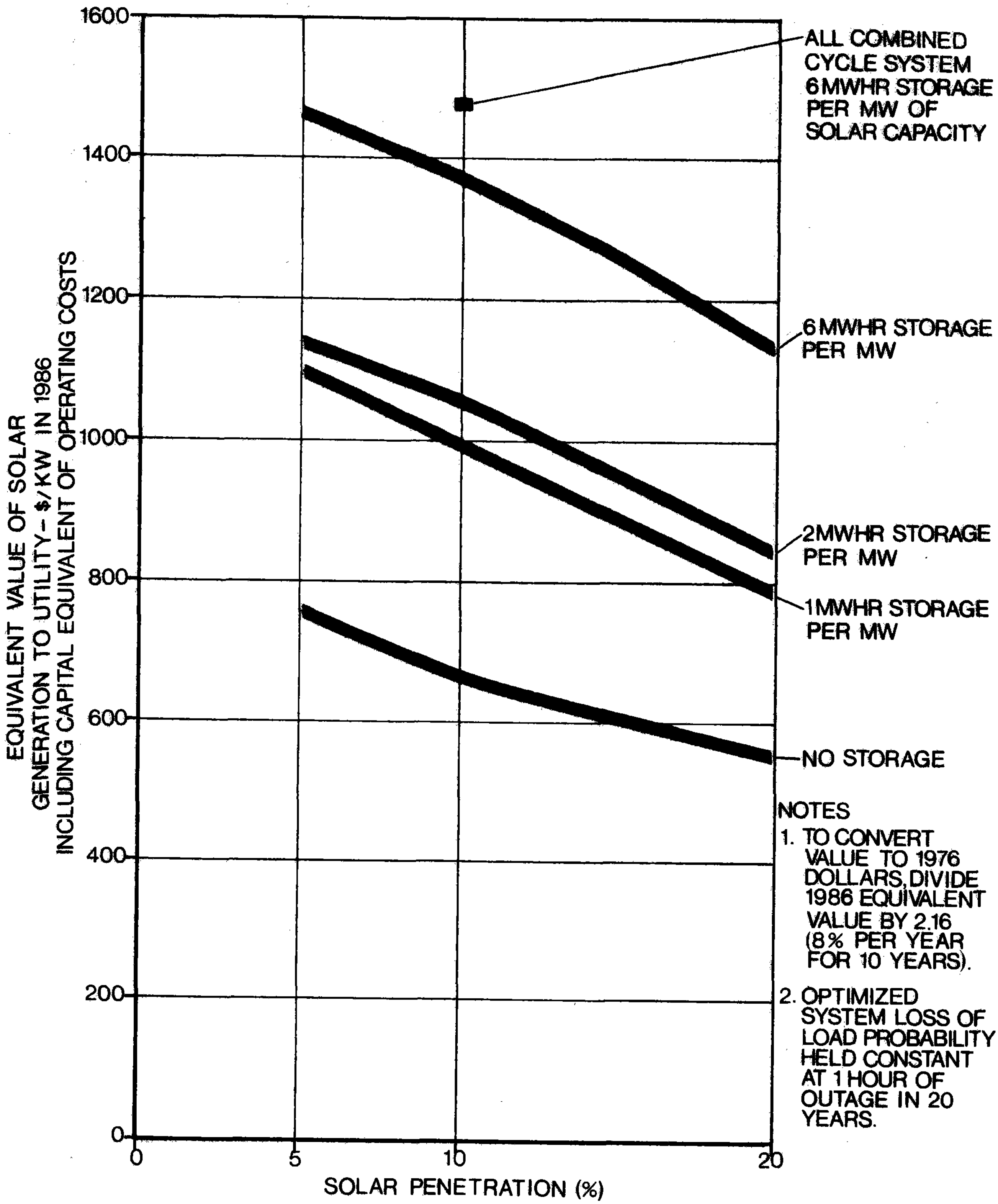


Figure III - 2

SOLAR BREAKEVEN COSTS

(EQUIVALENT VALUE OF SOLAR GENERATION TO UTILITY)



NOTES

1. TO CONVERT VALUE TO 1976 DOLLARS, DIVIDE 1986 EQUIVALENT VALUE BY 2.16 (8% PER YEAR FOR 10 YEARS).
2. OPTIMIZED SYSTEM LOSS OF LOAD PROBABILITY HELD CONSTANT AT 1 HOUR OF OUTAGE IN 20 YEARS.

Section IV
System Operation Considerations

IV. SYSTEM OPERATION CONSIDERATIONS

General

The preceding sections of this report have used production costing simulation and probability of loss of load techniques as a means to establish the load carrying capability and economic value of solar generation. Such modeling should be considered in the context of system operation/real time considerations to understand the limitations of the models used. A number of simplifying assumptions and compromises were necessary in the modeling and are worthy of discussion.

Dispatch Strategy

In the electric system models, the solar units were used to generate electricity and charge thermal storage simultaneously during available daylight hours and to accomplish peak shaving using storage during other hours. An alternate strategy making less effective use of solar unit capabilities would involve continued operation into the evening hours until storage was depleted. Both strategies are feasible in practice, from a system operation point of view. Because peak shaving using the stored energy results in the greatest practical benefit to the system, in the reliability and economic evaluations that dispatch strategy was used. The peak shaving dispatch strategy is not without its pitfalls, however. The strategy requires accurate foresight to avoid premature exhaustion of the stored energy and to maximize the capacity benefits available from the solar units. Although this dispatch strategy can be successfully implemented using any combination of units, the problem of premature exhaustion is accentuated when some of the solar units have less storage capability than the others.

Weekend Substrategy

Weekend and holiday operation of solar generation may be influenced by the fluctuations in production cost and pollutant emissions during these low-load periods. The variation in incremental cost or emissions is related to the mix of installed generation and the system load characteristics. If an individual electric system has a very high level of low fuel cost base load generation, this will result in a big swing during weekend/holiday daylight hours from peaking type incremental costs (i.e. 25-30 mills per kilowatt hour) to base type incremental costs (i.e. 2-7 mills per kilowatt hour). In this case, consideration should be given to providing large storage subsystem capacities which could store the solar energy received during the weekend/holiday periods for use during subsequent weekday periods. For most utilities such an incremental swing is not presently the case, and weekend/holiday operation would be similar to weekday operation. Also, it is likely that such large amounts of storage would be prohibitively costly. Because the effective fuel cost of solar generation is zero, it will probably never be economical to shut down solar generation in favor of energy produced by conventional plants.

Economic Versus Emissions Dispatch

The use of incremental dispatching, whether cost or emissions are minimized, is not in conflict with the peak shaving use of solar storage. Storage should displace conventional generation involving the highest cost or highest emission. Similar peak shaving logic has long been applied to hydroelectric generation, generally by establishing an artificial cost value which results in

Economic Versus Emissions Dispatch Cont'd.

full utilization of available energy. Relatively new techniques of air quality monitoring and supplemental dispatching for load shifting between plants, to avoid local emissions buildup, might affect the dispatch of energy from solar storage. This area will require in-depth individual system study.

Spinning Reserve Implications

Unloaded solar capacity, i.e. spinning reserve, becomes a crucial problem as the level of installed solar generation increases. It is generally undesirable to concentrate spinning reserve in a few units or in a number of non automatic generation control (AGC) units. In California the major investor owned utilities have established a spinning reserve performance standard, which require that hydroelectric units must be loadable for at least two hours in order for the hydro unit to be considered as an operating capacity resource. Hydro units with less than 2 hours of energy production capability may be used to meet energy requirements, but are not considered as firm operating capacity; therefore, additional capacity resources must be brought on line to maintain adequate levels of spinning reserve. This standard provides for emergency replacement/restoration on loss of a major conventional thermal unit, followed by resumption of previously scheduled hydro production. All regional reliability counsels have established similar performance standards. It is logical to extend these standards to solar generation to ensure similar performance. These standards in themselves may be adequate to alleviate the problems discussed in the next section.

Solar Generation During Cloudy Periods

In addition to a spinning reserve requirement, all utility systems must vary or regulate system generation to match constantly varying customer load. This is generally accomplished using a totally automated automatic generation control (AGC) scheme. Unfortunately, solar generation would have to respond to instantaneous insolation changes as well as to AGC control. This problem is similar to that existing today on combustion turbine units, where last-stage turbine metal temperature must be held below specified limits. In this case, the units respond to ambient temperature and AGC. More complex AGC algorithms are under development to prevent AGC objectives from being cancelled by the temperature response. Such algorithms could be extended to insolation response. Cloudy weather reduces sunfall and hence reduces the output of solar units in an uncontrolled way. This effect can be minimized by diversity in solar siting and by buffering solar output with supplemental energy from solar storage. Buffering could also be provided by additional companion operation of fast response combustion turbine units. Such combined operation would be expensive, however. In any event, a minimum regulating margin on conventional thermal units or hydroelectric units must be carried, in the event the solar input collapses.

Daily Capacity Planning

During the startup process, it is necessary to expend substantial amounts of energy to heat the steam turbine to operating temperatures prior to the production of any electrical energy. Because of this startup energy requirement, it may not be practical to attempt to start a solar unit on a cloudy day, since the energy

Daily Capacity Planning Cont'd.

required to start the unit may exceed the energy which could be collected during that day. In that case, the solar plant would store all the energy it could collect, but not produce any electrical energy.

From an operating standpoint, it may be desirable to retain one to two hours of energy in the storage subsystem when the solar unit is shut down in order to have energy available to heat the turbine prior to the first sunlight hour.

In the case of solar "income" energy generation, a finite probability exists that no generation will be available on a particular day. Run-of-the-river hydroelectric generation is more easily forecast than solar generation, yet it is similar to what we have termed "run-of-the-sun". As weather forecasting accuracy is most reliable in the 24 hour period immediately preceding real time, little planning use can be made of long range forecasts, except in locating desirable multi-day maintenance periods. On many utility systems, planning for adequate capacity for the next day is carried out each afternoon. The planning process recognizes variations in startup time from 16 or more hours for complex supercritical reheat conventional units to typically 5 to 15 minutes for combustion turbines. Long startups, if needed, must be initiated first to preserve a subsequent ability to execute shorter startups in response to short term dislocations. With solar generation in the mix, it may be necessary to increase unit commitments (i.e. the amount of capacity planned for the next day) of long startup time conventional units to allow for unforseen outages of solar units due to cloud cover. The next day, if revised forecasts were

Daily Capacity Planning Cont'd.

favorable, it would then be possible to cancel some of the excess unit commitments. Conversely, if weather were adverse, some or all of the solar capacity could be replaced by short startup time units. It is expected that solar units would, except in emergency situations, always be scheduled to produce the maximum possible energy output, since that energy has essentially zero incremental cost. As solar penetration in the resource mix increases, and as the proportion of large scale conventional capacity decreases, this planning process will become very critical. Better long range weather forecasting may be needed to facilitate maintenance planning and unit commitment.

Automatic Generation Control

The best method of controlled loading of solar units will be dependent on the penetration of solar generation expected in a given utility system, as well as on the inherent AGC problem of the system. Generally, the first units on a system could be manually block loaded in either a flat or load shaped pattern. Eventually, it would be necessary to introduce fully automated control for adequate system load regulation and spinning reserve pickup capability. With the introduction of AGC, the part load performance of solar generation becomes critical. Good heat rate performance for an extended range of partial loads is essential where units are controlled automatically without regard to incremental cost. The potential of buffering solar generation with delivery of energy to storage is desirable in connection with implementing AGC. Delivery to storage, while less efficient than straight generation, is preferable to total rejection of the solar input. Adaptive AGC

Automatic Generation Control Cont'd.

controls for solar may be needed to anticipate collapses of solar input during cloudy periods and rapid turnarounds thereafter. Telemetering of sunfall data may be required to dependably execute these algorithms.

