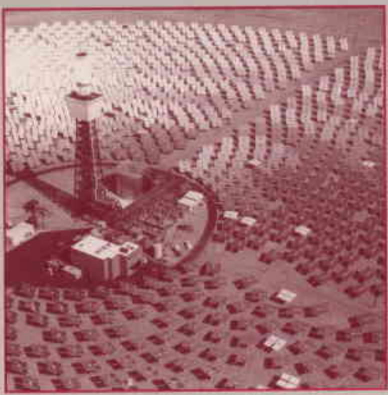
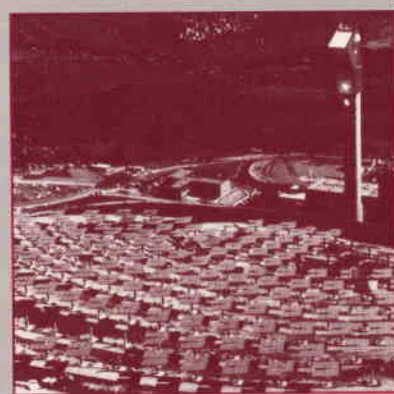
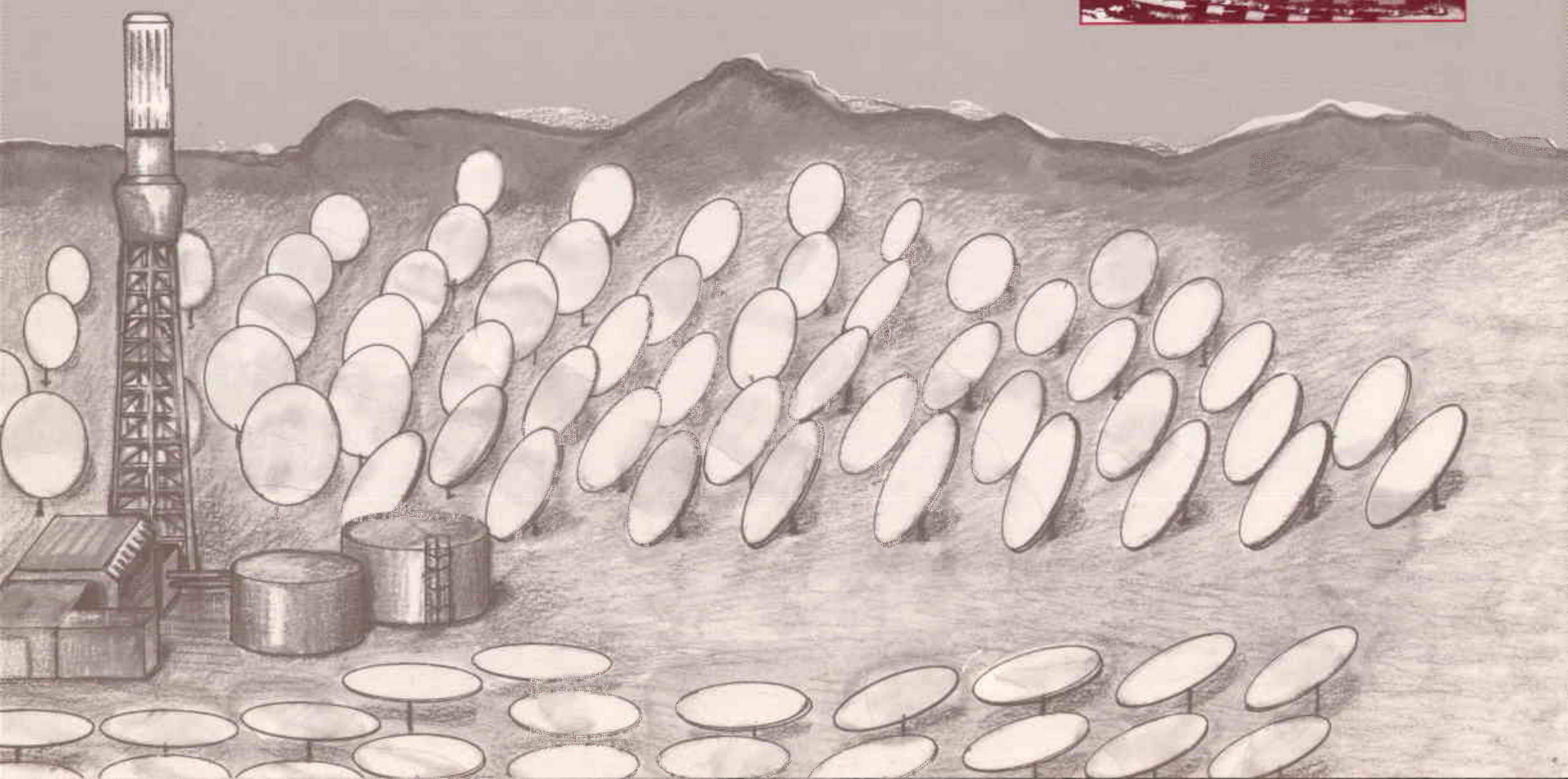
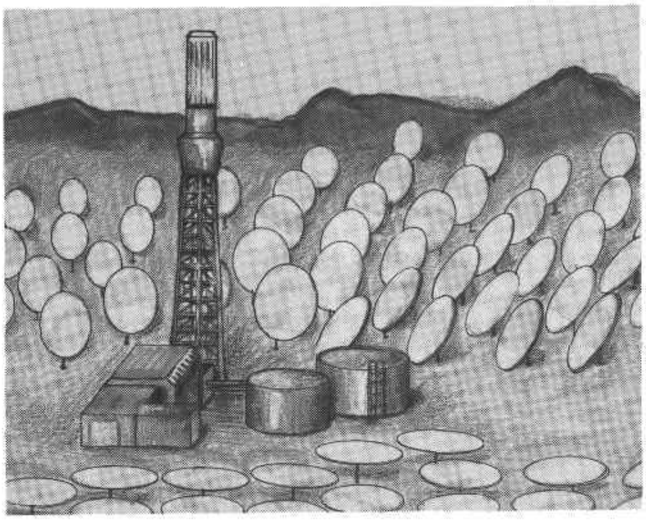
SERI/SP-220-3314



Central Receiver Technology
Status and Assessment







Central Receiver Technology
Status and Assessment

SERI/SP-220-3314
September 1989

DE89009465
UC Categories: 234, 235, 237

Preface

The research and development described in this document was conducted within the U.S. Department of Energy's (DOE) Solar Thermal Technology Program. The goal of this program is to advance the engineering and scientific understanding of solar thermal technology and to establish the technology base from which private industry can develop solar thermal power production options for introduction into the competitive energy market.

Solar thermal technology concentrates the solar flux using tracking mirrors or lenses onto a receiver where the solar energy is absorbed as heat and converted into electricity or incorporated into products as process heat. The two primary solar thermal technologies, central receivers and distributed receivers, employ various point and line-focus optics to concentrate sunlight. Current central receiver systems use fields of heliostats (two-axis tracking mirrors) to focus the sun's radiant energy onto a single, tower-mounted receiver. Point-focus concentrators up to 17 meters in diameter track the sun in two axes and use parabolic dish mirrors or Fresnel lenses to focus radiant energy onto a receiver. Troughs and bowls are line-focus tracking reflectors that concentrate sunlight onto receiver tubes along their focal lines. Concentrating collector modules can be used alone or in a multimodule system. The concentrated radiant energy absorbed by the solar thermal receiver is transported to the conversion process by a circulating working fluid. Receiver temperatures range from 100°C in low-temperature troughs to over 1500°C in dish and central receiver systems.

The Solar Thermal Technology Program is directing efforts to advance and improve each system concept through solar thermal materials, components, and subsystems research and development and by testing and evaluation. These efforts are carried out with the technical direction of DOE and its network of field laboratories that works with private industry. Together they have established a comprehensive, goal-directed program to improve performance and provide technically proven options for eventual incorporation into the Nation's energy supply.

To successfully contribute to an adequate energy supply at reasonable cost, solar thermal energy must be economically competitive with a variety of other energy sources. The Solar Thermal Technology Program has developed components and system-level performance targets as quantitative program goals. These targets are used in planning research and development activities, measuring progress, assessing alternative technology options, and developing optimal components. These targets will be pursued vigorously to ensure a successful program.

This report describes central receiver technology: its accomplishments to date, its current technology status, and the efforts still necessary to fully exploit it.

This document was written by Richard L. Holl, HGH Enterprises, Inc., under contract to DOE under the Solar Technical Information Program.

A Product of the
Solar Technical Information Program

SERI

Solar Energy Research Institute
A Division of Midwest Research Institute

1617 Cole Boulevard
Golden, Colorado 80401-3393

Operated for the
U.S. Department of Energy

NOTICE

This report was prepared as an account of work sponsored by an agency of the United States government. Neither the United States government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States government or any agency thereof.

Printed in the United States of America,
Available from:
Superintendent of Documents,
U.S. Government Printing Office,
Washington, DC 20402
Stock #061-000-00734-2

National Technical Information Service,
U.S. Department of Commerce,
5285 Port Royal Road,
Springfield, VA 22161
Price: Microfiche A01, Printed Copy A04

Codes are used for pricing all publications. The code is determined by the number of pages in the publication. Information pertaining to the pricing codes can be found in the current issue of the following publications which are generally available in most libraries: *Energy Research Abstracts (ERA)*; *Government Reports Announcements and Index (GRA and I)*; *Scientific and Technical Abstract Reports (STAR)*; and publication NTIS-PR-360 available from NTIS at the above address.

Contents

Introduction

Solar energy will provide an ever-increasing fraction of our future energy requirements. The disruption and arbitrary price escalation of oil supplies during the 1970s are reminders of the finiteness of our fossil-fuel resource. These fuels, which are actually solar energy that has been "stored" in plant materials for more than tens of millions of years, are now being used up in just a few hundred years. As a nondepletable resource, solar energy can and will replace fossil fuels as they are depleted.

Heat from the sun can be used in the same manner that it is used when generated by burning fossil fuels (the "stored" solar energy). Using heat energy from the sun, called solar thermal technology, is the basis for this report.

Although sunlight (solar radiation) is abundant and renewable, it is diffuse. The temperature from this diffuse source is sufficient to provide domestic hot water or home heating, but much higher temperatures are necessary to displace fossil fuels for producing electricity or using in many industrial applications. Solar radiation must be concentrated to produce these elevated temperatures; it must also be collected and moved to its point of use.

Central receiver systems combine concentration and collection of solar energy into a single operation, as shown in Figure 1. Two-axis tracking mirrors (heliostats) reflect and concentrate solar radiation onto a receiver located on top of a tower. These systems can achieve high concentrations (more than 1000 times), which allow collection at temperatures exceeding 538°C (1000°F) with an efficiency approaching 90%.

Central receiver systems must be very large to be economical; for example, at least a square mile of land is needed to produce about 50 MW of electricity. The southwestern United States with its abundant solar radiation and available land will be the primary location for central receiver systems.

The high-efficiency collection of solar energy at very high temperatures and the large plant size make central receiver systems ideal for utility-scale electric power generation.

