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# A Handbook For Solar Central Receiver Design

Sandia National Laboratories | Livermore

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*Central receiver systems use sun-tracking mirrors called heliostats to concentrate direct normal solar insolation on a receiver located atop a tower. Only solar energy capable of casting a shadow may be used for concentration. The concentrated energy is used to heat a receiver fluid to high temperatures. The collected solar energy may be employed for the generation of electricity or for the production of process heat.*

*Photographed at Solar One, the 10 $MW_e$ Solar Thermal Central Receiver Pilot Plant, located near Barstow, CA, USA.*

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# A HANDBOOK FOR SOLAR CENTRAL RECEIVER DESIGN

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## ABSTRACT

This Handbook describes central receiver technology for solar thermal power plants. It contains a description and assessment of the major components in a central receiver system configured for utility scale production of electricity using Rankine-cycle steam turbines. It also describes procedures to size and optimize a plant and discusses examples from recent system analyses. Information concerning site selection criteria, cost estimation, construction, and operation and maintenance is also included, which should enable readers to perform design analyses for specific applications.

## *ACKNOWLEDGMENTS*

*This handbook is a summary of work performed by many people and organizations supported by the United States Department of Energy Solar Thermal Technology Program and its predecessors over the past twelve years.*

*Significant contributions to the content of the handbook were made by many of my colleagues at Sandia National Laboratories including A. F. Baker, K. W. Battleson, N. E. Bergan, T. D. Brumleve, C. J. Chiang, D. B. Dawson, W. R. Delameter, S. E. Faas, J. M. Hruby, B. L. Kistler, G. J. Kolb, C. L. Mavis, H. F. Norris, L. G. Radosevich, A. C. Skinrood, J. W. Smith, M. C. Stoddard, and D. N. Tanner.*

*Draft inputs for portions of the handbook were prepared under contract by Bechtel Corporation, Black and Veatch Consulting Engineers, McDonnell Douglas Energy Systems, and the Battelle Pacific Northwest Laboratories.*

## *SOLAR THERMAL TECHNOLOGY FOREWORD*

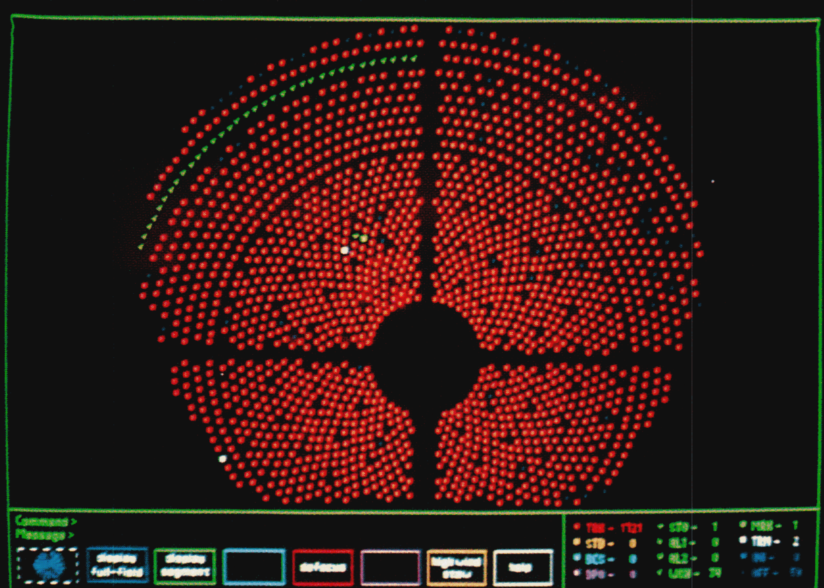
*The research described in this report was conducted within the U.S. Department of Energy's Solar Thermal Technology Program. This program directs efforts to incorporate technically proven and economically competitive solar thermal options into our nation's energy supply. These efforts are carried out through a network of national laboratories that work with industry.*

*In a solar thermal system, mirrors or lenses focus sunlight onto a receiver where a working fluid absorbs the solar energy as heat. The system then converts the energy into electricity or uses it as process heat. There are two kinds of solar thermal systems: central receiver systems and distributed receiver systems. A central receiver system uses a field of heliostats (two-axis tracking mirrors) to focus the sun's radiant energy onto a receiver mounted on a tower. A distributed receiver system uses three types of optical arrangements — parabolic troughs, parabolic dishes, and hemispherical bowls — to focus sunlight onto either a line or point receiver. Distributed receivers may either stand alone or be grouped.*

*This Handbook describes the design of central receiver systems for production of energy at nominally 500°C which can be used to generate electricity. It contains a description and assessment of the major components in a central receiver system and, further, describes procedures to size and optimize a central receiver power plant. Central receiver systems appear suitable as a cost-competitive energy alternative for electric utilities and for industries requiring a clean process heat source.*

# Contents



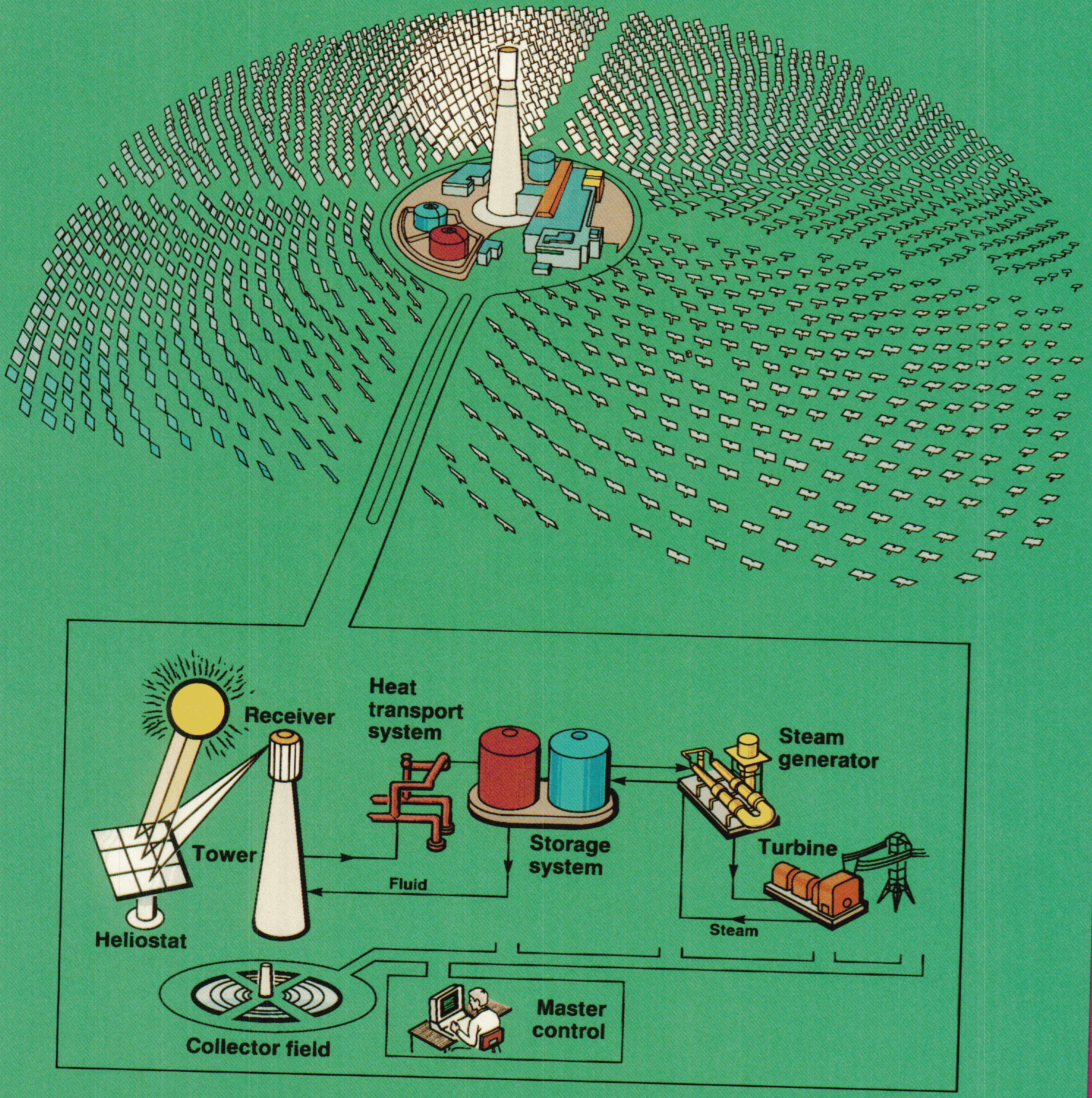


*Heliostat field graphics display at Solar One. Colors indicate operational status of individual heliostats in the field. Red indicates heliostats tracking the receiver, yellow indicates heliostats on stand-by, dark blue indicates heliostats which are out-of-service, light blue indicates heliostats being tested by the Beam Characterization System. Green indicates heliostats in a fixed position such as stow or wash; in this photograph, a row of heliostats has been fixed for washing.*

# A HANDBOOK FOR SOLAR CENTRAL RECEIVER DESIGN

## CONTENTS

# INTRODUCTION



*Schematic illustration of a solar thermal central receiver system. Major subsystems are distinguished by color in the location illustration on top and displayed by function in the lower portion of the illustration.*

# INTRODUCTION

This Handbook describes the status of solar central receiver technology as it exists in late 1986. Central receiver systems employ a field of tracking mirrors, called heliostats, that redirect and concentrate solar energy to a receiver on top of a tower. A schematic illustration of a solar central receiver system is shown on the chapter interleaf. The concentrated solar energy is absorbed by a fluid in the receiver. The absorbed thermal energy is conveyed to the base of the receiver tower where it may be used for work, such as the generation of steam for the production of electricity or the delivery of process energy. Most central receiver system designs also include a thermal storage system which can be used to operate the plant for several hours after sunset or during cloudy weather.

Good progress has been made in the development of central receiver technology during the past fifteen years. Many technology options have been brought to technical readiness through the efforts of more than ten countries. In the United States, under the sponsorship of the Department of Energy, central receiver technology has developed through analyses, hardware design and fabrication, and subsystem experiments.[1–6] This cooperative development program has involved scientists and engineers from industry, utilities, universities and national laboratories.

Depending upon the heliostat design, heliostat field layout, receiver design, and receiver fluid selection, central receiver systems can be used to heat fluids from 400–1000°C (750–1830°F). Considerable development has focused on components designed to heat the receiver fluid to roughly 550–600°C (1000–1100°F), suitable for generation of steam for Rankine-cycle steam turbines.

The technology of solar powered energy systems using the central receiver concept is approaching readiness for electric utility applications.[7] The 10 $MW_e$ Solar Thermal Central Receiver Pilot Plant, known as Solar One, has operated for nearly five years and is nearing the end of its power production test and evaluation period.[8] (Photographs of Solar One appear on the cover of this handbook and on some of the other chapter interleafs.) Results from this pilot facility and from other ongoing experiments are encouraging. Based on results of these experiments and on projections of future economics (including re-escalation of oil and gas prices), the central receiver concept promises to become a cost-competitive energy alternative for electric utilities and industries requiring a clean process heat source. Preferred locations for central receiver plants are regions with high direct normal insolation such as the southwestern United States.

This handbook has been prepared to summarize those aspects of central receiver technology necessary to conduct a scoping design calculation for a particular application. The objective is to provide information to those who wish to evaluate central receivers as a means of producing electricity. This information should be sufficient so that a preliminary, conceptual, feasibility assessment can be made considering cost, performance, and technology readiness factors.

The scope of the document is limited to central receiver technology available for use in utility-scale, Rankine-cycle electric power plants. Prototype hardware has been built and tested for this application and the technology is suitable for near-term construction.

Advanced research and development on systems and components for use in high temperature (above 550°C or 1020°F) central receiver systems also have been performed as a part of the DOE central receiver technology program as well as in the international programs. These systems may enable the production of electricity using Brayton-cycle turbines or the generation of very high-temperature process energy. Various receiver concepts have been studied for use in these high temperature systems.[9–13] Despite design, analysis and some experiments, these components are less ready for commercial use for near-term plants than the designs envisioned for use at 550°C (1020°F). Research is continuing, however, on a number of the concepts, and such systems are likely to be options in the future.

## ALTERNATE TECHNOLOGIES

Central receivers are one of a class of concentrating solar thermal technologies which also includes parabolic troughs and parabolic dishes. These technologies are schematically illustrated in Figure 1–1. Each of these systems can generate sufficiently high temperatures that electricity production is an attractive application. Together with photovoltaic systems, they represent the options for solar electric generation. Table 1–1 is a comparison of these four solar electric options highlighting their relative advantages and disadvantages. As indicated, central receiver systems are well suited for the generation of electricity at utility scale (plant sizes greater than about 10 $MW_e$ with capacity factors of 0.15 to 0.55).

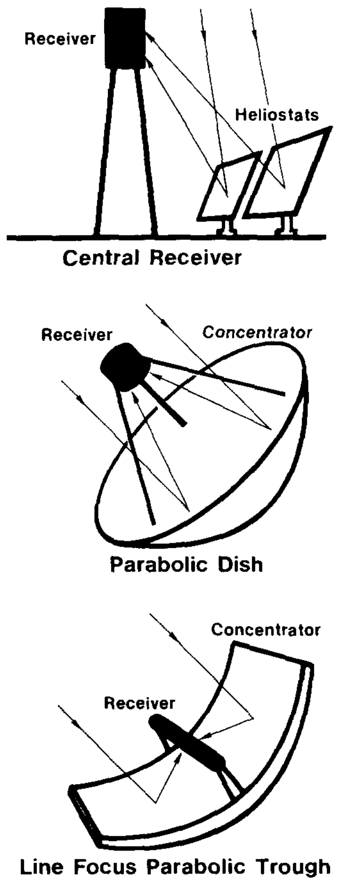



**Figure 1–1 Schematic of Three Concentrating Solar Thermal Technologies: Central Receiver, Parabolic Dish, and Parabolic Trough**

Table 1–1

SOLAR ELECTRIC GENERATION SYSTEMS COMPARISON

| System | Advantages | Disadvantages |
|---|---|---|
| Central Receiver | Thermal storage capability enables high capacity factors | Very large system required for good economy (>30-50 $MW_e$) needing large capital investment |
| | Relatively high efficiency | |
| | Usable as intermediate or near baseload | Low density collection field – large land area |
| | Utility familiarity with Rankine cycle power generation | Higher O&M than photovoltaics |
| Dish | Highest efficiency | Currently uneconomical storage capability (batteries) |
| | Small modules (25 $KW_e$) possible | Limited to peaking applications (utility) |
| | Low capital investment | |
| | Remote unattended siting possible | Higher O&M than photovoltaics |
| Parabolic Trough | Small modular system | Single axis tracking and lower operating temperature give lower efficiency than dish or central receiver |
| | Lowest concentrator system cost/ collector area | |
| | Higher density collector field | High thermal losses from interconnecting piping |
| | | Higher O&M than photovoltaics |
| Photovoltaics | Small modular system | Lowest efficiency |
| | Direct conversion – minimum support equipment | Currently uneconomical storage capability (batteries) |
| | Most mature technology in terms of deployment | Limited to peaking applications (utility) |
| | Lowest projected O&M | Current high cost of cells restricts economics |

## BACKGROUND

The first documented study of a central receiver power system was conducted in the USSR in the 1950's. In this system, large tilting mirrors were to have been mounted on railroad carriages. However, only a crude, manually operated, prototype heliostat was constructed. Further central receiver technology was not developed until a decade later.

The first carefully engineered central receiver experiments were built in the 1960's by Professor Giovanni Francia of the University of Genoa. In 1965, he constructed a solar steam generator that relied on the solar energy collected from 121 small heliostats. Two more plants soon followed. The last one, built in 1969, produced high temperature steam. This plant was the basis for the design of a similar facility—the Advanced Components Test Facility—which was built in Italy and installed in 1977 in the United States at the Georgia Institute of Technology.

Meanwhile, high temperature solar furnaces were operating in Europe and in the United States. The pace-setting French program culminated in the one MW solar thermal furnace at Odeillo in the eastern Pyrenees. This innovative facility was designed and is still used for experiments requiring extremely high temperatures (up to 4000°C or 7200°F) in exceptionally clean environments.

The Odeillo facility was the first solar thermal facility to produce electricity while connected to a utility grid. It was also the first facility to use a field of free-standing heliostats operating under automatic control.

During the 1970's, rapidly increasing fuel prices and the demand for cleaner environments gave impetus to advanced technologies suitable for harnessing the sun to generate electric power. Investigative studies identified the central receiver concept as one of the most promising options for electricity generation on a large scale.

U.S. government support for investigation of the central receiver concept was initiated through the National Science Foundation program Research Applied to National Needs in 1972. Support grew and the program was sponsored in turn by the Energy Research and Development Adminstration and the Department of Energy. Recently published histories detail the early development efforts.[14,15]

During the late 1970's, six central receiver pilot plants were constructed worldwide ranging in size from 500 $kW_e$ to 10 $MW_e$,[16–19] as well as a 5 $MW_t$ central receiver test facility located at Sandia National Laboratories in Albuquerque, New Mexico. A 5 MW plant in the Soviet Union has also been constructed and operated.[20]

In parallel with the design, construction, and testing at the pilot plants, component and subsystem development has been pursued aggressively. Competitive heliostat design, fabrication and testing have been carried through several design generations. Heliostat technology continues to progress with both technical innovations and cost reductions. Receiver designs using a number of receiver fluids and with different configurations and design features have also been produced and tested. Nearly twenty system conceptual design studies (summarized in References 21 and 22) have addressed site-specific design issues.

Conceptual design studies and component tests have identified molten-salt-cooled and liquid-sodium-cooled receivers as attractive alternatives to the water/steam technology employed at Solar One. Ongoing research efforts are aimed at verifying the performance of molten salt components for commercial scale systems. These advances provide a solid base for the next generation of central receiver plants toward which the information in this handbook has been collected and compiled.

## ORGANIZATION

The remainder of this handbook is organized into six chapters. A description of the principal technical components in a central receiver system and their development status is provided in Chapter 2. Chapter 3 discusses the issues which must be addressed as a part of the site selection process for a specific central receiver system. The conceptual design process and some example trade-off studies examining various technical options are described in Chapter 4. Design rules based on past studies are also included in Chapter 4 so that a scoping analysis may be performed. Plant design and construction procedures are reviewed in Chapter 5. Operation, maintenance and reliability issues for commercial plants are addressed in Chapter 6. Estimated costs by subsystem for commercial central receiver systems and energy cost estimation procedures are described in Chapter 7. Three appendices and a glossary are also included.

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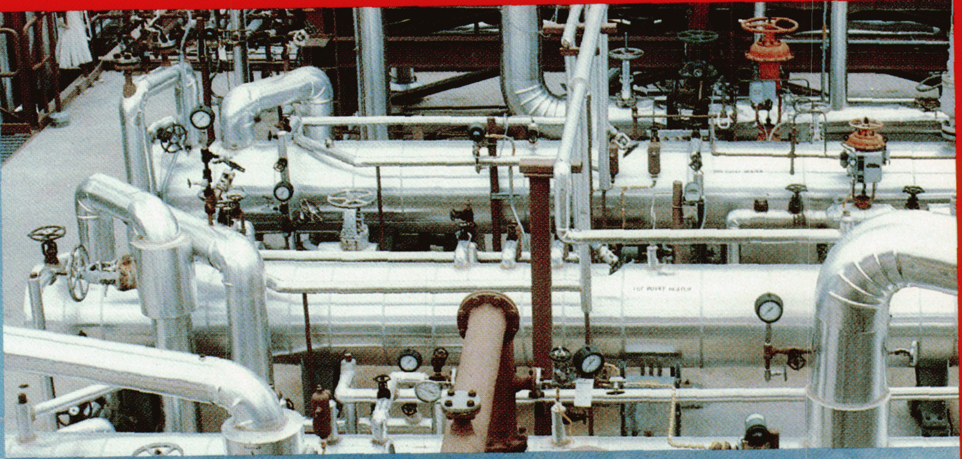
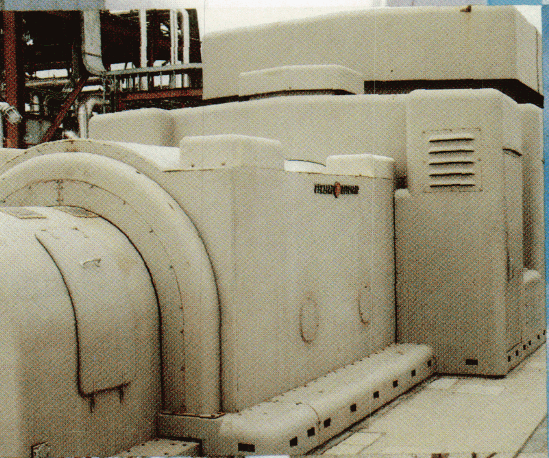
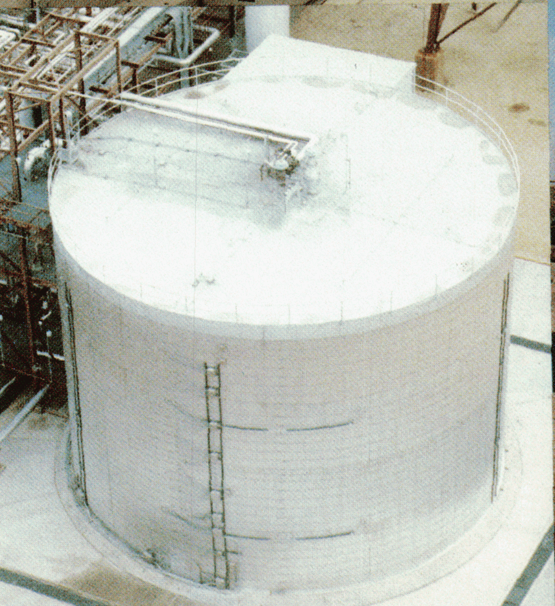
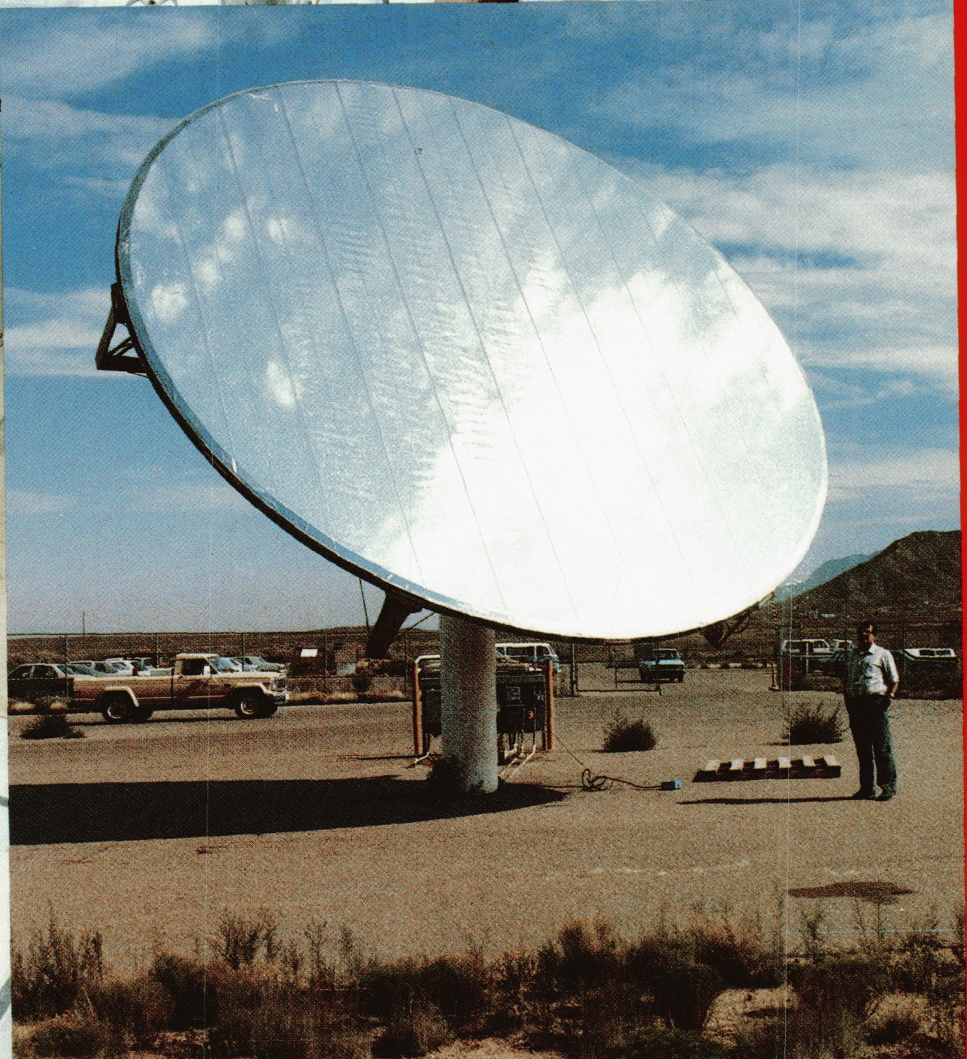
# TECHNOLOGY DESCRIPTION

*Photographs of typical components which may be used in a central receiver system. Clockwise from upper left: an external water/steam receiver, control room displays, heat transport system piping, a stressed membrane heliostat, a thermocline storage tank, a Rankine-cycle turbine generator, and a molten salt cavity receiver.*

# TECHNOLOGY DESCRIPTION

## GENERAL DESCRIPTION OF CENTRAL RECEIVER CONCEPT

In a solar central receiver, solar radiation is concentrated on a tower-mounted heat exchanger (receiver) by the use of mirrors called heliostats. The basic concept is illustrated on the Chapter 1 interleaf; a portion of that figure highlighting the major subsystems is repeated as Figure 2.1–1.

Computer controlled heliostats track the sun and reflect the sunlight to the receiver. The complete group of heliostats is called a collector field. The field may surround the tower or the field may be located on one side of the tower. (In the northern hemisphere, the field lies north of the tower while in the southern hemisphere, the field lies south of the tower.)

In the receiver, the collected solar radiation is converted to heat in a receiver fluid such as water/steam, liquid sodium, or molten nitrate salt flowing through small receiver tubes. If water/steam is the receiver fluid, the steam may be sent directly to the turbine generator. If one of the other receiver fluids is used, the energy in the fluid must be transferred to water/steam by means of heat exchangers before being used to generate electricity in the turbine generator.

An important aspect of central receiver systems is the ability to store excess thermal energy efficiently. The storage of energy during daylight hours allows operation of the turbine during non-solar periods. The marginal cost of collecting and storing this energy is less than the cost of increasing turbine size

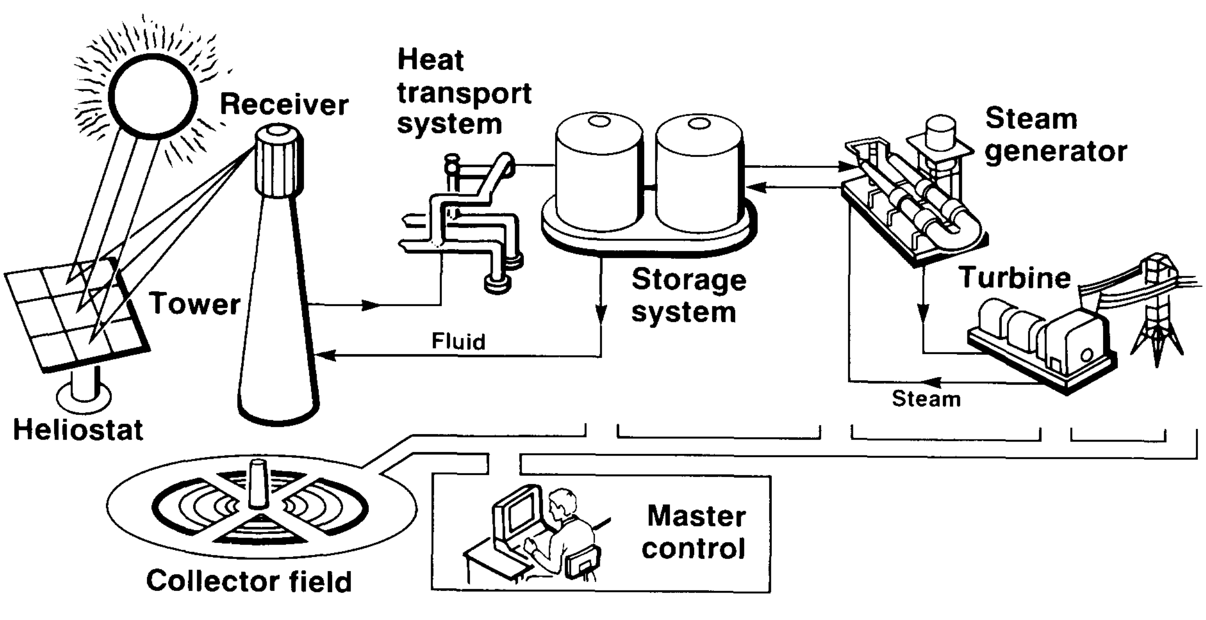



**Figure 2.1–1 Schematic Illustration of a Solar Central Receiver System**

to match the peak thermal output. Storage is also important for managing cloud transients during the day. Determination of the optimum storage size to fulfill the energy dispatch requirements of a particular application is a part of the central receiver design process.

The design and operation of a central receiver system is strongly influenced by the transient nature of the incident insolation. Thermal cycling of components is an important design consideration. The prediction of plant output and estimation of energy cost are dependent upon the site-specific prediction of available solar energy. Even at a given site, the reliance on short term data can be misleading and long term climatological data is preferred.

The solar plant control system is more complex than that of conventional power plants. In addition to the turbine generator, other major subsystems such as the collector field, thermal storage, receiver, and steam generator must be controlled. This complicates control requirements during startup, shutdown, and transient (cloud) operation when the interaction of subsystems is most critical.

Four system options, distinguished by the receiver and storage fluid, are considered to be the principal options for early commercial central receiver plants. Three alternatives for receiver fluid are water/steam, molten nitrate salt, and liquid sodium. A fourth system option, in which sodium is used as the receiver working fluid and molten salt is used as the storage fluid, is referred to as a sodium/salt binary. The following sections present more detailed information on subsystems and interfaces unique to these four central receiver system options.

## WATER/STEAM SYSTEM DEFINITION

A flow schematic of a water/steam central receiver system is shown in Figure 2.1–2. This system includes a tower-mounted water/steam cooled receiver heated by a field of heliostats. In this system, superheated steam from the receiver is routed directly to a steam turbine where it is used to produce electricity. A portion or all of the steam can also be routed to the thermal storage system.

Water/steam is the most commonly used heat-transfer fluid in the electric utility industry. The direct production of steam in a solar receiver would appear to be the most natural transition from fossil-fired plants to solar thermal plants. However, the transient nature of solar energy makes it difficult to directly couple total solar receiver output to a standard utility turbine. Buffering the receiver output through storage is beneficial.

High pressure steam is an uneconomical storage medium. In order to store energy in a water/steam system, the energy must be transferred to some other medium with heat exchangers. One possible storage medium is oil. Transfer of energy from steam to oil and back to steam results in energy losses.

The use of an intermediate fluid for energy storage required in a water/steam system results in efficiency losses because steam from storage is at a lower temperature and pressure than that from the receiver. This reduces the overall electrical generating efficiency for the plant, and that requires a larger, more costly solar plant. In addition, the requirements for high fluid pressure and two-phase heat transfer in the receiver

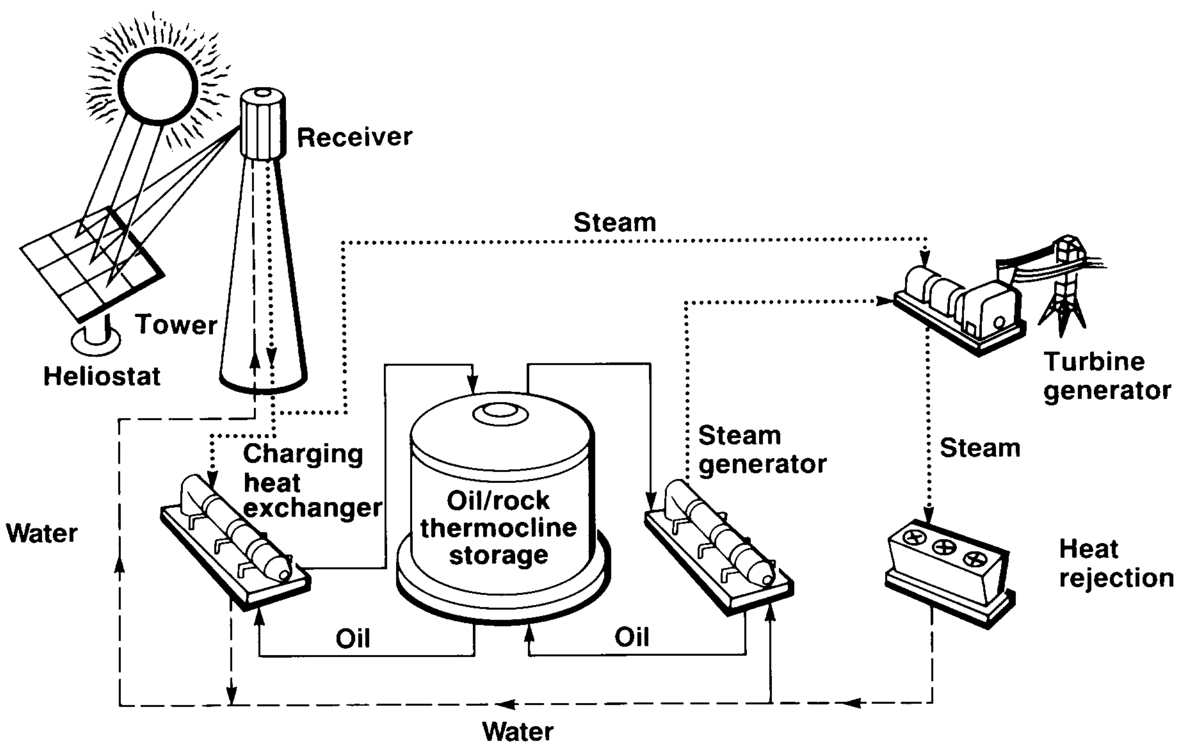



**Figure 2.1–2 Flow Schematic of a Water/Steam Central Receiver System**

directly influence receiver design, operation and control.

Solar One, the 10 $MW_e$ Solar Thermal Central Receiver Pilot Plant, employs water/steam as its working fluid. These design issues have been addressed in the Solar One design, and workable, but not necessarily economical, solutions have been found.

The major difference between water/steam and other working fluid concepts is related to the receiver, thermal storage system, and the turbine interfaces. These interfaces, described in the following paragraphs, in the Solar One plant are representative of a commercial water/steam system.

The Solar One receiver is a once-through to superheat design which boils and then superheats the steam to 510°C (950°F) at 10.3 MPa (1500 psi) in a single vertical pass through the receiver. Section 2.3 describes details of the receiver design.

The oil/rock thermocline storage system used at Solar One is charged by using steam from the receiver to heat a heat-transfer oil (Caloria HT43) in a heat exchanger. The hot oil circulates through a tank filled with small rocks and sand, heats the rocks and sand and establishes a thermocline in the tank (25% oil and 75% rock by volume). The system is discharged by routing hot oil from the tank through a steam generator.

The maximum temperature limitation of the oil (approximately 315°C or 600°F) requires that this process be conducted at reduced steam temperature and results in the output steam being derated to 280°C (530°F), as opposed to the 510°C (950°F) steam from the receiver.

This derated steam is introduced to the turbine through a special admission port in the turbine. The result of using this lower temperature derated steam is a reduction in turbine gross cycle efficiency from 34% (rated steam) to 28% (operating from storage).

The use of water/steam in a central receiver system together with a single pass to superheat receiver and thermocline storage has been adequately demonstrated at Solar One. Although this program has successfully demonstrated the technical feasibility of this concept, the economic viability of water/steam systems does not appear to be as good as other technology options.

The relatively low conversion efficiency, due primarily to operation through a reduced temperature storage system, has led to the proposal of higher efficiency systems utilizing other receiver fluids. These fluids (salt and sodium) allow storage at peak operating temperatures, decouple the turbine from solar transients, and allow the use of higher efficiency reheat Rankine cycles.

## MOLTEN SALT SYSTEM DEFINITION

A molten salt central receiver system consists of a tower-mounted molten-salt-cooled receiver heated by reflected energy from a field of heliostats. Figure 2.1–3 shows a flow schematic of this system. The molten salt used in these systems is typically a mixture (by weight) of 60% sodium nitrate and 40% potassium nitrate. Molten salt heated in the receiver is sent to the thermal storage system; hot salt is extracted from the storage system for generation of steam in the steam generator. The steam is used to produce electricity. The cooled salt is returned through the thermal storage system to the receiver.

In this configuration, the thermal storage system buffers the steam generator from solar transients and also supplies energy during periods of no insolation such as into the evening or on cloudy days. The use of a high temperature storable fluid, such as molten salt, in the receiver and thermal transport loop not only decouples the steam generation from solar transients, but also enables steam production at temperatures and pressures which are conventional utility practice for high efficiency turbine generator operation.

The molten salts used as a heat transfer fluid in a solar system are of the same family of molten salts used in commercial heat-treating and industrial process plants. Extensive operational experience has been accumulated with these salt mixtures over the last 40 years. The exact composition of the molten salt fluid is balanced between operating temperature requirements of the process and cost of the mixture. Typical salt mixtures have a freezing point in the 220–250°C (430-480°F) range. Each subsystem containing molten salt must be trace-heated and easily drained to assure that the salt does not freeze.

The molten salts are not toxic and when properly protected from the environment and from overheating, are compositionally stable over an extended period of time. These salts have a low vapor pressure at high temperature and do not react chemically with water/steam; hence, no unusual safety hazards are expected, other than those associated with

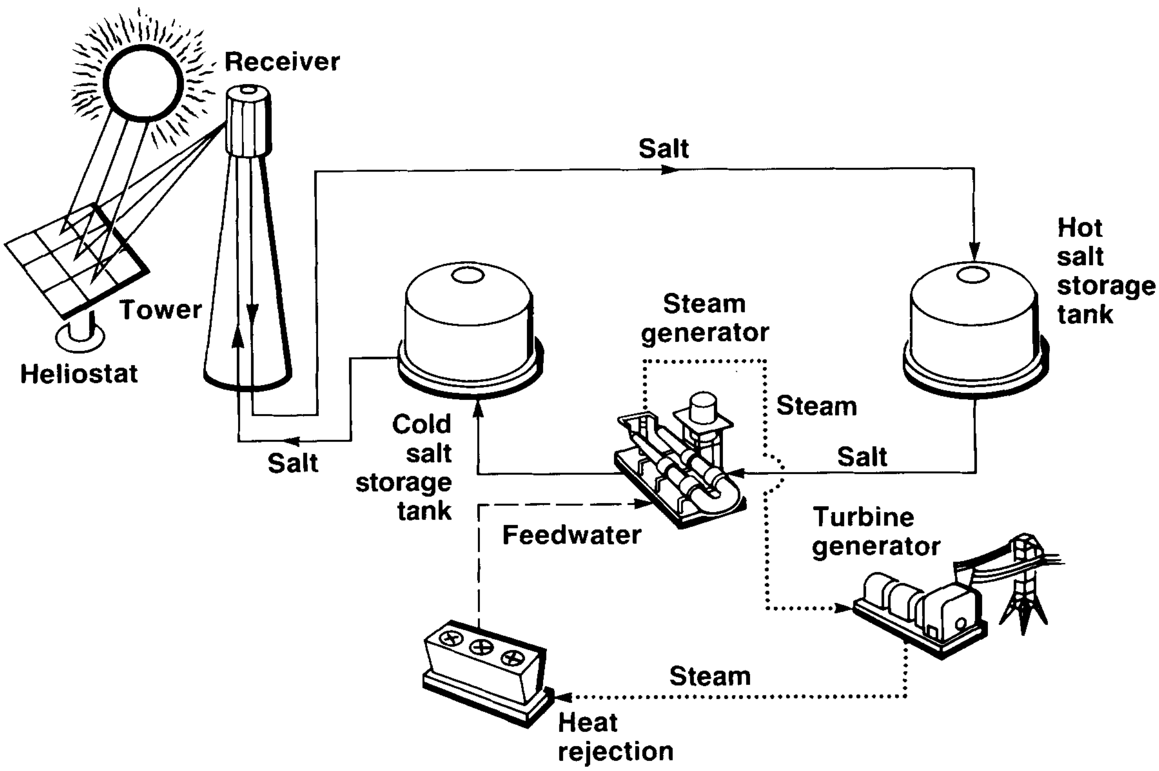



**Figure 2.1–3 Flow Schematic of a Molten Salt Central Receiver System**

any Class I chemical and high temperature fluid. The relatively inert characteristics of this fluid permit the design of the solar receiver, storage tanks and steam generator using standard ASME codes for high temperature containment and flow systems.

These characteristics and the relative low cost and commercial availability of the molten salt make this fluid attractive for use with solar central receivers. This is particularly true for systems with large amounts of thermal storage.

Most molten salt receivers built to date have been cavity type receivers. (Receiver designs are described in Section 2.3.) Cavity receivers may be fitted with doors to close the aperture and limit heat losses during the night and extended daytime shutdown. The doors can be designed to shut automatically if receiver coolant flow is interrupted, thus protecting the receiver from overheating. Advanced molten salt receivers for future plants may be either cavity or external designs.

For a molten salt receiver system with a design point of about 300 $MW_t$, the design point flowrate is about 2.52 $\times 10^6$ kg/hr (5.55 $\times 10^6$ lb/hr). An operating flowrate ranging from full flow down to 20% of full flow is required to operate in the variable solar environment.

The major difference between a molten salt and water/steam system is the storage and transport system. A salt steam generator is required to convert the thermal energy in the molten salt to steam for the turbine. The hot storage tank accumulates the salt flow from the receivers for use on demand by the steam generator system.

Use of molten salt for solar applications requires somewhat higher temperatures than those employed for industrial applications. A DOE funded technology development program was undertaken to verify material properties and performance of the molten salt at the higher temperatures. The industrial experience, coupled with the DOE work already completed or underway, has been instrumental in advancing molten salt system technology for solar plants. Additional technology data required to build large molten salt systems in the near term are being generated through ongoing cooperative DOE/industry programs.

## LIQUID SODIUM SYSTEM DEFINITION

A sodium central receiver system is equivalent to the molten salt system. Figure 2.1–4 illustrates a sodium central receiver system. It consists of a tower-mounted sodium-cooled receiver heated by reflected energy from a field of heliostats. In this design, sodium heated in the receiver is sent to the thermal storage system; hot sodium is extracted from storage to produce steam in a sodium/water steam generator. The steam is used in a conventional manner to produce electricity. The cooled sodium is returned through the thermal storage to the receiver. As with the salt system, the thermal storage system buffers the steam generator from solar transients and, in addition, supplies energy during extended periods of no insolation.

The relatively high thermal conductivity of liquid sodium permits receivers to operate at much higher incident solar flux levels (in excess of 1.5 $MW/m^2$) than those for the other fluids being considered for solar use (0.3 to 0.6 $MW/m^2$ for water/steam and 0.6 to 0.8 $MW/m^2$ for salt). The high sodium thermal conductivity minimizes front-to-back receiver tube temperature differences which permits higher flux for the same allowable stresses.

The major advantage of operation at high flux is a reduction in receiver size (absorbing area) for a specified power level. This size reduction is reflected in a reduced cost of the receiver as well as improved thermal efficiency through the reduction of area-dependent losses such as convection and radiation.

Sodium receivers designed to date have been external, either external cylindrical or billboard. The high flux, area-reduction benefits can be realized with the external configuration. Further reduction of losses through the use of cavity receivers is aperture size limited due to the fixed minimum heliostat spot size, and further loss reduction using the cavity approach with sodium receivers has not been shown to be beneficial.

The relatively high cost and low specific heat of sodium limit the economical usefulness of liquid sodium as a sensible heat storage medium. Sodium's lower volumetric heat capacity (product of density and specific heat) also results in larger, and thus more costly, storage tanks.

Use of sodium as a high temperature heat transfer fluid originated in the nuclear industry. Sodium remains liquid and is thermally stable at the elevated temperatures required for this application. The vapor pressure at 595°C (1100°F) is only slightly above atmospheric pressure. Major sodium equipment, similar to that required for solar

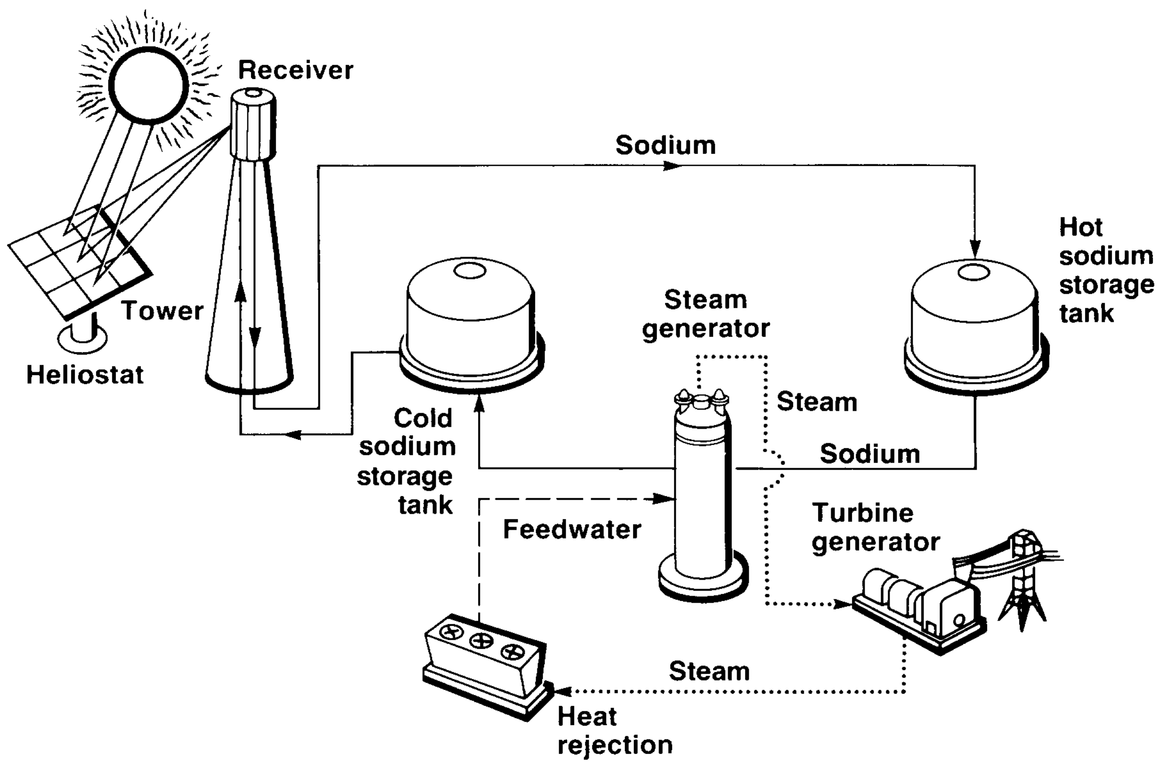



**Figure 2.1–4 Flow Schematic of a Sodium Central Receiver System**

use, has undergone extensive development for use in breeder reactor systems. This includes pumps, valves, lines, and steam generators. However, the highly reactive nature of sodium and water is an important consideration in the design of sodium components, principally the sodium steam generator, and potentially increases the cost of these components.

## SODIUM/MOLTEN SALT BINARY SYSTEM

A combination central receiver system concept has been proposed because of the high cost associated with using sodium as a thermal storage medium for large storage requirements. The sodium/salt binary system employs a liquid sodium receiver and a molten nitrate salt thermal energy storage system. A sodium-to-salt intermediate heat exchanger is required to couple the two. Molten salt is used for steam generation, supplying steam to the turbine. Figure 2.1–5 shows a schematic of this configuration.

The sodium/salt binary combines the attractive features of both liquid sodium and molten salt heat transfer fluids. Sodium is confined to the receiver loop where high heat transfer rates are important. Molten salt is used for thermal storage and steam generation because of its high thermal energy density, relative low cost, and relative safety in the event of a thermal storage or steam generator leak.

An additional feature of the sodium/salt binary system, when configured as shown

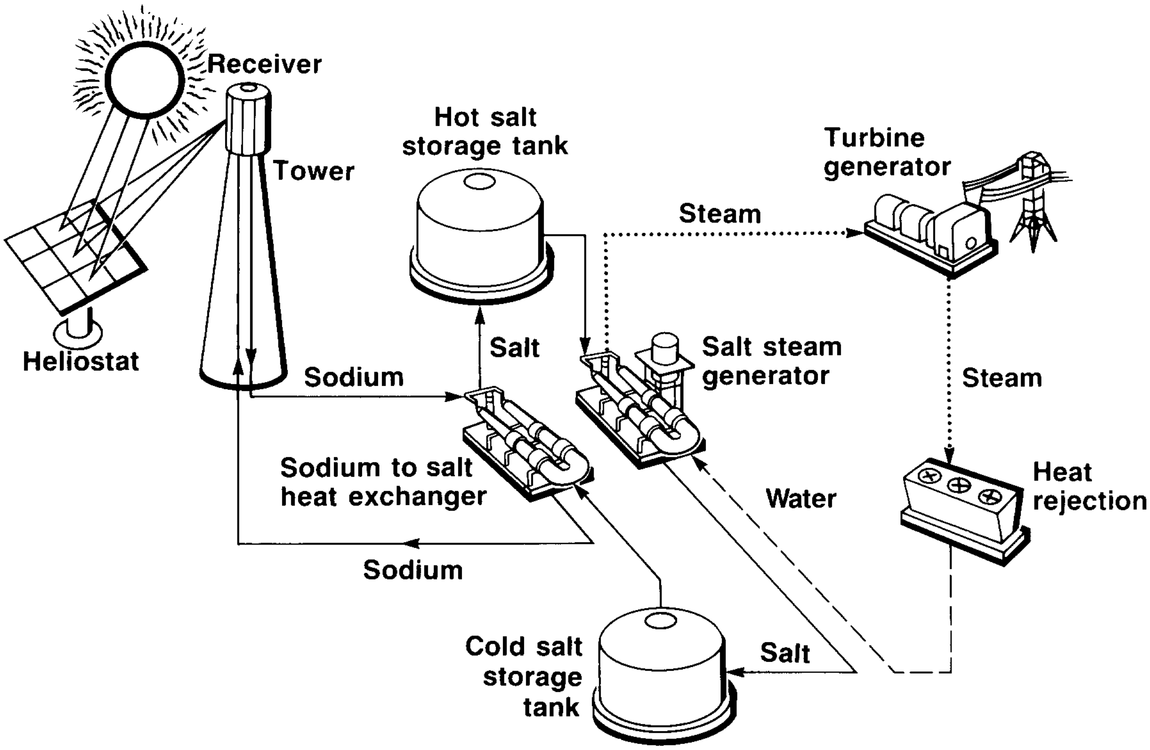



**Figure 2.1–5 Flow Schematic of a Sodium/Molten Salt Binary Central Receiver System**

in Figure 2.1–6,[1] is the potential elimination of high-head pumps for the receiver. The sodium receiver and intermediate heat exchanger could be designed as a closed-loop system in which the work required to circulate the sodium is due only to the friction pressure drops through the piping and components. For a 100 $MW_e$ plant this could represent a savings of several $MW_e$ from parasitics at full power when compared to the typical open circulation salt or sodium receiver loop in which the fluid is pumped up the tower and then throttled at the tower base before it enters the hot storage tank. However, some of this benefit (reduced parasitics) is negated because of the requirements of additional pumping associated with the sodium/salt heat exchanger.

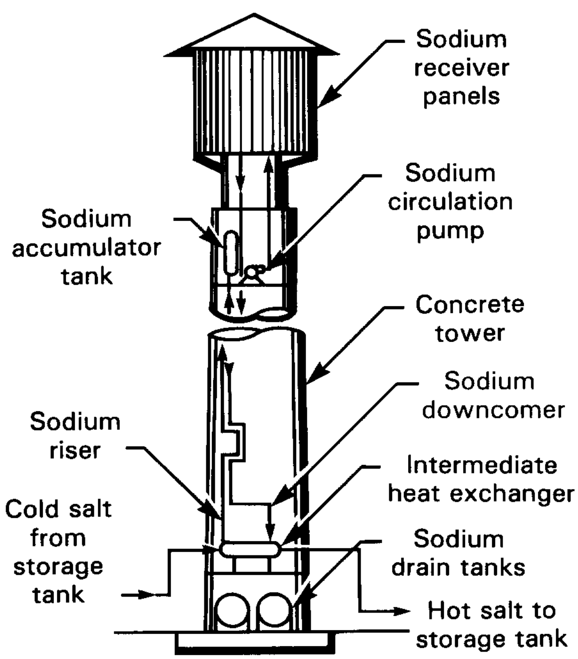



**Figure 2.1–6 Proposed Sodium Receiver and Tower Closed Loop Configuration**

The risk to plant personnel and equipment from a sodium fire is minimized in this configuration by containing all sodium equipment, except the receiver, within the concrete tower structure and by designing the system to quickly drain into a tank located on the tower foundation. Isolating the majority of the sodium equipment within the tower should facilitate containment and control of fires, and quick drain-down of the system should minimize the extent of leakage. The concrete within the tower structure will require protection from direct impingement of sodium. This protection can be supplied by using a steel liner in the tower base and appropriate shields or splash guards elsewhere.

The binary system has a higher degree of complexity resulting from the additional heat transfer loop. An area of uncertainty is the currently unknown reaction between sodium and molten salt should a leak occur in the intermediate heat exchanger. Current indications are that any reaction would be strongly exothermic, but that there should be little gaseous reaction product which might cause a pressurization problem.

## REFERENCES

1. Bechtel Corporation, "An Evaluation of Commercial Size Solar Central Receiver Plants," study funded by Pacific Gas and Electric Co., 1985.

# COLLECTOR SUBSYSTEM

The collector subsystem for a solar central receiver has as its basic function the interception, redirection, and concentration of direct solar radiation to the receiver subsystem. The collector subsystem consists of a field of tracking mirrors, called heliostats, and a tracking control system to maintain continuous focus of the direct solar radiation on the receiver while energy is being collected. When energy is not being collected, the controls must prevent the reflected energy from damaging the receiver, tower, or other structures, or from creating an unsafe condition in the airspace around the plant.

Because the heliostat field usually constitutes the largest fraction of the costs for a solar central receiver system, the central receiver development program has given particular attention to the development of low-cost designs and to estimation of mass production costs.[1,2] The emphasis in system design is on the interactive relationship between collector subsystem cost/performance trades and overall system economics. The cost criteria normally employed is the annual energy collected per dollar of life-cycle cost.

## COLLECTOR FIELD PARAMETERS

**Configuration.** The characteristics of the overall collector field are defined based on cost and performance trade studies which seek to minimize the cost of annual collected energy. These trade studies include consideration of the receiver, tower, and piping systems in addition to the performance and cost attributes of the collector field and its related equipment. Two field configurations have been developed: north and surround. In a surround field configuration, heliostats are arranged around a centrally located tower. The tower is usually located to the south of center to optimize field efficiency. In a north field configuration (or for plants located in the southern hemisphere, a south field configuration), all heliostats are arranged on the north side of the tower. Representative collector fields which have been developed as a result of such trade studies are shown in Figures 2.2–1 and 2.2–2 for surround and north-side fields, respectively. Selection between a north or surround field configuration is a function of the receiver configuration and is discussed in detail in Section 2.3.

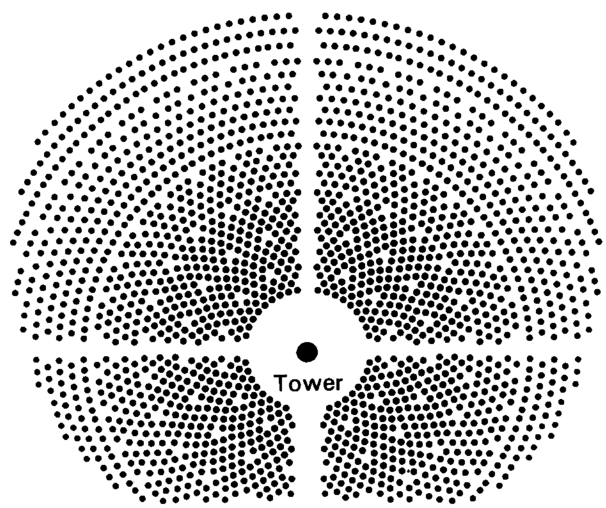



**Figure 2.2–1 Typical Surround Field Configuration**

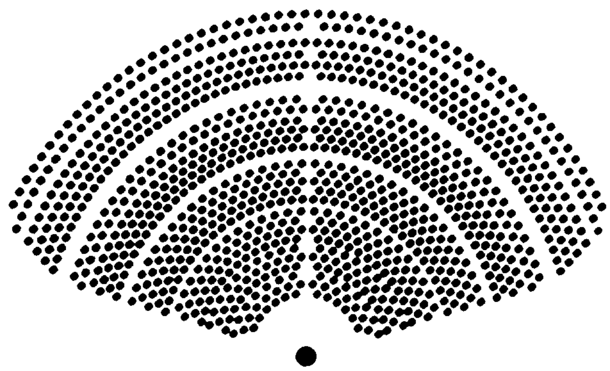



**Figure 2.2–2 Typical North Field Configuration**

**Performance.** The performance of the heliostat field is defined in terms of the optical efficiency, which is equal to the ratio of the net power intercepted by the receiver to the product of the direct insolation times the total mirror area. The optical efficiency includes the cosine effect, shadowing, blocking, mirror reflectivity, atmospheric transmission, and receiver spillage. Several optical loss factors are illustrated in Figure 2.2–3. The net efficiency for producing electricity includes receiver efficiency and thermal-to-electric conversion efficiency.

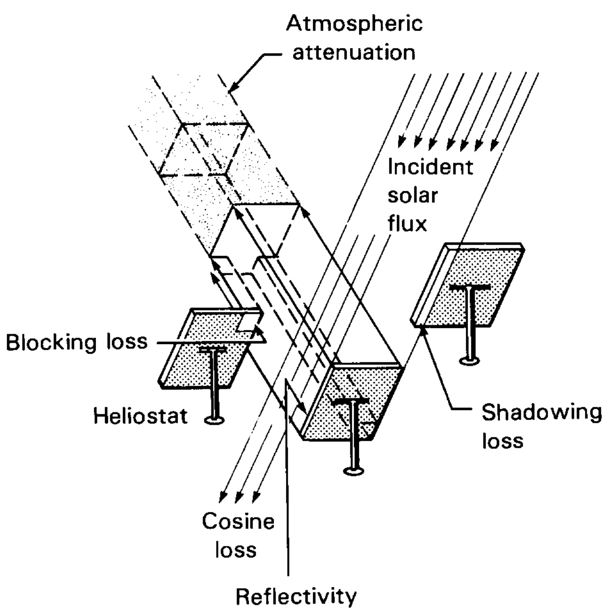



**Figure 2.2–3 Collector Field Optical Loss Processes**

The amount of insolation reflected by the heliostat is proportional to the amount of sunlight intercepted. The reflected power is proportional to the cosine of the angle (cosine effect) between the heliostat mirror normal and the incident sun rays; the ratio of the projected mirror area that is perpendicular to the sun's rays to the total area of the heliostat determines the magnitude of the cosine effect. The heliostat is oriented so that the incident sunlight is reflected onto the receiver. If the sun is due south and low in the sky, as it is in the winter, then the heliostats due north of the tower will be almost perpendicular to the sun's rays and, therefore, have almost the maximum cosine efficiency of 1.0. At the same time, heliostats due south of the tower will have a low cosine efficiency. Since the greatest fraction of the annual insolation occurs when the sun is in the southern sky, the annual average cosine will be greatest in the northern part of the heliostat field. Thus, in the northern hemisphere, heliostat fields are usually biased toward the north of the tower. (For the same reasons, heliostat fields located in the southern hemisphere will be biased south of the tower.)

Not all the sunlight that clears the heliostats reaches the vicinity of the receiver. Some of the energy is scattered and absorbed by the atmosphere; this effect is referred to as the attenuation loss. A good visibility day will have a small percentage of energy loss per kilometer. The losses increase when water vapor or aerosol content in the atmosphere is high.

The size of the image formed by a heliostat depends on mirror focusing and canting and on the size of the heliostat, the size of the sun (because rays from the center and edge of the sun striking one point on a heliostat are not exactly parallel), irregularities in the heliostat surface, and off-axis aberrations.

A focused heliostat cannot produce a point image because of the finite size of the sun. However, a focused heliostat can produce an overall smaller image than an unfocused heliostat because the effect of heliostat size on image size is reduced. With a fixed focus heliostat, off-axis aberrations cause some incremental spread in image size; the relative amount depends on the heliostat size, the slant range, and the off-axis angle, which varies through the day and is most severe for south field heliostats. Even with perfect focusing and perfect optics, the size of the image increases with the slant range because of the finite angle subtended by the sun. The minimum image diameter is 9.3 meters per kilometer of range.

If the receiver is not big enough to intercept the entire image of the heliostat, some of the energy will be "spilled" around the receiver. While spillage can be eliminated by increasing the size of the receiver, at some point increased size becomes counterproductive because increased receiver losses and receiver costs exceed the value of the additional energy intercepted by the receiver.

**Heliostat Layout.** The local heliostat density at any point within the collector field is determined through a tradeoff of cost and performance parameters influencing that portion of the field. This tradeoff considers the cost of heliostats, land, and interconnecting wiring. Clearly as heliostats are packed closer together, blocking and shadowing penalties increase, but related costs for land and wiring decrease.

While both shadowing and blocking increase if the heliostats are closer together, blocking has a more pronounced effect on the layout of heliostat fields. As heliostats are placed at greater radial distances from the tower, the receiver appears to be closer to the horizon. Therefore, heliostats must be placed at greater radial separations to be able to see the receiver.

As a design option within the collector field, alternate heliostat arrangements are possible. The two arrangements receiving the most study to date are the "cornfield" and the radial stagger arrangements. In the cornfield arrangement, heliostats are laid out along straight lines with uniform rectangular spacing being maintained throughout the section.

In the radial stagger arrangement, originated by the University of Houston, heliostats are laid out along radial spokes emanating from the concentric circles centered at the tower. The staggered characteristic of the layout means that no heliostat is placed directly in front of another heliostat in adjacent rings along a spoke to the tower. In this way, a reflected beam from one heliostat passes between its adjacent neighbors on the way to the receiver. The radial stagger layout pattern is illustrated in Figure 2.2–4.

Studies have shown that the radial stagger arrangement is the most efficient for a given land area. As a result, collector field designs for major central receiver systems are based on the radial stagger pattern. This pattern also reduces land usage and atmospheric losses.

**Wiring.** Collector field wiring represents a significant factor in the analysis of heliostat spacing. The two wiring

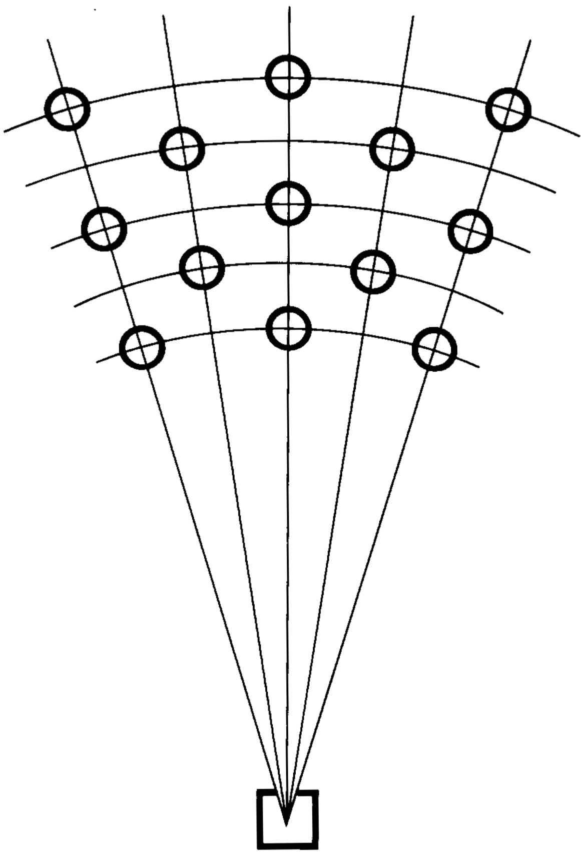



**Figure 2.2–4 Radial Stagger Heliostat Field Layout**

networks involved are the AC power system and the control system wiring. In each case, direct buried cable is essential for any type of cost effective design.

The typical AC power distribution system for the collector field consists of a regional power distribution center followed by a series of local step-down transformers. Power is supplied to the power distribution center at 4160 V through redundant primary power feeders. To facilitate field operations, the primary feeders are connected to the power distribution center through an auto transfer switch which is activated on loss of primary power.

The step-down transformers which are located throughout the collector field drop the voltage from 4160 V to 208 V which is compatible with most heliostat drive equipment. The 208 V power is then routed to each individual heliostat.

Heliostat control signals, which originate from a central heliostat array controller, pass through a similar distribution network. They are first routed to local heliostat field controllers which in turn communicate with the heliostat controllers located at the individual heliostats. To save costs, the communication cables are buried in common trenches with the power cables whenever possible.

Traditionally, the control wiring network has been made up of copper wire cable which forms a serial data highway between the heliostat array controller and the field controllers and also between individual field controllers and corresponding heliostat controllers. Alternate approaches involve the replacement of some or all of the copper wiring with fiber optical communication links.

The principal advantages of the fiber optical approach include the possibility of higher message traffic over a given data highway (or fewer data highways required), insensitivity to electromagnetic interference, and the potential for lower cost.

**Shape.** The general outline (shape) of these fields represents a contour of constant cost per unit energy collected. In general, this reflects a tradeoff between poorer performance of close-in heliostats on the south, east, and west sides and higher performance north side heliostats. The north side heliostats, however, suffer from atmospheric losses because of the long path lengths for the reflected beams which reduce interception by the receiver.

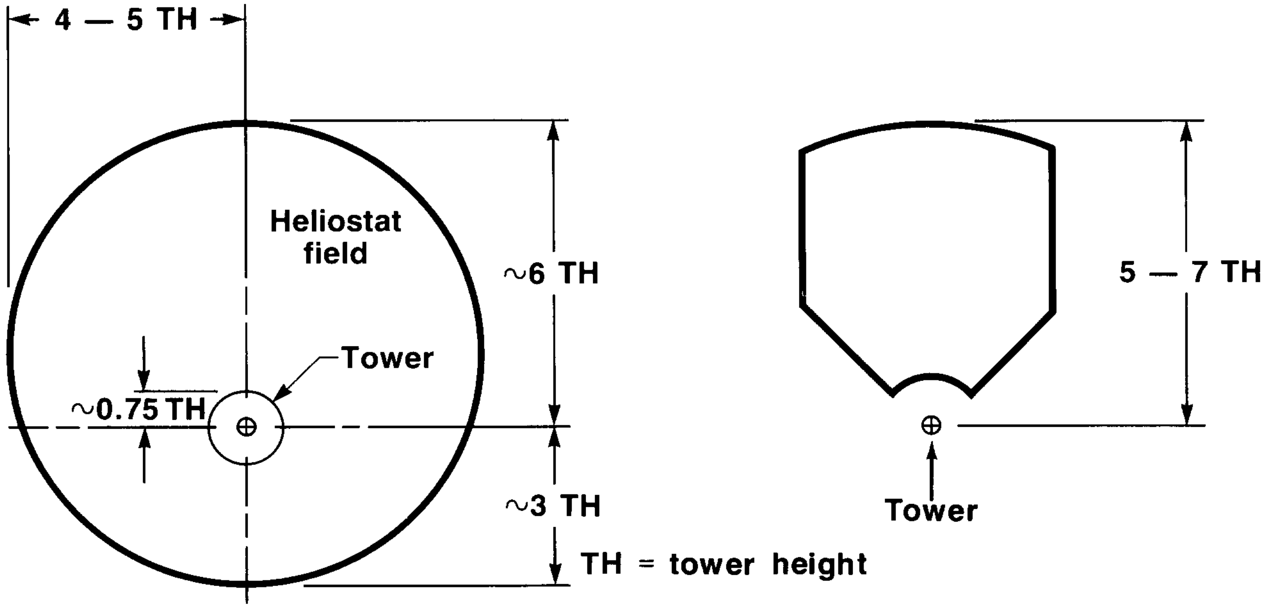



**Figure 2.2–5 Contours of North and Surround Heliostat Field Configurations**

The dependence of the annual performance on the heliostat's position relative to the tower is illustrated by representative optimum north and surround field designs in Figure 2.2–5. The observed shapes result from two effects. First, at a given radial distance, performance increases as the heliostat moves from south to north of the tower because the cosine effect is much better in the north part of the field. Second, the performance decreases in any direction as the radial distance of the heliostat increases. This decrease is caused by an increase in atmospheric attenuation and spillage losses.

The density of heliostats, chosen to minimize blocking, is greatest at the inner boundary and decreases with increasing radial distance from the tower. The average ratio of mirror area to land area is typically 0.20 to 0.25. The shape of the heliostat field remains relatively constant over a wide range of power levels.

## HELIOSTAT DESCRIPTION

The heliostat is the main element of the collector subsystem. A dictionary definition of a heliostat is "a mirror mounted on an axis moved by clockwork, by which a sunbeam is steadily reflected to one spot". The heliostat itself is the least dependent central receiver system component on overall system considerations; that is, unique heliostat designs are not required for each type of receiver heat transport fluid, receiver configuration, or end use application of thermal energy. This independence permits design emphasis to be placed on mass production as a means of reducing the unit cost of the heliostat, recognizing that the collector system represents a major portion of the overall system cost.

There are three main types of heliostats characterized by the type of mirror module and/or structural arrangement. Glass/metal heliostats have silvered glass as the reflecting surface and a relatively stiff structure to support the mirrors and withstand windloads. Membrane heliostats have a stressed membrane supporting a reflecting film. In a third option, the entire heliostat, either glass or membrane, may be enclosed in a pressurized bubble.[3]

Heliostats enclosed by a bubble are subjected to virtually no wind loads, and thus can have a lighter (and potentially lower cost) support structure. However, if the heliostat is enclosed in a bubble, the energy must pass through the bubble material twice, and in so doing can be absorbed and scattered by the bubble material or by dirt on the bubble material.

Stressed membrane heliostats offer the potential of lower cost through reduced material cost. A technology program is currently underway which is addressing the design and cost of such heliostats.[4]

**Development History**. The history of modern heliostats dates to the early 1970's. A summary of heliostat development in the United States is given in Table 2.2–1. Design features which have been incorporated in the various designs are also indicated in the table. Designs have been fabricated and tested in the quantities indicated.

As can be seen in Table 2.2–1, heliostat size has steadily increased. The growth in heliostat size was brought about by a continual effort to reduce the specific costs of heliostats (in $\$/m^2$) since the costs of the drive assemblies and pedestal were found to be, within reasonable limits, relatively insensitive to glass (mirror) area. The increase in reflective surface area for each pedestal drive assembly was shown to be beneficial in reducing the specific costs by spreading these relatively fixed costs over more reflective area. This reduction in the number of heliostats for a fixed system-required-mirror area also reduces the cost of installation and the number of field control components. Figure 2.2–6 illustrates the growth in heliostat size over time.

Sandia National Laboratories made an extensive evaluation of alternate heliostat designs at the conclusion of the Second Generation Heliostat Program.[5–12] Four different designs were produced in that program;[13–20] they are shown in Figure 2.2–7. The evaluation assessed the performance, development status, and, most importantly, the validity of projections of heliostat costs in mass production. The results of this evaluation, which are documented in the references, concluded that glass heliostats containing many of the features developed and tested during the program could be manufactured using mass production techniques at prices which would lead to substantial reductions in overall plant life cycle costs.

More recently, development and fabrication of even larger glass/metal heliostats and of stressed membrane heliostats have occurred. Versions of these two types are currently undergoing tests at the Central Receiver Test Facility. Figure 2.2–8 shows a large area heliostat, with a 150 $m^2$ reflective area. Figure 2.2–9 shows a 50 $m^2$ stressed membrane heliostat undergoing tests. Two 50 $m^2$ heliostats being tested are prototypes of planned 150 $m^2$ heliostats.

**Design Requirements**. The basic heliostat design requirements, summarized in Table 2.2–2, were developed during the second generation heliostat

Table 2.2—1

## HELIOSTAT DEVELOPMENT HISTORY IN THE UNITED STATES

| YEAR | PROGRAM TITLE | HELIOSTAT MANUFACTURER | SIZE $m^2$ | QTY | FEATURES: PEDESTAL | YOKE | PLASTIC ENCLOSED | VENETIAN BLIND | INVERTING | NON-INVERTING | WINDSPOILERS | MIRROR TYPE: LAMINATED GLASS | SANDWICH:GLASS/CORE/STEEL | ALUMINIZED MYLAR | SILVERED POLYMER |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1974 | National Science Foundation | McDonnell Douglas | 13.4 | 1 | ● | | | | | ● | | | ● | | |
| 1975–1977 | Pilot Plant System Research Experiment | Boeing | 48 | 4 | ● | | ● | | | ● | | | | ● | |
| | | Martin Marietta | 41 | 4 | | ● | | | ● | | | | ● | | |
| | | Honeywell | 40 | 4 | | | | ● | ● | | | | ● | | |
| | | McDonnell Douglas | 31.4 | 4 | ● | | | | | ● | | ● | | | |
| | | McDonnell Douglas | 37.5 | 2 | ● | | | | ● | | | ● | | | |
| 1977–1979 | Central Receiver Test Facility | Martin Marietta | 37.2 | 222 | | ● | | | ● | | | ● | | | |
| 1978–1979 | Pilot Plant Prototypes | Martin Marietta | 39.9 | 3 | ● | | | | ● | | | | ● | | |
| | | McDonnell Douglas | 44.5 | 3 | ● | | | | ● | | | | ● | | |
| 1979–1981 | Second Generation | Boeing | 43.7 | 3 | ● | | | | | ● | | | ● | | |
| | | Martin Marietta | 57.4 | 3 | ● | | | | ● | | | | ● | | |
| | | McDonnell Douglas | 56.9 | 3 | ● | | | | | ● | | ● | | | |
| | | ARCO (Northrup) | 57.8 | 3 | ● | | | | | ● | | | ● | | |
| | | Westinghouse | 81.7 | 0*1 | ● | | | | ● | | | ● | | | |
| 1980–1981 | Solar One*2 | Martin Marietta | 39.9 | 1911 | ● | | | | ● | | | | ● | | |
| 1981–1986 | Large Area | McDonnell Douglas | 95 | 5*3 | ● | | | | | ● | | ● | | | |
| | | ARCO | 95 | 1*4 | ● | | | | | ● | | ● | | | |
| | | ARCO | 150 | 2*5 | ● | | | | | ● | | ● | | | |
| | | Solar Power Eng. Co. | 200 | 1 | ● | | | | | ● | ● | ● | | | |
| 1984–1986 | Stressed Membrane | Solar Kinetics Inc. | 150 | 1*6 | ● | | | | | ● | | | | | ● |
| | | Science Applications International Corp. | 150 | 1*6 | ● | | | | | ● | | | | | ● |

*1 – 140m² Prototype built
*2 – 93 delivered to IEA/SSPS Plant
*3 – 85m² Dishes, Funded by mfr.
*4 – 1 Heliostat, 864 PV trackers, Funded by mfr.
*5 – 2 Heliostats, 43 PV trackers, Funded by mfr.
*6 – 50m² Prototype

program. Design specifications are included in four categories: operational modes, optical performance, survival and lifetime. Lifetime estimates were validated using accelerated life cycle testing. Testing in the second generation program and in subsequent work demonstrated that all of these requirements can be obtained on an operational basis in a cost effective manner.

**Collector System Components.** Major collector system components include the heliostat, heliostat controls, heliostat field controllers, heliostat array controller, and supporting equipment. Table 2.2–3 summarizes these components, their sub-elements and the quantity required in a central receiver plant.

The heliostat itself is made up of several major components which are listed in Table 2.2–3 and described separately below.

*Reflector.* The reflector or mirror module consists of a silvered glass mirror and some support structure in glass/metal heliostats or a reflective polymer-coated metal membrane in stressed membrane heliostats. Glass/metal mirror modules are usually rectangular, ranging in size from 0.6×3 m (2×10 ft) to 1.2×6.1 m (4×20 ft). Each glass/metal heliostat is made up of multiple mirror modules.