Optimization of Daily Operation

In a manner similar to the procedures used by utilities to optimize combined hydroelectric and thermal generation, computer programs to optimize combined solar and thermal generation may be necessary to assist operating personnel in reliably and economically using solar generation. These programs, which could eventually be used for fully automated system control, could use telemetered sunfall information as well as historical data to best plan the "desired" level of solar "capacity" for each hour. Hydroelectric and solar resources typically have a daily energy production limit and a variable output level. For utilities having high installed levels of base generation, these programs could also properly supplement the larger storage capability of pumped storage projects with short term on-site thermal storage if desired. An additional task for the program would be proper selection of the daily storage charging period. The required algorithm is similar to the pump back period selection for pumped storage hydroelectric projects. As indicated, considerable sophistication in system operation is implicitly required for any high degree of solar penetration in the resource mix.

Planned Maintenance Strategy

In the modeling effort that was discussed in the previous sections, planned maintenance of solar units was bunched into a period

Planned Maintenance Strategy Cont'd.

of weeks of very low potential output and high system capacity margin above load. Most utilities cannot accomplish such optimal maintenance patterns due to manpower and/or logistical problems. Generally, maintenance of individual units sequentially throughout the year, or at least during all except peak months, is planned. Some utilities use a travelling maintenance crew or crews to accomplish necessary work. Other utilities borrow from neighboring plants or hire temporary personnel for maintenance at specific stations. Simultaneous maintenance of numerous solar units may be economical, but it would represent a departure from present utility practice.

Outage/Forced Maintenance Strategy

Due to the critical daylight operation requirement, all deferrable outages (random failures for which shutdown may be deferred) must be pushed to non-critical hours. Adequate lighting of on-site tooling and gantry facilities must be available for night repairs. If not deferrable, partial forced outages would be desirable in preference to total outages, in that some operational capability from storage could be maintained. For this reason, multiple auxiliary equipment will be desirable in later plants as solar penetration increases.

Conclusions

Central station type solar generation in limited amounts can easily be assimilated by all except total hydroelectric utility systems. Solar would aggravate problems in total hydroelectric systems because adding such a severely "energy limited" resource to an already somewhat "energy limited" system would further reduce

Conclusions Cont'd.

operational flexibility.

As increased solar penetration is projected, the type and degree of companion fossil and nuclear thermal capacity must be carefully determined. This capacity will be necessary to firm the variability of the solar input. At high installed levels of solar generation, considerably increased sophistication in system operation will be essential in order to fully benefit from solar generation. In most cases, system operation tools and algorithms for solar integration are available based on present practices, and will require only minor revisions.

Section V
Solar Unit Costs

V SOLAR UNIT COSTS

Results presented in this section are for purposes of illustration only, and are intended to show an "order of magnitude" relationship between the calculated value of solar power plants developed in Section III, and the estimated cost of such plants. There are two categories of estimated cost that are of interest:

1. The cost of "commercial" solar power plants at some future time when the technology is "mature" and costs have been reduced to a minimum based on prototype experience and mass production.
2. The cost of a "first-of-a-kind" solar power plant that could be built today based on the present state of the art.

This section deals with the latter "first-of-a-kind" costs. Costs for "commercial" solar plants are much harder to estimate at this time, and beyond the scope of this effort, although such estimates have been produced by others.

Estimates of expected, "first-of-a-kind" costs are typically much higher than projections of ultimately achievable costs. Thus, as might be expected, the "estimated cost" discussed below is several times the "allowable costs" developed in Section III. This does not mean that solar thermal power plants cannot become economically feasible. It does, however, mean that a solar power plant, if built today without benefit of further technological development, would not be economically feasible. It also means that considerable effort will be needed to identify low cost design and construction techniques for components and systems having the greatest effect on overall cost.

Solar Unit Costs Cont'd.

Substantiation of the estimate provided here is found in recent cost estimates for small central receiver pilot plants. Because of scale differences, these costs range considerably higher on a $/kw basis than the estimate provided here for a larger scale unit.

As indicated in previous sections, the utility generation planning process normally makes use of construction cost estimates for generation projects included in a given resource plan. These estimates are usually based on specific designs at specific sites. The solar development is not at the point where such cost estimates for solar units could be relied upon as input for the present study. Nevertheless, because the design definition and cost engineering efforts associated with project cost estimates are integral parts of the planning process, available designs were reviewed from a design and cost stand-point to round out the utility point of view. The results of the cost estimate are presented in this section, while the results of the design review are summarized in Section VI.

A representative 100 MW central receiver solar plant preliminary design provided the necessary detail upon which a cost estimate for the receiver, heliostat field, and thermal storage could be established. The steam turbine cycle design which was used for cost estimating purposes is shown schematically in Figure V-1. A combined cycle generating station using this design is currently under construction on the Southern California Edison electric system.

The cost estimate produced a number close to $4000/kW for the total solar project investment in current dollars. Expressed in 1986 base dollars, true cost would exceed $8000/kW, or between five and ten times the allowable costs developed in Section III.

Solar Unit Cost Cont'd.

As indicated, this cost estimate for the solar part of the plant (i.e. solar heat source plus thermal energy storage) was based on a preliminary design concept, and it is based on present technology and field practices that would be used if the plant had to be built immediately.

The solar unit design on which the cost estimate was based is not identical to any solar unit configurations evaluated in Sections II and III. It involves about 4 MWh/MW of storage and a collector sized appropriately but not according to the sizing criterion suggested in Section II. Nevertheless, for "order of magnitude" comparison purposes, the design can be considered typical of the solar units evaluated in Sections II and III. Given that the estimate was done based on preliminary design concepts and conventional construction practice, the discrepancy between cost and value is indicative of the fact that all of the design and construction techniques needed to make the central receiver concept viable have not yet been identified. The cost estimate is summarized in Table V-1. More detailed lists of the estimated costs for the generating station and its thermal storage subsystem are presented in Tables V-2 and V-3. A discussion of the cost items which were included in the estimate is provided below as a reference for others involved in solar construction cost estimating and as a guide to the interpretation of the tables.

Direct Costs

The direct costs include the material, equipment and associated labor costs of construction. Direct costs are assumed to have a 30% labor and 70% material composition for the purpose of applying the

Direct Costs Cont'd.

indirect charges. The predominant direct cost is that of the heliostat assemblies, which accounts for two-thirds of the total construction cost. The heliostats are assumed to be mass-produced; however, they remain a high field cost item due to the labor required to place and align the foundation pedestal, mount the heliostat assembly, and align the reflecting surface. Testing would also be required for each heliostat. The costs included for site preparation are based on flat terrain. This cost could increase if the site required major earth work.

Other costs attributable to the solar collection part of the generating station include field heliostat controllers, heliostat cabling, central receiver, tower structure, and the master control computers. The field heliostat controllers are minicomputers which give 25 heliostats precise directional commands. These controllers are hard-wired through the heliostat cabling network to the master control computer. The central receiver includes the boiler-type configuration on the top of the tower structure.

A dry cooling tower was assumed in order to illustrate the significant capital cost of this option. An emergency diesel generator was included to supply power to move the heliostat reflecting surfaces out of line with the central receiver during an emergency shutdown. This is necessary to prevent damage due to overheating of the receiver.

Indirect Costs

The indirect costs are based on percentages currently realized by Southern California Edison Company in field construction. The engineering and construction management costs could be higher during

Indirect Costs Cont'd.

the period when solar is an unfamiliar technology, and because of the complex construction planning needed to insure proper scheduling of the 30,000 heliostats and the lengthy start-up and testing that would be required. The non-productive time and productivity loss could also increase due to the large area covered by the construction site and the desert locales being considered.

The construction overheads include the expenses incurred by SCE during a construction effort. The allowance during construction is specified by the Public Utilities Commission in lieu of a rate of return on capital invested. Miscellaneous construction expense is the cost of administrative services by various organizations within the company that cannot be readily identified against specific projects. In addition, many other general expenses of the company must be treated as overhead costs for the same reason. Ad valorem taxes on capital additions while under construction are also included as a capital expense.

SCE carries its own insurance on construction projects. The premiums incurred on capital additions while under construction are charged to the project as a construction overhead costs. Included in this cost are worker's compensation, general liability, excess liability, and builder risk.

Thermal Storage Costs

The thermal storage cost was estimated as a fixed base cost plus a variable cost which increases linearly with the storage rating. Included in the base cost is the energy transfer equipment and the fluid maintenance unit. The thermal charging unit is the heat exchanger transferring the energy from the central receiver

Thermal Storage Costs Cont'd.

steam to the reservoir fluid. The steam generator assembly transfers the reservoir fluid to the steam turbine inlet. Physical integrity of the storage fluid is maintained by the fluid conditioning unit.

The variable costs include the tanks, storage fluid, and other material and equipment having costs that are dependent on capacity of the energy storage system.

TABLE V-1

100 MW CENTRAL RECEIVER COST SUMMARY

	1976 ($M)	1986 ($M)
Direct Costs		
Heliostats	214	462
Receiver/Tower	15	32
Balance of Plant	13	28
Site Preparation	10	22
Thermal Storage (420 MWh)	12	26
	264	570
Indirect Costs	64	140
Construction Overheads	62	130
Total	390	840

TABLE V-2
100 MW Solar Thermal Conversion
Electric Generating Station Conceptual Cost Estimate
1976 Base Dollars

Direct Costs	($x1,000)
Field heliostat controllers	6,500
Heliostats	200,000
Heliostat cabling	7,400
Central receiver	7,800
Tower structure	6,800
Master control computers	3,000
Electric plant	12,000
Dry cooling tower	6,000
Switchyard	300
Emergency diesel generator (7.9 MW)	2,800
Structures and buildings	2,500
Site preparation	9,600
Total Direct Cost	264,700
Assume a 30% labor/70% material mix:	
Total Labor	79,700
Total Material	185,000
Indirect Costs	
Engineering	10,000
Non-productive time & productivity loss (15% labor)	11,900
Sales tax (6% material)	11,100
Small tools and consumables (8% material)	14,800
Subsistance	6,800
Temporary construction facilities and rentals	2,900
Field staff and office (2.5% total direct)	6,600
Total Indirect Costs	64,100
TOTAL CONSTRUCTION COST	328,800
Construction Overheads	
Allowance during construction	50,000
Miscellaneous construction expense	3,300
Ad valorem tax	5,900
Insurance	3,300
Total Construction Overheads	62,500
TOTAL PROJECT COST	391.300
STANDARD ESTIMATE ROUND-OFF	390,000