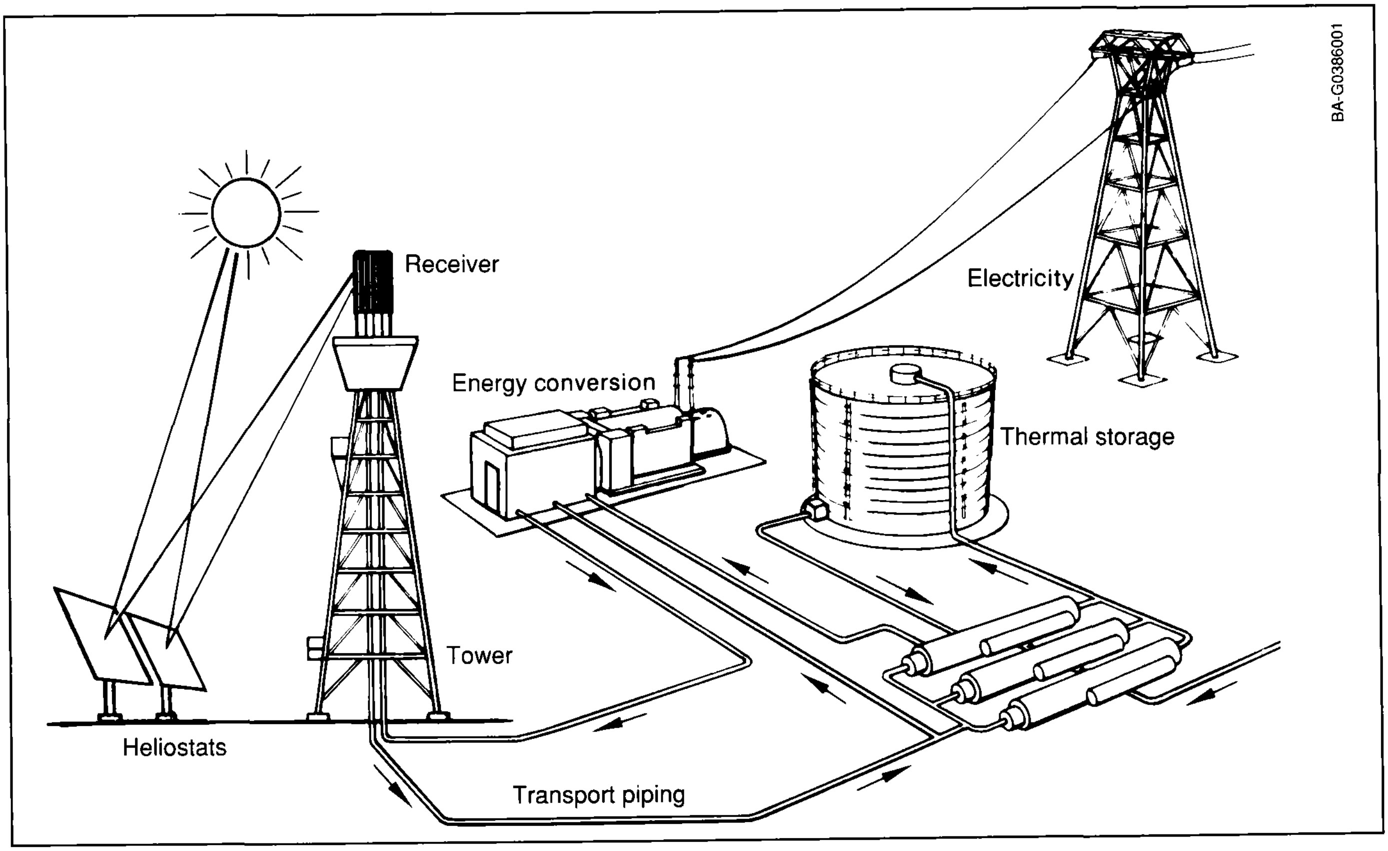


Figure 1. Principle of a central receiver system

Central receiver systems can produce superheated steam at the same temperatures and pressures used in modern power plants. Thus, these systems can be substituted directly for plants that burn fossil fuels in a utility boiler. Because about 34% of the energy consumed in the United States is used to produce electricity, this application represents a huge potential market for central receiver systems.

Industrial process heat, which consumes about 26% of the total energy used in the United States, is another large potential market for central receiver systems. Process heat and electric power production can be combined in a single plant called a solar total energy system. This system would be highly efficient because the process heat would come from the heat rejected by the electric power plant. Solar total energy systems must be near the user of the process heat and tend to be smaller than utility-scale electric power plants. The efficiency of producing both electricity and process heat helps offset the lower economies of scale of these plants.

A more futuristic application of central receiver systems would be to produce fuels and chemicals. This, ultimately, would allow solar energy to be the source of power for transportation and industry located in areas lacking abundant solar radiation.

The potential of central receiver systems to provide all of these applications has resulted in a vigorous development program funded by the U.S. Department of Energy (DOE) over the past 15 years. System components have improved over several generations of development. Full-system experiments have been built and tested to prove the basic system concepts, with major emphasis given to utility-scale electric power generation. The technical development still required will take at least 10 years.

This report describes central receiver technology: its accomplishments to date, its current technology status, and the efforts still necessary to fully exploit it.

Chapter 1
The Central Receiver System

The central receiver system takes sunlight (solar radiation) and converts it into electric power. The system has various subsystems and components, some specific to the solar application and some common to the utility industry. This chapter describes the various subsystems and their components and the different types of systems and discusses the cost and performance goals for the total system and its components.

System Requirements

The optimum size for a central receiver plant that produces electric power is about 200 MW_e. It consists of a heliostat field that collects the solar radiation and reflects it onto the receiver. The receiver, containing a heat-transfer fluid, accepts the concentrated solar radiation and converts it into heat. The thermal transport subsystem takes this superheated fluid either to the power conversion equipment that transforms the heat to electricity or to thermal storage, if provided. The cooled fluid then returns to the receiver where it is reheated. An integrated master control subsystem operates all the various plant subsystems. This subsystem provides the interfaces for data transfer and control signals between it and all of the other plant subsystems. The various elements of the system are identified in Figure 1.1, a photograph of the Solar One central receiver plant in Barstow, Calif., now out of operation.

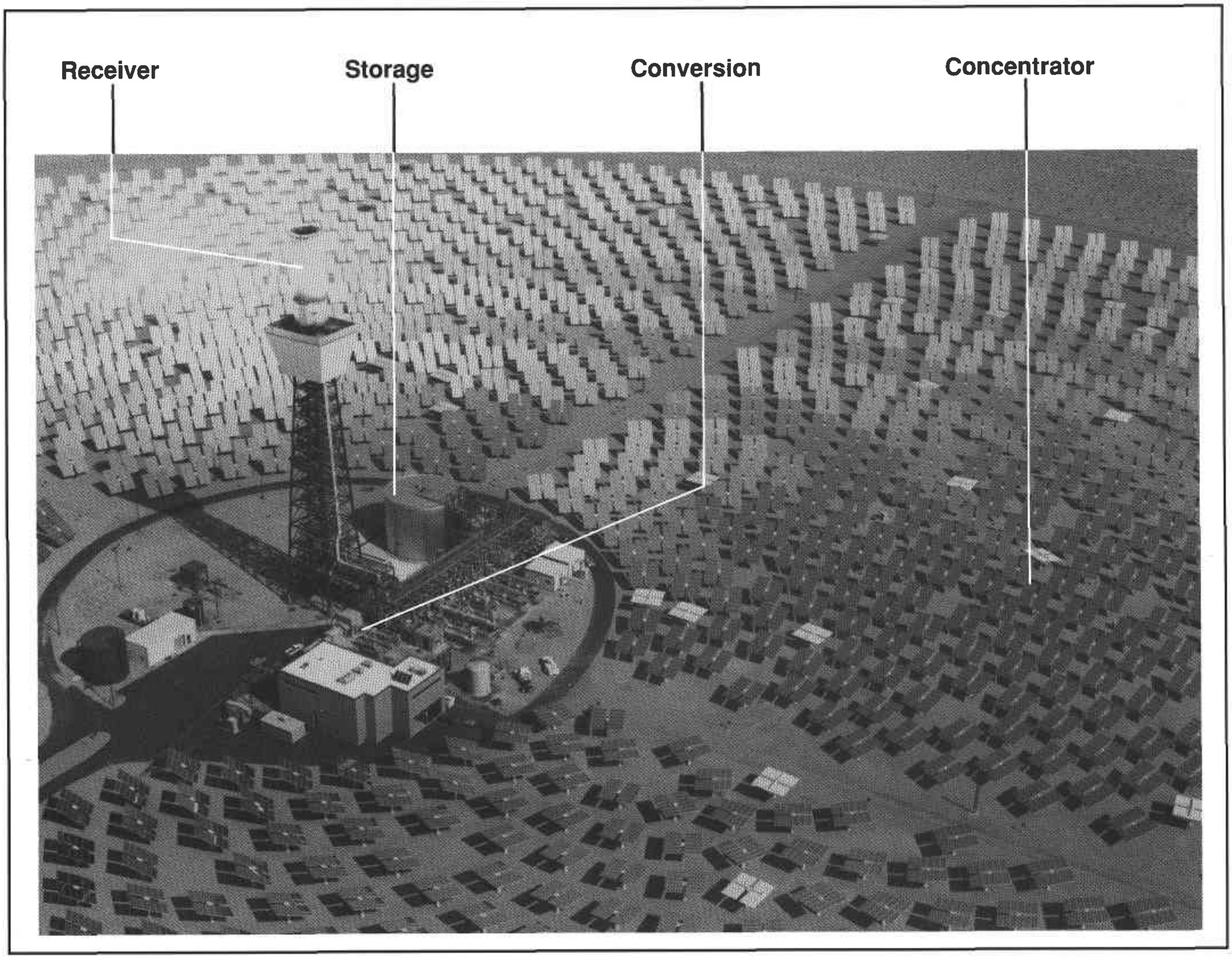


Figure 1.1. Solar One central receiver plant showing all major subsystems

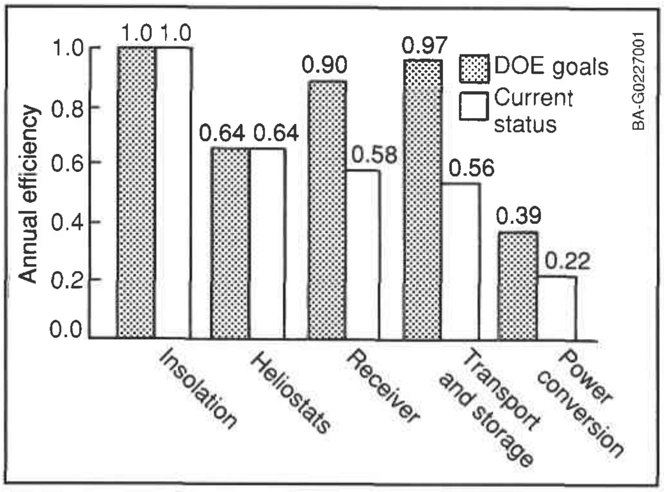


Figure 1.2. DOE's subsystem efficiency goals

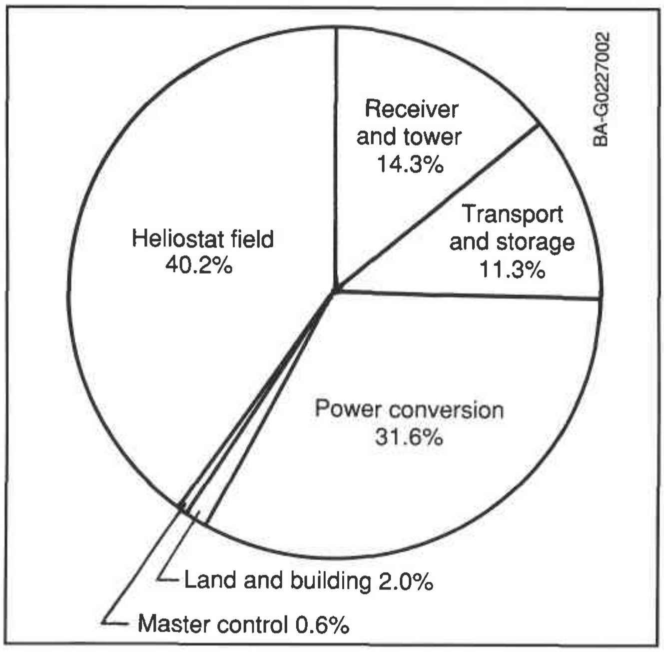


Figure 1.3. Typical cost breakdown for a central receiver plant

Thermal storage is often included in the central receiver system so electricity can be produced when solar radiation is unavailable. A fossil-fueled subsystem can also be used to produce electricity during these periods. This subsystem provides heat to the power-conversion equipment in the same form as that provided from either thermal storage or the solar receiver.

DOE program goals for subsystem efficiencies and a typical cost breakdown for central receiver power plants are shown in Figures 1.2 and 1.3, respectively. These cost and performance goals, which equate to a levelized cost of 4¢–7¢/kWh for the delivered electricity, would allow the central receiver system to compete commercially with fossil-fueled plants. The DOE goal of 5¢/kWh translates into approximately $280/m^2$ of heliostat area with an annual system efficiency of 22% in regions where solar radiation is the greatest (the southwestern United States). Although ambitious, attaining this goal would provide

Table 1.1. Heliostat Subsystem Components

Major Assemblies	Components
Heliostat	Reflector (mirrors) Reflector support structure Drive units (two axes) gear boxes motors Pedestal Foundation
Controls	Heliostat controller position sensor drive motor controller Field controller (one per 32 heliostats) computer software Array controller (one per field) time base computers software master control interface
Field wiring	Underground cabling AC power control system (heliostats to field controllers to array controller)
Support equipment	Handling equipment Maintenance equipment Heliostat washing equipment

electricity at very nearly the present costs of electricity from base-load plants. Of course, if costs of the heliostat area are brought below $280/m^2$, achieving an annual system efficiency of 22% would not be necessary to reach the levelized cost goal of 5¢/kWh.