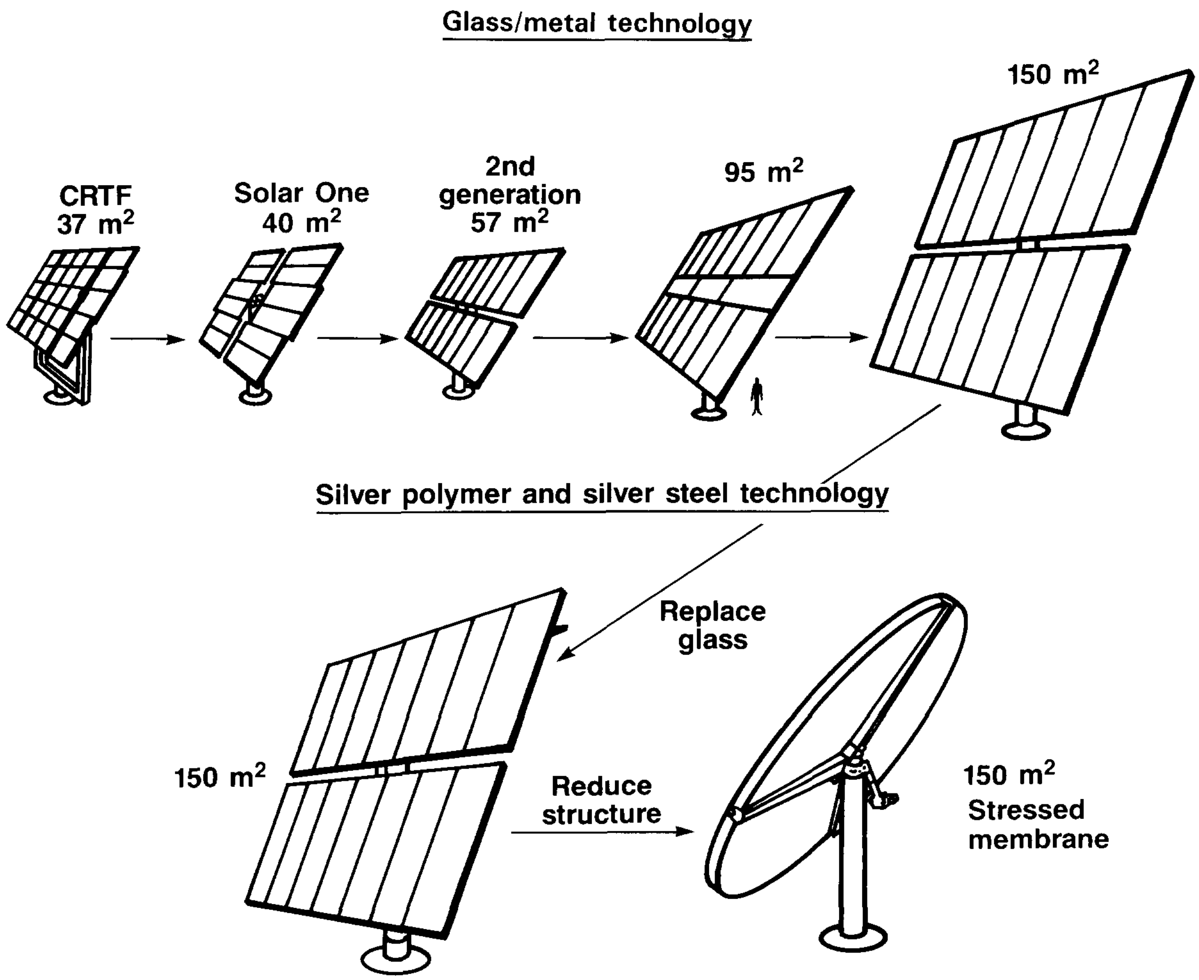



**Figure 2.2–6 Pictorial Representation of Heliostat Development**

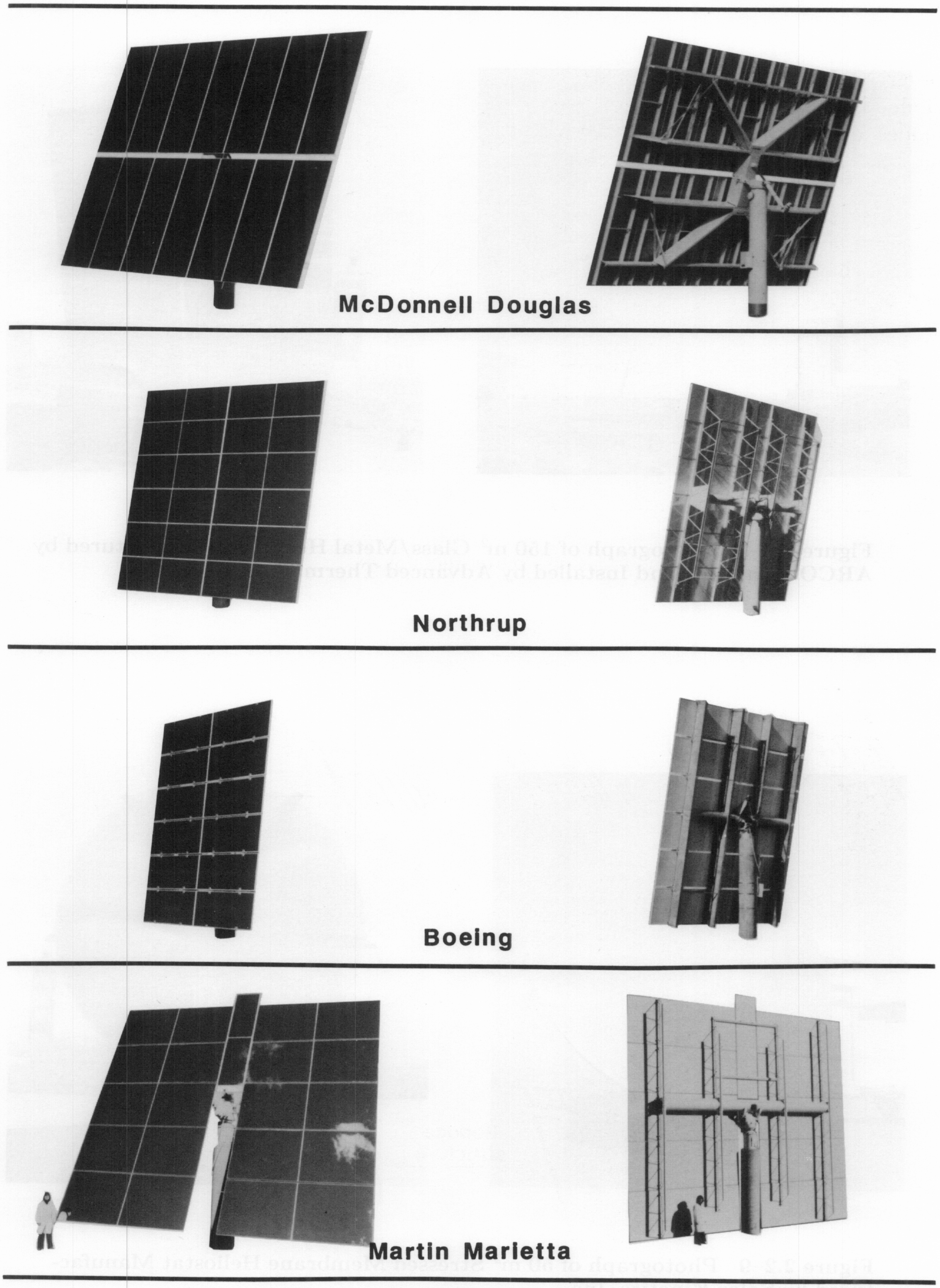



**Figure 2.2–7 Second Generation Heliostats**

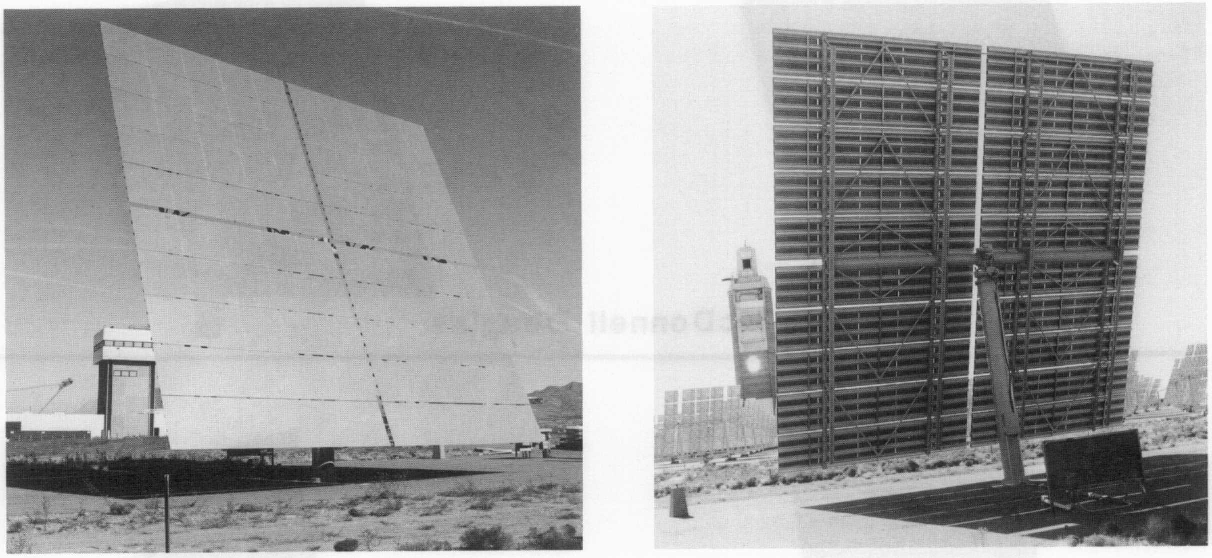


**Figure 2.2–8 Photograph of 150 m$^2$ Glass/Metal Heliostat Manufactured by ARCO Solar Inc. and Installed by Advanced Thermal Systems**

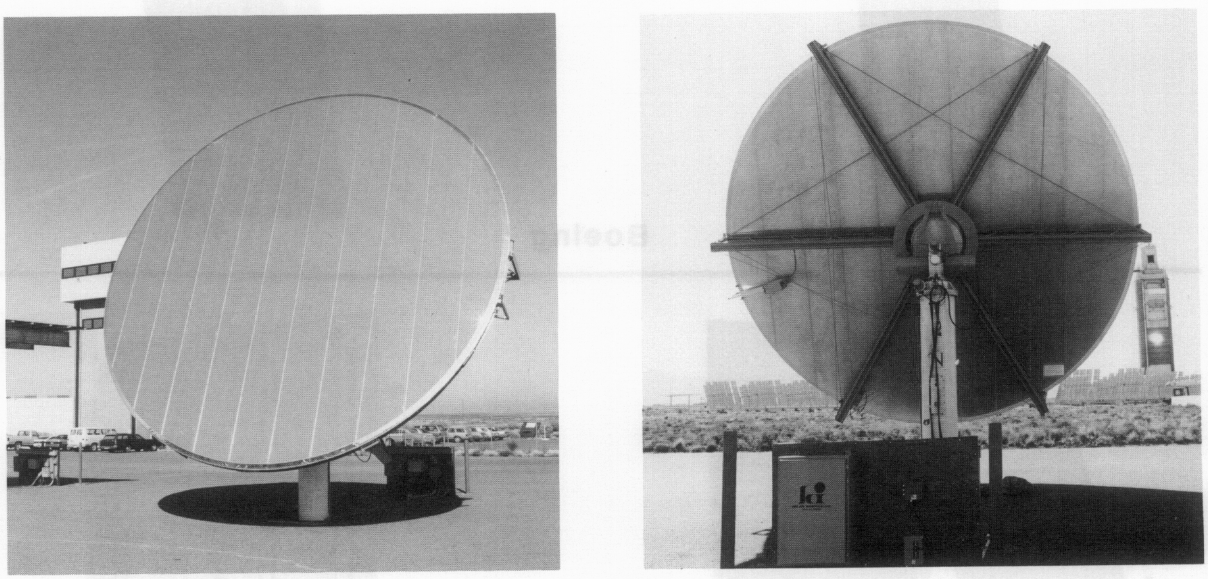


**Figure 2.2–9 Photograph of 50 m$^2$ Stressed Membrane Heliostat Manufactured by Solar Kinetics, Inc.**

Table 2.2-2
HELIOSTAT DESIGN REQUIREMENTS

| Category | Requirements |
|---|---|
| Operational Modes: | Normal modes (track, standby, wire walk, stow)<br>Track in up to 35 mph wind<br>Slew in 50 mph wind<br>Resolve tracking singularity in 15 minutes<br>Reposition in 15 minutes<br>Emergency defocus in 3 minutes<br>Electrical transients (operate through a 3 - cycle dropout) |
| Optical Performance: | Beam pointing (1.5 mrad RMS maximum, reflected beam error for each axis)<br>Beam quality (theoretical beam shape plus 1.4 mrad fringe, 32°F - 122°F)<br>Wind load deflection (3.6 mrad RMS maximum reflective surface deflection in 27 mph wind, discounting foundation)<br>Foundation deflection (0.45 mrad maximum set after survival wind, 1.5 mrad maximum twist or tilt in 27 mph wind) |
| Survival: | 90 mph wind, heliostat stowed<br>50 mph wind, heliostat in any orientation<br>Temperature, −20° to 122°F<br>Hail, — 3/4 inch at 65 ft/sec, any orientation<br>1 inch at 75 ft/sec, heliostat stowed<br>Cold water shock |
| 30-Year Life: | Life of all components must be cost-effective for 30 years<br>Mirrors and drive mechanism are critical components. |

Each mirror module usually has a slight concave curvature and is also canted (aimed) with respect to the plane of the support structure to better focus the reflected sunlight on the receiver and thus improve performance.

Extensive work has been done in the last few years on reflectors and glass technology. More detailed coverage of this work may be found in References 8, 9, and 21–47.

*Reflector Support Structure.* The reflector support structure supports the array of mirror modules. Usually this structure consists of a main beam or torque tube with several cross beams. The main beam is attached to the drive system while the mirror modules are attached to the cross beams. Truss type beams are the preferred option especially for larger heliostats because their depth can be varied to provide the required stiffness, with little weight penalty. A roll-formed section, while good for small depths, has a solid web which makes deep roll-formed sections weigh more and has less stability than truss type beams.

*Drive Systems.* The drive systems move the reflector assembly to provide accurate sun tracking capability. Heliostats require two axis drive systems. Many different system axes have been considered such as polar, equatorial, pitch/yaw and azimuth/elevation. The

Table 2.2–3
COLLECTOR SUBSYSTEM COMPONENTS

| Major Element | Quantity Required | Sub-Elements |
|---|---|---|
| Heliostat | 600,000 $m^2/100$ $MW_e$ | Reflector (mirror(s))<br>Reflector support structure<br>Drive unit(s) (gear box,motors, cabling, etc.)<br>Pedestal(s)<br>Foundation(s) |
| Heliostat Controls | One per heliostat | Drive motor controller<br>Position sensor<br>Interface with power system and heliostat field controller |
| Heliostat Field Controllers | One per group of approximately 32 | Interface electronics for heliostat controller<br>Computer, software<br>Interface electronics for heliostat array controller |
| Heliostat Array Controller | One per field | Time base, computers, software<br>Master control interface electronics |
| Support Equipment and Procedures | | Handling equipment<br>Maintenance trucks and equipment<br>Heliostat washing equipment<br>Operating procedures<br>Maintenance procedures |

systems currently in use or proposed are all based on the use of azimuth and elevation axes because of their lower cost.

A rotary drive is typically used in azimuth because of the large angular motion in azimuth (approximately $\pm$ 270° depending on site latitude and field configuration).

For the elevation drive, the rotational requirement for a non-inverting heliostat is 90°. Because of the smaller angular movement, a linear actuator such as a screw jack can provide elevation adjustment at a lower cost than a rotary drive.

*Pedestal and Foundation.* Past work has identified the single pedestal mounted heliostat as the preferred configuration. A pedestal mount costs less and both drives may be located at the top of the pedestal. Heliostat foundations have been studied for different heliostat sizes and soil types. When soil conditions will permit, a drilled pier type foundation is the most cost effective.

*Heliostat Control.* During plant operation, the heliostats require a control system to position the drive axes independently throughout the day. Two types of control systems have been considered for heliostat use: open loop and closed loop. In an open loop system, the heliostat is programmed to point using temporal and geometric algorithms in the control computer software. In a closed loop system, a sun sensor provides feedback to the control computer about whether the heliostat is pointing in the right direction to illuminate the receiver.

Because of lower costs, an open loop system is the preferred approach. The need to control the heliostat beams accurately to insure beam safety requires an open loop control system with the same accuracy as for tracking.

Current collector subsystem control systems have three major elements as shown in Figure 2.2–10: a heliostat array controller (HAC), a heliostat field controller (HFC) and a heliostat controller (HC). The HAC, a centrally located, oversight computer, provides information to many HFC's. Each HFC, located throughout the field, controls a group of heliostats (usually 32). The HC, located in the pedestal, controls the motors of an individual heliostat.

The control system must update the sun position and calculate new heliostat positions every few seconds since the angular relationship between the sun, the heliostat, and the receiver changes continuously as the sun moves at about 0.07 milliradians per second.

## HELIOSTAT WASHING

Optimum plant performance requires maintenance of high mirror reflectivity. Reflectivity is principally reduced by soiling and periodic heliostat cleaning is required to remove the dirt. (See Refs. 48–64.) The reflective performance of the heliostat field is expressed in terms of a cleanliness factor. This factor, expressed as a percent of the clean field reflectivity, measures the cleanliness of the heliostat field.

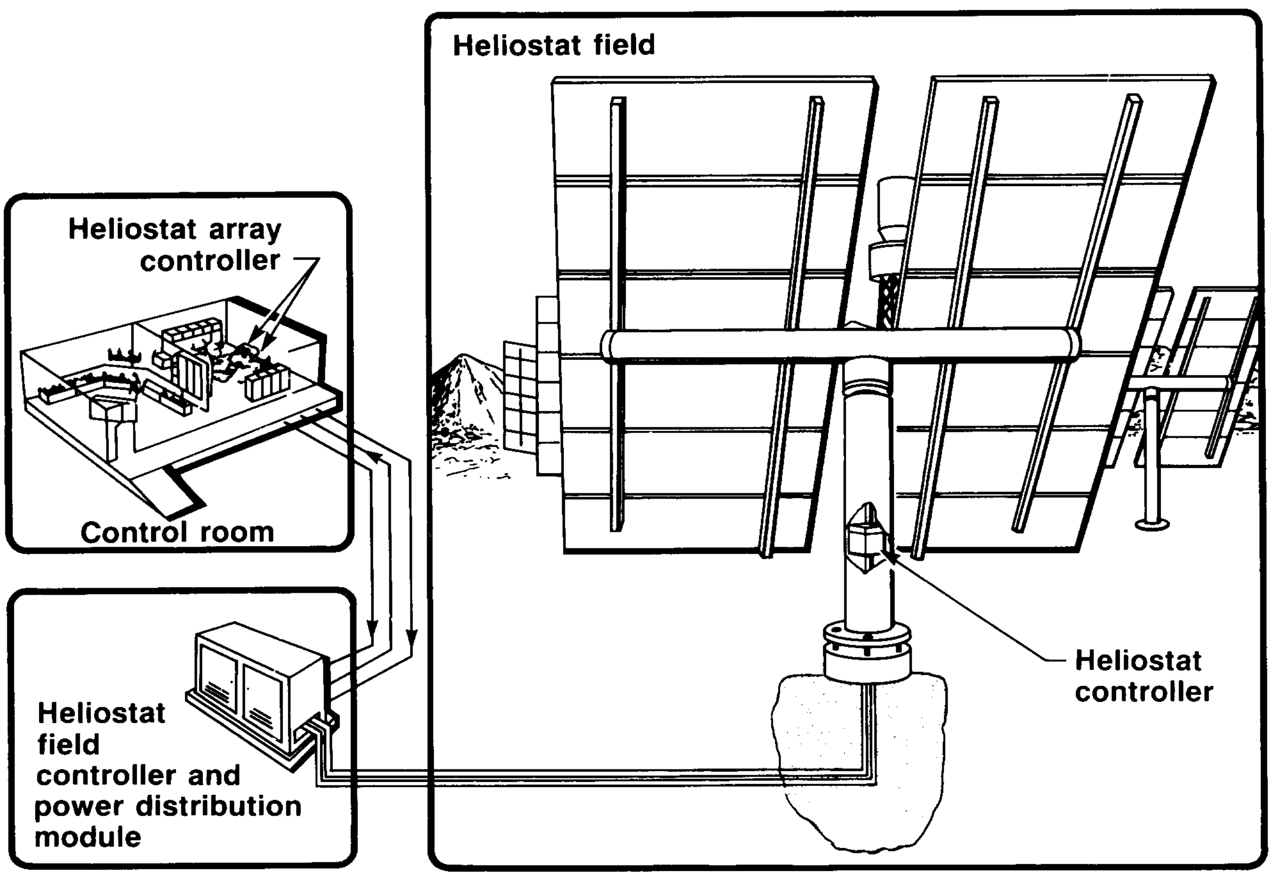



Figure 2.2–10 Collector System Control Components

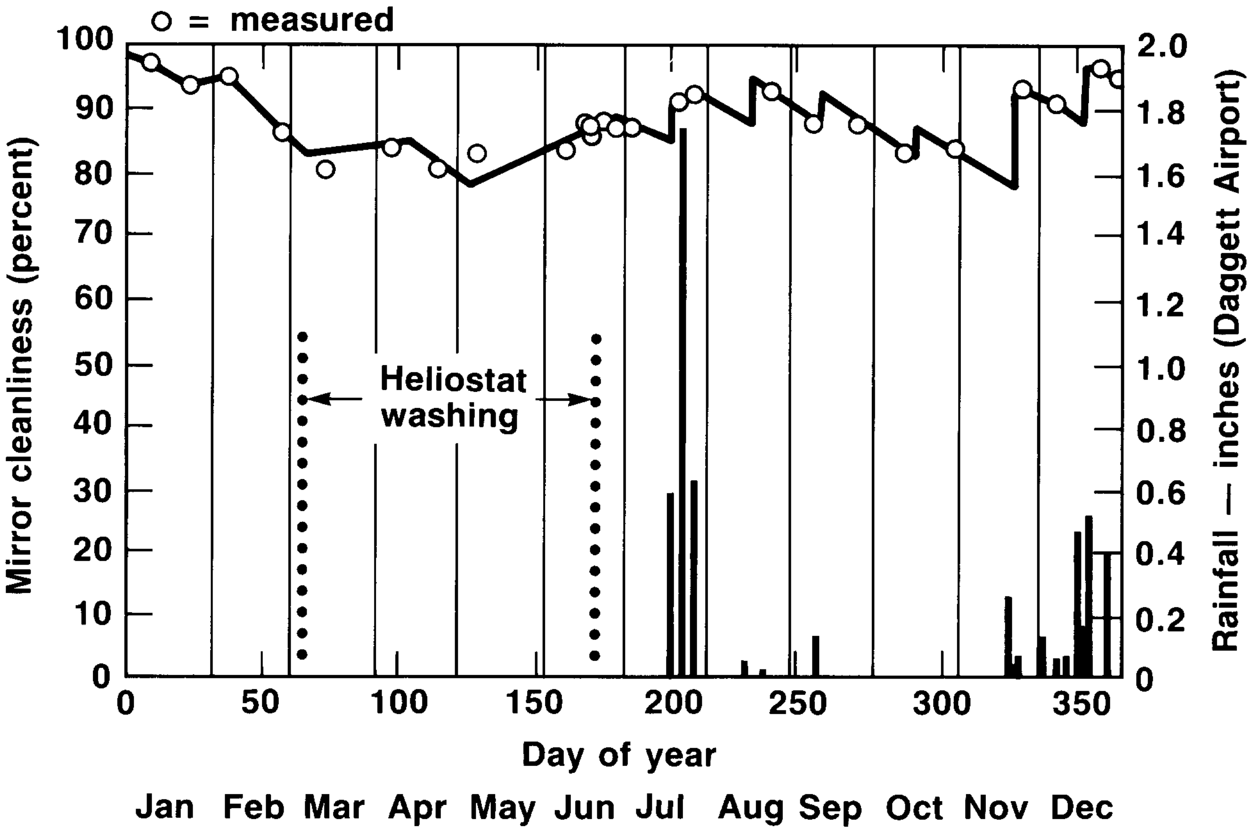



**Figure 2.2–11 1984 Solar One Heliostat Cleanliness**

At Solar One, a portable specular reflectometer is used to monitor the reflectivity of representative mirrors in the field. Figure 2.2–11 shows a record of mirror cleanliness during one year, 1984. This record indicates that both rainfall and mechanical cleaning are required to maintain high reflectivity. Because of farming activities, severe mirror soiling occurred between February and July 1984. Also many days of high winds caused severe dust storms. Mirror cleaning occurred during October at the plant; no rainfall is indicated because rainfall is based on that recorded at the Daggett airport, which is several miles from Solar One. In this instance despite rain at the plant, no rainfall was recorded at the airport.

Mirror soiling at Solar One is most severe on the outer 7.5–15 cm (3–6 in) edge of the mirror because of the way that moisture condenses on and evaporates from the glass due to temperature differences between the center and the edge of the mirror. A 10–12 percent difference in cleanliness between the center and edge has been recorded.

Solar One data on rainfall, washing, and mirror cleanliness indicate that three to six mechanical washings are required per year to maintain the reflectivity above 90% of the clean value reflectivity. Recent analyses suggest that it would be cost effective to wash the field more frequently, as often as bi-weekly.

For a soiling rate of 0.28%/day, the average rate in 1984, bi-weekly brush washing achieved an average mirror cleanliness of 97%. The benefit — an increase in plant energy output and plant revenues — resulting from increased washing was estimated to be two–three times the cost of carrying out the additional washings. Modifications were performed to the water spray with brush heliostat wash truck to increase its operating capability and permit more frequent washings of the heliostat field. Results indicated that one truck operator with a wash rate of 150-170 heliostats per eight hour shift could restore mirror cleanliness to 99% of the clean value, which would provide a 97% average cleanness with biweekly washing.

Figure 2.2–12 is a photograph of the wash truck used at Solar One. It has worked well for the heliostats used there. However, new equipment design will probably be required for cleaning of the very large heliostats likely to be placed in future plants. Stressed membrane mirrors require noncontact cleaning to prevent scratching the mirror.

Mirror soiling was also examined in detail at the IEA/SSPS central receiver plant in Almeria, Spain. Results indicate a higher soiling rate, owing to a combination of the very fine, dusty soil conditions and frequent winds. At the plant, water spray and/or rain have been shown to be sufficient to clean the mirrors to acceptable levels (>97% clean).

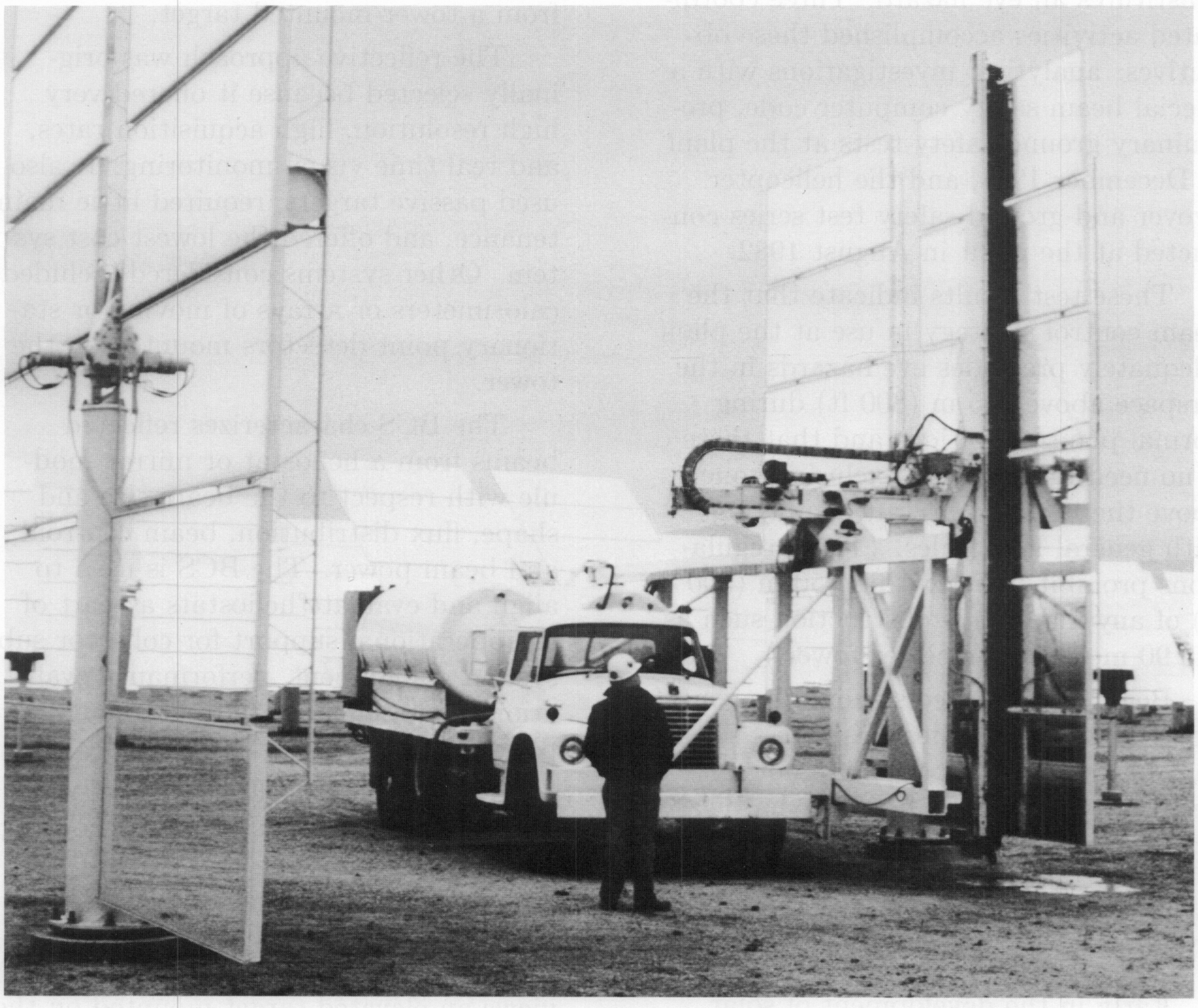


**Figure 2.2–12 Photograph of the Heliostat Wash Truck**

## BEAM SAFETY

In 1981-1982 detailed experiments conducted at Solar One examined the potential hazard of heliostat beams.[65] The principal objectives of this program were: 1) to identify and evaluate eye hazards caused by heliostat beams at ground level and in the airspace above the plant; 2) to confirm the adequacy of the adopted beam control strategy; 3) to confirm the adequacy of at least one beam control strategy for heliostats that are designed to stow horizontally face-up in high wind conditions; and, 4) to measure receiver brightness to see if it constitutes an eye hazard. Three coordinated activities accomplished these objectives: analytical investigations with a special beam safety computer code, preliminary ground safety tests at the plant in December 1981, and the helicopter flyover and ground safety test series conducted at the plant in August 1982.

These test results indicate that the beam control strategy in use at the plant adequately precludes eye hazards in the airspace above 245 m (800 ft) during normal plant operations and that there is no need for a special exclusion zone above the field for aircraft complying with general FAA rules. (These regulations prohibit flying within 150 m (500 ft) of any man-made obstruction such as the 90 m (300 ft) receiver tower.)

Beam safety aspects should be considered early in the design process so that beam control options are not unnecessarily limited by heliostat hardware or software decisions.

## BEAM CHARACTERIZATION SYSTEM

Early in the development of solar central receivers it was recognized that some means of aligning, monitoring, and evaluating large numbers of heliostats would be required. To meet these objectives, McDonnell Douglas, in 1974, created and tested a digital image radiometer (DIR).[66] Results showed that total beam power, irradiance distribution, beam centroid, tracking accuracy, and overall mirror reflectivity could be determined accurately and rapidly. A similar device, called the heliostat beam characterization system (BCS), was developed at the Central Receiver Test Facility in 1978 and used extensively in the evaluation of various heliostat designs.[67–71] Both systems use a video camera to measure the reflected light from a tower-mounted target.

The reflective approach was originally selected because it offered very high resolution, high acquisition rates, and real time visual monitoring. It also used passive targets, required little maintenance, and offered the lowest cost system. Other systems considered included calorimeters or arrays of moving or stationary point detectors mounted on the tower.

The BCS characterizes reflected beams from a heliostat or mirror module with respect to the beam size and shape, flux distribution, beam centroid, and beam power. The BCS is used to align and evaluate heliostats as part of the operational support for collector subsystem realignment, performance evaluation, and maintenance throughout the plant life.

The BCS is based on a digital image radiometer and associated recording equipment. The basic BCS consists of a number (four at Solar One)[72] of specially modified video cameras. As illustrated in Figure 2.2–13, each camera views an elevated target mounted on the tower beneath the receiver. One additional camera records sun shape data.

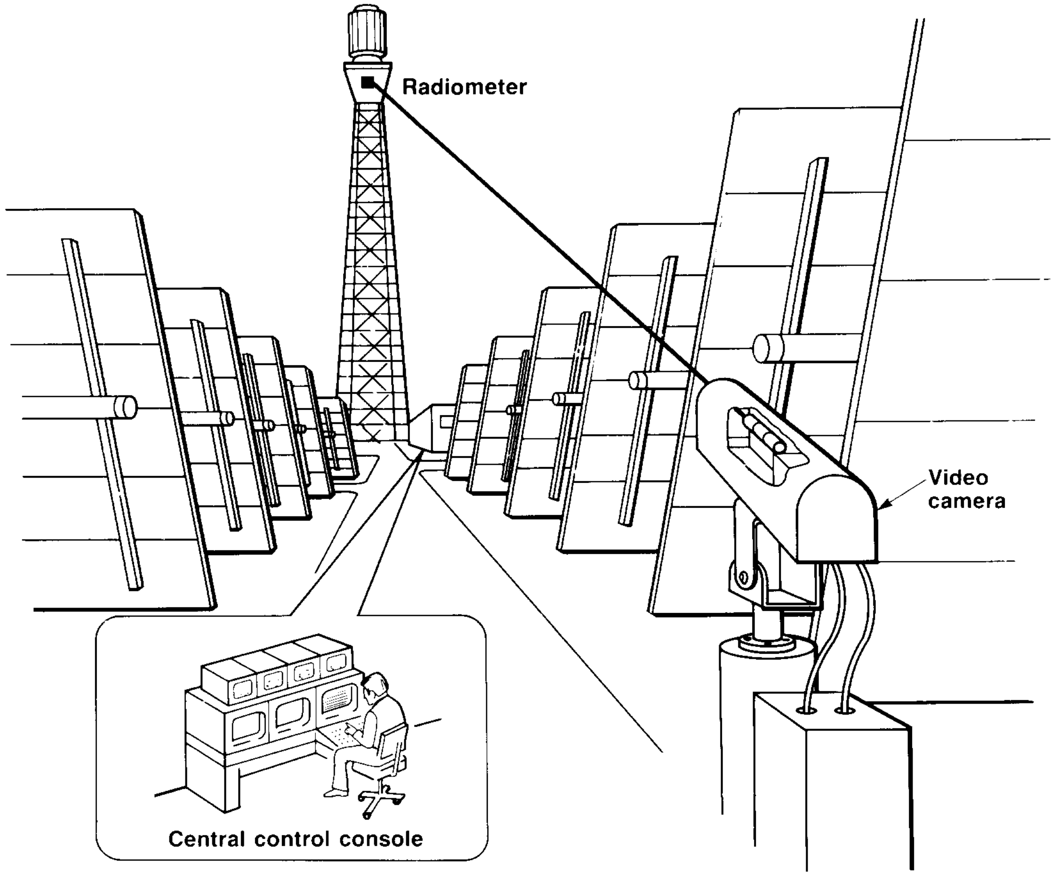


**Figure 2.2–13 Beam Characterization System Schematic**

The digitized video analog output signals provide a measure of beam intensity distribution from a heliostat.

The digitized intensity for a particular frame correlates with absolute intensity. Nearly simultaneous measurements are made by a calibration procedure using target-mounted radiometers. The targets are flat structures painted with a high temperature white paint specifically selected for its near-Lambertian reflecting characteristics to minimize glare and provide uniform reflection over the target surface. Three or more radiometers are positioned about the center of the target within the area of a centered beam image to provide reflected beam irradiance measurements over some portion of the moderate to high intensity regions of the beam.

A specially modified video camera tracks the sun and makes simultaneous measurements of the radiance distributions. Computer codes use these data, coupled with the absolute measurement of incident irradiance, to compare actual and ideal heliostat irradiance distributions. Additional radiometers located in the field as part of the data acquisition subsystem determine incident solar irradiance, which is used to establish heliostat reflective efficiency as measured at the target.

Beam centroid data are obtained to establish heliostat aiming errors which are then corrected as necessary by changing bias values in the heliostat array controller code. The aiming errors should be determined several times during the day so the best error correction can be made for all hours of the day. At Solar One, one average error correction is made for the entire day. More recent heliostat designs make error corrections that depend on the time of day. Supporting data on heliostat performance consist primarily of net power, tracking error variations, spillage power, overall power effectivity, and environmental conditions such as wind speed, direction, temperature, and solar irradiance. The operator uses these data, as well as displays of the beam contour on the target and solar radiance distribution, for engineering evaluation and verification of beam centroid data.

The Solar One BCS can measure heliostat beams at a rate of approximately one every one to two minutes. Most of this time is used to move blocking and shadowing heliostats into a stow position, which would not be required for alignment alone. Centroid measurement accuracy is of the order of 5 cm (2 in) although wind induced heliostat movement can cause the standard deviation of beam centroid location to exceed this value.

This centroid position error corresponds to a beam centroid angular error of approximately ± 0.15 mr. Beam power measurement accuracy is approximately ± 5% with low wind, clear sky conditions. Data required for heliostat bias updates, used to correct tracking errors, are subjected to a series of validity algorithms prior to transmission to the HAC, so that operator review of the data is not required.

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# RECEIVER SUBSYSTEM

The receiver subsystem intercepts and absorbs the concentrated radiant energy reflected from the collector subsystem and transfers this energy to a heat transport fluid. The receiver is mounted at the top of a tower. Its heat absorbing surfaces are similar to those of a fossil fueled boiler; that is, multiple panels composed of parallel tubes that are welded to inlet and outlet headers at either end. The heat transport fluid flows through the tubes, removing the solar energy absorbed on their outer surfaces.

The principal components of the receiver subsystem include the absorber surface, composed of multiple modular panels, and the receiver structure, to which the absorber panels are attached. Panel interconnecting piping, inlet and outlet manifold piping, surge tanks or steam drum (as appropriate) are also required.

In addition, a sodium/salt binary system configuration, described in Section 2.1, requires a sodium-to-salt intermediate heat exchanger whose operation is closely tied to that of the receiver.

Receiver design is dependent upon the choice of receiver working fluid. There are three principal candidates for the receiver heat absorbing fluid for near-term, Rankine-cycle, solar power plants: water/steam, molten nitrate salts, and liquid sodium. Attributes of these fluids are further discussed in Section 2.4.

## PERFORMANCE

Subsystem performance for different receiver configurations is the result of a variety of design tradeoffs among several loss mechanisms. These losses, shown schematically in Figure 2.3–1, include:

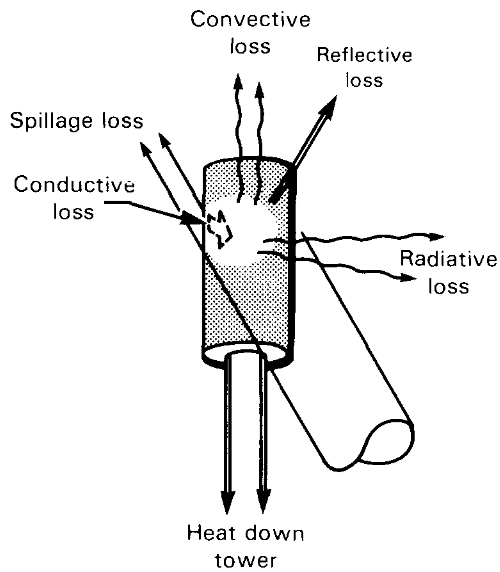


**Figure 2.3–1 Receiver Loss Processes**

*Spillage* — the energy reflected by the heliostat field, after accounting for atmospheric absorption between heliostat and receiver, which is not intercepted by an absorber surface containing the receiver heat transport fluid, or re-reflected or radiated from an intermediate surface to that absorber surface.

Spillage may be considered either a collector subsystem loss or a receiver subsystem loss.

Spillage can miss the receiver entirely, or merely fall outside the aperture in the case of a cavity receiver. It may result from receiver sizing tradeoffs or heliostat aiming errors. The receiver is normally designed to keep overall spillage less than five percent of the reflected light reaching the vicinity of the receiver.

*Reflection* — the light energy from the heliostat field scattered from the receiver surface and escaping from the receiver. High absorptivity paint is used on the absorber surfaces to minimize reflective loss. Reflection loss is generally five percent or less with a freshly-painted absorber surface, but may increase during service as a result of degradation of the coating.

*Convection* — the thermal energy lost in heating the air adjacent to the receiver. It is a combination of free (thermally driven) and forced (wind driven) convection, with the free convection component usually larger.

Estimation of the convective losses from central receivers has been the subject of analytical and experimental research in the program.[1–3]

*Radiation* — the thermal energy lost by infrared and visible light emission due to the high temperature of the receiver. Both the radiative and convective losses are a function of the temperature of the receiver and its configuration (cavity or external). Typical combined radiation and convection losses are in the range of five to fifteen percent of the peak incident energy at the receiver.

*Conduction* — the thermal energy lost through the insulating surfaces and structural members. This loss is less than one percent for a well insulated receiver.

Minimizing the energy losses of a receiver is important. Receiver design optimization should be done on the basis of minimizing the cost per unit energy delivered by the total system; thus the optimization reflects the cost and performance of all components of the system.

In Chapter 4 a more detailed discussion is given of the system optimization process and the principal receiver subsystem trade-offs that affect it.

## CONFIGURATION

Two general receiver configurations occur: external and cavity. Prototypical designs for external and cavity receivers are illustrated in Figure 2.3–2.

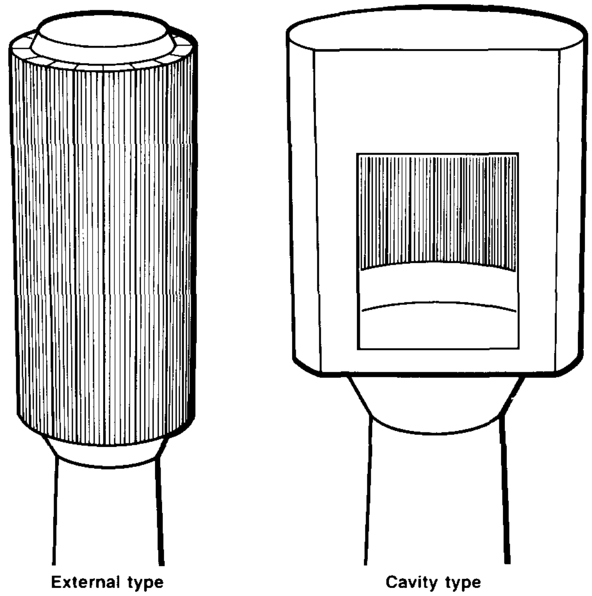


**Figure 2.3–2 Cavity and External Receiver Configurations**

External receivers have heat absorbing surfaces that are either flat, often called a billboard, or convex toward the heliostat field. For a large plant, an external receiver is typically a multipanel polyhedron that approximates a cylinder, with a surround heliostat field. The height to diameter ratio of a cylindrical receiver is generally in the range of 1:1 to 2:1. Smaller plants with external receivers typically use a north field configuration with a billboard or a partial cylinder receiver (omitting most of the south-facing panels).

In a cavity receiver, the radiation reflected from the heliostats passes through an aperture into a box-like structure before impinging on the heat transfer surfaces; this box and aperture define the cavity. A receiver may be composed of more than one cavity, each facing a different sector of the heliostat field. However, recent studies of the cavity receiver concept indicate that the preferred configuration is a single cavity facing a north, in the northern hemisphere, heliostat field.

The active heat transfer surfaces within a cavity are formed from panels like those used in external receivers; however, the panel arrangement within a cavity is concave facing the heliostats.

Other internal areas of the cavity, such as the roof and floor, do not normally serve as active heat absorbing surfaces. These areas must be effectively closed and insulated to minimize heat loss and to protect structure, headers, and interconnecting piping from incident flux. Although they are not exposed to high levels of direct flux, the inactive internal areas are exposed to radiation from the hot absorber panels. The inactive surfaces are typically uncooled and can reach temperatures exceeding those of the active panels.

The active panel area and inactive internal surface area are each typically two to three times the area of the aperture. The aperture size and geometry are chosen to minimize the sum of thermal losses and spillage losses. A vertical aperture of square or rectangular shape is typical.

Several factors distinguish external and cavity receivers. Radiative losses are generally larger for external receivers since the hot receiver panels are exposed and have larger view factors to the colder ambient environment. Cavity receiver panels are somewhat protected and have low view factors through the relatively small aperture. Similarly, reflection losses for an external receiver are slightly greater.

However, spillage losses are generally larger for cavity receivers because the heliostat radiation must fit through the relatively small aperture, and thermal convection losses may be larger because of the large heated surface area (active plus inactive) of the cavity.

The required absorber area in a cavity receiver is larger (by roughly 25%) than that required for an external receiver with the same thermal rating, allowable peak flux limit and flux gradient. This results from the greater difficulty in illuminating the cavity absorber area uniformly because of the cavity aperture.

The receiver mass and number of components are larger and generally more costly for a cavity than for an external receiver with a similar absorber area. On the other hand, the capability to use the thermal mass of the receiver and perhaps include a receiver door at the aperture exists for the cavity. The mass provides some thermal inertia which enables buffering of transient weather conditions. The door in a cavity receiver may be closed during times of low insolation to reduce thermal losses and simplify startup procedures.

Receiver tubes in a cavity are more protected from the effects of weather than are external receiver tubes; this may result in less degradation of high-absorptance coatings during service.

## DEVELOPMENT STATUS

Receiver prototypes utilizing each candidate working fluid have been tested in subsystem and system experiments. For systems designed to operate with conventional steam turbine cycles (e.g., inlet steam conditions of 540°C or 1000°F and 9.6 to 12.8 MPa, 1390 to 1860 psi), receiver fluid inlet and outlet temperatures are similar for all three fluids, although minor differences do exist that relate to the specific receiver fluid and interfaces with thermal storage media. Table 2.3–1 lists the receiver types which have been tested as a part of operating systems.[4–7] These systems are further described in Appendix A. Receiver subsystem experiments conducted as a part of the U.S. DOE solar central receiver program are outlined in Table 2.3–2.[8–14] (Only water/steam, salt and sodium receiver experiments are listed in the Table. Air receiver experiments have also been conducted.)

In addition to the receiver tests, a large number of system conceptual design studies have been performed in which specific receiver designs suitable for commercial scale operation have been completed. These designs and their major characteristics are outlined in Tables 2.3–3, 2.3–4, and 2.3–5. The tables highlight some of the significant features in each design. Each table focuses on the designs for a specific receiver heat transport fluid: water/steam in Table 2.3–3 (references 15–35), molten nitrate salt in Table 2.3–4 (references 36–50), and liquid sodium in Table 2.3–5 (References 51–63).

Table 2.3–1

RECEIVERS IN CENTRAL RECEIVER SYSTEMS
WHICH OPERATED IN 1986

| Plant | Configuration | Heat Transport Fluid |
|---|---|---|
| Solar One (Barstow, CA, USA) | External | Water/Steam |
| Themis (Targasonne, France) | Cavity | Hitec (nitrate salt) |
| IEA/SSPS (Almeria, Spain) | External<br>Cavity | Sodium<br>Sodium |
| CESA-I (Almeria, Spain) | Cavity | Water/Steam |

Table 2.3-2

RECEIVER EXPERIMENTS CONDUCTED AS A PART OF THE
U. S. DOE CENTRAL RECEIVER PROGRAM

| Test | $MW_t$ | Fluid | Receiver Configuration | Test Type | Test Facility | Date | Test Time (hours) |
|---|---|---|---|---|---|---|---|
| Martin Marietta | 1.0 | water/steam | cavity | radiant | Sandia | 1976 | 165 |
| Martin Marietta | 1.0 | water/steam | cavity | solar | CNRS | 1976 | 161 |
| Martin/Marietta/ Foster Wheeler | 5.0 | water/steam | cavity | radiant | Sandia | 1977 | 231 |
| Honeywell/Babcock & Wilcox | 5.0 | water/steam | cavity | radiant | Honeywell | 1977 | 198 |
| MDAC/Rocketdyne 5 tube | 0.21 | water/steam | 5 tube* | radiant | Sandia | 1979-80 | 400 |
| MDAC/Rocketdyne 70 tube | 5.0 | water/steam | external* | solar | CRTF | 1979-80 | 400 |
| Martin Marietta | 5.0 | nitrate salt | cavity | solar | CRTF | 1980-81 | 400 |
| ESG, Rockwell | 3.0 | sodium | external | solar | CRTF | late 1981 | 100 |
| MSEE | 5.0 | nitrate salt | cavity | solar | CRTF | 1983-85 | 500 |
| MSS/CTE | 5.0 | nitrate salt | cavity | solar | CRTF | 1986-87 | (in progress) |

Sandia - Sandia National Laboratories Radiant Heat Facility
CNRS - Centre Nationale pour la Recherche Scientifique - Odeillo, France
MDAC - McDonnell Douglas Astronautics Corporation
CRTF - Central Receiver Test Facility
ESG - Energy Systems Group
MSEE - Molten Salt Electric Experiment
MSS/CTE - Molten Salt Subsystem/Component Test Experiment
*Panel designs also tested earlier (1976-1977) at the Rocketdyne B-1 Test Facility

Table 2.3–3
WATER/STEAM COMMERCIAL RECEIVER DESIGNS

| YEAR | PROGRAM TITLE | PRIME CONTRACTOR | UTILITY PARTNER (Repowering Studies) | RECEIVER DESIGNER(S) | NO. RCVR MODULES IN SYSTEM | RECEIVER MODULE THERMAL RATING ($MW_t$) | SURROUND FIELD | NORTH FIELD | RECEIVER CONFIG. | | | | | | ONCE-THROUGH FLOW | RECIRCULATING FLOW | REHEAT RECEIVER | RECEIVER SRE TEST* (See Table 2.3–2) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | EXTERNAL CYLINDER | EXT. PARTIAL CYLINDER | EXTERNAL BILLBOARD | NORTH-FACING CAVITY | QUAD CAVITY | DOWN-FACING CAVITY | | | | |
| 1975–1977 | Solar One (Commercial System) | | | | | | | | | | | | | | | | | |
| | McDonnell Douglas | MDAC | – | MDAC/Rock | 1 | 560 | ● | | ● | | | | | | ● | | | a |
| | Martin Marietta | MMC | – | MMC/FW | 15 | 41 | | ● | | | | ● | | | | ● | | b |
| | Honeywell | HON | – | HON/B&W | 4 | 146 | ● | | | | | | | ● | | ● | | c |
| 1978 | Repowering/Hybrid Study Reeves Station, Unit 2 | PNM | PNM | MDAC/Rock | 1 | 111 | ● | | ● | | | | | | ● | | | a |
| 1979 | Advanced Water/Steam | | | | | | | | | | | | | | | | | |
| | Babcock & Wilcox | B&W | – | B&W | 1 | 390 | | ● | | ● | | | | | | ● | ● | |
| | Martin Marietta | MMC | – | MMC\FW | 1 | 550 | ● | | | | | | ● | | | ● | | |
| | Combustion Engineering | CE | – | CE | 1 | 640 | ● | | ● | | | | | | | ● | ● | |
| 1979–1980 | Repowering Conceptual Design | | | | | | | | | | | | | | | | | |
| | Newman, Unit 1 | EPE | EPE | B&W | 1 | 105 | | ● | | ● | | | | | | ● | ● | |
| | Northeastern Station, Unit 1 | B&V | PSO | B&W | 1 | 73 | | ● | | ● | | | | | | ● | | |
| 1981–1982 | Repowering Adv. Conceptual Design Newman, Unit 1 | EPE | EPE | B&W | 1 | 109 | | ● | | ● | | | | | | ● | ● | |
| 1982–1983 | Repowering Preliminary Design Newman, Unit 1 | EPE | EPE | B&W | 1 | 112 | | ● | | ● | | | | | | ● | | |

Contractors & Utilities
- B&V – Black & Veatch
- B&W – Babcock & Wilcox
- CE – Combustion Engineering
- EPE – El Paso Electric Co.
- FW – Foster Wheeler
- HON – Honeywell, Inc.
- MDAC – McDonnell Douglas Astronautics Co.
- MMC – Martin Marietta Corp.
- PNM – Public Service of New Mexico
- PSO – Public Service of Oklahoma
- Rock – Rockwell (Rocketdyne Div.)

* Receiver Tests:
- a – 5-TUBE/70-TUBE PANELS
- b – MMC 5 $MW_t$ TEST
- c – HONEYWELL 5 $MW_t$ TEST

Table 2.3–4
MOLTEN SALT COMMERCIAL RECEIVER DESIGNS

| YEAR | PROGRAM TITLE | PRIME CONTRACTOR | UTILITY PARTNER (Repowering Studies) | RECEIVER DESIGNER(S) | NO. RCVR MODULES IN SYSTEM | RECEIVER MODULE THERMAL RATING ($MW_t$) | SURROUND FIELD | NORTH FIELD | RECEIVER CONFIG.: EXTERNAL CYLINDER | RECEIVER CONFIG.: EXT. PARTIAL CYLINDER | RECEIVER CONFIG.: EXTERNAL BILLBOARD | RECEIVER CONFIG.: NORTH–FACING CAVITY | RECEIVER CONFIG.: QUAD CAVITY | RECEIVER CONFIG.: DOWN–FACING CAVITY | SINGLE PASS FLOW | MULTIPASS FLOW | REHEAT RECEIVER | RECEIVER SRE TEST* (See Table 2.3–2) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1977– | Advanced Central Receiver–Phase I | | | | | | | | | | | | | | | | | |
| 1978 | Martin Marietta | MMC | – | MMC | 9 | 208 | ● | | | | | | ● | | | ● | | a |
| 1978– | Hybrid Power System | | | | | | | | | | | | | | | | | |
| 1979 | Martin Marietta | MMC | – | MMC | 1 | 388 | ● | | | | | | ● | | | ● | | a |
| 1979– | Advanced Central Receiver–Phase II | | | | | | | | | | | | | | | | | |
| 1981 | Martin Marietta | MMC | – | MMC | 1 | 315 | ● | | | | | | ● | | | ● | | a |
| 1979– | Repowering Conceptual Design | | | | | | | | | | | | | | | | | |
| 1980 | Ft. Churchill Plant, Unit 1 | MDAC | SPP | MDAC | 1 | 330 | | ● | | | | ● | | | | ● | | |
| | Saguaro Power Plant, Unit 1 | APS | APS | MMC | 1 | 350 | ● | | | | | | ● | | | ● | | a |
| 1981– | Solar 100 Conceptual Design Study | | | | | | | | | | | | | | | | | |
| 1982 | SCE/MDAC/Bechtel | SCE | SCE | MDAC | 2 | 312 | | ● | | | | ● | | | | ● | | |
| 1981– | Repowering Adv. Conceptual Design | | | | | | | | | | | | | | | | | |
| 1982 | Ft. Churchill Plant, Unit 1 | MDAC | SPP | MDAC | 1 | 110 | | ● | | | | ● | | | | ● | | |
| | Saguaro Power Plant, Unit 1 | APS | APS | MMC | 1 | 181 | ● | | | | | | ● | | | ● | | a |
| 1981– | Adv. Molten Salt Receiver Design | | | | | | | | | | | | | | | | | |
| 1982 | Foster Wheeler | FW | – | FW/MDAC | 1 | 320 | | ● | | | | ● | | | | ● | | |
| | Babcock & Wilcox | B&W | – | B&W/MMC | 1 | 320 | ● | | | | | | ● | | | ● | | a |
| 1982 | Solar 100 SPOA ** | | | | | | | | | | | | | | | | | |
| | McDonnell Douglas | MDAC | ** | FW/MDAC | 2 | 323 | | ● | | | | ● | | | | ● | | b |
| | Martin Marietta | MMC | ** | B&W/MMC | 2 | 327 | | ● | | | | ● | | | | ● | | b |
| 1982– | Repowering Preliminary Design | | | | | | | | | | | | | | | | | |
| 1983 | Saguaro Power Plant, Unit 1 | APS | APS | B&W/MMC | 1 | 190 | | ● | | | | ● | | | | ● | | b |

Contractors & Utilities
- APS – Arizona Public Service Co.
- B&W – Babcock & Wilcox
- FW – Foster Wheeler
- MDAC – McDonnell Douglas Astronautics Co.
- MMC – Martin Marietta Corp.
- SCE – Southern California Edison
- SPP – Sierra Pacific Power Co.

* Receiver Tests:
- a – MMC– Advanced Central Receiver Phase II
- b – Molten Salt Subsystem/Component Test Experiment

** – Solar Program Opportunity Announcement Issued by SCE

Table 2.3-5
SODIUM COMMERCIAL RECEIVER DESIGNS

| YEAR | PROGRAM TITLE | PRIME CONTRACTOR | UTILITY PARTNER (Repowering Studies) | RECEIVER DESIGNER(S) | NO. RCVR MODULES IN SYSTEM | RECEIVER MODULE THERMAL RATING ($MW_t$) | SURROUND FIELD | NORTH FIELD | RECEIVER CONFIG.: EXTERNAL CYLINDER | EXT. PARTIAL CYLINDER | EXTERNAL BILLBOARD | NORTH-FACING CAVITY | QUAD CAVITY | DOWN-FACING CAVITY | SINGLE PASS FLOW | MULTIPASS FLOW | REHEAT RECEIVER | RECEIVER SRE TEST* (See Table 2.3-2) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1977-1978 | Advanced Central Receiver—Phase I | | | | | | | | | | | | | | | | | |
| | Energy Systems Group | ESG | – | ESG | 1 | 390 | • | | • | | | | | | • | | | a |
| | General Electric | GE | – | GE | 1 | 398 | • | | • | | | | | | • | | | b |
| 1978-1979 | Hybrid Power System | | | | | | | | | | | | | | | | | |
| | Energy Systems Group | ESG | – | ESG | 1 | 364 | • | | • | | | | | | • | | | a |
| 1979-1980 | Advanced Central Receiver—Phase II | | | | | | | | | | | | | | | | | |
| | General Electric (cancelled) | GE | – | GE | 1 | 370 | • | | • | | | | | | • | | | b |
| 1979-1980 | Repowering Conceptual Design | | | | | | | | | | | | | | | | | |
| | Permian Basin Station, Unit 5 | ESG | TES | ESG | 1 | 159 | • | | • | | | | | | • | | | a |
| | Paint Creek Station, Unit 4 | ESG | WTU | ESG | 1 | 226 | • | | • | | | | | | • | | | a |
| | Plant, Unit 3 | GE | SPS | GE | 1 | 142 | • | | • | | | | | | • | | | b |
| 1981-1982 | Repowering Adv. Conceptual Design | | | | | | | | | | | | | | | | | |
| | Paint Creek Station, Unit 4 | ESG | WTU | ESG | 1 | 226 | • | | • | | | | | | • | | | a |
| 1982-1983 | Repowering Preliminary Design | | | | | | | | | | | | | | | | | |
| | Carrisa Plains | ESG | PG&E | ESG | 1 | 107 | | • | | | • | | | | • | | | a |
| 1983-1984 | Repowering Final Design | | | | | | | | | | | | | | | | | |
| | Carrisa Plains (cancelled) | ESG | PG&E | ESG | 1 | 107 | | • | | | • | | | | • | | | a |

Contractors & Utilities
ESG – Rockwell (Energy Systems Group)
GE – General Electric Co.
PG&E – Pacific Gas & Electric
SPS – Southwestern Public Service
TES – Texas Electric Service Co.
WTU – West Texas Utilities

* Receiver Tests:
a – ESG – 3 $MW_t$ TEST
b – GE SRE (cancelled)

## MAJOR COMPONENTS

**Absorber Panels.** Absorber panels are fabricated in individual modules or subassemblies to facilitate handling during fabrication, shipment, and erection. It is desirable to have the modules designed to be completely interchangeable. Panel configuration for the molten salt Saguaro receiver, illustrated in Figure 2.3–3, is basically very similar to that of a conventional utility boiler panel. Each module consists of the panel tubes, inlet and outlet headers, buckstays, support struts, strongbacks, and insulation and sheathing (added during erection).

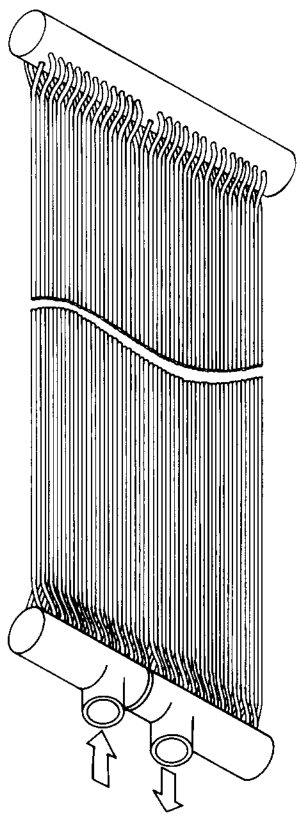

**Figure 2.3–3 Typical Receiver Panel Design**

The panel modules are designed to be hung vertically from the receiver unit support structure; this arrangement permits unrestricted downward thermal expansion of the panel.

Horizontal support for the panel to limit outward bowing of the tubes is provided by buckstays that traverse the panel at vertical intervals of approximately two meters. To accommodate vertical thermal expansion of the panel tubes, the buckstays either slide on the rigid strongback structure with rollers or are attached to the strongback by arms that pivot to permit vertical movement.

The tubes are attached to the buckstay by welded-on clips or other attachments that generally permit a small degree of movement to accommodate tube-to-tube differences in thermal expansion or initial fabrication fit-up. Experience with Solar One has shown that these elements must be designed carefully to prevent fatigue failures at tube attachment clips or buckling of the panel when thermal expansion is inhibited by seizure of buckstay rollers.

In most early designs of absorber panels (including Solar One), the individual tubes were joined to each other along their length by welding or brazing. This has the advantage of simplifying the attachment of the panel to the buckstays by reducing the number of required attachment points and preventing "shine-through" of solar flux through gaps between tubes onto uncooled backup structure.

However, longitudinal tube-to-tube joining also constrains tubes to act as if part of a monolithic structure. This is acceptable in conventional utility plants that undergo little cycling, but solar experience has shown that such constraint can lead to a variety of fatigue failure modes as a result of diurnal cycling, flux transients, and flux gradients across panels. Therefore, more recent receiver designs have utilized individually supported tubes, omitting any longitudinal tube-to-tube joining. In this case, every tube must be individually attached to the buckstays.

Near the ends of the panels, outside the absorption area, the individual tubes are bent or are joined to bent jumper tubes. This provides flexibility for accommodating differential thermal expansion of the tubes at the point where the tube ends (or jumper tubes) are joined to the header. The header often has stub fittings to facilitate joining and subsequent inspection of the tube-to-header welds.

Areas of the panel to be exposed to solar flux are treated to maximize their absorptivity by spray painting high-absorptivity black paint on the exposed panel surface. The paint used has been *Pyromark*, a product of TEMPIL Division, Big Three Industries, Inc. located in South Plainfield, NJ. This paint must be heat cured prior to operation of the receiver; this can be accomplished using a few heliostats after erection of the receiver.

The entire subassembly — comprising panel tubes, inlet and outlet headers, buckstays, supporting structure, and strongback — is designed to be shop-built and shipped as a unit. This concept (factory built, shipped to site) is limited to panels less than 30 meters (100 feet) long because of shipping constraints and limitations on the maximum continuous lengths of seamless tubing currently available. This limit on panel length sets an upper limit on the maximum thermal rating for a receiver, depending on the specific receiver configuration and the allowable flux limits.

Insulation and sheathing are added during erection. Including insulation, the gross (empty) weight of a single 30-meter panel module would be approximately two tons (1800 kg). If all panel modules for the receiver are identical and the same tube-to-header geometry is used for both inlet and outlet headers, fabrication is greatly simplified. The use of identical panel modules also simplifies receiver erection and panel replacement, and the number of spares needed is kept to a minimum.

**Receiver Structure.** The main support structure for the receiver is required to carry the weight of the absorber panels, interconnecting piping and tanks, receiver heat transport fluid, and auxiliary items such as cranes or a cavity door. The structure must also withstand ice and wind loads and seismic effects. Seismic criteria provide the greatest uncertainty in the design and costing of the receiver structure. Standard structural steel columns, beams, and trusses are used.

On a cavity or billboard receiver, where the major horizontal dimension of the receiver is typically larger than the diameter of the top of the tower, a transition section between the top of the tower and the bottom of the receiver structure proper will be included as part of the overall receiver structure. A structural steel transition section is generally not required for external cylinder or partial cylinder receivers, since the base diameter of the receivers approximates that of the tower top.

Platforms, stairs, and hand railings are provided with the receiver for access to components for inspection and maintenance. For large receivers, an elevator may also be provided from the top of the tower to the top of the receiver. A roof and enclosure are normally included for weather protection of maintenance activities and for prevention of wind-induced freezing of piping or valves. A crane and hoist may be included at the top of the receiver to facilitate maintenance, particularly replacement or repair of absorber panels. A room is usually provided in the transition section or at the top of the tower, for instrumentation and equipment used for receiver operation and control.

The structural and enclosure components for receivers are normally shielded from direct flux by the absorber surface, so they do not require thermal protection from high fluxes. However, if the structural members of a cavity receiver can be exposed to direct flux (either from normal spillage flux or from unexpected "walk-off" of the concentrated heliostat images), those portions of the support structure are insulated and covered with a stainless steel radiation shield painted with reflective white paint. Because the fluxes around the aperture are normally low, radiation shields and convective air are sufficient protection for the load-bearing structural members.

**Piping and Tanks.** Receiver piping and tank arrangements differ depending on the receiver fluid and the flow configuration (once-through, recirculating, or multipass). Sodium and molten salt receivers have inlet and outlet surge tanks. A water/steam receiver does not have surge tanks, but it does have a steam drum in recirculating flow configurations or a flash tank in once-through flow configurations.

The inlet accumulator tank and outlet surge tank atop the tower buffer the fast-responding temperature control valves from the slower responding receiver feed pump and control valves, permitting rapid response to flux change. During the transition from normal operation to a standby condition, these tanks may also accommodate the change in fluid and piping volumes resulting from temperature changes.

If the receiver feed pumps fail, the inlet accumulator tank provides a reservoir of fluid that can be passed through the receiver for a short period, allowing time for the heliostat field to defocus. A compressor with storage tank maintains a constant pressure of air (for molten salt) or inert gas (for sodium) in the tank for this purpose.

The outlet surge tank is located at the highest point in the fluid-flow circuitry, providing a means for monitoring the fluid level in the receiver system to insure that the panels are filled with fluid. Fluid level is maintained by adjusting the drag valve (at the base of the tower) which controls the amount of fluid leaving the receiver. The tank also provides for flow in the event of a downcomer blockage.

For multi-pass serial fluid flow in molten salt receivers, successive passes are connected by common headers or by transfer piping between pass headers. Once-through water/steam and liquid sodium receivers with parallel fluid flow require a distribution manifold from the riser (or inlet accumulator tank) to the panel inlet headers, and a collection manifold from the outlet headers to the downcomer (or outlet surge tank). All piping is designed with adequate flexibility for thermal expansion and drainability.

Drain lines equipped with drain valves extend from the bottom of each panel or from the low point of interpanel piping and feed into a common manifold that is usually connected to the riser (for salt or sodium) or the flash tank (for water/steam). Vent lines equipped with vent valves extend from the top of each panel or interpanel piping and feed into a common manifold that typically extends to the outlet surge tank. During fluid fill, air or inert gas trapped in the pressure-part circuitry is vented through these lines to the outlet surge tank. The vent valves are also opened to drain the receiver.

When sodium or salt are used as the receiver fluid, they must be maintained in the liquid state not only in the receiver but also in other portions of the system. This requires freeze protection, either heat tracing or insulation, or both, for the receiver fluid flow and containment components other than the absorber tubes. Insulation, but not heat tracing, is normally specified for water/steam receiver piping.

Design of the absorber panels, accumulator/surge tanks, and interconnecting piping must allow for draining of part or all of the fluid loop, either by gravity alone or assisted by an auxiliary pressurized gas system. Drain-down would occur nightly and during extended daytime loss of insolation events for most systems.

**Cavity Door.** For cavity receivers, the use of a door and selection of its configuration are guided by several considerations. Advantages include potential reduction of auxiliary power for overnight conditioning, reduced startup time in the morning or during the day, and maintenance of receiver temperature during temporary insolation loss. Potential improvements in receiver operation and efficiency must be weighed against the additional cost and design and fabrication complications associated with inclusion of a door in a receiver design.

For a cavity receiver with planar, vertical aperture or apertures, the door design is typically split horizontally into two sections. The sections open and close vertically, and are counterbalanced to facilitate rapid closure in the event of a power failure. The door sections are insulated on the side facing the cavity interior to minimize conduction heat losses. Careful design of the seal mechanism between door sections and the cavity structure is necessary to allow repeated operation of the door while minimizing convective heat loss through any gaps in the seal.

Testing and analyses have not conclusively established the need for a door to satisfy the above requirements, although most cavity receiver designs to date have included them. A cavity door is a part of the Molten Salt Subsystem/Component Test Experiment (MSS/CTE) at the Central Receiver Test Facility.

**Instrumentation and Controls.** The receiver control system has two primary functions: to maintain the receiver heat transport fluid outlet conditions at set point values during normal operations, and to operate and protect the receiver during transient and emergency conditions such as start-up, shutdown, cloud passages, and equipment/component failure. Because of input power and flux distribution changes caused by diurnal and meteorological conditions, the control system must vary the receiver heat transport fluid flowrate to maintain outlet temperature and pressure at the desired setpoint. Sensors used in the receiver control system may include thermocouples, pressure transducers, flux transducers, flow meters, and fluid level indicators. Control systems typically operate on feedback output from sensors that measure receiver outlet conditions. However, the use of feed-forward data (particularly flux levels) may be helpful.

Receiver control is closely tied to heliostat field control during start-up and shutdown. Once the full heliostat field is focused on the receiver, control of receiver outlet conditions to accomodate varying levels of insolation is achieved primarily by adjustments to the receiver feed pump flow rate, and secondarily by adjustments to valves controlling parallel flow paths in the receiver. In a once-through receiver each panel requires a flow control valve, while for a multipass receiver each control zone requires its own control valve.

## TOWER

The tower provides support for the solar receiver at the required height above the collector field. Tower height is primarily a function of the design point power of the plant; however, it is also influenced significantly by the receiver configuration and receiver fluid. The tower also provides support for the beam characterization system target, piping, and associated mechanical and electrical equipment. It transfers gravity loads from the tower and supported equipment to the subsurface beneath the tower foundation. It also transfers lateral wind and earthquake loads to the subsurface.

The receiver is located at the top of the tower. The beam characterization system target is located on the outside of the tower just below the receiver. Electrical and control equipment for the solar receiver are located within the tower immediately beneath the receiver. A secondary unit substation and motor control center serving the receiver may be housed within the tower at the ground floor level.

Primary access within the tower is by means of an elevator for transporting plant personnel and portable maintenance equipment. The elevator runs from the ground floor to the equipment room, near the top of the tower, with intermediate landings as required. Equipment too large or too heavy for the elevator can be handled by a hoist. A stairway provides access from the equipment room to the top of the tower. Emergency access for the tower is by means of a caged ladder. Aircraft obstruction lights and lightning rods are also provided on the tower.

Towers are constructed of steel or reinforced concrete. Steel towers are similar to guy-wire supported television transmission towers or free-standing microwave relay towers. Several central receiver design studies have considered guyed towers, but the presence of guy wires and their attachments to the tower in concentrated solar flux proved unworkable. An example of a free-standing steel tower is shown in Figure 2.3–4. Concrete towers are similar to tall chimneys at conventional fossil power plants. An example of a reinforced concrete tower is shown in Figure 2.3–5.

The choice of tower construction depends primarily on the required height of the tower. Free-standing steel towers are most likely to be cost effective when the height is less than 120 m (400 feet). Reinforced concrete towers have been shown to be more cost effective for towers taller than about 120 m (400 feet).

The foundation for the tower depends on the tower design, loads and soil conditions. Generally, the foundation is made of reinforced concrete proportioned to transfer gravity loads and overturning moments from the tower to the underlying soil at safe bearing pressures. A tower foundation underlaid by soft or

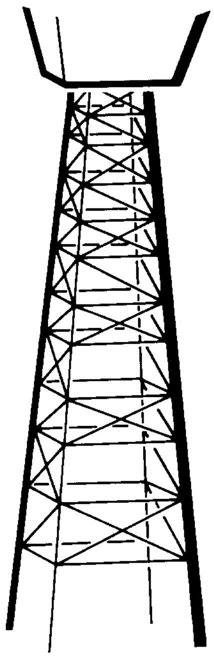

**Figure 2.3–4 Freestanding Steel Tower**

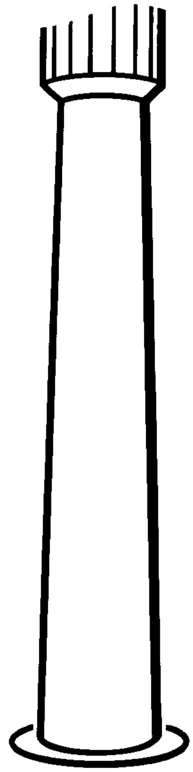

**Figure 2.3–5 Reinforced Concrete Tower**

loose soil is supported on piers or piles which deliver the loads to a deeper soil stratum having suitable bearing and settlement characteristics.

Design of the towers follows established codes, standards and specifications. Design loads for the tower include dead load, live load, wind load, and earthquake load.

Earthquakes produce lateral and vertical loads on the tower. Earthquake loads vary depending on the seismic risk zone in which the site is located, the proximity to known faults, the height and weight of the tower and the weight and location of the receiver, working fluid, and equipment.

## DESIGN ISSUES

Selection and design of the receiver subsystem results from cost/performance tradeoffs and risk assessment associated with each major design alternative. Cost involves both capital cost as well as operating and maintenance costs. Performance issues include design point and annual optical and thermodynamic efficiencies, as well as equipment availability and the operating environment of variable solar intensity due to site specific meteorological conditions. The designer must evaluate each decision in the context of total-system, life cycle economics. Candidate design configurations, when selected, must be examined in the context of the receiver subsystem itself and the total system.

Principal receiver design issues and accompanying factors include:

- Receiver sizing (plant electrical rating, solar multiple, and required receiver thermal rating).
- Energy collection system geometry (receiver configuration, tower

height, and layout of associated collector field).

- Receiver heat transport fluid selection (type, inlet/outlet conditions, interface with storage and/or working fluid).
- Materials selection (operating temperature, mechanical properties, fabricability, sensitivity to thermal cycling, and compatibility with heat transfer media).
- Absorber surface design (flux-limited design criteria, receiver fluid flow configuration, panel modularity).
- Seismic criteria (effects on structural support and pressure boundary components).
- Reliability/Availability (lifetime, cyclic operation, and operation and maintenance philosophy).

The overall design issues vary in importance and are interrelated when selecting and designing a receiver. Low cost is important, but it must not be obtained at the expense of high technical risk or with a design that is difficult to operate or maintain. General aspects of these design issues are discussed below, with reference to special features associated with water/steam, molten salt, or liquid sodium receivers. Design specifications for sample water/steam, molten salt and sodium receivers are included at the end of the section.

**Receiver Sizing.** Receiver size is defined by its thermal rating and its active absorber area. The thermal rating needed depends on system level requirements: plant output rating ($MW_e$ for an electric plant), type of receiver fluid and storage media, nature of the electric power generating system, and solar multiple. The required receiver absorber area is proportional to the thermal rating for a given allowable peak flux limit, and roughly inversely related to the flux limit (see Absorber Surface Design, below).

The minimum practical receiver size is largely a function of spillage considerations based on the size of the reflected heliostat beam and the size of its target, the receiver absorber surface or cavity aperture. As heliostat size increases, the reflected beam size also increases even with focused and canted mirrors. The receiver size must also increase to keep spillage losses within reasonable values.

The minimum receiver size defined by heliostat image size is different for receiver heat transport fluids with different allowable flux levels. A fluid like sodium, for example, with a very high allowable flux level, may have very compact receiver designs, reaching the minimum receiver size based on heliostat image size at a higher thermal rating than for the lower flux fluid.

The maximum practical size is set by considerations of panel length and atmospheric attenuation. As noted elsewhere, the maximum panel length that is currently considered practical to build, ship, and install is 30 meters (100 feet). For example, assuming a cylindrical receiver with a peak allowable flux of 1.2 $MW/m^2$ (a conservative value for a sodium-cooled design) and a characteristic height-to-diameter ratio of 1:1, a maximum rating of approximately 1300 $MW_t$ is expected.

The maximum thermal rating would be less for a height-to-diameter ratio greater than 1:1, and (neglecting attenuation) could be either greater than or less than 1300 $MW_t$ for a different flux limit. However, as a result of the large field sizes needed for receivers rated at 1000 $MW_t$ and larger, atmospheric attenuation from the most distant heliostats places an additional constraint on maximum receiver size. Typically, the maximum ratings of water/steam and molten salt receivers are determined primarily by panel length limitations, while sodium receivers are limited more by field size.

**Energy Collection System Geometry.** Characterization of the interaction of the field optics and the receiver is an important part of the design process. The flux profile of the energy redirected from the heliostat field as it reaches the receiver affects all aspects of receiver design, development, and operation, as well as the cost of other subsystems.

Receiver configuration is one factor determining field configuration: a north-facing cavity or billboard receiver requires a north field, whereas an external cylindrical receiver or "quad-cavity" requires a surround field. In turn, the field configuration and its relation to the receiver determine flux distributions on the receiver absorber surface, time-of-day and time-of-year energy collection, and optimum tower height. These interactions are described more fully in Chapter 4.

**Receiver Fluid Selection.** A key system issue which has major implications on receiver design is the selection of receiver media and associated receiver inlet and outlet temperatures.

The largest current central receiver plant, Solar One, utilizes water/steam as the receiver fluid. In that design, the water is heated to superheated steam in a single pass through the tubes. Use of water/steam means a single fluid is used in both the receiver and the turbine generator. Familiarity of the utility industry with water/steam in power plants is an important advantage.

In contrast to water/steam, molten salt and liquid sodium are both single phase fluids at low pressure in the receiver tubes. This eliminates concerns about heat transfer characteristics of the boiling region and tube strength requirements for high internal pressure conditions. Thinner walled tubes with less temperature drop may be used and higher receiver flux levels are possible. Also, reheat steam cycles may be employed much more easily than with a water/steam receiver.

However, sodium and nitrate salt both freeze at temperatures well above minimum receiver temperatures expected overnight or during extended shutdowns. This requires that allowances in both the receiver design and operational characteristics be made to assure that these heat transfer media remain in a liquid state throughout the flow loop.

Relative to one another, molten salt and liquid sodium each have advantages. Salt is cheaper than sodium by a factor of two and has a three to one advantage in its volumetric heat capacity, factors which are particularly important in the storage subsystem. Sodium, on the other hand, has a five times higher heat transfer rate. The high heat transfer rate means that sodium receivers, like water/steam receivers, can be single pass; that is, the entire temperature rise of the fluid from roughly 260°C to 540°C (500°F to 1000°F) takes place in a single pass through the solar flux. Sodium freezes at roughly 100°C (212°F) while salt freezes at an even higher temperature of 250°C (480°F).

Sodium can operate at somewhat higher temperatures than molten salt without suffering chemical degradation.

However, more rigorous quality assurance is required for component fabrication with sodium because of its high reactivity in contact with water or air. Sodium systems must be designed to maintain high sodium purity and to avoid major compatibility problems with containment materials.

**Materials Selection and Fabrication.** Three principal types of materials are used in the receiver: structural steels for receiver support structures, cavity doors, and panel module strongbacks; refractory insulation to retard thermal losses and protect uncooled structures from the effects of spillage flux; and high-temperature materials for pressure boundary components which contain the receiver heat transfer fluid.

Most solar service conditions are sufficiently similar to those of other industries that it is possible to use conventional materials; however, the effects of direct solar flux and frequent thermal cycling should be considered.

Standard structural steels are used for the receiver support structure. Materials for thermal protection and insulation are typically refractories in blanket or board form, of the type used in other industries. Except where exposed to direct solar flux, these thermal materials perform in solar applications as expected. In direct flux, such as on the ceiling or around the aperture of a cavity, conventional refractories degrade faster than would be expected from their predicted operating temperatures. The effect is not major except where the level of flux spillage is high, such as would occur during heliostat walk-off in the event of a power failure.