TABLE V-3

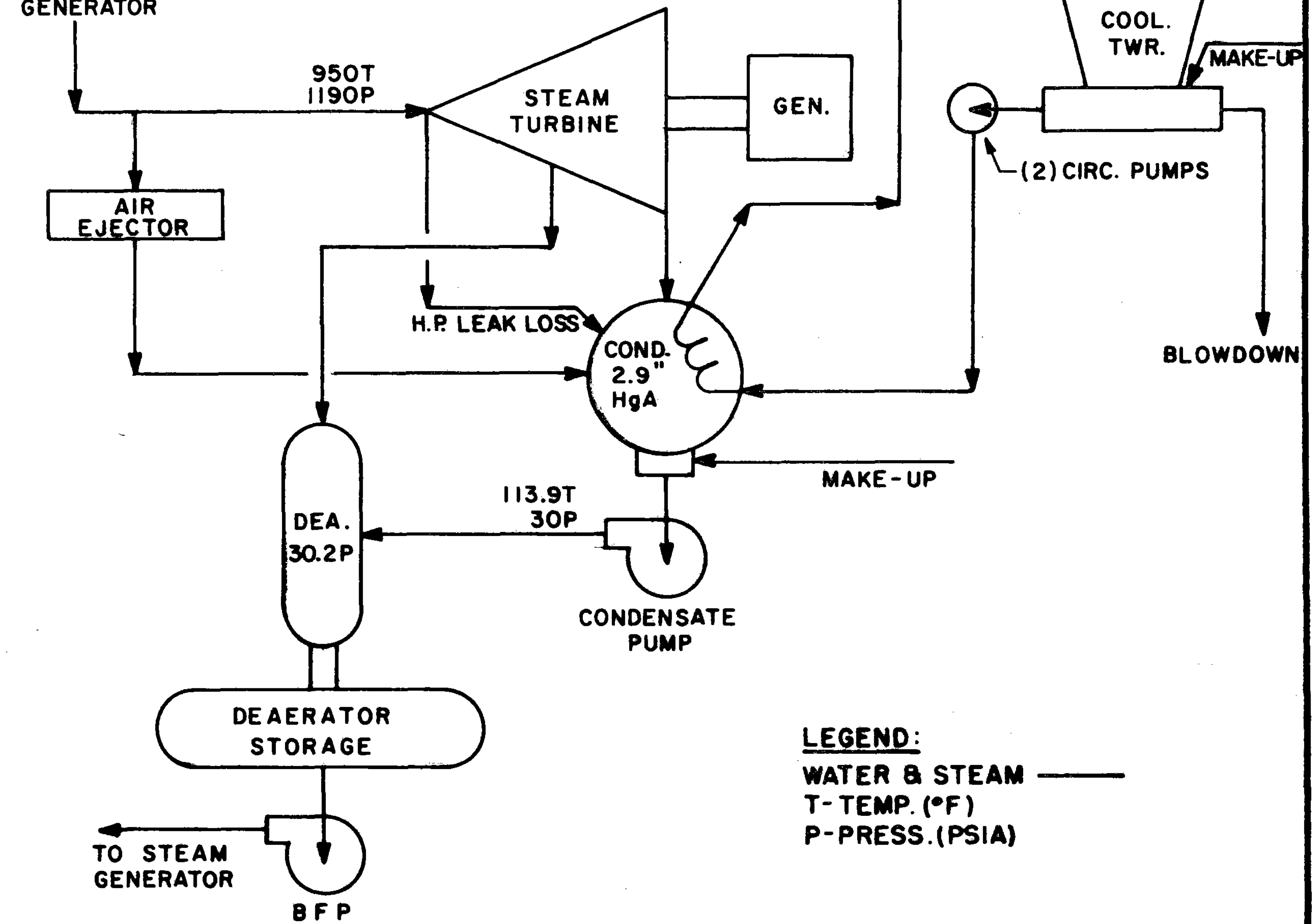
100 MW Solar Unit Thermal Energy Storage
Subsystem Cost Estimate 1976 Base Dollars

Fixed Cost*	($x1,000)
Thermal Charging Unit	1,200
Steam Generator Assembly	1,700
Fluid Circulation and Control	1,200
Instrumentation	200
Fluid Conditioning	200
TOTAL FIXED COST	4,500
Variable Cost*	
(Thermal Storage Unit - Cost per clock hour of storage = $1.3M)	
TOTAL VARIABLE COST	11,200
(For 6 MWh/MW (8.6 clock hour) of storage)	
Total Fixed Plus Variable Cost*	15,700

* Costs include indirects. Construction overheads are assumed to be covered in the total project cost.

FIGURE V-1

COMBINED CYCLE STEAM SIDE SCHEMATIC



Section VI
Plant Design
Considerations

VI PLANT DESIGN CONSIDERATIONS

General

A wide array of options is available for development by the U.S. solar energy program. If these can all be carried through the prototype development stages it will facilitate utility selection of optimum solar plants for commercial application in the future. The solar heat source can be of either the central receiver or distributed receiver type, either of which, depending on the specific geometry of mirrors and heat receivers, can supply solar heat over a large range of temperatures. Storage of thermal energy can be accomplished using a variety of storage media having a range of temperature capabilities, as well as the ability to store heat by means of a temperature change, phase change, or even chemical decomposition. Conventional steam cycles, as well as advanced thermodynamic cycles involving a variety of fluid media can be used for conversion of solar heat to shaft work, depending on the temperature capabilities of the heat source and of the storage media.

Thermal energy storage can be integrated into the power generation system either as a buffer between the heat source and the turbine, or in a configuration that allows charging or discharging of storbge in parallel with power generation directly from the heat receiver(s). In the latter case, there is a choice between using a single turbine for conversion of receiver and storage heat or a separate turbine for each source.

Finally, there are a variety of ways in which a solar heat source and a fossil heat source can be integrated, and these are related to the purpose of the hybridization. For example, the fossil heat source can be used in lieu of storage to allow extended operation

General Cont'd.

beyond daylight hours, to maintain steam conditions during intermittent sunfall conditions, and to provide a plant warmup and overnight temperature maintenance capability. Fossil supplementation can also reduce the temperature requirements on the solar heat source, e.g. by using a fossil fired superheater. Use of solar to provide heat at various points in a conventional fossil fired power plant has also been proposed, but the benefits are limited because the hours of solar availability are limited, and there are significant practical problems as well.

The possible combinations of the various design options mentioned above are quite numerous, and a number of trade-offs must be made in selecting the most promising design concept. In some cases, design choices will have a direct effect on the value of the solar power plant to the electric system, as in the case of the choice between a standby fossil heat source and thermal storage. (This particular comparison is discussed in Section VII.) In all cases, however, the options need to be examined relative to certain fundamental considerations.

First, the primary benefit of solar power technology for electric utilities will be to reduce their reliance on oil as a primary energy source for power generation. Thus, in terms of long term development objectives, concepts which allow solar to displace the greatest amount of oil are to be preferred. Thermal energy storage is seen to be desirable from this point of view, in that it expands the potential for displacement of oil using solar derived energy. Solar/fossil hybrid concepts are less desirable relative to this objective.

Second, it is customary and necessary in the utility industry

General Cont'd.

to design generating plants so that they can remain in service indefinitely (with the exception of routine maintenance and overhaul). Typically, the design philosophy is relatively conservative, because of the extreme economic penalties associated with equipment failures. The industry's insistence upon proven technology for major generation additions is not likely to be set aside, given the magnitude of the investment decisions related to the capital intensive nature of solar generation. Concepts which involve a large number of developmental subsystems and components can be expected to require much longer to achieve commercial maturity than those which do not.

Third, simplicity is a paramount virtue in power plant equipment and control system design, because of the higher staffing and maintenance costs and poorer reliability associated with complex and sophisticated designs. Like hydroelectric stations, solar power plants need not be identical in their operational characteristics to conventional types of thermal generation, and system complexity that would be required for the sole purpose of increasing their similarity would best be avoided. However, the standards of fluid and control system simplicity achieved in conventional thermal plants should serve as a guide in the definition of solar power plant systems.

The following discussion of specific design features expands upon some of the above general points.

Turbine Plant

In considering the basic design of a central receiver type solar generating plant, it appears that a viable design could be achieved using conventional, available equipment in all areas except three. These are: 1) Radiation concentration components, Turbine Plant Cont'd.

including controls. 2) Solar heat receivers. 3) Thermal energy storage.

Any solar design effort should be based on maximized use of conventional equipment. However, since the solar side of the plant will be developmental, the balance of the first generation solar plants should be designed in a manner that will enhance the necessary development work. This means a simple, straightforward conventional portion of the plant. Complex feedwater cycles with split flows and dual steam sources, reheat or other complications in the conventional portion of the plant will have their own problems unrelated to the areas under development. The resolutuion of problems resulting from interactions between systems in a complex plant could seriously inhibit the success of the solar portion of the plant, and difficulties in this area could reflect adversly on the overall concept.

Cooling System

It is recognized that a simple straightforward plant will not have the highest obtainable efficiency, but the overriding objective of the first solar plants should be to demonstrate the concept and develop the necessary hardware. Subsequent plants can attempt high efficiency.

This philosophy leads away from a dry cooling system. Dry cooling is not attractive in th solar development program, because it is a development program unto itself. Not only is the cooling system developmental, but dry cooling also results in high turbine exhaust steam conditions which reduce efficiency during hot summer peak periods and may tend to reduce turbine reliability and lifetime.

Pilot Plant

A large utility is interested primarily in the performance of commercial scale (i.e. upwards of 100 MW) plants. Therefore, the design approach for pilot scale (around 10 MW) plants should be oriented toward proving out concepts for the 100 MW plant. In principle, a commercial scale plant should be designed and optimized first. Then a pilot plant should be developed as a scaled down version of the 100 MW plant, rather than an optimized 10 MW plant. The need for a 10 MW size plant is accepted as a necessary stepping stone to the commercial size plant, but it should be designed as such and not as an end unto itself.

Turbine Considerations

Turbine operation is limited, in terms of rapid load changes, by restrictions placed on each machine by its manufacturer. These restrictions apply to the allowable difference between the steam temperature and the turbine metal temperature. The rate of change of the metal temperature is also limited.

The impact of intermittent clouds resulting in a rapid decrease in main steam temperature must, therefore, be considered. It is apparent that the main steam supply may have to be interrupted or diverted under this situation.

The ability to return to the main steam source will be dependent upon the ability to control steam temperature. The turbine could, for example, be too cold to accept rated steam temperature. Consideration of a wide range of steam temperature control in terms of bypassing, desuperheating, or mirror positioning will be necessary for load carrying continuity.

Turbine Considerations Cont'd.

The option of turbine operation with two different steam conditions also requires special consideration. The most viable approach appears to be the use of an admission type machine. This type of turbine can accept steam either at the normal high pressure admission point, or at a point between lower pressure stages. This is analogous to an extraction point, only in reverse, and with control valves.

Design allowance must be made for cooling the high pressure stages when operating on the lower pressure admission point (storage steam). This does not appear to be a major hurdle, however, as turbines of this design have been manufactured in the size range necessary for a 10 MW pilot plant.

The admission turbine, therefore, is a practical approach for the pilot plant. However, it appears that none have been built in the 100 MW size range. This is an area that would require some development work, but would not require any new basic technology. It should be pointed out that, although the basic technology is available, and turbine manufacturers are not reluctant to build admission turbines of this size, the cost of the first machines would be very high, and they would require debugging.

Auxiliary Boiler

The present approach to most peaking plants is to maintain the plant in an overnight mode that allows quick start-up in the morning. This necessitates, as a minimum, maintaining turbine steam seals and some deaerator pressure. The necessary steam to do this is provided by an auxiliary boiler.

Auxiliary Boiler Cont'd.

The solar plant in its final form may use its thermal storage to do the same thing. During the development of the ultimate plant, due consideration should be given to using an auxiliary boiler for this purpose, plus as a potential substitute for a thermal storage subsystem to maintain steam continuity during intermittent clouds, as well as to provide emergency power for heliostat operation.

Once Through Boiler Operation

The solar collectors in some designs under development are, in their basic form, once-through boilers. The control and operation of this type boiler, including any flash drums, is today somewhat con ventional. In keeping with the approach of maximizing the use of conventional equipment, the control and operation of the solar heat receivers should also be kept as conventional as possible. There does not appear to be any reason to do otherwise; doing so on the feedwater-steam side of the boiler will restrict the development problem to the solar side.