Several options for each of the major subsystems and their interfaces are available to meet these cost and performance goals. The selection of these options defines a specific system concept because many of the selections are interdependent. For example, the heat-transfer fluid used in the power conversion subsystem determines the preferred conditions for the heat supplied by the receiver or thermal storage subsystems. In turn, the thermal transport interface between thermal storage and the solar receiver makes the selection of heat-transfer fluids in these two subsystems interdependent.

The most promising system candidates identified have been developed to where a preferred system can be selected for a specific application. The rest of this chapter identifies the major options for the central receiver subsystems and the resulting system configurations.

Heliostat Subsystem

The heliostat subsystem intercepts, redirects, and concentrates direct solar radiation to the receiver subsystem. It consists of a field of tracking mirrors, a tracking control

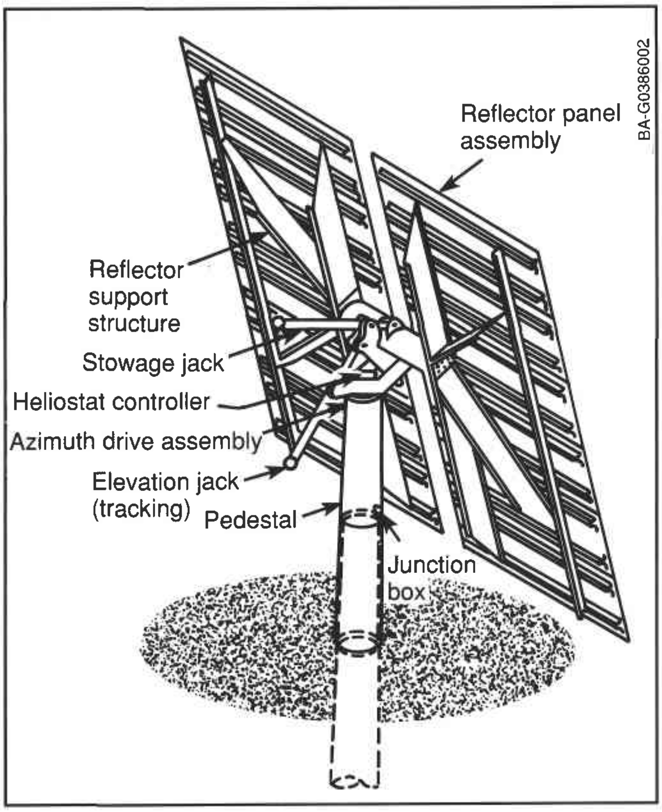


Figure 1.4. Heliostat assembly

system, field wiring, and support equipment. The tracking control system continuously focuses the direct solar radiation onto the receiver during collection. When solar radiation is not being collected, the controls must prevent the reflected radiation from damaging the receiver, tower, or other structures or from creating an unsafe condition in the airspace around the plant. The major elements and components are listed in Table 1.1 and illustrated in Figure 1.4.

The layout of the heliostat field depends on the design of the solar receiver. Two layouts have been developed: a surround heliostat field and a north heliostat field (see Figure 1.5). A surround field has the heliostats arranged around a tower that is usually located south of center to optimize efficiency. A north field has all of the heliostats arranged on the north side of the tower. (In the southern hemisphere the tower in the surround layout would be north of center, and the north field layout would become the south field layout.) A surround field requires an external receiver, where the heated panels form an external cylinder located on top of a tower. A north field requires a cavity receiver, where the heated panels are contained within a cavity and the reflected solar radiation passes through the aperture of the cavity. Receiver designs are discussed further in the next section.

The performance of the heliostat field is defined in terms of optical efficiency, the ratio of the reflected energy intercepted by the receiver to the solar radiation falling on the heliostats. Optical efficiency is affected by

- Reflectivity of the mirror

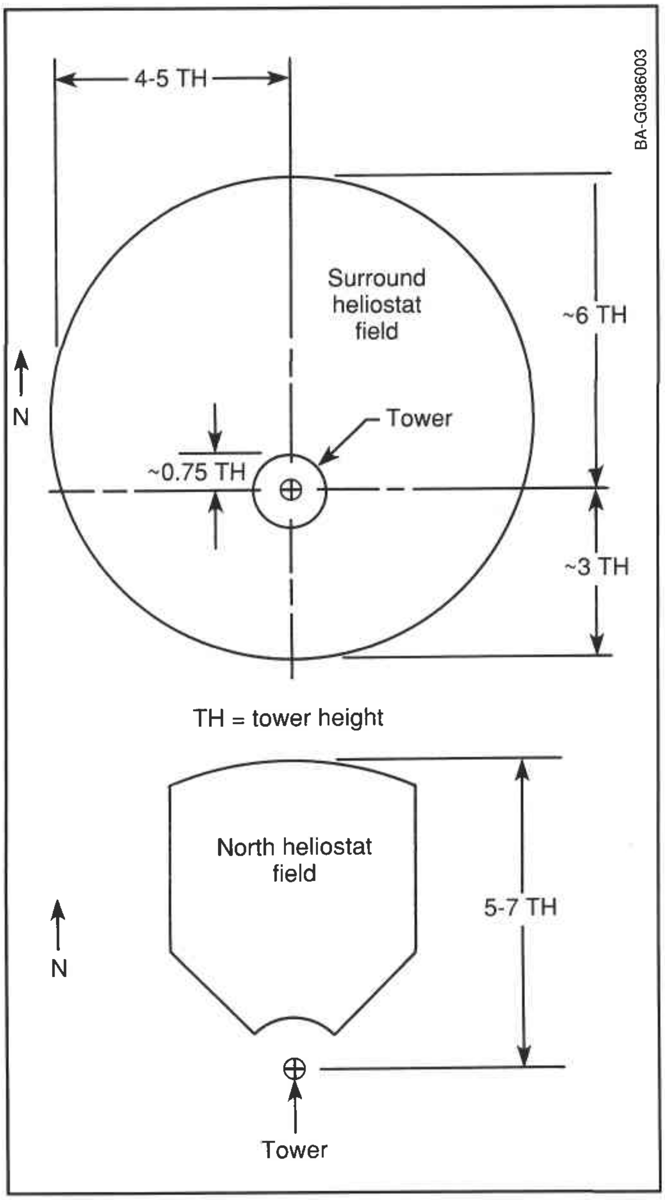


Figure 1.5. Contours of surround and north heliostat field layouts

- Shadowing, where the shadow from one heliostat covers another heliostat
- Blocking, where a heliostat blocks the beam reflected toward the receiver
- Attenuation, where the atmosphere weakens the reflected beam before it reaches the receiver
- Spillage, which is the fraction of the reflected beam that misses the receiver
- Cosine effect, which is the reduced mirror area available for reflection because the mirror is oriented to reflect the beam onto the receiver (hence, it is pointed midway between the directions of the sun and the receiver). The cosine effect is numerically equal to the value of the cosine of the angle between the mirror normal and the incident solar radiation.

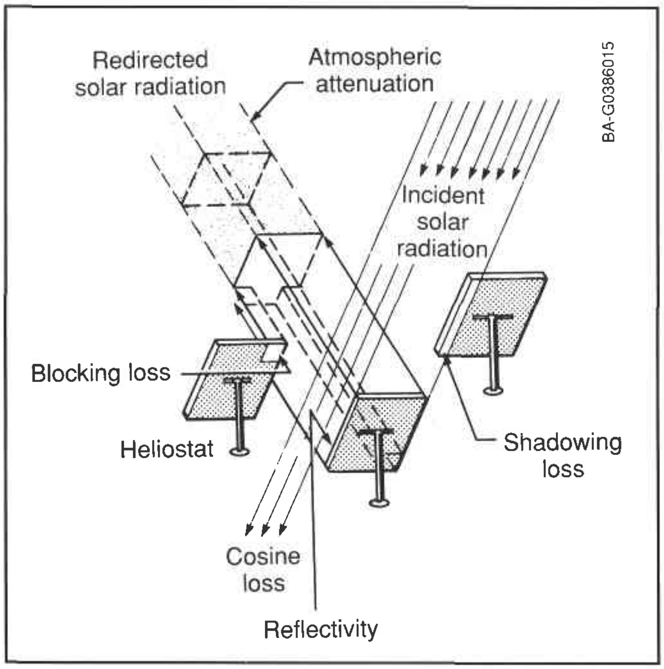


Figure 1.6. Heliostat field optical loss processes

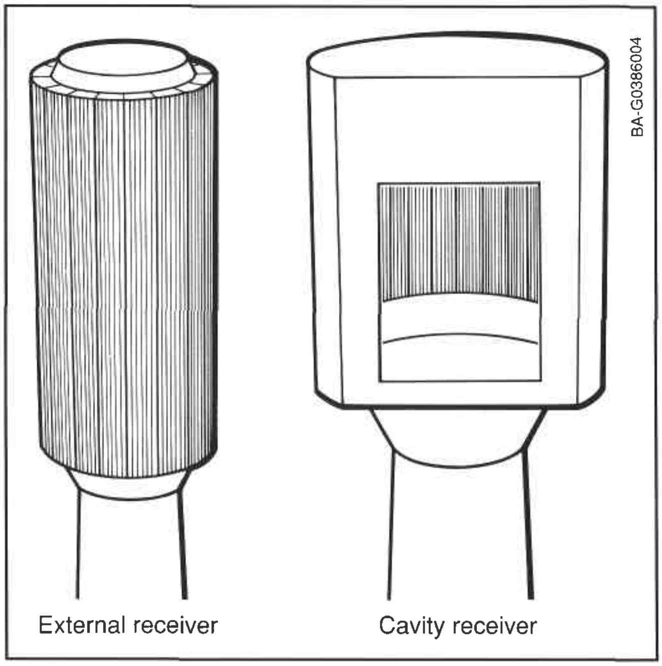


Figure 1.7. External and cavity receiver designs

These loss mechanisms are illustrated in Figure 1.6. The north field heliostat layout has a higher average value for the cosine effect than the surround field layout.

The long-term goal for the heliostat subsystem cost is \$40/m^2 of heliostat reflector area in high-volume production. In the past 10 years, heliostat costs have dropped from about \$900/m^2 (for 222 units) to estimates of less than \$100/m^2 for current designs in high-volume production.

Although the field and receiver efficiencies and designs are optimized together, the long-term goal assigned for field efficiency is 0.64, which is consistent with demonstrated performance. The corresponding goal for receiver efficiency is given in the following section.

Solar Receiver Subsystem

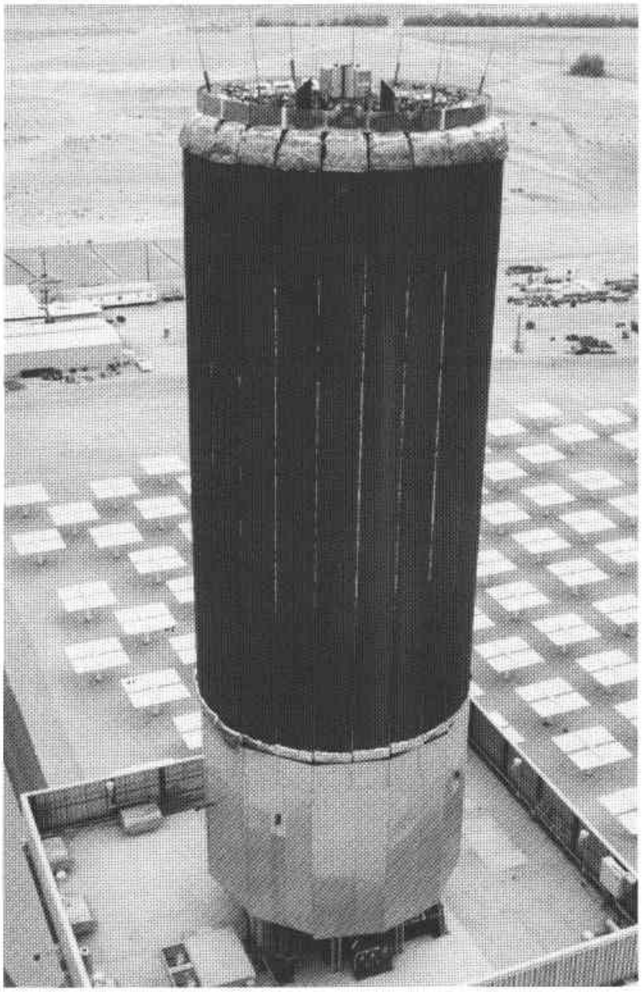
The solar receiver intercepts and absorbs the concentrated solar radiation reflected from the heliostats and transfers this energy to a heat-transfer fluid. Its heat-absorbing surfaces are similar to those of a fossil-fueled boiler; that is, multiple panels of parallel tubes are welded to inlet and outlet headers at either end. The heat-transfer fluid flows through the tubes, removing the solar radiation absorbed on the tubes' outer surfaces.