Corrosion resistance, high-temperature mechanical properties, cost, and ease of fabrication are the major factors affecting containment materials selection for receiver tubes, headers, tanks, and piping. The materials proposed for use with water/steam, molten salt, and liquid sodium receivers are essentially the same, although they differ somewhat in detail.

For piping and tanks, carbon steels are specified on the cold (inlet) side of the receiver, while AISI type 304 stainless steel is normally specified for the hot (outlet) side. Absorber tubes may be Alloy 800 (Incoloy), AISI types 304 or 316 stainless steel, chrome-molybdenum (Cr-Mo) alloy steels ranging from 0.5Cr–0.5Mo to 9Cr–1Mo, or carbon steels, depending on peak flux levels and maximum operating temperatures.

Header materials are usually the same as the tubes, except that Type 304 stainless can also be used with Alloy 800 or Type 316 stainless steel panel tubes. Economy and ease of fabrication increases in the order Alloy 800, 316, 304, carbon steel. The various Cr-Mo alloys occupy positions generally between the properties of 304 stainless and the carbon steels.

**Absorber Surface Design.** The active receiver absorber surface area is an important factor affecting receiver cost and receiver performance. With the exception of spillage losses, all other cost and performance criteria favor minimizing the active area. However, structural integrity requirements limit the maximum flux that a receiver absorber surface can withstand for a given lifetime.[64–67] The flux limit coupled with spillage considerations limits the minimum absorber area.

Absorber panel design must incorporate the minimum area consistent with peak flux levels, acceptable flux levels near the outlets where high interior tube temperatures will occur, and acceptable flux gradients across the panels. The final absorber configuration should have ultimately embodied the combination of all these factors and included analyses of the pressure drop and the tubewall, tube interior, and bulk fluid temperatures.

Trade-offs among many factors influence receiver absorber surface design. A higher receiver peak flux reduces receiver subsystem cost but shortens the panel lifetime. By reducing receiver size, higher peak flux also improves receiver thermal performance but may result in increased spillage losses in small systems as the receiver dimensions or aperture size approach the heliostat image size.

The design flux profiles ultimately must reflect conflicting desires for both higher flux levels (higher performance, smaller absorbers, and lower initial cost) and lower flux levels (lower thermal stress, and longer panel lifetime). The trade-off of these conflicting requirements is crucial for receiver design and may require modification of the collector field or aim strategy.

In addition to design point flux limit requirements, off-design conditions must also be considered. Variations in design flux resulting from seasonal and diurnal motions of the sun and from clouds must be characterized. The shifts in performance of local field areas with sun position and the changing image characteristics of heliostats in different field locations provide continuously varying flux, flux gradients, and thermal stresses on the receiver absorber panels.

Also, the interaction between the collector field and the receiver during both normal and abnormal conditions must be examined. Transient conditions such as warm-up during daily startup and potential overheating of the receiver panel following loss of coolant flow should be examined.

Transients resulting from cloud passage or from certain heliostat aim strategies impose both thermal stresses and additional control problems. Panel testing at the Central Receiver Test Facility has shown the need for feed-forward flux or panel temperature-distribution data. These data can be used to provide adequate panel control during cloud transients; this is particularly important for molten salt receivers which require multipass flow and the attendant long transit time for fluid passing through the receiver panels.

Flow routing is highly media dependent. It is governed primarily by the need for low flux in high-temperature panels, low pumping power requirements, and good thermal hydraulic stability over a wide load range. For stability reasons, it is preferable to have the fluid flow upward in a panel, so that the buoyancy of warmer, less dense fluid does not counteract pumping pressures at low flow rates. This presents no problem in a once-through panel design, where all panels are already designed to flow in one direction.

Molten salt receivers require multipass flow circuits to reach the desired outlet temperatures. A panel arrangement for all up-flow requires long interconnecting piping runs from the top (outlet) of one panel to the bottom (inlet) of the next panel. Alternatively, the flow can be serpentine (up and down), which requires only short lengths of jumper tube from the outlet of one panel to the adjacent inlet of the next panel. Molten salt receivers have been designed with both types of flow arrangements.

**Seismic Criteria.** Design criteria for the receiver support structure are similar to those employed in other types of applications. There are currently no universally accepted seismic design standards for a solar receiver. All structures, of course, must conform to the Uniform Building Code (UBC) standards or similar codes as applicable. The towers characteristic of central receiver plants amplify ground accelerations, producing horizontal and vertical accelerations on the receiver structure that can be several times higher than the actual ground accelerations or the UBC equivalent static design loads. The problem is particularly acute in areas, such as California, with high anticipated ground accelerations.

The problem for the system designer becomes one of weighing anticipated risks of damage to the receiver structure and pressure boundary components from a seismic event against the increased capital costs to design to minimize damage.

For the design of the Carrisa Plains project, which was located within 4 miles of the San Andreas fault in California, tentative seismic design standards were developed with the intent to allow a return to normal plant operations within two weeks of a major earthquake and to hold plant capital costs to a minimum. The design standards called for structural framing and panel design by dynamic analysis using predicted tower accelerations. Supporting analysis showed no significant distortions under these conditions.

A number of questions remain for future system designers to resolve before commercial receiver designs satisfy the requirements of both building codes and standards as well as plant owners and operators.

**Reliability and Availability.** In the near term, the receiver will likely be the plant component with the highest technical risk in any central receiver system. Since there is no redundancy associated with the receiver, the reliability and availability of the receiver will be a major issue in the plant design and economics. General aspects of reliability and availability are discussed in Chapter 6.

Factors which are important to receiver reliability include conservative structural design criteria, adequate quality assurance during construction and erection of the receiver, and regularly scheduled maintenance during operation. Actions that enhance reliability and availability are usually at the expense of increased capital cost or operation and maintenance costs, and must be considered in the light of their effect on annual energy collection.

Although absorber panels are normally designed for the same lifetime as that of the plant (typically 30 years), operating experience with utility boilers and solar receiver tests has demonstrated that occasional repairs to the panels and other receiver components can be assumed to be necessary, even for receivers utilizing mature technology.

Repairs should be anticipated during the design process; provisions should be made for access to components and ease of repair in the field. Receiver components expected to require repair or replacement include absorber tubes, tube-to-structure attachments, movable support structure elements associated with thermal expansion of the absorber surface, valves, heat tracing, insulation, and control instrumentation.

Replacement of modular panels should also be considered as an option: an operating life of less than 30 years with scheduled panel replacements every 10 to 15 years may be cost-effective. Whether replacement is planned for the entire receiver or only as required for specific panels, the use of modular absorber panels facilitates the process and, if all panels are identical, the number of spare panels required is kept to a minimum.

For near-term systems, a quality control system would likely be chosen in accordance with the ASME Boiler and Pressure Vessel Code, Section VIII, Division 1, Appendix 10. To ensure a leak-free installation, non-destructive weld examinations would be performed using liquid dye penetrants, magnetic particle examination, pressure testing, helium leak testing, and radiographic examinations, as appropriate.

## WATER/STEAM RECEIVER DESIGNS

Approaches to the design of a water/steam receiver include both subcritical single-pass-to-superheat and more conventional drum type configurations. Within the drum configuration, both forced and natural circulation designs have been considered. Detailed analyses of these concepts resulted in the selection of the single-pass-to-superheat design for Solar One and the commercial plant design it is demonstrating. Commercial water/steam receiver designs are summarized in Table 2.3–3.

Principal design characteristics for three water/steam receivers are summarized in Table 2.3–6.

One design of a water/steam receiver is shown in Figure 2.3–6. It is a cylindrical design which is made up of a number of independent heat absorbing vertical panels. The diameter of the receiver is governed by the reflected beam image size from a typical heliostat in the collector field and the ability to package all of the support structure, piping, valves, and other required hardware inside the cylindrical volume. The length of the receiver is set by the need to accommodate the total incident thermal power subject to a peak flux limitation of approximately 0.6 $MW/m^2$. The desired flux distribution and peak flux intensity is governed by the vertical offset aim points assigned to the individual heliostats.

An initial design concern of a single-pass-to-superheat receiver involved the issue of water carryover. Initial tests followed by extensive operating experience at Solar One have shown this not to be a critical factor. This is largely due to anticipating (feed forward) controls which modulate boiler feedwater flow in response to solar flux and boiler metal temperature.

The major drawbacks of the drum units are their difficulty in starting (the boiler portion of the receiver must be started first followed by the superheater) and the controlled heatup period required for the thick-walled steam drum to avoid unacceptable thermal stresses. The issue of drum wall thickness and associated thermal stresses becomes more limiting with larger receivers because of their larger size and capacity and resultant greater wall thickness for identical operating pressures.

In designing the water/steam receiver, the feedwater flow to individual sections (panels) of the receiver must be regulated to match the thermal power absorbed on the individual receiver panels. In addition, tube diameters must be selected so that heat transfer coefficients between the tubes and the water/steam

Table 2.3-6

WATER/STEAM RECEIVER DESIGN CHARACTERISTICS

| Plant Design Reference | Solar One (Pilot Plant) | Solar One (Commercial Plant) | El Paso Electric (Repowering) |
|---|---|---|---|
| Plant Power Rating - $MW_e$ | 10 | 100 | 42 |
| Receiver Characteristics: | | | |
| Absorbed Thermal Power - $MW_t$ | 37 | 506 | 112 |
| Receiver Configuration | 360° external cylinder | 360° external cylinder | 203° external partial cylinder |
| Receiver Diameter - m (ft) | 7.0 (23) | 17.0 (55.8) | 18.0 (59) |
| Receiver Active Height - m (ft) | 13.7 (45) | 25.5 (83.6) | 25.9 (85) |
| Receiver Mid-Height Elevation Above Ground - m (ft) | 78.6 (258) | 268 (880) | 155 (508) |
| Active Absorber Area - $m^2$ ($ft^2$) | 302 (3250) | 1370 (14,780) | 824 (8870) |
| Peak Absorbed Flux Limit - $MW/m^2$ | 0.35 | 0.6 | 0.37 |
| Receiver Net Weight - kg (tons) | 150,000 (165) | 1,090,000 (1200) | 605,800 (668) |
| Receiver Fluid Characteristics: | | | |
| Fluid Flow Configuration | single pass | single pass | recirculating |
| Design Flow Rate - kg/s (lb/s) | 16.4 (36) | 215 (475) | |
| Receiver Inlet Temp. - °C (°F) | 205 (400) | 220 (425) | 235 (460) |
| Steam Discharge Temp. - °C (°F) | 515 (960) | 515 (960) | 540 (1000) |
| Discharge Pressure - kPa (psi) | 10,700 (1550) | 11,100 (1615) | 10,100 (1465) |
| Absorber Panel Characteristics: | | | |
| Number of Panels | 6 PH<br>18 B/SH | 4 PH<br>20 B/SH | 4 PH<br>14 B/SH |
| Panel Width - m (ft) | 0.88 (2.9) | 2.16 (7.1) | PH: 1.77 (5.8)<br>B/SH: 1.74 (5.7) |
| Active Height - m (ft) | 13.7 (45) | 25.5 (83.6) | 25.9 (85) |
| Tubes per Panel | 70 | PH: 113<br>B/SH: 170 | PH: 46<br>B: 14 or 16<br>SH: 29 or 26 |
| Tube Outside Dia. - mm (in.) | 12.7 (0.5) | PH: 19.1 (0.75)<br>B/SH: 12.7 (0.50) | PH: 25.4 (1.0)<br>B: 38.1 (1.5)<br>SH: 28.5 (1.13) |
| Tube Wall Thickness - mm (in.) | 2.9 (.115) | 2.9 (.115) | PH: 3.4 (.134)<br>B: 3.4 (.134)<br>SH: 3.0 (.119) |
| Tube Material | Incoloy 800 | Incoloy 800 | PH: carbon steel<br>B: carbon steel<br>SH: Incoloy 800 |

Notes on panels: PH=preheater, B=Boiler, SH=superheater.

All B/SH tubes in single pass designs are once-through to superheat.

Recirculating design uses "interlaced" B/SH panels with separate sections of boiler tubes and superheater tubes on same panel.

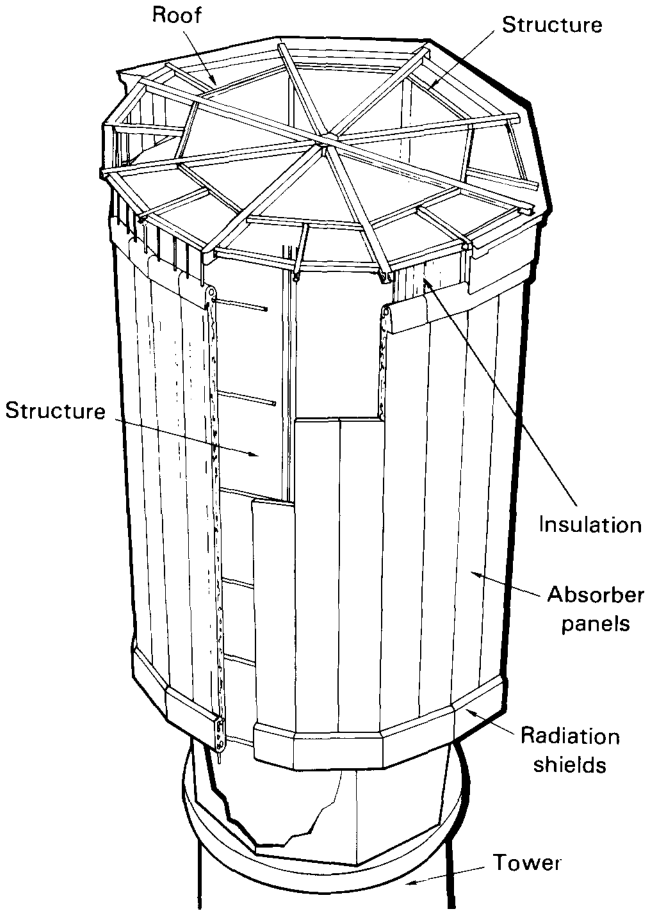


**Figure 2.3–6 Typical Water/Steam Receiver Design**

are sufficient to prevent unacceptable local tube temperatures. This is a complex design problem which involves simultaneous consideration of fluid dynamics within the receiver, local heat transfer, and the external heat flux distribution on the receiver surface. This latter factor directly influences the heliostat aim strategy to be implemented into the collector field.

The use of any water/steam receiver places stringent requirements on the quality of the feedwater supplied to the receiver boiler. In general, the feedwater chemistry requirements for the receiver are identical to those in existence for traditional fossil boilers. The requirements for the single-pass unit though, in contrast with the drum unit, are more severe due to the ease in which single-pass boiler tubes can be fouled by feedwater impurities. By contrast, contaminates as high as several hundred parts per million are allowed to accumulate within the recirculating drum boiler. This accumulation is controlled by a normal blowdown of drum condensate.

## MOLTEN SALT RECEIVER DESIGNS

The use of molten salt as a receiver coolant introduces other issues related to the thermodynamic and chemical properties of the salt. Key thermodynamic characteristics which affect the receiver design significantly include the salt's relatively high freezing point (220°C, 430°F), its thermal conductivity (approximately 0.43 W/m °C or 0.3 Btu/ft-hr °F) and the maximum allowable film temperature (595°C, 1100°F) required to prevent decomposition. It has a high volumetric heat capacity (product of density and heat capacity) which results in low volume flow for a given power level and thus requires a multi-pass design to get high velocities and high wall heat transfer coefficients. The key chemical characteristic is the potential corrosiveness of molten salt and that impact on material selection.[68]

Key features of three molten salt receivers are listed in Table 2.3–7, a receiver tested at the Central Receiver Test Facility, the Saguaro design and the Solar 100 design. The Saguaro receiver is illustrated in Figure 2.3–7.

The combination of the thermal conductivity and the maximum allowable film temperature along with panel material characteristics strongly influence

Table 2.3-7

MOLTEN SALT RECEIVER DESIGN CHARACTERISTICS

| Plant Design Reference | MSS/CTE (CRTF expt.) | Saguaro (APS Repowering) | Solar 100 SPOA (MDAC design) |
|---|---|---|---|
| Plant Power Rating - $MW_e$ | — | 60 | 100 |
| Receiver Characteristics: | | | |
| Absorbed Thermal Power - $MW_t$ | 5 | 190 | 323 |
| Receiver Configuration | North-facing "omega" cavity | North-facing "C" cavity | North-facing "omega" cavity |
| Aperture Width - m (ft) | opening: 2.1 (7.0)<br>w/wing: 2.7 (9.0)* | 18.3 (60) | opening: 15 (49.2)<br>w/wing: 20 (65.6)* |
| Aperture Height - m (ft) | 3.66 (12) | 18.3 (60) | 28.7 (94) |
| Cavity Depth (from aper.) - m (ft) | 1.8 (6) | 18.3 (60) | 18.3 (60) |
| Receiver or Aperture Mid-Height Elevation Above Ground - m (ft) | 66 (218) | 166 (546) | 224 (735) |
| Active Absorber Area - $m^2$ ($ft^2$) | 15.6 (168) | 761 (8190) | 1397 (15,040) |
| Peak Abs. Flux Limit - $MW/m^2$ | 0.6 | 0.53 | 0.6 |
| Receiver Net Weight - kg (tons) | 20,412 (22.5) | 1,354,000 (1490) | 1,270,000 (1400) |
| Receiver Fluid Characteristics: | | | |
| Fluid Flow Configuration | multiple pass | multiple pass | multiple pass |
| Design Flow Rate - kg/s (lb/s) | 12 (26) | 429 (945) | 814 (1800) |
| Receiver Inlet Temp. - °C (°F) | 290 (550) | 280 (530) | 290 (550) |
| Receiver Outlet Temp. - °C (°F) | 565 (1050) | 565 (1050) | 565 (1050) |
| Absorber Panel Characteristics: | | | |
| Number of Panels | 2 wing*<br>6 cavity | 12 | 2 wing*<br>18 cavity |
| Panel Width - m (ft) | W: 0.3 (1)<br>C: 0.46 (1.5)<br>or 0.69 (2.25) | 3.2 (10.5) | 2.44 (8) |
| Active Height - m (ft) | 3.66 (12) | 19.8 (65) | 28.7 (94) |
| Tubes per Panel | W: 12<br>C: 24 or 36 | 84 | 88 |
| Tube Outside Dia. - mm (in.) | W: 25.4 (1.0)<br>C: 19.1 (0.75) | 38.1 (1.5) | 25.4 (1.0) |
| Tube Wall Thickness - mm (in.) | 1.65 (.065) | 1.65 (.065) | 1.65 (.065) |
| Tube Material | W: 304 SS<br>C: Incoloy 800 | Incoloy 800 | Incoloy 800 |

Notes on panels: W=wing panel, C=cavity panel.
*"Omega" cavity design has an external wing panel at each side of aperture.

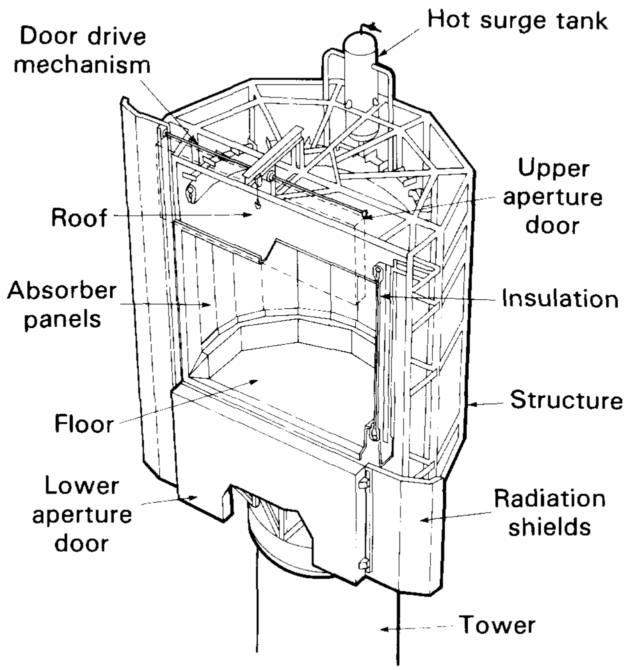


**Figure 2.3–7 Typical Molten Salt Cavity Receiver**

the derivation of maximum allowable incident thermal flux and flux distribution on the receiver. Fluid conductivity is important in determining maximum flux due to its effect on front (heated side) to back panel temperature gradients. The film temperature (the average temperature at the surface) affects the required flux distribution by limiting the incident flux on panels where the bulk salt temperatures are approaching the desired outlet temperature (typically 565°C, 1050° F).

The maximum allowable incident flux for salt systems is about 0.85 MW/m$^2$ when considering the above and the requirement for long service life.[64] The flux limit is a function of the tube size, tube material and heat transfer coefficient and varies within the receiver as a function of the salt temperature. Service life is defined by both elapsed time and total thermal cycles caused by the daily heating and cooling of the panels.

Several corrosion-resistant materials have been identified for use in molten salt systems. Experiments have examined the behavior of nitrate salt in contact with types 304 and 316 stainless, carbon steel, Alloy 800, and Cr-Mo steels. Corrosion behavior is related to the ability of nitrate salts to serve as strong oxidizers; in many respects corrosion rates and the types of corrosion layers formed on salt-exposed surfaces are similar to those observed in high temperature water/steam environments. The adherence of oxide layers is an important factor in maintaining acceptable corrosion rates in carbon steel and low-alloy chromium-molybdenum steels.

Molten salt receivers may be configured either as external or cavity receivers. Early system trade studies focused on north-facing cavities as well as quad cavities with four separate apertures facing north, east, south and west. The quad cavity concept involved panels which were heated on both sides (i.e. from north and east portions of the field). This concept was eliminated due to concerns over support of long panels. More recent studies as described in Chapter 4 suggest that a salt receiver in an external receiver configuration is an attractive option.

## LIQUID SODIUM RECEIVER DESIGNS

A commercial external billboard sodium receiver is illustrated in Figure 2.3–8. This receiver was designed for the proposed 30 MW$_e$ Carrisa Plains system. Characteristics of three sodium receivers which have been designed are outlined in Table 2.3–8.

Table 2.3-8

SODIUM RECEIVER DESIGN CHARACTERISTICS

| Plant Design Reference | IEA/SSPS (ASR) (Almeria, Spain) | West Texas Util. (Repowering) | Carrisa Plains (PG&E Repowering) |
|---|---|---|---|
| Plant Power Rating - $MW_e$ | 0.5 | 60 | 30 |
| Receiver Characteristics: | | | |
| Absorbed Thermal Power - $MW_t$ | 2.45 | 226 | 107 |
| Receiver Configuration | North-facing ext. billboard | 360° external cylinder | North-facing ext. billboard |
| Receiver Width or Dia. - m (ft) | 2.9 (9.5) | 14.0 (45.9) | 15.8 (52) |
| Receiver Active Height - m (ft) | 2.85 (9.35) | 15.4 (50.5) | 12.2 (40) |
| Receiver Mid-Height Elevation Above Ground - m (ft) | 43 (141) | 154 (505) | 125 (410) |
| Active Absorber Area - $m^2$ ($ft^2$) | 8.3 (89.6) | 676 (7280) | 193 (2080) |
| Peak Absorbed Flux Limit - $MW/m^2$ | 1.3 | 1.5 | 1.2 |
| Receiver Net Weight - kg (tons) | 19,730 (21.8) | 336,000 (370) | --- |
| Receiver Fluid Characteristics: | | | |
| Fluid Flow Configuration | multiple pass | single pass | single pass |
| Design Flow Rate - kg/s (lb/s) | 7.3 (16.1) | 585 (1280) | |
| Receiver Inlet Temp. - °C (°F) | 270 (520) | 330 (625)* | 320 (610) |
| Receiver Outlet Temp. - °C (°F) | 530 (985) | 630 (1165)* | 565 (1050) |
| Absorber Panel Characteristics: | | | |
| Number of Panels | 5 | 24 | 8 |
| Panel Width - m (ft) | 0.58 (1.9) | 1.83 (6.0) | 2.0 (6.5) |
| Active Height - m (ft) | 2.85 (9.35) | 15.4 (50.5) | 12.2 (40) |
| Tubes per Panel | 39 | 95 | 102 |
| Tube Outside Dia. - mm (in.) | 14.0 (0.55) | 19.1 (0.75) | 19.1 (0.75) |
| Tube Wall Thickness - mm (in.) | 1.0 (.039) | 1.24 (.049) | 1.24 (.049) |
| Tube Material | 316 SS | 316 SS | 316 SS |

*Typical inlet/outlet temperatures required to interface with air/rock storage system; 290°C/595°C is typical for commercial-scale sodium plant with sodium or molten salt storage subsystem.

Because of its high heat transfer rate, the use of liquid sodium as the receiver working fluid enables design and construction of compact, once-through, high efficiency receivers.

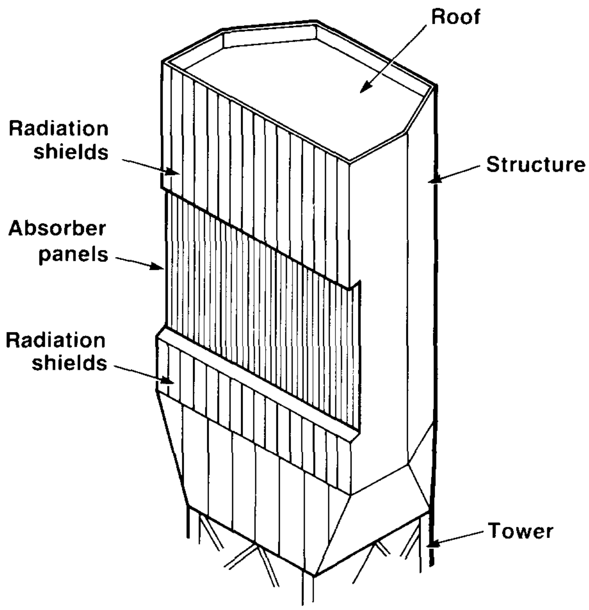


**Figure 2.3–8 Typical Liquid Sodium Receiver**

Liquid sodium receivers offer the potential for very high efficiency because sodium's thermal properties allow very high fluxes which minimize the area available for convective and radiative losses. Typical designs have used 1.2 to 1.3 $MW/m^2$, although recent studies have explored fluxes as high as 1.75 $MW/m^2$.[64] The risk with the high flux designs is an increase in tube temperature and a corresponding reduction in tube life.

High flux receiver designs reduce convective and radiative losses to levels that permit the construction of relatively inexpensive external receiver designs. The high flux capabilities also permit parallel flow through a number of independent panels, with a single pass to full outlet temperature. This simplifies the control problems associated with transient fluxes due to passing clouds and improves the transient response time of the receiver.

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# HEAT TRANSPORT AND EXCHANGE SUBSYSTEM

The heat transport and exchange subsystem provides controlled fluid flow and thermal energy exchange among the solar receiver, steam generator, and thermal storage subsystems. It consists of the pumps, piping and heat exchangers which provide the physical and functional interfaces for these subsystems. The arrangement of the heat transport and exchange subsystem is based on the heat transport medium and on the thermal storage tank configuration.

The function of the heat transport and exchange subsystem can be served through combinations of three basic arrangements: common receiver and storage medium, separate receiver and storage media, and side-stream storage and heat exchange. These system options are described in detail in Section 2.1. Molten salt is the fluid of choice for systems with a common receiver and storage fluid. A sodium/salt binary system uses sodium as the receiver fluid and salt as the storage medium. A water/steam receiver with oil/rock storage is an example of side-stream storage and heat exchange.

## MEDIA OPTIONS

Four fluids have received most of the consideration for use as heat transport media. These fluids include water/steam, oil, molten salt, and liquid sodium. The currently feasible temperature ranges for each heat transport medium are listed in the Table 2.4–1.

Salt, sodium, and water are the principal receiver fluid candidates. Oil has a lower operating temperature range and is generally envisioned only as a potential storage fluid in central receiver systems.

Table 2.4–1

FLUID AND TYPICAL OPERATING TEMPERATURES

| | |
|---|---|
| Water/Steam | 0°C to 540°C (32°F to 1000°F) |
| Caloria HT-43 | up to 315°C (600°F) |
| Molten Salt | 280° to 565° C (530°F to 1050°F) |
| Sodium | 150°C to 590°C (300°F to 1100°F) |

Physical properties of these transport fluids are listed in Table 2.4–2.[1–3] Note that sodium has very high thermal conductivity while salt has a larger energy density. The viscosity of sodium is lower than salt's. Features of each fluid are discussed below.

**Water/Steam.** Water/steam has the advantage of being the most familiar heat transport medium to the utility industry. Development of water/steam system components for use in large plants is mature, in contrast to the evolving status for salt and sodium. Moreover, water/steam has a much lower freezing point than molten salt and liquid sodium and lacks some of the hazards associated with molten salt and liquid sodium.

The use of steam for the production of electricity is a well-understood process. However, in a central receiver plant, electricity generation is tied to the

Table 2.4-2A

PROPERTIES OF HEAT TRANSPORT FLUIDS (SI Units)

| Fluid | TEMP °C (°F) | Density $kg/m^3$ | Specific Heat kJ/kg K | Energy Density $MJ/m^3$ K | Thermal Conductivity W/m K | Viscosity Pa | Typical Forced-Convection Film Coefficient $W/m^2$ K |
|---|---|---|---|---|---|---|---|
| Nitrate Salt | 316 ( 600) | 1888.6 | 1.71 | 3.22 | 0.50 | 0.00280 | 5700- |
| | 427 ( 800) | 1819.7 | 1.57 | 2.86 | 0.53 | 0.00165 | 11,400 |
| | 538 (1000) | 1741.2 | 1.44 | 2.51 | 0.56 | 0.00100 | |
| Sodium | 371 ( 700) | 860.2 | 1.298 | 1.12 | 72.340 | 0.000283 | 22.700- |
| | 538 (1000) | 820.1 | 1.256 | 1.03 | 65.420 | 0.000208 | 45,400 |
| Water | 204 ( 400) | 858.6 | 4.52 | 3.88 | 0.659 | 0.000136 | 7400- |
| (sat. liquid) | 316 ( 600) | 679.2 | 6.32 | 4.29 | 0.505 | 0.000087 | 68,100 |
| Steam | 316 ( 600) | 56.9 | 6.36 | 0.36 | 0.069 | 0.000033 | |
| (1500 psia) | 427 ( 800) | 36.8 | 2.93 | 0.11 | 0.069 | 0.000034 | 1700- |
| | 538 (1000) | 29.8 | 2.51 | 0.07 | 0.083 | 0.000036 | 8500 |
| Oil | 93 ( 200) | 805.7 | 2.09 | 1.69 | 0.130 | 0.00496 | 570- |
| (Caloria HT-43) | 204 ( 400) | 730.4 | 2.51 | 1.84 | 0.121 | 0.00103 | 5700 |
| | 316 ( 600) | 645.6 | 2.93 | 1.89 | 0.112 | 0.000425 | |

Table 2.4-2B

PROPERTIES OF HEAT TRANSPORT FLUIDS (ENGLISH UNITS)

| Fluid | TEMP °F | Density $lb/ft^3$ | Specific Heat Btu/lb°F | Energy Density $BTU/ft^3$ °F | Thermal Conductivity Btu/hr ft°F | Viscosity lb/ft hr | Typical Forced-Convect Film Coeff. Btu/hr $ft^2$ °F |
|---|---|---|---|---|---|---|---|
| Nitrate | 600 | 117.9 | 0.41 | 48.0 | 0.29 | 6.768 | 1000- |
| | 800 | 113.6 | 0.38 | 43.0 | 0.31 | 3.996 | 2000 |
| | 1000 | 108.7 | 0.34 | 37.0 | 0.32 | 2.426 | |
| Sodium | 700 | 53.7 | 0.31 | 16.7 | 41.8 | 0.684 | 4000- |
| | 1000 | 51.2 | 0.30 | 15.4 | 37.8 | 0.504 | 8000 |
| Water | 400 | 53.6 | 1.08 | 57.9 | 0.381 | 0.33 | 1300- |
| (sat. liquid) | 600 | 42.4 | 1.51 | 64.0 | 0.292 | 0.21 | 12.000 |
| Steam | 600 | 3.55 | 1.52 | 5.4 | 0.040 | 0.08 | |
| (1500psia) | 800 | 2.30 | 0.70 | 1.6 | 0.040 | 0.083 | 1500 |
| | 1000 | 1.86 | 0.060 | 1.1 | 0.048 | 0.088 | |
| Air | 600 | 0.0374 | 0.250 | 0.009 | 0.0271 | 0.072 | |
| (atm. press) | 1000 | 0.0272 | 0.263 | 0.007 | 0.0362 | 0.089 | 120- |
| | 1400 | 0.0213 | 0.274 | 0.006 | 0.0442 | 0.104 | 250 |
| | 1800 | 0.0175 | 0.282 | 0.005 | 0.0512 | 0.117 | |
| Oil | 200 | 50.3 | 0.50 | 25.2 | 0.075 | 12.0 | 100- |
| (Caloria HT-43) | 400 | 45.6 | 0.60 | 27.4 | 0.070 | 2.5 | 1000 |
| | 600 | 40.3 | 0.70 | 28.2 | 0.065 | 1.03 | |

real-time availability of sunlight, and cloud transients will directly affect steam turbine output. Consequently, a less efficient but more practical means of providing a fairly uniform steam supply to the turbine is to use a thermal storage subsystem. Because water/steam is not a desirable storage medium, this configuration requires the exchange of thermal energy with a storage medium such as oil/rock. A problem with this type of design is the temperature drop caused by the maximum allowable oil temperature and the thermal losses associated with the charging and discharging heat exchangers used to transfer thermal energy into and out of storage.

**Oil.** The use of oil as a heat transport fluid is limited to about 315°C (600°F), which is the maximum useful temperature of most common heat transport oils, including Caloria HT-43. The peak temperature limitation makes the oil unsuitable as a receiver medium for central receiver applications. However, oil can be used as a heat transport and/or storage medium. Because most oils do not freeze above ambient temperatures, they do not require trace heating. Oils are susceptible to thermal decomposition and are flammable. Precautions must be used to avoid excessive temperatures and spills.

The accidental introduction of water into the oil/rock storage tank at Solar One led to a rupture of the storage tank resulting in a fire in 1986.[4]

**Molten Salt.** Molten salt in central receiver systems commonly refers to a binary mixture of sodium and potassium nitrate salts. A 60% $NaNO_3$ and 40% $KNO_3$ mixture by weight, molten salt is a relatively inexpensive and nontoxic heat transport and exchange fluid.

The utility industry is less familiar with the use of molten salt than is the chemical process industry. In the chemical industry, molten salt has been shown to be reliable and safe as a heat transport medium when proper design considerations and adequate precautions are taken.[5,6]

Molten salt is a desirable medium as a receiver and storage fluid because it is stable up to temperatures of about 595°C (1100°F) and remains liquid down to temperatures near 245°C (470°F). In systems in which molten salt is used as both the receiver heat transport and thermal storage medium, the only heat exchanger needed is the steam generator.

Because molten salt freezes at about 245°C (470°F), provisions must be made to provide adequate heat tracing and draining of pipes and equipment.

**Liquid Sodium.** The use of liquid sodium as a heat transport fluid has been developed by the nuclear industry. Because liquid sodium, like molten salt, solidifies above room temperature (though at a temperature lower than salt), provisions must be made to provide adequate heat tracing and draining of pipes and equipment during periods of shutdown.

Sodium has excellent heat transfer properties allowing high-flux small receivers. It is, however, a more expensive, less dense medium and has a lower specific heat than molten salt.

In general, the operation of liquid sodium systems is similar to molten salt systems. One major difference is the reactivity of sodium when in contact with air or water. Enhanced quality assurance during fabrication and safe operating procedures must be employed to avoid sodium releases.

A sodium fire occurred at the IEA/SSPS central receiver plant in 1986. It resulted from non-conventional repair procedures undertaken to replace a valve in a sodium line.[7]

## DESIGN CONSIDERATIONS

The heat transport medium chosen affects the design of the components in the heat transport and exchange subsystem. The main components that make up the subsystem include piping, pumps, valves, heat exchangers, heat tracing, insulation, and instrumentation. In general, the design and operation of these components is similar to those of fluid systems for fossil-fueled power plants. The principal design considerations of each of these components are discussed below.

**Piping.** The heat transport piping material is selected based on the design temperature and transport medium of the system. High temperature applications frequently require the use of high temperature alloy steels. For example, carbon steel piping is typically used for temperatures less than 400°C (750°F), low-chromium alloy steels are used for temperatures ranging from 400–510°C (750°F to 950°F), and stainless steel piping is used for temperatures above 510°C (950°F).

In the case of molten salt, stainless steel piping is used for temperatures above 400°C (750°F) because of corrosion. (See Ref. 2.)

The wall thickness is selected on the basis of piping material and system pressure. (For molten salt systems, wall thickness is also governed by corrosion effects.) Water/steam systems operate at the highest pressures and typically require thicker walled tubes on the steam side than do molten salt or liquid sodium systems.

Thermal expansion, seismic excitation, and dead weight are taken into consideration in the piping design. Expansion loops are designed into piping lines to accommodate thermal growth. In addition, supports are included in the design to guide and anchor the pipe. Adequate slope for drainage is typically designed into piping systems which use molten salt or liquid sodium.

**Pumps.** Both high head and low head pumps are required in a solar central receiver plant. Pumps are used to deliver fluid to the solar receiver (high head) and through the solar steam generator (low head). Pumps for both types of service are available commercially for all of the heat transport fluids over a range of flow rates. The cyclic operation of this equipment may be different from conventional commercial use, however, and should be considered when equipment specifications are defined.

Pumps for sodium have been tested extensively by the Energy Systems Group at Rockwell.

Pumps suitable for use in a molten salt system have been tested at the Central Receiver Test Facility in a pump and valve experiment.[8]

For most molten salt applications, vertical shaft pumps are preferred over horizontal shaft pumps to reduce seal problems. For relatively low head applications — such as in the steam generator — vertical cantilever pumps are specified because they do not have bearings immersed in the heat transport fluid; however, for higher head applications — such as in the receiver — multi-stage vertical turbine pumps are required.

A vertical cantilever pump is illustrated in Figure 2.4–1 and a multi-stage vertical turbine pump in Figure 2.4–2. These pumps are characteristic of pumps which would be employed in commercial molten salt central receiver plants.

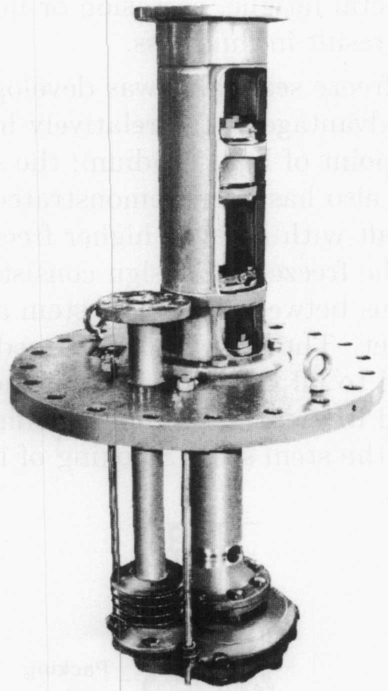

**Figure 2.4–1 Vertical Cantilever Pump**

Although valves are often used to control fluid flow, variable speed drives on pumps can be used to provide a more efficient means of flow control. Plant operating costs can be reduced by using pumps with variable speed drives instead of constant speed drives; the variable speed drive pumps operate more efficiently since power is not wasted through valve pressure drops. Also, by using pumps with variable speed drives instead of constant speed pumps and control valves, fluid hammer problems associated with startup and shutdown can be reduced significantly.

**Valves.** The use of valves in solar central receiver plants is similar to that in fossil-fueled power plants. Typically, valves are used for controlling fluid flow (control valves) or for isolating equipment or systems (isolation valves). Valve material and pressure class must be compatible with the pipe material as well as the design pressure and temperature of each piping section.

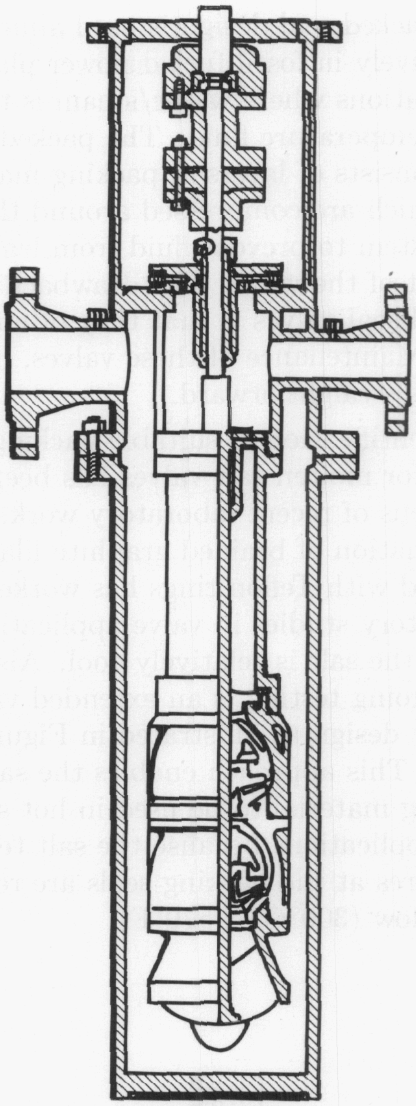

**Figure 2.4–2 Multi-stage Vertical Turbine Pump**

Seals for valves used in the heat transport and exchange subsystem can be packed, bellows, or freeze seal (suitable for salt or sodium only) designs.

The packed seal design is used almost exclusively in fossil-fueled power plant applications where water/steam is the high temperature fluid. The packed seal consists of layers of packing material which are compressed around the valve stem to prevent fluid from leaking out of the valve. The drawback of packed seal valves is that they often leak. Maintenance of these valves, however, is straightforward.

Identification of suitable packing material for molten salt valves has been the focus of recent laboratory work.[8,9] A combination of braided graphite filament coupled with Teflon rings has worked in laboratory studies in valve applications where the salt is relatively cool. Also undergoing testing is an extended valve bonnet design as illustrated in Figure 2.4–3. This approach enables the same packing material to be used in hot salt flow applications because the salt temperatures at the packing seals are relatively low (300°C or 570°F).

The bellows seal valve, illustrated in Figure 2.4–4, was developed to eliminate fluid leakage from very hazardous systems. A bellows seal consists of a flexible bellows housing that completely seals the fluid area from the moving stem. However, the bellows can fail, typically due to metal fatigue, corrosion or misuse, and result in fluid loss.

The freeze seal valve was developed to take advantage of the relatively high freezing point of liquid sodium; the same principle also has been demonstrated for molten salt with its even higher freezing point. The freeze seal design consists of an annulus between the valve stem and the bonnet. The heat transport medium is allowed to fill the lower part of the annulus and freeze; the solidified medium becomes the stem seal. Stroking of the

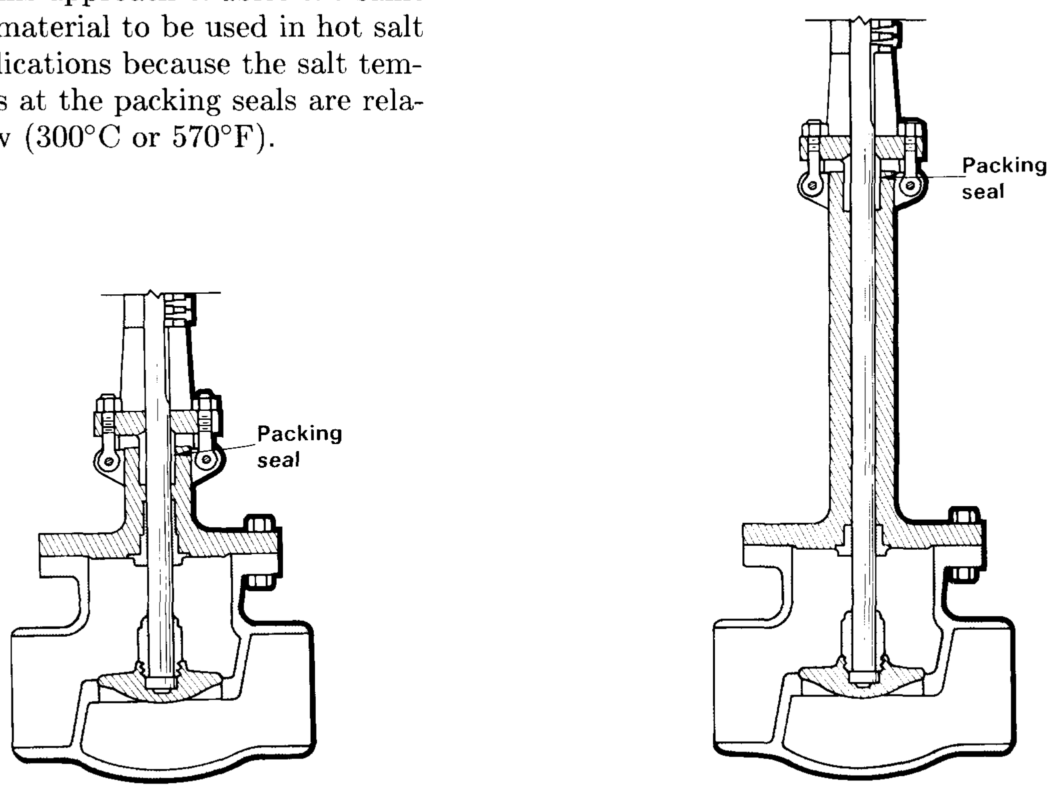


**Figure 2.4–3 Standard Packed Valve and Extended Valve Bonnet**

valve involves a fracture of the solidified medium and requires a larger actuator than for packed or bellows valves.

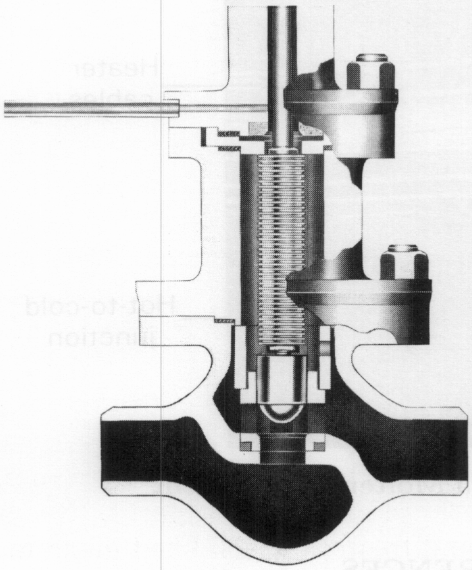

**Figure 2.4–4 Bellows Seal Valve**

**Heat Exchangers.** Heat exchangers, other than the receiver and solar steam generator, are required for configurations in which the receiver and thermal storage media are different. For example, a water/steam receiver fluid will require a heat exchanger if the fluid contained in storage is oil. Likewise, a liquid sodium receiver fluid will require a heat exchanger if the storage medium is molten salt.

The heat exchanger design is determined by a complete system optimization of important parameters including fluid properties, acceptable temperature differences, pressure drops, mass flow rates, operating costs and heat exchanger cost.

**Heat Tracing.** Heat tracing must be used with molten salt and liquid sodium to avoid solidification in the lines. Heat tracing must be capable of maintaining acceptable fluid temperatures during emergency shutdown conditions, prolonged periods of cloud cover and when fluid circulation or draining is not possible. In addition, heat tracing can be energized prior to startup to avoid thermal shock in piping and equipment.

Electrical heat tracing commonly consists of electrical resistance heaters, such as mineral insulated heating cables or tubular heaters, which are secured to piping, valves, and other equipment. A typical system is illustrated in Figure 2.4–5. Temperature control using heat tracing is achieved by temperature (thermocouple) feedback. The main concerns associated with heat tracing are the capital cost, parasitic power consumption and system reliability.[10]

**Insulation.** Insulation is applied to all components for which heat loss or personnel safety associated with high temperature is a concern. Insulation thickness is determined by trade-offs between the added capital cost of insulation and the value of thermal energy lost over the plant life. The insulation, typically of preformed calcium silicate, is secured to piping, valves, and other equipment. An inner layer of flexible, blanket-type insulation is occasionally applied over the heat-traced pipe and equipment. This minimizes convection losses through seams and gaps between the preformed insulation and the piping caused by the heat tracing. An exterior lagging is generally used to protect the insulation from environmental damage.

**Instrumentation.** Typical instrumentation used in the heat transport and exchange subsystem includes flowmeters, pressure gages, level sensors, thermocouples, and position indicators. This

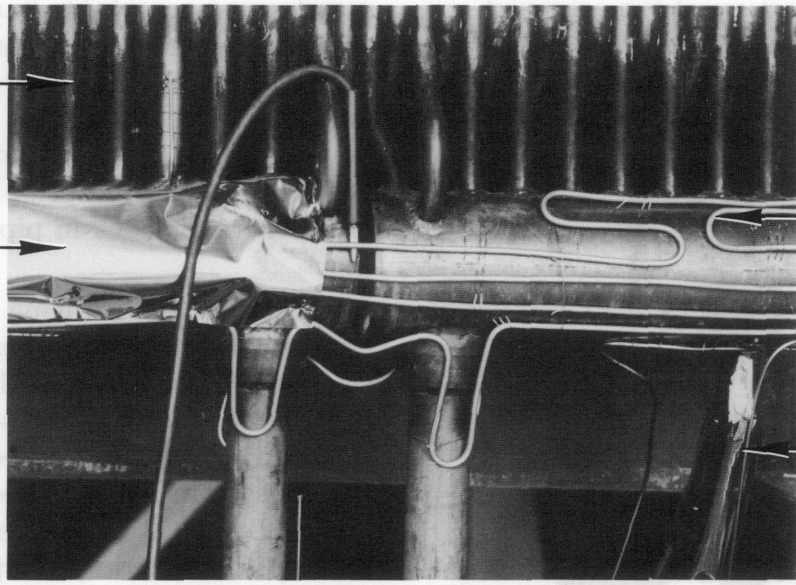


**Figure 2.4–5 Photograph of Heat Tracing in a Molten Salt System**

equipment is used for control and the collection of engineering data.[11]

Pressure transducers are used for both pressure measurements and flow measurements. (Flow is determined by measuring the pressure drop across an obstruction such as a wedge or a venturi.) The pressure transducers must be isolated from the salt or sodium but at the same time must be able to sense pressure variations. This is usually accomplished with a fluid coupling through a diaphram or bellows. Problems can result from the high temperature environment or the fluid coupling process itself.

A general challenge for instrumentation is the high temperature environment. Instrumentation must not only be able to survive the extreme temperatures but must also be compensated to provide accurate data over a wide temperature range.

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# THERMAL STORAGE SUBSYSTEM

The thermal storage subsystem stores thermal energy captured by the receiver subsystem and delivers it to the steam generator system. Storage of thermal energy provides continuous operation of the plant during periods of variable insolation, extends plant operation into nonsolar hours, avoids the potentially harmful transients arising from abrupt changes in insolation, insures power availability in emergency periods, and enables a shift of electricity generation to meet a demand profile which does not coincide with the insolation profile.

## TYPES OF STORAGE

Three generic types of thermal storage have been investigated in the solar central receiver development program: sensible heat, latent heat, and thermochemical energy.

In sensible heat storage, energy is stored as thermal energy in a storage medium. The storage medium undergoes no phase change over the temperature range encountered in the storage and energy extraction process.

A number of sensible heat storage media have been examined in the solar program. For temperatures pertinent to central receivers, consideration has been given to heat transfer oils, molten salt mixtures, liquid metals, and solids including rock, sand, ceramic bricks, and metal spheres. The ability to store sensible heat in a given volume of material depends on the product of the material's density and its specific heat. The choice of material, quantity, and cost involves a complex tradeoff among application, plant location, and end-use needs.

The latent heat that occurs in phase changes is another potential way of storing heat. Phase changes from solid to liquid involve the latent heat of fusion, which occurs over a relatively narrow temperature range. The phase change temperature must be compatible with the system temperature in which the thermal storage subsystem is integrated.

Latent heat storage suffers two major cost penalties. First, the cost of pure materials is high relative to those of competing sensible heat media. Second, in current designs, heat exchange from the media requires a large expensive surface area to provide adequate heat transfer through the solidifying material.

Thermochemical storage involves the storage of thermal energy in the heat of decomposition and the recombination of reversible chemical reactions. A large number of chemical reactions have been considered, both catalytic and noncatalytic. An attractive feature of thermochemical storage is the potential for storing and transporting the constituents at ambient temperature. This aspect has generated significant interest for long-term and even seasonal storage applications.

Thermochemical storage is conceptually attractive because high-grade heat could be stored at ambient temperature. However, only a few compounds have low enough material costs to be considered, and in most cases, gases are produced during the known high temperature reactions.

Combinations of sensible heat and thermochemical energy, or of sensible and latent heat, are possible. Combinations that are cost-effective depend upon the application and the operational control strategy. Sensible heat storage is likely to be the method of choice for near-term utility applications.

Sensible energy storage can be implemented in a central receiver plant in two ways: direct storage in which the receiver working fluid is the same as the storage media or indirect storage in which different fluids are used in the receiver and in storage.

In direct storage systems, the temperature of the thermal energy delivered either from storage or from the receiver can be nearly the same. In an indirect system, an intermediate heat exchanger is used to charge storage. Temperature drops must be provided between the receiver and storage and between storage and the load in order to transfer heat. Therefore, the receiver must be operated at a higher temperature to charge storage than is needed to operate directly to the load; or, a lower temperature must be produced at the load from storage than is produced directly from the receiver.

## DESIGN ISSUES

**Storage Media.** Molten nitrate salt and liquid sodium are each capable of being used as both the receiver and storage media; they can be used for high temperature storage up to 565°C or 595°C (1050°F or 1100°F), respectively.

Heat transfer oils, such as Caloria, have a higher specific heat and lower thermal conductivity than either molten salt or liquid sodium. However, they also have an upper temperature limit of about 315°C (600°F).

The temperature limitation restricts the use of heat transfer oil as a central receiver storage medium to applications of water/steam receivers with sidestream storage or an oil receiver. The moderate pressure and temperature of the steam produced from such a plant must be admitted to the intermediate pressure region of the turbine. The relatively high cost of heat transfer oils can be mitigated by using rocks in the storage tank; the inexpensive rocks are used to store a portion of the thermal energy and displace some of the oil.

The concept of an air/solid storage system also exists in which thermal energy is stored in a large bed of crushed rock or refractory bricks. Energy is transferred into and out of the bed by air; the air is circulated between the bed and a set of heat exchangers by a large fan. This concept eliminates the need for liquid storage tanks, and replaces expensive liquids with less expensive solids. However, air is not the working fluid of choice; requirements for large ducts and large compressors and fans limit the cost-effectiveness of this option.

**Configuration.** Two tank configuration alternatives exist. One alternative consists of separate hot and cold tanks; the other employs a single thermocline tank arrangement.

The separate hot and cold tank configuration consists of two or more tanks; all of the fluid contained in a given tank is at a uniform temperature. As a result of continuous charging and discharging of stored thermal energy, the fluid levels in the tanks in this configuration vary significantly during normal plant operation.

The thermocline tank relies on the thermal stratification of the storage medium. The stratification results from the variation in fluid density as a function of temperature. It requires the use of a relatively low thermal conductivity storage medium and on the ability of the medium to retain a thermal gradient barrier.

During normal plant operation, the fluid level in the thermocline tank remains fairly constant; however, the layer containing the thermal gradient between the high and low temperature zones moves up and down.

**Tank Design.** Three tank design concepts can be envisioned: (1) vertical, cylindrical hot and cold storage tanks with external insulation, (2) vertical, cylindrical storage tanks with internal insulation for the hot tank and external insulation for the cold tank, and (3) multiple, horizontal, cylindrical tanks for storing hot and cold fluid. Spherical tanks were considered early in some plant designs but are more expensive.

Carbon steel shells are adequate for tanks which contain prospective storage fluids at temperatures below 400°C (750°F). A typical design for a tank with a carbon steel shell is shown in Figure 2.5–1. This temperature limit is sufficient to accomodate an oil or oil and rock storage medium for either the separate or thermocline tank arrangements.

Molten salt or liquid sodium storage systems which operate at temperatures above 400°C (750°F) employ two-tank designs with separate tanks for the hot and cold fluids. One approach for a high temperature tank consists of a stainless steel tank with external insulation; this

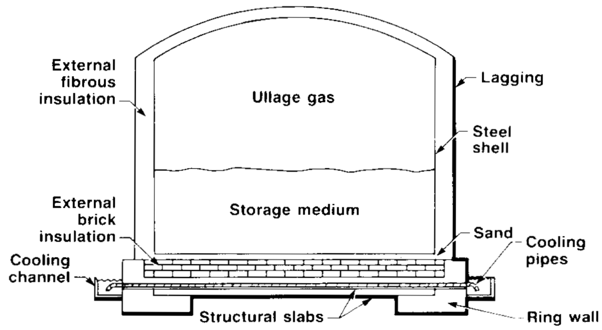


**Figure 2.5–1 Schematic of Low Temperature Carbon Steel Storage Tank**

concept is similar to the cold tank design illustrated in Figure 2.5–1.

Another high temperature tank concept uses a carbon steel tank with internal insulation and a liner. Two possible alternatives for the tank insulation have been identified for the high temperature tank concepts. In one alternative, shown in Figure 2.5–2, a thin Incoloy 800 liner is used to keep the molten salt or liquid sodium from contacting the internal insulation. The liner is of a waffle-like construction to accomodate thermal expansion and to transmit pressure loads through the internal insulation to the tank wall.

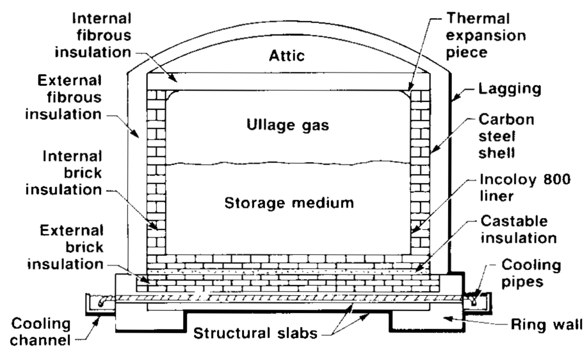


**Figure 2.5–2 Schematic of Insulated High Temperature Storage Tank**

For molten salt applications, an alternative internally insulated tank configuration consists of an annular layer of salt as the internal insulation material. In this design, the Incoloy 800 liner would have openings near the bottom of the tank which allow the molten salt to fill the annulus. Because of the salt's relatively low thermal conductivity, a thermal gradient is created between the liner and the carbon steel tank wall.

Because it contains hot storage fluid, thermocline tank construction can be similar to that of an externally insulated or internally insulated hot tank. Manifolds are typically used in thermocline tanks to remove and distribute returned storage medium to the top and bottom of a thermocline tank. This approach minimizes the fluid turbulence in the tank and reduces the growth of the temperature gradient layer of fluid in the tank.

Careful tank design requires consideration of structural design issues and storage medium leaks and their detection. Storage of hot fluids will exert continuous stress at elevated temperatures (as high as 595°C or 1100°F) on the storage tank walls for extended periods of time. This stress will cause slow creep of the containment materials, due primarily to grain boundary sliding, possibly resulting in rupture unless the design takes the creep-rupture stress into account. At the same time, raising and lowering the level of the contained fluids during system operation will subject the tanks to cyclic stresses, both thermal and applied, at an elevated temperature. The result is a combination of creep and fatigue stresses whose interaction can be significant.

Furthermore, the stresses at the joint of the bottom and side walls of a storage tank are significantly higher than those predicted for simple hoop stress. This stress level is a result of differential thermal expansion in the tank bottom and side wall. This problem appears to be more severe for stainless steel tanks than for carbon steel tanks because of the lower allowable stresses that result from higher operating temperatures.

Tank and tank liner integrity is critical to the safe and reliable operation of the thermal storage subsystem. Leaks not only necessitate replacement of the escaped storage medium, but also damage insulation and in some cases, jeopardize the tank foundation. Consequently, early detection and repair of a storage tank salt leak minimizes replacement and repair costs. Early leak detection is especially difficult and important for internally insulated hot storage tanks.

The hot and cold storage tank and thermocline storage tank configurations are typically supported by a concrete slab foundation. In addition, this foundation can consist of a concrete ringwall for extra reinforcement. For moderate to high tank temperature (260–540°C or 500–1000°F), the foundation is insulated and/or cooled to inhibit concrete strength degradation and to maintain the underlying soil bearing strength. The foundation cooling concept is illustrated in Figures 2.5–1 and 2.5–2.

Two other methods for storage tank support are top hung and tank leg support. These support alternatives accomodate tank thermal expansion while minimizing concrete strength degradation and maintaining the underlying soil bearing strength. The top hung support consists of suspending the storage tank from beams attached to a main support structure. This type of support is similar to that used for conventional fossil fueled steam generators. The tank leg support consists of supporting the storage tank on vertical support beams or legs. The leg support concept has one fixed leg located in the center of the tank and several outer legs which allow tank thermal expansion by means of sliding surfaces or wheels.

The maximum fluid volume which can be contained in a tank is influenced by the storage medium temperature, tank material and tank height. The storage medium temperature and tank material determine the stresses in the tank. Tank height is limited, in part, by the allowable soil bearing strength.

The storage tank configuration affects the number of storage tanks required. Separate hot and cold storage tanks require more tanks than a single thermocline tank. In addition, redundant tanks may be desirable to permit each tank to be empty for maintenance without dumping or getting rid of the thermal storage fluid.

## OPERATIONAL FEATURES

**Ullage Gas Control.** The purpose of the ullage gas control system is to minimize the buildup of contaminants in the storage medium and to prevent damaging differential pressures from developing between the inside of the storage tanks and the atmosphere. An ullage gas control system is used with molten salt, liquid sodium, and oil thermal storage systems.

For molten salt systems, air is typically used as the cover gas. In this case the ullage gas control system continually removes the carbon dioxide and water vapor from the tank cover gas. The presence of carbon dioxide and water vapor causes the formation of hydroxides and carbonates as salt decomposition products.

Argon is a typical cover gas in liquid sodium systems. The ullage gas control system removes the air and water vapor from the tank cover gas to prevent the oxidation of sodium in storage.

For oil systems, the ullage gas control system continually removes hydrocarbon gases from the storage tank.

**Sump, Heater, and Bulk Storage.** The purpose of the drainage sump tank is to store the fluid drained from the piping system and components located below the storage tank fluid level. Once drained, a sump pump transfers the drained fluid back to the storage tanks.

A heater, located in either the sump tank or storage tank, can be used to heat the storage medium during periods when the receiver is not in operation. The drainage sump tank can also be used for the initial melt down of salt or sodium prior to plant operation.

The bulk storage facility and handling equipment are used to store the bulk materials and transport the salt or sodium to the drainage sump tank for the initial meltdown process. The handling equipment provides make-up salt and sodium as required during normal plant operation.

**Startup.** The startup procedures employed when the plant is first put into operation depend primarily on the type of thermal storage medium used. For water/steam and heat transfer oils, the startup procedure consists of pumping the fluid to the solar receiver and routing the fluid directly to storage or transferring the energy by a heat exchanger to storage.

Sodium and salt are in a solid phase prior to startup. The first phase of the startup procedure involves heating the salt or sodium until approximately 20%

of the total inventory is melted. This initial melting can be accomplished by either electrical resistance heating or fossil heating. In the second phase of the starting procedure, the melted medium is pumped to the solar receiver where it is heated; the hot fluid is then routed to the intermediate drainage sump tank. The remaining bulk storage medium is gradually melted by the hot fluid. As more of the solid medium is melted, excess fluid is routed to the appropriate storage tank. This procedure is followed until the entire inventory of the storage medium is melted.

During periods of prolonged shutdown of molten salt and liquid sodium systems, a system for complete temperature control is required to prevent the storage fluid from solidifying. This system may use electrical heat tracing as well as electrical immersion or fossil heating. If used correctly, this system greatly simplifies the system startup following long term shutdown.

The maintenance requirements for the thermal storage subsystem depend on the chosen storage medium. Systems using oil must be carefully maintained and monitored because oils are highly flammable. Due to thermal decomposition of oils at high temperatures, continuous make-up and blowdown should be provided to maintain an acceptable fluid composition.

Molten salt and liquid sodium require special attention to monitor chemical degradation, the buildup of impurities, and fluid solidification. Liquid sodium, especially, requires extra attention to prevent its oxidation and to protect equipment and personnel.

## DEVELOPMENT STATUS

Thermal storage development activities have been conducted since the mid-1970s. A list of the major thermal storage system and subsystem experiments is shown in Table 2.5-1. This work is summarized in References 1-4.

In 1975, DOE funded several studies to develop solar thermal power systems which use water/steam-cooled central receiver technology. As part of these studies, storage systems were developed for both a 10 $MW_e$ pilot plant and a large-scale 100 $MW_e$ commercial plant. Laboratory experiments investigated concept feasibility and the thermal stability, compatibility, and fouling of various storage media. Two subsystem research experiments (SREs) were performed as a part of this effort as indicated in the table. (An SRE is an experiment of sufficient size to insure the successful operation of the full-size subsystem.)

The first experiment was designed by Martin Marietta and the Georgia Institute of Technology. A 1.6 $MWh_t$ two-stage sensible heat storage system used oil in the main stage and an inorganic nitrate salt (HITEC) in the superheat stage.

A second experiment was designed by McDonnell Douglas and Rockwell. The system, which had a 4 $MWh_t$ storage capacity, employed dual liquid (oil) and solid (rock/sand) storage media, with the thermocline principle applied to store both hot and cold storage media in the same tank.

Based on these test results and cost/performance estimates for the commercial-size plant, the single-stage oil/rock thermocline concept was selected for Solar One.[5] The thermal storage tank at the pilot plant contains Exxon's Caloria HT 43 heat transfer oil, gravel, and

Table 2.5-1
THERMAL STORAGE SUBSYSTEM/SYSTEM EXPERIMENTS

| Subsystem/System Experiment | Concept | Storage Medium | Operating Temperature Range | Capacity |
|---|---|---|---|---|
| 10-$MW_e$ pilot plant SRE (Newnan, Ga.) | two stages, hot/cold tanks | Oil, molten HITEC salt | oil – 238 to 295°C – (460 to 563°F salt – 270 to 482°C (519 to 900°F) | 1.6 $MWh_t$ |
| 10-$MW_e$ pilot plant SRE (Santa Susana, Calif.) | dual-media thermocline | oil, rock/sand | 218 to 302°C (425 to 575°F) | 4.0 $MWh_t$ |
| 10-$MW_e$ pilot plant (Barstow, Calif.) | dual-media thermocline | oil, rock/sand | 28 to 304°C (425 to 580°F) | 218 $MWh_e$ |
| Deep well irrigation pumping (Coolidge, Ariz.) | single-medium thermocline | oil | 200 to 288°C (392 to 550°F) | 0.9 $MWh_e$ |
| Midtemperature Solar Systems Test Facility (Albuquerque, N.M.) | single-medium thermocline | oil | 243 to 311°C (470 to 592°F) | 0.21 $MWh_t$ |
| Solar total energy (Shenandoah, Ga.) | single-medium thermocline | silicone oil | 360 to 399°C (500 to 750°F) | 3.3 $MWh_t$ |
| IEA 0.5-$MW_e$ power plant (Almeria, Spain) | single-medium thermocline | oil | 225 to 295°C (437 to 563°F) | 0.8 $MWh_e$ |
| IEA 0.5-$MW_e$ power plant (Almeria, Spain) | hot/cold tanks | liquid sodium | 275 to 530°C (527 to 986°F) | 1.0 $MWh_e$ |
| Molten nitrate salt SRE (Albuquerque, N.M.) | hot/cold tanks with an internally insulated hot tank | molten $NaNO_3$-$KNO_3$ | 288 to 566°C (550 to 1050°F) | 6.9 $MWh_t$ |
| THEMIS 2.5-$MW_e$ power plant (Targasonne, France) | hot/cold tanks | molten HITEC salt | 250 to 450°C (482 to 842°F) | 12 $MWh_e$ |
| CESA-1 1-$MW_e$ power plant (Almeria, Spain) | hot/cold tanks | molten HITEC salt | 220 to 340°C (428 to 644°F) | 3 $MWh_e$ |

sand. The diffuser manifold distributes the oil over the rock/sand bed to insure a sharp, uniform thermocline. The system operates over a temperature range of 218 to 304°C (425 to 580°F) and is sized to deliver 7 $MW_e$ over a four-hour period.

Operating from storage occurs at reduced turbine generator power because the temperature and pressure of steam generated from storage is less than that available directly from the receiver. Figure 2.5–3 shows a schematic of the pilot plant storage unit; Figure 2.5–4 presents an aerial view of the plant's storage tank.

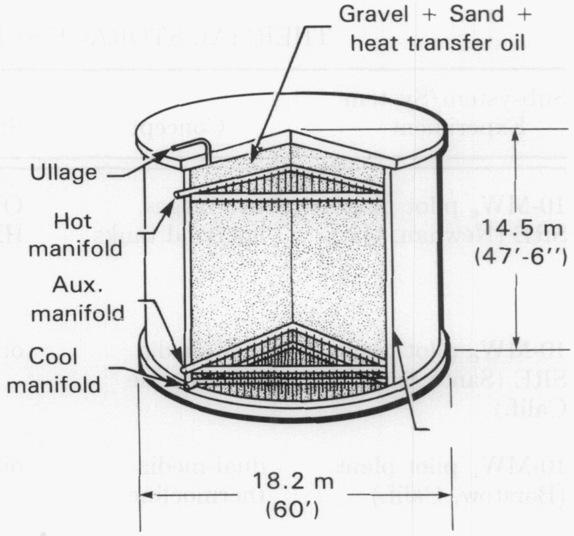


**Figure 2.5–3 Schematic Illustration of Solar One Storage System**

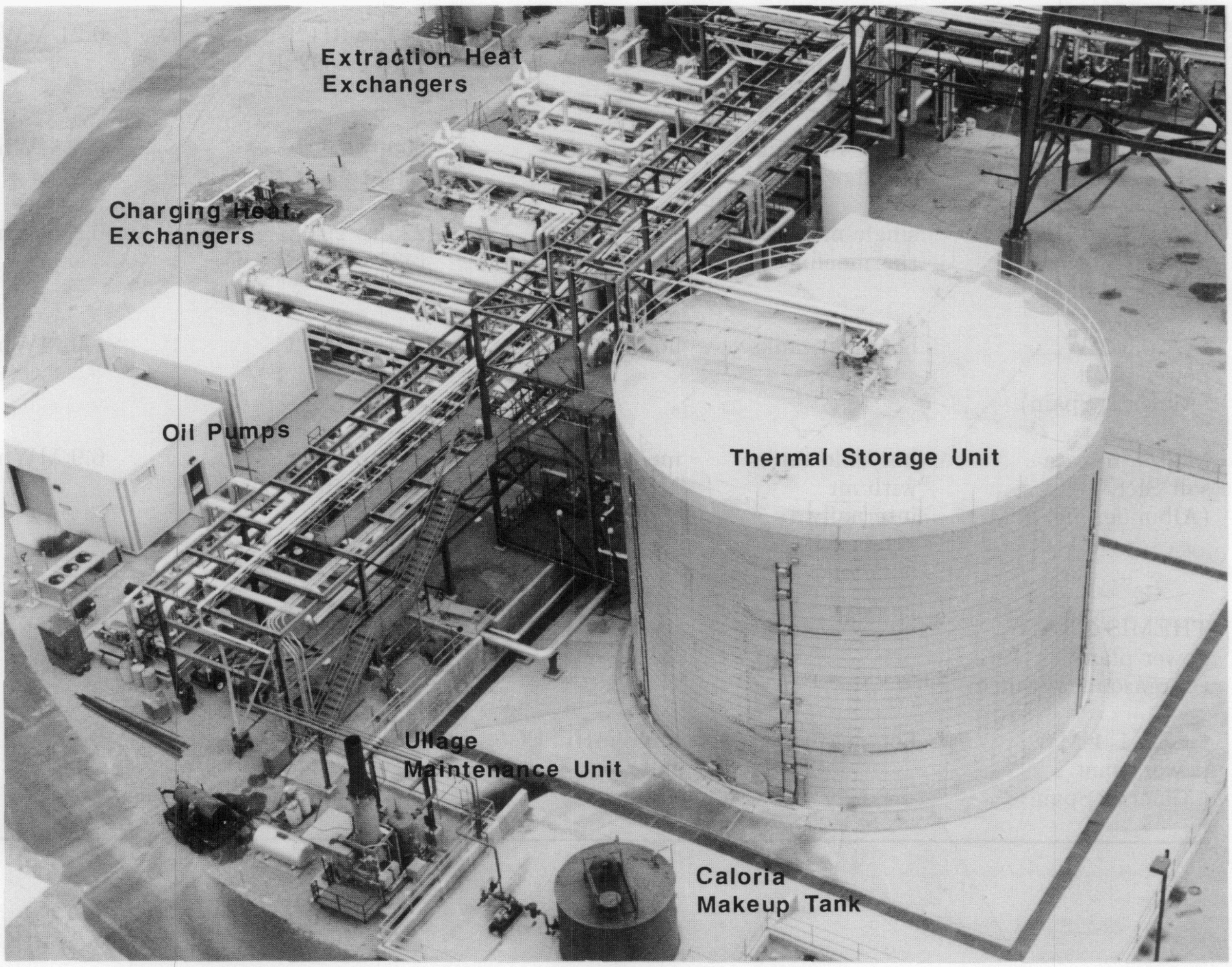


**Figure 2.5–4 Photograph of Solar One Storage System**

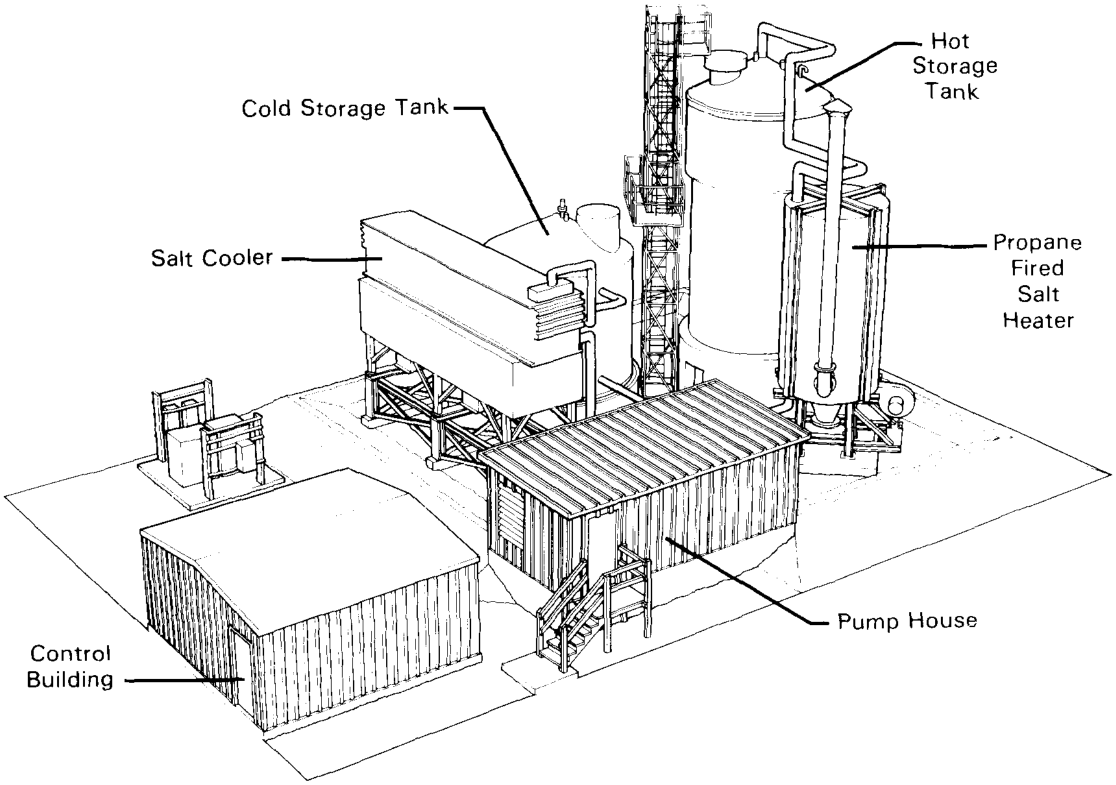


**Figure 2.5–5 Molten Salt Storage Experiment at CRTF**

Other storage experiments were performed outside the central receiver development program and as a part of the international central receiver projects. The round trip storage efficiencies vary from 70% for Solar One's indirect system to the low 90's% for the direct systems.

More recently, Martin Marietta[6] conducted an important molten salt subsystem research experiment at the Central Receiver Test Facility. A 7 $MWh_t$ internally insulated, dual tank (separate hot and cold tanks), sensible heat system utilizing molten nitrate salt was constructed. The hot tank was insulated both internally and externally so that the tank shell, maintained at 288°C (550°F), permitted the use of carbon steel rather than more expensive stainless steels for shell construction. A waffled membrane liner of the type used in liquid natural gas storage applications protects the internal insulation from the hot salt.

Figure 2.5–5 illustrates the experiment, consisting of hot and cold tanks, sumps and pumps, a propane fired heater (to simulate the solar receiver), an air-cooled heat exchanger, and the interconnecting piping valves and requisite heat tracing.

This storage system was used as a part of the recent Molten Salt Electric Experiment,[7] conducted at the CRTF. In this full system experiment of molten salt technology, 0.75 $MW_e$ was produced for the local utility grid. The performance of the system experiment dramatically demonstrated the value of the storage system in buffering insolation transients at the receiver from the steam generator. On a few experimental days with numerous cloud transients, the output of the receiver varied, while the output of the turbine remained steady due to use of the storage system.

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# MASTER CONTROL SUBSYSTEM

The master control subsystem provides an overall command, control and data acquisition capability for a central receiver plant. This system integrates the control of the other subsystems to achieve effective single-console evaluation and control.

A major part of the control system function is managing daily startup and shutdown. Since changing from one operating mode to another may involve numerous steps and considerations, the master control system may be used to automate these mode changes.

Major benefits of a well-designed master control system with automation are that plant energy output is increased and reliability is improved. Decreasing operator workload allows the operators to concentrate on making important discretionary decisions.

The master control system is configured to control and monitor the overall plant as well as each of the major plant subsystems. Master control automatically directs heliostats to track the receiver and controls receiver flow. When desired receiver outlet conditions are achieved, the receiver fluid is directed to thermal storage. Control of the thermal storage, steam generator and turbine generator systems involves temperature, pressure and flow instrumentation to maintain and optimize energy storage and electricity generation.