Overall Unit Control

Another conventional concept that is applied to plants using once through boilers is that of an overall boiler-turbine unit control system. The interactions between plant systems is complex and necessitates some characterized and coordinated "feed forward" loops in ordur to avoid temperature and flow instability during load changes. Solar thermal power plants having once-through boilers will lend themselves to control by an overall control system rather than by independent subloops. However, computerized overall plant control has drawbacks from a utility point of view.

Overall Unit Control Cont'd.

Southern California Edison's experience and operating philosophy leads to a primary reliance upon skilled and experienced operators for proper plant operation and problem diagnosis.

Section VII
Application and Extension of Results

VII APPLICATION AND EXTENSION OF RESULTS

INTRODUCTION

The applications of the results of this study and future work along these lines can best be discussed in the context of the iterative design optimization process into which such efforts fit. As applied to solar thermal conversion concepts, the process involves design definition, performance assessment, economic evaluation, cost estimation , design optimization, and then starts over again with a new definition of the design. Prior to the start of this study, the basic features of solar thermal conversion electric generation systems had been defined as part of the ERDA Solar Thermal Conversion Phase I Program. In the reliability analysis (Section II), performance of these systems as a part of an electric utility system was analyzed. Based on this analysis, their dollar value was determined by the economic evaluation, (Section III). The cost estimate and design review (Sections V and VI) pointed out critical concerns for future cost and design optimization. The next step will be to use the information presented here to identify the combination and configuration of subsystems that will have the highest ratio of economic value to total cost. The new reference designs that result can be reanalyzed and evaluated in future integration studies. For the most part, design optimization studies require detailed evaluations of subsystem costs that are beyond the scope of this study. However, it is possible, based on the results at hand, to illustrate the application and suggest possibilities for extension of this study in the design optimization process. The following topics will be addressed.

Introduction Cont'd.

1. Suggested applications of the quantitative study results and related findings.
2. Implications of the present study for subsystem sizing.
3. Limitations of the present study and suggestions for future work to improve models and input information and to investigate alternate assumptions.

APPLICATION OF STUDY RESULTS

Three areas of design optimization can be addressed to varying degrees using this study's output.

1. Subsystem selection.
2. Subsystem sizing.
3. System configuration selection.

For example, using the results, the value to the electric system of introducing a fossil heat source into the solar unit design can be determined and compared to the cost of doing so to see when and under what conditions such an approach is worthwhile. This has been done and will be discussed in the following paragraphs.

Economic Value of Solar Hybrid

One major solar/fossil hybrid concept under active study by others involves the use of parallel solar and fossil heat sources that can be used alternately to power a generating unit. Because such a solar hybrid design has the potential for providing the desirable combination of low cost solar-produced energy and around-the-clock availability, it was desirable to attempt to estimate its value to the utility system. Although no detailed studies of a hybrid design were performed, it was possible to estimate the

Economic Value of Solar Hybrid Cont'd.

performance of the hybrid based on the pure-solar studies outlined in Sections II and III. A hybrid unit, consisting of a non-storage pure solar unit with an auxiliary fossil fuel heat source, was evaluated.

Because the hybrid design allows operation at rated capability at any hour of the day, it was assumed that the hybrid design would have approximately the same load carrying capability as a conventional generating unit. This assumption is approximately valid at high levels of hybrid operation (30-40% capacity factor). However, 40% + 23% = 63% = solar with 13 h. storage as the level of operation of the fossil portion of the hybrid is reduced to zero, the value of the hybrid must approach that of a pure solar unit with no storage. The pure solar unit may operate at up to 23% capacity factor under the assumptions of this study.

The potential equivalent capital value of a 10% penetration of solar/fossil hybrid generation (including capital costs and the capital equivalent of O&M and fuel costs) is presented in Figure VII-1, together with the equivalent value of the same level of pure solar generation. The economic value is plotted as a function of the level of energy production from the units, expressed in terms of annual capacity factor, and as equivalent full power hours (MWh/MW) of "pure solar" storage.

By deducting the equivalent capital value of the fossil fuel required to achieve an increased level of hybrid operation, the potential value of the capital related portion of the hybrid design may be developed. Assuming that the hybrid fossil energy costs are the same as the costs of energy produced by a conventional combustion turbine (about 66 mills/Kwh levelized), the capital portion of the
1976 (?)

Economic Value of Solar Hybrid Cont'd.

the hybrid maybe plotted, as illustrated in the lower curve on Figure VII-1. It is seen that the value of the solar hybrid (after deducting fuel cost) decreases, as the level of operation increases and that the pure solar unit nearly always has a higher value to the system. Note that if the heat rate of the fossil portion is reduced from that of a combustion turbine, the fossil energy cost is reduced, thus raising the potential value of the capital related portion of the hybrid design. It should also be noted that both methods of increasing the capacity factor (i.e. hybridization and storage) add to the cost of the solar generating unit. If the hybrid design is to be economically competitive, the cost of hybridization must be less than the cost of adding storage and collector capability to a pure solar unit design.

Subsystem Allowable Costs

To illustrate the use of study results in trade-off studies, Table VII-1 presents the results of simple calculations to explore the economics of thermal energy storage and solar collectors for various collector and storage cost assumptions. The Table was based on data from the 5% solar penetration cases of Section III. The first set of calculations (lines 1-4 of the table) established the allowable storage subsystem cost, assuming; (1) that the 1986 dollar conversion subsystem cost is $350/kW; (2) that the solar unit with no storage had breakeven economics; and (3) that the collector subsystem cost would scale linearly with its size. The allowable storage subsystem cost per unit of storage capacity under these assumptions (and implicitly under the assumptions used in the calculation of the total plant allowable costs,) is seen in columns 7 & 8 to be greatest

Subsystem Allowable Costs Cont'd.

by far for the first increment of storage capability. Both average and incremental allowable costs are presented, the latter being more indicative of the point at which the benefit/cost ratio for the last increment of added subsystem capacity falls below 1.

The second set of calculations (lines 5-8) established the allowable collector subsystem cost, for solar units with varying storage capabilities under the assumption that storage subsystem costs can be ignored. Under this assumption, the value to the electric system afforded by the storage capability and associated additional collector significantly increases the average allowable collector cost (column 9). Note that in this calculation the value of each additional increment of collector (column 10) is greater than the average value of the total amount of collector needed in the case with no storage. For example, the $\$130/M^2$ incremental value of the additional collector associated with going from a storage capability of 2MWh/MW to 6MWh/MW is more than double the $\$61/M^2$ average value of the collector for the no storage case. Thus, for this assumed case, it is seen that additional collector area is easily justified if the cost of storaging the energy it produces is negligible.

The third set of calculations (lines 9-12) is similar to the second with the exception that non-zero storage subsystem costs consistent with the estimates of Section V are assumed. Again, however, the net impact of providing the solar unit with extended operation capability is to increase allowable collector subsystem costs as seen again from columns 9 and 10, thus enhancing the prospects of economic feasibility for the assumed configuration. Note that, depending on storage subsystem costs, only the first increment of additional collector corresponding to 1 MWh/MW of storage may be justifiable based on the incremental allowable collector costs in column 10.

While these calculations do not unequivocally establish the preference for solar unit designs that include storage, it does appear that the benefit/cost ratio for the first increment of storage plus extra collector will be greater than one, unless storage costs are higher than indicated by the estimate in Section V. Additional increments would be less likely to show favorable economics in the 5% penetration scenario. While it is obviously premature to propose an "optimum" storage capability for future commercial solar units, there does seem to be justification to pursue the development of compatible short term thermal storage technology in connection with the development of solar heat source technology.

SUGGESTIONS FOR FURTHER STUDY

Based on the limitations of the present study, the following paragraphs will suggest directions for further work both to extend the present analysis and to provide a better basis for future analyses.

The calculated economic value of solar generation is sensitive to assumptions in the following areas:

1. Solar radiation input to the individual solar unit.
2. The provisions for transforming the radiation input into electricity, i.e. the collector type and the configuration of subsystems.
3. The electric system in which the solar unit operates.
4. The manner in which the solar units are operated, i.e. the dispatch strategy.

Suggestions for Further Study Cont'd.

5. The economic and fuel availability constraints affecting the planning and operation of the electric system.

The present study used a limited set of assumptions in these areas. The sensitivity to these assumptions must be understood, if maximum insight is to be gained.

Solar Radiation Input

For the present study, it was assumed that only 5 solar power plant sites would be developed, thus effectively limiting the maximum capacity which would be constructed at a single site. This assumption limited the amount of solar generating capacity which could be lost due to a single cloud formation simultaneously obscuring multiple solar generating units. Because the likelihood of losing a large amount of generating capability due to a single contigency, such as a cloud cover, is much greater than the likelihood of losing the same amount of generating capability due to simultaneous random outages of a number of unrelated generating units, the potential effects of cloud cover obscuring multiple solar generating sites should be evaluated. Varying assumptions on the amounts of solar generation which could be simultaneously shielded by a single cloud formation would affect solar unit load carrying capability and should be evaluated. It is not unreasonable to expect that environmental considerations would tend to favor development of a limited number of independent solar generation sites, and the penalties in terms of reduced load carrying capability should be clearly identified before the total number of sites are determined.

Solar Unit Characteristics

The assumed 70% rate of energy removal from storage limits the

Solar Unit Characteristics Cont'd.

potential load carrying capability of solar units, especially at high levels of solar penetration. The effect of varying this rate of energy removal from storage, should be investigated. Efficiency reductions and energy losses associated with energy removal from storage should also be considered. Other energy storage methods such as batteries, and pumped hydroelectric storage should also be considered in future optimization studies.

For the study, the size of the collector field was tied to the amount of storage capability and the level of peak daily sunfall. However, there may be significant economic advantages to selecting a collector field size which differs from the "optimum" size used for these studies. Therefore, additional studies in this area should consider:

a) collector fields designed to produce peak output in the afternoon, rather than at noon, as in this study;

b) collector fields larger (or smaller) than the "optimum" used for these studies; and

c) increased collector field and storage unit sizes to extend unit operation during the non-summer months.

In addition to variations in relative rating and efficiency of the various subsystems, alternative configurations of the various subsystems should be considered. Collector subsystem configurations and concepts such as distributed concentrator/absorber systems which produce heat source output profiles markedly different from those assumed should be evaluated. In designs that omit storage, the effect of these differences could be significant. Likewise, consideration should be given to designs in which storage is integrated as a buffer

Solar Unit Characteristics Cont'd.

between the collector and turbine rather than being in a parallel path between these two subsystems.

Electric System

The sensitivity of the results to electric system load pattern should be explored. As an extreme example, solar power plants would not be worth as much when integrated into a system having a winter-time evening annual peak as they would be when integrated into the present SCE system.

Dispatch

The ability of solar units to operate so as to implement the optimal dispatch strategies assumed should be evaluated. Likewise, the cost penalties associated with providing the required cycling capability should be evaluated. The impact of differences between ideal operation and operation within the constraints of cost optimum design should be studied.

In addition, it should be noted that the "optimum" dispatch strategy used did not account for loss of energy production capability associated with storage operation. Adjustments to the dispatch strategy to account for this should be considered.

Ideally, for future integration studies, it would be desirable to have a solar unit model that accounts for realistic equipment and system design characteristics in using solar radiation profiles and desired solar unit output profiles to simulate the actual operation and technical performance of solar thermal power plants.

Scenario

Solar units were evaluated in the context of conventional fuel cost and availability assumptions that are reasonable for the study

Scenario Cont'd.

base year, 1986. However, the cost and availability of fuel, oil in particular, may be altered significantly in the decades beyond 1986. The range of possible fuel scenarios beyond the year 2000 is probably most appropriate for purposes of solar integration studies.