Depending on the heliostat field layout, receivers are either external or cavity, as shown in Figure 1.7. Externalreceivers have heat-absorbing panels arranged to approximate a cylinder. The optimum height-to-diameter ratio of the cylinder is generally in the range of 1:1 to 2:1 as the result of a trade-off between receiver cost and spillage. The external receiver at Solar One is shown in Figure 1.8.

In a cavity receiver the solar radiation reflected from the heliostats passes through an aperture into a box-like structure before impinging on the heat-transfer surfaces; the box and aperture define the cavity. The active heat-transfer surfaces within a cavity are formed from panels like those used in external receivers; however, the panel arrangement is concave facing the heliostats. Because the other internal areas of the cavity, such as the roof and floor, normally do not actively absorb heat, they must be closed and insulated to minimize heat loss and to protect the structure, headers, and interconnecting piping from incident solar radiation. A cavity receiver was tested at the Themis, France, power plant in the mid-1980s (see Figure 1.9).

Cavity receivers have some disadvantages over external receivers. Their absorber area is generally larger than that required for an external receiver because the cavity absorber area is more difficult to illuminate uniformly. The receiver mass and number of components are also larger and generally more costly than they are for an external receiver with a similar absorber area. The advantages are that the door in a cavity receiver may be closed during times of low solar radiation, which would reduce thermal losses and simplify start-up procedures. Also, because the cavity receiver tubes are more protected from the weather than those in the external receiver, the high absorptance coatings on the tubes may degrade less during operation.

The heat-transfer fluid selected affects the choice of solar receiver design. This selection depends on the fluid's cost and its effectiveness as a receiver coolant, a heat-transfer fluid, and a thermal storage medium (if storage is desired). The three fluids studied and tested most extensively are listed in Table 1.2 together with their relative advantages and disadvantages.



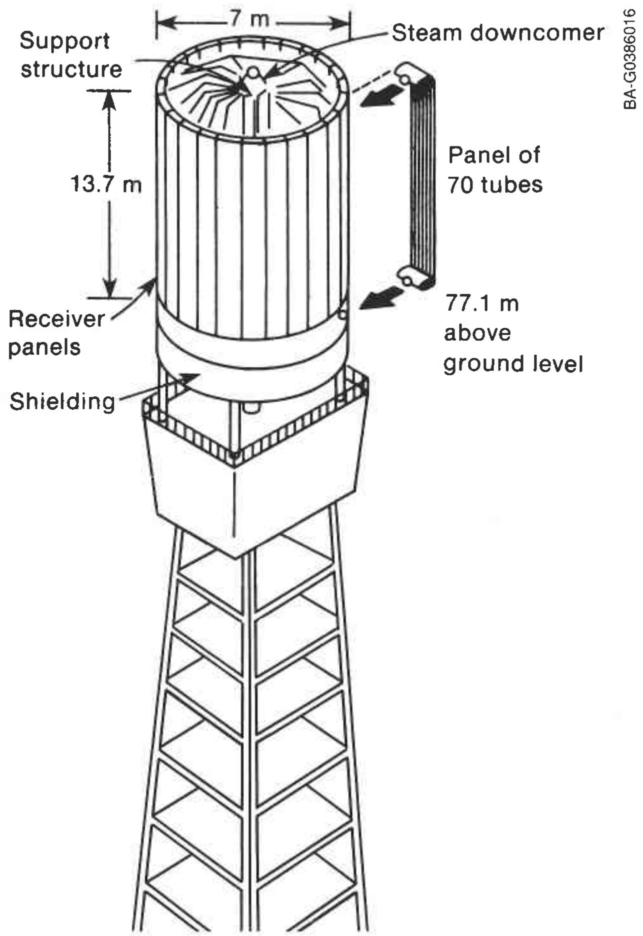


Figure 1.8. Solar One's external receiver

Because the size of the receiver affects the cost of the receiver and its supporting tower and because the receiver size can be reduced in proportion to the maximum radiation that can be absorbed on the panels, choosing a heat-transfer fluid is critical. The high pressure of a water/steam receiver requires thicker tube walls. These walls limit the maximum allowable radiation because the temperature gradient causes thermal stresses across the tube wall. The high thermal conductivity of liquid sodium allows the smallest receiver size. One objective of the research and development program is to establish the maximum allowable solar radiation on receiver panel tubes.

The major assemblies and components of the solar receiver subsystem (listed in Table 1.3) vary with the choice of receiver coolant and other features, and, of course, simple designs minimize receiver cost. A receiver concept that could reduce the receiver's size and its complexity, called the direct absorption receiver (DAR) is now being developed. In the DAR a falling film of heat-transfer fluid (molten salt) absorbs the reflected solar radiation directly. The status of this concept is described in Chapter 2.

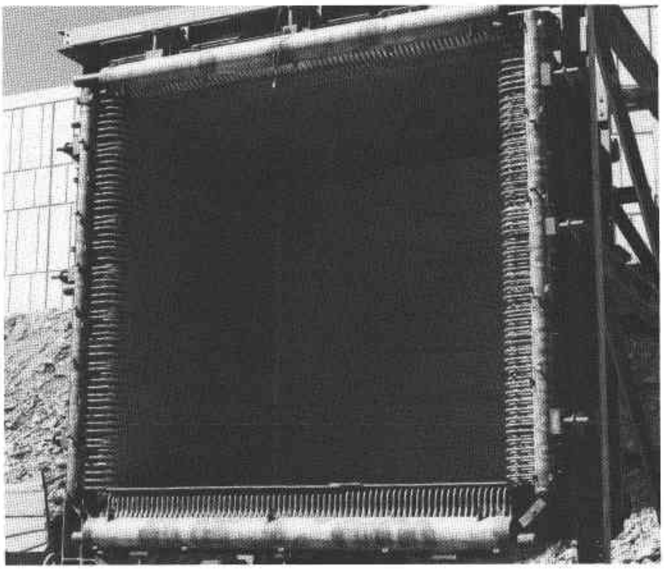


Figure 1.9. Themis Cavity receiver

Table 1.2. Advantages and Disadvantages of Three Heat-Transfer Fluids

Heat-Transfer Fluid	Advantages	Disadvantages
Water/steam	Common commercial use Good heat-transfer properties Direct to turbine Lowest cost fluid	High pressure Unsuitable as thermal storage fluid
Molten nitrate salts (60% sodium nitrate 40% potassium nitrate)	Good heat-transfer properties Good thermal-storage fluid Stable to 595°C (1103°F) Low pressure Low-cost fluid	Freezes at about 230°C (446°F) No utility experience Large-scale components must be developed
Liquid sodium	Best heat-transfer fluid Components developed in nuclear program Low pressure	Reacts with air and water Freezes at 98°C (208°F) Poor thermal storage fluid More costly fluid

Table 1.3. Receiver Subsystem Components

Major Assemblies	Components
Absorber panels	Coolant tubes (absorptive paint) Headers Support structure Provision for thermal expansion Insulation
Receiver structure	Main support structure Roof and enclosure Aperture door (cavity only) Platforms, stairs, and railings Radiation protection Crane and hoist (typical)
Piping, tanks, and valves	Inlet and outlet surge tanks (except water/steam system) Panel interconnecting piping Fill and drain pipes and valves Vent lines and valves Trace-heating for piping, headers, and valves (salt and sodium only) Flow control valves
Instrumentation	Thermocouples Pressure transducers Flux gauges Flow meters Fluid level indicators
Tower	Tower structure (steel or concrete) Foundation Elevator and stairs Support equipment room(s) Lighting Lighting protection Aircraft obstruction

Minimizing energy losses is an important part of the receiver's design optimization. The loss mechanisms are

- Reflection—the light energy from the heliostat field scattered from the receiver surface and escaping from the receiver. High absorptivity paint used on the absorber surfaces keeps the reflective loss to less than 5% of the incident energy.
- Convection—the thermal energy lost to the air around the receiver. A combination of natural and forced convection, it is typically 3%–5% of the absorbed energy.
- Radiation—the thermal energy lost by infrared and visible light emission because of the high temperature of the receiver (typically 3%–5%). The radiative and convective losses depend on the temperature of the receiver and its design (cavity or external).
- Conduction—the thermal energy lost through the insulating surfaces and structural members. This loss is less than 1% for a well insulated receiver.

Measuring receiver losses has been a major goal of subsystem and system test programs because this information can be used to minimize the losses in subsequent designs. Typical receiver efficiency versus average surface temperature is shown in Figure 1.10.

DOE's long-term goal is to reduce the cost for the receiver subsystem to $30/m^2 of heliostat reflector area and increase the efficiency to 0.90. Recent studies indicate that both are achievable and that costs could be lower with further development.

Thermal Transport and Storage Subsystem

The thermal transport and storage subsystem carries thermal energy from the receiver subsystem, stores it (if desired), and delivers it to the power conversion subsystem. Thermal energy storage allows the plant to operate

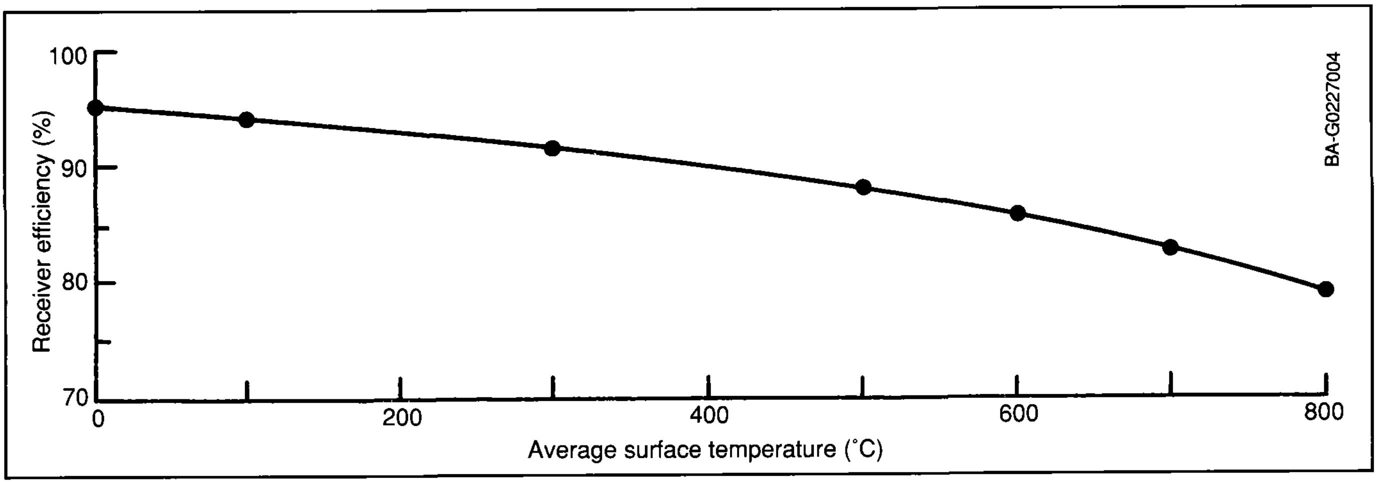


Figure 1.10. Typical receiver efficiency versus temperature

continuously during periods of variable solar radiation, extends plant operation into hours when there is no solar radiation, avoids the potentially harmful transients arising from abrupt changes in solar radiation, ensures power availability in emergencies, and allows electricity generation to meet a demand profile that does not necessarily coincide with the solar radiation profile. It also allows electric power production at the plant rating that yields the maximum efficiency.