The principal functions of the master control system may be divided into four major categories[1] as illustrated in Figure 2.6–1. Control strategy and system architecture insure good coordination between the solar and nonsolar portions of the plant. The man-machine interface

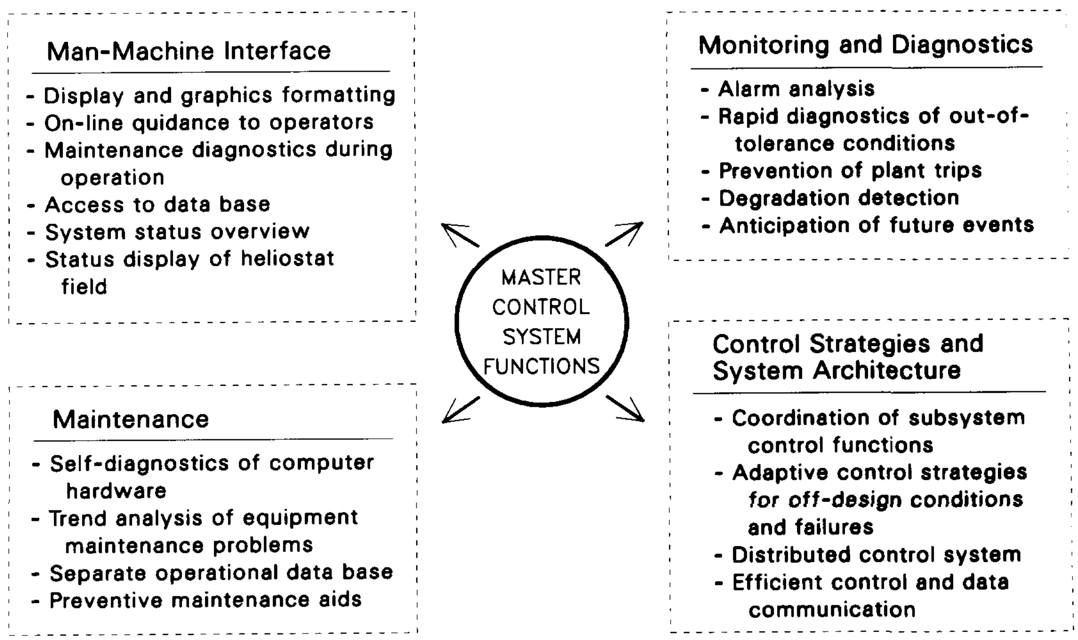


**Figure 2.6–1 Principal Functions of the Master Control System**

provides status and guidance information to plant operators; a good interface requires that both the hardware and software be designed with human factors in mind.

Monitoring and diagnostic functions keep track of and anticipate system and subsystem conditions which deviate from expected or nominal conditions. A significant goal is to analyze alarms and minimize plant downtime. The maintenance function includes a self-diagnostic capability and records of maintenance activities enabling trend analyses.

## MAJOR COMPONENTS

The major elements of the master control system are illustrated schematically in Figure 2.6–2.

The major equipment associated with the master control system includes the operator's console which provides the principal man-machine interface, distributed process controllers for each of the major subsystems, system computers which provide data and events storage and some processing, and connection among the various elements via a local area network.

The operator's console provides for exchange of information between the operator and the control hardware and software. The console keyboards should be organized to satisfy the operator's demands for information and interaction with the process as quickly and easily as possible. Some function keys should incorporate an annunciating capability which could be configured to indicate

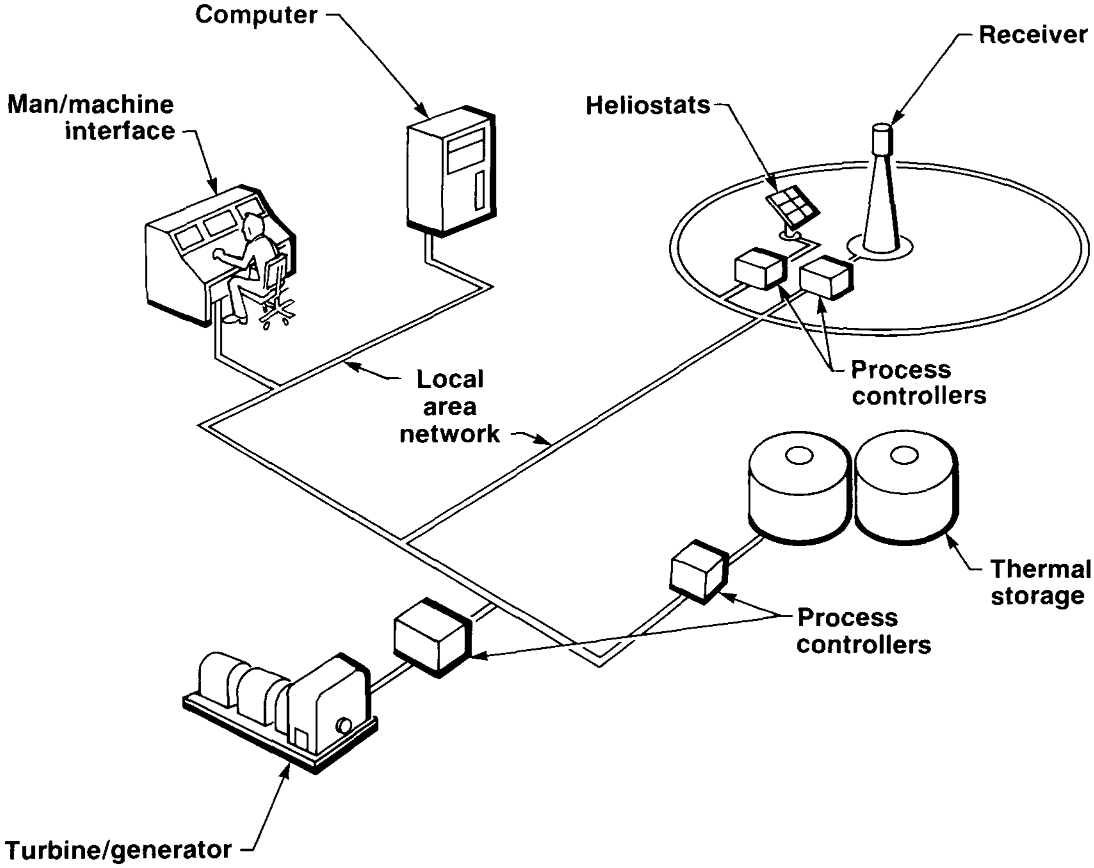


**Figure 2.6–2 Schematic Illustration of Major Control System Components**

operating conditions and guide the operator for fast response. The overall console should be human engineered to provide the operator with optimal viewing of the screens and interaction with the touch-screen and keyboards.

Key characteristics to be considered for computer equipment and the associated supplier include demonstrated reliability and serviceability in an industrial or utility environment, redundancy, as appropriate, to reduce significant single point failures, hardware design and software applications personnel, and the availability of a knowledgeable, competent, quick response supplier service organization.

Process control may be accomplished by using functionally and physically distributed monitoring and control devices that provide manual control capability and access for automatic computer control. A distributed process controller is usually located in the field near the process and the final control device such as a valve or motor. The distributed process controller should include a high level programming capability which will provide the controls engineer with the flexibility to define process control routines. The process controllers read process inputs, execute the control algorithms, and drive the control elements; they are redundant, so that a single failure will not disrupt plant operations.

The process controllers communicate with the centralized control console over a local area network or redundant data highway. Distributed, digital systems are basically multiplexing systems. That is, information (commands or data) passing between the remotely located control hardware and the centrally located command and display hardware is electronically condensed so that many signals are transmitted over a single cable.

Not specifically illustrated is the equipment interlock system, a separate computer which monitors and prevents a function from occurring if prerequisite conditions do not exist for safe and correct execution of the function. The equipment interlock logic functions can be implemented like the control functions and integrated into the control system hardware. However, a key requirement of this system is that single failures affect as few logic paths as possible.

While each subsystem may be provided with separate safety systems, the hardwired equipment interlock logic system provides safety for all systems based on hardwired information about trips occurring in each system. Trip switches should be provided for each system, wired from the operator consoles in the control room, as well as a master switch that trips all systems in the total plant. This safety system should be powered from an uninterruptible power supply capable of supplying adequate power to operate until the plant is safe.

## DESIGN CONSIDERATIONS

Design of the master control system must be an integral part of the plant design process. Factors such as daily plant startup and shutdown, cloud disturbances and load changes, plant operating mode changes, and heliostat field control are unique to a central receiver plant. These factors produce trade-offs which affect design, procurement and construction as well as overall project cost projections and capitalization.

Control of the collector subsystem is the most unique aspect of a central receiver master control system. Control procedures must be provided for beam movements which will allow safe access to the collector field during the day. Operationally, the reflected beams from the heliostats must be moved from the overnight stow position to a standby position (located near the receiver) and eventually to track on the receiver.

At Solar One, this transition was accomplished by having the reflected beams follow an imaginary "wire" (from a point below ground in the heliostat field to a point in space near the receiver), a procedure known as the "wire walk." This procedure utilizes the fact that if all of the beams are pointed at a point on the wire, they will diverge beyond that point, and will then reach a safe level at the minimum distance beyond the wire and thus produce a safe flux level at a low altitude. During collector system shutdown, which requires moving from a standby position to stow, the startup procedure was reversed.

When the collector field loses power, all heliostats tracking the receiver stop. If power is not restored for some time, the reflected beams will move slowly off the receiver in a direction relative to sun movement. The collector control system hardware/software design should be such that power can be restored quickly (hardware) and the field can be commanded to standby immediately after power is restored (software). The cost of these characteristics might be traded against the cost of improving the receiver design to provide some tolerance to flux levels with no fluid flow. Another cost trade might incorporate an automatic slew device (possibly air operated) to move the beam off the receiver during a power loss.

Heliostats are built to withstand a certain wind speed. When this speed is exceeded, the heliostat should be positioned to a safe predefined orientation (high wind stow). This can be either a manual or an automatic operation. At Solar One, a pushbutton is available that the operator can depress at his discretion. A wind speed readout is also available in the control room for operator reference.

The control system requires a number of support systems including electrical power, environmental conditioning, and fire protection. There are also specific lighting, architectural features, and cabling provisions required.

Uninterruptable power supplies (UPS) are desirable for all control electronic equipment and most other electronic equipment. The need is to provide the control system with enough power to shut the plant down safely and quickly. Tradeoffs may be necessary where the cost of the required uninterruptible power supply is substanially more than the cost of replacing the equipment or providing integral or internal automatic safety protection. Another benefit of an uninterruptible power supply is line-voltage-spike and noise suppression. Computer equipment subjected to poor line voltage will eventually malfunction or may be permanently damaged.

## SOLAR ONE MASTER CONTROL SYSTEM

The master control system at Solar One is an example of one approach to controlling a central receiver plant.[2–6] The plant is an excellent demonstration of the use of modern digital control system technology. The master control system at Solar One employs five computers to supervise operation and data acquisition: an operational control system (OCS), two heliostat array controllers (HACs), a data acquisition system (DAS), and a beam characterization system (BCS). Their relationship is illustrated in Figure 2.6–3.

At Solar One, the operational control system supervises two heliostat array controllers (one is a backup), three subsystem distributed process controllers (SDPCs) that control the plant's main process loops and programmable process controllers that provide the plant's personnel and equipment protection logic. The "red line unit" (RLU) and interlock logic system are safety systems. The data aquisition system computer collects data for plant evaluation, and the beam characterization system computer evaluates heliostat tracking errors, and beam quality. Tracking errors are provided to the heliostat array controllers for error corrections.

Solar One operates automatically under the supervision of the operator. In the morning the operator, through keyboard commands, positions the heliostats at standby operating points (four tracking points in space near the receiver), initiates water circulation in the receiver, and then issues a command to the computer to start the plant. The operational control system computer takes over and automatically directs heliostats to track the receiver, controls receiver flow, and puts the various receiver components into operation. When receiver steam conditions are correct, steam is routed to the turbine or thermal storage.

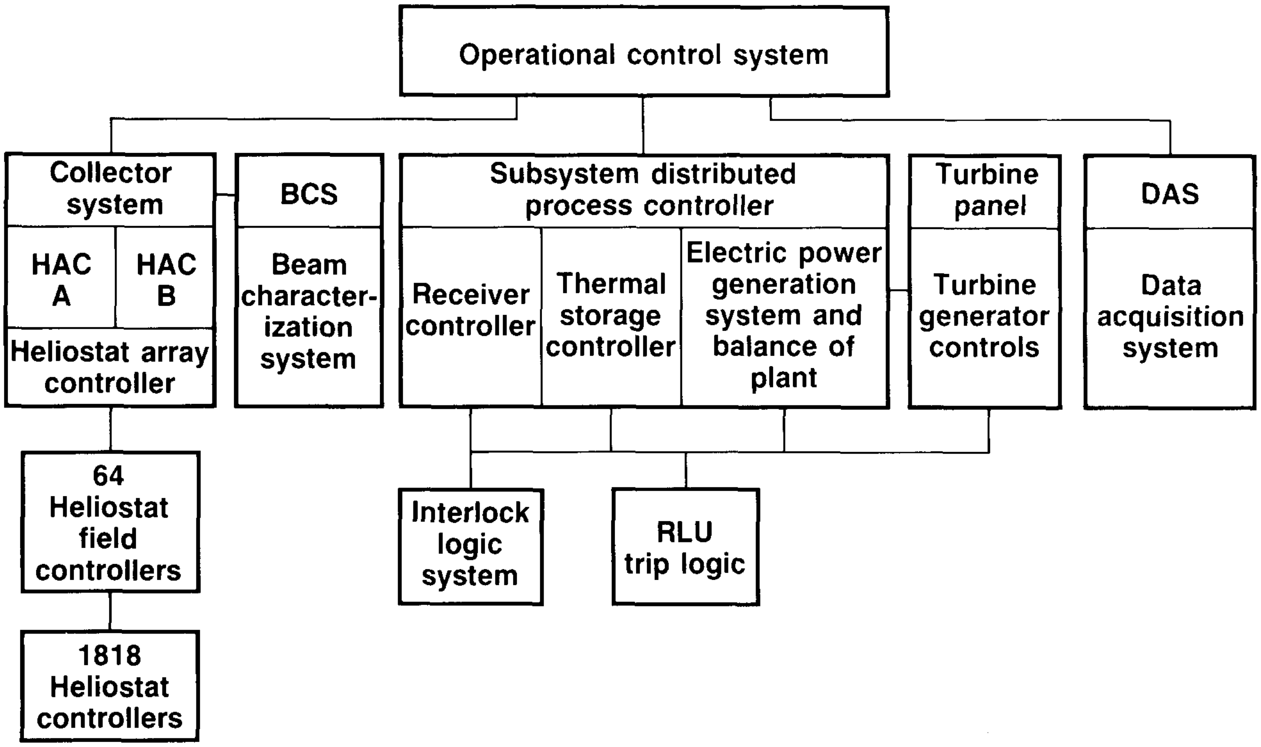


**Figure 2.6–3 Solar One Master Control System**

For power production operation, the operator then sychronizes the turbine to the utility electric grid. The plant operates for the rest of the day under supervisory control of the operational control system computer.

If conditions change, such as a cloud shadowing the collector field, the control system will automatically make adjustments and attempt to keep the plant in the best operating state. If an abnormal event occurs, the operator receives alarm messages, indicating what parameters are out of normal operating range. The operator can at any time make changes in any plant operating condition.

The operator receives information on plant operation through color-graphic video displays, and interacts with the system through keyboards, light pens, function keys, and function switches. There are very few dedicated analog controls, switches, control knobs, and meters in the control room. A picture of part of the Solar One control console is on the Chapter 6 interleaf.

The majority of the information displayed on the video screens is in the form of functional diagrams like the receiver page output also pictured on the Chapter 6 interleaf. Real time data, displayed near the graphics symbols, represent plant components such as pumps, valves, and steam lines. Plots of plant data can be displayed in real time and for the previous twenty-four hours. Process out-of-limit conditions are annunciated through the color-graphic displays and printers rather than through dedicated annunciator panels that are common to conventional power plants.

Overall, Solar One experience has shown that modern computer control technology can be effectively used in the utility industry. The plant has been operated by Southern California Edison operations and maintenance personnel; no special qualifications for these personnel have been required. The control system, coupled with equipment design, provided a plant power turndown ratio of twenty-to-one.

In addition, the plant has operated during severe cloud transients without evidence of process upsets. A major benefit of the plant automation has been the reduction of plant startup time, both in the morning and after cloud passage. The automated computer control system allows the operator to devote significant time to evaluating and improving the plant's performance.

## POTENTIAL FOR UNATTENDED OPERATION

In the long term, significant reductions in operating costs could be achieved through the elimination of operators. This is especially important for small ($\leq$ 10 $MW_e$) plants where the cost of 24-hour per day on-site operating staff is prohibitive.

Two options are possible for minimization of operating costs: remote operation or unattended operation.[8,9]

Remote site operation refers to the capability to operate a plant from a master console which is at some location other than the plant's main control room (possibly several miles away). An operator would not be in attendance at the plant but would be monitoring and controlling from the remote location.

Unattended operation refers to a completely automatic 24-hour operation of an entire plant without any monitoring or control by an operator. The plant could remain unattended for extended periods of time, weeks or even months. However, periodic maintenance and inspection would be required.

A solar plant which is to be operated from a remote site or have unattended operation will require a high degree of automation throughout the plant using highly sophisticated process and master control systems. The initial plant design must take into account the various plant, systems, and subsystems requirements necessary for remote or unattended operation. Automated maintenance processing may be required as well as smart alarm processing.

Control system, computer and peripheral hardware is available which would meet unattended operation specifications. However, special purpose software would need to be developed for a particular plant design.

To allow remote or unattended operation, the basic control system (one which executes closed-loop control, performs interlocking and accepts setpoint and discrete commands) must be capable of communicating its control information to an external computer where supervisory and unattended controls would be implemented. For maintenance purposes, the unattended controls computer must also have access to all subsystem controller data bases and calibration data of all control instrumentation.

The unattended control software might benefit from being implemented using expert system architecture. Expert knowledge could be included as an integral part of unattended controls either by testing the solar plant using knowledgeable operators and coding their experience and practices or by using artificial intelligence techniques which would allow the unattended controls computer to develop its own knowledge base.

A maintenance computer program would be an important part of a control system for unattended operation. The complexity of this program would be determined by the extent to which the unattended capability is expected to maintain an operational status or to maintain availability.

A basic maintenance program would access a data base of instrumentation calibrations and retrieve instrumentation input values from the process control system to verify the validity of the inputs. Valid inputs are essential to insure proper control at all levels and to maintain safety. The degree of program complexity is directly related to how an invalid, or erroneous, input is traced and resolved.

The maintenance program would also report invalid inputs to the unattended controls and alarm processing program. The unattended controls program would use this information to determine the appropriate action required for continued safe operation while the alarm processing program would suppress the input from alarming so that invalid alarms do not occur.

The program could also help maintain plant performance. A data base of selected data could be kept according to time. For example, the turbine-generator load might vary for the same insolation level, time-of-day and seasonal conditions. The program would perform traces to determine the cause. If the program found excessive leakage through a commanded closed valve, the program could activate a software switch to bring into service a redundant control valve or isolate the leaky valve or simply report the abnormal condition to the unattended controls program for the appropriate response.

A sophisticated maintenance computer program would require many man-years of development, implementation and testing. However, maximizing plant availability and performance continuously over the life of the plant could outweigh the intial costs, especially if the cost is spread over several similar plants.

Alarm processing is another significant part of an automated control system. Despite the importance of alarms to the safe operation of a plant, the effectiveness and value of an alarm system is often diluted by numerous alarms occurring at the same time in a critical situation. At that time, there are a few key alarms which require the quickest appropriate response. The other alarms are extensions of the key alarms and represent the cascade effect of one problem causing another. These other alarms do not provide any additional useful information and should be suppressed to provide a more effective alarm system.

Attempts at automatic alarm suppression have taken the form of a tree or hierarchy where alarms which occur under another alarm are suppressed. Care must be taken to insure that important diagnostic information is not lost in the suppression process. Development of such alarm suppression schemes, or alarm processing in general, are quite involved and complex but highly valuable to operators and unattended control for rapid response and recovery.

Nuisance alarms also occur. Many of these alarms occur when a subsystem is shut down because it is not needed for the particular mode of plant operation.

They also occur when a process variable fluctuates slightly above and below the alarm value. The fluctuation may be real or due to calibration drift. The input which is associated with the alarm should be reported to the maintenance computer program so that diagnostics can be performed. In either case, the alarm has no real operational value because the subsystem associated with the alarm is shut down or the alarm value is not matched to the process.

These types of alarms are distracting and interfere with normal operation of the plant and increase the potential for operational error, particularly when they occur during a critical situation.

Automatic alarm processing would be required for unattended operation and is highly desirable for operator operation as well. This capability would reduce operational error and speed recovery from a potentially unsafe condition. Thereby, plant trips and restarts could be curtailed and plant operation maintained.

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# STEAM GENERATOR SUBSYSTEM

Energy from the storage fluid is transferred to feedwater and steam in the steam generator; superheated steam at design temperature and pressure is produced for use in the turbine generator. A steam generator is required in both molten salt and liquid sodium systems. For water/steam systems, steam is produced directly in the receiver, but if the water/steam system includes storage, a steam generator is required.

Design issues for the steam generator include the type of steam system or circulation arrangement and the heat exchanger configuration. Potential circulation systems include once-through, a modified once-through scheme referred to as a Sulzer design, and recirculation. Heat exchanger types include straight tube, hockey stick, helical coil, and U-tube.

## WATER/STEAM SYSTEMS

Steam generators are required in water/steam systems only to extract energy from the storage system. These heat exchangers are referred to as the extraction heat exchangers at Solar One and are considered a part of the storage system.[1] Solar One has two identical sets of heat exchangers; each set includes a preheater, boiler and superheater. The two sets enable a turndown ratio of 10-to-1. All heat exchangers are horizontal, carbon steel, shell and tube heat exchangers. Double tubesheets are used for leakage control. The water/steam is on the tube-side of the preheater and superheater because of its greater pressure but is on the shell-side of the pool-type boiler.

## SODIUM SYSTEMS

Sodium steam generators have undergone development and testing as a part of the nuclear industry.[2] Confidence exists that a sodium steam generator could be procured for service in a sodium central receiver plant.

A sodium steam generator was tested as a part of the central receiver system at the International Energy Agency Small Solar Power Systems Project located in Almeria, Spain.[3,4]

As illustrated in Figure 2.7–1, that steam generator, a Sulzer design, is a vertical helical-tube-type with a once-through operation mode. The three heating tubes are coiled around a central displacement chamber filled with nearly stagnant sodium and housed in a cylindrical shell. Within the tubes, water or steam flows from the bottom to the top. Hot sodium (525°C or 975°F) enters the steam generator at the top, flows downward between the outside shell and the displacement chamber around the coiled heating tubes, where the heat transfer takes place, and leaves through an outlet at the bottom (275°C or 525°F). Water enters the three helical tubes at the bottom (190°C or 375°F, 110 bar or 1595 psi) and exits as steam at the top (520°C or 970°F, 100 bar or 1450 psi). The nominal thermal capacity of the steam generator is 2.2 MW.

The design employed was selected because it was an available design for a sodium/water steam generator. Operation of the steam generator for more than 1500 hours during the three year

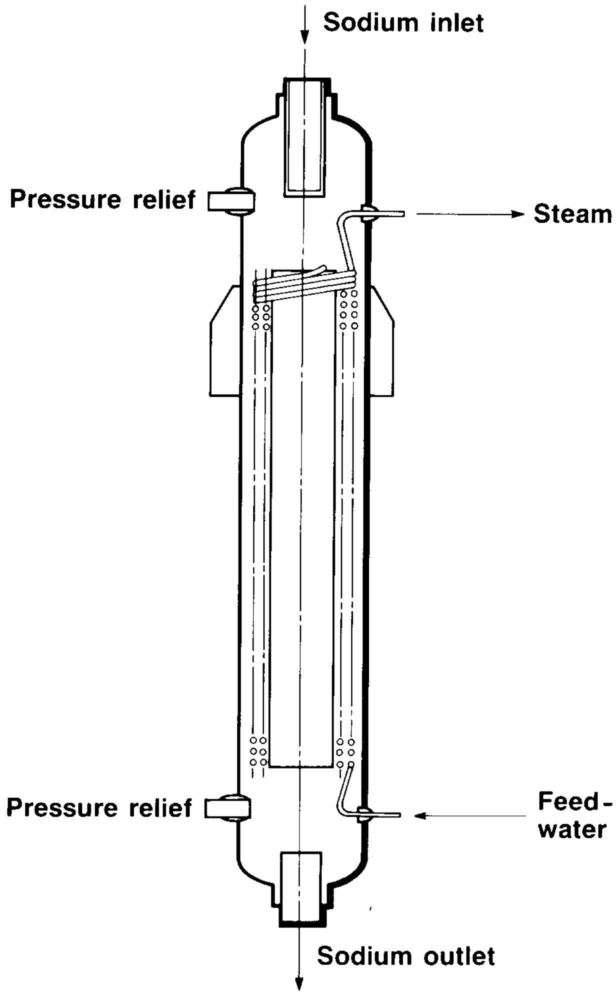


**Figure 2.7–1 Single-Shell Once Through Sulzer Steam Generator**

test period indicated that design conditions were fully satisfied. It operated in a stable manner over a range of load conditions and demonstrated a high level of flexibility with respect to system pressure and power needs.

## NITRATE SALT SYSTEMS

Salt steam generators suitable for use in molten salt central receiver systems have been studied and tested as a part of the central receiver program. In 1982, Babcock and Wilcox[5] and Foster Wheeler Solar Development Corp.[6] were funded to perform parallel design studies of a molten salt steam generator subsystem for a high-temperature, high-pressure reheat power cycle.

In both studies, alternate steam system and heat exchanger configurations were reviewed. The once-through designs were rejected by both teams because of perceived problems associated with the daily startup requirements or from the use of nitrate salt. Once-through designs are popular in nuclear applications where they are not cycled and where sodium is used as the heat transport fluid.

Both companies selected as their preferred design a more expensive, but conventional, drum-type recirculation system. This configuration can be either a forced-recirculation type (as selected by Babcock and Wilcox) or a natural-recirculation type (as selected by Foster Wheeler). The cycle efficiency is slightly lower than once-through systems owing to parasitic power consumed by recirculation pumps and energy lost in blowdown. (This penalty is less in natural recirculation systems.) However, the recirculation system can readily accommodate frequent startups and load swings.

A recirculation system incorporates the advantages of the Sulzer design and has additional benefits. Feedwater quality requirements are typically less stringent than for once-through or Sulzer designs. A steam drum separates the water from the steam, but unlike the Sulzer cycle in the blowdown mode, only a very small portion of the water leaves as blowdown. The remainder is recirculated back to the evaporator along with the entering feedwater. In this manner, the blowdown quantities and the corresponding energy loss are minimized.

Disadvantages of this design include thick steam drum walls which limit the rate at which startup can occur. Also, the recirculation design has a higher capital cost than the Sulzer design because the evaporator and steam drum must be sized to handle a mass flow in excess of the full load steam rate.

With a nitrate salt steam generator, the tubes must be of Incoloy 800 or a similar expensive material to resist both the stress-corrosion cracking in the evaporating section and the salt corrosion in the superheating section. Minimum feedwater temperatures to the vessel must be maintained to prevent salt freezing in the vessel or excessively low sodium temperatures in the cold storage tank. As turbine-generator load drops, final feedwater temperatures also drop unless main steam is used in the final feedwater heater to maintain outlet temperature.

A nitrate salt steam generator was fabricated and tested as a part of the Molten Salt Electric Experiment.[7,8] This steam generator, designed by Babcock and Wilcox is pictured in Figure 2.7–2. The subsystem included an evaporator, steam drum, boiler water recirculation pump, superheater, and attemperator. The attemperator was required for this particular system experiment in order to match the desired inlet conditions of the specific turbine generator set employed.

The evaporator and superheater are U-tube, U-shell heat exchangers, with low pressure salt on the shell side and high-pressure water and steam on the tube side.

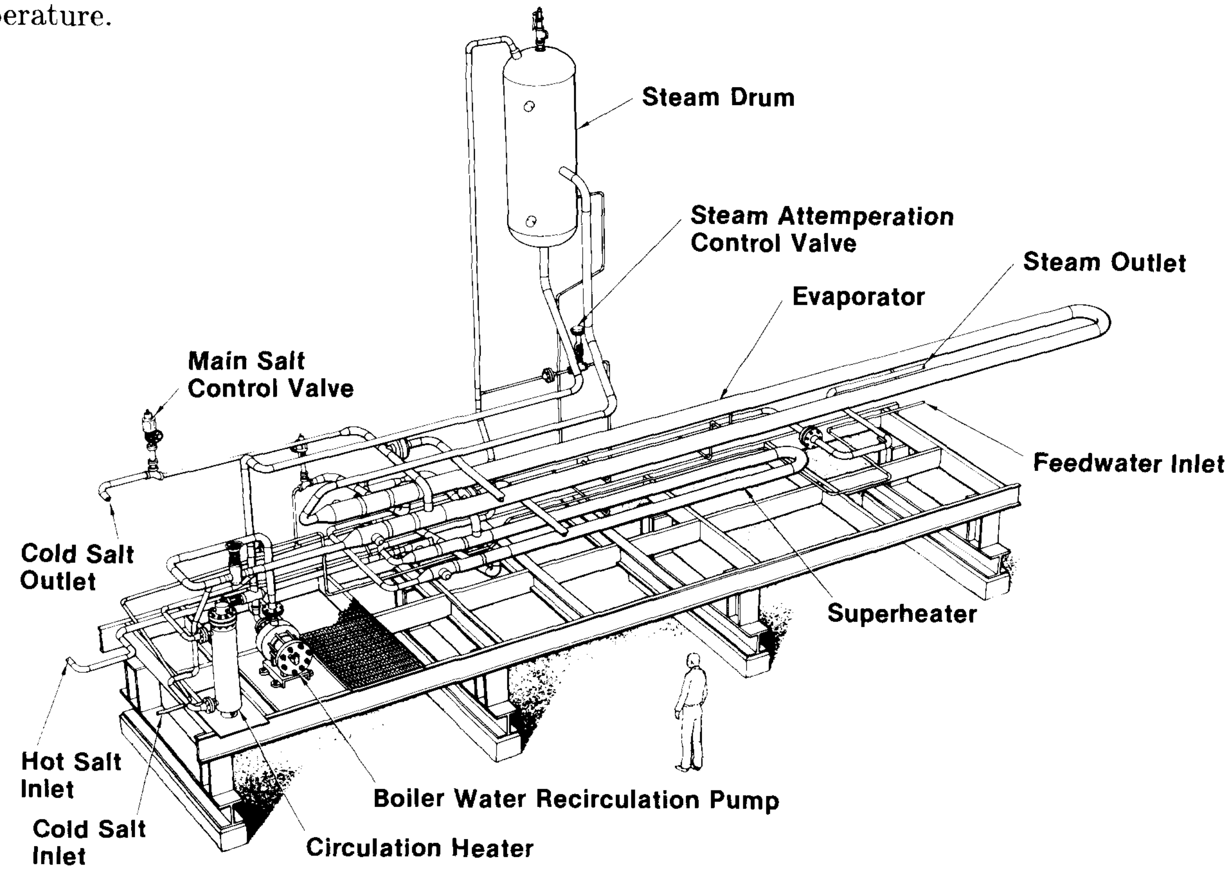


**Figure 2.7–2 Schematic Illustration of the Molten Salt Steam Generator Tested as Part of the Molten Salt Electric Experiment**

A conventional steam drum operating at 295°C (565°F) and 83 bar (1200 psi) is located above the evaporator. The steam drum separates water droplets from the saturated steam before the steam enters the superheater and receives feedwater from the feedwater heater. Outlet steam from the superheater (540°C or 1000°F, 76 bar or 1100 psi) can be attemperated to 510°C (950°F) by mixing with a small amount of saturated steam from the drum. Salt flow from the superheater to the evaporator is also attemperated to 455°C (850°F) when necessary by mixing with salt flow from the cold tank. This enabled use of chrome-moly piping and fittings in the evaporator rather than stainless steel.

In tests, the steam generator performance was good despite failures of the immersion heater recirculation pump, and some leakage which resulted in system delays.

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# ELECTRIC POWER GENERATING SYSTEM

The electric power generating system consists of the turbine generator plant and its ancillary components. Conventional power plant equipment is suitable for central receiver plant use.[1]

## CYCLE ARRANGEMENTS

Two superheated steam Rankine power conversion systems are used in the electric utility industry: reheat cycles and non-reheat cycles.

In non-reheat cycles, the steam entering the turbine expands through the turbine stages to the condenser with no intermediate energy input. In reheat cycles, the turbine steam flow is withdrawn from the turbine at an intermediate point in the expansion path and heated again to superheated conditions, after which it re-enters the turbine and undergoes further expansion.

Two types of reheating are commonly employed: direct reheat, in which expanded steam from the turbine is reheated by the same heat source which superheats the main steam and indirect reheat, in which expanded steam from the turbine is reheated by higher-temperature steam from elsewhere in the cycle (such as extraction and/or main steam).

Direct reheat allows the steam to be reheated to the same temperature as the main steam and offers the greatest thermodynamic advantage. Indirect reheat offers less thermal advantage than direct reheat, but it does not require returning the steam to the steam generator.

Because of their relatively small size (by utility standards), central receiver plants to date (less than 10 $MW_e$ in size), have employed non-reheat cycles. Commercial scale central receiver plants in the 100 $MW_e$ size range will likely employ reheat cycles.

## CYCLE EFFICIENCIES

Although the efficiency of a process is usually expressed on a percentage basis, the efficiency of Rankine steam power conversion systems is commonly expressed as the heat input, in Btu's, necessary to produce 1 kWh of electrical energy. This term is known as the heat rate, and has dimensions of Btu/kWh. The turbine heat rate is calculated by dividing the heat added to the steam in the steam generator by the electrical output at the generator terminals. The overall efficiency of the power conversion system for a solar power plant can be best expressed by the turbine heat rate, together with an expression of auxiliary power requirements.

Increases in main steam temperature always result in a higher cycle efficiency. For base-loaded, fossil-fired plants, a 540°C (1,000°F) main steam temperature is common industry practice. Temperatures above 565°C (1,050°F) will require further research and development of turbine forgings and casings. For cycling plants, turbine manufacturers are willing to warrant machines at 540°C (1,000°F) operating main steam temperature provided the steam generator can provide cooler steam during startup at a temperature matching that of the turbine metal.

Higher main steam pressures generally result in a higher cycle efficiency. The selection of main steam pressure is usually made on the basis of technical limits, including requirements for turbine and steam generator reliability and ease of operation, and an economic tradeoff between cycle efficiency and capital cost. Main steam pressure in a non-reheat cycle is limited to approximately 12.4 MPa (1800 psig). However, no such limitation exists in a reheat cycle.

## COMPONENT REQUIREMENTS

Most of the special requirements imposed on the turbine-generator of a solar power plant stem from the cyclic nature of its operation. Transient operating conditions are accompanied by changes in pressure, temperature, and internal forces in the turbine. Of these, the changes in temperature are the most serious from the standpoint of equipment life.

The condenser of a solar power plant is not significantly affected by thermal cycling, since its operating temperature is quite close to ambient temperature. The primary requirement imposed on the design of a solar plant condenser results from breaking of the condenser vacuum during nightly shutdown.

This vacuum breaking is often chosen as an alternative to the energy consumption of the condenser air removal equipment and the steam seal system, which seals the points where the turbine shaft penetrates the pressure boundary. However, it results in repeated flexing of the flat condenser shell panels and subjects the joints to fatigue loading.

Breaking the condenser vacuum also exposes the moist internal surfaces of the condenser to oxygen and consequent corrosion, unless an inert cover gas is used. A nitrogen cover gas was selected at Solar One and for the Carrisa Plains design to prevent oxygen from entering the condenser shell.

For plants with once-through steam generators, a full-flow inline condensate demineralizer (polisher) system is required to remove impurities from the feedwater during both startup and normal operations. A condensate demineralizer system may also be necessary in plants with recirculation-type steam generators, depending on the operating steam pressure used and the conditions existing in the condenser during overnight shutdown. A major part of the demineralizer's morning startup duty is filtering out particulate iron corrosion products from overnight shutdown.

## AUXILIARY POWER REQUIREMENTS

Two categories of auxiliary equipment have power requirements in the electric power generating system. The large pumps and fans used to handle the working fluid and the fluids in the heat rejection system comprise one category. For a cycle of a given arrangement, the power consumed by these pumps is roughly proportional to the gross plant output.

The second group includes the smaller pumps, compressors, fans, and miscellaneous equipment used for equipment cooling, raw water treatment, service water supply, lubricating oil supply and purification, and other general uses around the plant. These loads increase somewhat as plant size increases, but not in proportion to the gross electric output of the plant. For this reason, the total auxiliary power requirement of the power conversion system represents a progressively smaller fraction of the gross cycle output as the plant size increases.

The variation in the auxiliary power requirement of the power conversion system with plant size is illustrated by a comparison of three recent solar plant designs: the 10 $MW_e$ Solar One plant, the 30 $MW_e$ Carrisa Plains design for Pacific Gas and Electric Company, and the 100 $MW_e$ Solar 100 design for Southern California Edison Company. Table 2.8-1 gives the auxiliary power requirements of each of the three power conversion systems when operating at full output.

Table 2.8-1

AUXILIARY POWER REQUIREMENT OF THREE SOLAR POWER CONVERSION SYSTEMS[a] OPERATING AT FULL OUTPUT

| Plant | Gross Output ($kW_e$) | Auxiliary Power: Consumption ($kW_e$) | Auxiliary Power: Fraction of Gross Output (%) |
|---|---|---|---|
| Solar One[b] | 9,720 | 1,074.8[c] | 11.1 |
| Carrisa Plains | 33,500 | 2,067 | 6.2 |
| Solar 100[d] | 110,000 | 4,751.1[e] | 4.3 |

(a) Total plant auxiliary power consumption, less power consumption of heliostat field, sodium or salt systems, and steam generator.

(b) Ref. 2, p. 23.

(c) Excludes heliostat load of 53.5 $kW_e$.

(d) Ref. 3

(e) *Ibid*, pp. V-8 and V-9, Categories III, IV, V, VII, VIII, IX, X.

## WATER CONSUMPTION REQUIREMENTS

The water consumed by a Rankine steam power conversion cycle is generally for two purposes: (1) evaporative removal of waste heat from the main condenser and (2) makeup of purified water to the steam cycle, to compensate for blowdown leaving the steam generator

Of these, the evaporative removal of waste heat from the main condenser is the larger user of water. This evaporative cooling usually takes place in a wet cooling tower after the water has been heated by passage through the tubes of a surface-type main condenser.

Dry cooling is an alternative for plants located in regions with limited water supplies.

The amount of water consumed in the cooling tower is dependent on a number of factors, all of which can be varied during the design process to give an optimum balance between cooling efficiency, water consumption and capital costs. Significant factors include the actual atmospheric wet-bulb temperature, relative humidity when the plant is in operation, and the operating profile of the plant throughout the year.

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# HYBRIDIZATION SUBSYSTEM

Fossil-fueled components may be included in a central receiver plant to supplement the solar heat source with a fossil source; this configuration is often referred to as a solar-fossil hybrid.

Inclusion of a hybridization subsystem in a central receiver plant will be a result of economic considerations for a specific plant. For example, the cost of energy from solar-only electricity generation and from fossil-only generation might be comparable. Then the hybrid mode would be desirable in order to extend the hours of operation of the plant during periods of poor or no insolation such as during cloudy weather or at night. Thermal storage requirements could be relaxed in this case.

Alternatively, the cost of energy from solar-only electricity generation could be lower than that from fossil-only generation. But the costs of thermal storage and high solar multiple plants might be such that fossil generation is favored for extended operation of the power plant.

A recent assessment of hybrid central receiver plants of about 80 $MW_e$ in size may be found in Reference 1. The reference also describes development of a computer code employing real insolation data and time-of-day pricing for electricity which can be used to help evaluate the value of a hybridized central receiver plant for a specific application.

Two configuration options have been identified for a hybrid arrangement of solar and fossil fuel components to provide increased operating flexibility.

The first option, shown in Figure 2.9–1, consists of a fossil-fueled steam generator which operates in parallel with the solar steam generator. This configuration can be achieved two ways. The first approach involves repowering an existing fossil fueled power generating station. In this approach, solar steam generation systems are added to the existing plant facilities. The second approach involves building a new power generating facility which includes fossil-fueled and solar steam generators in parallel.

The repowering option was the subject of a number of system design studies in the DOE central receiver program.[2] Results of these studies indicated that repowering is attractive when the costs of solar generation are less than fossil costs.

The second configuration option, shown in Figure 2.9–2 consists of a fossil-fueled, heat-transport-medium heater located in parallel with the solar receiver.

This configuration can be implemented by including in the design of a new solar central receiver facility a bypass around the receiver that routes the heat transport medium through an auxiliary fossil-fueled heater. Valving and piping are included to control the flow of the heat transport medium so that partial or full flow can go through either the receiver or fossil-fueled heater. After leaving the receiver or the heater, the heat transport medium is routed through the solar steam generator or to the thermal energy storage subsystem.

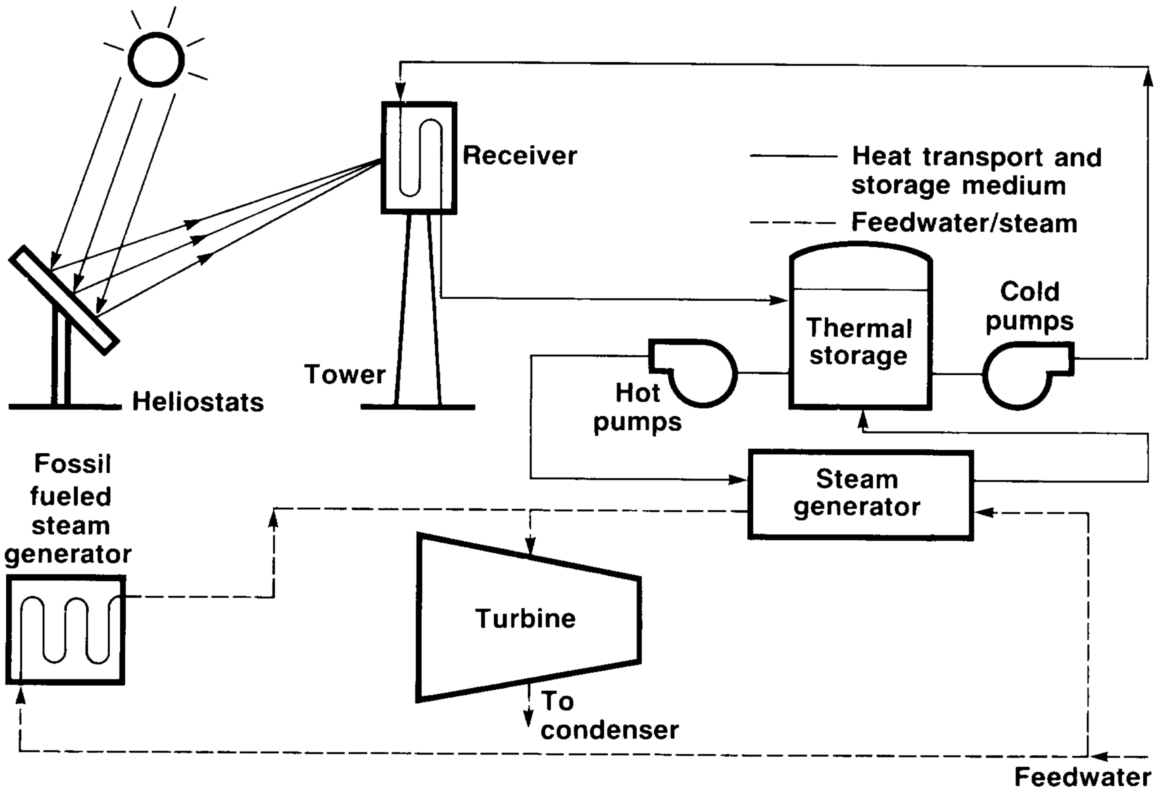


Figure 2.9–1 Hybrid Central Receiver System Employing a Parallel Fossil-fueled Steam Generator

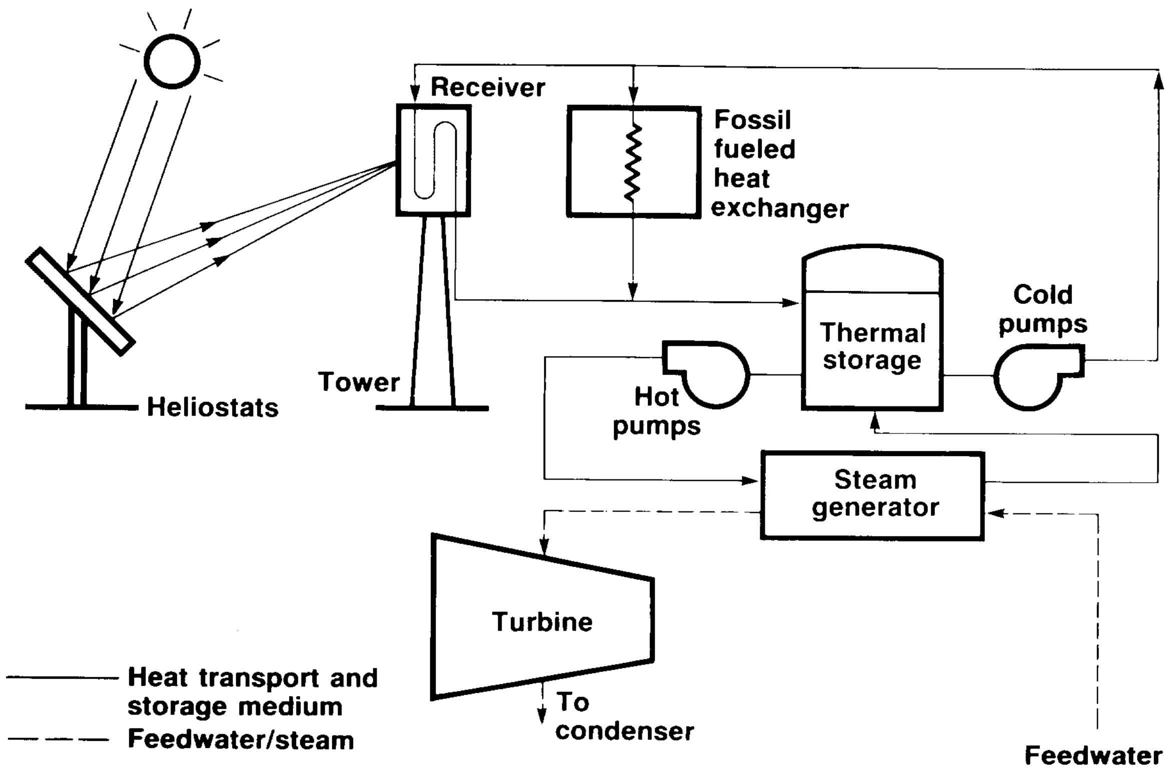


Figure 2.9–2 Hybrid Central Receiver System Employing A Fossil-fueled Media Heater

Although Figure 2.9–2 represents an application in which the receiver and thermal storage media are the same, this approach can also be used for applications which use different receiver and thermal storage fluids.

The complexity of the nonsolar subsystem options is notably different. The configuration with two steam generators in parallel is significantly more complex and expensive than the configuration with the fossil-fueled heat transport medium heater.

The fossil-fueled steam generator is a high pressure, two phase fluid system which requires careful monitoring and control. Reliable operation of a fossil-fueled steam generator requires constant monitoring and regulation of feedwater flow, steam flow, steam pressure and temperature, fuel flow, and fuel pressure. It also requires matching of these parameters with the turbine requirements as determined by the loading on the generator. The complexity of the overall plant controls is compounded when two steam generators are operated in parallel.

In contrast, a fossil-fueled, heat-transport-medium heater is a low pressure, single fluid phase, heat exchanger that does not require constant attention and employs relatively simple controls.

Design and fabrication of a fossil-fueled media heater is straightforward. A propane fired salt heater was built and used as a part of the thermal storage test at the CRTF.[3]

The size of the hybrid subsystem in a new plant depends primarily on the desired fossil generating capability of the plant. Secondary considerations include the configuration of the fossil subsystem and the capacity, if any, of the thermal storage subsystem. For a new plant with a fossil-fueled steam generator, the nonsolar subsystem is sized to produce the steam flow and steam conditions needed by the turbine for the desired level of power production as well as for any steam heating requirements.

Hybridization permits the use of a very small thermal storage subsystem which serves as a buffer; in some cases, if the fossil subsystem is sized properly, thermal storage can be eliminated altogether. On the other hand, if the objective is to reduce the cycling of the fossil subsystem, the thermal storage capacity can be increased and the size of the fossil subsystem can be reduced. However, this approach will limit the amount of electricity produced during extended periods of little or no insolation such as occurs during several consecutive days of cloud cover.

Fuel options for the fossil subsystem consist of oil, gas, and coal. The fuel alternative selected depends upon such factors as cost, availability, handling and storage, and emission control requirements.

Handling and storage requirements for the fuel options vary greatly. The use of oil requires provisions for storage, pumping, receiving, and heating. For gas, either storage or a pipeline supply and compression capabilities are required. The use of coal requires the most complex handling equipment, consisting of unloading facilities, conveyors, crushing equipment, surge storage capabilities, and complex system controls.

Emission controls for the fossil fuel options depend upon local, state, and federal regulations. A detailed investigation of these regulations must be carried out to determine the exact requirements for the particular application. Of the three fossil fuel options identified above, the use of coal requires the most complex emission controls. Not only must the exhaust gas be processed, but the resulting ash must also be controlled and disposed of. For oil, less complex and less costly emission controls are required; further, almost no ash disposal problems exist. Gas is the cleanest burning fuel; as such, little is required in terms of emission controls.

## REFERENCES


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2. J. C. Gibson, *Solar Repowering Assessment*, Sandia National Laboratories Livermore, SAND81–8015, 1982.

3. *Molten Salt Thermal Energy Storage Subsystem Research Experiment, Volumes I and II*, Martin Marietta Corporation Contractor Report, SAND80–8192, 1985.

# BALANCE OF PLANT

The balance of plant subsystem is a grouping of diverse plant elements which are required for plant operation but which have not been discussed as a part of other major plant subsystems. Many auxiliary systems are similar to their counterparts in conventional fossil-fueled power plants. In general, all components provide support to primary plant subsystems. They allow the primary plant subsystems to perform their functions in an efficient, reliable, and safe manner.

Typical auxiliary systems are listed below in Table 2.10–1. These systems are required to support a solar thermal central receiver electrical power generating station. The list includes some systems that are not utilized on a full-time basis but which are essential to the safe and efficient startup and shutdown of a power generating facility. Auxiliary systems with similar or complementary functions are grouped into categories. Several of the more important categories listed in Table 2.10–1. are described briefly in this section.

**Auxiliary Power Supply.** The systems in the auxiliary power supply category provide electrical power to all plant electrical equipment. The generator voltage is stepped down into several lower voltage levels and is distributed throughout the plant by transformers, switchgear feeder breakers, motor control centers, and power panels. AC power of 120/208 V, 480 V, 2400 V, and 4160 V, along with 125 V DC power obtained from a station battery, is provided by the auxiliary power system. Uninterruptible power, as required by computers and critical control and instrumentation functions is provided by static-type inverters.

**Compressed Air.** The compressed air systems provide compressed air to all plant equipment requiring station and control air. Station air is provided by a compressor to plant equipment and service disconnects. Control air is provided to pneumatic controls and instruments by the service air compressor or by a separate, dedicated, oil-free compressor. In either case, the control air is filtered and dried using either desiccant or refrigeration dryers. Reservoir tanks are provided to act as surge tanks and reduce the cycling of the compressors.

**Equipment Cooling.** The systems in the equipment cooling category provide cooling water to plant equipment coolers. The cooling water systems employ either a closed cycle with pumps, heat exchangers, and head tank or an open cycle operating in parallel with and using water from the turbine cycle heat rejection system. The temperature of the cooling water for either type of system is controlled to ensure relatively constant water temperatures.

**Fire Protection.** The fire protection category provides fire protection facilities throughout the generating station. The fire protection provisions include sprinkler systems, fire hose cabinets, fire hydrants, hand-held fire extinguishers, and $CO_2$ or halon systems. Fire protection water is provided from a dedicated source.

**Water Supply and Storage.** The systems in the water supply and storage category provide service water to the plant. Storage tanks, pumps, and service water piping are used to make the service water available to all facilities requiring its use. In addition, service water hose connections are provided throughout the facility.

TABLE 2.10-1

TYPICAL AUXILIARY SYSTEMS*

**Auxiliary Power Supply**
- AC Power Supply–120/208 V
  480 V, 2400 V, 4160 V
- DC Power Supply–125 V
- Essential Service AC & DC
- Emergency Generation

**Auxiliary Steam**
- Auxiliary Steam Supply

**Buildings and Structures**
- Generation Structure
- Control House/Instrument Repair
- Service Building/Machine Shop
- Chlorine Shed
- Circulating Water Pump Building
- Water Treatment Building
- Warehouse
- Administration Building
- Heliostat Warehouse/Maintenance Shop

**Bulk Materials**
- Bulk Material Receiving
- Bulk Material Storage and Handling

**Combustion Gas Exhaust**
- Chimney
- Induced Draft

**Communication**
- Intra-Plant Communication
- Commercial Telephone
- Microwave

**Compressed Air**
- Station Air
- Control Air

**Compressed Gas Storage**
- Hydrogen, $CO_2$, Chlorine, Nitrogen

**Construction Facilities**
- Power
- Water
- Buildings
- Security
- Lighting
- Roads and Parking
- Communications
- Laydown and Storage
- Sanitary Facilities
- Fire Protection
- Welding

**Control**
- Load Control
- Unit Protection
- Instrument Enclosures
- Control and Multi-System Panels
- Master Control

**Electrical**
- Water Freeze Protection
- Grounding and Lightning Protection
- Raceway
- Cathodic Protection
- Heat Transport Medium Freeze Protection

**Equipment Cooling**
- Auxiliary Cooling Water
- Closed Cycle Cooling Water
- Storage Tank Foundation Cooling

**Fire Protection**
- Generation Structure Fire Protection
- Solar Systems Fire Protection

*This table is not intended to be a complete list of auxiliary systems. Requirements for auxiliary systems depend on the nature of the plant.

**Fuel Gas** (for Hybrid Plants)
- Fuel Gas Supply
- Burner Gas Supply
- Heat Transport Medium Heater Gas Supply

**Fuel Oil** (for Hybrid Plants)
- Fuel Oil Receiving and Storage
- Fuel Oil Supply

**Information**
- Annunciation
- Vibration Monitoring
- Weather Monitoring

**Lighting**
- Building Lighting
- Solar Receiver/Tower Lighting
- Collector Field Lighting
- Energy Storage Area Lighting

**Plant Maintenance**
- Chemical Cleaning
- Shutdown Corrosion Protection

**Primary Power**
- 115 kV Substation
- 12.5 kV Substation
- Site Transmission

**Sampling and Analysis**
- Combustion Gases Sampling and Analysis for Hybrid Plants
- Fossil Steam Cycle Sampling and Analysis for Hybrid Plants
- Water Supply Sampling and Analysis
- Plant Effluent Sampling and Analysis
- Heat Transport Medium Sampling and Analysis
- Solar Steam Cycle Sampling and Analysis

**Site**
- Roads and Parking
- Fencing and Security
- Grading and Drainage
- Site Fire Protection
- Area Lighting
- Landscaping
- Land

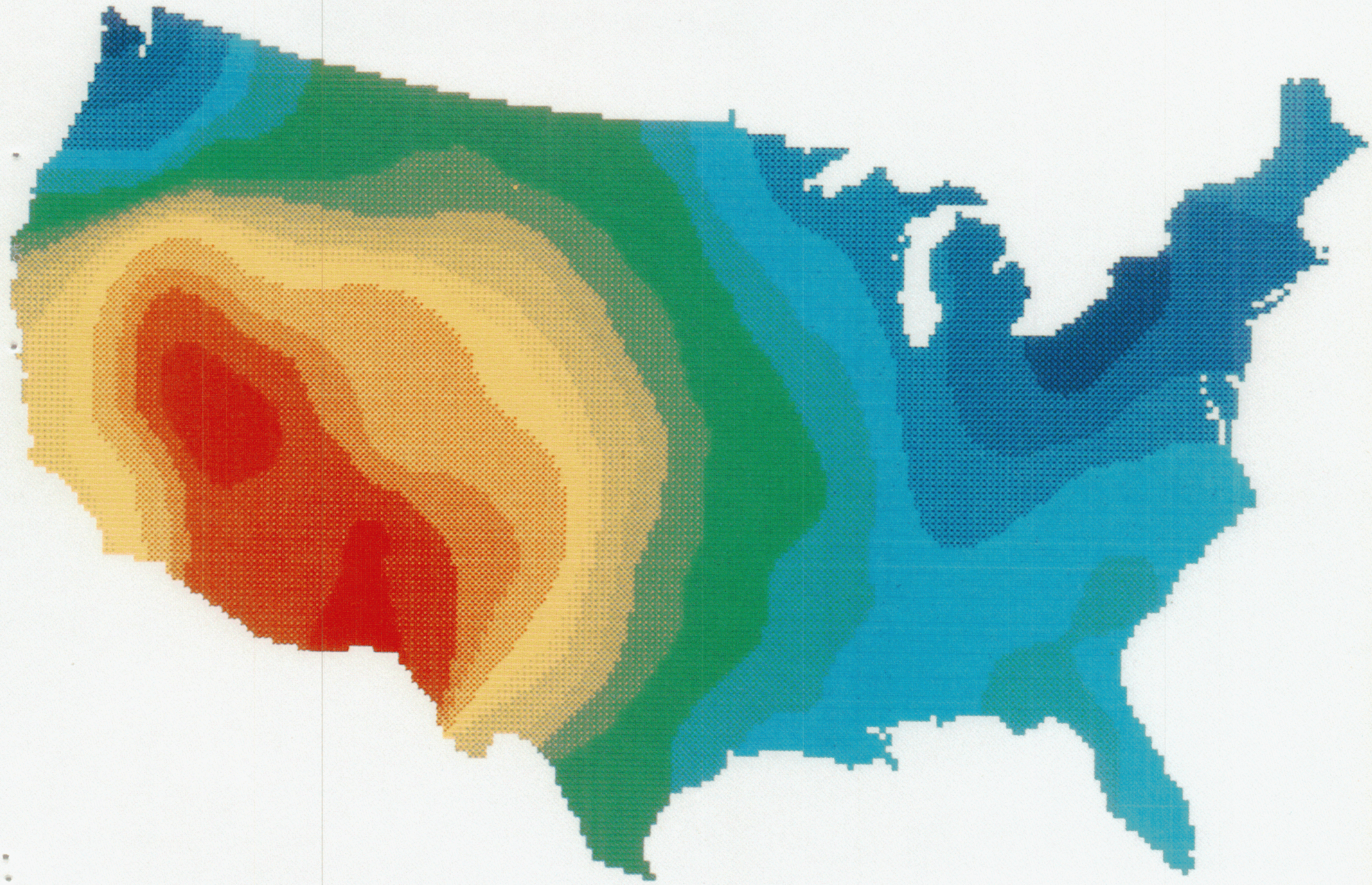
**Space Conditioning**
- Control House/Instrument Repair Space Conditioning
- Service/Machine Shop Building Space Conditioning
- Change House Space Conditioning
- Water Treatment Building Space Conditioning
- Warehouse Space Conditioning
- Solar Receiver Tower Space Conditioning

**Waste Collection and Treatment**
- Chemical Waste Drainage and Treatment
- Sanitary Drainage and Treatment
- Wastewater Collection and Treatment
- Oil Spill Prevention
- Heat Transport Medium Spill Prevention

**Water Supply and Storage**
- Service Water
- Fire Water
- Potable Water

**Water Treatment**
- Potable Water Treatment
- Demineralized Water Makeup Treatment
- Cooling Tower Water Makeup Treatment

# SITE SELECTION



Annual Mean Daily Direct Beam Solar Radiation, kWh/m²/day

| | | | | |
|---|---|---|---|---|
| 2.5-2.8 | 3.6-3.8 | 4.6-4.8 | 5.6-5.8 | 6.6-6.8 |
| 2.9-3.1 | 3.9-4.1 | 4.9-5.1 | 5.9-6.1 | 6.9-7.1 |
| 3.2-3.5 | 4.2-4.5 | 5.2-5.5 | 6.2-6.5 | 7.2-7.5 |

*Upper: Photograph of Solar One, the 10 $MW_e$ Solar Thermal Central Receiver Pilot Plant located near Barstow, CA, USA.*

*Lower: Annual mean daily direct beam solar radiation in kwh/$m^2$/day in the continental United States. Data obtained from the SOLMET/ERSATZ data base which includes 235 sites. Map provided by the Solar Energy Research Institute, Branch 215.*

# SITE SELECTION

Considerations which affect the choice of a site and the selection of a specific system configuration for a solar thermal central receiver plant which generates electricity are presented in this chapter. The objective is to familiarize the reader with those considerations which are important for selecting a solar plant site. The intent of this chapter is not to provide a detailed methodology with which a reader can select a site. Several references[1–3] are available for specific site selection methodology.

To site a central receiver plant, key plant characteristics must first be defined; among the more important plant characteristics are its rated electrical output, type of service, configuration, and energy storage characteristics. Next, site selection criteria including foremost the insolation characteristics as well as requirements for land and water, and proximity of transportation and transmission lines must be evaluated. Environmental concerns and safety issues must also be addressed.

## PLANT DEFINITION

Defining the mission of a solar thermal central receiver plant is a critical prerequisite to establishing the key characteristics of the plant. Many of these key characteristics have a significant impact on site selection. For example, plant rated electrical output has an important impact on the amount of land required. Also, the type of receiver and storage fluids and the fossil hybrid configuration have an impact on environmental issues.

In the utility setting, the rated electrical output, type of service, configuration, and energy storage characteristics are defined primarily on the basis of the projected needs of the utility. These needs depend on, among other things, the projected load growth of the system, planned retirements of existing units, and anticipated fuel costs.

**Plant Rated Electrical Output.** The size range for a solar thermal central receiver plant is nominally 10 $MW_e$ to 300 $MW_e$, with 100 $MW_e$ as a typical plant size which has been studied. It may be more cost effective to use a modular approach for solar plant construction than to build one large solar plant. The modular approach allows the generating capacity of the plant to increase over a period of time, in a manner similar to the typical growth in demand. In addition, the modular approach requires a smaller initial capital investment and produces revenue earlier than one large plant.

**Type of Service.** The mission of the plant should identify the type of service for which the plant will be used. Type of service indicates whether the plant is a peaking, intermediate or base-load unit and the time of day during which the plant energy is dispatched.

The three categories of unit loading relate to the plant's capacity factor. Units in peaking service typically have a capacity factor of 0.15 or lower. The range of capacity factors for intermediate load plants is nominally from 0.20 to

0.40 while base-load units typically have capacity factors between 0.50 and 0.70. With the appropriate amount of energy storage, a solar central receiver plant can be designed for any of these categories.

The time of day during which the solar plant is dispatched depends primarily on the utility's demand profile; however, it also is influenced by the generation mix and fuel costs. Demand for electricity varies throughout the day and is a function of the type of customers which the utility serves as well as certain environmental factors.

By designing a central receiver system with the appropriate amount of thermal storage, the solar plant can be dispatched for the necessary length of time at any time of the day. For specific site selection, the amount of thermal storage and the corresponding solar multiple are important considerations in determining the total land area required.

**Plant Configuration.** Defining the configuration of the solar plant includes specifying the receiver fluid and whether the plant will be a stand-alone solar plant or a solar/fossil hybrid plant. Specification of the plant configurations depends largely on the mission of the plant as well as on the degree of risk the utility associates with each receiver fluid.

If the mission of the plant dictates a relatively low capacity factor and little or no shift in time from the hours of sunlight to the hours of generation, all three of the receiver media discussed in Chapter 2 (water/steam, liquid sodium and molten salt) should be considered. In this case little or no storage is required. However, if the capacity factor is relatively high and/or there is a shift in the generation period, liquid sodium or molten salt are the preferred choices for receiver fluid. In this case energy storage is required and water/steam receivers with energy storage are typically less cost effective than either liquid sodium or molten salt systems with energy storage.

As discussed in Section 2.9, a nonsolar, fossil-fueled subsystem can be used in parallel with any of the three receiver fluids. A stand-alone solar plant will likely be selected if the mission is primarily to displace fuel. On the other hand, if the utility has specified a high capacity factor for the plant or there is a strong need for reliable plant operation, even on days when the sky is overcast, a solar/fossil hybrid configuration will be preferred.

**Energy Storage.** Thermal energy storage capacity is dependent on the mission of the plant. Plants with low capacity factors and little or no shift in time from the hours of sunlight to the hours of generation, require little if any storage capacity. Conversely, plants with large capacity factors and/or large shifts in the generation period require large thermal energy storage capacities. Selection of storage capacity based on plant design trade-offs is described in Section 4.2.

## SITE SELECTION CRITERIA

For a solar central receiver power plant, the primary criteria used for site selection include insolation, land, meteorological conditions, water, transportation, transmission lines, and aircraft interference.

**Insolation.** Immediately outside the earth's atmosphere the sun's radiant power or insolation is relatively constant, varying from 1.32 kW/m$^2$ to 1.42

$kW/m^2$ (418 $Btu/ft^2$-hr to 450 $Btu/ft^2$-hr) during the year. It is most intense during the northern hemisphere winter (January 2) since the earth is closer to the sun during this period.[4]

As the solar radiation passes through the earth's atmosphere a portion is absorbed or scattered by particulates, aerosols, and molecules. Two components of the insolation then arrive at the earth's surface: direct (capable of providing a sharp shadow) and diffuse (multi-directional). Heliostats can reflect only the direct component to the receiver at the tower top. The diffuse component is not reflected to the receiver. Direct normal insolation at sea level at noon during a clear day is about 950 $W/m^2$ (300 $Btu/ft^2$-hr).

At a point on the earth's surface, the radiant power changes both seasonally and diurnally. The shape of the daily insolation curve varies due to the seasonal changes in length of the days and the varying elevation of the sun. This variation affects the rate at which energy can be accumulated.

Other factors such as latitude, altitude, and weather also influence insolation levels. Latitude affects insolation due to the longer air paths for sunshine at higher latitudes, but the effect is modest. Excluding weather, the annual clear-day direct normal insolation varies by about 10% for locations between 26° and 40° N. The annual clear-day (ignoring clouds) operational hours for sun elevations greater than 15° vary by less than six percent between these same latitudes (from about 3510 to 3330 hours, respectively).

Compared to the effect of latitude, more substantial variations in insolation are caused by altitude and weather, including the effects of atmospheric water vapor, clouds, smoke, fog, haze, and airborne particulates.

Insolation contour maps illustrate the combined effects of latitude, altitude, and weather. Figure 3–1, (a)–(d) shows the direct normal daily insolation contours in $MJ/m^2$ for the United States for four representative months (covering summer and winter solstice, and spring and autumn equinox). Figure 3–2 illustrates the annual average daily direct normal insolation in $MJ/m^2$ in the United States. The annual mean daily direct beam solar radiation is also illustrated in units of $kWh/m^2$ (3.6 MJ = 1 kWh) on the chapter interleaf.[5,6]

The contours are only approximate (errors may exceed 20% in some areas) for several reasons: (1) only a modest amount of data is available for defining the curves, (2) widespread direct normal insolation measurements have been made only since about 1975; (3) prior to 1975, most data included both solar components, and computer models had to be used to estimate the direct component; (4) most of the data come from coastal and near coastal areas with little data from the western desert, and (5) the geographical resolution of the map is inadequate to account for local insolation variations such as those caused by mountain-generated clouds and other effects. Consequently, site specific insolation data is required before locating a solar plant. The contour maps should only be used as a general guide.

Note that a rough interpolation from the maps of the annual average insolation for Barstow, CA, would result

## March

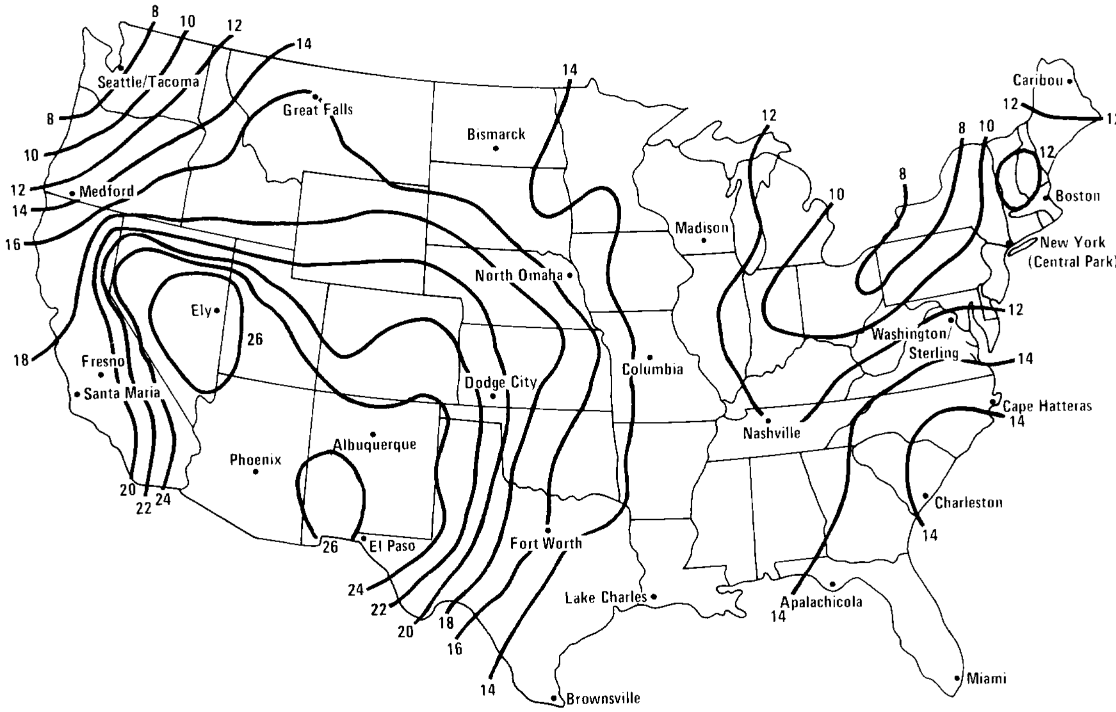



**Figure 3–1a Average Daily Direct Normal Insolation in MJ/m$^2$ For the Month of March**

## June

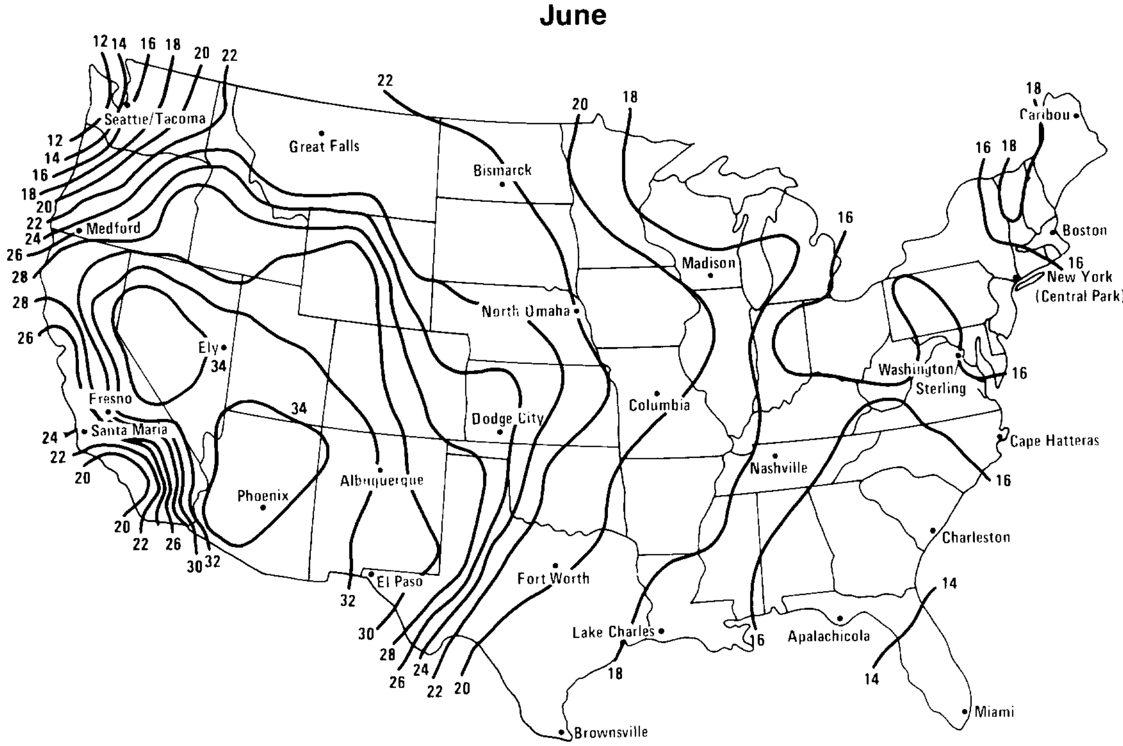



**Figure 3–1b Average Daily Direct Normal Insolation in MJ/m$^2$ For the Month of June**

## September

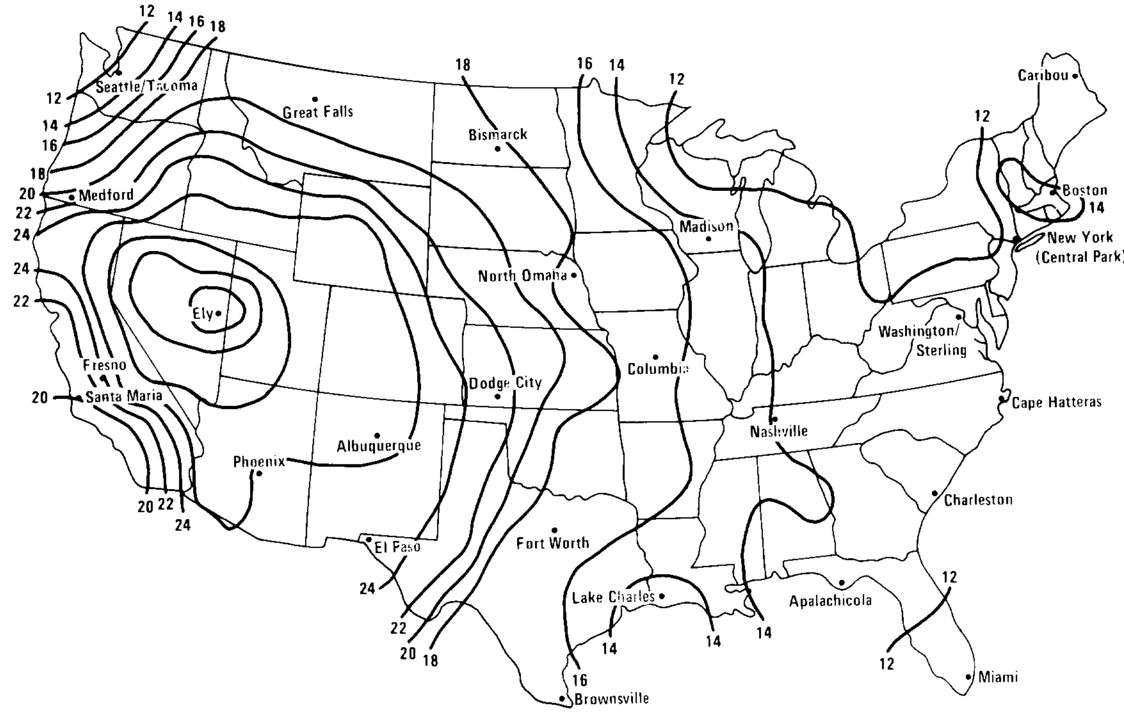



**Figure 3–1c Average Daily Direct Normal Insolation in MJ/m² For the Month of September**

## December

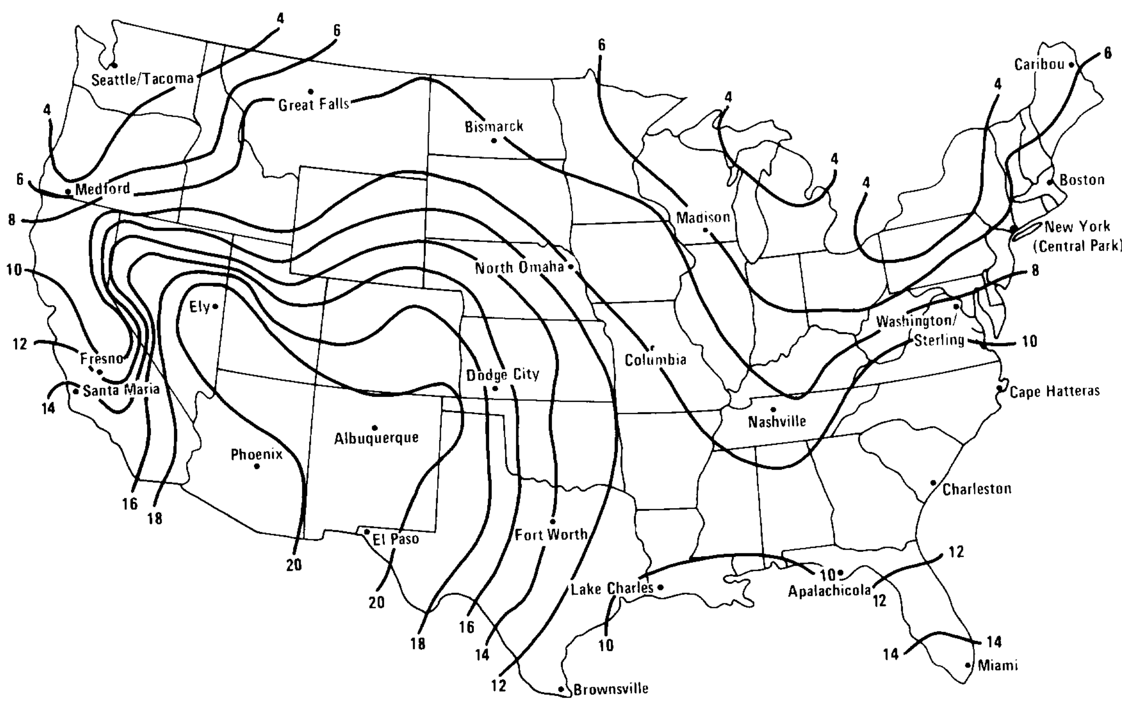



**Figure 3–1d Average Daily Direct Normal Insolation in MJ/m² For the Month of December**

Annual

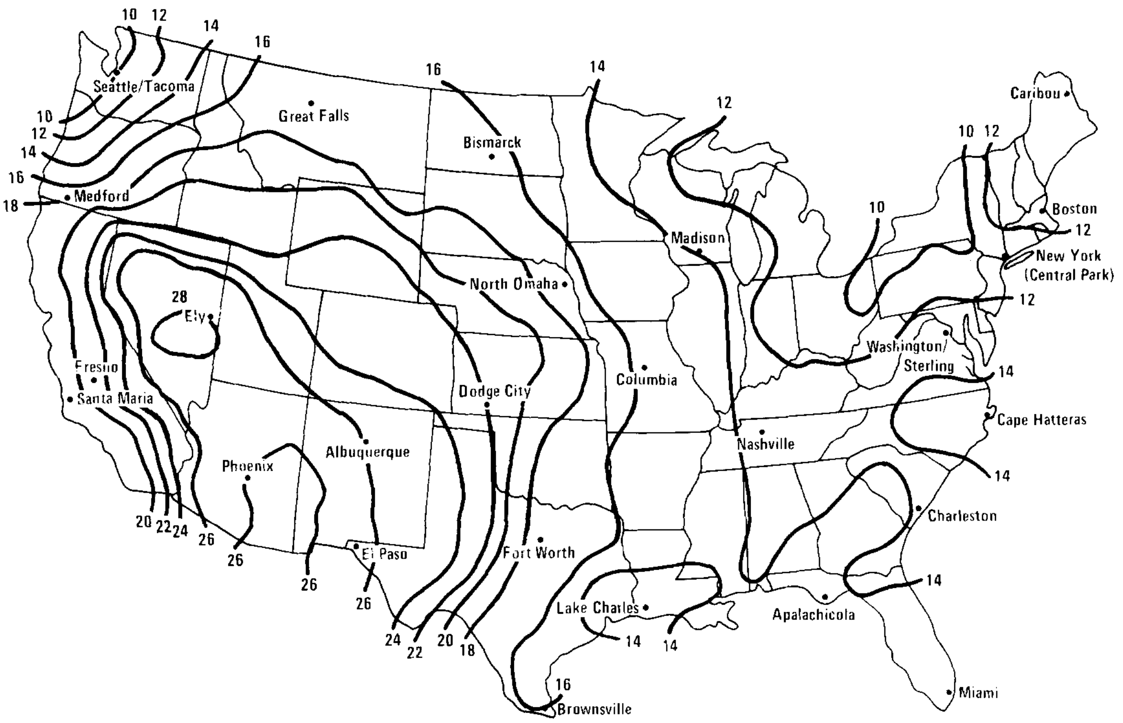



**Figure 3–2 Annual Average Direct Normal Insolation in MJ/m$^2$ in the United States**

in a value of about 21 MJ/m$^2$ or 5.8 kWh/m$^2$-day (1870 Btu/ft$^2$-day) while the measured, sunrise to sunset, 1976-1979 average value at the pilot plant site is 7.5 kWh/m$^2$ (2365 Btu/ft$^2$-day). Table 3–1 shows some sample insolation data for several U.S. locations.[7]

Experience at Solar One has illustrated the variability in solar insolation which occurs from year to year. Figure 3–3 shows the monthly averages of the daily direct normal insolation observed at Solar One for several different time periods. Effects which have influenced the insolation levels at Solar One during its operation are believed to include effects of the El Chichon volcanic eruption and increased air pollution in the local area.