In addition to the above, there are a variety of institutional issues beyond the scope of the present study that deserve serious consideration, including financing, land use, and environmental considerations. There is a need to anticipate the problems and questions that may arise in these areas.

TABLE VII-1 ANALYSIS OF SUBSYSTEM ALLOWABLE COSTS

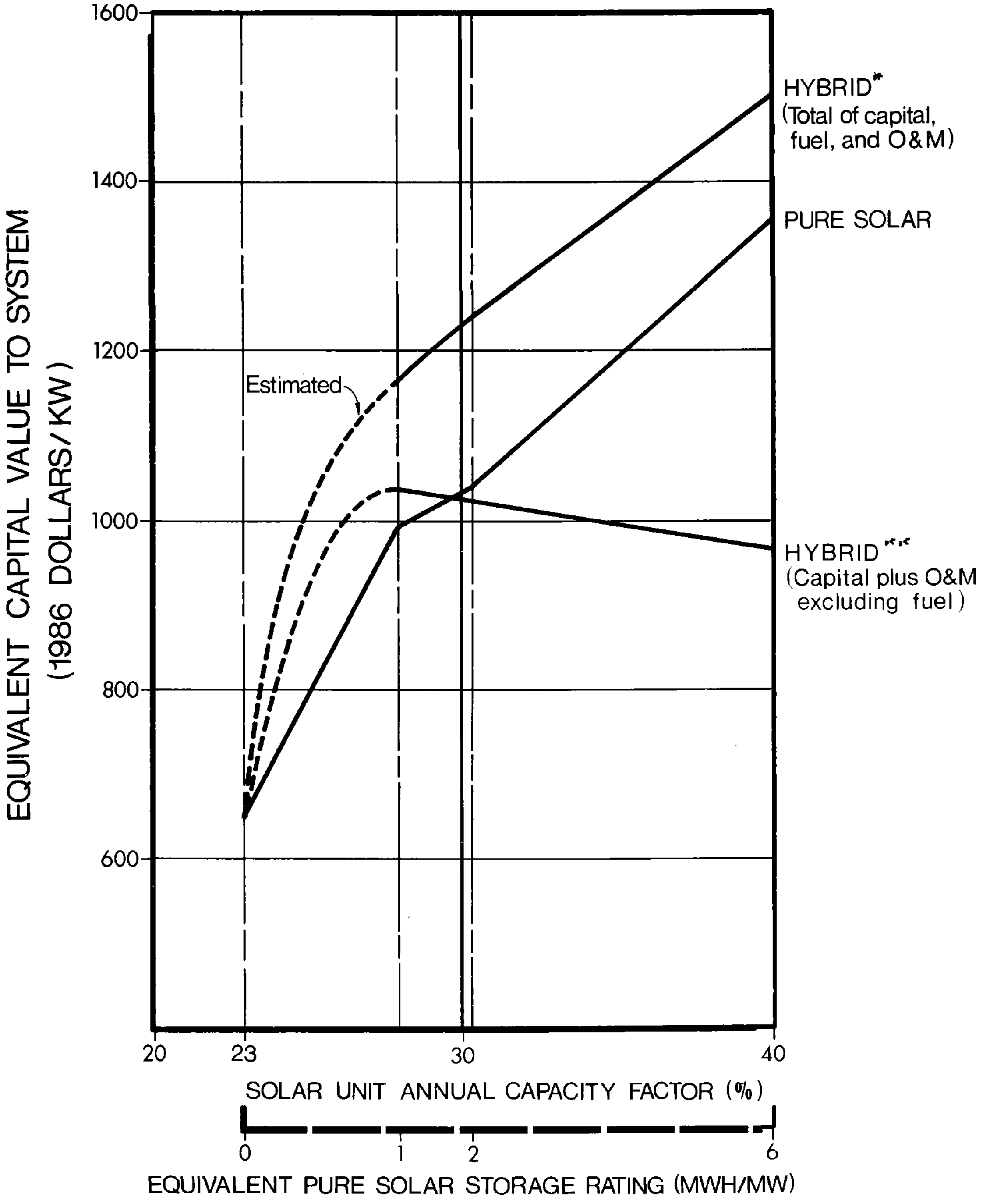
	1	2	3	4	5	6	7	8	9	10
					Assumed Costs		Allowable Costs			
							Storage ($/kWh)		Collector $/M^2	
	Storage Rating MWh/MW	Relative Collector Size	Total Plant Allowable Cost $/kW	Collector $/kW	Storage $/kW	Conversion $/kW	Average	Incremental	Average	Incremental
Allowable Storage Cost Based on Assuming $60/M^2 Collector Cost	0	1	753	403	--	350	--	--	--	--
	1	1.18	1093	475	--	350	268	268	--	--
	2	1.29	1141	520	--	350	136	3	--	--
	6	1.71	1457	689	--	350	70	37	--	--
Allowable Collector Cost Based on Assuming Storage Cost to be Zero	0	1	753	--	0	350	--	--	61	--
	1	1.18	1093	--	0	350	--	--	94	283
	2	1.29	1141	--	0	350	--	--	92	65
	6	1.71	1457	--	0	350	--	--	97	130
Allowable Collector Cost Based on Non-zero Storage Costs	0	1	753	--	0	350	--	--	61	--
	1	1.18	1093	--	140	350	--	--	77	167
	2	1.29	1141	--	180	350	--	--	71	11
	6	1.71	1457	--	340	350	--	--	67	56

Notes:

1. Table is based on results for 5% solar penetration in 1986 dollars and assumes .15kW electrical output capability per M^2 of concentrating mirror area.
2. Average subsystem allowable cost = $\dfrac{\text{total plant allowable cost - cost of other subsystems}}{\text{size of subsystem}}$
3. Incremental allowable cost = $\dfrac{\text{value added to total plant - incremental cost increase in other subsystems}}{\text{incremental increase in subsystem size}}$
4. Storage costs are based on estimate in Section V.

ECONOMIC VALUE OF SOLAR/FOSSIL HYBRID GENERATION vs. PURE SOLAR

(FOR 10% SOLAR/HYBRID PENETRATION)



* Estimated hybrid value includes capital equivalent of operation and maintanence (O&M) and oil fuel required to produce supplemental energy. Solar portion of hybrid, based on non-storage design operates at 23% capacity factor.

** Derived value of capital related portion of hybrid, excluding capitalized fossil fuel required to achieve high capacity factor operation; fossil energy cost assumed same as combustion turbine energy cost.

Appendix A

APPENDIX A

GENERATION RESOURCE PLANNING DISCUSSION AND DEFINITIONS

INTRODUCTION

Because of the lead times involved in adding generation capacity to a large electric system, it is necessary to develop and evaluate plans for future resource additions that cover a planning period of 10-20 years. Such a resource addition program is illustrated in Figure A-1.

The Electric System

The electric system comprises a mix of different types of resources. Typically resources such as nuclear, coal and hydroelectric which are expensive to install but relatively cheap to operate are desired to cover the base load, i.e. that part of the daily electrical energy requirement that is constant. Conversely, "peaking" resources that are called on only occasionally to operate during high demand period can have higher $/KWh operating costs, since they operate only short periods of time, provided their investment cost is low. There is a need for such low capacity factor generation to serve the peak demand periods, as illustrated by the load duration curve (See Figure II-5 or III-1). Intermediate between peaking and base load resources are those such as combined cycle and conventional oil fired plants which are called on to deliver electricity when demand is above the minimum level. To minimize operating costs, the most efficent units in this intermediate category are dispatched first unless environmental restraints take precedence. Table A-1 summarizes the future resource mixes for SCE to provide an example of various resources types, and Figure A-2 illustrates their roles in serving the system load.

GENERATION RESOURCE PLANNING

A flow chart showing the steps involved in SCE's generation resource planning process and the information input required for each step is included as Figure A-3. The scope of the present study is limited to the first five blocks. The first step is to review the present resource plan and the results of previous studies to determine the necessary proportions of different types of generation. The second step is to develop a set of alternative resource plans for evaluation. Then in the third step, each is analyzed and adjusted until it has adequate load carrying capability in relation to the forecast load. The fourth step involves two parallel activities. Capital costs estimates are developed for the generation projects identified with the alternative resource addition schedules, and the operation of the electric system is simulated for a 20 year period. The simulation takes into account startups, overhauls, and dispatch criteria, and provides total and unit fuel requirements, energy cost estimates, operating and maintenance costs, pollutant emission levels, plant capacity factors, incremental energy costs, etc. The results have a number of uses in fuel supply and financial planning as well as in engineering and environmental studies. In the fifth step the best plan is selected using the capital and production cost estimates for the alternative plans combined with other judgement factors.

ANALYTICAL TOOLS

Two computer programs are used extensively in the SCE generation planning process. The POLL (Probability of Loss of Load) program was discussed in Chapter II of the main report. The second computer program is the production costing simulation program.

Analytical Tools Cont'd.

It simulates the daily operation of the electric system for up to a 20 year period and computes fuel requirements, energy costs, operating costs, plant capacity factors, and other measures of system and unit performance. The following is a brief discussion of the engineering, mathematical and logical ideas which constitute the philosophy of the system simulation performed by the program.

Load Representation

For each year of study, the annual Edison net peak load is required as input. The program simulates a calendar year within 52 variable-day weeks; the peak load of each week being represented by an input percentage of the annual peak load. A week is then simulated by the combination of five different daily load shapes. Four of these general day shapes (Monday, peak weekday, Saturday and Sunday) are input as twelve percentage values which, when multiplied by the weekly peak, give the bi-hourly loads for the day. Since a normal week consists of a Monday, a peak weekday, a Saturday, a Sunday and 3 average weekdays, the majority of the days in a month are average weekdays. Hence, a small change in the level of the average weekday load shape will greatly influence thd energy representation for the month. For this reason and because the historic shape of an average day in the SCE system is similar to that of the peak weekday, an average weekday shape is obtained by multiplication of the peak weekday shape by an input weekly percentage value.

To represent the seasonal change in the daily load shapes, provision is also made to handle different shapes for one to six periods in a year. The length, in weeks, of each period is also

Load Representation Cont'd.

flexible.

The provision to change yearly the 52 values (used to obtain average weekday shapes from the peak weekday shapes) permits the variation of energy and load factor each week of each year.

Unless otherwise specified, each of the 52 weeks simulated by the program will contain a Monday, a peak weekday, 3 average weekdays, a Saturday and a Sunday for a total of 7 days. This results in a 364-day year. Should it be desired to simulate specified holidays, more than 364 days and/or the exact starting day in the week for a new year, a maximum of 10 special weeks per year may be designated. For these special weeks the number of days (from 1 to 11) and the desired day shape for each day can be specified. For example, this permits representation of a holiday in the middle of the week by a Saturday or a Sunday day shape and the following day by a Monday shape. To represent 365 or 366 days in a year, the first and/or last weeks in a year are often specified and contain more than seven days.

Because the use of bi-hourly loads might tend to flatten the peak for a day, the weekly peak (instead of the largest load during the peak weekday) is used during calculation of start-up requirements.

Spinning Reserve Calculation:

The manner in which weekly and daily spinning reserve requirements are calculated is optimally selected. For the solar study, spinning reserve was specified as being the maximum capacity of the largest unit installed or 7 percent of peak, whichever was greater. Daily spinning reserve requirements are used during daily unit start-

Unit Representation and Special Energy Transactions:

up calculations.