The design of the thermal transport and storage subsystem depends somewhat on the heat-transfer fluid selected as the receiver coolant. This fluid is circulated from the receiver to either charge thermal storage or supply thermal energy to the power conversion subsystem. Normally, thermal energy is stored as sensible heat of the storage medium. That is, the high-temperature fluid from the receiver is stored in a tank until needed for power production. The cooled fluid is then stored until it is reheated in the receiver.

Sensible-heat storage can be implemented by either direct storage, in which the receiver working fluid is the same as the storage medium, 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 transfer heat from the receiver fluid to the storage medium (charge storage). Temperature drops must be provided between the receiver and storage and between storage and the power conversion subsystem to transfer heat. Therefore, the receiver must be operated at a higher temperature to charge storage that is needed to directly produce electricity.

Sensible-heat storage can use separate hot and cold tanks or use a single thermocline tank arrangement, as shown in Figures 1.11 and 1.12, respectively. Normally, vertical cylindrical tanks are used for either concept. The separate hot- and cold-tank design uses two or more tanks; all of the fluid contained in a given tank is at a uniform temperature. Because of the continuous charging and discharging of stored thermal energy, the fluid levels in the tanks vary significantly during normal plant operation.

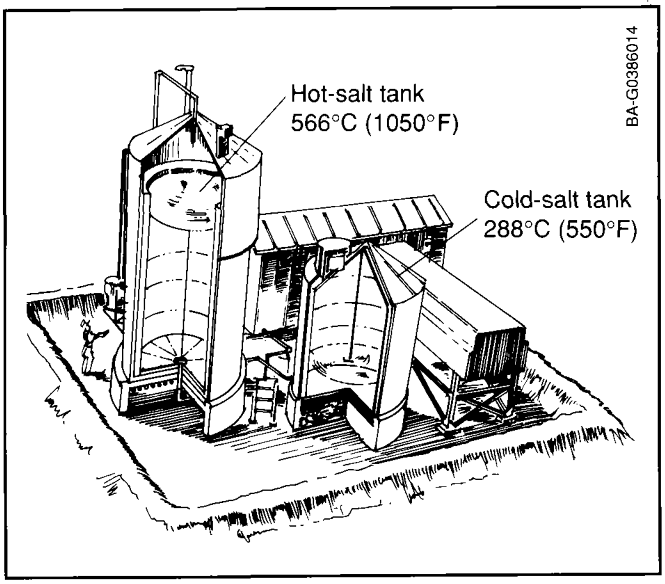


Figure 1.11. Two-tank thermal storage

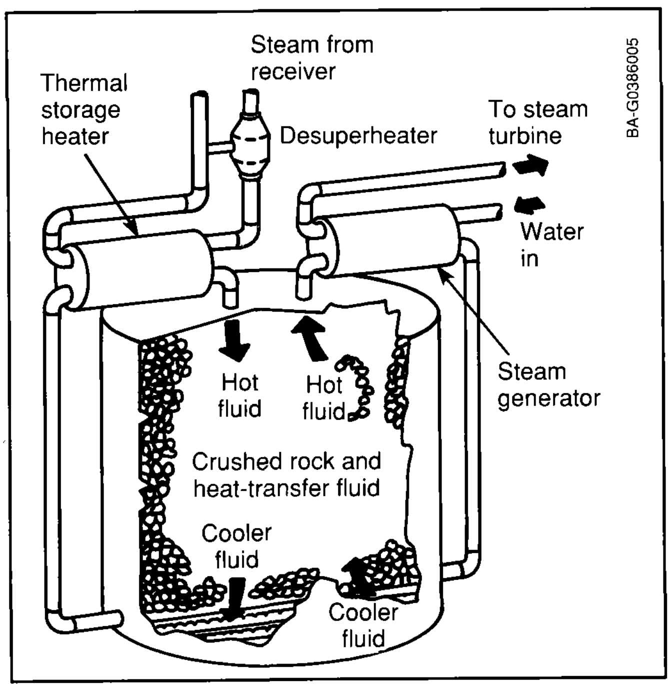


Figure 1.12. Single-tank thermocline thermal storage

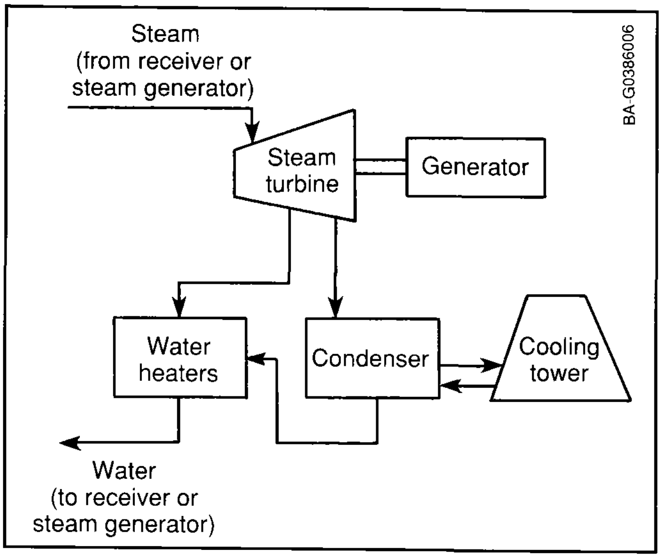


Figure 1.13. Steam Rankine power conversion cycle

A thermocline tank relies on the thermal stratification of the storage medium that results from the variation in fluid density as a function of temperature. This stratification requires using a relatively low thermal conductivity storage medium and relies 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.

Molten nitrate salt and liquid sodium can each be used as both the receiver coolant and the storage medium, providing direct storage. They can be used for storage up to 566°C (1050°F) for molten salt or 593°C (1100°F) for liquid sodium. Both fluids require thermal protection (e.g., heat tracing) to prevent freezing because of their elevated melting points (98°C [208°F] for sodium and 230°C [446°F] for nitrate salt). Lower cost and higher volumetric heat capacity make nitrate salt the preferred storage medium.

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). This temperature limitation restricts the use of heat-transfer oil as a storage medium to applications of water/steam receivers where direct storage of superheated steam is not possible. The moderate pressure and temperature of the steam produced from such a storage system means the steam must enter the turbine at the intermediate pressure region. The relatively high cost of heat-transfer oils can be mitigated by using rocks in a thermocline storage tank to store a portion of the thermal energy and displace some of the oil.

The major elements of the thermal transport and storage subsystem are

- Heat-transfer fluid
- Thermal storage media (if different from the heat-transfer fluid)
- Storage tank(s) and foundation(s)
- Heat exchangers (for indirect storage)
- Piping, pumps, and valves
- Insulation for all heated components
- Trace heating (for molten salt or liquid sodium systems)
- Ullage gas system
- Start-up and maintenance equipment
- Instrumentation and controls.

The long-term goals for the thermal transport subsystem are \$25/m^2 of heliostat reflector area and an efficiency of 0.99. The thermal storage goals are \$20/kWh (thermal) of storage and an efficiency of 0.98. These goals are consistent with current projections.

Power Conversion Subsystem

The power conversion subsystem converts the thermal energy collected in the plant to electricity. Conventional power plant equipment can generally be used in central receiver systems.

The Rankine cycle, using a combination of water and steam as the working fluid, is used for power conversion (see Figure 1.13). Plants using either molten salt or liquid sodium as the receiver coolant require a steam generator, which consists of shell-and-tube heat exchangers for preheating, evaporating, and superheating the working fluid. Either forced or natural recirculation is used in the evaporator with molten salt. An auxiliary preheater maintains the feedwater temperature entering the steam generator at a higher level than the freezing temperature of the salt during start-up and low flow conditions. Also, a reheater is provided for systems using a reheat cycle. The balance of this subsystem uses off-the-shelf equipment; however, the requirements for cyclic operation in a solar plant must be considered in preparing the equipment specifications.

The gross efficiency of Rankine-cycle power conversion systems is the electrical output at the generation terminals divided by the heat added to the steam in the steam generators. The net efficiency of this subsystem for a solar power plant can be described by the gross turbine efficiency, together with an expression of auxiliary power requirements.

High main-steam temperatures are desired for high-cycle efficiency. For base-loaded, fossil-fired plants, a 540°C (1000°F) main-steam temperature is common industry practice. Selecting 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 trade-off between cycle efficiency and capital cost. Main steam pressure in a non-reheat cycle is limited to approximately 12.4 MPa (1800 psig). A steam pressure of 16.8 MPa (2400 psig) is typically used in a reheat cycle.

Two categories of auxiliary equipment have power requirements in the power conversion subsystem. The large pumps and fans used to handle the working fluid and the fluids in the heat rejection system constitute the first category. For a cycle of a given arrangement, the power consumed by this equipment is roughly proportional to the gross plant output. The second category 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 represents a progressively smaller fraction of the gross cycle output as the plant size increases.

The long-term cost goal is $350/kW$_e$, which will be difficult to achieve; but the net efficiency goal of 0.39 is well within current technology.

Master Control Subsystem

The master control subsystem provides an overall command, control, and data acquisition capability for a central receiver plant, including controlling the other subsystems in a single-console control. A major part of the control system function is managing daily start-up and shutdown, which involves numerous steps. The master control subsystem simplifies this by automating these mode changes.

The master control system provides the following functions:

- Man-machine interface
  - Display and graphics formatting
  - On-line guidance to operators
  - Maintenance diagnostics during operation
  - Access to data base
  - System status overview
- Control strategies and system architecture
  - Coordination of subsystem control functions
  - Adaptive control strategies for off-design conditions and failures
  - Distributed control system
  - Efficient control and data communication
- Monitoring and diagnostics
  - Alarm analysis
  - Rapid diagnostics of out-of-tolerance conditions
  - Elimination of trips to plant
  - Degradation detection
  - Anticipation of future events
- Maintenance
  - Self-diagnostics of computer hardware
  - Trend analysis of equipment maintenance problems
  - Separate operational data base
  - Preventive maintenance aids.

The major equipment includes the operator's console, where the operator can access the control hardware and software; 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.

Process control uses monitoring and control equipment that can be operated manually or automatically through the master control. A distributed process controller is usually located in the field near the process and near the final control device such as a valve or motor. 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 master control console over a local area network or redundant data highway using multiplexing systems. That is, information (commands or data) passing between the remote control hardware and the central command and display hardware is electronically condensed so that many signals are transmitted over a single cable.

Operating costs can be lowered significantly by reducing the number of operators. Two options are possible for minimizing operating costs: remote operation or unattended operation. Remote operation is operating a plant from a master console that is somewhere other than in the plant's main control room (possibly several miles away). The operator would be monitoring and controlling from that remote location.

Unattended operation refers to a completely automatic 24-hour operation without any operator. The plant would be unattended for weeks or even months except for periodic maintenance and inspection. Unattended operation of the solar portion of the plant is possible; unattended operation of the power conversion subsystem is unlikely.

Hybrid Plants

Fossil-fueled components may be included in a central receiver plant to supplement the solar heat source. This design is often referred to as a solar-fossil hybrid. Including a hybrid subsystem depends on the economic benefits for a specific plant. For example, if the costs of energy from solar-only and fossil-fuel-only electricity generation are comparable, then the hybrid mode could extend the hours of plant operation during periods of poor or no solar radiation, eliminating the need for thermal storage. Or, if the cost of energy from solar-only electricity generation is lower than that from fossil-fuel-only generation, but thermal storage increases the costs, then fossil-fuel generation again could be used to extend plant operation.