**Land.** The amount of land required for a solar central receiver power plant depends on the electrical power output of the plant and the solar multiple. (Solar multiple is defined as the peak thermal power absorbed by the receiver divided by the thermal power needed to operate the turbine at its rated load.) Typically, a large solar multiple corresponds to a large amount of thermal storage. For example, a plant with a solar multiple of 1.5 may have about three hours of storage; whereas a plant with a solar multiple of 2.1 may have up to nine hours of storage. A 100 MW$_e$ plant with a solar multiple of 1.5 requires approximately 1-1/4 square miles of land. Land requirements vary almost linearly with plant rating and solar multiple as illustrated in Chapter 4.

The selected plant site should be relatively flat or, in the northern hemisphere, have a slight south-facing slope

Table 3-1
SAMPLE DIRECT NORMAL INSOLATION DATA

| Site | Year | Direct Normal Insolation Annual ($kWh/m^2/yr$) | Direct Normal Insolation Daily Average ($kWh/m^2/day$) |
|---|---|---|---|
| Albuquerque, NM | 1978-79 | 2351 | 6.44 |
| Alhambra, CA | 1979 | 1891 | 5.18 |
| Barstow, CA | 1976-79 | 2723 | 7.46 |
| Blythe, CA | 1976-77,79 | 2632 | 7.21 |
| Escondido, CA | 1978-79 | 2084 | 5.71 |
| Lancaster, CA | 1976-79 | 2767 | 7.58 |
| Las Vegas, NV | 1979 | 2533 | 6.94 |
| Los Angeles,CA | 1979 | 1865 | 5.11 |
| Page, AZ | 1979 | 2307 | 6.32 |
| Palm Springs, CA | 1977-79 | 2515 | 6.89 |
| Ridgecrest, CA | 1976-77,79 | 2865 | 7.85 |
| Sun Valley, CA | 1979 | 2110 | 5.78 |
| Tucson, AZ | 1977 | 2321 | 6.36 |
| Victorville, CA | 1976-79 | 2723 | 7.46 |
| West Los Angeles, CA | 1979 | 2004 | 5.49 |
| Yucca Valley, CA | 1976-79 | 2865 | 7.85 |

Only full-year data is shown. Monthly data is also presented in Reference 7. For conversion to English units: 1 $kWh/m^2$ = 317 $Btu/ft^2$.

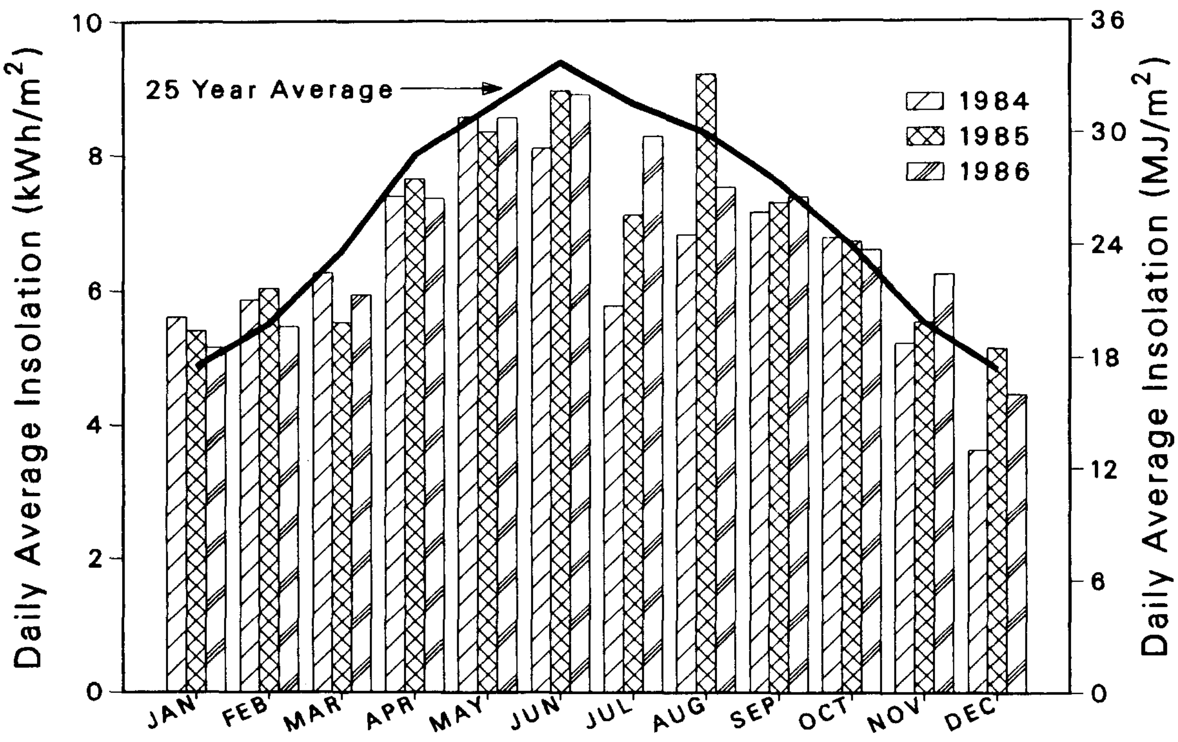


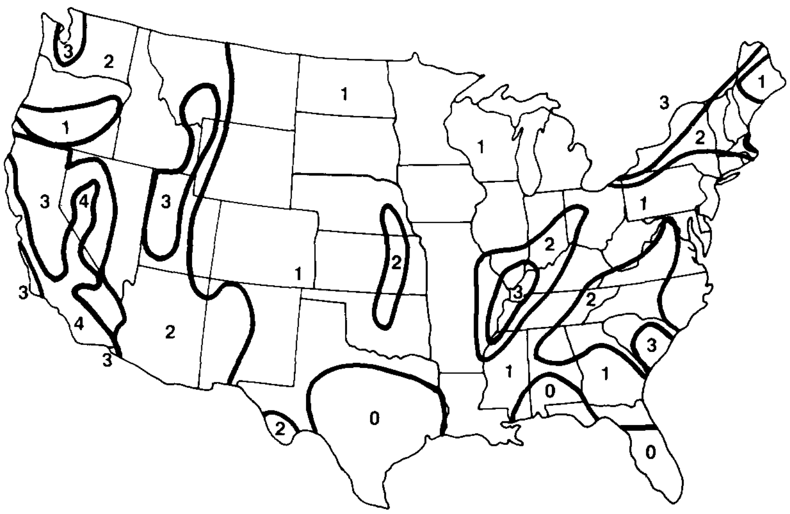

**Figure 3–3 Monthly Average of Daily Direct Normal Insolation at Solar One**

to optimize the collector subsystem performance. The soil conditions of the plant site determine the types of foundations for the heliostats and receiver tower. Also, the seismic risk characteristics of the plant site affect the designs and costs of the receiver tower and equipment supports. Obviously, locations of low seismic risk are preferred. The Uniform Building Code seismic zone map of the United States is shown in Figure 3–4.[8]

**Meteorological Conditions.** Meteorological conditions have both positive and negative impacts on the selection of a solar plant site. At both the Central Receiver Test Facility and at Themis, rain and snow have been very effective in washing heliostats. Thus, periodic rainfall and snowfall can help lower plant costs. However, if rainfall and snowfall occur too frequently, the insolation available to the plant may drop.

Among the other negative meteorological conditions are wind, ambient temperature and severe weather. As discussed in Section 2.2, heliostat specifications limit operation of the plant in high wind conditions. The ambient temperature and humidity affect thermal cycle efficiency as with other power plants. Severe weather conditions, such as hail, tornadoes, hurricanes and flash flooding, could seriously affect plant operation.

**Water.** The water requirements for a solar central receiver power plant are essentially the same as those of a fossil-fueled power plant with a comparable electrical output rating and capacity factor. Both types of plant require cycle heat rejection, service, potable, and cycle makeup water. However, for a solar central receiver plant, additional deionized water is required for washing the heliostats. A 100 $MW_e$ fossil-fueled power plant with evaporative condenser



Seismic Risk Map of the United States

Zone 0 — No damage.
Zone 1 — Minor damage; distant earthquakes may cause damage to structures with fundamental periods greater than 1.0 second; corresponds to intensities V and VI of the M.M.* Scale.
Zone 2 — Moderate damage; corresponds to intensity VII of the M.M.* Scale.
Zone 3 — Major damage; corresponds to intensity VIII and higher of the M.M.* Scale.
Zone 4 — Those areas within Zone No. 3 determined by the proximity to certain major fault systems.

*Modified Mercalli Intensity Scale of 1931

**Figure 3–4 Seismic Zone Map of the United States**

cooling requires approximately $2 \times 10^6$ $m^3$ ($71 \times 10^6$ $ft^3$) of water per year. The additional heliostat washing water requirement, depending on the washing frequency, is typically 5,000 – 15,000 $m^3$ ($1.8 \times 10^5$ – $5.3 \times 10^5$ $ft^3$) per year.

**Transportation.** A solar thermal central receiver power plant is similar to a fossil-fueled power plant in that the proximity of the plant to existing highways and railroads is desirable. If possible, the plant site should be located relatively close to a populated area capable of providing construction workers and operating personnel for the plant. Another similarity between fossil-fueled and solar plants is that fog induced by a cooling tower could pose a safety hazard on a nearby highway during certain atmospheric conditions.

**Transmission Lines.** The location of a solar power plant site close to existing transmission lines is desirable. This minimizes the cost of interfacing the plant's output with the utility grid.

**Aircraft Interference.** If the site of a solar central receiver power plant is in close proximity to an airport, additional safety considerations are required since the tower could pose a collision hazard to aircraft. Federal Aviation Administration regulations concerning low altitude federal airways and airport control zones must be considered in plant location and design.

## ENVIRONMENTAL IMPACT

The overall environmental impact of a solar central receiver power plant is less than that of a fossil-fueled power plant of the same electrical rating. This results primarily from the absence of the combustion process; few environmentally undesirable emissions must be controlled. Assessment of the environmental impact at Solar One was a part of its operational evaluation.[9,10] The evaluation revealed that environmental impacts were relatively benign. The effects of clearing, grading and compacting the soil denuded the site initially. No effects on vertebrate populations or shrubs occupying downwind areas were observed. Furthermore, there was no indication that the plant altered the avifauna of the region.

**Waste Disposal.** Water and liquid waste disposal techniques in solar plants are the same as those used in fossil-fueled power plants. In most applications, evaporation ponds dispose of waste water from sources such as steam cycle and cooling tower blowdown. Other liquid wastes, such as acid waste, normally are collected and treated.

Solid waste disposal of ash and particulates associated with fossil fuel combustion is not required with a solar plant application, unless it is hybridized.

For solar plants which use oil, molten salt or liquid sodium, small amounts of these media, along with impurities, contribute to waste from leaks and occasional blowdown for purification purposes. Waste oil can be burned. However, molten salt and liquid sodium are usually purified and reused, thus minimizing the need for waste disposal.

**Emission Control.** In a solar stand-alone plant, few undesirable emissions must be controlled. Depending on local conditions, cooling tower emissions may increase local fog intensity and increase the possibility for long visible vapor plumes.

**Ecosystem.** The extent of the displacement of vegetation and habitat from the plant site depends on the amount and types of construction activities. For those parts of a solar plant which have a counterpart in a fossil fueled power plant, such as the turbine building, cooling tower, evaporation pond, and roads, the impacts on the ecosystem are similar to those for the fossil fueled plant. However, for the unique aspects of solar plants, such as the heliostat field, impacts on the ecosystem are different because heliostat land treatment disrupts the original site vegetation and habitat on a larger scale.

Glint (reflected light from the heliostat field) poses a hazard to birds and insects flying near the receiver since birds and insects flying into high solar flux will be killed during plant operation. Also the receiver tower, similar to a fossil plant chimney, poses a collision hazard to birds. Experience shows that glint and tower kills of birds occur infrequently, unless the plant is located in major flyways for birds.

Accidental spills and discharges of oil, molten salt, and liquid sodium in local water supplies must be adequately controlled by compliance with existing design and safety codes. The waste water from heliostat cleaning operations will not affect the local water supply if deionized water, biodegradable solutions, or waste water collection and disposal methods for detergent solutions are used. To minimize the erosion caused by site runoff water, the water should be channeled into storm culverts before emptying into local water supplies. If current regulations and standards are maintained, no major effects on the ecosystem should occur.

**Noise.** Noise emissions inside and outside the solar central receiver power plant boundary must be controlled by conventional noise abatement practices. Without noise emission safeguards, hearing hazards to plant personnel and persons offsite might result from turbines, electric generators, cooling tower fans, and water splash. If conventional noise abatement practices are used, the noise level from a solar plant may be less than that from a fossil-fueled plant of the same electrical rating.

Noise from several different sources might also disturb wildlife in the vicinity of the plant site. However, no significant effects of noise on wildlife are expected. Experience has shown rapid acclimation to noise by both mammals and birds.

**Visual.** Solar One has been described as "the most beautiful power plant in the world".[11] R. Banham, a professor and member of California's Arts Advisory Board has proposed further that the plant be operated for the artistic effect achieved with the heliostat images in stand-by position (though it is unlikely that this would be cost-effective).

However, for people living near the site, it is conceivable that a central receiver could be aesthetically objectionable when the receiver tower dominates the field of view. Unfavorable reactions to a receiver tower are a function of factors such as the tower size, the observed tower position within the local terrain, and the scenic value of the local landscaping; however, these reactions are no different than reactions to a typical stack for a fossil-fueled power plant. The overall visual impact is related to the number of residents, travelers, and visitors who have a clear view of the tower and is subjective, based on different residential and public use area viewpoints.

**Cultural.** Cultural resources, including archaeological and historical resources, are another environmental concern associated with the selection of both a region and a local plant site. Therefore, selected plant sites are expected to be restricted from such areas as Indian reservations, national forests and parks, state and local parks, wildlife reservations, historic monuments, natural landmarks, and significant archaeological regions.

**Socioeconomic.** The construction and operation of a solar central receiver power plant can have both negative and positive socioeconomic impacts on the surrounding area. The impact of construction is generally intense, but of relatively short duration while the impact of plant operation tends to be generally mild, but of longer duration.

Potential negative impacts include an increase in public facility use and local traffic congestion. Potential positive impacts include an increase in local government revenue and local economic activity. The effect on current and future land uses may be either positive or negative, as is the case for a fossil-fueled power plant.

Plant construction may result in a significant, but short-term, increase in housing demand depending on the ability of nearby communities to supply labor and the level of on-site housing. Plant operation may result in additional permanent housing requirements. Also, the use of public facilities such as schools, hospitals, and churches as well as the need for additional police and fire protection may grow. The magnitude of these impacts will depend on the size of the affected communities and the number of plant personnel employed at the plant site. Local traffic congestion may occur as a result of an inadequate number of roadways to the plant site and the temporary addition of construction worker traffic.

General economic activity such as retail sales, employment, and personal income will increase with construction and operator employment and local expenditures for materials and equipment. Subsequently, operation and its resultant multiplier effects may induce additional retail and service opportunities. Other positive socioeconomic impacts include the increase in local government revenues. The amount of added revenue depends on the applicable state and local tax laws.

## SAFETY

Potential safety hazards to plant personnel exist in any type of power plant. Among these hazards are burns from high temperature equipment and components, falls from high elevations, and contacts with high voltage power sources. These hazards exist in solar power plants as well as in fossil-fueled power plants. However, several hazards are unique to solar plants, including glint (concentrated reflected light from heliostats) and heat transport fluids.

**Glint.** Glint poses a potential burn hazard to the skin and eyes of plant personnel, people living and driving near the plant, and occupants in overflying aircraft. For plant personnel working within the heliostat field, it is highly unlikely that a serious burn injury would occur from accidental exposure to glint because of blockage by adjacent heliostats. However, plant personnel near the receiver are close to the focal points of the heliostats and are, therefore, in more serious danger of accidental exposure to high levels of solar flux. For this reason, plant personnel should be restricted from the receiver and from open towers when the receiver is in operation.

For the occupants of overflying fixed wing aircraft, exposure to glint is unlikely because of the speeds and heights at which these aircraft typically fly. However, occupants of low flying balloons and helicopters are more susceptible to accidental exposure to glint; hence, greater safety precautions are required for these situations.

Beam safety issues and the results of analyses and experiments are described in Section 2.2. These studies indicate that safe operating procedures can eliminate this hazard.

Extra safety precautions should be taken by plant personnel who may be exposed to high solar flux levels. These precautions include the use of protective clothing and eye wear by people working in the vicinity of the receiver, use of glare reducing windows and optical shields in buildings and structures which might be exposed to glint, establishment of access and safety zones throughout the plant, and voice contact between control room operators and plant personnel who are in the heliostat field or near the receiver during plant operation.

**Heat Transport Fluids.** In power plants water/steam is conventionally used and standard utility procedures should be employed. Consideration of the use of oil, molten salt, and liquid sodium as high temperature fluids in solar central receiver power plant applications requires new design and safety codes to insure their safe and controlled use. Past industrial experience has shown that each of the alternate fluids can be used safely.

*Oil.* Adequate safety measures are required with the use of oil because of possible fire hazards and accidental oil releases. When using an oil as a high temperature fluid, extra precaution should be taken to avoid prolonged exposure to excessive temperatures. Such exposure could result in the thermal decomposition and combustion of the oil. Also, oil is a source of pollution when spilled.

*Molten Nitrate Salt.* Molten nitrate salt is neither explosive nor flammable and is classified as a Class I oxidizer, the least hazardous of the four classifications. However, molten salt is capable of igniting combustible material with which it comes in contact. At operating temperatures, it can also cause severe burns to plant personnel. Although molten salt is nontoxic and highly soluble in water, an accidental release of a large quantity of salt could affect the ground water supply

*Liquid Sodium.* The safety issues for the use of liquid sodium in a solar plant are similar to those for molten salt except for the fact that liquid sodium oxidizes quickly in air and reacts violently with water to produce hydrogen gas. Even a small leak of liquid sodium may result in a significant sodium fire or a hydrogen explosion. Consequently, extra precautions must be taken when using liquid sodium for solar central receiver power plant applications.

Water, foam, vaporizing liquids, and other fire extinguishing agents which are used to extinguish most fires must not be used for sodium fires. Special dry powders, consisting of graphite or sodium carbonate, are effective for sodium fire control. These dry powders blanket the fire while cooling the liquid sodium to below its ignition temperature. Gas blanketing with nitrogen or argon is another effective means of controlling and preventing sodium fires.

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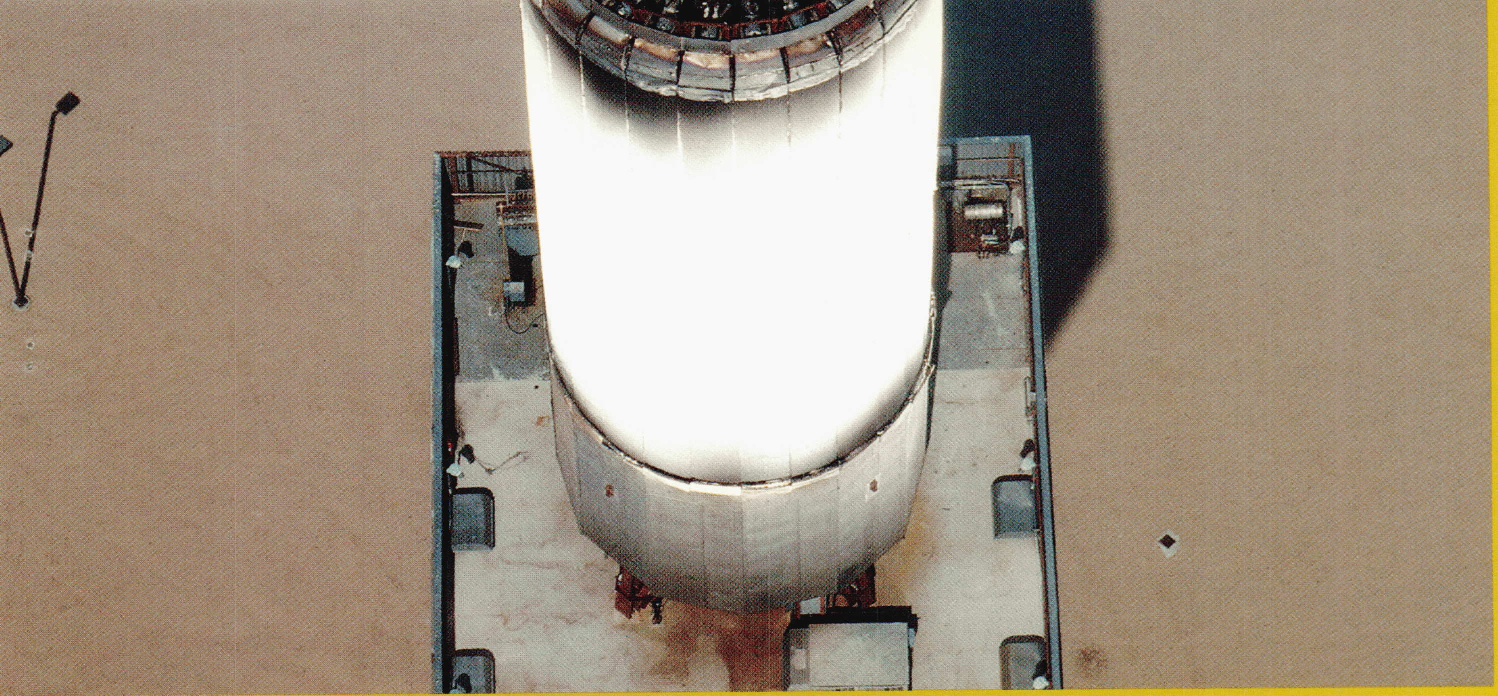
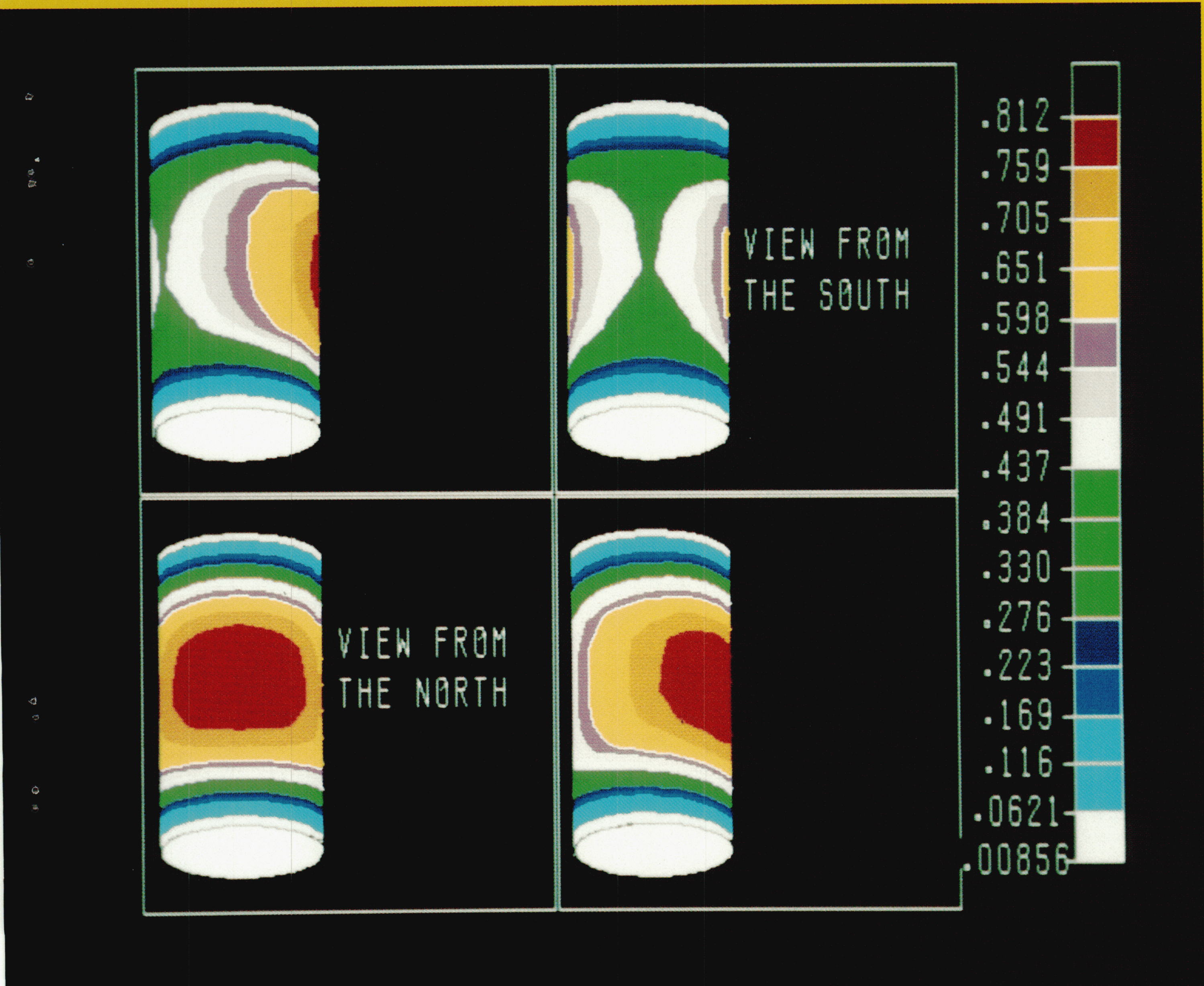


# TECHNOLOGY SELECTION



*Upper: Solar One receiver illuminated with concentrated solar radiation.*

*Lower: Design point flux map for a 320 $MW_t$ cylindrical, molten nitrate salt external receiver. Flux levels shown are incident flux in $MW/m^2$.*

# TECHNOLOGY SELECTION

Previous chapters in this Handbook have described available technology options and site selection considerations for construction of a central receiver plant. Selection and sizing of plant components for a specific application require the performance of trade studies as a part of the conceptual design process. This chapter presents the design process together with results from recent conceptual design and trade studies.

The basis for the design of a central receiver plant is an overall systems analysis, intended to define the "optimum" plant design. The objective in designing an optimized plant is to select the technology options that produce the lowest energy cost or that result in the highest energy value to cost ratio for specific applications of interest.

The two objectives — low energy cost or high energy value — are distinguished because they may not necessarily be the same due to time-of-day and/or time-of-year energy value variations. Conceptual designs of central receiver systems focus largely on the determination of systems that produce the lowest levelized energy cost. The impact of energy value considerations has only recently been explicitly included in the design process.

However, in both cases, the optimization analysis examines competing cost and performance factors which combine to generate a configuration with the lowest cost or highest value of energy. Underlying this analysis is an evaluation of technical risk and the need to assure that the plant will perform as designed.

Low energy cost is determined by comparing the levelized energy cost of various alternate system configurations. To calculate the levelized energy cost, capital costs, operating costs and return on investment are considered. The net present value of all costs is assessed and an equivalent annual cost that is level over the plant's lifetime (i.e. constant from year to year) is calculated. This annualized cost, divided by the net energy production, is the levelized energy cost.

Energy value is strongly dependent on the utility environment so a general optimization is difficult to perform. Plant production of energy is evaluated as a function of time-of-day and time-of-year. Given the values associated with various time periods (recently estimated in some design studies based on the selling price of the electricity or on the conditions for so-called utility "standard offers"), the energy value or revenue is then calculated.

Factors which may be quantified and used for comparative purposes include the overall plant efficiency, at design point and on an annual basis, and the cost and value of the energy produced. However, qualitative factors are important and influence the selection process. These include operational issues and personal assessments of development risk. In order to compare options, both types of factors must be included.

The principal selection criterion among design alternatives is the optimum cost/performance of a complete central receiver system. Technology options such as heliostat type or receiver configuration cannot be evaluated out of an entire plant context. Comprehensive evaluation of technology options requires that an optimum design exists for each component in the system for which both peak, or design point, and annual average performance estimates may be made. It also requires capital cost and operation and maintenance information. Finally, to obtain actual energy cost numbers an economic scenario must be assumed. These factors are combined into a system for which the levelized energy cost may be calculated.

This analytical design approach yields quantitative values for performance and cost of energy which may be compared for each technological alternative. Experience from component and system tests coupled with engineering judgment yields a qualitative assessment of operational factors and development risks which must be considered along with the quantitative performance and cost values. Factors not generally considered explicitly in the optimization process but which are important include:

- detailed operation and maintenance costs
- detailed operational issues unique to individual concepts and configurations
- availability and reliability
- potential advantages of simplicity or the impact of design/operational conservatism
- implications of off-design operation
- operator (human) element in plant operations.

It is important that these issues be addressed at the subsystem and component level as a part of data formulation for the design process. Experience at both the Central Receiver Test Facility and at Solar One has verified the necessity for considering these issues at a subsystem or component level as a part of the optimization input procedure.

## CONCEPTUAL DESIGN PROCESS

Selection of specific central receiver technology options requires trade-off studies and a conceptual design. Since there are a number of options available, the objective of the design process is to examine the effect of the selection of one option relative to another. The available options are discussed in Chapter 2 for a specific application — near-term, commercial-scale technology for electricity generation.

For purposes of design and optimization, it is useful to divide the plant into two portions: energy collection and energy utilization. The energy collection portion includes the heliostat and heliostat field, the receiver, tower and associated plumbing. The energy utilization portion of the plant includes the energy storage system, fossil hybrid components (if any), steam generator, the electric power generating system, and the balance of plant.

As illustrated in Figure 4.1–1, there are three major elements of the conceptual design process necessary for central receiver technology selection. The first is the definition of the characteristics of the desired plant. The second is the optimization and analysis of the energy collection portion of the plant. The third is the optimization of the energy utilization portion of the plant. Plant design parameters are determined at different stages of this design process, as listed in Table 4.1–1.

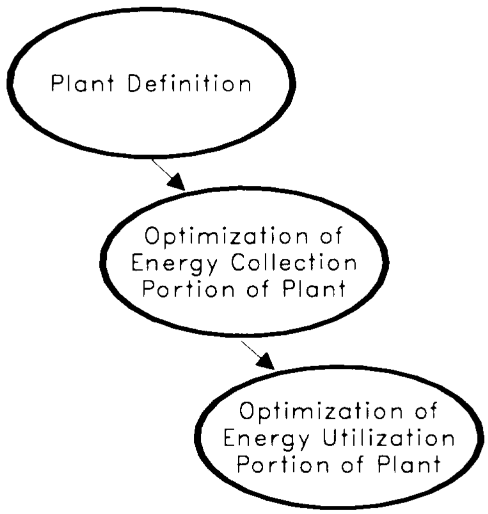



**Figure 4.1–1 Three Phases of Central Receiver Conceptual Design Process**

Trade studies are performed to compare one option to another. Depending upon the stage at which a variable is determined, a complete plant design may be required. For example, the fluid and configuration shown in the first column of Table 4.1–1 must be specified to complete the rest of the design. Then the results of the whole process can be used to compare the two options.

## PLANT DEFINITION

The eight variables listed in the left column of Table 4.1–1 must be specified to initiate the conceptual design process.

An important site variable is the plant latitude which determines the upper limit on the amount of exoatmospheric solar energy reaching the site on a daily, monthly and annual basis. Also important is the site-specific weather pattern. This is affected by altitude and proximity to mountains, bodies of water and/or population centers. The previous chapter discusses insolation characteristics for various United States locations. Design examples cited in this chapter assume a Barstow, CA location at roughly 35°N and insolation characteristic of that site (specifically 1984 weather for most calculations).

The next two variables listed in Table 4.1–1 are the plant size or rating for a specific design point. Since the

Table 4.1–1
PLANT DESIGN PARAMETERS IN EACH OF THE THREE DESIGN PHASES

| Plant Definition | Energy Collection Optimization | Energy Utilization Optimization |
|---|---|---|
| Site | Solar multiple | Storage size |
| Design point | Receiver thermal power | Annual energy |
| Design point power | Heliostat area | Plant cost |
| Capacity factor | Land area | |
| Receiver fluid | Tower height | |
| Storage fluid | Receiver peak flux | |
| Field configuration | Receiver dimensions | |
| Receiver configuration | | |

insolation varies as a function of the time-of-day and time-of-year, the plant rating is best defined at a single point-in-time referred to as the design point. The design point, a specific time-of-day and time-of-year, is used to size the plant components and to specify point-in-time component efficiencies.

When the plant rating is specified, the design point must also be given. Different design points will have different effects. A design point on a day with very high insolation levels, for example, will enable plant components to handle the energy flows at peak insolation conditions. However, at other times components may be oversized for the lower insolation levels and plant annual performance may be reduced by the amount of time spent at off-design conditions. Conversely, selection of a design point at a relatively poor insolation time will guarantee more uniform delivery of energy throughout the year, but will result in energy being thrown away during time periods of higher insolation.

The selection of the plant design point affects the thermal power rating for the system. This rating often corresponds to the maximum power condition and serves as a critical sizing point for plant hardware.

The location of the design point in calendar time depends generally on the field configuration which is closely coupled to receiver configuration. For north fields in northern hemisphere plant sites, the design point when selected for maximum flux conditions typically occurs between the winter solstice and the spring equinox. For a surround collector field, the usual design point occurs between equinox and summer solstice. The exact design point time for each case is determined by a combination of insolation and collector field performance characteristics and by design objectives.

Selection of the design point may influence the relative performance of north and surround fields. North field performance is better during the winter while the peak efficiency for a surround field occurs in the summer.

In the trade studies to be discussed in this chapter, a design point of noon on spring Equinox (March 21) was selected. Plant sizes from 15 to 200 $MW_e$ have been studied.

Another important variable in the conceptual design process is the plant capacity factor, although it is not a true independent design variable in central receiver system design. The value of the capacity factor indicates the type of service — baseload, intermediate, or peaking — that the plant is designed to provide. It is calculated as the ratio of the energy produced on an annual basis and the amount of energy the plant would have produced if it operated at its design point rating for the entire year.

The capacity factor is dependent upon the design point rating and the operating performance of the plant. For purposes of scoping studies, previous work can be used to determine the appropriate design variables (plant rating and solar multiple) based on the desired capacity factor.

The remaining parameters to be specified during the plant definition phase include the field and receiver configuration — whether north or surround, or cavity or external, and the choice of the receiver and storage fluids. Choices for near-term technology for the latter have been described previously and include water/steam, molten nitrate salt, and liquid sodium for the receiver fluid and oil/rock, molten nitrate salt and sodium for the storage medium.

For comparative studies among these alternatives to be performed, separate conceptual designs must be completed and the results compared. In examples described later in this chapter, north and surround field configurations, cavity and external receiver configurations and molten salt and liquid sodium receiver fluids were studied.

## ENERGY COLLECTION ANALYSIS AND OPTIMIZATION

The optimization of the energy collection portion of the plant requires the definition of the plant parameters discussed above as well as specification of the performance and cost factors associated with converting incident sunlight on the collector field into thermal energy at the base of the tower. Table 4.1–2 lists significant factors which influence the energy collection optimization. These factors are illustrated in Figure 4.1–2. In many cases, treatment of these factors involves the development of analytical models.

Factors listed in Table 4.1–2 are principally concerned with representation of the various parts of the energy collection system. Several less obvious issues have a significant influence on the results of the optimization analysis. The solar disk representation deals with the incident energy distribution across both the sun disk itself and the energy distribution which exists immediately adjacent to the actual visible disk. Atmospheric conditions such as haze greatly affect the solar disk. This is an important factor in characterizing the energy distribution being reflected from individual heliostats.

Nodal structures for the collector field model and image generator refer to the number and nature of the computational cells assumed to characterize the collector field and receiver absorbing surfaces.

Three insolation models are available to support the optimization analysis. These approaches base the insolation values on either measurements of direct insolation, measurements of global or total horizontal insolation and meteorological data, or models of atmospheric and meteorological data, using the exoatmospheric solar constant as a base. The third method is preferred for use in field design computer codes.

Once physical models and assumptions are established for the factors listed in Table 4.1–2, cost algorithms are used to support the optimization process. Significant cost elements and their functional sensitivity to system sizing parameters are listed in Table 4.1–3.

In addition to the sizing sensitivity parameters listed in Table 4.1–3, many other cost related factors must be developed to support the analysis. These factors do not change with plant size but more closely reflect assumptions about hardware and equipment costs, and other construction-related factors. These factors are summarized in Table 4.1–4.

The optimization of the energy collection portion of the plant involves consideration of the factors listed in Tables 4.1–2, 3, and 4; they all influence the cost of annual energy collected. Computer codes have been developed to evaluate these various options in a coherent

Table 4.1-2

SIGNIFICANT PHYSICAL FACTORS
AFFECTING ENERGY COLLECTION OPTIMIZATION

| Factor | Issue |
|---|---|
| Sun | Solar disk representation<br>Site-specific, long-term insolation |
| Collector Field | Heliostat layout pattern |
| Heliostat | Size and shape<br>Number and configuration of reflective facets<br>Facet cant and curvature<br>Mirror surface waviness<br>Tracking accuracy<br>Gravity and wind-induced deflection |
| Heliostat Image | Analytical procedure for flux calculator |
| Shading and Blocking | Analytical representation of process |
| Atmospheric Attenuation | Form, magnitude |
| Energy Losses | Heliostat reflectivity<br>Receiver absorptivity<br>Receiver reradiation<br>Receiver convection |

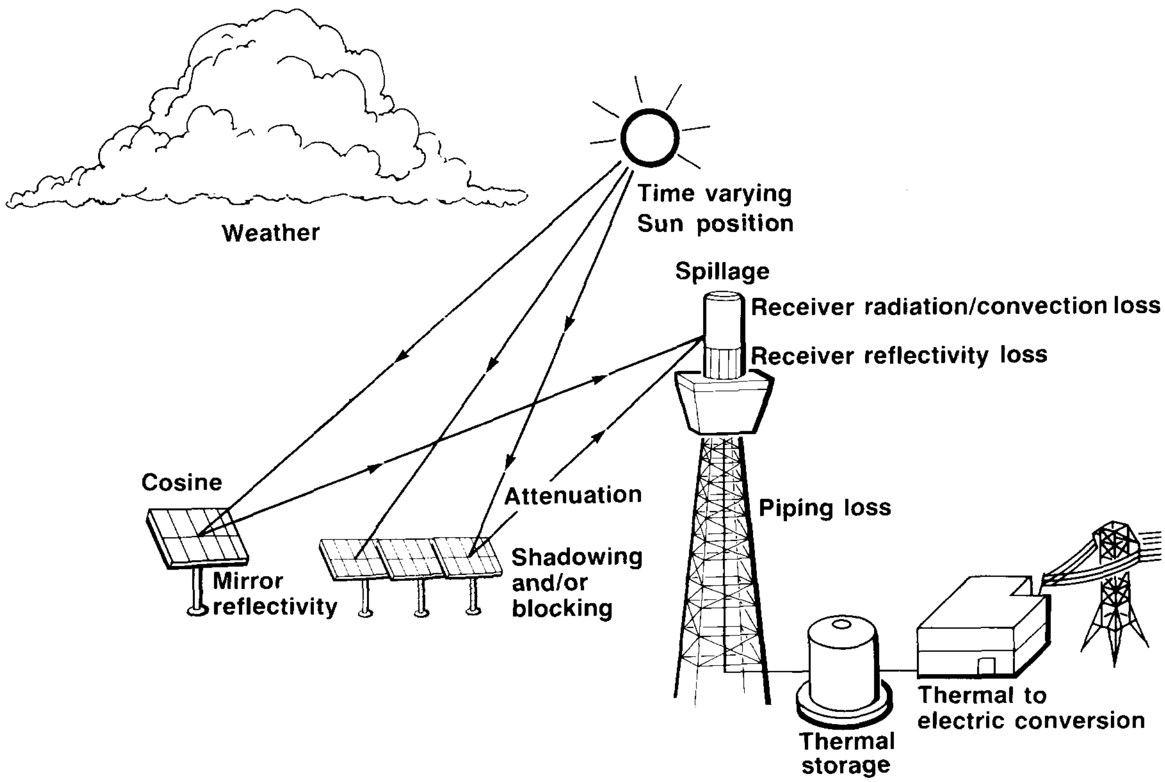



**Figure 4.1-2 Variables in the Design and Optimization of Central Receiver Systems**

Table 4.1-3

SIGNIFICANT COST FACTORS
AFFECTING ENERGY COLLECTION OPTIMIZATION

| Factor | Functional Sensitivity |
|---|---|
| Heliostat | Mirror surface area |
| Land | Land area |
| Wiring | Heliostat spacing, number of heliostats |
| Receiver | Absorber area |
| Tower | Height |
| Pump | Tower height, thermal power |
| Piping | Tower height, receiver thermal rating |
| Balance of Plant | Plant size |
| Operation and Maintenance | Plant size |

Table 4.1-4

ADDITIONAL COST RELATED CONSIDERATIONS
AFFECTING ENERGY COLLECTION OPTIMIZATION

| Cost Factor | Consideration |
|---|---|
| Heliostat | Mass production assumption<br>Factory location and transportation costs |
| Land | Raw land cost<br>Site preparation costs |
| Wiring | Cable costs<br>Trenching method and costs<br>Cable routing |
| Tower | Site specific factors:<br>· solid bearing strength<br>· foundation design<br>· wind speeds<br>· seismic activity<br>· type of tower |
| Receiver | Configuration (cavity or external)<br>Fluid |
| Pump | Reference pump configuration and cost |
| Piping | Basic pipe costs<br>Pipe support equipment |

fashion. These codes are required because of the large number (hundreds or thousands) of heliostats in a single system, the strong dependence of system performance on sun position, and the large number of design options to be considered. Information about these computer codes can be found in Appendix C.

It is important to gain an intuitive insight into the factors which drive an optimized design toward one configuration. Detailed optimization studies have been performed using the computer codes mentioned above. From these studies, simpler relations have been developed which may be used for scoping calculations.

The results show that higher costs or reduced performance of an individual element or subsystem can be compensated for by other elements in the system. For example, high receiver costs, which may be required to maximize receiver performance, can be compensated for by increasing the number of heliostats, thus enabling use of a lower cost receiver with less than optimum performance.

Factors influencing the outcome of the optimization analysis and their effect are listed in Table 4.1–5. These factors are grouped in terms of those favoring larger and smaller elements of the energy collection system.

## ENERGY UTILIZATION ANALYSIS AND OPTIMIZATION

The energy utilization portion of the plant involves the turbine generator, thermal storage, any fossil hybrid contribution, and value of electricity as a function of time-of-day and time-of-year. The goal of this optimization analysis is to select the proper combination of turbine generator size, thermal storage capacity, and fossil fuel input to create the greatest revenue at minimum cost.

**Dispatch Strategy.** The plant dispatch strategy is an important variable which reflects the particular application of the central receiver plant being designed. A sun-following dispatch strategy is one in which electricity is supplied to the grid at times roughly coincident with the times that energy is collected. The use of thermal storage, however, enables other dispatch strategies such as a simple time delay, which would push delivery of electric energy to the grid from the daylight hours to the mid-day and early evening hours. A more complex strategy which maximizes the value of energy based on time-of-day, day-of-week and time-of-year can also be employed. In this case, energy can be stored overnight or on weekends to enable electric energy delivery when it is of most value to the utility.

**Storage.** The hours of storage refers to the amount of thermal energy required for the production of rated electricity for the specified time.

In addition to supplying steam for operating the turbine, storage can be used to supply steam for sealing the turbine during non-operating periods. This reduces the electric parasitic power consumed. Additional storage can be used to accelerate the startup procedure. Using storage to perform these functions will increase the capacity required.

Analyses indicate that molten salt storage systems optimize at high capacity factors due to the incremental cost advantage of the salt storage system over the incremental cost of the turbine generator system. This trend continues up to a capacity factor in excess of 60% when turbine generator operation

Table 4.1-5

OBSERVED TRENDS IN ENERGY COLLECTION OPTIMIZATION

| Favors Larger Fields | Favors Smaller Fields |
|---|---|
| Expensive Receiver | Expensive Heliostats |
| Low Cost Heliostats | Low Cost Receiver |
| Inexpensive Land and/or Field Wiring | Expensive Land and/or Field Wiring |
| Low Atmospheric Attenuation | High Atmospheric Attenuation |
| | Restricted Area |
| **Favors Larger Receivers** | **Favors Smaller Receivers** |
| Low Receiver Cost/m$^2$ | High Receiver Cost/m$^2$ |
| Low Receiver Losses/m$^2$ | High Receiver Losses/m$^2$ |
| Large Flat Heliostat | High Performance Heliostat |
| Severe Heliostat Aberrations | Smaller Heliostat |
| Large Beam Spread | High Peak Flux Limit |
| Low Peak Flux Limit | |
| **Favors Taller Towers** | **Favors Shorter Towers** |
| Large Fixed Cost | Low Fixed Cost |
| Low Tower Cost | High Tower Cost |
| Restricted or Expensive Land | Inexpensive Land |
| Expensive Heliostats | Low Cost Heliostats |
| | Large Beam Spread |

approaches 24 hours per day in the summer. An increase in salt storage capacity above that level would result in an under-utilized collector/storage system with a corresponding increase in incremental cost.

For a storage system based on liquid sodium, the optimum cost configuration occurs at a capacity factor of approximately 30% to 40%. Increases above this range result in higher storage system costs due to the large inventory of expensive liquid sodium.

These conclusions are based on a constant value of electricity. As "time value of electricity" considerations are introduced, different optimum conditions may develop for each of the two storage approaches.

The use of a water/steam receiver with a hot oil storage system leads to different results. In this case, the thermal energy storage for electricity generation results in lower efficiency because of the poor steam conditions available for turbine operation when operating from thermal storage. This loss in generating potential must be offset by an attractive off-peak "time value of electricity" to justify substantial storage for a water/steam system. The fact that turbine operation is no longer buffered from receiver operation also complicates this approach to storage from an overall plant design point of view.

**Hybridization.** In a hybrid plant, part of the plant capacity is provided by burning fossil fuel. The fossil fuel is used either to heat the storage fluid directly or to fire a conventional steam boiler. In a hybrid system, the capacity factor results from a combination of thermal storage and fossil-fired operation.

The results of a design study will depend on the relative cost of the storage system and the fossil system capital and operating costs. These costs are traded against the turbine generator incremental cost to arrive at a preferred design of the energy utilization equipment. High fossil system costs tend to drive a design toward larger thermal storage capacity, while high storage costs and/or low fuel costs drive the design toward larger fossil fired capability.

One final factor which can influence the relative attractiveness of a hybrid system involves the utility's capacity mix. Although it is beyond the scope of this discussion to treat the effects of a utility's generating capability on the design of a solar plant, it is important to understand some of the basic considerations.

A solar plant requires a larger backup generating capacity than a more traditional plant due to the random availability of the solar input. This backup capacity can be achieved by burning fuel in another plant on the grid or at a hybrid solar plant. If a utility has other high-efficiency plants, it will probably not add a hybrid capability to the solar plant. If, however, the backup capacity does not exist elsewhere on the grid, the lowest cost alternative may be to hybridize the solar plant.

A conceptual or preliminary design of a specific system or the comparison of several systems requires the iterative use of one or more large computer codes. However, to compare in gross terms a number of options or to acquire a general understanding of the relative sizes of the major components of central receiver systems, certain scaling relationships and trends can be used parametrically. This technique can also establish initial estimates of input values for use in the detailed optimization procedures.

Results from previous optimization studies are presented in this section. Specific results are from a family of system studies entitled the *System Improvement Studies* performed at Sandia National Laboratories Livermore in 1985 and 1986. Other central receiver system evaluation studies are described in References 1–4.

The goal of the *System Improvement Studies* was to understand and optimize the expected performance and reliability and to decrease the cost and technical risk of central receiver systems. The approach was to first evaluate and use the results of system and component experiments in the United States and in other countries. Next, improved methods to define the optimum central receiver configuration for specified near-term applications were developed. These optimum configurations were used to examine and compare a number of base case designs. Specific results for the base case designs are presented in the following section. In this section, design rules gleaned from these studies are presented to enable evaluation of alternate central receiver systems.

**Plant Definition.** The first step is to refer to Table 4.1–1 and to specify the plant definition variables for the plant to be evaluated. Specific results in this section were derived, as described above, for conditions of a Barstow, California site and a March 21 design point. Annual energy calculations employed detailed insolation data from Barstow recorded in 1984.

The definition of capacity factor directly relates plant rating and annual plant output. Past analyses have determined that, at constant thermal to electric conversion efficiency, annual electrical output is directly proportional to receiver design point thermal rating and the average annual insolation.

The ratio of "user capacity factor" to the capacity factor used in the design rules in this report is shown in Figure 4.2–1 as a function of the user site

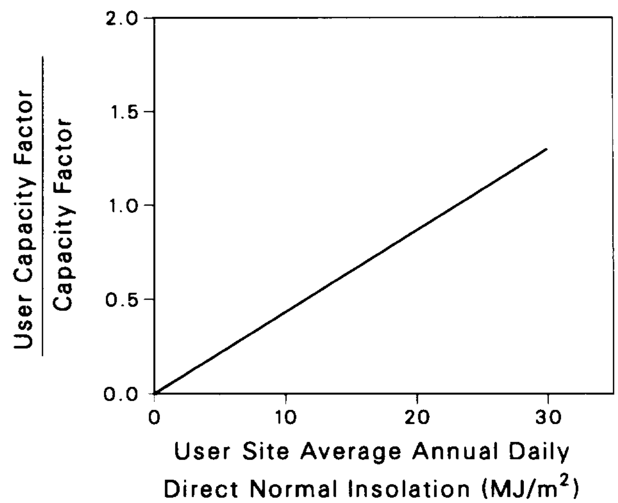



**Figure 4.2–1 Capacity Factor Correction Ratio to Account for Site Differences in Insolation**

insolation. (Average insolation levels in the United States are discussed in Chapter 3.) To include the effects of differing insolation at different sites, the user should first specify the desired plant capacity factor or "user capacity factor", defined above, and then convert it to the capacity factor described in this section, specific for plants with insolation typical of Barstow. In the design of plants, insolation differences affect the size and cost of the collector system.

## ENERGY COLLECTION SYSTEM

**Solar Multiple.** The first energy collection variable which must be determined is the design point solar multiple. Solar multiple is specified at a specific design point and is defined as the ratio of the receiver thermal rating and the rated thermal input of the turbine generator. It reflects the amount of oversizing of the collector and receiver relative to the rest of the system. Solar multiples for central receiver plants are generally greater than one; the excess energy is stored in the thermal storage subsystem.

The relationship between the solar multiple and the plant capacity factor (converted from the "user capacity factor" using Figure 4.2–1) is shown in Figure 4.2–2. The band of values results from differences in assumed insolation levels, hours of storage, and performance differences among systems.

Although the two are related, it is important to remember the distinction between solar multiple and capacity factor. The solar multiple is a design and sizing variable while capacity factor is a performance parameter. This means that the solar multiple of a plant is fixed, while the capacity factor can be reduced by factors such as poorer than

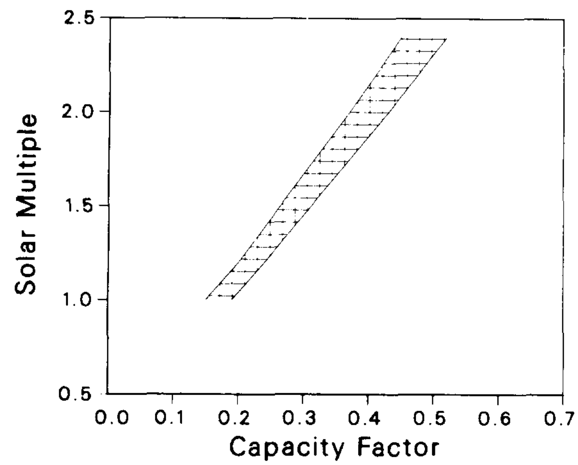



**Figure 4.2–2 Plant Solar Multiple as a Function of Capacity Factor**

expected weather or longer than anticipated downtimes.

In the process of conceptual design and technology selection, a range of capacity factors should be specified initially and then confirmed when full annual performance simulations of the optimum plant design are complete.

**Receiver Size.** The sizes of the receiver, tower, and collector field are all strongly related to the receiver design point thermal rating. This parameter can be related to the overall plant characteristics of plant rating or design point power and solar multiple as shown in Figure 4.2–3.

The receiver thermal power will vary a few percent depending upon whether the receiver is an external or cavity receiver. This effect is sufficiently small that it is not included in the figure.

Physical constraints limit the size of a single receiver. Receiver tubes with lengths longer than about 30 meters are unavailable. Furthermore, receiver panels larger than that cannot be fabricated

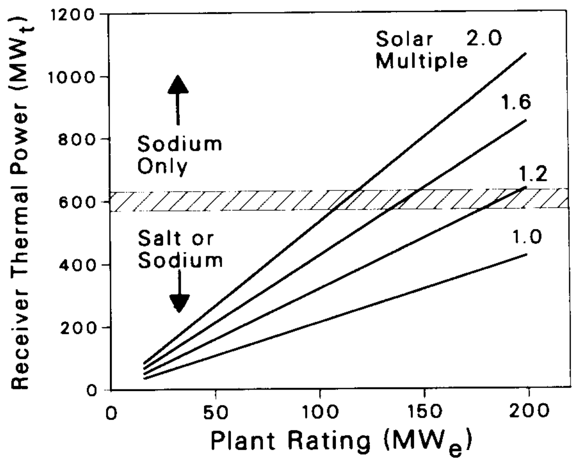



**Figure 4.2–3 Receiver Thermal Power as a Function of Plant Rating and Solar Multiple (Relation for Single Tower Plants Only)**

at the receiver manufacturer's and transported to the site. These size restrictions limit the maximum receiver thermal power for a single receiver. Depending upon flux restrictions, the height limits are reached at different power sizes for sodium and molten salt. (Allowable flux levels are discussed later in this section.) Figure 4.2–3 indicates the physical limits on molten salt receivers as indicated by the horizontal dashed bar.

Note that multiple receiver and collector systems can be used if large molten salt systems with high solar multiples are desired. For example, an energy utilization system sized to accept 800 $MW_t$ of thermal energy can be matched with two 400 $MW_t$ energy collection systems. The privately funded Solar 100 design, for example, employed a modular two-field design. The first field provided 100 $MW_e$ with a 27% capacity factor. The addition of the second field in a phased construction approach was designed to yield 100 $MW_e$ output with roughly a 54% capacity factor.

**Field Sizing.** The receiver configuration (external billboard, external cylindrical, single cavity, or a variation of one of these) directly influences the local performance of individual heliostats within the collector field and is the dominant factor that determines the shape of the collector field.

The field efficiency at the design point determines the field size and cost. For a noon design point on any given day of the year, a north field is more efficient than a surround field. Thus, north fields in general require fewer heliostats to deliver a given amount of energy to the receiver at the design point.

This difference is due to the differences in cosine losses associated with the two configurations. Figure 4.2–4 shows contours of constant cosine performance plotted in terms of equivalent tower heights. The contours show the superiority of north-side heliostats and the relatively poor annual average performance of south side heliostats.

The performance difference between north and surround fields is reduced by the lower atmospheric attenuation associated with the average shorter slant range from the heliostat to the receiver typical of the surround field.

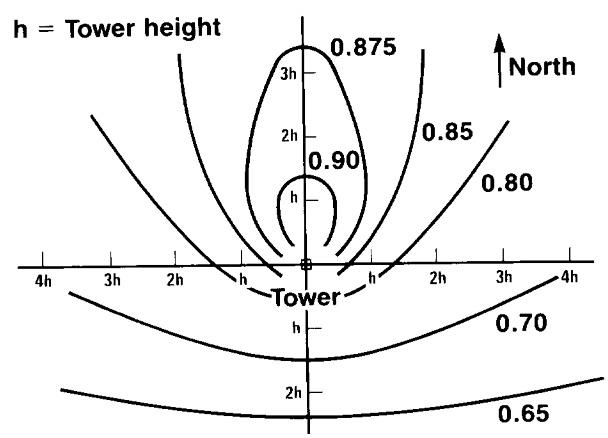



**Figure 4.2–4 Contours of Annual Average Cosine**

The annual energy produced by a surround field can be greater than by a comparable north field. This results from the fact that the decrease in efficiency at hours away from noon is relatively less severe for a surround field than for a north field. Furthermore, the highest field efficiencies for a north field occur in the winter when less total energy is available for collection owing to the shorter days and to the lower insolation levels. Conversely, the best field efficiency for a surround field occurs in the summer when the days are long and the insolation levels are high.

Coupled field and receiver optimizations provide information sufficient for scoping calculations. Using the receiver thermal power as the basis, the design point heliostat reflective area, total plant land area, tower height, and receiver size may be determined.

The heliostat reflective area as a function of the receiver thermal power is illustrated in Figure 4.2–5 for both north and surround fields. The required area is a function of the individual heliostat size. The smaller heliostats deliver smaller images at the receiver and consequently have less spillage and fewer aberration effects. The difference for 50 $m^2$ heliostats relative to 150 $m^2$ heliostats is roughly 5%. (However, larger heliostats cost less per unit area, and a cost performance trade-off is required in detailed design.)

An important lesson learned from Solar One is that the field should be sized conservatively. Additional reflective area should be considered to insure the plant will operate longer near the design point.

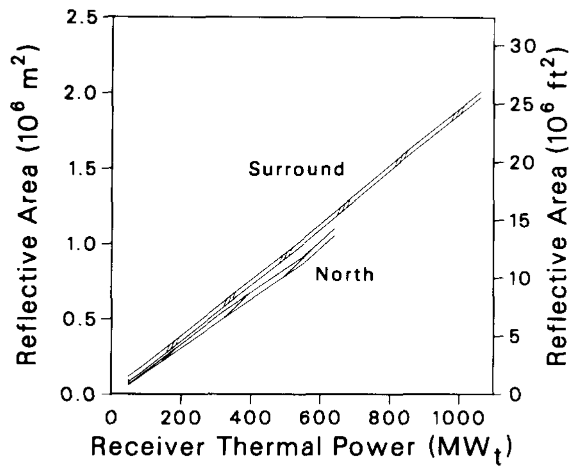



**Figure 4.2–5 Heliostat Reflective Area as a Function of Receiver Thermal Power for North and Surround Field Configurations**

The land required for the plant is shown in Figure 4.2–6. This includes both the land required for the heliostat field and the remainder of the plant. Although land requirements are substantial, their costs have only minor effects on the optimization. At $10,000/acre (considered high for undeveloped desert land), the heliostat field land cost equates to less than $10/$m^2$ of glass area, considerably less than the total heliostat cost.

**Tower Sizing**. Tower height is strongly influenced by the cost and performance assumptions for other systems. Tower heights for both north fields and surround fields receivers are shown as a function of the receiver thermal power in Figure 4.2–7. The cost estimates for towers of this type vary because of differences in the estimated cost of concrete, construction and foundation assumptions, and a perceived penalty on construction height. Tower costs typically increase exponentially with height.

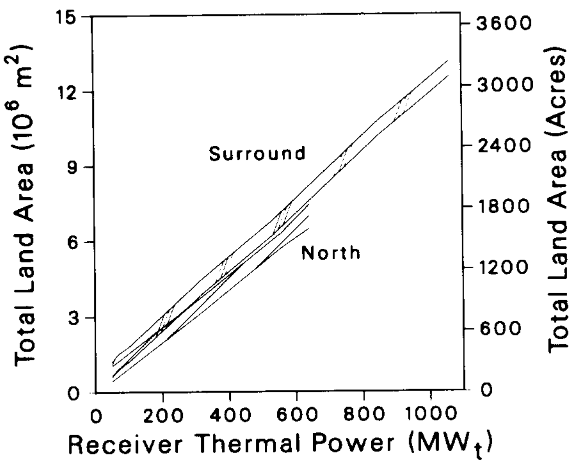



**Figure 4.2–6 Central Receiver Plant Area as a Function of Receiver Thermal Power for North and Surround Field Configurations**

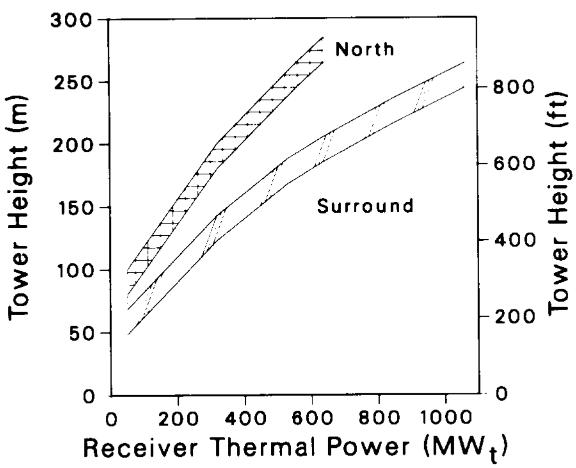



**Figure 4.2–7 Tower Height as a Function of Receiver Thermal Power for North and Surround Field Configurations**

**Receiver Sizing.** A convenient parameter for defining the size characteristics of a solar receiver is the active or illuminated absorber area. For a given set of design and thermal constraints such as the flux limit, the absorber area is generally proportional to the receiver peak thermal rating. To size the receiver, a flux limit must be selected.

Determination of the flux limit requires a finite element analysis of creep and fatigue effects on receiver tubes in a specific thermal/hydraulic design. Analyses have been performed[5] which can be used to select an appropriate flux limit. Peak allowable flux ranges based on this work as a function of the receiver lifetime are shown in Figure 4.2–8.

The flux limit is a function of both the receiver working fluid and the receiver tube material. Owing to its higher thermal conductivity, the heat transfer coefficient for sodium is significantly higher than that for molten salt. This results in significantly higher allowable flux limits for sodium receivers relative to salt receivers when designed to the same lifetime specification. The tube material and thickness also affect the allowable flux limit.

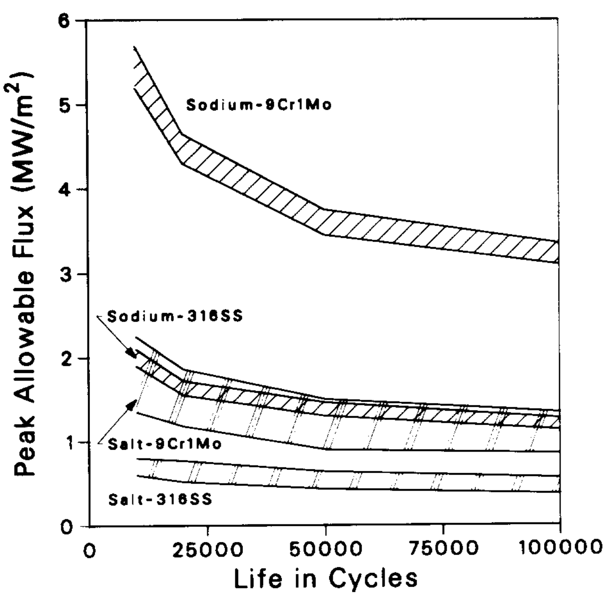



**Figure 4.2–8 Peak Receiver Tube Allowable Flux Levels as a Function of Tube Life for Sodium and Molten Salt Receiver Fluids and 9Cr1Mo and 316SS Receiver Tubes**

A goal in the central receiver program has been to design receivers for a thirty-year lifetime. One cycle per day for thirty years would use roughly 11,000 cycles of lifetime. At issue is the amount of lifetime reserved to cover for weather and other transients which also cause receiver thermal cycles.

Analysis of 1984 weather data at Barstow combined with thermal hydraulic analysis of the fluid in the tubes and structural analysis of the tubes has led to a recommended peak allowable incident (as opposed to absorbed) flux of 0.85 $MW/m^2$ for molten salt and 1.75 $MW/m^2$ for sodium, in fabricated receivers using 316 stainless steel. However, variations in flow rates or in the location of the peak flux on the receiver will lead to a different flux limit within the ranges shown on Figure 4.2–8.

With these peak allowable flux and lifetime results, the receiver absorber area may be determined as a function of the receiver thermal power as shown in Figure 4.2–9. The absorber area varies as a function of the receiver configuration and the receiver working fluid as indicated.

Receiver shape, characterized by the height to width ratio of the aperture for cavity receivers and as the height to diameter ratio for external cylindrical receivers, varies as a function of size. Ratios of aperture height to width dimensions for cavity receivers generally range from 0.7 for small receivers to 1 or slightly larger for larger receivers. Ratios of the height to the diameter for cylindrical external receivers generally range from 1 to over 2 for very large systems.

A difference in width and diameter for receivers associated with north versus surround fields results from slant-range related differences in heliostat image

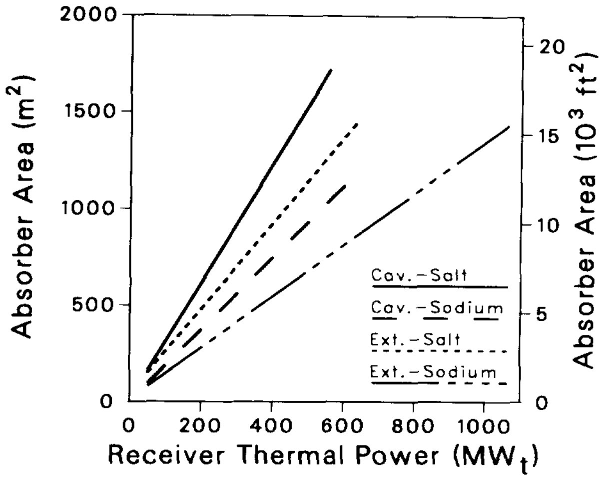



**Figure 4.2–9 Receiver Absorber Area as a Function of Receiver Thermal Power for Molten Salt and Sodium Receiver Fluids and Cavity and External Receiver Configurations**

sizes. The heliostats in a north field are, on the average, farther away from the receiver than for a surround field. Another reason for the difference is that heliostats in the east and west portions of a north field have a foreshortened view of the east-west planar cavity aperture. The height is driven by the requirement to selectively aim heliostats in the vertical direction to provide the desired flux distributions on the receiver. The lower allowable fluxes associated with salt require a larger dispersion of the heliostat aim points, hence a greater height relative to the corresponding aperture width. The absolute height is also limited by the requirement to minimize spillage while providing adequate flux distribution.

**Receiver Flux Profiles and Heliostat Aiming.** A detailed analysis is required to determine specific heliostat aim points by trading allowable heat flux levels on the receiver with lesser amounts of spillage. When specifying individual heliostat aim points, those heliostats with the highest (best) interception factors are evaluated for re-aiming away from the receiver center line in order to spread the flux distribution about the receiver.

If a proper flux distribution cannot be produced, the analysis is repeated with a slightly larger receiver to improve the interception factor of all heliostats to lessen the spillage. The improved interception factor and the ability to create the proper flux distribution is offset by the higher cost and increased receiver heat losses of the larger receiver.

The results of a heliostat aiming analysis for an external cylindrical receiver are shown on the chapter interleaf. Because of the greater optical efficiency of heliostats in the north sector of the field, the highest flux levels are on north-facing panels. Based on this flux pattern and the analysis of receiver flow routing, local fluid heat transfer and temperature increase in receiver tubes can be verified. Further, verification that maximum allowable fluid and tube material temperatures are not exceeded can be assured. Off-design flux distributions for various times of day and days of the year must also be investigated to insure that the most severe heat transfer condition is being considered and that adequate receiver turndown control capability exists.

## ENERGY UTILIZATION SYSTEM

The optimization process for the energy collection system results in systems which deliver minimum cost thermal energy. The utilization of that thermal energy is generally outside the scope of the optimization, particularly for salt or sodium systems where the turbine-generator is totally decoupled from the collection system by thermal storage and the steam generator. Sizing of the energy utilization components requires assessment of the energy usage rather than detailed optimization.

**Thermal Storage Sizing.** The size of thermal storage is directly related to the energy utilization requirements of the total plant and only secondarily to the details of the collection system. The key requirements affecting storage size are the turbine rating, cycle efficiency, desired plant capacity factor and plant operating strategy.

An estimate of the storage size in hours at peak plant turbine rating is shown in the upper portion of Figure 4.2–10 as a function of plant capacity factor. The hours shown are derived from the minimum storage requirement associated with the net accumulation of energy. This amount is determined by the differences in energy from the collection system and the energy required to supply the steam generator and turbine/generator at rated conditions. This analysis assumes the turbine runs continuously from the time energy inflow exceeds outflow requirements, until the accumulated energy is depleted. These results are site specific because the average distribution of available insolation over the day and year affects the results.

In the lower portion, Figure 4.2–10 shows the specific storage capacity size for various turbine sizes and as a function of capacity factor.

These are minimum storage requirements and the effect of utility grid dispatch is not included. Delaying turbine start until an evening peak demand time period can substantially increase the

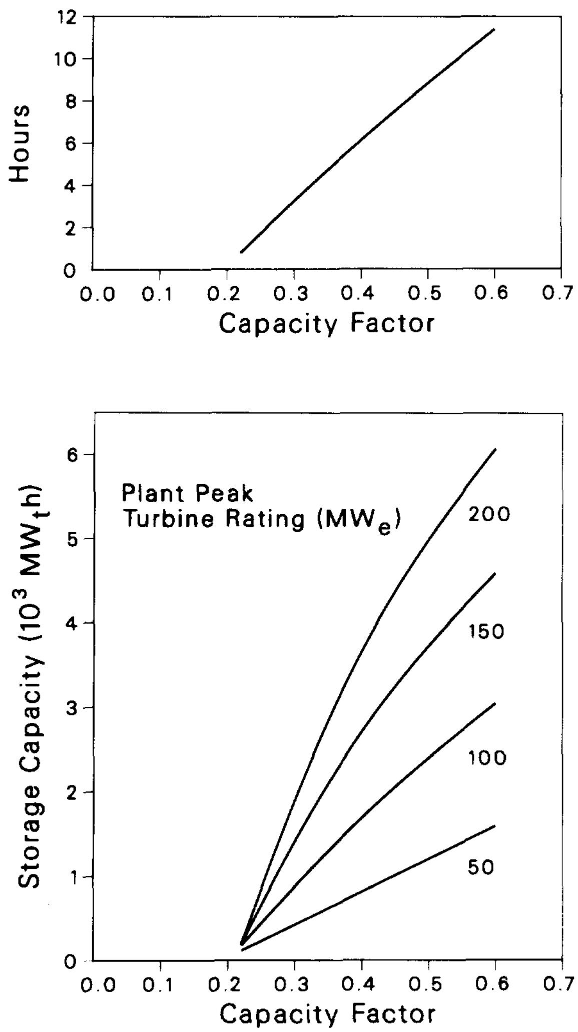



**Figure 4.2–10 Thermal Storage Size as a Function of Plant Capacity Factor (Hours indicate hours at peak turbine rating.)**

storage requirement for low capacity factor plant designs. For example, a plant designed for a 27% capacity factor, will require more than double the storage requirement (from 2.5 hours to 5 hours) if the turbine start is delayed to 5 pm in the winter. This effect is less for plants with higher capacity factors.

The use of sodium for storage is expensive. The relative cost of sodium per unit of energy stored is several times that of salt. This is due to differences in specific heat (sodium has about 80% the heat capacity of salt) and the relative cost per pound (higher by as much as a factor of five). Additionally, the lower density of sodium increases the tank sizes, and, therefore, further increases the cost per unit of energy stored.

Storage media requirements for a molten salt system are shown in Figure 4.2–11. As previously discussed, salt storage can be employed with a salt receiver or with a sodium receiver. The solid line indicates the amount of salt required specifically for storage.

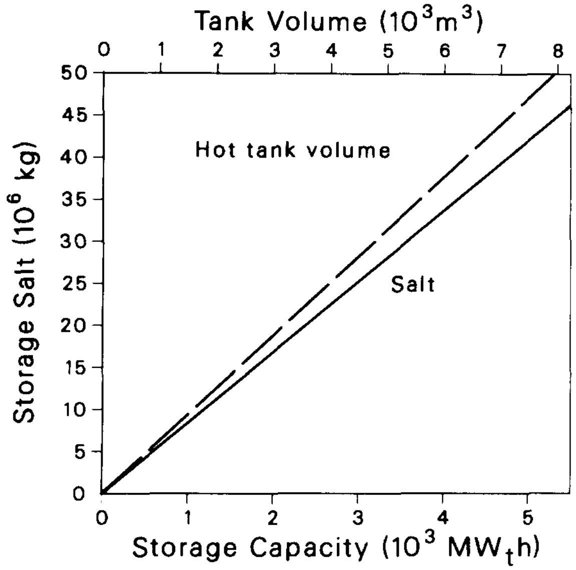



**Figure 4.2–11 Salt and Tank Volume Requirements as a Function of Storage Size**

Media requirements for salt in the transport system are related to the receiver thermal size. Figure 4.2–12 shows the salt requirements for the piping, receiver, and steam generator. Although not precise, the amount of sodium required in a sodium/salt binary system can be generally approximated by this curve.

The dashed line in Figure 4.2–11 indicates the hot tank volume size required for that amount of salt in the storage system. The required cold tank volume is roughly 90% of the hot tank volume. These tank volumes are related to total salt weight in the system. The total salt weight is the sum of the salt required for storage and the additional salt required for the salt loop as shown in Figure 4.2–12. The cost of salt, estimated to range from \$0.65 to \$1.30 per kilogram, can be a significant plant cost item.

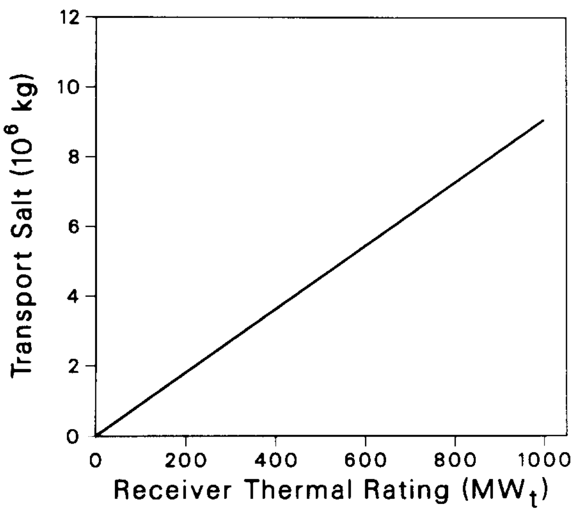



**Figure 4.2–12 Transport System Salt Requirements as a Function of Receiver Thermal Size**

In general, tanks are similar to large petroleum storage tanks with height to diameter ratios of less than one. The volumes indicated in Figure 4.2–11 are active volumes and do not include ullage space, which in some cases has been estimated to require an additional 5%.

The plant transport system contains a number of pumps required to circulate the fluid. Significant pumping requirements are associated with the receiver and steam generator. Estimated flow rate requirements as a function of the receiver and steam generator thermal ratings are shown in Figure 4.2–13. These flow rates, along with the tower heights and other pressure requirements in the thermal loop, can be used to determine pump requirements and sizes.

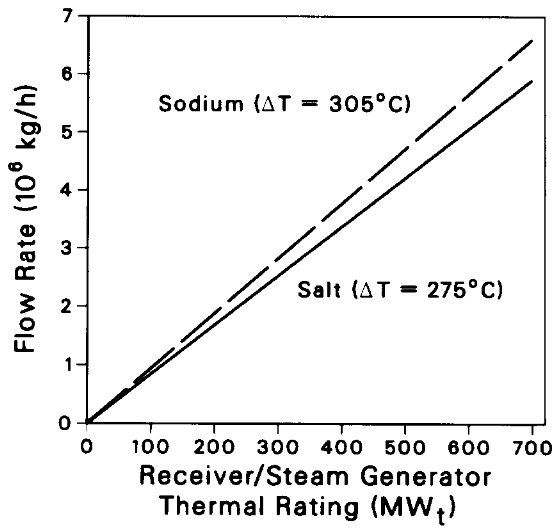



**Figure 4.2–13 Salt or Sodium Flow Rate as a Function of Receiver/Steam Generator Thermal Rating**

Two major salt pumps are required in a sodium/salt hybrid plant. One is sized for receiver duty, through the sodium/salt heat exchanger, and the other sized for steam generator duty.