In order to model the characteristics of each installed generating unit, the following information is input to the program;

1. Unit efficiencies (heat rate).
2. Unit air emission rates.
3. Fuel cost and type.
4. Overhaul requirements.
5. Start-up cost.
6. Inservice and retirement dates.
7. Energy constraints.
8. Start-up priority.

The special energy feature of the program allows simulation of energy and/or capacity purchases and sales. Such transactions can be specified to apply to certain weeks, on certain types of days during the week, and for certain hours of the day.

Definitions:

The following definitions, exerpted from the 1964 National Power Survey, provides additional background relative to generation resource planning as well as definitions of key terminology.

I. Definitions of Terms Used in Reserve Planning

The wording of many of the listed definitions is that included in the "Glossary of Electric Utility Terms" prepared by the Edison Electric Institute (see reference bibliography). This publication also refers to Federal Power Commission and American Institute of Electrical Engineers (ASA) definitions. Where the wording, or the sense, of the definition is the same, more than one reference is indicated. Additional definitions as needed for the study of reserves are shown where no standard version is available.

Capacity

Net Generating Station Capability (EEI).—"The capability of a generating station as demonstrated by test or as determined by actual operating experience less power generated and used for auxiliaries and other station use. Capability may vary with the character of the load, time of year (due to circulating water temperature in thermal stations or availability of water in hydro stations), and other characteristic causes. Capability is sometimes referred to as Effective Rating" (This capability, sometimes referred to as "normal" capability, is available for continuous 24 hour-a-day operation and the definition is applied to individual generating units as well as to stations.)

Overload Capacity (FPC).—"The maximum load that a machine, apparatus, or device can carry when operating beyond its normal rating but within the limits of the manufacturer's guarantee." (No time limit for operation is given by the definition. It is assumed that this capacity is available for use over the daily peaks and for emergency use.)

Emergency Capability.—This is a short time top rating for a machine and is intended for emergency use only. It may be the same as or higher than the overload capacity. Operating time less than 100 hours per year are commonly used as limits. Examples are generating units operating in the overpressure range or with the top feedwater heater by-passed.

Net System Capability (EEI).—"The net generating station capability(ies) of a system at a stated period of time (usually at the time of the system's peak load), plus capability available at such time from other sources through firm power contracts, less firm obligations at such time to other companies or systems." ("Gross" and "net" as referred to system capability are before and after subtracting firm sales to other systems.)

Firm Power (FPC, EEI, ASA).—"Power or power producing capacity intended to be available at all times during the period covered by a commitment, even under adverse conditions."

System Interconnection (FPC, EEI, ASA).—"A connection between two electric systems permitting the transfer of electric energy in either direction."

Load

Annual System Maximum Demand (EEI) (Peak Load).—"The greatest demand on an electric system during a prescribed demand interval in a calendar year." (The clock hour integrated demand will be used in the study.)

Coincident Demand (FPC, EEI).—"The sum of two or more demands which occur in the same demand interval."

Interruptible Power (FPC, EEI).—"Power made available under agreements which permit curtailment or cessation of delivery by the supplier." (If the interruption can be made in a short time, this load may be considered a part of spinning reserve.)

Outages

Forced Outage (AIEE, EEI).—"A forced outage is an outage which requires that the turbine generator and/or a boiler be taken out of service at once or as soon thereafter as possible. This includes cases where the cause of the outage is of such a nature that the unit is not removed from service until the off-peak period of the same day or the following weekend."

Scheduled Outage (EEI).—"A scheduled outage is one widely controllable as to time of occurrence so that if desired it might have been or was avoided during the peak load season of the year. Such outages, including regular periodic inspections, will generally have been scheduled months in advance. However, unforeseen outages should be included within the category of a scheduled outage if they can be deferred beyond the immediate day or week to a period or season wherein load conditions are predominantly of a non-service demand nature."

Forced Derating (AIEE).—"A forced derating is a reduction in capability of a unit resulting from a forced outage of a component or piece of equipment."

Scheduled Derating (AIEE).—"A scheduled derating is a reduction in capability of a unit resulting from a scheduled maintenance outage of a piece of equipment, a component of the unit, or unit parts."

Reserves

The following definitions related to reserve capacity illustrate the several purposes for which such capacity is planned. These are:

(a) Spinning reserve which is immediately available to meet system emergencies, and to compensate for hour-to-hour load estimating errors.

(b) Reserve capacity to replace equipment forced out of service or on scheduled maintenance.

(c) Reserve capacity planned to meet error margins in load estimates.

The selection of a spinning reserve magnitude is an operating function and is a secondary consideration in planning reserve capacity. Equipment forced outages and the major maintenance schedule are the dominant factors. The general objective in load forecasting is to arrive at a single, most probable value, which is then used in the capacity requirement analysis. If a range of deviation is estimated, studies can include computations which show the effect of such deviations on the required reserve capacity. In the proposed power survey, where analyses will be made at five year intervals, from 1970 to 1980, the patterns of system expansion can be effectively studied using the single best estimate.

Margin of Reserve Capacity, (System Reserve), (Capability Margin), (FPC, EEI).—"The difference between net system capability and system maximum load requirements (peak load). It is the margin of capability available to provide for scheduled maintenance, emergency outages, system operating requirements, and unforeseen loads. On a regional or national basis, it is the difference between aggregate net system capability of the various systems in the region or nation and the sum of the system maximum (peak) loads without allowance for time diversity between the loads of the several systems. However, within a region, account is taken of diversity between peak loads of systems that are operated as a closely coordinated group." (In place of net system capability, the total emergency capability for the system is sometimes used. The margin of reserve so obtained is not entirely applicable for long duration outages and its use is limited in part to short duration load peaks and forced outages.)

Percent Reserve Margin.—Difference between net system capability and peak load in percent of peak load.

Spinning Reserve Capacity, (EEI, ASA, FPC.)—"Generating units connected to the bus and ready to take load."

This includes reserve generating capacity which can be made available in a short time (such as 5 minutes) through diesel, gas turbine, and hydro generation, and interruptible load. (It is sometimes referred to as "operating" or "ready" reserve.)

TABLE A-1

Example of Distribution of Resource Types
in the Near Future (top line)
and After System Capacity has Doubled (bottom line)

	Base Load	Intermediate	Semi-Peaking	Peaking	Total System Capacity
First Year	2,586 MW	7,625.2 MW	2,784 MW	1,672.6 MW	14,668 MW
	17.6%	52%	19%	11.4%	100%
Ten Years Hence	11,644 MW	9,097 MW	4,044 MW	4,158 MW	28,946 MW
	40.2%	31.4%	14.0%	14.4%	100%

FIGURE A-1

REPRESENTATIVE SOURCE ADDITION PROGRAM

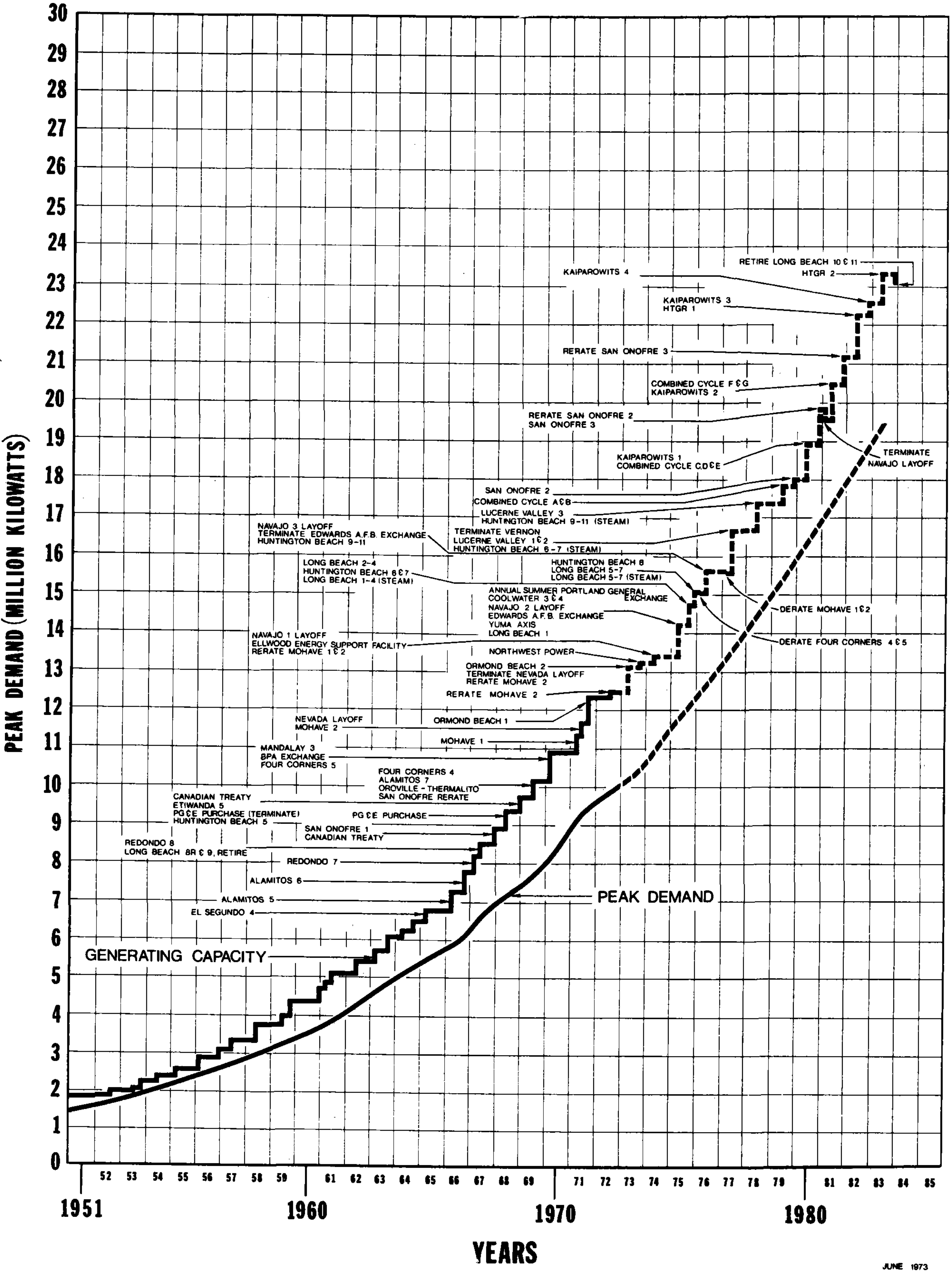
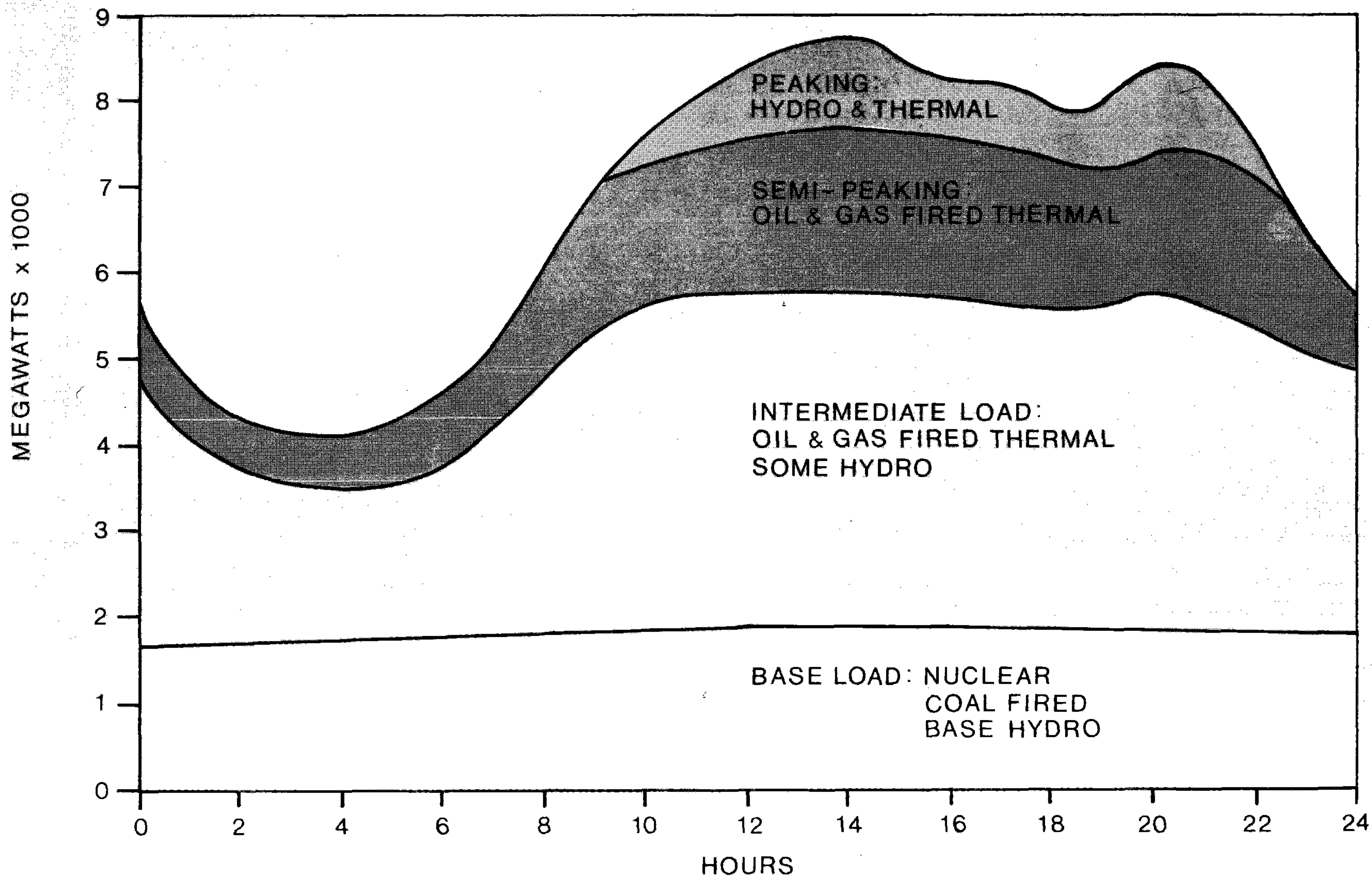