Two design options have been identified for a hybrid arrangement of solar and fossil-fuel components. The first option (Figure 1.14a) consists of a fossil-fueled steam generator using a high pressure, two-phase fluid system that operates in parallel with the solar steam generator. To operate a fossil-fueled steam generator reliably requires constant monitoring and regulation of feedwater flow, steam flow, steam pressure and temperature, fuel flow, and fuel pressure. It also requires matching these parameters with the turbine requirements as determined by the loading on

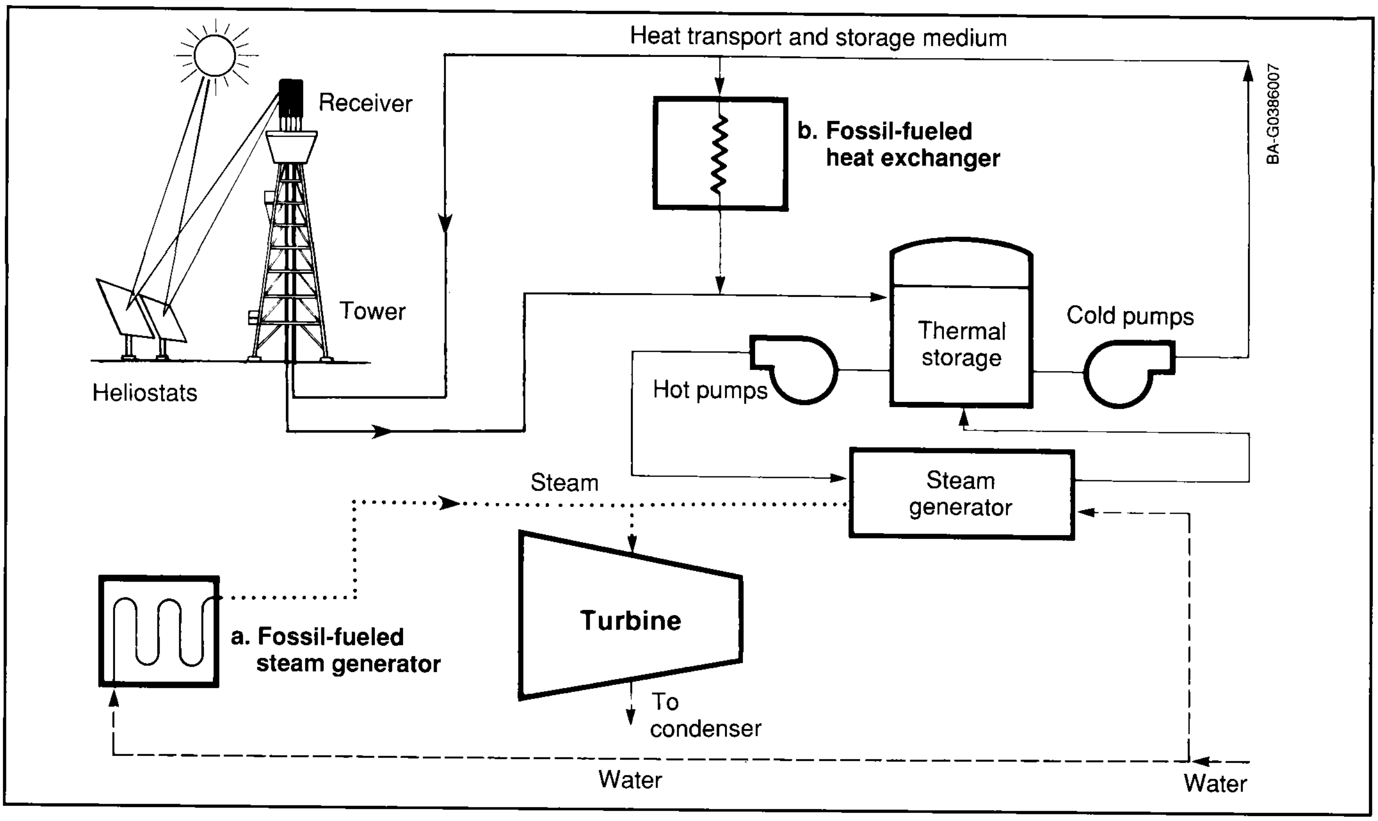


Figure 1.14. Hybrid central receiver systems using either (a) parallel fossil-fueled steam generator or (b) fossil-fueled media heater

the generator. The complexity of the overall plant controls is compounded when solar and fossil-fueled steam generators are operated in parallel.

The second design option (Figure 1.14b) consists of a fossil-fueled heater in parallel with the solar receiver. This design has a bypass around the receiver that routes the heat-transfer fluid through an auxiliary fossil-fueled heater. Valving and piping control the flow of the heat-transfer fluid so that part or all of the fluid can flow through either the receiver or the fossil-fueled heater. After leaving the receiver or the heater, the heat-transfer fluid is routed through the solar steam generator or to the thermal energy storage subsystem.

Fuel options for the fossil-fueled subsystem consist of oil, gas, and coal. The fuel selected depends on cost, availability, handling and storage, and emission control requirements.

System Designs

The system concepts selected as most promising for solar central receivers are based primarily on the heat-transfer fluid used, which includes water/steam, molten salt, and liquid sodium. A fourth option is to use liquid sodium as the receiver coolant and molten salt as the thermal storage medium. All preferred systems use thermal storage and the steam-Rankine power conversion cycle. All can be used with a fossil-fueled system with either design described in the preceding section, although a water/steam system would preferably use the parallel steam generator.

Water/Steam System

A schematic of a water/steam central receiver system (like the 10-MW_e system tested at Solar One from 1982 to 1988) is shown in Figure 1.15. This system uses a tower-mounted water/steam cooled receiver heated by a field of heliostats. The concentrated solar radiation in the receiver causes the water to boil and then superheats the steam to 510°C (950°F) at 10.3 MPa (1500 psig). This superheated steam is then routed directly to a steam turbine where it is used to produce electricity. Some or all of the steam can be routed to the thermal storage system.

Steam from the receiver heats an oil (such as Caloria HT43) in a heat exchanger to charge the oil/rock thermocline storage system. 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 top of the tank through a steam generator and back into the bottom of the tank.

The oil has a maximum temperature (about 315°C [600°F]) that requires this process to be conducted at a reduced steam temperature, which lowers the output steam to 280°C (530°F). Using this lower temperature steam, which enters the turbine through a special admission port, reduces the turbine gross cycle efficiency from 34% (rated steam) to 28% (operating from storage).

The relatively low conversion efficiency, resulting primarily from operating through a reduced-temperature storage system, has led to the proposal of higher efficiency systems using other receiver fluids. These fluids (molten salt and liquid 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

A molten-salt central receiver system, as shown in Figure 1.16, consists of a tower-mounted receiver heated by reflected energy from a field of heliostats. Small systems similar to this were tested at the Central Receiver Test Facility (CRTF) (750 kW_e) and at Themis, France (2.5 MW_e), in the mid-1980s. The molten salt used 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 subsystem where the hot salt is extracted to produce steam in the steam generator. The steam is then used to generate electricity. The cooled salt is returned through the thermal storage subsystem to the receiver.

In this design the thermal storage subsystem buffers the steam generator and steam turbine from solar transients and also supplies energy when there is no solar radiation. Using a high-temperature storable fluid in the receiver and thermal transport loop not only decouples the steam generation from solar transients but also enables steam production at the temperatures and pressures required for high-efficiency turbine generator operation.

Liquid-Sodium System

A liquid-sodium central receiver system, as shown in Figure 1.17, is very similar to the molten-salt system. It also has a tower-mounted receiver heated by reflected energy from a field of heliostats. Small liquid-sodium receivers (less than 5 MW_t) were tested at the CRTF and at the Almeria, Spain, facility in the mid-1980s. In this design liquid sodium heated in the receiver is sent to the thermal storage subsystem where the hot sodium is extracted to produce steam in a sodium/water steam generator. The steam is used in a conventional manner to generate electricity. The cooled sodium is then returned through the thermal storage subsystem to the receiver. As with the molten-salt system, the thermal storage subsystem buffers the steam generator from solar transients and supplies energy during extended periods of no solar radiation.

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

The major advantage of operating at high flux is that the receiver (absorbing area) can be smaller for a specified power level. Reducing the size lowers the cost of the