Although pump costs are low relative to the total plant cost, they can have a significant impact on life cycle costs because of their parasitic requirements. This is discussed in more detail in Chapter 6.

**Annual Energy Estimate.** It is difficult to estimate accurately the annual energy output of a solar central receiver plant using simplified design rules. Annual energy output is a function of the specific weather pattern at a site and the operation philosophy employed. Operation of Solar One and other central receiver systems has dramatically illustrated the inaccuracy of simplistic annual performance estimates.

A computer model of energy flow through a plant using actual weather data and realistic estimates of startup and other transient phenomena is required for accurate estimation of plant output. Use of such a code, SOLERGY, for specific systems analyses is described in the following section.

Based on previous studies, Figure 4.2–2 illustrates the expected relationship between the capacity factor and the solar multiple. Since the capacity factor is defined as the ratio of the annual energy to the product of the nameplate rating of the plant and the hours in a year, given either the capacity factor or the annual energy output for a specific sized plant, the other can be deduced. Figure 4.2–14 shows this relationship.

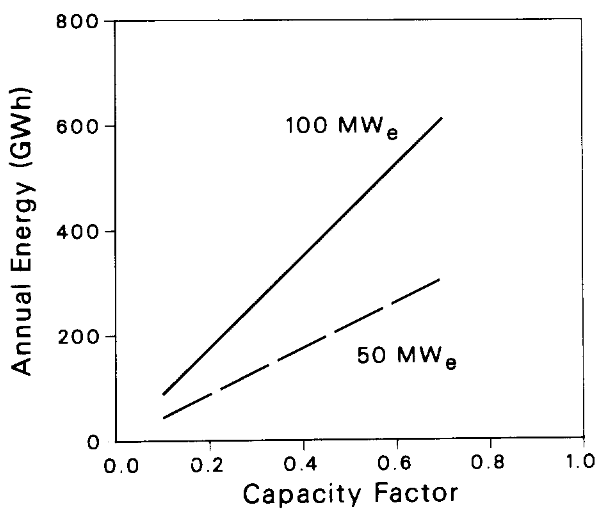



**Figure 4.2–14 Plant Annual Energy Output as a Function of Capacity Factor for 50 and 100 MW$_e$ Plants**

**Energy Cost.** The cost of energy, often calculated as the levelized energy cost, is calculated as the ratio of the annualized cost of the plant to the net annual energy production. Section 7.3 describes in detail the procedures for the calculation of the levelized energy cost. Capital cost estimates for central receiver plant components are described in Section 7.2.

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# COMPARISON OF THREE SYSTEMS

Results from the recently completed *System Improvement Studies* [1,2] are presented in this section to provide an example of the results and sensitivities in central receiver systems analyses. In this work, the results of system and component experiments in the United States and in other countries were evaluated first. Next, improved methods to define the optimum central receiver configuration for specified near-term applications were developed. Finally, these optimum configurations were used to examine and compare a number of base case designs.

The objective of this work was to examine the effect of configuration on performance and cost of utility-scale central receiver systems sized from 15 – 200 $MW_e$. Variables included in this study were the heliostat size and type, heliostat focusing strategy, field configuration, tower height, and receiver design and working fluid. Options included glass/metal and stressed membrane heliostats, external and cavity receivers, and liquid sodium and molten nitrate salt receiver fluids. Salt storage was assumed for all systems.

## ANALYTICAL APPROACH

The analytical approach for designing and evaluating performance of central receiver systems used a design and optimization computer code DELSOL[3] together with detailed structural and thermal codes for the receiver. The detailed analysis was performed on the receiver because it is the system component with the greatest cost and performance uncertainty. The principal objective was to design the receiver for peak performance with minimum margins of conservatism.

A family of analytical tools was used to design systems and to estimate their performance. These tools are indicated together with the principal input parameters and major outputs, on Figure 4.3–1. As illustrated, the design process is highly iterative.

DELSOL was used to lay out the heliostat field and to size the tower and receiver. In DELSOL, the preferred design is based on a cost/performance optimization. Information about specific components such as heliostat type or size and receiver configuration, together with the plant size and site, are specified as input. Different receiver working fluids are distinguished by the input value for the allowed peak flux and by small differences in the receiver cost model. A separate finite element analysis of tube lifetimes was used to determine the peak allowable flux.[4]

As indicated in Figure 4.3–1, output from DELSOL includes receiver dimensions and flux profiles on the receiver surface. This information was used to perform detailed thermal analyses to estimate receiver thermal performance and to determine mass flow rates and pressure drops. An output of the thermal calculation, performed using the computer codes DRAC[5] for external receivers and CAVITY[6] for cavity receivers, is tube and fluid temperature distributions. Thermal losses and efficiencies are also estimated.

The temperature profiles are required for the structural performance and lifetime calculations. Finite element

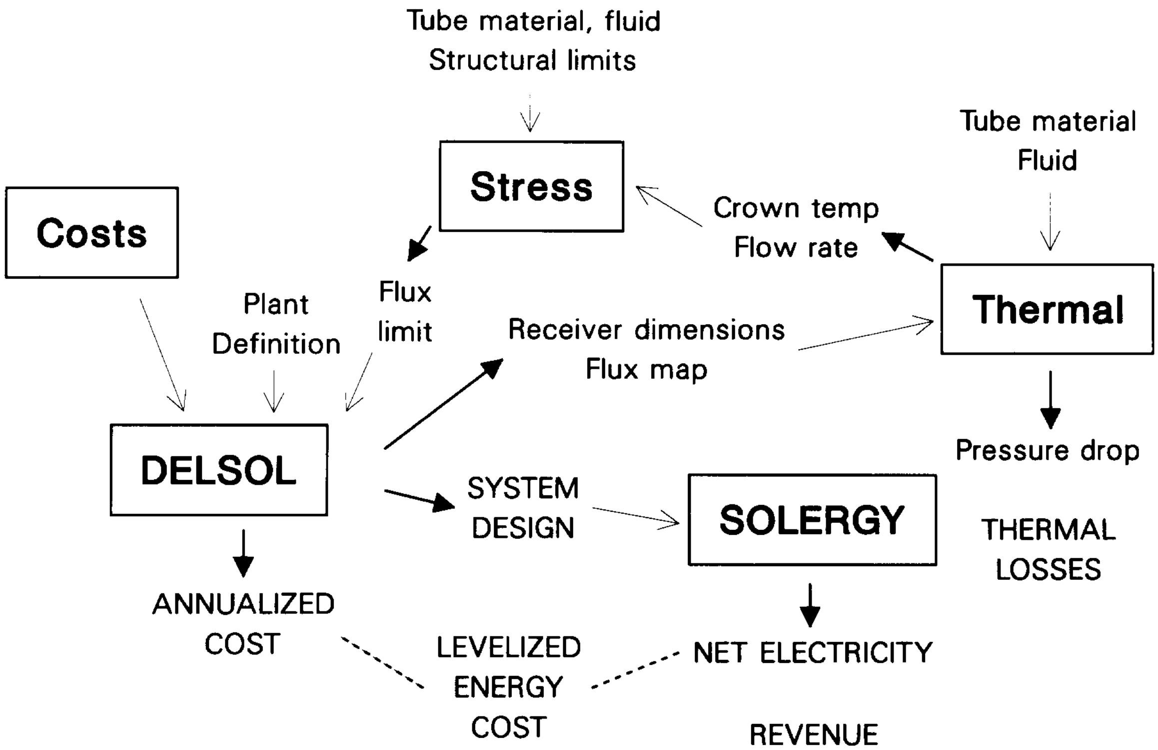


**Figure 4.3–1 Interaction of Analytical Tools in System Design Process. (Boxes indicate computer codes. Inputs and outputs designated with arrows.)**

analysis of receiver tubes was performed to determine the peak allowable flux levels for a 20,000 cycle lifetime. The specification for cycles was determined by examining average insolation variations. For sodium receivers, a peak incident flux level of 1.75 $MW/m^2$ was determined and for salt receivers, 0.85 $MW/m^2$. These flux levels were used to design the systems which were examined using thermal-hydraulic codes; the temperature profiles were used to verify that the flux limits were not exceeded.

Cost models in DELSOL were developed from the actual costs for central receiver systems and estimated costs from detailed and conceptual design studies. The cost of each component is scaled appropriately. For example, the tower cost is assumed to vary with tower height while the receiver cost scales with the receiver absorber area. Cost scaling relationships are discussed in detail in Chapter 7.

Annual net electric output from the base case designs was estimated in two ways. Simple models in DELSOL, which estimate the plant performance based on five representative days throughout the year, were used for the initial design. A better estimate was obtained through use of the computer code SOLERGY[7] in which power flows through the plant at fifteen minute intervals. Input to this code is a data tape of actual weather and insolation conditions in 1984 at Solar One. In both calculations, the effect of operating and non-operating parasitic power requirements was included. The SOLERGY code also evaluates the effect of plant dispatch strategies on the net electricity produced.

## OPTIMIZED SYSTEMS

Three system configurations were examined in detail: an external cylindrical liquid sodium receiver, an external cylindrical molten nitrate salt receiver, and a cavity molten nitrate salt receiver. Receiver and tower designs are illustrated in Figure 4.3–2. The external receivers were designed with surround heliostat fields while the cavity receiver was associated with a north heliostat field. Base case designs of 320 $MW_t$ receivers which were a part of 100 $MW_e$ systems were developed. The design characteristics for these systems are listed in Table 4.3–1. Design point, cost and annual performance estimates for these systems are listed in Tables 4.3–2, 4.3–3 and 4.3–4, respectively.

**Table 4.3–1**

CHARACTERISTICS OF
320 $MW_t$ SYSTEMS

| | Sodium External | Molten Salt External | Molten Salt Cavity |
|---|---|---|---|
| Number of heliostats | 6156 | 6167 | 5360 |
| Land area ($10^6$ $m^2$) | 4.1 | 4.2 | 3.5 |
| Tower height (m) | 138 | 135 | 200 |
| Panel height (m) | 16 | 22 | 22 |
| Absorber area ($m^2$) | 448 | 788 | 1005 |
| Peak flux level ($MW/m^2$) | 1.70 | 0.82 | 0.85 |
| Avg. flux level ($MW/m^2$) | 0.79 | 0.46 | 0.32 |
| Number of fluid passes | 1 | $\geq 7$ | $\geq 7$ |

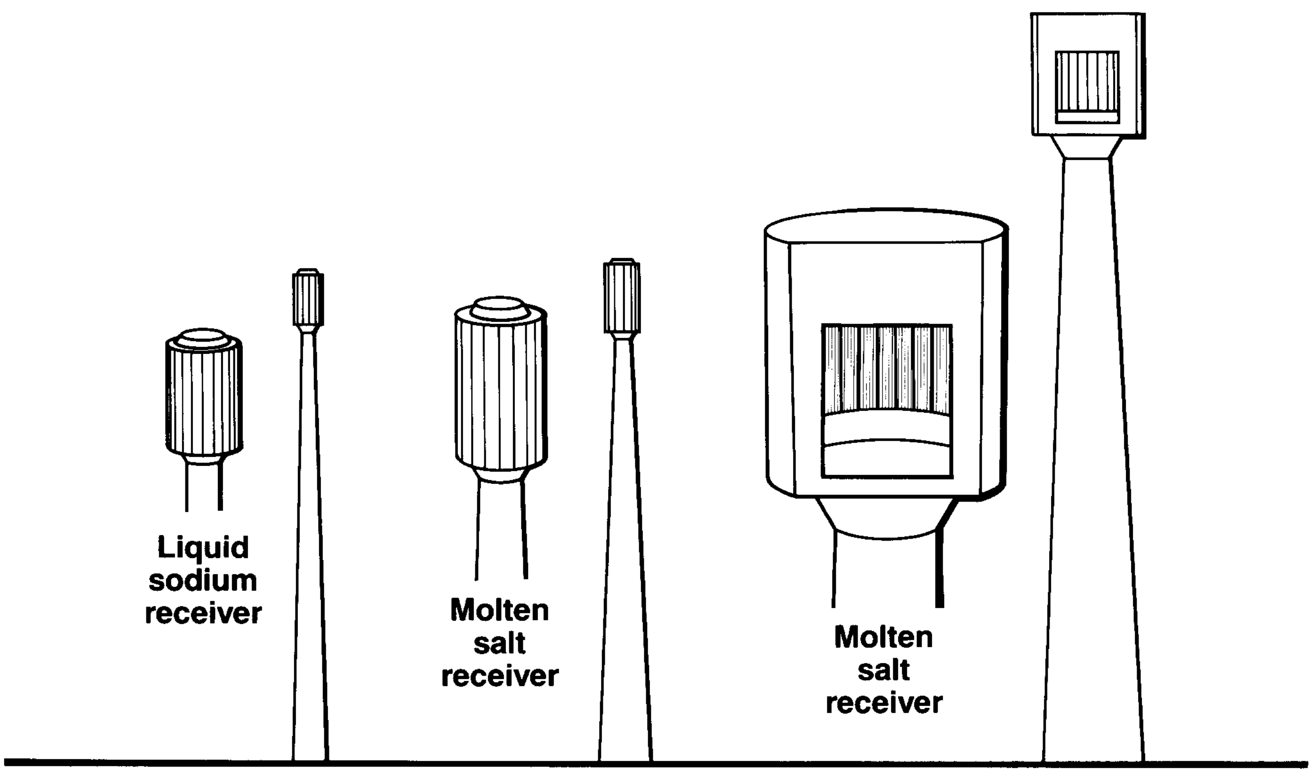


**Figure 4.3–2 Comparison of Three 320 $MW_t$ Central Receiver Systems: External Sodium, External Salt, and Cavity Salt (Drawings are to scale.)**

**Table 4.3–2**

DESIGN POINT PERFORMANCE
OF 320 $MW_t$ SYSTEMS

| tenpoint | Sodium External | Molten Salt External | Molten Salt Cavity |
|---|---|---|---|
| Field efficiency (%) | 66.4 | 65.6 | 75.2 |
| Spillage (%) | 4.3 | 1.0 | 3.0 |
| Convective loss (%) | 0.9 | 1.6 | 3.2 |
| Radiative loss (%) (emitted & reflected) | 7.7 | 9.4 | 6.0 |
| Receiver efficiency (%) | 91.4 | 89.0 | 91.4 |

**Table 4.3–3**

COST ESTIMATES FOR
320 $MW_t$ SYSTEMS

| (M$) | Sodium External | Molten Salt External | Molten Salt Cavity |
|---|---|---|---|
| Field | 74.0 | 74.2 | 64.6 |
| Tower | 3.3 | 3.1 | 5.7 |
| Receiver | 18.1 | 23.7 | 28.8 |
| Piping/Pump | 10.9 | 10.7 | 15.5 |
| Heat exchanger | 9.0 | 0 | 0 |
| Total direct costs | 220.4 | 216.5 | 215.0 |
| Annualized cost | 20.88 | 20.51 | 20.36 |

**Table 4.3–4**

ANNUAL PERFORMANCE AND
ENERGY COST OF 320 $MW_t$ SYSTEMS

| | Sodium External | Molten Salt External | Molten Salt Cavity |
|---|---|---|---|
| Field efficiency (%) (including spillage) | 57 | 59 | 64 |
| Receiver efficiency (%) | 87 | 83 | 84 |
| Plant efficiency (%) | 14.4 | 14.5 | 14.6 |
| Gross electricity (MWh) | 255,000 | 252,700 | 239,80 |
| Net electricity (MWh) | 204,100 | 202,100 | 189,100 |
| Levelized energy cost (¢/kWh) | 10.2 | 10.1 | 10.8 |

A sodium cavity receiver configuration was also designed and evaluated.[8,9] The 320 $MW_t$ size had a smaller absorber area (566 $m^2$) than the salt cavity (1005 $m^2$) but it was larger than the sodium external (448 $m^2$). Its performance was estimated to be comparable to that of the sodium external receiver with high spillage (8%) and low convective and radiative losses (3%). High cavity ceiling temperatures were observed which require additional attention in a more detailed design study. For this size, the levelized energy cost was similar to the other systems.

Despite the fact that the receiver systems each produce the same amount of power at the base of the tower at the design point (noon on March 21), there are marked differences in size. The sodium external receiver is the smallest receiver because of its high allowable peak flux. The external salt receiver is about 70% larger. The cavity salt receiver has an absorber area which is roughly 25% larger than the external salt receiver although both receivers were designed with the same peak allowable flux. Geometrical constraints from focusing the energy through the cavity aperture result in a lower average flux on the receiver panels. The cavity receiver is larger and more expensive because of the mass of the cavity structure. This relationship was also observed for the sodium external and cavity receivers.

Towers for the surround field systems are shorter than the tower required for the north field system. However, more heliostats and a larger land area are required for the surround fields than for the north field configuration. This is a result of the higher optical efficiency of the north field configuration due principally to the better cosine efficiency of heliostats located north of the tower.

Capital costs of system components also vary. The external receivers are cheaper, with the small sodium receiver the cheapest. Field costs for the cavity system are considerably less, offsetting high receiver and tower costs.

The cost of a sodium-to-salt heat exchanger is included in the sodium system so that energy can be transferred to the salt storage assumed for all systems. (The base storage size for each of the systems is 330 MWh or 1.25 hours.)

Annual energy estimates for these plants were calculated using a sun-following dispatch strategy in SOLERGY and are listed in Table 4.3–4. Despite the same thermal power at the design point and the higher efficiency of the north field configuration, the cavity system produces less electricity than the surround configurations. This is a result of differences in performance throughout the day and throughout the year. North field systems have relatively poorer performance at hours away from solar noon and have their best optical performance in the winter months when the hours of sunlight and total available insolation are lower. In contrast, surround systems have more uniform optical performance throughout the day (although lower at noon) and have their best performance in the summer months.

Despite a lower annualized cost for the cavity/north field system, the lesser amount of net electricity produced results in a somewhat higher levelized energy cost for that system relative to the two surround field systems. However, this study predicts that all systems will produce electricity at costs competitive with one another.

**Effect of Heliostat Size.** All three systems were designed with a 100 $m^2$ heliostat with an assumed cost of $\$120/m^2$. A trade study examining the effect of heliostat size on system performance and cost was performed. Results are tabulated in Table 4.3–5. The relative cost of the reflective area varies with individual heliostat size. Results of previous heliostat cost studies were used to obtain the cost estimates listed in Table 4.3–5. Other studies comparing a 150 $m^2$ glass metal heliostat with a similarly sized stressed membrane heliostat indicated that if cost goals were met, a 150 $m^2$ stressed membrane heliostat was preferred.

Stressed membrane heliostats are currently under development in the central receiver technology program. Continuing technical development and cost reductions are anticipated to reach the assumed cost and performance goals.

**Effect of Plant Size.** Cost and performance as a function of plant size (for fixed solar multiples) were calculated. Field and receiver annual efficiencies for the three systems are shown as a function of plant size in Figure 4.3–3. They are relatively insensitive to changes in plant electrical rating or solar multiple.

Efficiencies for the three plants evaluated in this study are shown in Figure 4.3–4. Plant loads are included during the time the plant is not operating. The annual calculation based on 1984 weather data at Barstow also includes 15 randomly selected forced outage days and 15 consecutive scheduled outage days in December. Transient effects of cloud passage and startup/shut down are included in the calculation.

For a constant solar multiple, increasing the plant's electrical rating increases the plant efficiency. This results largely from two effects. First, turbine efficiency increases with size for the same inlet and outlet conditions. Second, parasitic loads, as a percentage of gross plant electric output, decrease with increasing plant size. This effect significantly affects the design and performance of smaller plants.

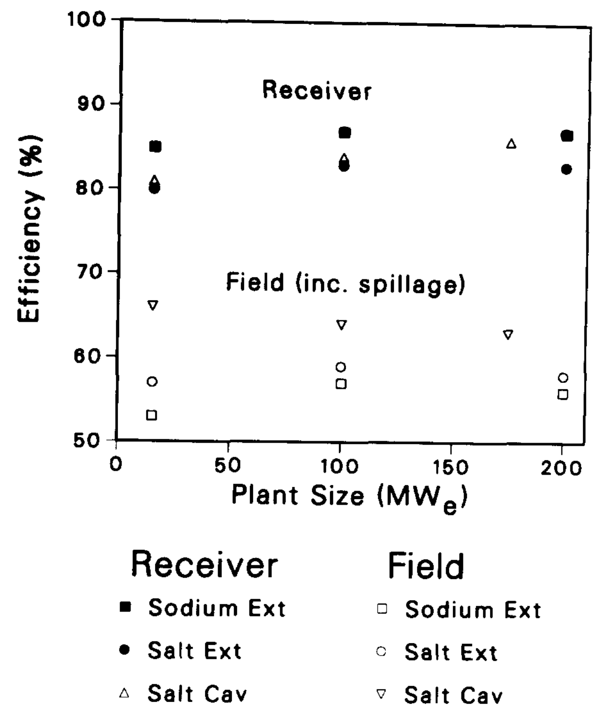


**Figure 4.3–3 Field and Receiver Average Annual Efficiency as a Function of Receiver Thermal Size for the Three Systems**

**Table 4.3–5**

COMPARISON OF COST AND PERFORMANCE OF 320 $MW_t$ SYSTEMS EMPLOYING DIFFERENT GLASS/METAL HELIOSTAT SIZES

| | Surrounding Field | | | North Field | | |
|---|---|---|---|---|---|---|
| | 50 $m^2$ | 100 $m^2$ | 150 $m^2$ | 50 $m^2$ | 100 $m^2$ | 150 $m^2$ |
| Heliostat cost ($\$/m^2$) | 160 | 120 | 88 | 160 | 120 | 88 |
| Number of heliostats | 10836 | 6179 | 4000 | 9453 | 5448 | 3566 |
| Total mirror area ($m^2$) | 584,060 | 590,095 | 600,800 | 509,517 | 520,284 | 535,613 |
| Annual energy onto receiver ($MW_{th}h$) | 070,615 | 871,711 | 873,696 | 795,035 | 796,065 | 797,003 |
| Field Cost ($\$/MW_{th}h$) | 111 | 85 | 65 | 106 | 82 | 63 |

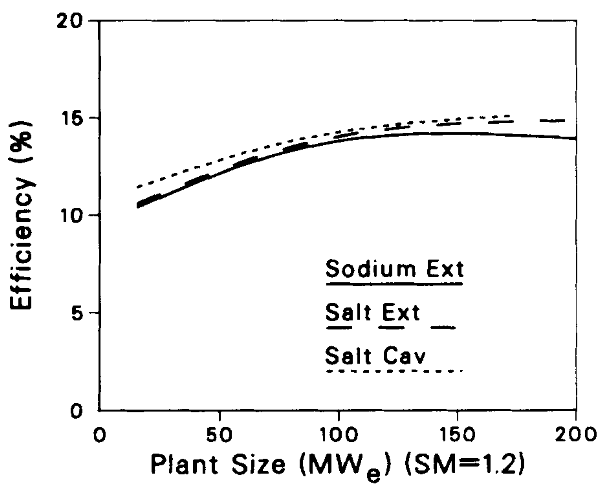


**Figure 4.3–4 Estimated Plant Annual Efficiency of the Three Systems as a Function of Plant Size for a Fixed Solar Multiple**

An annual energy stairstep chart for one of the 100 $MW_e$ systems (external molten nitrate salt system with a solar multiple of 1.2 and 1.25 hours of storage) is shown in Figure 4.3–5. Each of the factors that reduce the power as it is transformed from solar energy into electricity are indicated. Fractional energy loss processes are indicated on the bottom of the figure.

A sensitivity study examining parameters used in the calculation of annual energy from this system was performed. Results are tabulated in Table 4.3–6. The parameters which most significantly affect the overall performance of the plant are those in the "front end" of the system. These include the heliostat availability, the heliostat cleanliness, and the receiver absorptivity. Uncertainties in the values of start-up or transient parameters affect the plant output to a lesser degree because they occur during periods of lower insolation and are of short duration.

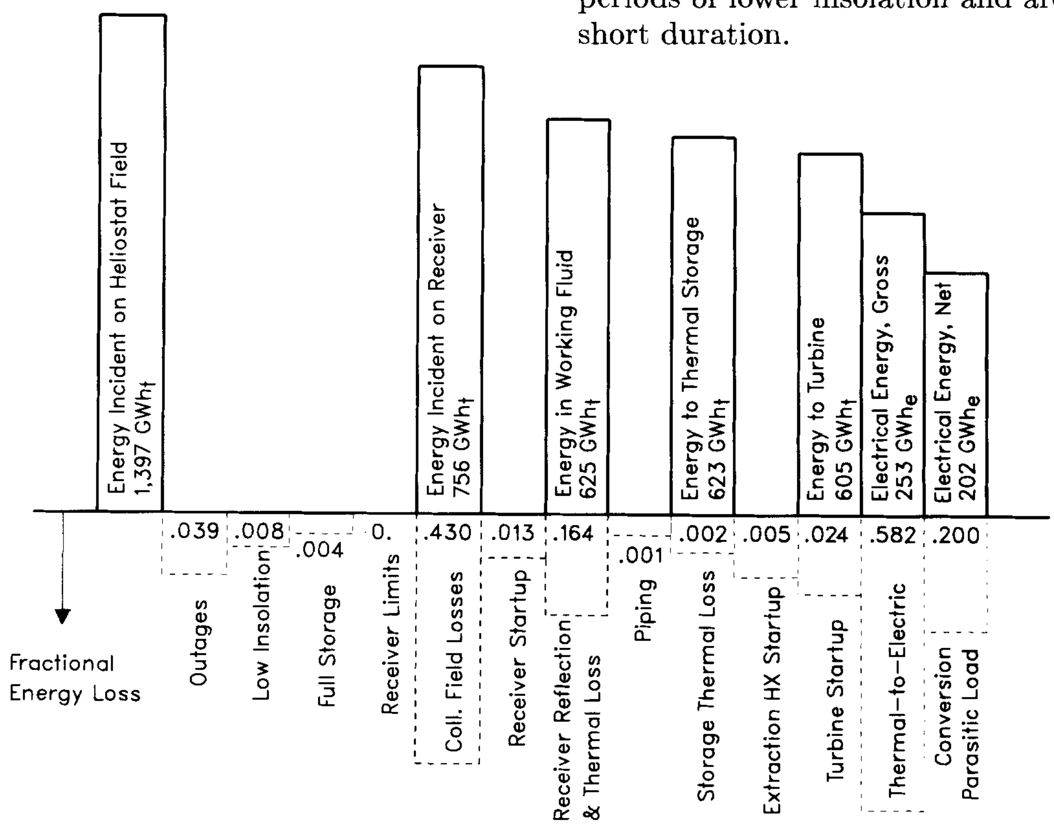


**Figure 4.3–5 Energy Efficiency Stairstep for a 100 $MW_e$ External Salt System**

Calculations over a range of plant sizes from 15 $MW_e$ to 200 $MW_e$ indicate that energy costs for the three configurations are close to one another over this range. Energy costs are highest for small plant sizes and are lowest at the large sizes. Results for plants with a solar multiple of 1.2 are illustrated in Figure 4.3–6.

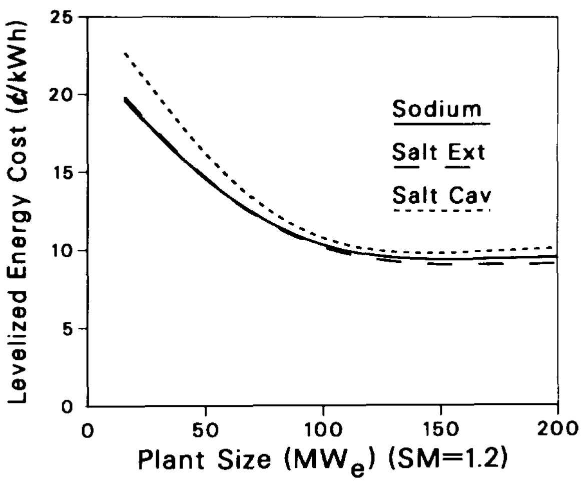


**Figure 4.3–6 Levelized Energy Cost for the Three Systems as a Function of Plant Size for a Fixed Solar Multiple**

As expected, for a constant solar multiple, increasing the plant size will increase the absolute number of dollars required to build and operate the plant. However, due to economies of scale (i.e., the average cost per unit declines with increasing size), the annualized cost per kW of installed capacity declines with increasing plant size. This occurs in both the installed cost (a 200 $MW_e$ turbine costs less than twice as much as a 100 $MW_e$ turbine) and in the O&M costs (the operating cost of a 200 $MW_e$ turbine is less than twice the operating cost of a 100 $MW_e$ turbine).

Levelized energy costs also decrease with increasing solar multiple and capacity factor for a fixed plant electrical rating. This is due to changes in the plant capital cost and overall efficiency. As Figures 4.3–7 and 4.3–8 show, economies of scale reduce the cost per unit of thermal energy as the solar multiple

Table 4.3 6

ANNUAL ENERGY SENSITIVITY STUDY USING SOLERGY COMPUTER CODE+

| Parameters | Nominal Value | Variation | Change in Net Annual Electricity |
|---|---|---|---|
| Collector field reflectivity | 0.91 | 0.82 | – 14.2% * |
| Collector field area | 589,000 $m^2$ | 559,000 $m^2$ | – 6.8% * |
| Receiver absorptivity | 0.948 | 0.898 | – 7% * |
| Receiver thermal losses | 27.4 $MW_t$ | 41.4 $MW_t$ | – 8% |
| Receiver start-up energy | 15 $MW_t$h | 30 $MW_t$h<br>7.5 $MW_t$h | – 1.5%<br>+ 0.5% |
| Receiver start-up time | | 15 minutes<br>4 minutes | + 0.5%<br>– 4% |
| Storage tank loss factor | 0.1 | 0.2 | 0 |
| Storage tank capacity | 330 $MW_t$h | 165 $MW_t$h<br>669 $MW_t$h | – 4%<br>+ 1% |
| Extr. heat exch. start-up delay | 15 minutes | 30 minutes | – 1.7% |

* Percent change in net electric output is greater than percent change in parameter
+ Analysis for a 100 $MW_e$ salt external system with 1.25 hours of storage and 1.2 solar multiple

increases. This same effect was observed with increasing electrical rating as shown in Figure 4.3–6; however, increasing the solar multiple only results in economies of scale for the solar part of the plant since the non-solar portion of the plant is unchanged.

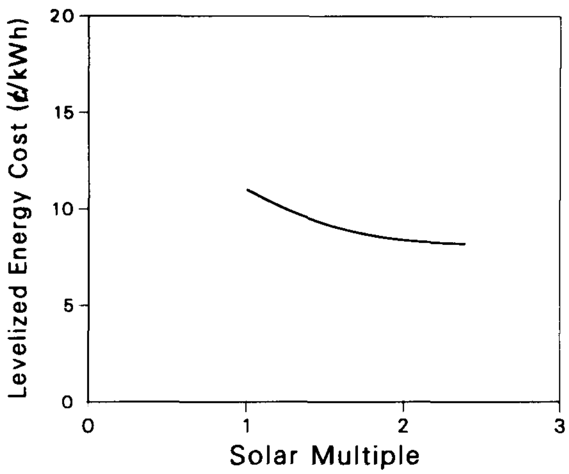


**Figure 4.3–7 Levelized Energy Cost as a Function of Solar Multiple for a 100 $MW_e$ External Salt Receiver System**

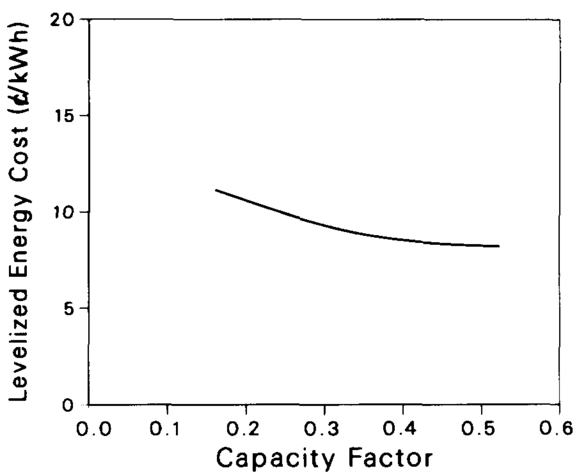


**Figure 4.3–8 Levelized Energy Cost as a Function of Capacity Factor for a 100 $MW_e$ External Salt Receiver System**

Increasing the solar multiple does result in increased capital efficiency of the non-solar portion of the plant because more electric energy is produced each year for each dollar of investment in the non-solar equipment. This increased utilization of the non-solar components only slightly increases that portion of the annualized cost (due to increased annual O&M costs), while the amount of energy produced increases at a much faster rate.

## CONCLUSIONS

Results of these system studies indicate some trends for central receiver technology selection for near-term, Rankine-cycle electric plants, consistent with the assumptions employed in structuring the study. Large heliostats, while somewhat poorer in optical performance, are preferred for commercial-scale, Rankine-cycle plants because of their lower relative cost. The optimum field configuration is a function of the assumed costs of the heliostats, tower and receiver. North field configurations offer the best field performance and are preferred when heliostat costs are high. Surround field configurations result in smaller, less expensive receivers and towers and are preferred when heliostat costs are low. When sized for the same design point, surround fields deliver greater annual energy than do north fields. For the heliostat costs assumed in this study, $\$120/m^2$, the surround field configurations provide energy at a somewhat lower cost than do the north field systems.

With respect to receiver fluid and configuration selection, study results indicate that receiver thermal performance is not a significant distinguishing feature between cavity and external receivers. Higher receiver fluxes are possible and are desirable for smaller, less costly, and more efficient receivers. An external molten nitrate salt receiver appears to be a good candidate that merits additional study.

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# ENERGY VALUE OPTIMIZATION

Typically, solar thermal plants have been designed with the objective of minimizing the levelized energy cost. However, an alternative is to design and operate a solar plant to maximize the value/cost ratio. If the value of electricity varies, for example, as a function of the time-of-day, an optimal solar central receiver plant will differ from one optimized for minimum levelized energy cost. Results of a recent study[1] in which value was estimated for a fixed set of conditions and dispatch strategies were evaluated for their effect on the value/cost ratio are described in this section.

A sun-following dispatch strategy starts the turbine as soon as there is enough energy to do so and runs it until storage is depleted. This strategy results in the minimum levelized energy cost because energy discard is minimized; however, no effort is made to shift the output to higher value time periods. A value-maximizing dispatch strategy attempts to shift the output to the highest value periods. Turbine startup is delayed and storage is used to carry over energy from lower value periods during the days and weekends to higher value periods. This yields a significantly higher value; it also slightly increases the levelized energy cost because there is a small increase in energy discard and potentially, an increase in the size of storage.

In this work, the value of electricity was based on the avoided costs in the Southern California Edison's (SCE) standard offer Number 2, payment option number 2.[2,3] The SCE standard offer was selected because the load demand profile of SCE is typical of a summer peaking utility in the Southwest. Also, the available weather data for use in the simulation was for Barstow, California, which is in the SCE service territory. In addition, there were no peak or mid-peak demand/payment periods on the weekends for the SCE standard offer. This increases the value of storage (used to carry over energy from the weekends to the peak demand days) and results in the greatest difference in value between a plant employing a sun-following dispatch strategy and one operating with a value maximizing strategy.

There are two parts to SCE's avoided cost payment: an energy payment and a capacity payment. The value of the capacity payment depends upon whether power is available (and contracted for) on a "firm" or "as available" basis. Firm capacity payments under this offer are at least twice as large as for as-available capacity payments. Under the SCE standard offer number 2, to be considered firm capacity, an electricity producer must have an 80% on-peak capacity factor during the summer peak months. This requirement was significant in this study since the July weather for 1984 was particularly poor and may have affected the results.

The SOLERGY[4] computer code was used to simulate the operation of a central receiver power plant using both operating or dispatch strategies. The value of the energy output calculated in SOLERGY was determined using a subroutine VALCALC. The VALCALC calculation includes an estimate of the value of the estimated parasitic loads; parasitics are subtracted from the gross output when the turbine is operating and the value of the parasitics is calculated according to utility rules when the turbine is not operating.[5]

The calculated energy values are first year values; no assumptions are made about inflation or real escalation rates for fossil fuels or capital equipment. Thus, it is assumed that every year is like the first year when the value and cost are compared (i.e., fuel costs and capital cost are the same). If there is real energy escalation over the life of the plant then the levelized value will be higher than the first year value.

The results discussed are for molten salt external receiver systems designed as described in the previous section. The results should not vary significantly for other configurations and working fluids. Figure 4.4–1 shows the effect on levelized energy cost of increasing the storage size for a 100 $MW_e$ plant with a solar multiple of 1.2. The plant capital costs vary with storage size but remain the same for both dispatch strategies. The reason that the value-maximizing dispatch strategy has a higher levelized energy cost than the sun-following dispatch strategy is that there is slightly more energy discarded. Six hours of storage is sufficient to avoid energy discard.

Figure 4.4–2 shows the value of the energy generated for the same plant designs and dispatch strategies as those shown in Figure 4.4–1. The sun-following dispatch strategy is unaffected by the size of storage since the energy is dispatched as soon as it is available and the minimum amount of storage shown is sufficient to avoid significant discard. The value-maximizing dispatch strategy, however, shows a considerably higher value. For this dispatch strategy, the

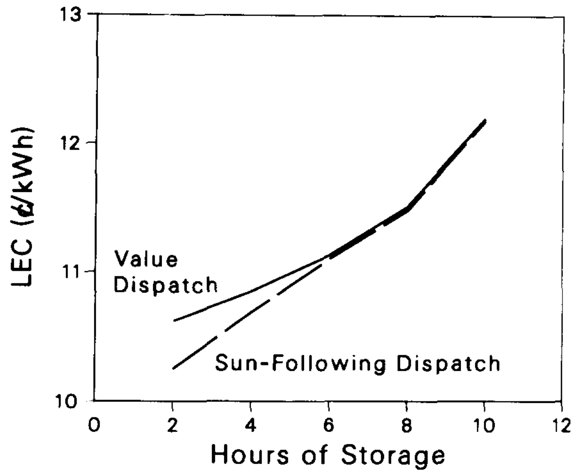


**Figure 4.4–1 Effect of Storage Size on Levelized Energy Cost for a 100 $MW_e$ External Salt Receiver System for Two Alternate Dispatch Strategies. Value indicates a value-maximizing dispatch strategy.**

value for the two hour storage design is markedly lower than the rest of the curve. This occurs because with only two hours of storage the plant could not qualify for firm capacity payments and the value was calculated according to the as-available payment schedule.

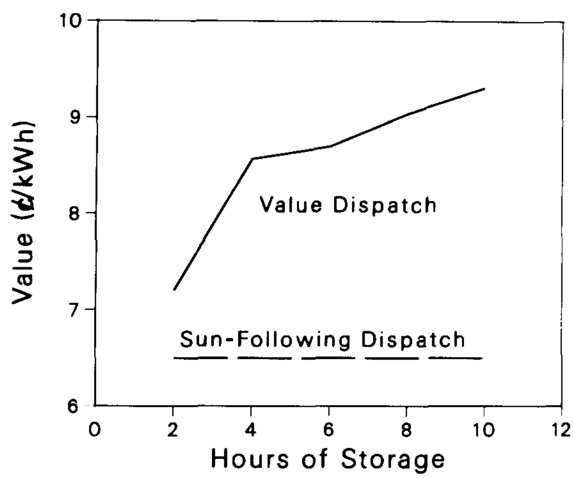


**Figure 4.4–2 Effect of Storage Size on Energy Value for a 100 $MW_e$ External Salt Receiver System for Two Alternate Dispatch Strategies. Value indicates a value-maximizing dispatch strategy.**

The optimum storage size, based on the maximum ratio of the ratio of the energy value and energy cost, is very broad and lies between 4 and 8 hours of storage. This is because adding additional storage above 4 hours (up to 8 hours total) increases the value at about the same rate as it increases the levelized energy cost. Regardless of the actual value, it is clear that in order to meet the peak period requirements and maximize the value/cost ratio, a storage size greater than the optimal "sun following" storage size will be required.

To determine the true optimum, a simulation using several years of weather data would be required.

**Effect of Plant Size.** The same analysis was repeated for 15.6 $MW_e$ and 200 $MW_e$ designs at a solar multiple of 1.2. At each power level the optimal amount of storage (hours of storage that maximizes the value/cost ratio) was determined: 8 hours for the 15.6 $MW_e$ design, 4 hours for the 100 $MW_e$ design, and 4 hours for the 200 $MW_e$ design. Figure 4.4–3 shows the levelized energy cost and first year value as a function of plant size. Levelized energy costs decrease with increasing plant electrical rating at a given solar multiple. In this case, the value also decreases slightly with increasing plant size. This occurs because large plant sizes have higher efficiencies, and hence, higher capacity factors for the same solar input. Higher capacity factor plants are able to put more energy on the grid, but a greater percentage of the output is dispatched during lower value periods. Thus, the value per $kWh_e$ is lower, but the total revenue per kilowatt of installed capacity is higher. These numerical results are specific to this study and are not generally applicable.

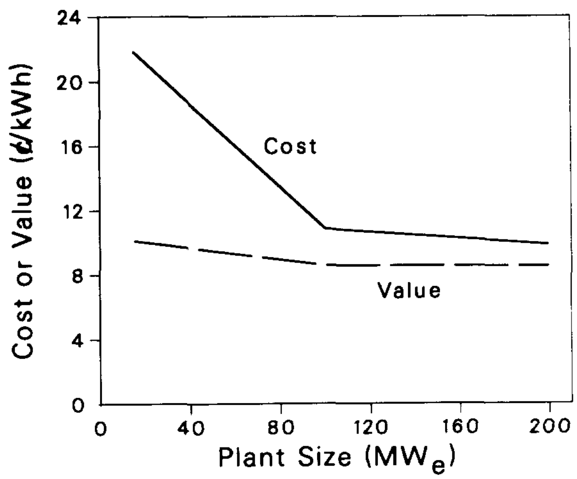


**Figure 4.4–3 Levelized Energy Cost and Value of an External Salt Receiver System Employing a Value-Maximizing Dispatch Strategy as a Function of Plant Size. (Calculation specific to 1984 Barstow weather and 1985 SCE standard offer.)**

**Conclusions.** The optimal design and operating strategy for a central receiver plant combines configuration and value maximization through the use of a selected dispatch strategy which in turn are dependent on the specific utility environment. To make an accurate determination of value, the evaluation must be done for each individual utility using local weather data and other conditions.

In general, for reasonable plant sizes, selection of solar multiple is determined by the value analysis, while selection of the plant rating is determined by the capital constraints of the builder or the need for new capacity. Once a plant is designed and built, the optimal dispatch strategy is the one that maximizes the energy revenue from the plant.

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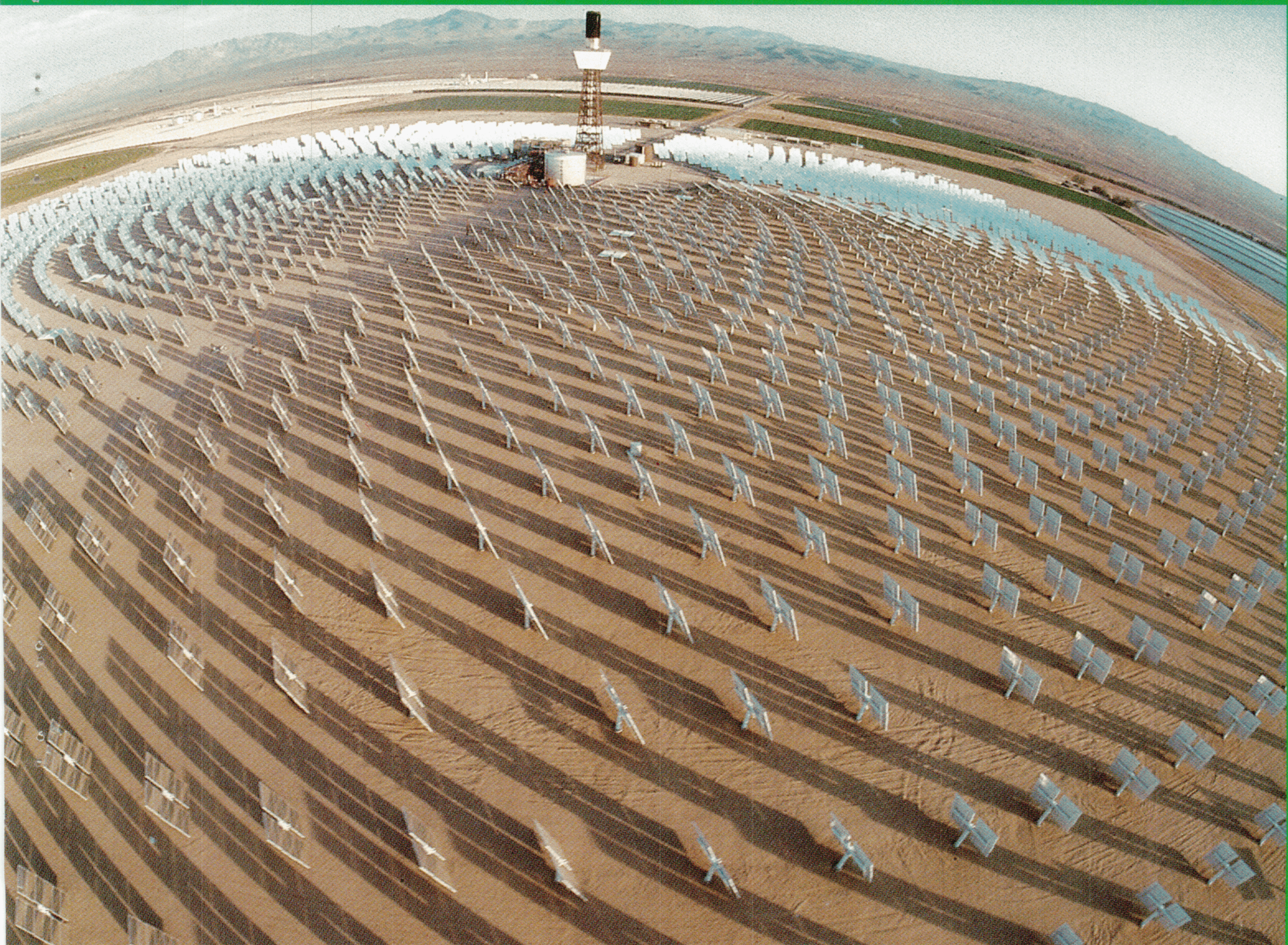
# DESIGN



*Upper: Photograph of Themis, located in Targasonne, France, characteristic of a central receiver system employing a north field configuration and a cavity receiver.*

*Lower: Solar One, located near Barstow, Ca, USA, characteristic of a central receiver system employing a surround field configuration and an external, cylindrical receiver.*

# DESIGN

The design and construction process for a solar thermal central receiver power plant is similar to the process used for fossil-fueled power plants. Two basic approaches are used for design and construction of power plants in the utility industry. One is the turnkey approach which employs a single engineer/constructor who has complete responsibility for design, procurement, construction and startup with minimal owner involvement. The other approach is the multiple contract approach which involves a designer/construction manager and one or more construction contractors. In this latter approach, the designer/-construction manager works with the utility throughout the design and construction process. Regardless of who performs the various functions, the design and construction process includes the same basic steps.

## DESIGN

The design of a solar power plant involves an interactive process in which the level of detail is refined in each of several phases. These design phases include conceptual design, preliminary design, detailed design, licensing, and procurement. System integration is a continuing function, irrespective of design phase. It is important clear through construction. The design phases are not successive steps; some phases overlap other phases and some proceed concurrently. In addition, there is a high degree of information exchange among the various design phases.

**Conceptual and Preliminary Design.** There is not general agreement on the precise definition of the conceptual and preliminary design phases within the utility industry; however, they typically involve selection of the plant size, site and site arrangement, identification of the major pieces of equipment and systems, and specification of applicable codes and standards.

Typically though, the utility specifies the nominal plant output rating and type of operation — whether for base-load, cycling, or peaking service — based upon results of utility generation expansion studies. Further refinement of the output rating may occur during the conceptual design phase based on turbine studies undertaken by the designer. For central receiver plants, the utility is also likely to specify the receiver and storage media to be used and the possible addition of a fossil hybrid arrangement.

The next step in the design process is to identify the key characteristics of the plant, including identification of system configurations and major pieces of equipment. This effort involves several types of analysis because the goal of the design process is to develop a design which is cost effective; that is, the plant should provide the intended generation level efficiently, with high reliability and low operating and maintenance cost, while having the lowest possible total cost.

As described in the previous chapter, compromises must be made among these characteristics. For example, increases in plant reliability usually require higher capital and/or operating and maintenance costs. Tradeoff studies are conducted to identify the plant characteristics which provide a balance of the most desirable qualities. These characteristics may include the energy storage capacity, fossil hybridization capability, and receiver and heliostat field configuration. Other studies are conducted in order to determine such factors as turbine throttle steam conditions, type of boiler feed pumps, number of feedwater heaters, allowable steam generator salt or sodium temperatures, reheat or nonreheat turbine, and type of heat rejection.

Site selection should be completed early in the conceptual design phase since site features may affect other conceptual work, such as site arrangement. As discussed in Chapter 3, the site selected must allow for major plant requirements such as land area, water quantities, insolation levels, and transmission interfaces.

Major structures are laid out on the selected site relative to one another. The site arrangement is based on structure size and orientation, piping and electrical interconnections among the structures, and geographical limitations of the site. Site arrangement is further refined when, after equipment procurement, additional structures or other modifications may be required. Information about exact dimensions, erection requirements, and environmental needs often is available only after specific equipment is purchased during the procurement phase.

To facilitate the detailed design, the applicable codes and standards that govern plant design are identified. No codes or standards unique to solar thermal central receivers have been established. However, many codes and standards which apply to structures, mechanical systems, and electrical systems in fossil-fueled power plants are applicable to the same components in solar thermal central receiver plants. Table 5–1 lists the issuing organizations of major Federal codes and standards. The complete list of codes and standards for a particular plant will also include local and state codes.

The systems that comprise the power plant are identified and defined in the preliminary design. This is accomplished by dividing the plant into unique categories, and subdividing each category into systems. For each system, the function, interfaces with other systems, and requirements for key components are described. This systems approach to design is a proven method for configuration control; in addition, it facilitates orderly construction, checkout and startup of the plant.

**Licensing.** Federal, state and local laws require licensing and environmental studies before the construction of power plants can begin. Table 5–2 includes a list of potential licensing requirements for a solar thermal central receiver power plant.

The licensing process typically follows preliminary design because the principal plant characteristics must be known before the environmental impacts of the plant can be assessed properly. Moreover, utility investors and constructors are reluctant to commit significant amounts of money without assurance that the licensing requirements will be satisfied.

**Procurement.** Procurement begins during the conceptual design phase and continues through most of the detailed design phase. The procurement and detailed design phases are interrelated.

Table 5-1

ISSUING ORGANIZATIONS OF MAJOR FEDERAL CODES AND STANDARDS FOR UTILITY POWER PLANTS

**Structural**

| | |
|---|---|
| ACI | American Concrete Institute |
| AISC | American Institute of Steel Construction |
| AISI | American Iron and Steel Institute |
| ANSI | American National Standards Institute |
| ASTM | American Society for Testing and Materials |
| AWS | American Welding Society |
| CRSI | Concrete Reinforcing Steel Institute |
| NAAMM | National Association of Architectural Metals Manufacturers |
| NACE | National Association for Corrosion Engineers |
| OSHA | Occupational Safety and Health Act |
| PCI | Prestressed Concrete Institute |
| SSPC | Steel Structures Painting Council |
| UBC | Uniform Building Code |

**Electrical**

| | |
|---|---|
| AFBMA | The Anti-Friction Bearings Manufacturers Association |
| ANSI | American National Standards Institute, Inc. |
| ASTM | American Society for Testing and Materials |
| EEI | Edison Electric Institute |
| ICEA | Insulated Cable Engineers Association |
| IEEE | The Institute of Electrical and Electronics Engineers, Inc. |
| IES | Illuminating Engineering Society |
| NEC | National Electrical Code |
| NEMA | National Electrical Manufacturer's Association |
| NESC | National Electrical Safety Code |
| NFPA | National Fire Protection Association |
| OSHA | Occupational Safety and Health Act |
| UL | Underwriters Laboratory, Inc. |

**Mechanical**

| | |
|---|---|
| AFBMA | The Anti-Friction Bearings Manufacturers Association |
| AGMA | American Gear Manufacturers Association |
| AISC | American Institute of Steel Construction |
| AMCA | Air Moving and Conditioning Association |
| ANSI | American National Standards Institute, Inc. |
| API | American Petroleum Institute |
| ASHRAE | American Society of Heating, Refrigerating and Air-Conditioning Engineers |
| ASME | American Society of Mechanical Engineers |
| ASTM | American Society for Testing and Materials |
| AWS | American Welding Society |
| AWWA | American Water Works Association |
| EEI | Edison Electric Institute |
| HEI | Heat Exchange Institute |
| HI | Hydraulic Instutute |
| IGCI | Industrial Gas Cleaning Institute |
| ISA | Instrument Society of America |
| MSS | Manufacturers Standardization Society of the Valve and Fitting Industry, Inc. |
| NFPA | National Fire Protection Association |
| OSHA | Occupational Safety and Health Act |
| PFI | Pipe Fabrication Institute |
| SSPC | Steel Structures Painting Council |
| TEMA | Tubular Exchanger Manufacturers Association |
| UL | Underwriters' Laboratory, Inc. |

**Control**

| | |
|---|---|
| ANSI | American National Standards Institute, Inc. |
| ASME | American Society of Mechanical Engineers |
| IEEE | The Institute of Electrical and Electronics Engineers, Inc. |
| ISA | Instrument Society of America |
| NEMA | National Electrical Manufacturer's Association |
| NESC | National Electrical Safety Code |
| NFPA | National Fire Protection Association |
| SAMA | Scientific Apparatus Makers Association |

Table 5 2

LEGAL AND REGULATORY LICENSING REQUIREMENTS

| Government Agency | Jurisdiction | Requirements |
|---|---|---|
| **Federal** | | |
| Environmental Protection Agency | Air Quality<br>Water Quality<br>Hazardous Waste | EIS review<br>Wastewater treatment<br>Flue gas treatment |
| Occupational Safety and Health Adminstration | Health and Safety | Noise, light, and general working conditions in and around plant |
| Bureau of Land Management | BLM Lands | Management plans and right-of-way permits |
| Federal Aviation | Airspace | Permit and lights for towers over 200 ft |
| Corps of Engineers | Navigable Waters and Waters of the U.S. | Dredge and fill permits, EIS review, and Permits for construction in navigable waters |
| **State** | | |
| Public Utilities Commission | Utilities | Public convenience certification |
| Energy and Environment Commissions | Energy Development, Environment Impacts | Notice of intent<br>Power plant certification |
| Solid Waste Management | Solid Wate | Permit for waste disposal |
| Water Resources | State Waters | Permit to appropriate water |
| Lands Commission | State Lands | Permit or lease for state lands and right-of-way |
| Health Department | Occupied Structures | Certification of buildings for handicapped person access (applicable if structure receives state funds) |
| Air Quality Management | Air Quality | New source performance review, prevention of significant deterioration, determine best available control technology, and permit to construct and operate. |
| Water Quality Management | Water Quality | National pollution discharge elimination system. Water quality certification. |
| **Local and Regional** | | |
| County | Licensing<br>Zoning<br>Compliance | Rezoning and use permits |
| County and City | As Required | Right-of-way.<br>Building permit. |
| County Flood Control and Water Conservation District | Water Use | Water allocation. |

The sequence of equipment purchase is determined both by lead time and interface design information requirements. A long lead time analysis should be conducted to identify the appropriate lead times for equipment. This analysis looks not only at the time required to design and fabricate a particular item but also when it is required on-site to support the overall construction schedule.

Long lead time items are often large, one-of-a kind pieces of equipment. In a fossil plant design, the steam generator and turbine generator are among the first two pieces of equipment purchased. In a solar central receiver power plant, these same pieces of equipment as well as the heliostats and the solar receiver should be purchased first. While the solar steam generator is less complex and its lead time is shorter than that for a fossil-fueled steam generator, considerable design information is required from the steam generator manufacturer before other major pieces of equipment can be purchased.

For a central receiver system, a procurement lead time analysis will likely indicate that one of the first items to be procured will be heliostats, not because they must be installed first but because specific heliostat cost and performance information is required for receiver procurement. The heliostat purchase contract would include a specified mirror surface area, based on preliminary design analyses, with unit price adjustments.

Using this procurement strategy, next to be purchased is the receiver which would have to deliver a specified level of thermal output based on the heliostats already purchased. The receiver manufacturer would lay out the heliostat field, identify the exact mirror surface area required, develop the heliostat aiming strategy, and establish the height of the receiver tower to meet the receiver performance specification.

This strategy, different from the one employed for Solar One and the recent Carissa Plains design, is attractive to both architectural and engineering firms who would likely integrate the design and construction, and to receiver designers. It gives the receiver supplier sufficient knowledge and control over the receiver's operating environment so that a receiver warranty can be provided. The evaluation of bids from receiver manufacturers should include evaluation of the receiver cost itself as well as the cost impacts of the receiver on the heliostat field cost (through the unit price adjustment), tower costs, and other significant plant costs. The engineer/system designer would analyze the results submitted in the receiver proposal based on total plant cost and performance before recommending a preferred receiver supplier.

The specifications and documents used for procurement of equipment and materials integrate the intent of the design and utility industry standards with an understanding of manufacturers' capabilities. Thus, in many cases, procurement packages do not correlate directly with the plant design systems. For example, the group of manufacturers who supply a certain type of valve would be asked to bid on all valves of that type regardless of the system in which the valves are located.

Procurement of plant components must include careful documentation of the expected operating environment. Such documentation insures that proposed hardware is reviewed from the standpoint of cyclic operation and that suppliers can be held accountable for component performance.

**Detailed Design.** Procurement and detailed design are closely integrated and interdependent. The detailed design evolves through a series of modifications, additions, and deletions to the preliminary design. The changes are the results of equipment information received from manufacturers, detailed studies not previously completed, and careful consideration of system operation and the effects on interfacing systems.

Detailed design includes preparation of specifications of purchased equipment, construction drawings and component lists to allow the construction contractor to build the power plant, and operating instructions to allow the utility to start up and run the plant. All these documents are generated by the designer and are subject to considerable review, checking, and analysis before being issued for construction.

## CONSTRUCTION

Constuction is managed through use of a detailed construction plan and schedule. Cost and quality are also controlled by means of well-developed and rigidly enforced procedures.

Like procurement, construction interacts with design. This is particularly true when the contractor is furnishing certain equipment and materials. However, this interaction also applies to design work performed by the constructor. In this case, the design engineer and constructor must exchange information and insure that interfaces are properly coordinated. Firms differ in the amount of design performed by the design engineer and by the constructor; however, the importance of coordinating the effort is the same.

**Definition of Work Packages.** Construction of any power plant requires the contributions of many construction specialists. Some utilities prefer to work directly with a single prime construction contractor who is responsible for managing the work of several specialist construction contractors; others prefer to work with multiple prime construction contractors and an independent construction manager. The scope of the work packages in the construction specification(s) depends primarily on the utility's preference; however, in some cases, the construction schedule, resource availability, and extent of design completion dictates the number and scope of construction work packages. In any case, construction specifications will not necessarily correlate with the systems used in the design process.

**Construction Activities.** The construction work packages identify activities which follow a logical sequence. Sequencing includes consideration of safety, optimization of resource utilization, cost effectiveness and quality control. The scoping and sequencing of work packages places great importance on the safety of the construction labor force as well as plant operating and maintenance personnel.

The critical construction path for a central receiver plant involves the tower and receiver since their construction is a result of a long serial sequence of activities starting with the tower foundation and ending with the installation of the receiver on top of the tower along with the necessary piping and plant service systems required at the top of the tower.

Due to the highly repetitive aspect of the collector field construction, innovative time saving construction techniques should be employed on the heliostat foundation and wiring installation as well as final heliostat placement and activation.

**Checkout and Startup.** Upon arrival at the construction site, each piece of equipment is inspected to insure that it is as specified and undamaged. Following installation, the equipment is checked again to make sure it was installed properly. After all the equipment in a system is installed, that system is tested for proper operation. When all systems have demonstrated proper operation, to the extent that is possible, on a system by system basis, the entire plant is brought into operation. The plant is then operated over its entire load range and its performance is compared with the design requirements.

Collector field activation and checkout also involve a series of functional, tracking and optical verification tests which are required for each heliostat. These tests employ the beam characterization system described in Section 2.2.

Other unique solar plant startup issues include thermal curing of receiver paint and special leak check and inspection procedures before the filling of large storage tanks.

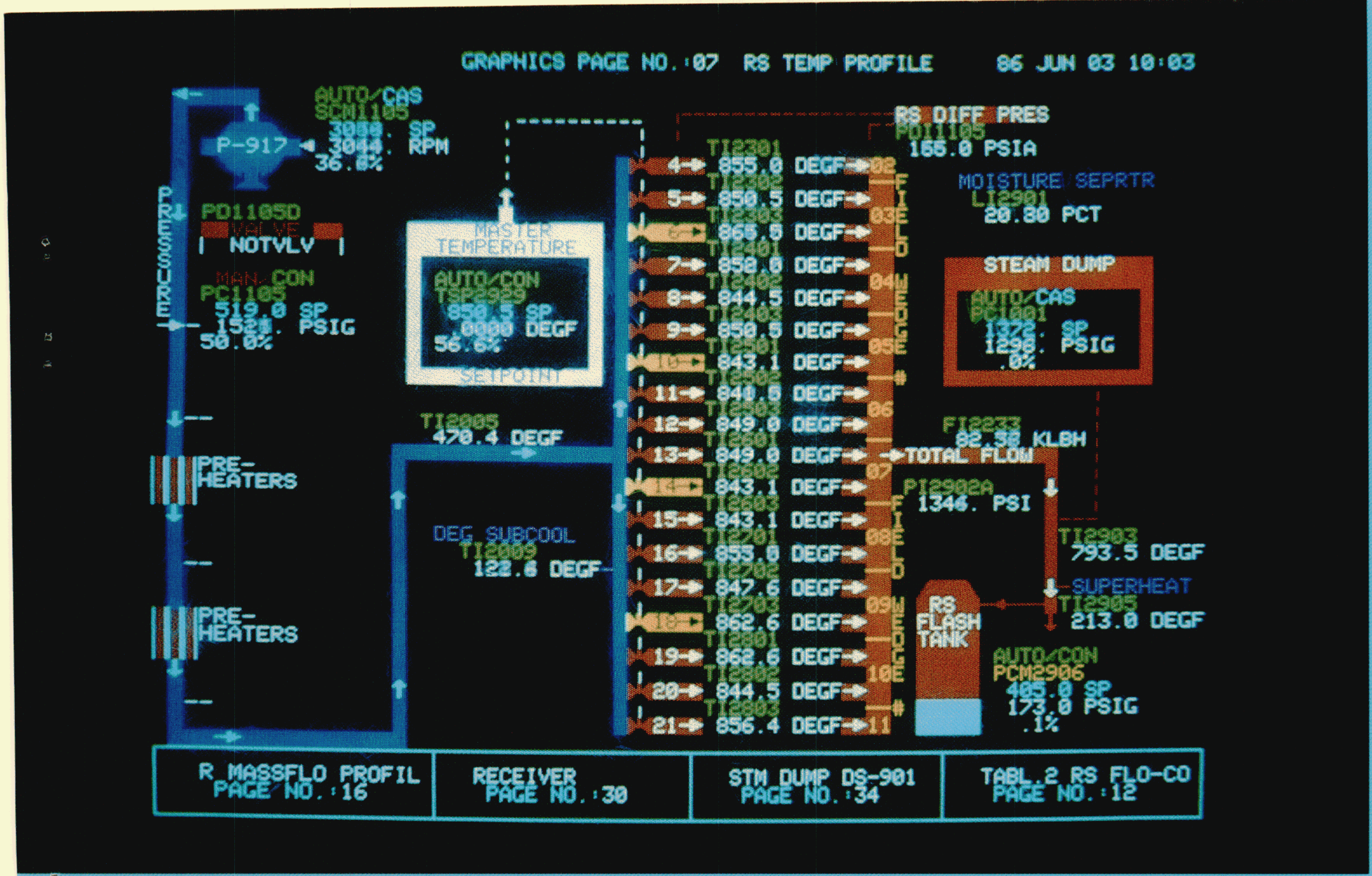
## SCHEDULE

The length of time required to design and construct a power plant depends upon the plant rating, the licensing climate in the area which has jurisdiction over the plant, and the state of the equipment and construction markets.

Utility industry experience indicates that about six to six and one half years are required to design and construct a 650 MW coal fueled power plant. This time decreases to five years for a 200 MW coal fueled plant. Recently, through the use of standard reference plant designs, these times are being reduced to about four years, not counting licensing. By using the reference plant design approach, preliminary design and significant portions of procurement and detailed design specifications are available before the project begins. Nuclear plants, because of the licensing climate, may take eight to twelve years from preliminary design through construction.

For solar thermal central receiver power plants, it is anticipated that the time required to design and construct a plant would be about five years, including licensing. The length of time will be reduced with experience and the evaluation of standard plant designs.

The greatest uncertainty in this schedule is the time required for licensing. Because solar plants have fewer adverse environmental impacts than do fossil-fueled or nuclear plants, the time required for licensing is estimated to be about 12 to 18 months for a new, stand-alone solar thermal central receiver power plant.



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PRE-HEATERS
R MASSFLO PROFIL PAGE NO.:16
RECEIVER PAGE NO.:30
STM DUMP DS-901 PAGE NO.:34
TABL.2 RS FLO-CO PAGE NO.:12


# OPERATION

*Upper: Graphics display page from Solar One Subsystem Distributed Process Controller. Display indicates operational status of the receiver subsystem. As indicated, the receiver is operating and steam at roughly 800°F and 1350 psi is being produced. Conditions for individual receiver panels are displayed.*

*Lower: Collector system control console in the Solar One control room. Control system employs advanced digital electronics.*

# OPERATION

Operation, maintenance and reliability information which can be used to plan and predict operation and maintenance functions associated with solar central receiver plants is presented in this chapter. Key elements discussed include operating characteristics, plant parasitic requirements, maintenance, and reliability and availability.

A plant operations and maintenance plan has the goal of insuring high plant availability with minimum life cycle cost. Operations and maintenance considerations must be a part of the design process and the plan must be developed in concert with system and subsystem design and include scheduled replacement or refurbishment.

The information in this chapter is principally derived from operating experience at Solar One[1] and analysis of the performance of the planned Solar 100 plant.[2,3] Although Solar 100 was designed to use molten nitrate salt as both the receiver fluid and the storage fluid, information should be generally applicable to sodium plants as well.

## OPERATION

**Solar One Experience.** Experience at Solar One has established the benefits of automating plant control functions. Plant automation, while reducing the manual interfaces, does not eliminate them entirely. Provisions for manual override are still required.

During its operation, Solar One successfully operated in all of its steady state operating modes. In addition, it moved to and from each steady state mode and demonstrated emergency shutdowns.

Solar One demonstrated that cyclic operation is an important consideration in the requirements specification, design, procurement, installation, and quality assurance for both the conventional plant equipment and the solar-unique equipment. Cyclic operation of Solar One has affected the lifetime and failure rates of pumps, valves, instrumentation, and piping in what are considered conventional power plant portions of the plant.[1,4]

**Operating Modes.** Operation of a solar central receiver plant normally occurs in a number of distinct operating modes.

A description of the principal operating modes envisioned for a specific commercial 100 $MW_e$ salt system, the *Solar 100* design,[2,3] follows.

The main operating modes for the energy collection portion of the plant are normal operation (including startup and shutdown), and warm or overnight hold. There is an additional nonoperating mode of cold shutdown.

**Normal Operation.** In this mode, salt is supplied to the receiver at about 290°C (550°F) with adequate pressure to maintain receiver flow and control. The salt flow is regulated by a bypass valve downstream of the receiver feed pumps. This valve adjusts the salt flow to maintain the salt level in the receiver inlet surge tank.

Three half-capacity receiver feed pumps are included in the Solar 100 design. The system runs on one pump at up to 50% rated flow and two pumps from 50 to 100%. One pump is kept in reserve. A receiver inlet surge tank serves as a buffer to protect the cold salt line and also provides a reservoir of salt. The salt flow through the receiver is regulated by control valves to maintain 565°C (1050°F) outlet temperature.

Receiver control uses outlet temperature feedback as the outer control loop. An inner control loop senses heat flux to provide rapid response feed-forward control under variable insolation conditions.

There are times such as in the early morning, late afternoon, or in hazy weather conditions when the energy redirected from the heliostat field is degraded. The control system is designed so that a minimum of 20% rated flow is maintained in each circuit under these low receiver power conditions. A bypass loop allows the lower temperature salt flow from the receiver to be diverted to the cold storage tank.

To generate electricity, the receiver fluid is supplied to the steam generator from storage at 565°C (1050°F). The steam generator produces primary steam at 540°C (1005°F) and 12.8 MPa (1850 psi) and reheat steam at 540°C (1005°F). The salt is returned to the warm tank at 290°C (550°F). Feedwater is supplied at 240°C (460°F).

During startup, the feedwater preheaters operate at a reduced temperature. Drum steam is fed to the final preheater to peg its temperature at 240°C (460°F). The steam generator must be started in advance of the anticipated turbine start time. To accomplish this efficiently, adequate thermal energy must be left in storage at the end of the preceding operating day.

Startup is initiated with one steam generator salt pump. Below 35% load, steam flow is controlled by the turbine throttle valve. Salt flow is adjusted to maintain drum pressure. The second pump starts when the salt flow rate approaches 50% of rated flow.

**Warm or Overnight Hold**. During periods of no insolation, such as nighttime or cloudy days, the energy collection system is put in an overnight hold mode. The receiver door, if there is one, is closed and the heliostats are stowed. Receiver fluid circulation is halted, and trace heaters are used on demand, or the receiver is drained.

The shutoff valves on both salt and steam sides isolate the superheater and reheater during shutdown. The temperature changes slowly, and these units do not require the use of trace heating.

The evaporator and preheater are isolated in the same way. The preheater requires almost immediate trace heating. The evaporator requires minimal trace heating depending on the duration of the hold. Evaporator drum pressure is monitored because heat contained in the salt at shutdown continues to make steam. When the steam generator undergoes rapid shutdown (no sliding pressure), steam is vented from the drum or steam is blown to the condenser.

Trace heating is required in the line from the preheater to the cold tank for overnight hold. Other major lines because of their thermal mass and insulation require trace heating only during extended shutdown. However, trace heating of valves in these lines is generally required.

**Other Operating Modes.** In addition to normal operation, maintenance and night stow, repositioning of the whole field or individual heliostats must be accomplished in high winds and in the event of emergencies such as failure of the receiver fluid control system. Beam safety is a major consideration during this period with individual heliostat motion controlled in a manner that precludes concentrated beams on the ground, or the unprotected tower structure, or above the clearout air space over the plant.

## PLANT PARASITICS

Operation of a central receiver power plant in its various modes requires the expenditure of energy often referred to as parasitic power. Plant parasitics are lost revenue and are, therefore, directly related to life cycle cost.

A solar central receiver plant has all of the parasitic loads associated with a conventional plant with the exception of those associated with the boiler equipment. In addition, the solar portion of the plant requires parasitic power associated with the operation of solar-unique equipment. In general, the parasitic requirements of the conventional equipment are the dominant factor in determining total loads.

In the operation of a solar central receiver plant, it is important to remember that parasitic loads are a 24-hour per day concern. They must be minimized during both operating and non-operating periods. Parasitic loads are dominated by large rotating equipment (pumps, fans, and compressors) and by electrical heating equipment. Because of this consideration and the significant amount of time in off-design operation, rotating hardware should be carefully designed. The use of half-size parallel equipment or efficient variable speed drive equipment may be justified.

Thermal energy lost from the system is a hidden parasitic power penalty. Thermal losses can be reduced by minimizing flows of hot fluids during non-operational periods, maintaining insulation and lagging in good condition, repairing internal and external leaks promptly, and minimizing startup delays.

Current local weather data should be used to decide when or if the plant should be started on cloudy or partly cloudy days. Aborted startup attempts consume significant amounts of parasitic power.

In all solar plants, power must be supplied to the collector field and thermal storage subsystems. Turning off the collector field power at night has not proven to be effective because of low collector field power consumption and concerns about cycling power to the field electronics.

For water/steam systems, the power requirements associated with the receiver are minimal as the feedwater pumps are primarily sized by the Rankine cycle requirements. For salt or sodium systems, the receiver feed pump requirements, although significant, represent only a portion of the solar specific parasitics.

The steam generator hot fluid feed pumps contribute substantially to the total load. Even though the design point requirements for these pumps are usually lower than the receiver feed pumps, their duty cycle is a function of turbine operation time. In storage coupled systems, these pumps tend to operate at design point most of the time.

The steam generator total parasitic load usually exceeds the receiver feed pump requirements because the receiver only operates at about one-half design flow rate on the average. The duration of the receiver duty cycle is directly related to hours of sunshine; the turbine operation time is usually longer than the receiver run time because of storage.

The cyclic operation of a solar plant contributes to the overall parasitic requirements. The need for trace heating during overnight shutdown can be costly. However, operational procedures can be devised which minimize these requirements, such as the draining of certain components.

Procedures must be reviewed for the overnight shutdown of the turbine and steam related equipment. The standard utility practice of maintaining a vacuum in the condenser and supplying steam blanketing for the turbine can get costly when done on a nightly basis.

At Solar One, breaking the condenser vacuum at night would shut down many plant systems including the auxiliary steam system, vacuum system, condensate system, circulating water system, and cooling tower system. This approach resulted in dramatic reductions in parasitic power demand with little penalty for startup the next day.

To accurately estimate parasitic requirements for a plant, the plant duty cycle must be estimated. Much of the conventional equipment and the steam generator duty cycles are related to turbine run time. Other equipment operates only when solar energy is available. A conservative duty cycle for parasitic power calculation assumes that this equipment operates from sunup to sundown on every average operating day.

Operational assumptions must be made to estimate the parasitics during times when portions or all of the equipment is shut down. These requirements can differ depending on the duration of the shutdown: overnight, all day, or several days of non-operation.

Estimates of the parasitic requirements for the Solar 100 power plant made by McDonnell Douglas are shown in Table 6–1 in terms of power (kW). This molten salt design was modular and includes two fields, towers and cavity receivers coupled with a single electric generating system rated at 100 $MW_e$. The plant, designed but never built, was to have been located in the Southern California Edison territory in the Lucerne Valley. The values are given for design point, average, and shutdown operating times for each of the subsystems and components. The field, receiver, and lighting loads are related to the number of daylight hours. The steam generator, turbine equipment, and miscellaneous are related to turbine run-time. Other balance of plant equipment runs continuously. Trace heat is on demand, but is related to the number of evening hours.