Figure A-2

TYPICAL GENERATION DISPATCH SUMMER DAY-1971



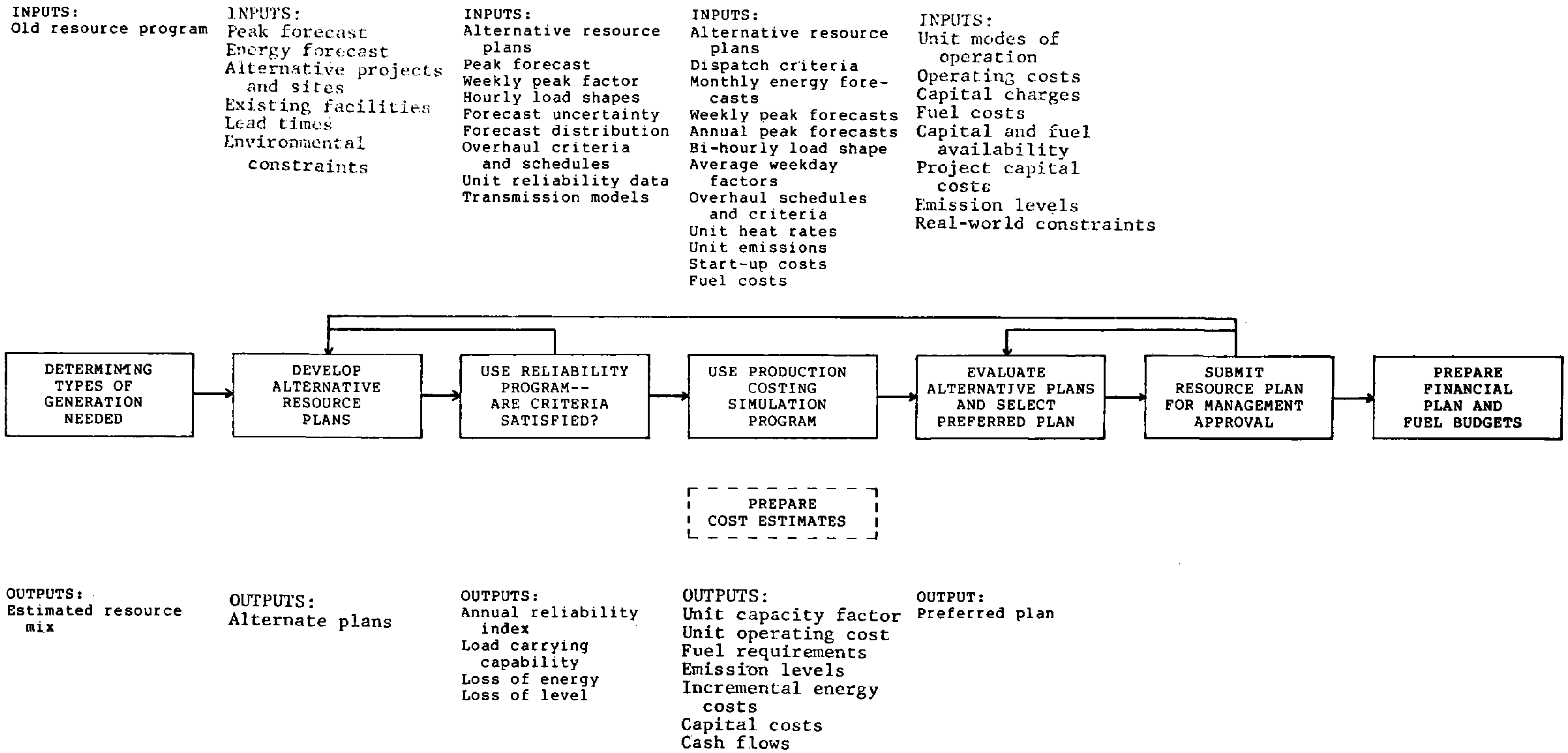


FIGURE A-3 GENERATION RESOURCE PLANNING PROCESS FLOW CHART

Appendix B

APPENDIX B

SOLAR UNIT INPUT/OUTPUT AND OUTAGE ASSUMPTIONS

The decision to have the solar turbine units rated to convert and deliver the maximum possible output from the available solar heat source made it possible to avoid duplicating other computations of solar output based on sunfall (solar radiation conditions). It was possible to simply use published output curves for summer optimized central receiver configurations and normalize these curves to the 100 MW level at noon on 6/21. The curves used were developed by the University of Houston for theoretical sunfall conditions at 35 degrees north latitude using a "clear air model". They were obtained from Reference 1 and are reproduced in Figure B-1. It was necessary to adjust these curves for conditions in specific siting areas that might not satisfy a clear air model. Ratios of measured to theoretically computed normal incidence radiation (See Table B-1) were calculated using data in References 2 and 3, and then applied to the data in Figure B-1. This procedure was used to produce a tabular presentation of normalized solar plant output data for siting areas around Inyokern, California and Albuquerque, New Mexico. Data needed to evaluate the sensitivity to heliostat field configuration was generated for Inyokern in like manner based on later University of Houston data, for winter optimized configurations. In addition, solar unit output curves based on measured data for Phoenix, Arizona were available in Reference 4 and were likewise normalized to the 100 MW output level on 6/21.

In addition to output levels at different locations during

Solar Unit Input/Output And Outage Assumptions Cont'd.

different months and hours of day, the load loss calculation and production simulations required information about the effect of sunfall irregularities on solar unit availability. Available information about these irregularities was placed in the form of total and partial sunfall outages consistent with the input formats of the computer programs. For simplicity, it was assumed that on any day in which the total sunfall was less than 50% of the amount possible, the solar unit would not be operated because of sunfall irregularities. For the purpose of the model, this was equivalent to a total forced outage. A relationship (see Figure B-2 and Table B-2) between average percent sunshine and numbers of days with less than 50% was developed based on data in National Weather Service summaries (Reference 5) for the southwest. For the areas of Inyokern, Albuquerque, Phoenix, and Las Vegas, Reference 6 contains data on mean daily sunfall per month. The percent of possible sunfall and total sunfall per month were available for Las Vegas; with this information the total sunfall corresponding to 100% and the percent of possible sunfall for the other areas could be determined. Then using Figure B-2, the number of days per month with less than 50% sunfall were found for Inyokern, Albuquerque and Phoenix. This result is tabulated in Table B-3. Partial sunfall outage rates were determined by requiring that the combination of total and partial sunfall outages account for difference between the possible sunfall and that amount actually observed.

The approach described above provided data that was

Solar Unit Input/Output And Outage Assumptions Cont'd.

consistent with computer program input requirements. Clearly, there is some loss in accuracy resulting from the simplifying assumptions and from the use of data that has been manipulated and aggregated. We consider it acceptable compared with the uncertainties resulting from other assumptions and procedures. In a similar vein it was not considered worthwhile to make corrections for turbine part-load efficiency. Based on heat rate variations with load for machinery in the 100 MW range, the overall effect of this particular omission should be less than 5%.

There is one area where information loss as a result of aggregation of sunfall data raises a potential serious concern. Table B-2 illustrates that sunfall outages in the southwest occur predominantly during the winter months, and in any given year, sunfall outages are not distributed evenly among the months. This is indicative of a pattern in which rainy and overcast days are grouped together sequentially. It is also indicative of weather patterns large enough to affect many separate siting areas for as much as a week at a time. For example, this happened in the eastern desert of California in early January of 1974. Such disturbances and their effect on storage dispatch strategy have not been accounted for in our work.

References

1) "Solar Thermal Power Systems based on Optical Transmission" University of Houston and McDonnell Douglas Astronautics report: NSF/RANN/SE/Gl-39456/PR/74/2, p 53, 12/21/74.

2) "Direct Solar Radiation Available on Clear Days" Threlkeld, J. L. and Jordan, R. C. University of Minnesota: ASHRAE No. 1622, p 64, 1/58.

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3) "Solar Thermal Conversion Mission Analysis: Aerospace Corporation report: ATR-74 (7417-16)-2, Vol. III, p 80 - p 80, 11/15/74.

4) "Solar Power Systems and Component Research" Martin Marietta report: NSF/RANN/SE/AER 74-07570/FR/75/1 P 01 - p 091, 1/75.

5) "Local Climatological Data", U.S. Dept. of Commerce, National Weather Service, 1/69 to 12/74.

6) "Dynamic Conversion of Solar Generated Heat to Electricity" Monthly Technical Progress Narrative No. 1, NASA Contract No. XAS 3-1-18014, p A3, 10/15/73.