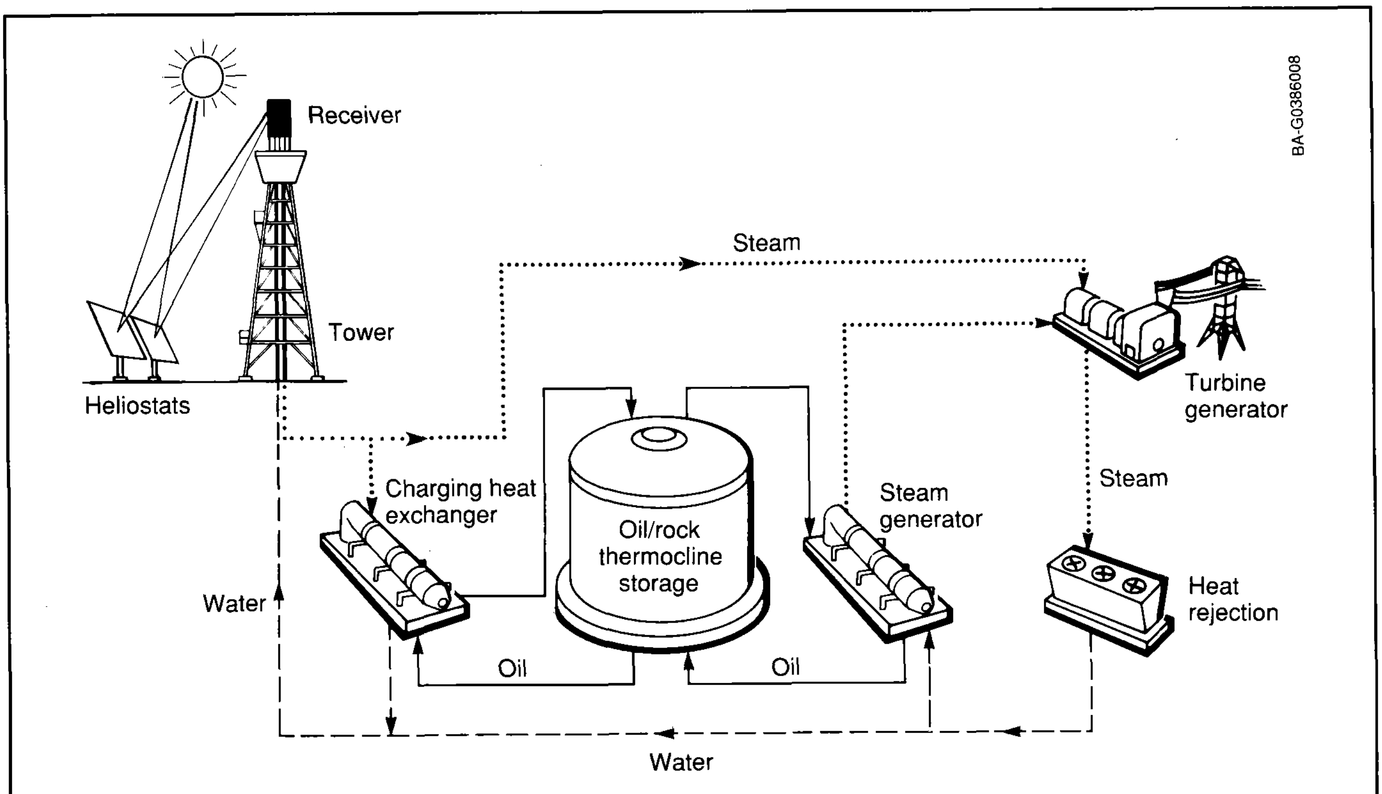


Figure 1.15. Schematic of a water/steam central receiver system

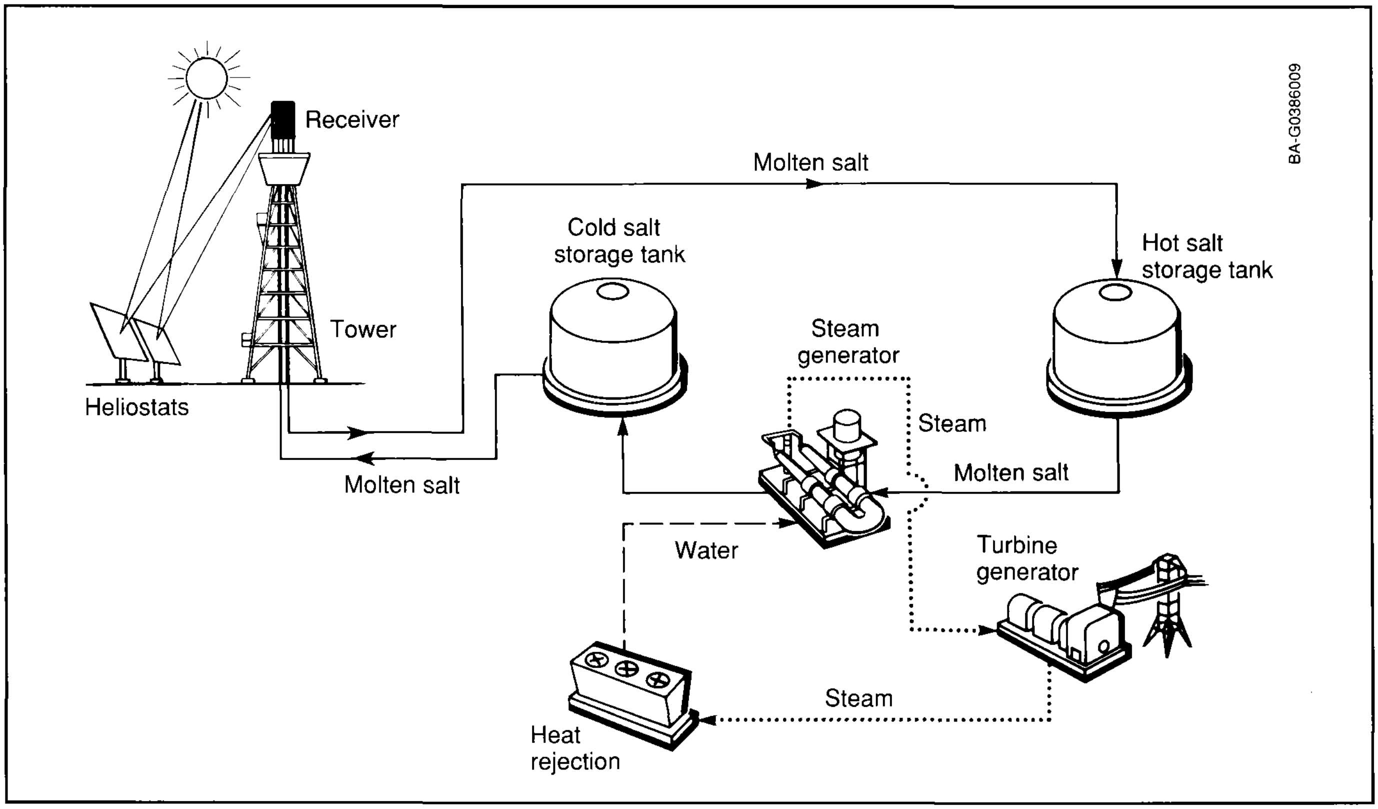


Figure 1.16. Schematic of a molten-salt central receiver system

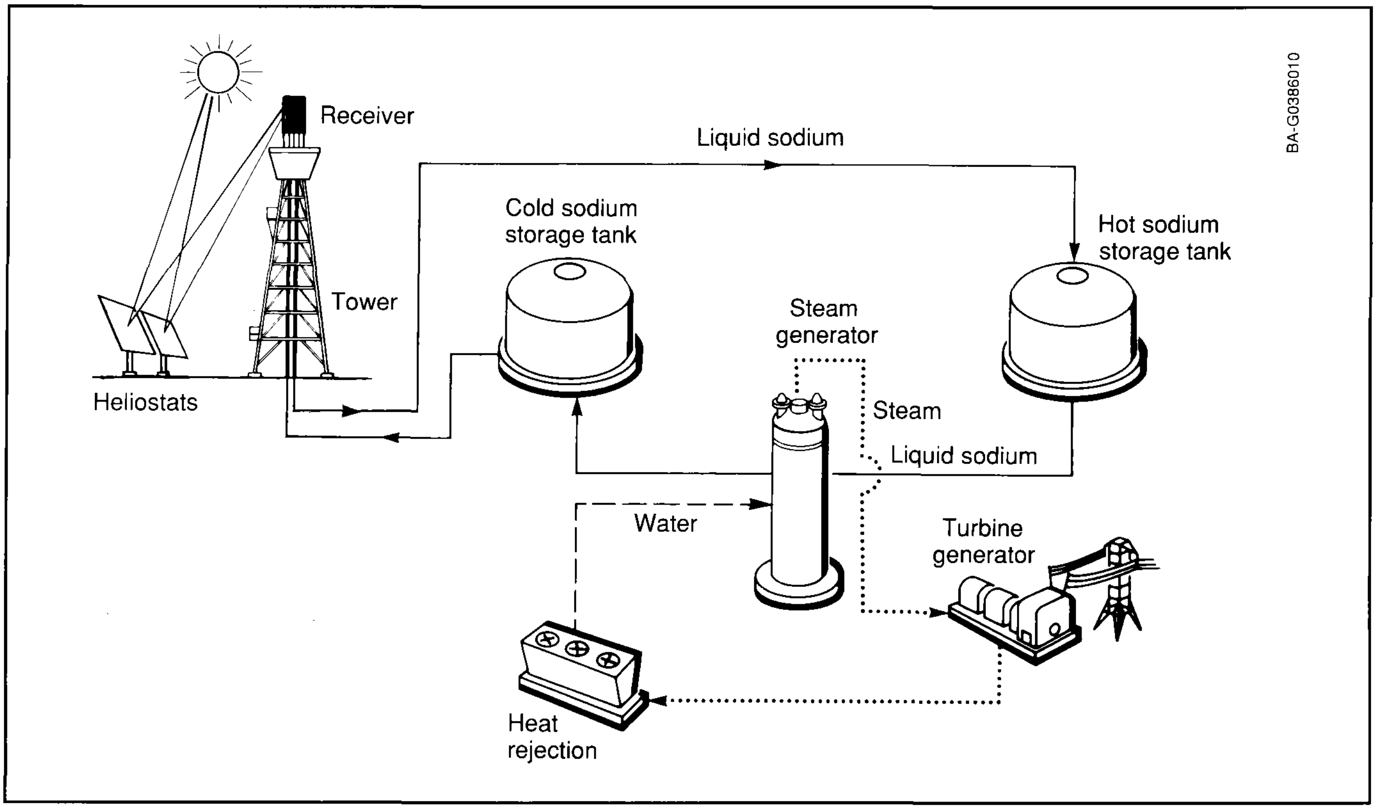


Figure 1.17. Schematic of a liquid-sodium central receiver system

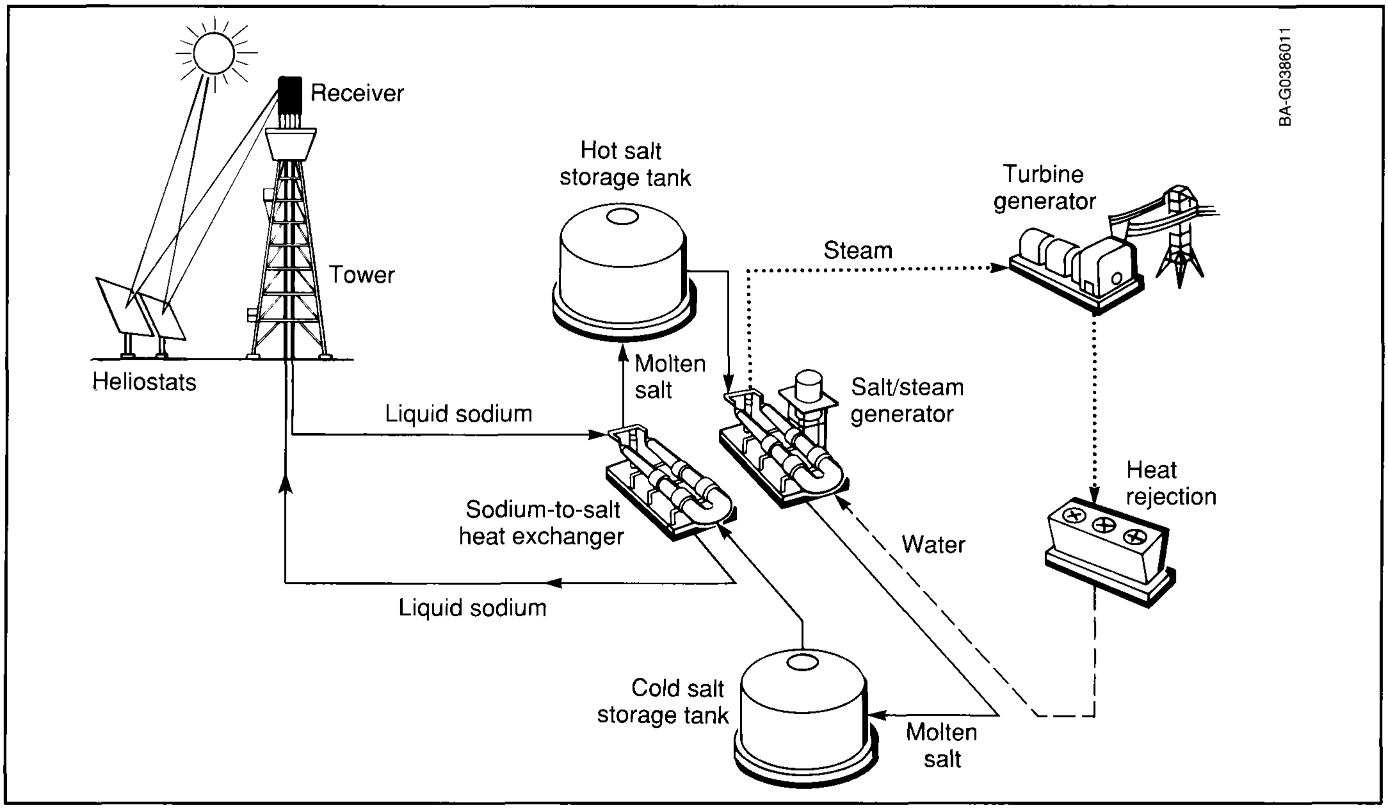


Figure 1.18. Schematic of a binary central receiver system

receiver and tower and improves thermal efficiency by reducing area-dependent losses such as convection and radiation. 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 (a product of density and specific heat) also results in larger, and thus more costly, thermal storage tanks.

Liquid-Sodium/Molten-Salt System

A conceptual design for a combination central receiver system, as shown in Figure 1.18, has been proposed that makes use of the excellent heat-transfer properties of sodium as the receiver coolant and the good properties of molten salt for thermal storage. In this design, a sodium-to-salt heat exchanger transfers the thermal energy collected in the receiver into storage. At this point, the plant is identical to the molten-salt system.

Sodium fires and chemical reactions from the liquid sodium contacting the molten salt are a concern in this system. Isolating all of the sodium equipment, except the receiver, within the concrete tower structure will help contain and control any fires and will minimize the risk to plant personnel. Also, having the system drain quickly into a tank located on the tower foundation minimizes leakage. A steel liner in the tower base and appropriate shields or splash guards elsewhere will protect the concrete in the tower structure from direct impingement of sodium.

The additional heat-transfer loop adds to the complexity of this system. In addition, sodium and molten salt would react chemically should the intermediate heat exchanger leak.

Chapter 2
Research and Development

Extensive research and development has been conducted in support of the central receiver system. Major progress has been made in developing components, subsystems, and materials for solar applications, and testing subsystems and full systems. The focus of all development effort has been to achieve competitive electric power costs from the central receiver system.

This chapter traces central receiver research and development from the early experiments that established concept feasibility to the current status where the concepts and path needed to make the system economically viable are identified.

The earliest experiment was a 1000-kW_t solar furnace constructed in 1970 at Odeillo Font-Romeu in the Pyrenees mountains in southern France. The system used 63 hydraulically driven heliostats, each with a reflective area of 42 m^2. The heliostats were arranged on a terrace rising to the north, and all reflected onto a second, larger parabolic concentrator that focused the beams back onto a tower-mounted receiver. Figure 2.1 shows the facility with the secondary concentrator in the back, the tower containing the receiver at its focus, and some of the heliostats in the foreground.

The facility was constructed by the French National Center for Scientific Research to conduct high-temperature materials research. In 1976, it was converted into a 60-kW_e electric power experiment with an oil-cooled receiver, an oil/thermocline thermal storage unit, and a small steam turbine. This was the first solar electric experimental power plant using the central receiver principle. The facility is currently being used to test materials.

The Odeillo plant provided a starting point for technology development. It also provided confidence in the ability of the silvered glass mirrors to withstand the effects of weather.