Figures 6–1 through 6–4 show operation time lines during normal sunny day operation of the Solar 100 plant as estimated by McDonnell Douglas for four different times of the year. Receiver output, thermal storage input (output), and turbine output are shown above the timeline. Parasitic loads are shown as step functions below the line. Major equipment on and off times are also identified. These plots are somewhat idealistic since they indicate rapid

Table 6-1

PLANT AUXILIARY POWER REQUIREMENTS[1]
ESTIMATED FOR THE SOLAR 100 PLANT

| System | 110 $MW_e$ gross guarantee point | Average value used during operation | Overnight and short shutdown | Extended shutdown |
|---|---|---|---|---|
| Field | | | | |
| Normal tracking | 342[2] | 342[2] | 0 | 0 |
| Unstow/stow (kWh/day) | (262) | (262) | 0 | 0 |
| Receiver | | | | |
| Pumps | 3306 | 1760 | 0 | 0 |
| Trace heating | 0 | 0 | 75 (wings[3])<br>1000 (cavity[3]) | 0 |
| Steam Generator | | | | |
| Pumps | 1091 | 1091 | 0 | 0 |
| Trace heating | 0 | 0 | 117[1] | 0 |
| Turbine Generator Pumps | | | | |
| Feedwater | 2040 | 2040 | 0 | 0 |
| Hot well | 124 | 124 | 0 | 0 |
| Circ. water | 1021 | 1021 | 0 | 0 |
| Cond. vac | 51 | 51 | 51 | 0 |
| Cool twr make-up | 38 | 38 | 0 | 0 |
| Circ. boost | 61 | 61 | 50 | 0 |
| Equip. cooling | 20 | 20 | 30 | 0 |
| Cooling Tower Fans | 398 | 398 | 0 | 0 |
| BOP Misc. Equip. | | | | |
| Air comp | 29 | 29 | 29 | 29 |
| Trac heating | 0 | 0 | 433[3] | 50 |
| HVAC | 607 | 303 | 303 | 303 |
| Lighting | 50 | 50 | 300 | 50 and 300 |
| Misc. | 100 | 100 | 200 | 100 |
| Plant Control | 110 | 110 | 110 | 110 |
| Total Auxiliary Power Requirements | 9388 | 7538 | 2698 (max) | 892 (max) |

[1] All values are given in $kW_e$ unless otherwise noted

[2] Includes heliostat controller (HCs) and all other control electronics in plant control

[3] Intermittent use

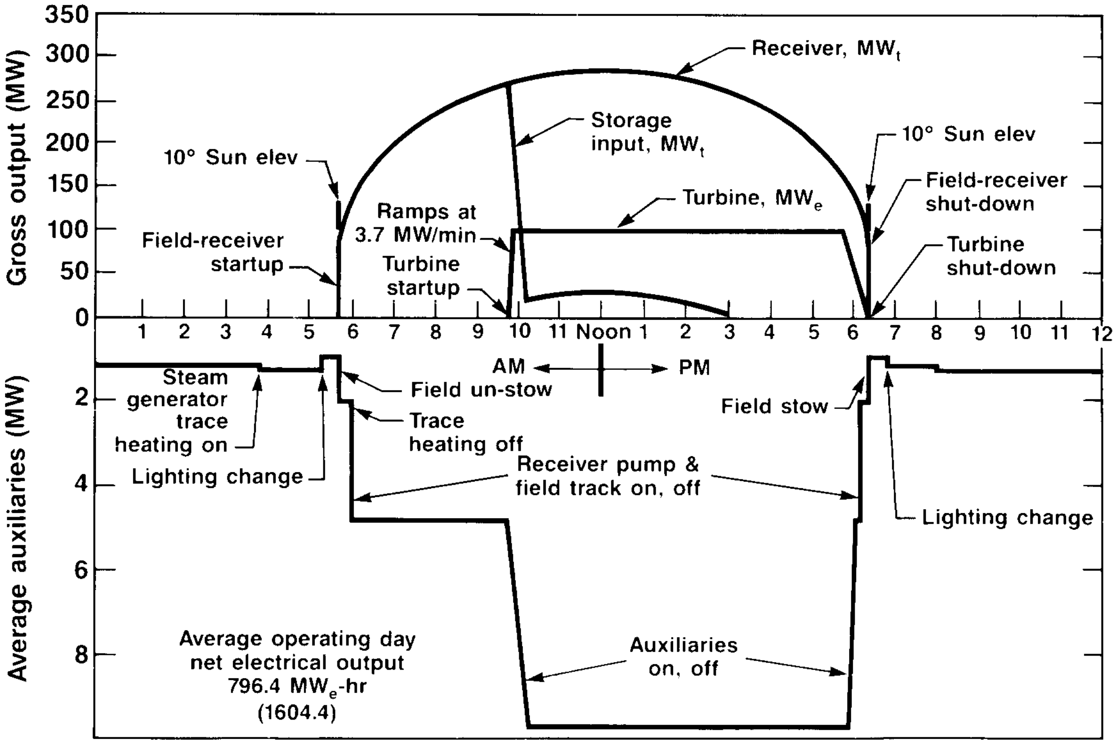


**Figure 6–1 Sample Operation Time Line, Estimated for the Solar 100 Plant, Summer Solstice**

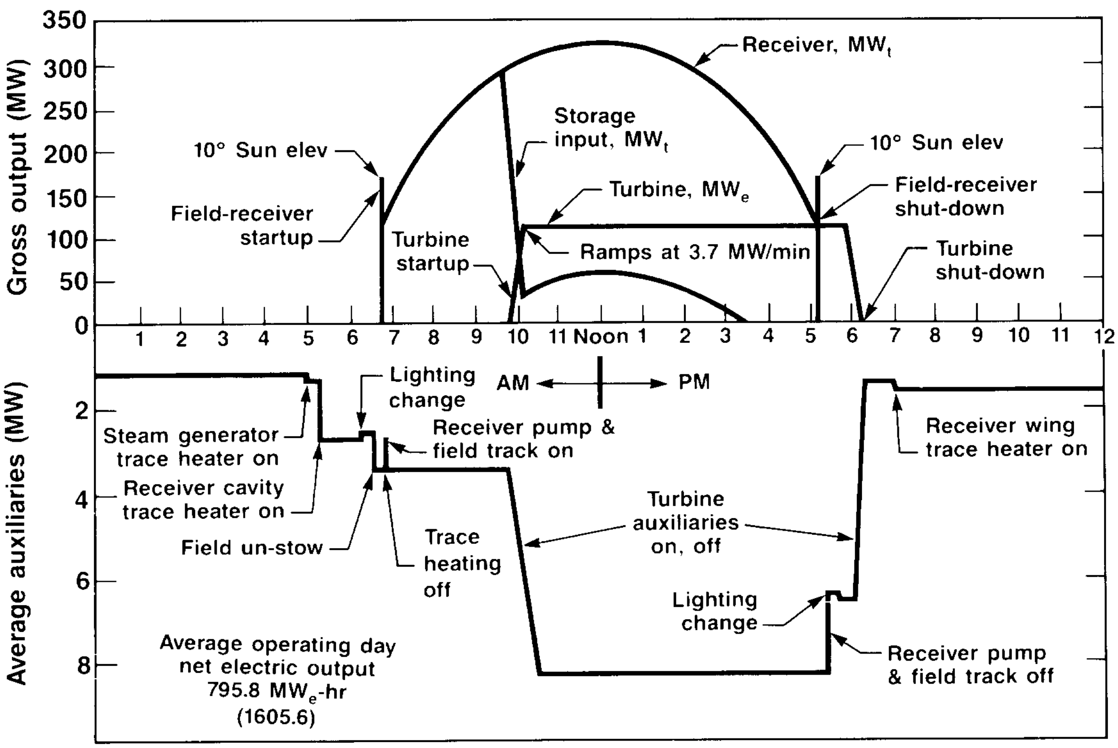


**Figure 6–2 Sample Operation Time Line, Estimated for the Solar 100 Plant, Fall Equinox**

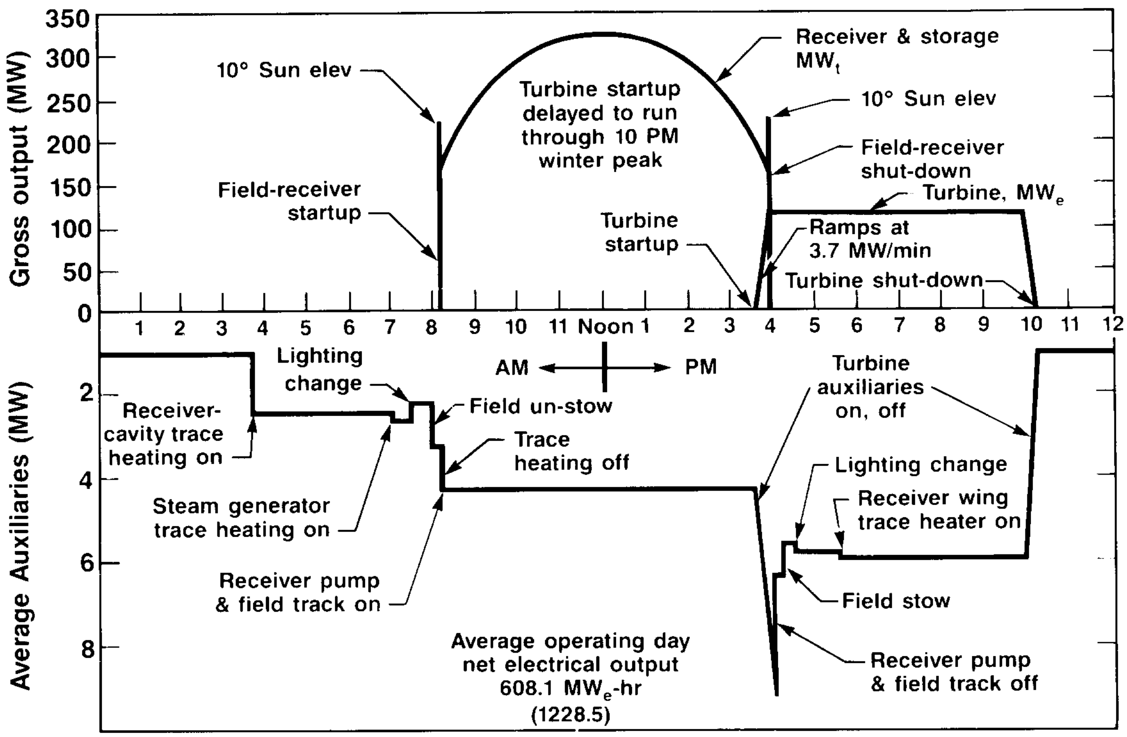


**Figure 6–3 Sample Operation Time Line, Estimated for the Solar 100 Plant, Winter Solstice**

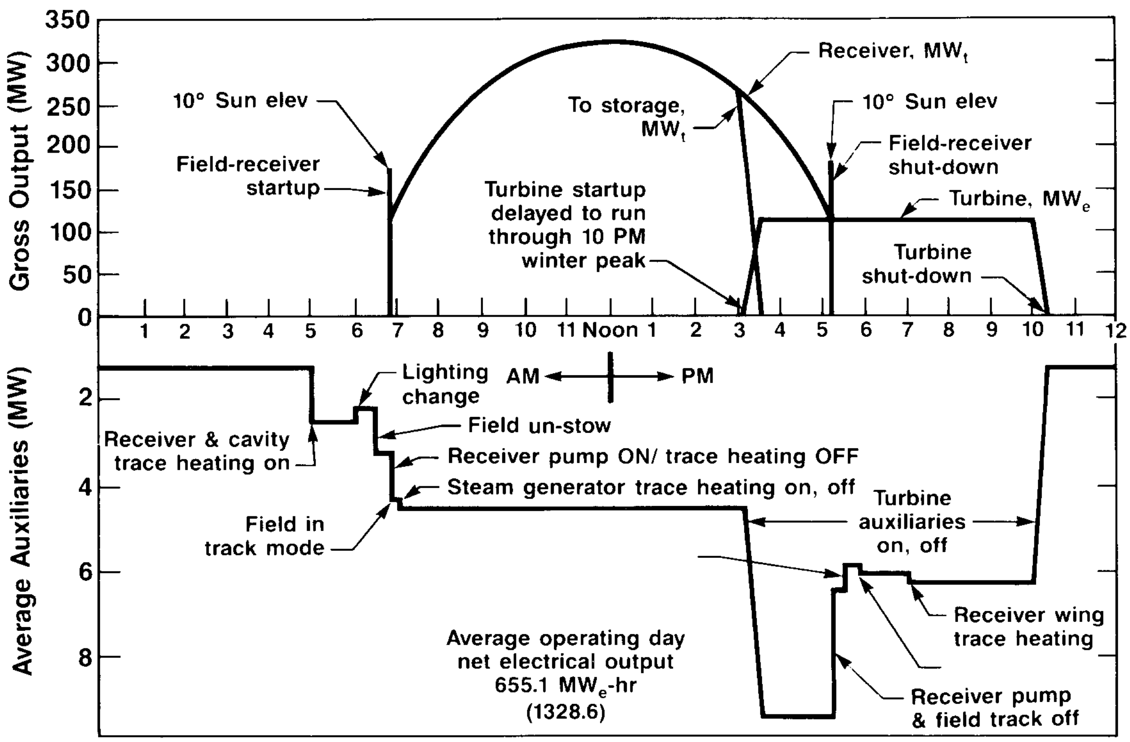


**Figure 6–4 Sample Operation Time Line, Estimated for the Solar 100 Plant, Spring Equinox**

switching of major plant systems in a highly efficient manner; however, they indicate the general effects and trends.

Figures 6–3 and 6–4 show that the turbine startup was delayed until sundown in one case and slightly before sundown in the other. This was done in order to provide power from the plant during the evening peak demand period (5 pm to 10 pm). During the spring equinox, the turbine was started before sunset because thermal storage was filled to capacity.

Because parasitic power requirements are directly related to solar availability, the amount, as a percentage of gross turbine output, varies throughout the year. Table 6–2 lists the estimated parasitic loads of the Solar 100 plant as a percentage of gross electric output for each month. The relative amount of parasitics is less in the summer and increases during the winter months. During the summer, plant output is at a maximum and non-operating time is at a minimum. The converse is true for the winter months.

Table 6–2

RELATIVE MONTHLY PARASITIC LOADS ESTIMATED FOR THE SOLAR 100 PLANT

| Month | Parasitic as a Percent of Gross Electric Output |
|---|---|
| January | 16.7 |
| February | 13.9 |
| March | 12.8 |
| April | 11.6 |
| May | 11.4 |
| June | 10.5 |
| July | 10.6 |
| August | 10.5 |
| September | 10.4 |
| October | 11.0 |
| November | 12.2 |
| December | 13.1 |

## MAINTENANCE

Because of the planned 30-year plant operating life for utility central receiver plants, maintenance is a key element of plant life cycle cost.

The information provided in this section reflects Southern California Edison's operation and maintenance philosophy developed for their fossil-fuel-fired plants and carried over into the operation of Solar One. Plant owners with different approaches to operations and maintenance can use the information to support their own analysis and planning.

**Solar One Experience.** A major lesson learned at Solar One is the importance of heliostat washing. The buildup of dust and other materials on the mirror surface reduces the reflectivity and directly reduces plant output. A combination of spray and mechanical washing has been shown to provide the greatest benefit and is more cost effective than spray washing alone.[1]

At Solar One, the plant solar systems required a lower percentage of total plant maintenance labor and cost than anticipated. Relative maintenance costs by subsystem for Solar One are shown in Figure 6–5.[5] Labor for the solar systems required 45% of total plant maintenance labor hours and 39% of the total plant maintenance cost. The conventional systems in the plant required more maintenance labor and higher cost than expected. On balance, the total plant labor for all systems was near that expected, and total maintenance costs were very close to budget.

### Maintenance Categories

Maintenance activities generally occur in three groups. First at the equipment itself, removal or replacement or in place repair can occur. Second, repairs

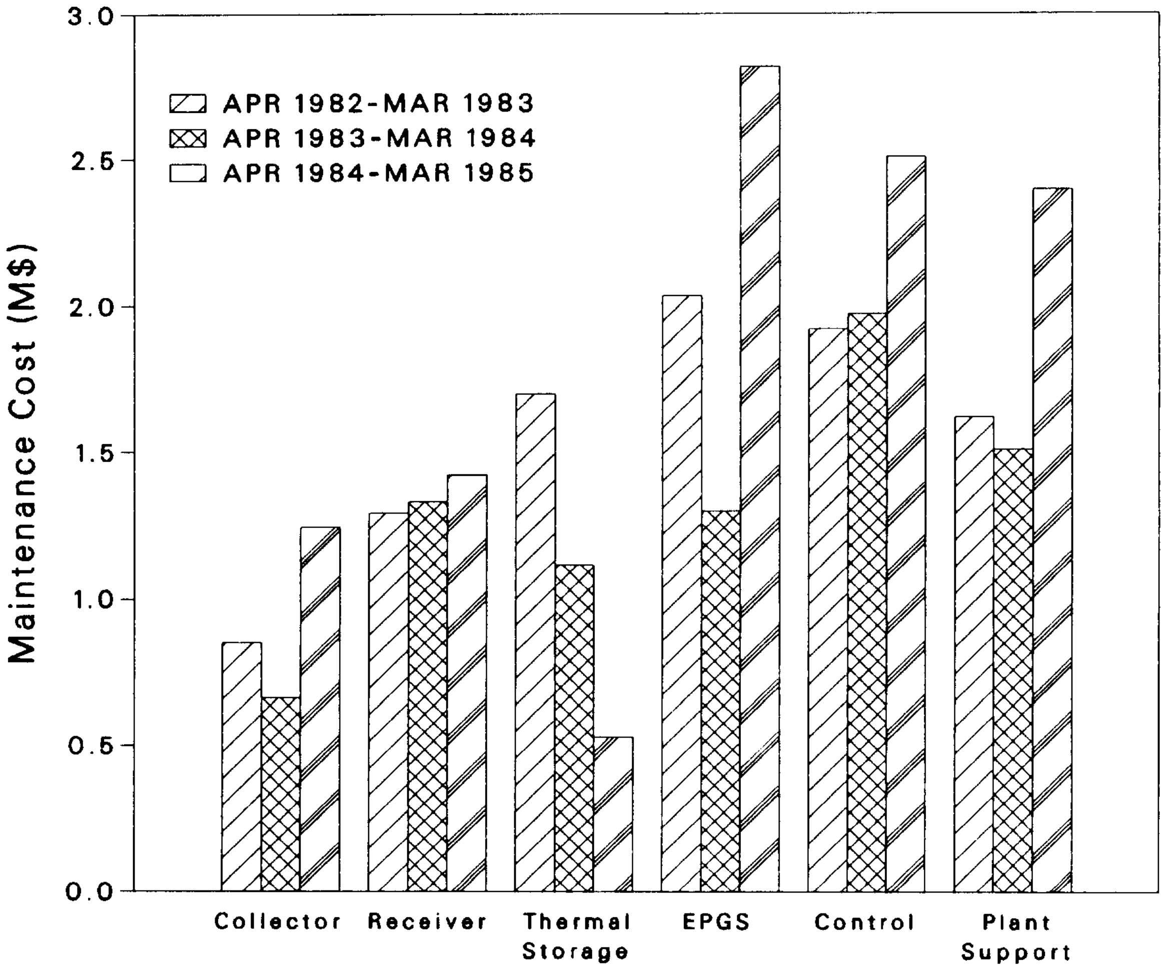


**Figure 6–5 Solar One Maintenance Cost by System**

can be performed at an on-site shop and third, an off-site shop can be employed for repair or overhaul.

Experienced personnel with normal power plant skills and knowledge should be used to staff the plant. Specialized training can be provided as needed. The need for special tools and test equipment and heavy motorized equipment should be minimized.

All maintenance functions performed on plant hardware, including support equipment, are categorized in one of three maintenance levels defined as follows:

*On-line*—Maintenance performed on plant equipment while installed in its operating location. This includes scheduled and unscheduled (corrective) actions required to inspect, service, calibrate, and isolate faults, replace components, repair in-place, and verify system operation.

*Off-line, On-site*—Maintenance performed on plant equipment subsequent to removal from its operating location or installed condition and accomplished in the plant maintenance and repair building. This includes disassembly, inspection, repair, service, calibration, reverification operation, and proof testing or load reverification.

*Off-site*—Maintenance performed on plant equipment at designated offsite locations; for example, at manufacturing facilities. It consists of maintenance that requires equipment, facilities, or skills which are not economical to establish at the plant maintenance facility. This includes repair, overhaul and rebuilding.

The basic field maintenance concept is to remove and replace failed functional assemblies.[6] For each item, actions required to remove and replace, the crew size, the time required to remove and replace spares and spare parts, and the support facilities and equipment must be defined.

**Corrective Maintenance.** Removal and replacement of a complete functional assembly implies that a spare item is available on-site to replace the failed item. The failed item is repaired, functionally tested, and returned to spares stock. Procedures must provide sufficient data to identify the failed item, system maintenance preparation (operational mode or status requirements), safety precautions, special replacement requirements, support equipment, and any servicing or functional test required following replacement.

In some cases, parts are replaced on-site. Examples include panel switches and indicators, electrical connectors, and valve packing, seats, poppets, or other internal parts. These spare parts are stocked on-site.

A standard repair process is employed for static mechanical, structural and other nonoperating components such as piping, support structures, electrical cables and wiring. Actions include welding or splicing in new sections, corrosion control, cleaning, refinishing and painting. Building materials and raw stock parts need to be stocked on-site.

Removal, repair and reinstallation is required for functional assemblies and other major items when in-place repair is not feasible and repair by replacement is not warranted due to high cost of replacement items.

Table 6–3 presents McDonnell Douglas estimates of the total corrective maintenance (not including scheduled maintenance) in man hours per year by major subsystems for a 100 MW solar plant operating at a 27% capacity factor (one module of the proposed Solar 100 project).

Table 6–3

CORRECTIVE MAINTENANCE ESTIMATED FOR THE SOLAR 100 PLANT

| System | Manhours/year |
|---|---|
| Collector | 3791 |
| Receiver | 61 |
| Steam generator | 40 |
| Thermal storage and transport | 40 |
| Electric Power generator | 198 |
| Balance of plant | 13 |
| Plant control | Service Contract |
| Total | 4143 |

**Scheduled Maintenance.** Scheduled maintenance is categorized as routine or planned outage. Routine scheduled maintenance includes inspection, servicing, cleaning, painting, calibrating, testing, and component replacement or change-out which can be accomplished during normal system operation or during daily non-operating periods (i.e., overnight).

Planned outage consists of the refurbishment or major overhaul of system equipment. System planned outages should be scheduled concurrently when possible and planned well in advance to reduce down time and assure availability of maintenance support equipment, replacement parts, bulk materials, and personnel.

Certain tasks may be amenable to being performed by outside maintenance organizations working under negotiated service contracts. The use of service contracts for these tasks can be preferable to establishing new skill classifications and incurring training and capital equipment expenses.

Maintenance performed in the plant maintenance and repair shop should essentially be limited to bench type repairs which can be accomplished with standard multi-purpose tools and test equipment. Maintenance beyond this capability should be accomplished off-site unless increased capability in the form of additional tools and test equipment is justified by cost considerations or technical reasons. Repair parts and bulk materials to support maintenance of components designed as on-site shop repairable must be stocked in the maintenance facility.

Plant equipment designated for off-site maintenance is repaired at existing utility maintenance facilities or a supplier manufacturing facility. Repaired or overhauled items should be subjected to the original product acceptance test or equivalent prior to returning to spares stock.

Table 6–4 lists the McDonnell Douglas estimates of the total scheduled maintenance by man hours per year and major subsystems for the same single module version of the planned Solar 100 plant.

**Plant Resources.** Support resources needed for a solar central receiver plant can be divided into spares and repair parts, documentation, training, special tools and test equipment, facilities and staff. These resources are described separately below.

*Spares and Repair Parts.* A preliminary spares analysis must be conducted based on the hardware configuration and the mean time to repair. Repairable functional assemblies, upon failure, are removed from the system, placed in the repair cycle, and subsequently returned to spare stock inventory.

Initial spares quantity for these items is the sum of the pipeline quantity and a contingency supply. If hardware production is ongoing, the quantity of spare parts purchased at startup should be minimized. Consumption of spares as the plant operates will soon reveal the real need. However, if production is over, enough spares estimated to support two years of operation should be purchased.

Under operating conditions, the quantity is based on the maximum number of items in the repair pipeline at any given time, calculated by using the failure rate and the projected repair cycle time. The initial spares quantity of non-repairable items (i.e., those discarded at failure) is set at the predicted number of failures per year plus a contingency quantity. The initial spares quantity should be stocked at the repair location when the first year of operation begins.

The discard factor represents the number of failures which result in an item being discarded instead of repaired.

Table 6 4

SCHEDULED MAINTENANCE
ESTIMATED FOR THE SOLAR 100 PLANT

| Item | Annual manhours | Remarks |
|---|---|---|
| Collector | | |
| - Heliostat corrosion/ Structural inspection | 125 | |
| - Wash heliostat reflectors | 12,000 | Reflector washing is an on-condition maintenance requirement. This is estimated to result in 12 washings per year |
| Receiver | | |
| - Corrosion structural Inspection | 82 | |
| - Receiver mounted crane | 14 | |
| Steam Generator | | |
| - Corrosion inspection | 44 | |
| Turbine/generator | | |
| - Oil check | 104 | |
| - Trip test | 16 | |
| - Stop valve check | 4 | |
| - Extraction check valve test | 12 | |
| Thermal Storage and Transport | | |
| - Salt pump checks | 110 | |
| - Salt storage tanks | 100 | |
| - Fluid maintenance | - | Service contract |
| Plant Control | | |
| - Control equipment | - | Service contract |
| - Auxiliary equipment | - | Service contract |
| Balance of Plant | | |
| - Water treatment system | 165 | |
| - Compresses air system | 165 | |
| - Cooling water system | 40 | |
| - HVAC | 40 | |
| - Chemical feed system | 165 | |
| - Chemical feed tanks | 104 | |
| Miscellaneous | | |
| - Pipe hangers | 215 | |
| - Heat tracing | 60 | |
| - Lifting devices | 144 | |
| - Portable control unit | 72 | |
| TOTAL | 13,781 | |

The product of the total number of failures per year and the discard factor equals the number of replacement items to be procured during subsequent years.

Table 6–5 shows estimates of spare parts by subsystem for both initial quantities and annual replacements made by McDonnell Douglas in their detailed design of Solar 100. These are specific to the design decisions made in that design effort but are representative of the needs of a commercial plant.

*Documentation.* Plant characteristics including physical configuration, performance, operating features and limitations, test data and requirements, must be provided to completely describe the system. Documentation should include a system description book, equipment data book, and drawings and diagrams. In addition to the station manuals, user's manuals should be provided which contain operating instructions and maintenance data.

Operational functions should be described in sufficient detail to permit development of overall system operating manuals. Sufficient data must be provided so that a skilled and knowledgeable technician can maintain plant functions.

*Training.* Training should concentrate on the tasks, skills, and knowledge that utility operational and maintenance personnel need to operate and maintain the solar systems in the plant safely and effectively. It is anticipated that most of the training would be conducted at the solar plant site; however, it may be necessary to have some portions of the instruction conducted at off-site locations such as at equipment supplier facilities.

Courses for solar plant personnel might include solar equipment orientation, control room operations, plant equipment operations, electrical/electronic equipment maintenance.

*Special Tools and Test Equipment.* In addition to the traditional power plant support equipment such as welding, flushing, water conditioning and mobile lifting and hoisting equipment, the solar plant will require equipment and tools unique to the collector system.

*Facilities.* In order to support collector field maintenance, additional onsite facilities will be required for storage of maintenance support spares and for repair. In addition to usual utilities, this area should be furnished with parts, racks, and bins and a loading dock.

The facilities needed to house and support the collector repair activities are determined by both the nature and the frequency of repairs. Special fixtures may be required. Where possible, other items can be disassembled, inspected, reassembled and tested on standard work benches.

**Staffing.** Supervisory, operations, maintenance, clerical and security requirements must be considered in developing a staffing estimate. Staffing estimates were performed by McDonnell Douglas in the Solar 100 study. The calculations were based on the specific guidelines for operation by Southern California Edison which were standard in 1982 when the design was performed. The personnel recommendations and organization for the Solar 100 plant are illustrated in Figure 6–6; they were derived from the accepted provision of personnel to operate and maintain established Southern California Edison plants.

Solar unique personnel requirements were added. The solar manpower requirements were developed by detailed analysis of equipment characteristics.

Table 6 5

RECOMMENDED MAJOR SPARES LIST
BASED ON ESTIMATES FOR THE SOLAR 100 PLANT

| Item | Initial Quantity | Annual Replenishment |
|---|---|---|
| Collector System | | |
| Controller | 112 | 8 |
| Elevation drive | 23 | 2 |
| Azimuth drive | 24 | 2 |
| Position sensor | 102 | 102 |
| Drive motor | 43 | 74 |
| Incremental encoder | 30 | 51 |
| Pedestal | 2 | - |
| Mirror module | 4 | 7 |
| Reflector structure | 2 | - |
| J-box | 10 | - |
| Field controller | 14 | 1 |
| Drive motor assembly | 20 | - |
| Thermal Storage and Transport | | |
| Oil-fired salt heater burner | 1 | - |
| Sensors | | 2 |
| Receiver System | | |
| Panel | 2 | - |
| Door motor | 1 | 1 |
| Trace heater | 1 | 2 |
| Valve repair kits | 5 | 7 |
| Sensors | 4 | 1 |
| Orifice | 2 | 2 |
| Salt pump seal kits | 1 | - |
| Steam Generator | | |
| Valve repair kits | 12 | 20 |
| Sensors | 2 | 2 |
| Salt pump seal kits | 1 | - |
| Sensors | 4 | 7 |
| Trace heater | 1 | 1 |
| Plant Control | | |
| Spares are furnished as needed by the suppliers under service contracts | | |
| Balance of Plant | | |
| Circulating water pump rotor | 1 | - |
| Condensor tubes | 250 | - |
| Main transformer bushing | 4 | 1 |
| Auxiliary transformer | 4 | 1 |
| Auxiliary steam boiler burner | 1 | - |
| Valve repair kits | 12 | 16 |
| Sensors | 6 | 6 |

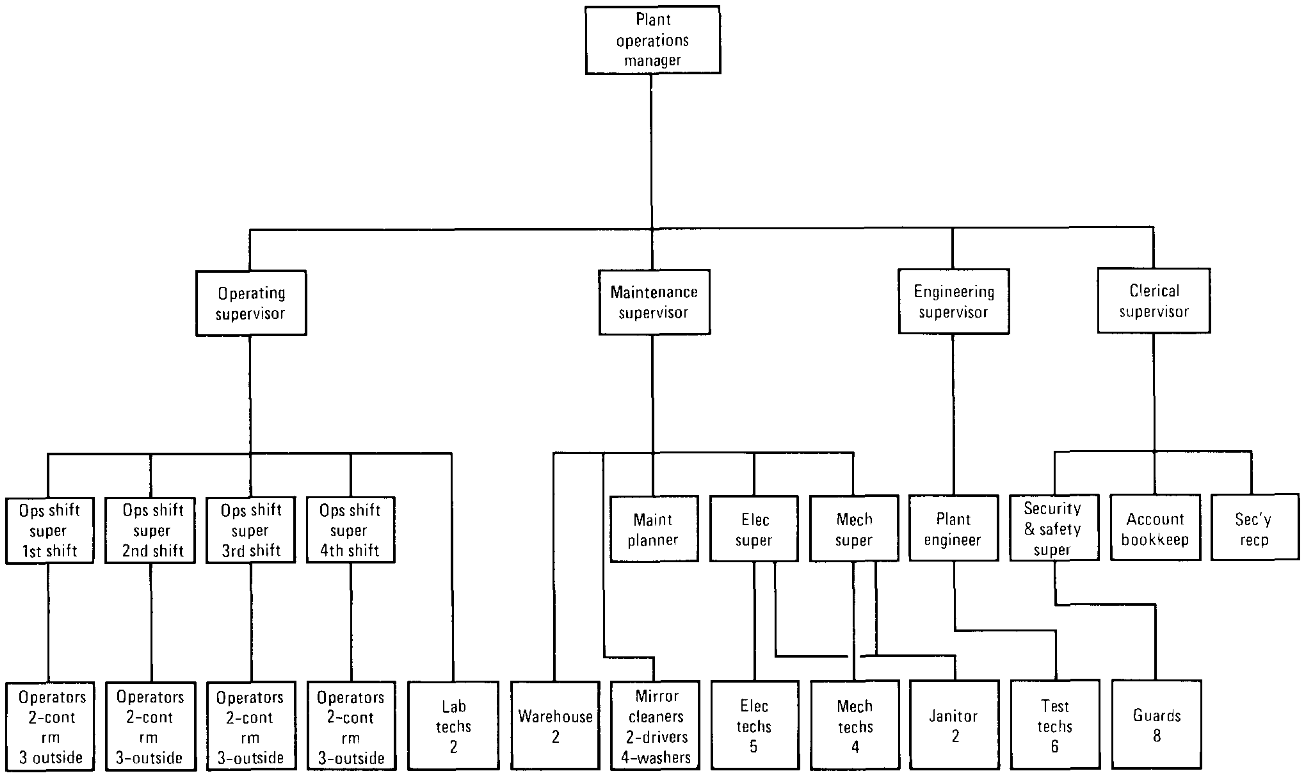


**Figure 6–6 Operations Organization and Staffing Estimated for the Solar 100 Plant**

Predicted failure rates, equipment quantities, annual operating hours, crew sizes, and estimated repair times were combined to develop annual manhour estimates. The resulting manhour numbers were then converted into equivalent numbers of personnel needed. The total quantity of personnel was segregated into the necessary crafts and skills and combined with the turbine generator and balance of plant personnel to form the plant total staffing requirements.

Potential support by a separate utility external maintenance division was not considered in the development of this staffing plan, but may be preferable in some situations. Also it is likely that these estimates will be different for plants with different operating philosophies.

**O&M Costs.** Based on the above philosophy, the total O&M cost per year was estimated to be around $10 million for a 100 MW (Solar 100) plant at 27% capacity factor. This amounts to slightly above 4 cents a kWh. This is estimated to reduce to less than 3 cents per kWh for a 54% capacity factor plant with two collector fields. These estimates were for a first-of-a-kind plant. Values of around 1.2 cents per kWh (equivalent to a coal plant) are considered to be achievable as the technology matures.

## RELIABILITY AND AVAILABILITY

Solar plant reliability and availability estimates must consider the varying operating schedule due to diurnal and seasonal insolation variations. Maintenance (both forced and planned) can be performed at night or on cloudy days to reduce the effects of outages; a component that fails late in the daily operating period will cause less actual forced outage time than one that fails earlier in the day. A rigorous statistical analysis of all plant components is not justified because a reasonably accurate estimate of plant outages can be made considering the major effects.

The forced, or unplanned, outage predictions made by McDonnell Douglas for their Solar 100 design are shown in Table 6–6. These were obtained by analyzing each component that could cause plant shutdown and assigning both a failure rate and a recovery time. Industry data banks and previous experience were used to obtain a component-caused system downtime. Most of the historical failure rate data is based on steady-state operation of the equipment. Allowances to account for possible increases in failure rate due to the cyclic operation of the equipment were included.

The major component results were totaled to obtain the overall plant downtime charged to a system. Operating hours shown are based on the expected operational characteristics of Solar 100.

A relatively small downtime was calculated for the collector field because the predicted heliostat failure rate is 0.0005 per day, and conventional power industry practice excludes power losses of less than 2% in forced outages. Heliostat availability has been 99% or better at Solar One. The small outage shown for the collector field is for 3-phase power and control distribution centers containing transformers that can cause an

Table 6–6
PLANT AVAILABILITY PREDICTIONS
ESTIMATED FOR THE SOLAR 100 PLANT

| | Heliostat Field | Receiver | Steam Generator | Turbine | Salt Loop (Receiver/ Steam) Generator | Master Control System | Total Plant |
|---|---|---|---|---|---|---|---|
| Operating time (hours/year) | 3313 | 3313 | 5256 | 5256 | 3313/3256 | 8760 | |
| Forced outage (hours/year | 0.1 | 52 | 63.6 | 220 | 20 | 0 | 417.6 |
| Planned outage (hours/year) | 0 | 47 | 47 | 252 | 0 | 0 | 252[1] |
| Forced outage rate(%) | 0 | 0.59 | 0.72 | 2.51 | 0.22 | 0 | 4.0 |
| Planned outage rate (%) | 0 | 0.31 | 0.31 | 1.94 | 0 | 0 | 1.94[1,2] |
| Total outage rate (%) | 0 | 0.90 | 1.03 | 4.19 | 0.22 | 0 | 5.94[1,2] |

[1]Assumes all planned outage performed concurrently
[2]Applicable to reduction of gross electrical output

average loss of 159 heliostats when failure occurs. No downtime was assigned to the master control system because it is a fully redundant system.

Planned outage time, also shown in Table 6–6, was obtained from estimates by utility plant operators. For example, the turbine generator system planned outage is based on a 4-week shutdown every four years. It is assumed that all major planned outages (such as turbine and heat exchanger) will be performed concurrently in the 4-week shutdown, and all minor planned outages (such as pump and valve) will be performed overnight.

The outage rates shown on Table 6–6 assume that all maintenance is performed on a 24-hour basis and that only the unavoidable portion is charged against operating time. The unavoidable portion is estimated by allocating the outage hours proportional to operating and nonoperating time periods for each system. Also, the planned shutdown is scheduled for winter months, when the plant operates at reduced output due to low solar insolation.

The Solar 100 results based on these assumptions indicate that a plant availability of 94% could be achieved. This predicted value should be considered as a goal. The realized availability will depend heavily on maintenance practices and minimum activities during operating time. The overall plant availability calculated above is highly dependent on the 24-hour (implying overnight) maintenance assumption.

In practice, plant availability at Solar One during the utility operation period of two and one-half years (following the initial test and evaluation period) has been between 80 and 85%. In addition, detailed reliability analyses have been performed for Solar One to understand the performance analytically.[7] Availability for the commercial plants evaluated and discussed in Chapter 4 was assumed to be 90%.

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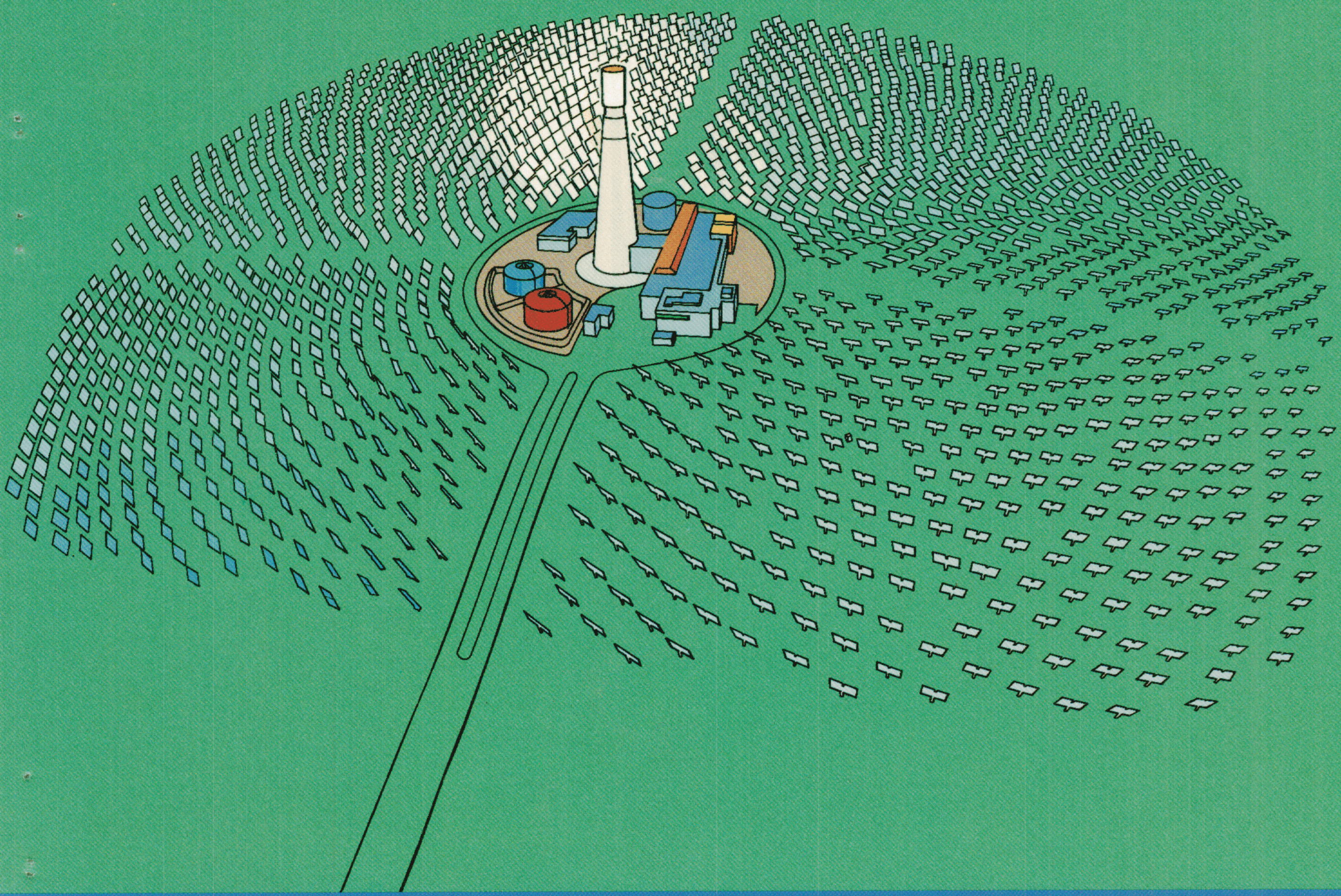
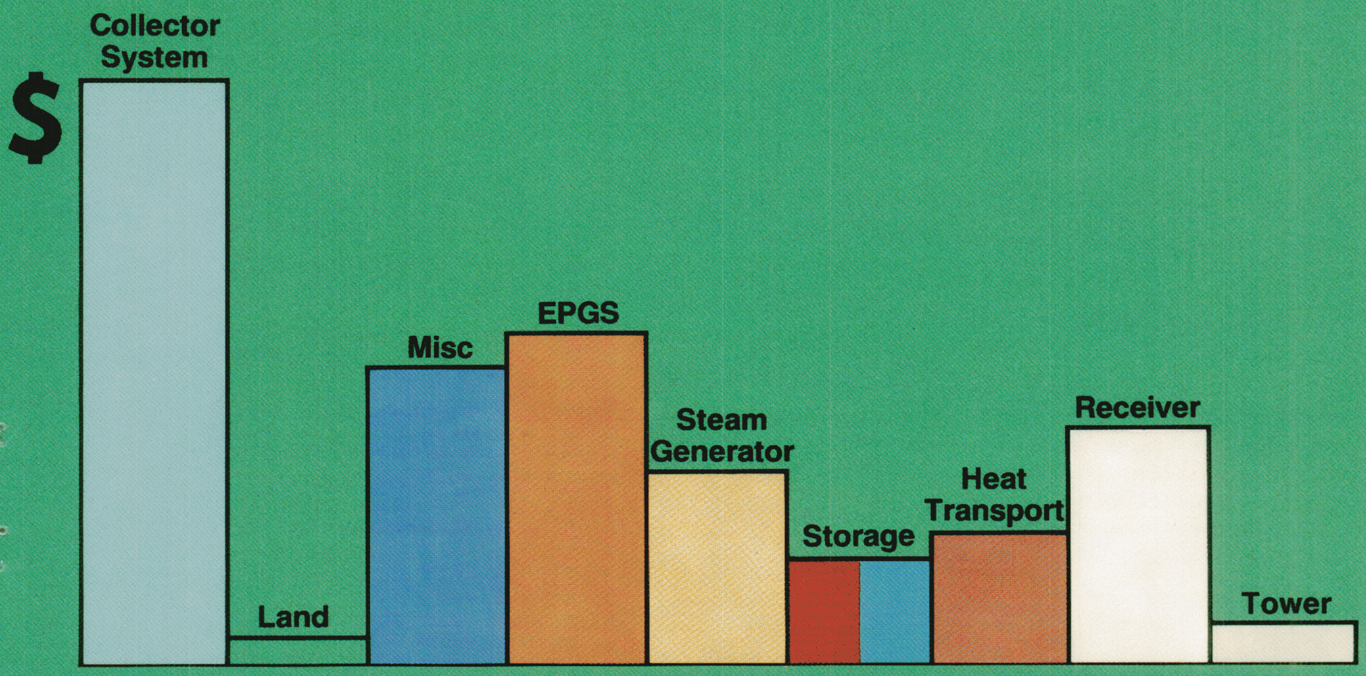


# COSTS



$
Collector System
Land
Misc
EPGS
Steam Generator
Storage
Heat Transport
Receiver
Tower

*Proportional direct capital costs for major plant elements estimated for a commercial 100 $MW_e$ (solar multiple = 1.2) external, molten nitrate salt solar central receiver system. Costs estimated using the methodology described in this chapter and assuming heliostat costs of \$120 per $m^2$. Total direct plant costs are estimated to be \$217 million. The levelized energy cost calculated using assumptions described in Section 7.3 is ten cents per kilowatt-hour.*

# COSTS

Evaluation of the economic viability of central receivers is required for each potential application. This evaluation requires assessment of the capital costs of system components and the associated operating and maintenance costs together with financing assumptions and a definition of the economic environment for construction and operation. The purpose of this chapter is to present information which will enable a preliminary evaluation of the economic feasibility of solar thermal central receiver systems. The economic analysis presented in this chapter provides a baseline estimate of energy costs. The reader may want to choose other parameters that more exactly match his organization's economic projections.

Several topics are discussed in this chapter. First discussed are the sources of cost data and the organization of direct capital costs by subsystem and various scaling algorithims that have been developed. Cost estimating relations are presented for the principal solar thermal components. These relations are a function of one or two design variables and allow the estimation of the cost of a component over a broad range of values of the controlling design variable. An economic methodology for estimating the levelized energy cost (LEC) is also presented and described. Calculations follow which use the cost estimating relations. Economic and operating assumptions are discussed and energy cost results for a number of assumptions are also presented. Several examples are shown to illustrate the sensitivity of the levelized energy cost to alternate costs and financial assumptions.

Finally, the impact on system design, costs, and economics is evaluated for two situations (multiple time-of-day pricing and limited capital) where design for minimum energy costs may not be economically feasible or the economic optimum.

## MAJOR ISSUES

**Cost Data Base.** Solar central receiver power plants represent a new technology, and much has been learned about cost estimation for these systems during the development effort over the past fifteen years. Cost and economic data for central receiver Rankine-cycle electric generating systems are available from a number of design studies of both systems and components. These studies have been performed with varying degrees of detail. For example, cost estimates for plant designs may be categorized into five groups by the level of detail: conceptual design, advanced conceptual design, preliminary design, final design, and construction or "as built". The reduction in the contingency associated with the cost estimate for a more detailed design reflects the differences in the certainty of costs among these levels.

From 1977 – 1980, a large number of conceptual design studies were performed for central receiver systems and components. Over twenty site-specific system studies were done in this period. A larger number of design studies were performed that focused exclusively on specific components including the heliostat, receiver, tower, storage, steam generator, and turbine. These studies at the component level were very useful for development of the technology, but the cost estimates in these studies are in general not directly applicable to current systems. Component level costs are difficult to compare among studies because of many differences. In general, component level costs may not include all elements of a subsystem. Despite differences in system-level designs, generally the system studies are more complete. The participation of the same industrial firms in both the component and system studies has insured continual updating based on continued component development.

For these reasons, cost data presented here is generally derived from system level studies. The potential sources of cost data from system design studies, funded by the DOE and by others, are listed by level of design in Table 7.1–1.[1–10] In the DOE program, a few of the conceptual design studies were funded for more detailed study. The results of the advanced conceptual design and preliminary design studies, indicated by an asterisk, are the principal sources of cost data. In addition, the as-built costs are available in detail for the DOE funded plant–Solar One. Non-DOE plants for which some data exists include the privately funded Solar 100 study and the French pilot plant–Themis. Characteristics of the plants in the cost estimate data base are listed in Table 7.1–2.

Cost estimates were examined in detail for each of these systems.[11,12] A computer accounting program named the Cost Data Management System[13,14] was used to enable comparison of the data with a consistent account structure. Comparison of all of the costs yielded cost scaling relations for each plant subsystem or component.

In many cases, interpretation of the data was required. The repowering studies (Pioneer Mill, Newman, and Saguaro) were based on the retrofit of existing plants. As a result, little or no budget was included for land, structures or improvements, turbine plant, or miscellaneous equipment. The Solar One data is reasonably complete but of limited value for a representative commercial plant because it is small, experimental (and thus included extra equipment for experimental measurements), and first of a kind. Its prototype status resulted in high indirect costs, high engineering design charges, and unusual research and development costs.

Cost relationships are presented in the following section based on a consistent evaluation of the costs in the data base listed in Table 7.1–2. However, reductions in cost are expected for many of the components as the technology matures.

**Effect of Learning.** Learning, mass production, and economies-of-scale are inter-related concepts which affect the future costs of solar thermal components and systems. The impact of learning on costs is most often discussed in the context of learning curves.[15,16] In general, the concept of learning and learning curves is based on the assumption that repetition of a task reduces the cost of accomplishing that task over time as better methods are "learned" and incorporated into the process. In the broadest sense, learning encompasses improvements in design as well as improvements in the manufacture or construction of that design. Empirical evidence has shown that the cost of accomplishing a task tends to be reduced by a constant

Table 7.1-1

SOURCES OF COST DATA FROM SYSTEM DESIGN STUDIES BY LEVEL OF DESIGN

| | Conceptual | Advanced Conceptual | Preliminary | Final | As-Built |
|---|---|---|---|---|---|
| **DOE** | (1980) | (1982) | (1983) | | |
| | Eight Utility Repowering Studies | Saguaro | *Saguaro | | *Solar One |
| | | Newman | *Newman | | |
| | Six Industrial Process Heat Repowering Studies | Pioneer Mill | *Pioneer Mill | | |
| | | *Sierra Pacific | *Carissa Plains | | |
| | | *Paint Creek | | | |
| | Seven Cogeneration Studies | | | | |
| **Other** | | | | | |
| | | *Solar 100 (private initiative 1982) | | *Themis† (French power plant) | |

*Indicates inclusion in cost estimate data base
†Limited data available

Table 7.1-2

COST ESTIMATE DATA BASE

| Plant Name (Location) | Size | Receiver Fluid | Receiver Config. | Level of Design | Date |
|---|---|---|---|---|---|
| Themis (France) | 2.5 $MW_e$ | Salt | Cavity | Built | 1982 |
| Pioneer Mill (Hawaii) | 31.6 $MW_t$ | W/S | Twin cavity | Prelim. design | 1983 |
| Solar One (California) | 10 $MW_e$ | W/S | External cylinder | Built | 1981 |
| Carrisa Plains (California) | 30 $MW_e$ | Sodium | External billboard | Prelim. design | 1983 |
| Newman (Texas) | 40 $MW_e$ | W/S | External billboard | Prelim. design | 1983 |
| Saguaro (Arizona) | 60 $MW_e$ | Salt | Cavity | Prelim. design | 1983 |
| Paint Creek (Texas) | 60 $MW_e$ | Sodium | External cylinder | Advanced conceptual design | 1982 |
| Solar 100 (California) | 100 $MW_e$ | Salt | Cavity | Advanced conceptual design | 1982 |

fraction for every doubling of the cumulative output.

Mass production and learning are closely related subjects. The benefits of learning are often captured through mass production or, from another point of view, mass production allows the effects of learning to accrue. Mass production reduces costs through mechanization and integration. Small orders built by hand can be more cheaply built by machine as the production level increases. Higher production volume also allows integration of manufacturing operations under one roof rather than relying on specialty subcontractors.

An aspect of learning mentioned above is the modification of the design of an object for less cost to help it accomplish its function. One possible design change is an increase or decrease in size. Economies-of-scale refers to a decrease in the cost per unit of size as size increases. For example, a 10,000 gallon tank may cost $10,000, while a 20,000 gallon tank may not cost double that, but something less, perhaps $15,000. Economies-of-scale are usually tied to real advantages of constructing larger components. For instance, a 20,000 gallon tank would require less than double the wall area (and hence material) required by a 10,000 gallon tank.

Economies-of-scale, learning, and mass production can have a significant impact on the costs of components, in general. The discussion of each individual component in the following section includes a more specific look at the importance of these effects.

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# CAPITAL AND O&M COSTS

Cost elements for a central receiver system may be aggregated in various ways. Elements for which a specific cost relationship is given in this section include: collector system, receiver, tower, transport, storage, energy conversion system, and balance of plant. It makes little difference how costs are allocated and subsequently aggregated as long as all plant components are included.

The total capital cost is required for calculation of the levelized energy cost. Capital costs account for all costs incurred before plant operation and generally include the direct costs, indirect costs, contingency factors, and startup costs. The indirect costs are costs not attributable to any particular subsystem, a portion is often referred to as General and Administrative. The indirect costs are normally a percentage of the direct costs and should not vary widely from plant to plant for a mature technology.

Contingency may be applied uniformly to all plant elements based on the level of detail in the cost estimate or aggregated into different values to account for greater uncertainty in the cost or performance of a particular component (such as the receiver.) Indirects, contingency, and startup costs are usually assumed to be 20 – 35% of the direct costs.

## COLLECTOR SYSTEM

The collector system is composed of the field of heliostats, associated wiring and the beam characterization system. The collector system is the most expensive component of a central receiver system. The importance of this component to system economics has resulted in a large number of studies over the years aimed at developing designs for better performance and reduced costs.

The major subcomponents of a heliostat are the reflective assembly, mirror module support, drive unit, foundation/pedestal, and controls/field wiring. The mirror module is the most costly subcomponent, with the others trailing in cost importance roughly in the order cited above. Heliostat designs have evolved toward larger and larger sizes over the years in an attempt to capture economies-of-scale. Control and field wiring costs tend to be independent of unit size, so their cost per $m^2$ falls as the heliostat gets bigger. Design improvements to drive units have increased their load bearing capabilites without increasing their cost. This has allowed larger mirror areas to be incorporated in the latest designs without suffering a cost penalty for the additional load that must be borne.

Heliostats using stressed-membrane mirror modules are a relatively new design that offers hope of achieving lower costs. Preliminary estimates by developers indicate that stressed-membrane heliostats may afford a 25% reduction in costs over glass-metal heliostats with comparable performance. Additional development and analysis of the stressed-membrane heliostat will be necessary, however, to match the design and operational maturity of the glass-metal design.

More than any other component, the cost of a heliostat is affected by assumptions regarding the level of production and the general state of the solar thermal industry. The cost of manufacturing

Table 7.2-1
HELIOSTAT PRICE ESTIMATE (1986$ - Small Build)

| Design | Heliostats for 30 $MW_e$ Plant | One Time Cost per Heliostat | Recurring Cost per Heliostat | Total Heliostat Costs | Heliostat Costs $/m$^2$ |
|---|---|---|---|---|---|
| Solar One | 6000 (39m$^2$) | $ 370 | $26 K | $158 M | 676 |
| Second Generation | 4300 (55m$^2$) | $ 500 | $30 K | $131 M | 554 |
| Large Area | 1600 (150m$^2$) | $1700 | $36 K | $ 60 M | 251 |
| Stressed Membrane | 4700 (50m$^2$) | $ 960 | $25 K | $122 M | 519 |
| Stressed Membrane | 1600 (150m$^2$) | $4400 | $30 K | $ 55 M | 229 |

a heliostat drops rapidly as annual production increases from a few hundred to several thousand units or more. Estimates of 1986 prices for heliostats of several candidate designs purchased for a single 30 $MW_e$ plant are listed in Table 7.2-1.[1]

Note that this table indicates the *prices* at which the heliostats are estimated to be sold and are different from the *costs* described elsewhere in this section. The prices include indirect costs and profit as well as direct costs. This is the price offered by the component manufacturer, which is equal to the cost for the plant builder. It is important to recognize the difference between direct and indirect costs for the manufacturer of a component and direct and indirect costs for the plant contractor.

Current estimates of installed glass metal heliostat costs for the first few commercial-sized plants range from $150-250/m$^2$ depending on the production rate and number of years of continuous production. If demand for heliostats was sufficient to support a dedicated facility producing 50,000 units per year, then costs would drop to $60 - 80/m$^2$. Estimated costs for each of the major heliostat components when produced at this rate are shown in Table 7.2-2.[1] Cost estimates are shown for 150 m$^2$ heliostats for three designs — a glass-metal version and two stressed-membrane designs designated by their manufacturer. As the cumulative number of units is produced in the plant, costs will drop further. Costs as a function of the year of production are also shown in Table 7.2-2.

In addition to the heliostats and field wiring, a beam characterization and meteorological system is also included with the collector system. This cost is nearly constant over a range of field sizes — roughly one million dollars. This cost is relatively small for large systems but may be significant for very small systems.

## RECEIVERS

The receiver type and its working fluid are the most distinguishing characteristics among alternative solar thermal central receiver systems. Water-steam receivers were developed early in the program, while the greatest interest in

Table 7.2-2

HELIOSTAT COST ESTIMATE
JUNE 1986 DOLLARS
150 $m^2$ MASS PRODUCTION
PRICE in $\$/m^2$

| Component | Stressed Membrane SKI | Stressed Membrane SAIC | Glass Metal |
|---|---|---|---|
| Reflective Assembly | $21.00 | $30.30 | $32.80 |
| Support Structure | 8.70 | 6.30 | 10.40 |
| Drives | 11.60 | 11.60 | 11.60 |
| Drive Electrical | 0.95 | 0.95 | 0.95 |
| Foundation | 6.70 | 6.70 | 6.70 |
| Pedestal | 1.90 | 1.90 | 1.90 |
| Field Wiring | 4.00 | 4.00 | 4.00 |
| Controls | 1.90 | 1.90 | 1.90 |
| Field Assembly/Checkout | 1.30 | 1.30 | 6.30 |
| Total Price Year 1 | $58.05 | $64.95 | $76.55 |
| Price Year 2 | $52.25 | $58.45 | $68.90 |
| Price Year 4 | $47.00 | $52.60 | $62.00 |
| Price Year 8 | $42.30 | $47.35 | $55.80 |

SKI – Solar Kinetics, Inc.
SAIC – Science Application International Co.

the near-term has been directed toward molten nitrate salt and liquid sodium receivers.

Receiver subcomponents include the absorber panels, circulation equipment, structural components, and instrumentation and control. The absorber panels often account for as much as 50% of the total receiver cost (not including the tower). Circulation equipment and structural components split the majority of the remaining costs, with instrumentation and control representing a relatively minor cost.

Receiver working fluid, its temperature and pressure, and the choice between an external or cavity structural design are the primary design factors which influence receiver cost. The corrosive/erosive nature of the working fluid, along with its temperature and pressure, dictate absorber material type and wall thickness. Stainless steels or nickel-based alloys are required. The expense of these types of materials combined with extensive fabrication requirements causes the absorbers to be an expensive piece of equipment. Structural costs are affected most by the choice between external and cavity designs; the wrap-around structures required for cavity receivers are generally more expensive than the more compact structures characteristic of external absorber designs. Differences in the flux limits of absorber panels designed for different working fluids affect the size and weight of the panels that must be supported and the structural requirements. Pumping costs vary among the different working fluids because of their differences in volumetric heat capacity.

Differences in estimates of the cost of receivers can usually be traced to the absorber. Operation at elevated temperatures and frequent cycling from high to low temperatures creates difficult thermal and mechanical stress problems. Solutions to these problems generally involve some tradeoffs between material type, tube wall dimensions, flux levels, design operating temperature, and allowance for expansion. Uncertainty as to the proper combination of these design variables has contributed to uncertainty about the initial cost, lifetime, and maintenance costs.

Mass production and learning cannot be expected to have the cost reduction impact for receivers that is expected of heliostats. The distributed nature of the heliostat is unique among central receiver components. Receivers will benefit from the learning effect if a generic design can be developed that is commonly used. Standardization of design and construction techniques should at least reduce the large construction contingencies associated with some near-term projects that are required to cover material and labor cost uncertainty for the receiver.

Economies-of-scale exist for the receiver as a whole due largely to economies-of-scale that exist for the structure, circulation equipment, and instrumentation and control. Receiver costs could be logically correlated with several different variables including heliostat field size, receiver thermal power rating, and absorber surface area. Each variable relates to the physical size of the receiver, but absorber area has the advantage of being a dimensional parameter that relates directly to the amount of material and labor needed for construction of the absorber.

Receiver cost estimates as a function of the receiver absorber area are shown in Figure 7–1. The large uncertainty in receiver costs as a function of the receiver configuration, manufacturer, and specifications is indicated by the range of values highlighted. In general, cavity receivers are more expensive than comparably rated external receivers. However, there is considerable overlap in the cost estimates. Also, cost estimates are believed to vary because of differing degrees of conservatism in the initial designs that have been analysed and costed.

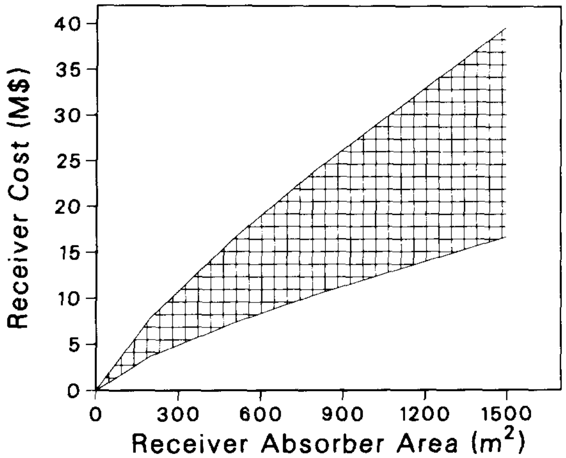


**Figure 7–1 Receiver Cost as a Function of Absorber Area (Band indicates range of estimates for commercial-scale receivers.)**

## TOWER

Towers may be constructed from either steel or concrete.[2] Steel is generally preferred for towers less than 120 meters high (400 feet) and concrete for taller towers, although the demarcation separating steel from concrete is not precise.

The cost of the tower and tower foundation will generally run about one quarter of the total cost of the other receiver subcomponents, but can vary drastically for a given height depending on the receiver weight, receiver bulk, seismic loading, wind loading, and soil bearing capacity.

Tower costs are affected largely by height once the site-specific loading conditions (seismic and wind loads; soil bearing capacity) are fixed. Some differences exist between the different receiver types due to differences in receiver weight or bulk for the same receiver power rating. These differences tend to be small, however, compared to the potential impact of the variation in site specific design conditions, especially seismic conditions. Towers show strong diseconomies-of-scale when their costs are correlated with height. However, when tower costs are correlated with concentrator field size, economies-of-scale are identified for tower heights of 30–260 meters; this apparent anomaly exists because the tower need only be a little bit taller to accommodate a much greater percentage increase in concentrator field size.

Little reduction in cost is expected for towers through the process of learning. Both steel and concrete tower construction incorporate techniques that are currently employed for building similar structures for other purposes. Some learning may occur if standard plant sizes and designs are developed, but the percentage reduction in cost would probably be even less than that for receivers.

Estimated costs for towers as a function of the tower height are illustrated in Figure 7–2. The band indicates a greater uncertainty in costs at very high heights. This may result from dramatically increasing costs of construction through higher labor and erection rates as a function of height.

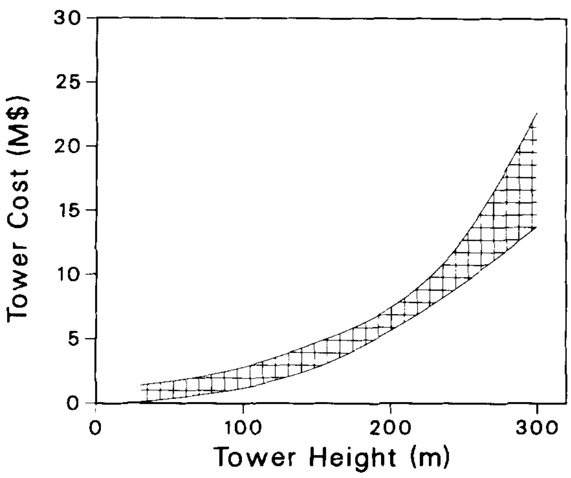


**Figure 7–2 Tower Costs as a Function of Tower Height**

## TRANSPORT

The transport system is defined here to include the riser and downcomer within the tower plus horizontal piping connecting the base of the tower with the storage and energy conversion components. The transport component is comprised of standard piping system subcomponents including pipe, pipe supports, fittings, valves, pumps, expansion joints, heat tracing, and insulation. Pipe, fittings, and valves account for the majority of the costs for most piping systems.

The choice of working fluid affects the cost of the transport component in several ways. Differences in volumetric heat capacity directly control the relative size of pipe required to transport thermal energy at a given rate. Pipe wall thickness is controlled by the pressure bearing requirements and the corrosive or erosive nature of the fluid. Fluid temperature and corrosiveness/erosiveness determine the piping material type that is selected.

Once the working fluid is selected, transport system design hinges on two fundamental decisions. The first tradeoff considers the selection of an optimum pipe diameter and the tradeoff between capital costs and pumping power. The second tradeoff considers the selection of optimal insulation thickness and the tradeoff between insulation cost and thermal energy losses. The optimum pipe size and insulation thickness must be selected based on a simultaneous solution to the two tradeoffs. The optimal design will vary depending on the cost of the individual transport subcomponents, the cost of pumping power, the value of lost thermal energy, and the thermal characteristics of the working fluid.

The transport system is built from standard materials and equipment that are commonly used in the process industries. As such, no significant cost reductions due to learning are anticipated to accrue in the future as more solar thermal systems are installed. Cost uncertainties that exist for the transport component are largely due to the complexity of the design optimization and changes to one or more of the economic factors influencing the design tradeoffs.

Unit transport costs initially decline with increasing heliostat field size, but then begin to rise as field size approaches one million square meters. This results from the trade between lower unit piping costs but rising unit pumping costs as field size and tower height grows. The former dominates for relatively small piping systems while the latter becomes more important for larger systems. Transport costs are usually correlated with peak fluid flow rate or a variable proportional to peak flow rate such as plant thermal power rating or heliostat field size.

Transport system costs as a function of the receiver thermal rating are shown in Figure 7-3.

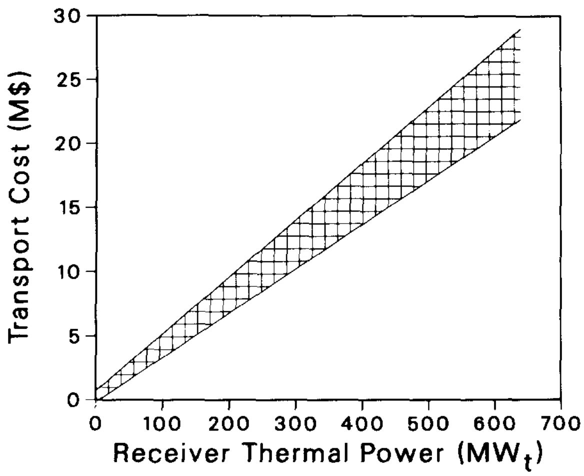


**Figure 7-3 Transport System Cost as a Function of Receiver Thermal Power**

## STORAGE

Storage serves as an energy buffer between collection and delivery and as a means to increase the capacity factor of the solar thermal system. Greater utilization of the energy conversion system through storage can lower the overall cost of supplying energy on an annual basis. Storage subcomponents include structural steel tanks, liners, foundation, insulation, storage medium, medium maintenance equipment, and instrumentation. The portion of the total storage cost of each subcomponent depends on the type of storage medium, but the tank (and liner, if necessary), storage medium, and medium maintenance equipment tend to dominate.

Design options impacting cost are largely fixed once a specific storage medium is selected. The size and cost of most subcomponents are generally derived directly from the volume of fluid required to meet a certain thermal capacity in MWh. Externally-insulated carbon steel tanks are adequate for oil-rock storage or cold tanks for salt or sodium, but the higher temperature associated with molten salt or sodium hot tanks requires either internal insulation and a liner to protect the carbon steel tank or a tank made from stainless steel. Optimum insulation thickness is determined via a tradeoff between additional capital costs and the value of thermal energy losses.

Molten salt, sodium, and oil-rock storage systems are constructed from relatively common civil and structural materials and have been built for non-solar applications, but generally not at the large sizes contemplated for solar thermal systems. The challenge of building large storage systems creates some uncertainty in their cost and may add to cost contingencies in the near-term. In the long run, some cost reductions may result from learning as contractors refine their construction techniques if some uniformity in design can be employed.

Storage systems as a whole show economies-of-scale with capacity due to large economies-of-scale for the containment, instrumentation, and medium maintenance equipment subcomponents. The unit cost of civil work and the storage medium is relatively constant regardless of capacity. Storage costs are sometimes broken into power-related (charging and discharging) and capacity-related groups and correlated with thermal power rating ($MW_t$) and capacity (MWh), respectively.

Capacity-related costs dominate thermal energy storage systems, however, and cost correlations based on MWh alone predict costs well for the entire storage system. Costs for thermal storage as a function of storage capacity are shown in Figure 7–4.

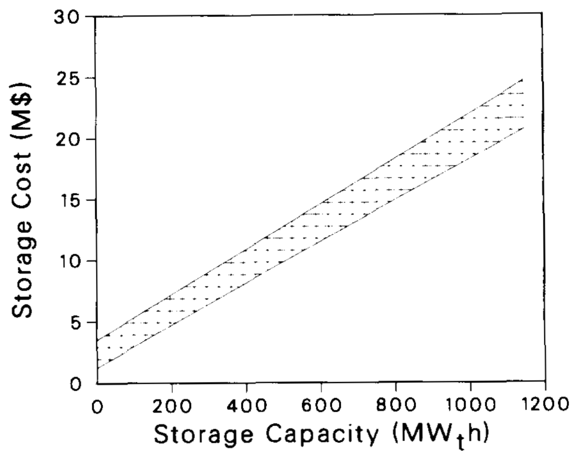


**Figure 7–4 Storage System Cost as a Function of Storage Capacity**

## ENERGY CONVERSION

The principal energy conversion subcomponents are the steam generator, turbine-generator, condenser, and cooling tower for electric generating solar thermal systems. Industrial process heat systems would only require the steam generator. The turbine-generator can account for as much as 50% of the total energy conversion component cost. The other three subcomponents roughly split the remaining 50%.

Steam inlet and exit conditions control the cost of the turbine-generator for a given power rating. Higher inlet temperatures and pressures create more stringent material requirements in the turbine, but also increase the volumetric energy density (joule/$m^3$) and thermodynamic efficiency. In general, design conditions which enhance conversion efficiency also tend to reduce costs by reducing the volumetric throughput required to generate a given power level. Eventually, the material cost increases brought about by higher temperatures and pressures exceed the benefits of increased volumetric and thermodynamic efficiency. Steam generator, condenser, and cooling tower costs can be influenced by the choice of approach temperatures. The ambient air conditions have an obvious impact on the cost of the latter two subcomponents, while the inlet temperature of the solar thermal fluid places limits on the steam generator design and cost.

Energy conversion components are common to any Rankine cycle power plant, and as such little or no cost reductions are expected due to learning. A possible exception may be the smaller size (< 5 $MW_e$) Rankine systems. Rankine systems of this size have been relatively uncommon in the past, especially at steam conditions near 540°C (1000 °F). The lack of extensive previous installation of these sizes has resulted in more uncertainty in their cost compared to larger Rankine systems. The recent interest in cogeneration has created more offerings of smaller steam power systems and could result in some cost reductions through learning and/or increased competition.

Each of the energy conversion subcomponents shows strong economies-of-scale. The system unit cost per $kW_e$ drops by about a factor of four when comparing the cost of 1 $MW_e$ systems with 100 $MW_e$ systems. Energy conversion economies-of-scale are partly the result of the same factor that causes economies-of-scale for most fluid handling systems: increasing the volumetric capacity requires a smaller percentage increase in the materials required to contain the increased flow. Reduced fabrication labor requirements (per unit of size) also play a part in the unit cost reduction. Energy conversion costs are usually reported and correlated in terms of $/$kW_e$ of generating capacity. Other variables such as steam rate (lb/hr) or thermal capacity ($MW_t$) could be used, but convention dictates that electric power rating be used. Costs are shown as a function of electric power rating in Figure 7–5.

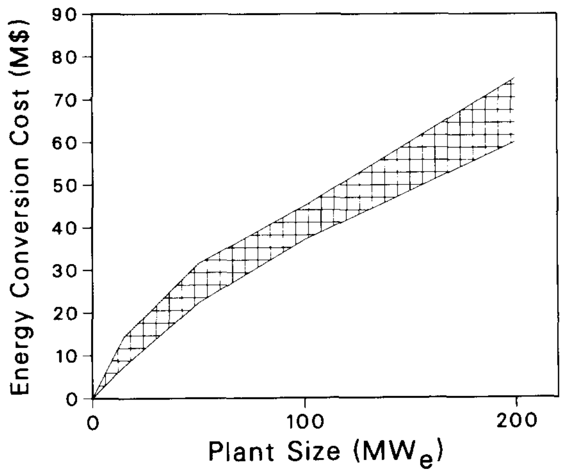


**Figure 7–5 Energy Conversion System Cost as a Function of Plant Rating**

## BALANCE OF PLANT

As the name suggests, balance of plant represents a rather diverse combination of other plant subcomponents that don't fit in directly with the components discussed above, but which are essential items. The diverse nature of balance of plant subcomponents presents an almost unlimited number of possible groupings. Principal subcomponents include land and site preparation, structures, power conditioning (plant substation or switchyard), central plant instrumentation and control, and service facilities. Each of the above subcomponents is fairly self-descriptive, except for service facilities. Service facilities includes equipment such as maintenance vehicles, water supply and communication gear.

The critical variable affecting balance of plant costs is the purchase cost of land and the amount of civil work required to prepare its surface. Both are site-specific. Land costs are extremely variable. Various sources suggest purchase costs ranging from \$500 – \$10,000 per acre. Generic studies also must guess at how much cut and fill will be required.

Not all of the uncertainty in balance of plant costs is due to land and site preparation. Requirements for most of the other subcomponents are not derived from direct engineering calculations. The quantity of equipment required is much more judgmental and subjective than for the other solar thermal system components. Much of this uncertainty will only be reduced as more solar thermal facilities are built and specific requirements are better documented. The current uncertainty in balance of plant requirements may necessitate additional contingency in the estimates of near-term plants. In the long run, a more exact knowledge of balance of plant requirements should mediate the uncertainty and costs.

All of the balance of plant subcomponents except land and site preparation exhibit economies-of-scale. The driving forces for economies-of-scale are as varied as the individual subcomponents. In general, there tend to be relatively large minimum costs associated with each of the subcomponents. Because land and site preparation unit costs don't decline with plant size, the percent of balance of plant attributable to this subcomponent rises with plant size as the other subcomponents fall in relative importance. The diverse nature of the balance of plant subcomponents makes it difficult to select a cost correlating variable.

Balance of plant costs as a function of the receiver thermal rating are shown in Figure 7–6. The receiver thermal rating is used rather than the electric plant rating since plants with the same nameplate rating but with different solar multiples will have different land and support requirements.

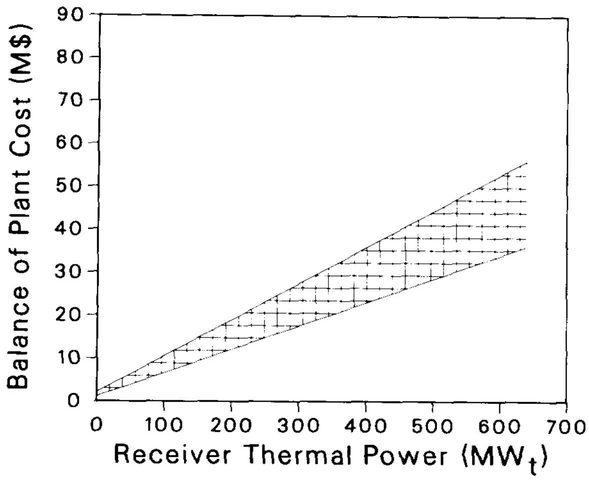


**Figure 7–6 Balance of Plant Costs as a Function of Receiver Thermal Power**

## OPERATIONS AND MAINTENANCE

Operations and maintenance (O&M) costs include direct operating labor, direct maintenance labor and materials, storage medium replacement, and plant overheads. Either of the first two subcomponents will dominate O&M cost, depending on plant size. Storage medium replacement and plant overhead tend to represent relatively minor portions of O&M. Direct operating labor represents a higher fraction of O&M for smaller plants; maintenance labor and materials becomes relatively more important for larger plants. Storage medium replacement costs depend, of course, on the storage system size and type.

Operations and maintenance is similar to balance of plant in that there is a limited calculational relationship between physical plant design variables and O&M requirements. One exception to this generalization is storage medium replacement costs, which depend directly on the size of the storage component and the type of storage medium. The general lack of precision in defining the requirements for operating labor, maintenance labor, and materials creates uncertainty in their cost. Since the "quantity required" for these O&M subcomponents is not established by design calculation, estimates must be developed based on experience with similar facilities. The lack of previous experience with solar thermal systems makes it difficult to project O&M requirements and costs. Uncertainty usually adds to the estimated costs by contributing to increased contingencies. To the extent current O&M estimates include this contingency premium, cost reductions may be expected from learning in the future.

Operations and maintenance costs show economies-of-scale with plant size due mostly to the direct operating labor subcomponent and to a lesser extent maintenance labor and materials. For example, little increase in operating manpower would be anticipated between a field of 500 heliostats and a field of 5000. However, heliostat maintenance costs, and especially washing costs, are expected to be nearly proportional to the number of heliostats. Other solar thermal components also experience maintenance labor and material costs that are proportional to their capital costs. Thus, economies-of-scale for maintenance tend to follow economies-of-scale shown for the capital cost. Storage medium replacement costs vary directly with the volume of storage medium and experience no economies-of-scale.

Selecting a cost correlating variable for O&M creates some difficulty because of the lack of a common controlling design variable. Heliostat field size, plant power rating, and plant capital cost are three commonly selected scaling parameters. Each represents a different measurement of overall plant size. Field size is generally preferred over power rating since the latter may remain fixed for some widely varying system designs involving alternative storage capacity.

An alternate approach is to assume that annual O&M costs may be assumed to be a fraction of the plant total direct costs. Estimates of 1.5% to 2% have been made in previous design studies.

REFERENCES

1. C. L. Mavis, Private communication, 1986.

2. *Tower Cost Data for Solar Central Receiver Studies*, Stearns-Roger Engineering Company Contractor Report, SAND78-8185, 1979.

# LEVELIZED ENERGY COST CALCULATION

A levelized energy cost (LEC) is a life cycle cost which includes a plant's capital cost, operation and maintenance cost, taxes, interest, and return on investment. A LEC approach provides an economically correct treatment of these costs and allows an equitable comparison of alternative solar thermal power systems.[1-3]

In this section general economic principles relating to LEC calculations such as the time value of money, discount rate, and net present value are defined and explained. The appropriate use of LEC analyses for choosing between alternatives is discussed. A description of a general approach to LEC calculations that is applicable to all energy systems follows. Finally, a simplified approach for calculating a LEC using the standard economic assumptions from the National Solar Thermal Technology Five Year Plan[4] is presented.

The procedure presented for calculation of the levelized energy cost is specific to tax laws and conditions present at the time the Five Year Plan was developed. Readers will certainly want to make economic calculations based on their own procedures and assumptions. The Five Year Plan methodology is presented in detail because central receiver energy costs presented in this handbook were calculated using this approach.

## LEC METHODOLOGY

**Fundamental Economic Concepts.** The purpose of an economic evaluation is to select the best investment, i.e., the investment that maximizes the wealth of the investor. An economically correct methodology for comparing alternatives must properly consider (at a minimum) the time value of money and inflation. For example, solar plants require higher capital investment than fossil plants; however, fossil plants have a recurring fuel cost over the life of the plant.

As a result of the time value of money, expenses or revenues (cash flows) which occur at different times cannot be directly compared on a face value basis. The most common way to correctly interpret cash flows occurring at different times is through a present value calculation. In a present value calculation, a discount rate compensates for the time value of money. The discount rate is the minimum rate of return that an investor is willing to accept from the investment; in the case of a lender, the discount rate is equivalent to the interest rate charged on the loan. Interest (discount) rates are a function of the intrinsic productivity of capital (or how much additional capital can increase output of goods and services), the expected inflation rate, and a risk premium having to do with the variability of the cash flows. The rate of constant dollar interest is the compensation for postponing consumption when there is no inflation. The greater the uncertainty in the timing or magnitude of a cash flow (risk), the higher the real interest (or discount) rate will be.

Inflation has a significant impact on economic evaluations. It is a decrease in the purchasing power of currency over time and affects all the expenses and revenues associated with an investment. In periods of inflation, investors demand higher returns (higher discount rates) as compensation for postponing consumption because money received later will buy fewer goods and services than it will today.

Economic evaluations can handle inflation in one of two ways. The first approach is to include the effects of the expected inflation rate into all revenue and expense streams. This approach is called a nominal (or current) dollar method, and results in estimates of the actual face-value cash flows to occur in each year. The second method of accounting for inflation is to exclude the effects of inflation from all cash flows. This approach is called a real (or constant) dollar method, since it expresses all cash flows in dollars of constant purchasing power. Either approach to inflation will yield a correct evaluation of energy alternatives. It is important though that all the economic calculations remain consistent, i.e. either nominal or real.

**Using Net Present Value Analysis.** All possible investments of the same risk will not necessarily earn the same rate of return. Deciding which investment to select can be done by calculating the net present value. The net present value is the difference between the present value of the cash flows to be received and the amount of the investment. For an investment to be attractive, the net present value must be greater than zero.

Selecting investments with negative net present values decreases wealth and selecting investments with positive net present values increases wealth. Businesses and individual investors attempt to maximize their wealth and select investments on this basis. Wealth maximization occurs when all positive net present value investments are chosen. When choosing between mutually exclusive investments (e.g., the energy source for a particular power plant) the alternative with the largest net present value will be the one that maximizes the wealth of the investor.

**Using Levelized Energy Cost Analysis.** Deciding between alternatives on the basis of capital cost, system efficiency, or any other single parameter will not necessarily yield the most economically efficient method or maximize the wealth of investors. The LEC approach can be used to choose appropriately between alternatives.