TABLE B-1

Measured vs Theoretical Direct Radiation

RATIO OF MEASURED TO THEORETICAL NORMAL INCIDENCE SOLAR RADIATION, KW/M^2

SOLAR TIME(hr)	LATITUDE Degrees North	April 12		August 5		December 4	
		A	I	A	I	A	I
6	36	0	0	1.34	1.40	0	0
	32	(0)	(0)	(1.91)	(2.22)	(0)	(0)
7	36	1.20	1.12	1.34	1.40	0	0
	32	(1.22)	(1.14)	(1.30)	(1.36)	(0)	(0)
8	36	1.08	1.05	1.21	1.23	1.28	1.42
	32	(1.06)	(1.04)	(1.20)	(1.21)	(1.10)	(1.21)
9	36	1.08	1.02	1.18	1.15	1.25	1.16
	32	(1.07)	(1.02)	(1.17)	(1.13)	(1.15)	(1.07)
10	36	1.05	0.99	1.14	1.12	1.15	1.05
	32	(1.06)	(1.00)	(1.14)	(1.11)	(1.08)	(0.98)
11	36	1.04	0.99	1.06	1.08	1.12	1.00
	32	(1.05)	(1.00)	(1.05)	(1.08)	(1.07)	(0.95)
12	36	1.04	0.97	1.02	1.07	1.12	0.99
	32	(1.05)	(0.98)	(1.03)	(1.07)	(1.07)	(0.94)
13	36	1.04	0.98	1.08	1.08	1.12	0.97
	32	(1.05)	(0.99)	(1.08)	(1.08)	(1.07)	(0/92)
14	36	1.05	0.99	1.14	1.09	1.14	0.98
	32	(1.06)	(1.00)	(1.13)	(1.09)	(1.07)	(0.91)
15	36	1.07	1.01	1.16	1.12	1.17	0.97
	32	(1.06)	(1.00)	(1.14)	(1.11)	(1.08)	(0.90)
16	36	1.09	0.99	1.17	1.15	1.60	1.28
	32	(1.08)	(0.98)	(1.17)	(1.13)	(1.38)	(1.10)
17	36	1.20	0.97	1.26	1.18	0	0
	32	(1.22)	(0.99)	(1.22)	(1.14)	(0)	(0)
18	36	0	0	1.26	1.18	0	0
	32	(0)	(0)	(1.99)	(1.82)	(0)	(0)

A - Albuquerque
I - Inyokern

TABLE B-2

Sunfall Outage Data

Year	% Sunshine for Month												No. Days 50% Sunshine											
	J	F	M	A	M	J	J	A	S	O	N	D	J	F	M	A	M	J	J	A	S	O	N	D
74	62	92	78	97	94	98	83	92	97	80	80	68	12	0	6	0	0	0	4	1	0	4	4	8
73	69	62	70	87	84	88	93	86	97	95	73	74	9	10	7	2	5	2	2	3	1	0	6	5
72	92	92	97	86	94	86	95	89	85	55	70	72	0	0	0	4	0	2	0	2	3	13	7	8
71	91	89	93	91	83	98	95	78	97	87	75	63	1	1	0	1	3	0	0	4	0	4	7	9
70	71	78	87	91	95	93	78	86	100	89	82	76	7	4	3	0	0	0	3	1	0	1	3	5

Location: Las Vegas

TABLE B-3

Sunfall Statistics for Three Areas
5 Year Averages

Month	ALBUQUERQUE % Sunshine	ALBUQUERQUE Days < 50%	INYOKERN % Sunshine	INYOKERN Days < 50%	PHOENIX % Sunshine	PHOENIX Days < 50%
Jan	74	6.2	75	5.9	74	6.2
Feb	74	6.2	79	4.8	78	5.1
Mar	74	6.2	81	4.3	76	5.6
Apr	77	5.4	85	3.2	80	4.5
May	80	4.5	90	1.8	84	3.4
Jun	83	3.7	94	0.7	84	3.4
Jul	76	5.6	86	2.9	73	6.5
Aug	76	5.6	88	2.3	74	6.2
Sep	81	4.3	93	1.0	83	3.7
Oct	79	4.8	84	3.4	81	4.3
Nov	77	5.4	84	3.2	79	4.8
Dec	71	7.0	77	5.4	72	6.7
Annual Average	76.8	5.4	84.7	3.2	78.2	5.0

Figure B-1

NORMALIZED SOLAR HEAT SOURCE OUTPUT

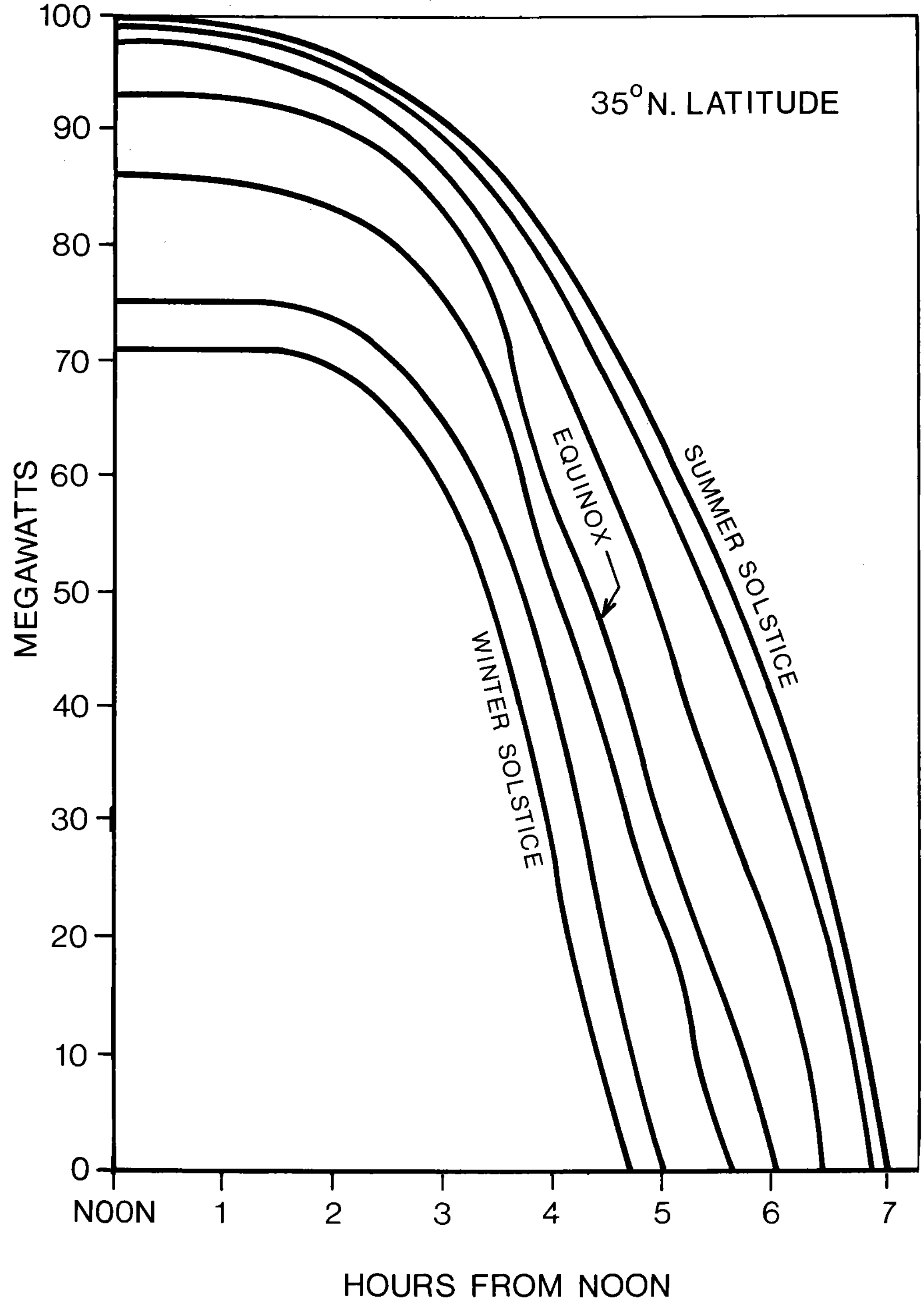
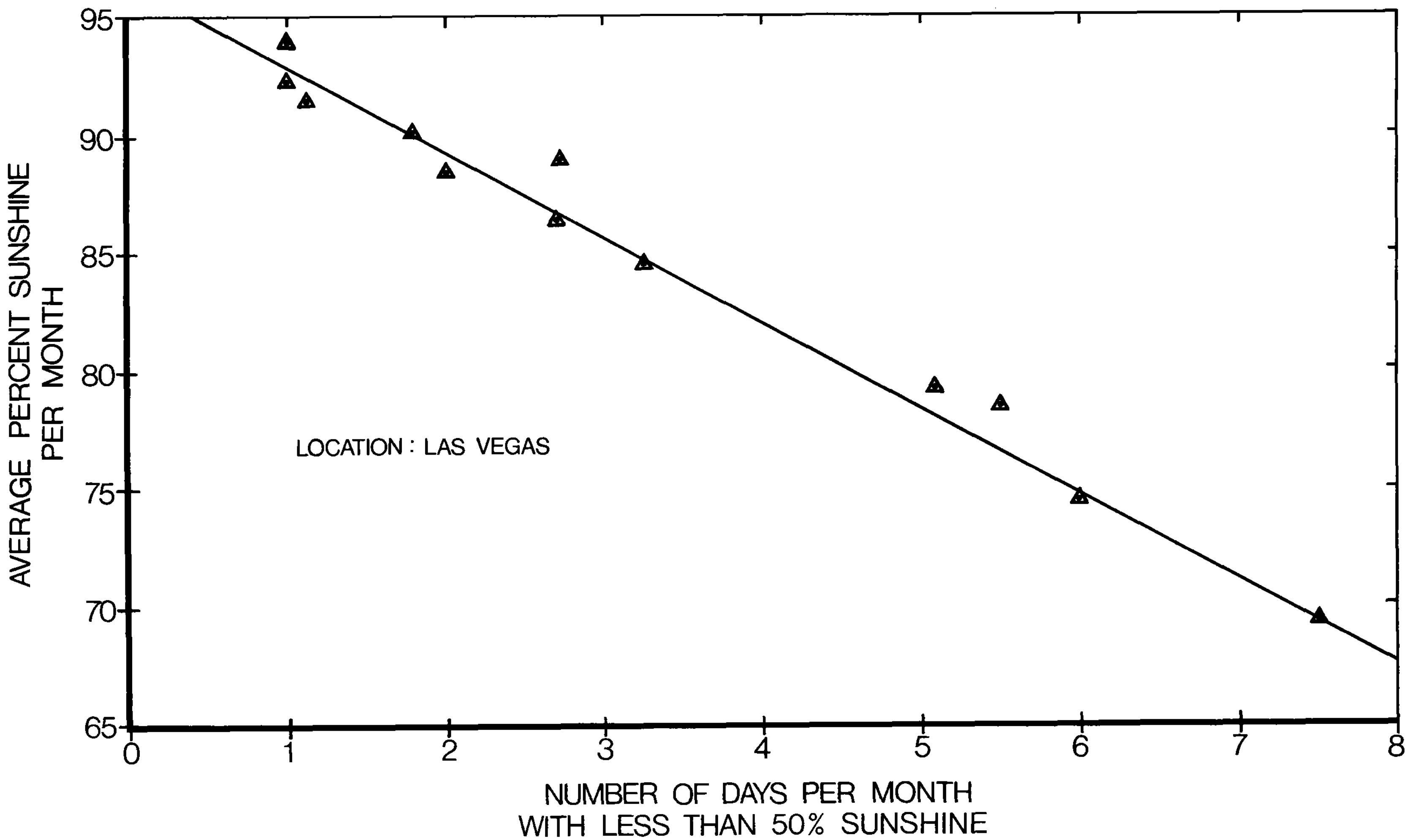


Figure B-2

SUNFALL OUTAGES VS. POSSIBLE SUNFALL



Section VI
Plant Design
Considerations