There are two important constraints in LEC calculations. The first is that a selection between alternatives using the LEC approach is only reasonable when the alternatives are providing equivalent service. If the characteristics or use of the energy systems are dramatically different (for instance, a peaking plant being compared to a base load plant) the LEC cannot be used by itself to determine which alternative is better since the value of the energy produced by each plant may be dramatically different.

The second constraint is that LEC comparisons are only appropriate when the economic assumptions used in the calculations are consistent. This constraint is especially important when comparing LEC calculations from different sources. The economic assumptions will substantially affect the magnitude of the LEC calculated even though they may not alter a relative comparison of concepts. Use of levelized energy costs to compare technologies must be restricted to cases where the economic assumptions are equivalent.

**Levelized Energy Cost Mechanics.** The general steps involved in calculating a LEC (once the annual energy output and all plant costs are known) are to 1) calculate the capital recovery factor and fixed charge rate(s), 2) calculate present values for all cost streams, and 3) calculate annualized costs and levelized energy cost. These steps are discussed below.

The annualized cost is made up of capital costs and recurring costs. Since the tax laws treat these costs differently they must be considered separately in the LEC analysis. The present value of all recurring costs must be multiplied by a capital recovery factor (CRF) to yield a single annual cost that represents all recurring costs over the life of the plant. This single annual cost is equivalent to the loan payment where the principal is equal to the present value of all the recurring cost. The CRF is calculated as shown below.

$$CRF = \frac{k}{1-(1+k)^{-N}} \tag{1}$$

where

k = discount rate

N = plant lifetime

The contribution of the capital costs to the annualized cost is the product of the present value of the capital construction costs and the fixed charge rate (FCR). The FCR accounts for income taxes (including depreciation and investment tax credit effects), return on equity, interest on debt, insurance, property taxes and other taxes. The FCR is calculated as shown in the following equation.

$$FCR = CRF * [(1-t*DPF-itc)/(1-t)+ p*(1+g_i)/(k-g_i)*(1-((1+g_i)/(1+k))^N)] \tag{2}$$

where

| | | |
|---|---|---|
| CRF | = | capital recovery factor |
| t | = | effective income tax rate |
| DPF | = | depreciation factor (defined below) |
| itc | = | investment tax credit |
| p | = | insurance and effective property and other tax rate as a fraction of capital cost |
| $g_i$ | = | general inflation rate |
| k | = | discount rate |
| N | = | plant life |

This formula for the FCR assumes that property taxes are constant in real terms.

The depreciation factor is calculated from the following formula:

$$DPF = \sum_{i=0}^{n_1} \frac{dp_i*(1-itc/2)}{(1+k)^i} \tag{3}$$

where

| | | |
|---|---|---|
| $dp_i$ | = | depreciation fraction allowed in year i |
| i | = | year relative to year 0 (the last year of construction) |
| itc | = | investment tax credit |
| k | = | discount rate |
| n | = | depreciation lifetime |

The reference time period for the present value calculation in Equation 3 and the other present value calculations in this section is year 0, the last year of plant construction. The choice of the year to use as the basis for present value calculations is a matter of convention.

Equation 3 assumes that the plant construction is completed at the end of a tax year, so the value of the first year's depreciation is not discounted. The values of $dp_i$ are determined from Accelerated Cost Recovery System (ACRS) depreciation schedules for the appropriate tax life of the investment. The tax life depends upon both the type of property and the ownership. ACRS depreciation schedules are summarized in Table 7.3–1.

Table 7.3–1

ACRS DEPRECIATION SCHEDULES (PERCENTAGE DEPRECIATION IN EACH YEAR)

| | Depreciation Lifetime | | |
|---|---|---|---|
| YEAR | 5 YEAR | 10 YEAR | 15 YEAR |
| 1 | 15 | 8 | 5 |
| 2 | 22 | 14 | 10 |
| 3 | 21 | 12 | 9 |
| 4 | 21 | 10 | 8 |
| 5 | 21 | 10 | 7 |
| 6 | | 10 | 7 |
| 7 | | 9 | 6 |
| 8 | | 9 | 6 |
| 9 | | 9 | 6 |
| 10 | | 9 | 6 |
| 11 | | | 6 |
| 12 | | | 6 |
| 13 | | | 6 |
| 14 | | | 6 |
| 15 | | | 6 |

If land costs are included in the cost of the plant, a special FCR for land should be used because land cannot be depreciated for tax purposes. The land FCR (FCRL) is calculated as:

$$FCRL = CRF * [1/(1-t)+ p * (1+g_l)/(k-g_l)*(1-((1+g_l)/(1+k))^N)] \quad (4)$$

where

CRF = capital recovery factor
t = effective income tax rate
p = insurance and effective property and other tax rate (fraction of installed cost)

This formula for FCRL assumes that property taxes are constant in real terms.

The next step for calculating the LEC is to determine the actual cash flows (nominal dollars) of all capital costs. Each year's construction cash flow can be calculated as follows:

$$C_i = CAP_b * FR_i * (1+g_c)^{i-b} \quad (5)$$

where

$C_i$ = capital cost expended in year i
i = year relative to year 0 (the last year of construction)
$CAP_b$ = total plant capital cost estimate in year b
b = base year for capital cost estimate relative to year 0
$FR_i$ = fraction of $CAP_b$ intended to be spent in year i
$g_c$ = capital cost escalation rate

The present value of all capital construction costs can then be calculated as:

$$PVC = \sum_{\text{all } i} \frac{C_i}{(1+k)^i} \quad (6)$$

where

$C_i$ = capital cost in year i
b = year relative to year 0 (the last year of construction)
k = discount rate

If land costs are included in the analysis, the present value of land cost (PVL) (assuming land is resold at the end of the plant's life) can be calculated as:

$$PVL = \frac{LC_b * (1+g_l)^{i-b}}{(1+k)^i} - \frac{LC_b * (1+g_l)^{N-b}}{(1+k)^N} \quad (7)$$

where

$LC_b$ = land cost estimate in year b
$g_l$ = land escalation rate
i = year land purchased relative to year 0
b = year of land cost estimate relative to year 0
k = discount rate
N = plant lifetime

The next step is to calculate the present value of all operations and maintenance (O&M) costs, (PVO).

$$PVO = (1+g_o)^{-b} * OM_b * \left(\frac{1+g_o}{k-g_o}\right) * \left(1 - \left(\frac{1+g_o}{1+k}\right)^N\right) \qquad (8)$$

where

$g_o$ = O&M escalation rate
b = base year for O&M cost estimate relative to year 0
$OM_b$ = O&M annual estimate in year b without allowing for escalation
k = discount rate
N = plant lifetime

For plants that require fuel (such as hybrid plants), the present value of fuel (PVF) costs is calculated as:

$$PVF = (1+g_f)^{-b} * F_b * \left(\frac{1+g_f}{k-g_f}\right) * \left(1 - \left(\frac{1+g_f}{1+k}\right)^N\right) \qquad (9)$$

where

$g_f$ = fuel escalation rate
b = base year for fuel cost estimate relative to year 0
$F_b$ = fuel annual estimate in year b without allowing for escalation
k = discount rate
N = plant lifetime

The annualized cost of the plant (expressed in year b dollars) can then be calculated as:

$$AC = (1+g_i)^b * [FCRL * PVL + FCR * PVC + CRF * (PVO + PVF)] \qquad (10)$$

where

AC= annualized cost in year b dollars
b = base year for costs relative to year 0

The LEC is then calculated as:

$$LEC = \frac{AC}{AOUT} \qquad (11)$$

where

LEC = levelized energy cost
AC = annualized cost
AOUT = annual energy output in appropriate units

Levelized energy cost comparisons can be made on the basis of either real or nominal dollars. A real dollar LEC is an energy cost which is level over time in dollars of constant purchasing power. A nominal dollar LEC is level over time in the actual dollars of each year. Nominal dollar LEC calculations are always numerically higher (for any positive inflation rate) than real dollar LEC calculations because general inflation over the plant's lifetime is included in the energy cost.

In general, the equations defined above can be used directly to estimate either a real or nominal LEC depending on whether the inputs are expressed in real or nominal terms. Alternatively, real and nominal dollar LEC's can be converted from one to the other via the following formula.

$$LEC_r = \frac{LEC_n}{CRF} * \frac{(k - g_i)}{(1+g_i) \ * \ [1 - ((1+g_i)/(1+k))^N]} \quad (12)$$

where

LEC$_r$ = real dollar LEC
LEC$_n$ = nominal dollar LEC
CRF = capital recovery factor
k = discount rate
$g_i$ = general inflation rate
N = plant lifetime

The direct approach to calculating a real dollar LEC requires that nominal depreciation credits be discounted by an assumed inflation rate which results in the following modification to Equation 3:

$$DPF = \sum_{i=0}^{N-1} \frac{dp_i \ * \ (1 - itc/2)}{((1+k) \ * \ (1+g_i))^i} \quad (3a)$$

Equation 3a calculates the depreciation factor by discounting real credits by the real discount rate. This yields exactly the same depreciation factor as Equation 3 which discounts nominal credits by the nominal discount rate.

## LEC CALCULATIONS EMPLOYING SOLAR THERMAL FIVE YEAR PLAN ASSUMPTIONS

The Solar Thermal Five Year Plan provides standard economic assumptions for use in LEC calculations. These assumptions are presented in Tables 7.3–2 and 7.3–3 for electric power and industrial process heat applications, respectively. Fixing the economic assumptions reduces the LEC calculation to equations 13–16 shown below.

$$PVC = (\text{Capital Cost}) * (PVCF) \quad (13)$$

where PVCF = capital cost present value factor,

$$PVL = (\text{Land Cost}) * (PVLF) \quad (14)$$

where PVLF = land cost present value factor, and

$$PVO = (\text{Annual } O\&M \text{ Cost}) * (PVOF) \quad (15)$$

where PVOF = O&M cost present value factor.

Capital, land, and O&M costs should be estimated in price year dollars corresponding to the first year of plant construction for the present value factors in these equations to be correct. Economic parameters yielding a real dollar LEC estimate (in first year of construction dollars) from equations 13–16 are shown in Table 7.3–4.

The LEC can then be calculated:

$$LEC = \frac{1}{AOUT}(PVC \ * \ FCR_r + PVL \ * \ FCRL_r + PVO \ * \ CRF) \quad (16)$$

where

FCR$_r$ = real fixed charge rate
FCRL$_r$ = real fixed charge rate for land
CRF = real capital recovery factor
AOUT = annual energy output in appropriate units

Values of the economic variables in the above equations are presented in Table 7.3–4.

Table 7.3-2

STANDARD ASSUMPTIONS[4] FOR ELECTRICITY FROM A SOLAR THERMAL PLANT

| Variable | Value | Description |
|---|---|---|
| Plant construction time | 3 years | Representative of probable construction time for a large solar installation. Time for small plants would be much shorter. Uniform construction cost over the period is assumed. |
| Cost Years | | All are assumed to be estimated in the year construction begins and are escalated to the year costs are actually incurred. Land is purchased the year construction begins. |
| General Inflation Rate | 0.04 | Assumed to represent long-term trend in capital and 0&M cost escalation over plant's lifetime. |
| Economic Life | 30 years | Standard assumption for utility plant lifetime. |
| Depreciation time | 10 years | Current tax law for utility investments in solar generating plants. Would vary with ownership. |
| Depreciation schedule | ACRS | Current tax law. |
| Investment tax credit | 0.1 | Current tax law. |
| Discount rate | 0.0315 | Assumed as the real after-tax cost of capital. Utility capitalization structure and debt/equity costs taken from Reference 5. |
| Property and other taxes | 0.01 | Annual property and other tax payment in real terms as a fraction of plant capital. |

Table 7.3-3

STANDARD ASSUMPTIONS[4] FOR INDUSTRIAL PROCESS HEAT FROM A SOLAR THERMAL PLANT

| Variable | Value | Description |
|---|---|---|
| Plant construction time | 3 years | Representative of probable construction time for a large solar installation. Time for small plants would be much shorter. Uniform construction cost over the period is assumed. |
| Cost Years | | All are assumed to be estimated in the year construction begins and are escalated to the year costs are actually incurred. Land is purchased the year construction begins. |
| General Inflation Rate | 0.04 | Annual increase in overall price level. Assumed to represent long-term trend in capital and O&M cost escalation over plant's lifetime. |
| Economic Life | 20 years | Standard assumption for industrial project evaluation. |
| Depreciation time | 5 years | Current tax law for industrial investments in solar generating plants. |
| Depreciation schedule | ACRS | Current tax law. |
| Investment tax credit | 0.1 | Current tax law. |
| Discount rate | 0.10 | Assumed as the real after-tax cost of capital factoring in a risk premium for the possibility that the plant revenues would vary significantly from projections. |
| Property and other taxes | 0.01 | Annual property and other tax payment in real terms as a fraction of plant capital. |

Table 7.3–4.

ECONOMIC PARAMETERS FOR SOLAR PLANT LEC CALCULATION USING SOLAR THERMAL FIVE YEAR PLAN ASSUMPTIONS

| Variable | Electric | IPH |
|---|---|---|
| PVCF | 1.0318 | 1.1033 |
| PVLF | 0.7031 | 1.1824 |
| PVOF | 19.2258 | 8.5136 |
| $FCR_r$ | 0.0663 | 0.1360 |
| $FCRL_r$ | 0.1140 | 0.2449 |
| $CRF_r$ | 0.0520 | 0.1175 |

## REFERENCES


1. J. W. Doane, et al., *The Cost of Energy from Utility-Owned Solar Electric Systems*, ERDA/JPL 1012-76/3, 1976.

2. T. A. Williams, et al., *Solar Thermal Financing Guidebook*, Battelle Pacific Northwest Laboratories, PNL-4745, May 1983.

3. T. A. Williams, J. A. Dirks, and D. R. Brown, *Long Term Goals for solar Thermal Technology*, Battelle Pacific Northwest Laboratories, PNL-5463, May 1985.

4. National Solar Thermal Technology Program, *Five Year Research and Development Plan 1986–1990*, DOE/CE-0160, September 1986.

5. *Technical Assessment Guide*, Electric Power Research Institute, 1982.

# COST SENSITIVITIES

Variations in the inputs for levelized energy cost calculation are examined to illustrate the sensitivity of the calculated energy cost to these variations. In general, there are three types of levelized energy cost model inputs: financial variables, cost variables, and performance variables. The variables investigated in this section are listed in Table 7.4–1.

Table 7.4–1

LEC SENSITIVITY VARIABLES

| | |
|---|---|
| Financial: | discount rate |
| | depreciable life |
| | construction period |
| | inflation rate |
| | tax credits |
| | tax rate |
| Cost: | capital |
| | land |
| | O&M |
| Performance: | annual output |

The base case for the sensitivity analysis assumed a 100 $MW_e$ plant with an initial cost of $250,000,000 ($2500/$kW_e$), annual O&M costs of $5,000,000 (2% of capital), and land costs of $10,000,000. Standard economic assumptions for a utility-owned electric power plant (see Table 7.3–2) were employed along with an assumed annual power output of 458 GWh to exactly yield a LEC of $0.05/kWh.[1,2] LEC sensitivity to these base case assumptions are discussed below.

The standard after-tax discount rate for a utility-owned power plant is 3.15% based on the utility's capitalization structure and debt and equity rates presented in EPRI's Technical Assessment Guide.[3] The actual cost of capital may vary for any particular owner, even among utilities. Discount rates ranging from 2-5% cause the levelized energy cost to vary by a factor of 1.4 as shown in Table 7.4–2.

Table 7.4–2

LEC SENSITIVITY TO DISCOUNT RATE

| Rate % | LEC $/kWh |
|---|---|
| 0.02 | 0.0437 |
| 0.03 | 0.0491 |
| 0.0315 | 0.0500 |
| 0.04 | 0.0551 |
| 0.05 | 0.0616 |

Current interpretation of tax laws has assigned a 10 year depreciable life to utility investments in solar generating equipment. The Accelerated Cost Recovery System (ACRS) defines depreciation schedules for 5, 10, and 15 year property (see Table 7.3–1). Five or 15 year depreciable lives are easily conceivable if tax laws are changed slightly or reinterpreted. The variation in levelized energy cost with changes in plant depreciable life is shown in Table 7.4–3.

Table 7.4–3

LEC SENSITIVITY TO DEPRECIABLE LIFE

| Life Yrs. | LEC $/kWh |
|---|---|
| 5 | 0.0469 |
| 10 | 0.0500 |
| 15 | 0.0526 |

The plant construction period impacts the amount of interest during construction that is included in the LEC.

The standard assumption assumes that plant construction is completed in three years. The impact on LEC of completing construction in one year or five years is shown in Table 7.4–4.

Table 7.4–4

LEC SENSITIVITY TO CONSTRUCTION PERIOD

| Const. Period Years | LEC $/kWh |
|---|---|
| 1 | 0.0487 |
| 3 | 0.0500 |
| 5 | 0.0514 |

Inflationary assumptions do not affect a real dollar levelized energy cost except for treatment of the depreciation credits. Depreciation credits are specified in nominal terms and must be deflated in a real dollar analysis. The result of varying the inflation assumption around the standard 4% is shown in Table 7.4–5.

Table 7.4–5

SENSITIVITY TO INFLATION RATE

| Rate % | LEC $/kWh |
|---|---|
| 2 | 0.0484 |
| 4 | 0.0500 |
| 6 | 0.0514 |

Tax credits can have a major impact on the economic feasibility of a solar power plant. Current tax law allows investors to take a 10% investment tax credit. Through 1985, an additional 15% Federal energy tax credit was also available. Future tax laws may disallow investment tax credits altogether. Tax credits ranging from 0-25% caused the LEC to vary by a factor of 1.28 as shown in Table 7.4–6.

Table 7.4–6

LEC SENSITIVITY TO TAX CREDITS

| Rate % | LEC $/kWh |
|---|---|
| 0 | 0.0548 |
| 10 | 0.0500 |
| 25 | 0.0429 |

Marginal effective (combined federal and state) corporate tax rates are currently at or near 50% which is the assumption in these calculations. Corporate tax rates may be substantially reduced under several versions of tax reform legislation currently being considered by Congress. The impact on the levelized energy cost of tax rates ranging from 30-50% is shown in Table 7.4–7.

Table 7.4–7

LEC SENSITIVITY TO TAX RATES

| Rate % | LEC $/kWh |
|---|---|
| 30 | 0.0465 |
| 40 | 0.0479 |
| 50 | 0.0500 |

The relative impact on the levelized energy cost of varying capital, O&M, and land costs depends on the actual cash flows for each of these components, the discount rate, and their individually unique tax treatment. Higher discount rates give more weight to initial capital costs while lower discount rates tend to accent recurring O&M costs. The variation in the levelized energy cost for a 20% increase in capital, O&M, and land cost is shown in Table 7.4–8.

Table 7.4–8

LEC SENSITIVITY TO INCREASED COSTS

| Cost Factor (+20%) | LEC $/kWh |
|---|---|
| capital | 0.0575 |
| O&M | 0.0522 |
| land | 0.0504 |

Variation in system performance has a simple, direct impact on the levelized energy cost. For example, a 20% decrease in annual energy output increases the LEC by 25%.

The sensitivity analyses investigated above are intended to illustrate how variations in individual parameters affect the system LEC rather than being representative of any particular financial arrangement. The potential impact of alternative financial situations on system LEC is briefly illustrated here by employing the Solar Thermal Five Year Plan financial assumptions for utility and industrial ownership. The distinguishing financial assumptions for these two cases and their resultant levelized energy costs are shown in Table 7.4–9. A more detailed discussion of alternative financing of solar thermal power plants may be found in Reference 4.

Table 7.4–9

LEC SENSITIVITY TO OWNERSHIP

| Distinguishing Characteristic | Utility-Owned Plant | Industrial-Owned Plant |
|---|---|---|
| discount rate | 0.0315 | 0.010 |
| economic life | 30 years | 20 years |
| depreciable life | 10 years | 5 years |
| LEC ($/kWh) | 0.0500 | 0.0991 |

## THE IMPACT OF LIMITED CAPITAL ON PLANT DESIGN AND ECONOMICS

The levelized energy cost methodology is described elsewhere in this chapter as an appropriate tool for preliminary economic comparisons of solar thermal power systems. However, the LEC methodology focuses only on costs and does not incorporate unique economic factors facing specific owners and utilities. Selecting a plant design based on minimizing LEC presumes all of the plant's power output is sold at the same price, regardless of when it is put on the grid. The impact of time-of-day pricing on plant design and economics was discussed in Chapter 4. The methodology also places no limits on the amount of capital available for investment. The impact of limited capital availability on plant design and economics is discussed here.

Solar thermal plants are driven to larger sizes by three different forms of economy-of-scale. Strict economies-of-scale exist for many components: i.e., unit costs decline as unit size gets larger. System efficiencies also tend to improve with plant size due mostly to improved energy conversion efficiency and decreased parasitics as a percent of plant power output. Solar thermal plants are also economically driven to add storage and achieve higher capacity factors. The advantage of higher capacity factors stems from greater utilization of fixed energy conversion costs as well as strict economies-of-scale resulting from a larger energy collection system.

The cost drivers noted above work together to push the minimum energy cost system to a power level in the range of 100–200 $MW_e$ with large capacity factors. Most economies-of-scale are captured by a 100 $MW_e$ plant, but even a system of this size could cost nearly half a billion dollars, depending on specific assumptions regarding component cost. Four possible strategies for reducing the required investment are to:

1) reduce power level
2) reduce capacity factor
3) reduce both the power and capacity factor
4) trade lower initial quality and cost for higher annual O&M costs

Normalized LECs and capital investment requirements are shown in Tables 7.4–10 and 7.4–11 below. The figures in the tables indicate two important observations: 1) relatively small increases in LEC (20-30%) allow relatively large reductions (50-75%) in capital expenditures and 2) increasing the levelized energy cost by lowering the plant's power rating is more effective at reducing initial plant cost than a similar increase in levelized energy cost brought about by decreasing plant capacity factor at a fixed power rating. For example, a high capacity factor 30 $MW_e$ plant has nearly the same size energy collection (concentrator, receiver, tower, transport) system as a low capacity factor 100 $MW_e$ plant, but a much smaller and less expensive energy conversion system.

One implication of a limited capital scenario is an investor facing a high marginal cost of capital and hence a high discount rate. Investors with high discount rates will prefer systems with lower intial cost, but higher annual O&M costs, all else equal. Higher real discount rates put a premium on up-front costs and tend to minimize the importance of recurring costs occurring several years hence.

An illustration of the potential impact of different discount rates on system selection is shown in Table 7.4–12. Two solar thermal systems are postulated. The first is a relatively capital-intensive, low O&M system and the second a system with lower initial costs, but higher annual O&M. Levelized energy costs have been estimated for each system under low and high discount rate assumptions. As shown in Table 7.4–12, an investor with a high discount rate (Investor #2) would prefer the less capital-intensive system (System #1) and vice-versa for an investor with a low discount rate.

As discussed previously, revenue stream considerations have a substantial impact on plant design and economics. Combining the capital cost constraint with a variable avoided cost structure will naturally complicate matters. The best advice is to consider several different plant configurations. Capital availability may limit the range of plant size and capacity factors, but once in the ballpark, a relatively small investment or reallocation of capital among system components may yield an attractive marginal return.

## REFERENCES


1. T. A. Williams et al., "Characteristics of Solar Thermal Concepts for Electricity Generation," Battelle Pacific Northwest Laboratories, January 1987.
2. T. A. Williams and J.A. Dirks, "Economic Evaluation of Solar Thermal Energy Systems Using a Levelized Energy Cost Approach," PNL-SA-13507, *Proceedings of Seventh Miami International Conference on Alternative Energy Systems*, Miami, Florida, December 1985.
3. Electric Power Research Institute, *Technical Assessment Guide* 1982.

4. T. A. Williams, et al., *Solar Thermal Financing Guidebook*, Battelle Pacific Northwest Laboratories,PNL–4745, 1983.

# APPENDICES

# APPENDIX A

# CENTRAL RECEIVER TEST FACILITIES AND PLANTS

Summary descriptions of central receiver test facilities and plants are provided in Tables A–1 and A–2, respectively. Additional information about the test facilities and plants may be found in A. C. Skinrood, *Characteristics of Central Receiver Systems*, Sandia National Laboratories Livermore, SAND 86-8058, 1987, and in *Solar Thermal Central Receiver Systems*, M. Becker, ed., Springer-Verlag, Berlin, 1986.

Table A–1

CENTRAL RECEIVER TEST FACILITY INFORMATION

| Name | Central Receiver Test Facility | Advanced Components Test Facility | Centre National de la Recherche Scientifique Solar Furnace | Central Receiver Facility |
|---|---|---|---|---|
| Location | Sandia National Laboratories Albuquerque, NM, USA | Georgia Institute of Technology Atlanta, GA, USA | Laboratoire d'Energétique Solaire, Odeillo, France | Weizmann Institute of Science Rehovot, Israel |
| Size ($MW_t$) | 5.5 | 0.4 | 1.0 | 3.5 |
| Heliostat Size (m) | 6.0 × 6.0 | 1.10 (diameter) | 6.0 × 7.5 | 7.4 × 7.4 |
| No. of Heliostats | 222 | 550 | 63 | 64 |
| Field Configuration | north | surround | north | north |
| Peak Flux at Center Beam ($W/cm^2$) | 225 | 200 | 1600 | ~200 |

Table A-2

CENTRAL RECEIVER PLANT INFORMATION

| Plant Name | EURELIOS | Central Electrosolar de Almeria (CESA-1) | International Energy Agency Small Solar Power Systems (IEA/SSPS) Central Receiver System (CRS) | Sunshine Project Solar Thermal Power Generation System #1 Unit of Nio Solar Thermal Power Plant (SUNSHINE) | Centrale Solaire Thermis 2.5 MW (THEMIS) | 10 $MW_e$ Solar Thermal Central Receiver Pilot Plant (SOLAR ONE) |
|---|---|---|---|---|---|---|
| Plant Rated Output ($MW_e$) | 1.0 | 1.0 | .5 | 1.0 | 2.0 - 2.5 | 10.0 |
| Plant Location | Adrano, Scicily, Italy | Tabernas (Almeria, South Spain) | Tabernas (Almeria, South Spain) | 43-1 Nio, Nio Town Kagawa Pref., Japan | Targasonne, Pyrenees Orientales, France | Daggett, California, United States |
| Plant Sponsor | Commission of the European Communities and the Governments of France, Italy, and Germany | Instituto de Energias Renovables JEN Ministerio de Industria y Energia | Nine IEA member countries of Austria, Belgium, Germany, Greece, Italy, Spain, Sweden, Switzerland, and United States | Agency of Industrial Science and Technology, Ministry of International Trade and Industry | Agence Francaise pour la Maitrise de l'Energie, (AFME) Electricite de France (EDF) | United States Department of Energy and Utility Associates (Southern California Edison, Los Angeles Dept. of Water and Power) |
| Schedule and Status | Test program completed in in July, 1986. Future of plant uncertain. | Test program continuing. | Test program continuing. | Test program completed, facility dismantled. | Test program completed July 1, 1986. Future plans uncertain. | Power Production to be completed in July, 1987. Future plans uncertain. |

Table A-2
CENTRAL RECEIVER PLANT INFORMATION (CONT)

| | EUR. | CESA-1 | IEA | SUNS. | THEMIS | SOLAR 1 |
|---|---|---|---|---|---|---|
| Sunshine Hours Per Year | 2250 at >250 W/$m^2$ | 3000 (E) | 3000 (E) | 2200 | 2400 | 3600 - 4000 (52% of daylight hours have zero skycover) |
| **HARDWARE** | | | | | | |
| HELIOSTATS | | | | | | |
| Total Number | Cethel/MBB 70/112 | 300 | MM/MBB 93/30 | 807 | 201 | 1818 |
| Reflective Area Per Helio ($m^2$) | 52/23 | 39.6 | 39.3/53.6 | 16 | 53.7 | 39.3 |
| Total Plant Reflective Area ($m^2$) | 6216 | 11,880 | 5262 | 12,912 | 10,740 | 71,447 |
| RECEIVER | | | | | | |
| Type | Cavity | Cavity | Cavity/External | Cavity | Cavity | External |
| Receiver Fluid | Water/Steam | Water/Steam | Sodium | Water | Hitec Salt | Water/Steam |
| Receiver Fluid Inlet Temperature (°C) | 37 | 200 (model) | 270 | — | 250 | 104-175 |
| Receiver Fluid Outlet Temperature (°C) | 512 | 525 | 530 | 250 | 450 | 516 |
| Receiver Fluid Outlet Pressure (bars) | 62 | 108 | 2.7 | | 1-2 | 105 |
| Peak Heat Flux on the Absorber (MW/$m^2$) | .60 | 56 | 60/1.5 | | 69 | 35 |
| Maximum Thermal Power Rating of the Receiver ($MW_t$) | 4.8 | 8 | 2.7/2.7 | — | 9 | 43.4 |

Table A-2

CENTRAL RECEIVER PLANT INFORMATION (CONT)

| | EUR. | CESA-1 | IEA | SUNS. | THEMIS | SOLAR 1 |
|---|---|---|---|---|---|---|
| THERMAL ENERGY STORAGE | | | | | | |
| Storage Description | Buffer | Two Tank Hot and Cold | Two Tank Hot and Cold | Five Tank Accumulators | Two Tank Hot and Cold | Oil/Rock Thermo cline |
| Storage Fluid | Molten Salt and Hot Water | Hitec Salt | Sodium | Pressurized Water | Hitec Salt | Caloria HT-43 |
| Storage Fluid High Temperature (°C) | 430-Salt 410-Water | 340 | 530 | 249 | 450 | 302 |
| Storage Fluid Low Temperature (°C) | 275-Salt 206/170-Water | 220 | 275 | 197 | 250 | 218 |
| Storage Capacity ($MW_t$-h) | .3 Water .06 Salt | 18 | 5.5 | 17.857 | 40 | 165 |
| Hours of Storage | .5 | 3.5 (840$KW_e$) | 2 | 3 | 5 | 4 |
| STEAM GENERATOR | | | | | | |
| Type | — | Evaporator and Reheater | Helical Coil Once Through | — | Evaporator and Superheater | N/A |
| TURBINE GENERATOR | | | (Steam Motor) | 7-Storage Impulse Steam Turbine | | |
| Manufacturer | Ansaldo | Siemens | Spilling | — | ALSTROM | GE |
| Nameplate Rating ($MW_e$) | 1.2 | 1.2 | .617 | — | 2.5 | 12.5 |
| Heat Rate (kW) | 3.97 (4.82 net) | 4.35 | — | | 3.57 kW | 9,700 Btu/kW-hr @1465 psia/950°F/2.5″ Hg |
| Cooling Tower Type (wet, dry) | | Dry | Wet | Wet | Dry | Wet |

Table A-2
CENTRAL RECEIVER PLANT INFORMATION (CONT)

| | EUR. | CESA-1 | IEA | SUNS. | THEMIS | SOLAR 1 |
|---|---|---|---|---|---|---|
| **PLANT PERFORMANCE** | | | | | | |
| Reference Day | March 21 | Dec. 21 | March 21 | | March 21 | March 21 |
| Reference Time | 1200 | 1000 | 1200 | | 1200 | Solar Noon |
| Reference Insolation ($W/m^2$) | 1000 | 700 | 920 | | 1040 | 950 |
| Solar Multiple | 1 | 1.93 (June 21) | 1.11 | | | 1.25 (June 21) |
| Heliostat Field Efficiency | Cethel/MBB .74/.8 | .72 | .845 | | .84 | .90 |
| Receiver Efficiency | .86 (without pyrex) | .91 | .88/.92 | .748 | .95 | .82 |
| Storage Utilization Factor | .15 | .05 | 1.0 | | 0 | |
| Power Conversion Systems Gross Efficiency | .27 | .27 | .272 | .168 | .28* | .345 |
| Power Conversion Net Efficiency When Operating From Storage | — | .21 | .23 | .168 | | .25 |
| Overall Reference Day Plant Efficiency | .16 | .13 | .165 | .085 | .15* | 0.174 |

*Project figures, TBD.

# APPENDIX B
# SAMPLE PROBLEM

Staff at a southwestern utility system have completed a generation expansion study. They identified the need for a plant with a net rating of 100 $MW_e$ and an annual capacity factor of approximately 0.4. The utility owns four square miles of land which is suitable for a solar thermal central receiver facility, per criteria discussed in Chapter 3. The average daily direct normal insolation (DNI) for the site is read from Figure 3-1 as 7.5 $kWh/m^2/day$.

The system planer follows the approach presented in Section 4.2 of this Handbook to assess the feasibility of a solar thermal central receiver system in meeting the utility's needs.

**Step 1. Plant Definition**

On the basis of the generation expansion study, the solar plant rating would be 100 $MW_e$ with a capacity factor of 0.5. After evaluating factors discussed in Sections 2.3–3 and 4, the planner selects molten salt as the receiver fluid and molten salt as the storage fluid because of the need for extended energy storage. Also, a north facing cavity receiver and a two tank molten salt thermal storage configuration are selected.

The capacity factor for the calculation is estimated using Figure 4.2–1 based on a user capacity factor of 0.5 and a user DNI of 29 $MJ/m^2$ to be 0.4.

**Step 2. Solar Multiple**

From Figure 4.2–2, for a capacity factor of 0.4, the solar multiple is read as 2.0.

**Step 3. Receiver Size**

For a plant rating of 100 $MW_e$ and a solar multiple of 2.0, the corresponding value of receiver thermal power is read from Figure 4.2–3 as 530 $MW_t$.

**Step 4. Field Sizing**

Based on Figure 4.2–5, for a north cavity receiver of thermal rating 530 $MW_t$, the reflective area required is 850,000 $m^2$ (or $9.15 \times 10^6$ $ft^2$).

**Step 5. Land Area**

For a 530 $MW_t$ north cavity receiver, the total land area requirement is $5.7 \times 10^6$ $m^2$ (or 1440 acres) from Figure 4.2–6.

**Step 6. Tower Height**

From Figure 4.2–7, for a north cavity receiver rated at 530 $MW_t$, the tower height is 245 m (or 805 ft.)

**Step 7. Receiver Sizing**

For a 530 $MW_t$ cavity salt receiver, the absorber area required is shown in Figure 4.2–9 as 1,630 $m^2$ (or 17,500 $ft^2$).

**Step 8. Thermal Storage Sizing**

Based on a plant rating of 100 $MW_e$ and a 40% capacity factor, 6 hours of storage and a storage capacity of 1,600 $MWh_t$ are required as shown in Figure 4.2–11.

**Step 9. Annual Energy Estimate**

The electricity produced throughout the year by the solar plant is shown in Figure 4.2–14.

### Step 10. Levelized Energy Cost

This step requires additional economic input from the user. Based on assumptions and procedures described in Section 7.3 and on cost estimates contained in Section 7.2, the cost of energy from this system is estimated to be \$0.10/kWh.

# APPENDIX C
# COMPUTER CODE DESCRIPTIONS

A number of computer codes have been developed for use in the design and analyzes of solar central receiver plants. Industrial, government, and academic institutions have developed individual analytic tools to model different aspects of central receiver systems. This section describes significant computer codes that were written and documented as a part of the U. S. DOE Central Receiver Technology Program.

Each computer code covers a different area of design or analysis; some provide detailed calculations; others faster, but less-detailed, solutions. Certain codes require inputs obtained from the outputs of other codes.

These codes are used as a part of the process for conceptual design, preliminary design, and detailed design. Generally, they evaluate three aspects of central receiver systems: field optical performance, system performance, and receiver performance.

Table C–1 lists major, documented codes useful in the evaluation of central receiver systems. A description of each code follows.

## MIRVAL

**Basic Features.** MIRVAL[1] is a Monte Carlo ray-tracing program which simulates individual heliostats and a portion of the receiver as it calculates optical performance of well-defined solar thermal central receiver systems. It was created for detailed evaluation and comparison of fixed heliostat, field, and receiver designs. It accounts for the effects of shadowing, blocking, heliostat tracking, and random errors in tracking and in the conformation of the reflective surface, insolation, angular distribution of incoming solar rays to account for limb darkening and scattering, attenuation between the heliostats and the receiver, reflectivity of the mirror surface, and aiming strategy.

Power runs that occur at a point in time, and energy runs, which integrate power over time, require about the same time to execute. Rays of light, selected from the vicinity of the sun, are traced until they are intercepted by the receiver, lost in a prior absorption process, or deflected enough to miss the receiver. For a power run, the output includes the power incident on the receiver; the power density on the terminal surface; the power shadowed by the mirrors or the receiver, or both; the power blocked by mirrors; the power incident on the ground; the power that clears the heliostats after reflection but misses the receiver, and the power that clears the heliostats but is absorbed or scattered before reaching the receiver. For energy runs, the output refers to time-averaged power.

Three receiver types (external cylinder, cylindrical cavity with a downward-facing aperture, and north-facing cavity) and four heliostat types (three which track in elevation and azimuth including one enclosed in a plastic dome, and one with lowered mirror modules supported on a rack that rotates about a horizontal axis) are included in the code. MIRVAL

Table C–1
MAJOR COMPUTER CODES

| Name | Use | Description | Ref. |
|---|---|---|---|
| **FIELD OPTICAL PERFORMANCE** | | | |
| MIRVAL | optical performance of fixed designs | models heliostat(s) to partial receiver using Monte Carlo ray tracing | 1 |
| HELIOS | flux density of fixed designs | models heliostat(s) to target using cone optics | 2 |
| University of Houston Codes | | | |
| NS | interception and flux data; dirunal and annual performance data for fixed designs. | models heliostats to base of tower; uses Hermite polynomials and shading-blocking and processor | 3 |
| RC | detailed cost/performance optimization of solar components using NS interception data and annual shading and blocking performance. | Optimizes heliostat spacings and field, tower, and receiver dimensions, on level or multiplanar fields. | 4,5 |
| IH | uses RC data to specify heliostat locations and computes performance for each heliostat. | detailed layout processor; interpolates NS data base for interception; models heliostats to base of tower. | 6 |
| CAVITY/ CREAM | Generates node structure in cavity and computes node insolation, redistributes radiation, and estimates node temperatures | 2 band energy exchange; viewfactor calculation; iterative temperature determination. | 7,8 |
| DELSOL | performance and optimization of complete system | models heliostat to energy out of plant, optics handled with Hermite polynomials | 9 |

Table C-1
MAJOR COMPUTER CODES (Continued)

| Name | Use | Description | Ref. |
|---|---|---|---|
| **SYSTEM PERFORMANCE** | | | |
| SOLERGY | plant annual energy production for different dispatch strategies | first law energy analysis of system | 10 |
| DELSOL | performance and optimization of complete system | models heliostats, field receiver and balance of plant components, calculates levelized energy cost | 9 |
| SUNBURN | comparison of solar only, fossil only and solar/fossil hybrid plants | examines cost and performance of hybrid systems based on time of day energy value | 12 |
| **RECEIVER PERFORMANCE** | | | |
| RADSOLVER | radiation transfer in cavity receivers | wavelength dependent energy exchange using band models | 13 |
| DRAC | absorption of energy in working fluid | transient and steady state thermo-hydraulic analysis of solar receiver tubes | 15,16 |
| CAVITY | radiation transfer and energy absorption in cavity receiver | simplified combination of DRAC and RADSOLVER | 18 |
| CAVITY/ CREAM | Generates node structure in cavity and computes node insolation, redistributes radiation, and estimates node temperatures | 2 band energy exchange; viewfactor calculation; iterative temperature determination. | 7,8 |

can be modified to evaluate other heliostats or receivers by changing a small number of subroutines.

**Typical Applications and Uses.** MIRVAL calculates field efficiencies and flux maps when a rigorous optical model is desired. It has been used as a check on the flux calculations of other codes such as DELSOL, HELIOS, and the University of Houston codes.

**Program Details.** Three different types of information must be supplied to MIRVAL:

(1) A file which groups the heliostats in the heliostat field in a regular way is required for efficient calculations. The coordinates of the centers of each heliostat are read by a preprocessor, which creates the necessary file so that mirrors affected by an incoming light ray can be identified.

(2) Sunshape information which describes the angular dependence of power coming from the sun must be provided.

(3) A namelist provides the balance of the system description. This includes information regarding heliostat type, configuration, dimensions, and performance; receiver type and dimensions; zoning options; insolation; attenuation; starting and stopping times for a calculation; miscellaneous parameters; and graphs.

### HELIOS

**Basic Features.** HELIOS[2], a computer code originally developed for modeling the Central Receiver Test Facility, uses cone optics to evaluate flux density. This pattern can be matched to actual measurements of the flux density from the modeled heliostat, which is obtained with a beam characterization system. HELIOS can be used to analyze the flux density arising from fields of from 1 to 559 individual heliostats or 559 cells containing multiple heliostats.

The performance of central receiver heliostats, parabolic dish, and other reflecting solar energy collector systems can be evaluated with this code. Calculations are made with respect to fields of individual solar concentrators and a single target surface. Safety considerations with respect to abnormal heliostat tracking can be evaluated.

Effects included in detail in HELIOS are declination of the sun, earth orbit eccentricity, molecular and aerosol scattering in several standard clear atmospheres, atmospheric refraction, angular distribution of sunlight, reflectivity of the facet surface, shapes of focused facets, and distribution of errors in the surface curvature, aiming, facet orientation, and shadowing and blocking.

**Typical Application and Uses.** HELIOS is used where a detailed description of the heliostat is available and an extremely accurate evaluation of flux density is desired. It has been used to evaluate heliostat compliance to design criteria, as well as characterization of the Solar One heliostats, IEA heliostats, Second Generation heliostats, and CRTF heliostats. It is also used for personnel safety calculations.

**Program Details.** Input data to HELIOS are divided into seven groups:

(1) Problem and output data define the amount of output, plotting, degree of shadowing and blocking, execution of flux density calculations, heliostats

to be evaluated, and execution of atmospheric attenuation calculations.

(2) Sun parameters define insolation, sunshape, method and frequency of evaluating sunshape convolution, sunshape error distribution, concentrator errors, sun tracking errors, and calculation bounds.

(3) Receiver parameters define target points, target point output, degree and type of power density output, target orientation, focal points, aim points, type of receiver, shape and location of aperture, overall shape of the receiver, location and shape of the tower, and target surface.

(4) Facet parameters define facets on heliostats, subfacets for power density calculations, shape of facet surface, facet reflectivity, and whether gravity or wind loading effects are to be included.

(5) Heliostat parameters define the number of heliostats, focusing and canting, tracking mode, criteria for shadowing and blocking, and heliostat jitter from discrete motion of the drive motors.

(6) Time parameters define the days and times of day to be evaluated and the day that heliostat facets are aligned.

(7) Atmospheric parameters define atmospheric pressure, standard sea level pressure, atmospheric temperature at the top of the tower, attenuation model, and propagation loss model.

## UNIVERSITY OF HOUSTON FIELD CODES[3–8]

The University of Houston codes consist of a suite of four Fortran 77 codes, each with a number of optional operating modes. These codes deal primarily with the optical design of heliostat fields and receivers. Thermal and economic algorithms are incorporated to enable optimization, performance and design studies of the complete solar thermal plant. These algorithms, along with data and program controls are contained in four input modules, and are input by selection of an appropriate set of modules or by directly editing these modules; thus no external data are required. The bulk of the code is not affected and need not be recompiled. Honeywell 66/60 and VAX 780 versions are available.

(1) The DRIV module contains data relating to variable dimensioning, time controls, the sun, field boundaries and exclusion zones, program options, and output options.

(2) The FIELD module contains data on the collector field including site-related information, tower height, and cell size. Various field-related cost parameters and coefficients for distribution of heliostats in the field and choices of heliostat layout patterns are also in this module. The field may be an arbitrarily inclined plane or up to five such intersecting planes. Insolation data may be input directly or calculated from long term monthly average weather parameters. Heliostat to receiver attenuation is modeled through use of monthly average visual range data.

(3) The HELIOS module includes all inputs related specifically to rectangular or circular heliostats. Image degradation, focusing and canting, and heliostat costs including O&M are specified in this module. Guidance errors are considered to be isotropic.

(4) The RECVER module contains all inputs that deal with describing the receiver geometry, losses, and aim points. Controls allow choice of cylindrical receivers or flat receivers with specified azimuth and angle. Cavity receivers may be represented by apertures with unspecified interiors. Sophisticated one and two-dimensional aiming strategies are available. Receiver, tower, and piping costs are specified also.

Selection of a DRIV module (and a standard option) defines the type of run: interception data, annual performance, field optimization, solar thermal system optimization, heliostat layout or annual performance. Selection of specific modules defines the problem: a FIELD module defines the site and weather, a HELIOS module defines the heliostat design and a RECVER module selects among models for flat, cavity, cylindrical, receivers employing salt, sodium or steam working fluids. All cost and essentially all performance algorithms are contained in these modules and are accessible for user modification.

By generating and using data bases, considerable CPU time saving can be saved. Node files allow rapid calculation of receiver interception and of flux maps while shading and blocking data bases accelerate field and system optimization.

**NS Cellwise Performance.**

*Basic Features.* NS evaluates central receiver optical performance for a specified geometry by dividing the field into orthogonal cells that have a north-south orientation and using a single heliostat (or four heliostats for close-in cells) to represent all heliostats in the cell. A variety of image generators are available, the most frequently used being a 2-dimensional Hermite expansion of images.

NS generates a "node file" which stores the interception fraction on each element of the receiver for each cell in the field (typically 204 words). The NS performance simulation includes models for astronomical features, the collector field, heliostat mounting systems, shading and blocking, and effects on heliostat images due to heliostat geometry, focus and cant, orientation, atmospheric losses, and sunshape.

*Typical Applications and Uses.* The University of Houston has used NS to evaluate field performance for DOE-funded solar central receiver system design contracts and to determine flux distributions for specific receiver designs.

Typical VAX CPU time is 30 sec. Hour by hour power or efficiency data for a specified heliostat field can be generated for a clear day in each month and integrated with a node file and weather data to provide annual performance. Receiver panel powers and gradients can be printed for each instant. Special timing sequences provide sunrise startup data and cloud passage data. In addition "drift studies" provide for multiple flux maps with the heliostats either fixed (sun drift) or slewing on either axis. A typical annual run requires 1–3 minutes of VAX 780 CPU time.

*Program Details.* A node file, which contains interception fractions for each receiver node from each cell in the field, is generated by NS. A node file allows NS, RC or IH to generate interception data or flux maps as required. When provided coefficients for optimized heliostat spacings and field boundaries from RCELL, NS generates system power and efficiency hourly on one clear day in each month. Weather factors are applied to estimate annual performance. Performance factors are reported for each cell and summed to provide performance at design point and annually.

**RCELL Cellwise Optimization.**

*Basic Features.* RCELL, a companion to NS, optimizes the heliostat field spacing and the boundaries for a given receiver and tower height. Optimization is accomplished by minimizing the annual energy cost on the basis of annual average performance. Costs include capital and present value of operation and maintenance for the heliostat field, receiver, tower, piping, and pump. Fixed costs can also be included.

*Typical Applications and Uses.* The University of Houston has used RCELL to optimize heliostat fields and to provide layouts for these fields for a number of DOE funded central receiver system design contracts, including Solar One.

Options are provided to generate a shading and blocking data base (typically 6 CPU minutes on the VAX 780) and to reuse it in subsequent optimizations (30 CPU seconds). The GOPT option allows simultaneous optimization of tower height, receiver area, heliostat spacings and field boundaries for a defined power level (2 CPU minutes). Other options allow improvement of an existing data base, provide special outputs to IH to allow definition of heliostat locations corresponding to the optimized field, or allow performance calculations for a nonoptimized, user-defined heliostat field.

*Program Details.* RC is based on a variation approach to system optimization. RC generates a shading and blocking data base which contains data for 19 times on each of 12 days, and 16 combinations of heliostat spacings. In subsequent runs this data base is read, along with the interception data generated by NS. Operating iteratively RC selects optimized spacings and field boundaries satisfying the optimization conditions. In the GOPT mode, tower height and receiver area are also optimized. Performance data are provided; receiver flux maps can be requested; an itemized cost and performance table is generated, and the system cost/performance ratio is calculated.

**IH (Individual Heliostat Layout and Performance Code).**

*Basic Features.* IH determines locations of heliostats for a collector field optimized by RCELL and calculates the performance of this field. IH uses the same methods as NS, except that performance calculations are made for each heliostat instead of for each cell.

*Typical Applications and Uses.* Optimized spacing and boundary information is transferred from RCELL. IH defines a radial-staggered heliostat field, automatically choosing slip planes and decompression ratios to accommodate the converging radial spacings while approximating the RCELL optimization condition (typical VAX 780 CPU time is 2 minutes). Up to five intersecting sloping planar regions can be accommodated, approximating the effects of rolling terrain. Special interpolation routines allow interception data or aim points, generated at cell centers by NS, to be distributed to each heliostat. Special formats provide performance data for each heliostat in a pictoral format which greatly aids interpretation of outputs.

*Program Details.* As in NS, data are contained in the input modules IHDRIV, FIELD, HELIOS, and RECVER. In addition, appropriate data is read from files generated by RCELL and NS. Consequently, little additional user input is required to initiate an IH layout or performance run. A performance can accommodate 5000 or more heliostats, and an annual run can involve 50 to 100 time steps, outputting up to five parameters each. Options to reduce run time and output data are available.

### CAVITY-CREAM (Cavity Analyses Code)

**Basic Features.** CAVITY-CREAM is a 2 band (solar and IR) model for handling the thermal and radiation problem in a cavity. It interfaces with NS to generate the initial solar flux distribution within the cavity. A variation of the Nusselt method is used to generate view factors between cavity nodes. Reflected and radiated energy from each node is rescattered until absorbed or lost from the cavity aperture. Adiabatic surface temperatures are relaxed iteratively while a user supplied model determines tube wall surface temperatures and effective IR emissivities.

*Typical Applications and Uses.* NS first models a cavity as a flat aperture providing a node file to RCELL. RCELL optimizes the heliostat field. The optimal field is used with NS and a geometry file from CAVITY to provide a solar flux map on the interior cavity walls (several CPU minutes). After CREAM generates a view factor file (5 CPU minutes) and redistributes the solar band energy (one CPU minute), the cavity design can be examined for hotspots and modified to reduce them. Finally CREAM iteratively redistributes the IR and provides temperature distributions on all surfaces, cavity efficiency factors, receiver panel flows and temperature gradients (about 5 CPU minutes).

*Program Details.* This FORTRAN code is presently available on the Honeywell 66/60 computer. CAVITY generates the cavity surfaces and nodes based on simple user inputs. CREAM computes and stores for future use view factors between the nodes for any concave receiver. A tube wall model is supplied by the user (only a screen-tube air cooled wall is presently available).

A special routine computes field cell visibility fractions to avoid granularity effects in the flux distribution. Special aiming routines are available to reduce peak flux levels without illuminating the aperture lip or the cavity floor or roof. Incident radiation is distributed by successive absorption and scattering of the reflected sun light from each node. In a separate calculation, emission from each node based on assumed temperatures is similarly redistributed. The resulting temperatures are calculated and the process is iterated several times to convergence. Conductive and convective losses are provided for but not currently modeled.

### DELSOL

**Basic Features.** DELSOL3[9] is a performance and design optimization code which uses an analytical Hermite polynomial expansion/convolution-of-moments method for predicting images from heliostats. It typically requires much less computer time for performance calculations than either MIRVAL or HELIOS, the two Sandia codes that preceded it. Performance is evaluated on the basis of zones that are formed by sectioning the heliostat field radially and azimuthally or on the basis of individual heliostats. Time varying effects of insolation, cosine, shadowing and blocking, and spillage are calculated, as are the the time independent effects attributable to atmospheric attenuation, mirror reflectivity, receiver reflectivity, receiver radiation and convection, and piping losses. In order to determine field layouts, optimization runs use a data base created by a performance run and a system configuration that is based on the lowest levelized energy cost for the total system. Many system sizes can be optimized in a single run.

**Typical Applications and Uses.** DELSOL3 is used for system studies. It has been used to evaluate, on the conceptual level, the system levelized energy cost for a variety of technical options and range of sizes, and the effects of heliostat parameters on system cost and performance. System results described in Chapter 4 were obtained using DELSOL3.

**Program Details.** DELSOL3 can be used to analyze a wide variety of systems because of the diversity of information that the user may define. Namelists are used to input data, including:

(1) Basic information dealing with time and type of performance calculation, site location, insolation, weather, sunshape, attenuation, and design point parameters.

(2) Field information on configuration, boundaries, layout density, land constraints, slip plane criteria, individual heliostat locations, and field rotation.

(3) Heliostat information on dimensions, shape, individual panels, reflectivity, errors in heliostat angles, the surface normal, and the reflected vector, canting, focusing, and image accuracy.

(4) Receiver-related information such as type, size, reflectivity, tower height, tower shadow, aiming strategy, aim points, number and location of cavities, aperture size, and shape and orientation.

(5) Flux-related information on time of evaluation, shape and location of the surface on which flux points are located, flux points, flux limits, and apertures which can see the flux points.

(6) Efficiency reference values for power, radiation and convection, hot and cold piping losses, thermal-electric conversion, off-design operation, parasitic loads, storage, and plant factor.

(7) Optimization-related input on heliostat density, tower height, receiver width and height, aperture width

and height, aperture sizes relative to each other, power level, tower location, land constraints, solar multiple, output, and storage.

(8) Cost data on heliostat, land, field wiring, tower, receiver, pumps, piping, storage, heat exchangers, electric power generating system, and fixed costs.

(9) Economic analysis information relating to contingencies, spare parts, distributables and indirects, escalation, inflation, start of construction, fixed charge rate, discount rate, property tax and insurance, investment tax credit, income tax rate, debt financing interest rate, return on equity, depreciation, and operating and maintenance charges.

DELSOL3 is written in FORTRAN77. Running times can vary from 30 seconds to greater than 10 minutes on a CRAY 1, or from 5 minutes to 1 hour on a VAX 11-780.

## SOLERGY

**Basic Features.** SOLERGY[10] is a computer code which estimates the annual performance of a solar thermal electric power plant. SOLERGY is a quasi-steady-state plant model with a constant (but user-variable) time step. SOLERGY models a solar power plant in which the energy collection and production subsystems are connected through thermal storage. All energy collected by the heliostat/receiver subsystem is sent to thermal storage. Electrical production requires energy to be extracted from thermal storage. Steam is then generated to run the turbine. Code modification would be required to model a plant which runs the turbine directly from the receiver. (An early code, STEAEC,[11] was used to model water/steam receivers which are not coupled through storage.)

Factors such as energy losses and delays incurred in start-up, effects of ambient weather conditions on plant operation and efficiency, effects of hold time and charge and discharge rates on deliverable energy from storage, subsystem maximum and minimum power limits, and parasitic power requirements are taken into account in the computation of the annual electrical output of the plant. Default parameters may be easily modified through the use of namelist inputs. In calculating annual energy, SOLERGY models first law thermodynamics (conservation of energy). Solar energy incident on the heliostats is followed through the plant and reduced by losses as it passes through the various subsystems - actual fluid temperatures and flow rates are not computed.

**Typical Applications and Uses.** SOLERGY has been used to analyze the performance of the central receiver power plants described in Chapter 4. Typical output data and sensitivity results are described in Section 4.3.

**Program Details.** The input to SOLERGY is through namelists. The namelists include descriptions of:

(1) Collector field efficiency as a function of the azimuth and elevation angles obtained from MIRVAL or DELSOL.

(2) Collector field parameters such as field size and reflectivity and operating limits (ambient temperature, wind speed, and solar elevation angle).

(3) Receiver parameters such as maximum and minimum operational

limits, absorptivity, thermal losses (radiation, convection, and conduction) versus wind speed if desired, and startup requirements. Piping losses are calculated as a function of ambient temperature.

(4) Turbine parameters such as startup characteristics and thermal to electric conversion efficiency (versus ambient wet-bulb temperature and turbine input power).

(5) Thermal storage subsystem (tank(s), and charging and discharging heat exchanger(s)), parameters such as maximum and minimum tank capacities, charging and extraction rates, loss factors, and startup requirements.

(6) Plant location, including latitude, and local international time zone.

In addition to the input namelists, SOLERGY requires an input weather tape that includes insolation, wind characteristics, and ambient temperature and pressure for the specific site. SOLERGY is a FORTRAN77 code and has been used on a VAX780.

## SUNBURN

**Basic Features.** The computer program SUNBURN[12] calculates the levelized value and the levelized cost of electricity generated by hybrid solar central receiver electric power plants. For each hour of a year, the thermal energy use, or dispatch, strategy used by SUNBURN maximizes value by operating the turbine when the demand for electricity is greatest and by minimizing overflow of thermal storage. This dispatch strategy is applicable to solar hybrid plants having different heliostat field size and different thermal storage capacity. Solar only and fuel only plants can be simulated as well. A version of the program, which runs on a microcomputer, is available.

**Typical Applications and Uses.** SUNBURN was used to determine the optimal power plant configuration, based on value-to-cost ratio, for initial operation dates from 1990 through 1997 for plants sized at 80 $MW_e$ net using one year of actual weather data for Barstow, CA.

**Program Details.** SUNBURN performs an hour-by-hour performance simulation and calculates the levelized value of electricity generated by, and the levelized cost of, solar only, solar hybrid, or fuel only central receiver electric power plants. SUNBURN uses actual weather data and a flexible value-maximizing dispatch strategy.

SUNBURN assumes that the value of a hybrid plant owned by a utility is equal to the avoided costs of the utility for generating electricity.

The economic methodology used for calculating and expressing value and cost figures levelizes value and cost over the lifetime of the plant. It is a constant dollar analysis with amounts expressed in 1984 dollars.

## RADSOLVER

**Basic Features.** RADSOLVER[13] is a computer program which calculates the radiation energy transport in arbitrarily shaped solar cavity receivers. In contrast to the common assumption of gray surfaces used in the modeling of radiation transport, RADSOLVER accounts for the wavelength-dependence of emission and reflection with a band model of the radiative properties. It is assumed in the band model that the wavelength spectrum is subdivided into a finite but arbitrary number of wavelength bands within which the reflectances (emittances) of the cavity surfaces are approximated by constants. The consideration of the wavelength-dependence may be important in solar receiver applications where surfaces may have significant variations in reflectance (emittance) over the wavelength range between solar and thermal radiation.

The phenomena included in RADSOLVER are thermal emission, reflection and absorption of thermally emitted and solar energies, and multiple reflections of both types of radiant energy among the zones of the cavity. The basis of RADSOLVER is the radiosity method of radiation heat transport analysis which has been modified to account for the wavelength-dependence of the surface optical properties. Energy that would be transported within and from the cavity by convection (natural or forced) is not taken into account, and RADSOLVER is therefore strictly applicable to cavities whose interior air mass is stably stratified in a windless environment. It should be noted, however, that since radiation transport is the principal mode of energy transfer in solar cavity receivers, the neglect of convection may not be overly conservative in design studies which are aimed at determining the survivability of materials under high temperature conditions.

For a solar cavity whose interior surface is subdivided into an arbitrary number of zones, RADSOLVER determines:

- the heat transfer (the net energy flux into a zone that would be available, for example, for input to a working fluid)
- the irradiation and radiosity (the fluxes of incoming and leaving solar and thermal radiation at each zone)

RADSOLVER also calculates the temperatures of any adiabatic zones present in the cavity.

**Typical Applications and Uses.** RADSOLVER has been used to analyze the CESA-1 (Central Electrica Solar de Almeria) water-steam cavity receiver in Almeria, Spain. Reference 13 contains an example of the modeling of the CESA-1 receiver.

**Program Details.** Although RADSOLVER is applicable to enclosures of arbitrary geometry having an arbitrary number of apertures, the user must, in general, supply the configuration factor matrix ($F_{ij}$) and the zonal areas corresponding to his particular application. Configuration factor tabulations and/or other computer programs such as SHAPEFACTOR[14] can be used for this purpose. There is, however, the special option within RADSOLVER to calculate the configuration factors and zonal areas for a cylindrical solar receiver that has been subdivided into zones which are disks, flat annular rings, and cylindrical segments. This option can be used if the cavity aperture is in an end-plane of a cylinder and if the distribution of the direct solar irradiation is axially symmetric. Complex cavities having as many as 200 zones have been calculated with RADSOLVER.

The user must also supply the direct solar radiation incident on the receiver; these inputs can be obtained from computer programs such as MIRVAL, HELIOS, DELSOL, or NS. Another required input is the wavelength-dependent reflectance characteristics for each of the cavity surfaces.

## DRAC

**Basic Features.** DRAC[15] is the first in a series of driver programs for the more general code TOPAZ[16] (Transient One-Dimensional Pipe Flow Analyzer). DRAC is a relatively easy-to-use code which permits the user to model both transient and steady-state thermohydraulic phenomena in solar receiver tubing. Users may specify arbitrary time-dependent incident heat flux profiles and flow rate changes, and DRAC will calculate the resulting transient excursions in tube wall temperature and fluid properties. Radiative and convective losses are accounted for, and the user may model any receiver fluid (compressible or incompressible) for which thermodynamic data exist.

DRAC models a fluid-flow/heat transfer configuration that is frequently encountered in the design and use of solar central receivers, namely, the absorption of redirected solar heat flux from the heliostat field into a moving receiver fluid. DRAC is capable of determining transient as well as steady-state tube wall and fluid temperatures during operation. The user specifies arbitrary incident heat flux and flow rate disturbances for a single tube. DRAC then calculates the resulting tube wall cross-sectional temperature profiles and fluid properties as a function of axial position and time.

DRAC is not a self-contained code but rather a "user-friendly" interface to TOPAZ and DASSL[17], two general purpose codes developed at Sandia National Laboratories Livermore. TOPAZ was written for the purpose of modeling a highly general class of transient problems encountered in the design and evaluation of solar central receiver components and systems. TOPAZ permits modeling of an arbitrary arrangement of one-dimensional-transient flows including branching, closed loops, cocurrent, and countercurrent flows. TOPAZ can also model two-dimensional-transient heat conduction in the fluid containment. Furthermore, special provisions have been made to include the "solar boundary conditions" (radiative and convective boundary conditions). TOPAZ is specially suited to treat arbitrary working fluids both incompressible (e.g., molten salt and liquid sodium) and compressible (e.g., air, He, and water-steam). In addition, the code is highly modular, permitting treatment of new components, control equations, and fluids as the need arises.

DASSL is a family of mathematical subroutines which performs fully implicit integration of systems of ordinary differential equations. The time step is automatically selected to provide efficient integration while user-specified error tolerances are maintained. DASSL was found to be especially well suited to integrating the TOPAZ equations.

The user provides a concise set of namelist input data to DRAC. DRAC then generates a computational mesh compatible with TOPAZ to use in spacially discretizing the partial differential conservation equations. Once this task has been completed, all that remains is for DASSL to integrate the resulting system of ordinary differential equations in time.

**Program Details.** The fluid flow-heat transfer configuration to be analyzed by DRAC is input in a single namelist. A heat transfer fluid enters a single receiver tube where it is heated by incident solar flux. The user specifies a constant inlet temperature, a time-dependent inlet mass flow rate, an exit pressure, and a time-dependent peak solar flux. The code then calculates the one-dimensional-transient fluid temperature, pressure, and mass flow profiles. The code also calculates two-dimensional transient tube wall temperature distribution while neglecting axial conduction effects.

The following constants make up the single namelist:

(1) Receiver tube dimensions, orientation, minimum friction factor, material type, solar absorptivity, and tube wall emissivity.

(2) Fluid type, inlet temperature, outlet pressure, and density.

(3) Ambient temperature and coefficient of convective heat transfer to ambient.

(4) Axial heat flux description.

(5) Variation of peak heat flux with time description.

(6) Variation in fluid inlet mass flow with time description.

(7) Computation time and editing requirements.

## CAVITY

**Basic Features.** CAVITY[18] is a code designed to couple the solution of the radiative exchange in cavity type receivers with the conduction and convention exchange to the working fluid. Radiative losses are calculated via a single band radiation exchange model, and an estimate is made of the convective losses. The code can be used to model any working fluid for which property data exists.

Prior to the CAVITY code, this coupled problem was solved by manually iterating between a radiative exchange code for cavities such as RADSOLVER and a thermal-hydraulic code for pipe flow such as DRAC until convergence was obtained. This was a time-consuming and tedious procedure. CAVITY was created to eliminate this manual iteration procedure.

**Typical Applications and Uses.** The CAVITY code was used to perform thermal analyses of the salt and sodium cavities investigated in the recently completed System Improvement Studies.

The code is currently being used to estimate convective and radiative losses for the MSS/CTE Category B receiver. CAVITY code estimates will be compared with experimental data and possibly more detailed two band radiation models.

**Program Details.** To use CAVITY, the user must first generate a mesh that describes the receiver geometry. CAVITY itself has no mesh generation capabilities. Typically the user generates the mesh using PATRAN[19] and then calculates the exchange factors for the surfaces using SHAPE FACTOR.[14]

CAVITY solves the equations for the radiative exchange in the cavity and the conductive-convective exchange to the working fluid.

The radiative exchange calculation is performed using the net flux method. The user is required to input an initial temperature guess for each of the cavity surfaces (adiabatic and absorbing surfaces). The user is also required to input the radiative exchange matrix and the incident solar flux for each surface. The aperture behaves as a black surface at a temperature of absolute zero and no heat flux crosses the adiabatic surfaces. Using this information, the net flux on each absorbing surface and the temperature of each adiabatic surface is calculated via energy balance equations.

The net fluxes are then used as boundary conditions for solving the conduction-convection governing equations. The appropriate fluxes for each tube are determined from the user specified-string of surface numbers which make up the tube path. The user must also specify the inlet and desired outlet fluid temperatures for the tube pass. The user then computes tube rate flow and fluid temperatures as a function of path position using energy balance equations.

The radiative exchange calculation and convective - conductive calculation are repeated until all parameters (i.e., temperatures, flow rates, etc.) converge to within a specified tolerance. Following convergence, convective losses for the cavity as a whole are estimated using the correlations suggested by Siebers and Kraabel.

CAVITY currently runs on Sandia Albuquerque and Livermore CRAY computers. The SHAPEFACTOR and PATRAN codes, which provide input to CAVITY, run on a VAX.

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# GLOSSARY

**Absorber:** The portion of the receiver that absorbs radiant energy.

**Absorptance:** The ratio of the total absorbed radiation to the total incident radiation; equal to one (unity) minus the sum of the reflectance and the transmittance.

**Absorptive Coating:** A coating which improves the absorptance of a material.

**Angle of Incidence:** The angle between the central ray incident on a surface and the normal to the surface at the point of incidence.

**Annual Average Solar Efficiency:** The ratio of the annual solar energy that is delivered to a thermal process to the product of the annual direct normal insolation and the heliostat reflective area.

**Atmospheric Attenuation:** The loss of solar power by absorption and scattering as a result of atmospheric conditions between the collector and the receiver.

**Availability (Operating):** The percent of time the unit is available for service, whether operated or not (available hours divided by the total hours in the period under consideration, expressed as a percentage).

**Base Load Plant:** A power plant in operation on an almost continuous basis; a plant with a capacity factor greater than 0.6.

**Beam Characterization System:** A video-based system for the rapid and automatic measurement and characterization of flux delivered by any single heliostat onto a target near the receiver.

**Binary:** A central receiver system in which different heat transport fluids are used for the receiver fluid and the storage fluid.

**Blocking:** The interception of part of the reflected sunlight from one heliostat by the backside of another heliostat.

**Bottoming Cycle:** The lower temperature cycle in any energy conversion system in which two (or more) separate cycles are used in cascade fashion (exhaust of one feeds input to another). See Topping Cycle.

**Brayton Cycle:** The thermodynamic cycle upon which combustion or gas turbines are based, in which the working fluid is always in a superheated gaseous state.

**Buckstay:** A structural support for a receiver panel or wall.

**Buffer Storage:** The use of some form of thermal energy storage (typically less than one-half hour of storage) for decoupling the transients associated with the energy source from the end-use process.

**Capacity:** The normal maximum power output rating of a generating unit or plant.

**Capacity Credit:** The amount of generating capacity displaced by a solar power plant, expressed in megawatts (MW) or as a fraction of the nominal solar plant output. Determined by individual utilities.

**Capacity Factor:** Energy production in a given time interval (generally annually) divided by the energy that would have been generated if the plant had operated at its full capacity for the same time interval.

**Cavity Receiver:** A solar energy receiver in the form of a cavity in which the solar radiation enters through one or more openings (apertures) and is absorbed on internal heat exchanger surfaces.

**Central Receiver Power System:** See **Solar Thermal Central Receiver Power System.**

**Closed-Loop System:** In this context, a thermal energy storage system in which no part is vented to the atmosphere.

**Cloud Cover:** That portion of the sky cover which is attributed to clouds, usually measured (in tenths of sky covered) by a trained observer.

**Cogeneration:** The production of electricity or mechanical energy, or both, in conjunction with industrial process heat.

**Collector Efficiency:** The ratio of the energy collection rate of a solar collector to the radiant power intercepted by it under steady-state conditions (includes cosine loss).

**Collector Subsystem:** An array of individually controlled heliostats, including the wiring and controls, that redirects the available insolation onto a receiver.

**Concentration Ratio:** The ratio of the reflected radiant power impinging on a surface to the radiant power incident upon the reflecting surface.

**Cosine Loss:** The reduction of the projected heliostat area visible to the sun which is caused by the tilt of the heliostat. Cosine loss is proportional to the cosine of the angle of inclination of the normal of the heliostat surface to the sun's rays.

**Cost/Performance Ratio:** A measure used in evaluating system design alternatives wherein both cost and system performance are taken into account.

**Cost/Value Ratio:** A measure used in evaluating how the cost of a system over its lifetime compares with the value of its product (e.g., energy).

**CRTF:** The Central Receiver Test Facility in Albuquerque, New Mexico.

**Design Point:** The time of day and day in a year for which the system or component performance is specified.

**Direct Insolation:** The solar energy incident on a surface that comes from within the solid angle subtended by the solar disk; that sunshine which can cast a sharply defined shadow. The direct part of the insolation can be focused by an optical system. The direct component should be distinguished from the diffuse or multidirectional component of solar radiation. Cloud, fog, haze, smoke, dust, and molecular scattering increase the diffuse component.

**Discount Rate:** The annual rate used in present worth analyses that takes into account inflation and the potential earning power of money while moving the present worth forward or backward to a single point in time for comparison of value.

**Diurnal:** Recurring every day.

**DOE:** The United States Department of Energy.

**Downcomer:** The pipe carrying the hot heat transport fluid down the tower.

**Emissivity:** The ratio of the radiant energy given off by a surface to that given off by a blackbody at the same temperature.

**End Use:** The final use of the thermal output of a solar central receiver plant, e.g., in a turbine to generate electricity or in an industrial process.

**External Receiver:** A solar energy receiver in which the solar radiation is absorbed on external surfaces.

**Fixed Charge Rate:** The amount of revenue per dollar of capital expense that must be collected annually to pay for the fixed charges associated with plant ownership, e.g., return on equity, interest payment on debt, depreciation, income taxes, property taxes, insurance, repayment of initial investment, etc. It may also include operations and maintenance expenses expressed as a fraction of the capital cost.

**Flux (Radiant):** The time rate of flow of (radiant) energy.

**Flux Density:** The radiant flux incident per unit area.

**Heat Tracing:** An auxiliary pipe heating system to prevent freezing of liquid within the pipes.

**Heat Exchanger:** A component in which thermal energy is transferred from one fluid to another, e.g. a steam generator for transferring thermal energy from the Heat Transport Fluid to the Working Fluid for a Rankine cycle steam turbine, or for transferring thermal energy from the Receiver Fluid to the Heat Transport Fluid (if different).

**Heat Transport Fluid:** The fluid used for transporting or transferring thermal energy from one area to another within the system. See Receiver Fluid; Working Fluid.

**Heliostat:** An assembly of mirrors, support structure, drive mechanism, and mounting foundation which tracks the sun in two axes of motion to continuously reflect sunlight onto a fixed receiver.

**Heliostat Characterization System:** A video system for the rapid and automatic measurement of heliostat aiming errors and beam quality.

**Heliostat Packing Density:** The ratio of total reflective surface area to the total land area used by a group of heliostats.

**Hours of Storage:** The number of hours a plant can produce power at a stated output level, normally at full-rated system load, when operating exclusively from an initially fully-charged storage unit.

**Hot/Cold Tank Storage:** A thermal energy storage system utilizing separate tanks for the charged (hot) and uncharged (cold) storage media.

**Hybrid:** A power generating plant in which energy is derived both from collection of solar energy and from a fossil energy source.

**Insolation:** The solar energy incident on a unit surface per unit time.

**Intercept Factor:** The fraction of direct or reflected rays incident on the receiver aperture whose trajectories reach the absorber.

**Irradiance:** See Flux Density.

**Levelized Fixed Charge Rate:** The fixed charge rate that produces a constant level of payments over the life of a plant whose present worth is the same as the present worth of the actual cash flow.

**Levelized Energy Cost:** The constant annual revenue per unit of energy required over the lifetime of a plant to compensate for its fixed and variable cost.

**Nameplate Rating:** The full-load continuous rating of a power plant under specified conditions as designated by the manufacturer.

**Parasitic Power, Parasitic Energy:** Power required to operate the plant (*e.g.*, the power to operate pumps, motors, computers, lighting, air conditioning, *etc.*). The parasitic energy is the energy consumed by such uses for a specified period. The *net power* produced by a solar thermal plant is the *gross power* generated less the parasitic power losses, and similarly for *net energy* production.

**Peak Load:** The maximum load in a given time interval.

**Peaking Plant:** A power plant operated intermittently to cover peak demand periods; generally plants with capacity factors less than 0.18.

**Penetration (Solar):** The solar power plant capacity as a percentage of the utility grid capacity.

**Plant Availability:** The percentage of time a plant is able to provide power if so required.

**Pointing Error per Axis:** The standard deviation (RMS), for each axis, of the difference between the desired aimpoint and the beam centroid location. The error is in the heliostat reflected ray coordinate system and is expressed in milliradians.

**Power Tower:** A solar thermal central receiver power system.

**Process Heat:** The heat which is used in agricultural, chemical, or industrial operations.

**Radiant Power:** See Flux (Radiant).

**Radiation:** The emission and propagation of energy through space (or through material medium) in the form of waves (or photons).

**Rankine Cycle:** The thermodynamic cycle upon which water-steam turbines are based, in which the working fluid is pressurized as a liquid, evaporated and perhaps superheated, put through a turbine to extract its energy, and subsequently condensed at low pressure.

**Receiver:** That element of a solar central receiver system to which solar radiation is directed by the heliostats and where it is absorbed and converted to thermal energy.

**Receiver Fluid:** The fluid that is circulated through the receiver to absorb the solar radiation as thermal energy. The Receiver Fluid is normally the same as the Heat Transport Fluid used elsewhere in the system, but may be different (in which case a Heat Exchanger is required). See Heat Transport Fluid; Working Fluid; Heat Exchanger.

**Receiver Efficiency:** The ratio of the thermal power absorbed by the receiver working fluid and delivered to the base of the tower to the solar radiant power delivered to the receiver under reference conditions.

**Reflectance:** The ratio of the reflected radiant flux to the incident radiant flux.

**Reheating:** A process in which the gas or steam is reheated after a partial isentropic expansion to reduce moisture content. Also known as resuperheating.

**Repowering:** The refitting of existing fossil-fueled utility or process heat power plants with solar energy collection systems in order to displace a portion or all of the fossil fuel normally used.

**Riser:** The pipe carrying the cold heat transport fluid up the tower.

**Set Point:** The value selected to be maintained by an automatic controller.

**Shadowing (or Shading):** The shading of the reflective surface of one heliostat from the sun's rays by another heliostat.

**Solar Constant:** The normal insolation just outside the earth's atmosphere.

**Solar Multiple:** The ratio of the thermal power that is absorbed in the receiver fluid and delivered to the base of the tower at the system design point to the peak thermal power required by the turbine-generator (or other end use). Extra thermal energy is stored in the storage system.

**Solar One:** The **Ten Megawatt Electric (10 $MW_e$) Solar Thermal Central Receiver Pilot Plant** located near Barstow, CA.

**Solar 100:** A proposed 100 $MW_e$ solar central receiver power plant designed in 1982. Plant was never constructed.

**Solar Only:** The operation of a hybrid power plant (or repowered plant) on the solar energy subsystem output alone. See Stand-Alone.

**Solar Thermal Central Receiver Power System** (also known as **Solar Thermal Central Receiver Power Plant, Solar Central Receiver Plant,** and **Solar Central Receiver System):** A solar power system which concentrates the available solar energy by means of an array of heliostats to a tower-mounted receiver. The energy absorbed at the receiver is removed as thermal energy.

**Solar Time:** The time as reckoned by the apparent position of the sun. Solar noon occurs when the sun reaches its zenith.

**Specular:** Having the qualities of a mirror which reflects with no scattering.

**Spillage:** The radiation which is reflected from the collector subsystem but which misses the receiver's absorber surface.

**Stand-Alone:** A solar thermal central receiver power system that operates on solar energy only, with no on-site backup power system.

**Storage Capacity:** The amount of net energy which can be delivered from a fully charged storage subsystem ($MW_th$).

**Storage-Coupled:** The use of an energy storage system to permit operation of the end-use system during periods when solar power from the receiver is inadequate (or not present) to satisfy the load.

**Stow:** A position or act of reaching a position of storage for the heliostats.

**Sun Position:** The azimuth and elevation angles for specifying the direction to the central ray from the sun.

**Ten Megawatt Electric (10 $MW_e$) Pilot Plant:** The prototype solar thermal central receiver power system near Barstow, California. The plant has been operating since 1981 with the capability of producing 10 $MW_e$ of electricity for use in the Southern California Edison system.

**Thermal Energy Storage Subsystem:** A rechargeable unit capable of storing thermal energy for later use. Examples are storage as sensible heat in nitrate salt, sodium, rocks, water, or oil.

**Thermocline Storage:** The storage of thermal energy in which the hot and cold media are in the same container (tank) and which uses the thermocline principle. Such storage relies on a lower density hot fluid floating atop a higher density cooler fluid of the same type, or on hot solid material being separated from cooler solid materials by a thermal gradient as in air-rock, air-ceramic-brick applications.

**Topping Cycle:** The higher temperature cycle in any energy conversion system in which two (or more) separate cycles are used in cascade fashion (exhaust of one feeds input to another). See Bottoming Cycle.

**Trace Heating:** See Heat Tracing.

**Tracking Systems:** The motors, gears, and actuators that are instructed by computer command to maintain a proper heliostat orientation with respect to the sun and receiver positions.

**Turndown Ratio:** A measure of the lower limit that can operate a system safely. May be specified as a ratio or as a percentage of full-rated conditions.

**Working Fluid:** The fluid that performs work for the end-use system, e.g., the steam in a steam turbine-generating system, hot gas in a Brayton cycle gas turbine, or fluid providing thermal energy for a process heat application. Steam and hot gases are the most common Working Fluids. The Working Fluid is often different from the Heat Transport Fluid and/or the Receiver Fluid, requiring a Heat Exchanger. See Heat Transport Fluid; Receiver Fluid; Heat Exchanger.