Heliostats

Because the heliostat field is the largest single cost of a solar central receiver system (see Figure 1.3), the central receiver program has concentrated on developing low-cost designs and estimating mass production costs. The design emphasis is on the interactive relationship between collector subsystem cost/performance trade-offs and overall system economics. The cost criterion normally used is the annual energy collected per dollar of life-cycle cost.

Glass/Metal Heliostats

The development of glass/metal heliostats progressed through three successive stages: feasibility, screening of alternative concepts, and cost reduction. The first U.S. heliostat was built by McDonnell Douglas in 1974 under a grant from the National Science Foundation. This heliostat, shown in Figure 2.2, used a single, back-silver glass mirror mounted on a tubular steel pedestal, a harmonic azimuth drive, and a linear drive for elevation. It had closed-loop tracking that used a sensor tube mounted and aligned

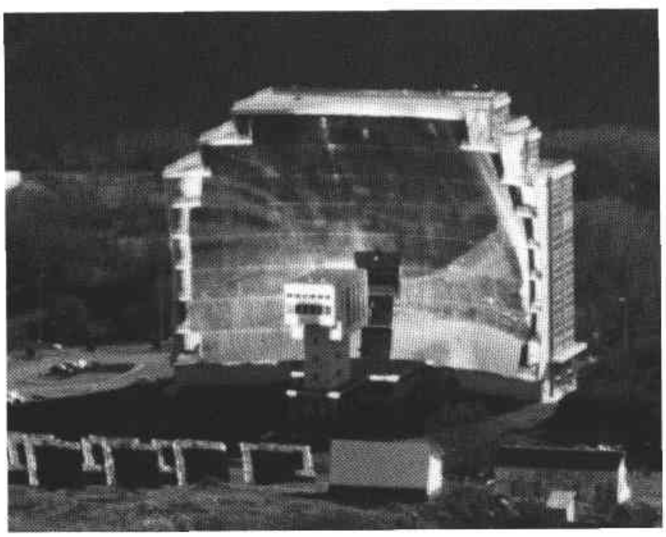


Figure 2.1. The French National Center for Scientific Research solar furnace at Odeillo, France

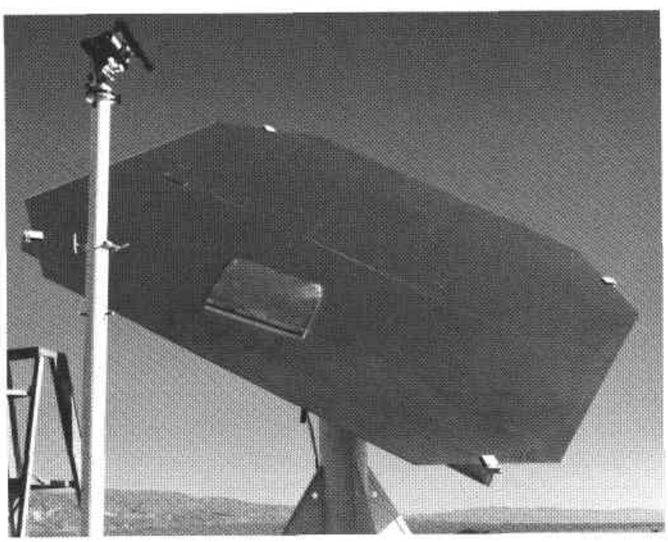


Figure 2.2. National Science Foundation heliostat

between the heliostat and the target for the reflected beam. This was similar to the tracking control scheme used for the Odeillo heliostats. Testing at China Lake, Calif., confirmed that the beam's quality was adequate and the tracking accurate and provided the confidence necessary to proceed with central receiver development.

The effort to select the preferred design began in 1975 when four contractor teams were funded to study designs for first-generation heliostats. These two-year efforts culminated in the fabrication and testing of prototype heliostats based on the concepts developed (Figure 2.3). The Honeywell, Martin Marietta, and McDonnell Douglas designs were glass/metal heliostats exposed to the environment; the Boeing design used a reflective surface that was an aluminized or a silvered plastic membrane protected from the environment by a plastic dome. The glass/metal heliostats included a tilt/tilt mount and drive by Honeywell, a yoke-mounted design by Martin Marietta, and a pedestal-mounted design by McDonnell Douglas.

During the course of this development, 222 heliostats were procured for the CRTF (see the appendix). Martin Marietta provided the CRTF with its first-generation heliostat design using 25 mirror modules on each heliostat. This first-generation program resulted in the selection of the following features for glass/metal heliostats:

- Single, pedestal-mounted design
- Azimuth/elevation drives
- Silvered glass mirrors
- Open-loop control for tracking.

Based on these selections, a contract was negotiated with Martin Marietta in 1981 to provide 1818 heliostats for Solar One and 93 for the International Energy Agency's Central Receiver Plant near Almeria, Spain (Figure 2.4).

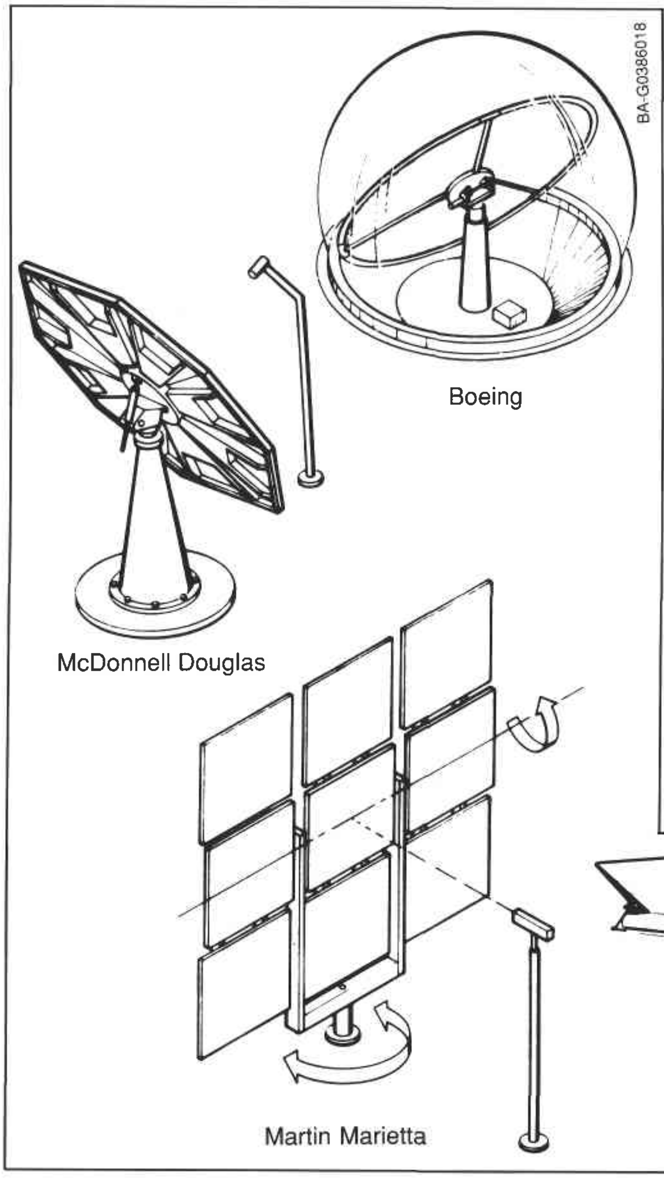
With the generic heliostat configuration and concept established, development focused on achieving minimum life-cycle costs for the energy collected. The specific objectives became to

- Minimize capital costs
- Equal or exceed the performance of the first-generation designs
- Increase the lifetime to 30 years
- Minimize maintenance cost.

A cost breakdown for the Solar One first-generation heliostat, adjusted for high-volume production, is shown in Figure 2.5. Subsequent development addressed all cost elements, although the reflector modules and the drive units were the costliest.

A second generation of heliostats designed to lower the capital and operating costs under mass production was built and tested. Detailed manufacturing, installation, and maintenance plans were developed to support the cost estimates. Four contractors each built two prototypes (shown in Figure 2.6) that were tested at the CRTF.

These heliostats represented the culmination of the development of glass/metal technology and provided a technically sound heliostat subsystem at reasonably attractive costs. All of the designs were judged to be technically viable with prospects for low cost under mass production. The designs were substantially larger than the first-generation



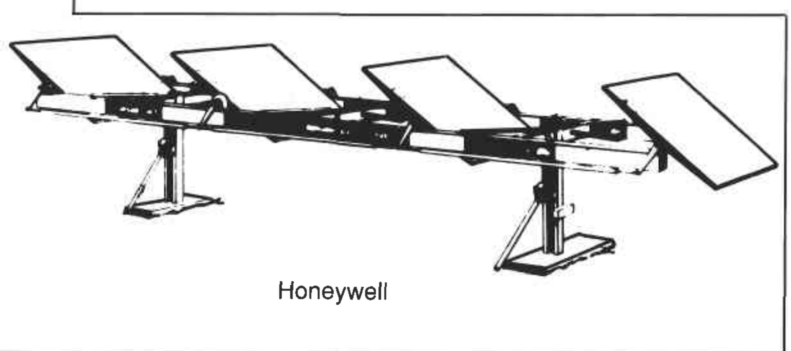


Figure 2.3. First-generation heliostats

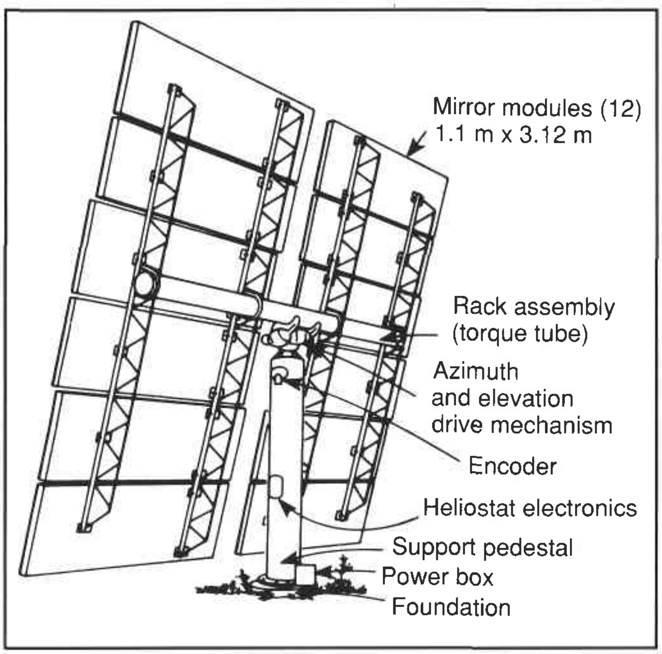


Figure 2.4. Solar One heliostat

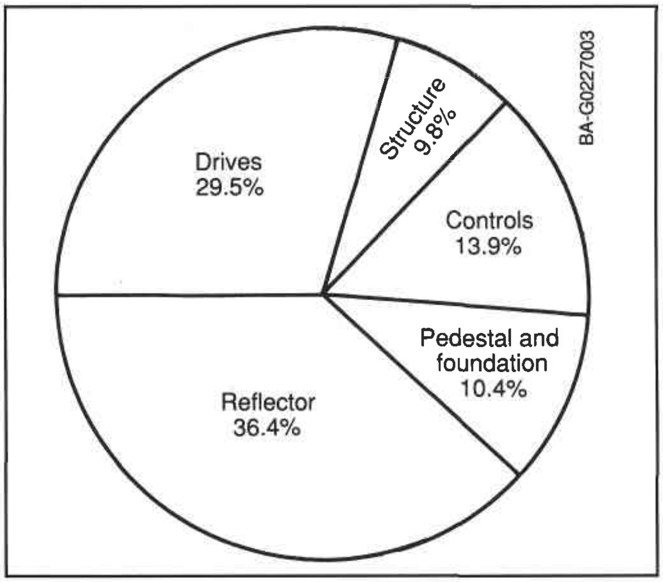


Figure 2.5. Cost breakdown, first-generation heliostat

heliostats, which was a major driving force in reducing costs. These larger heliostats offered lower cost for a field having a fixed total reflector area because they had

- Fewer drive assemblies
- Fewer pedestals, foundations, and structural assemblies
- Fewer controllers
- Lower installation cost
- Lower maintenance costs.

Several companies applied the technical and economic lessons learned from the first- and second-generation heliostat programs to produce large-area heliostats with very favorable cost predictions. McDonnell Douglas produced six 93-m^2 dish concentrators based on a scale-up of its

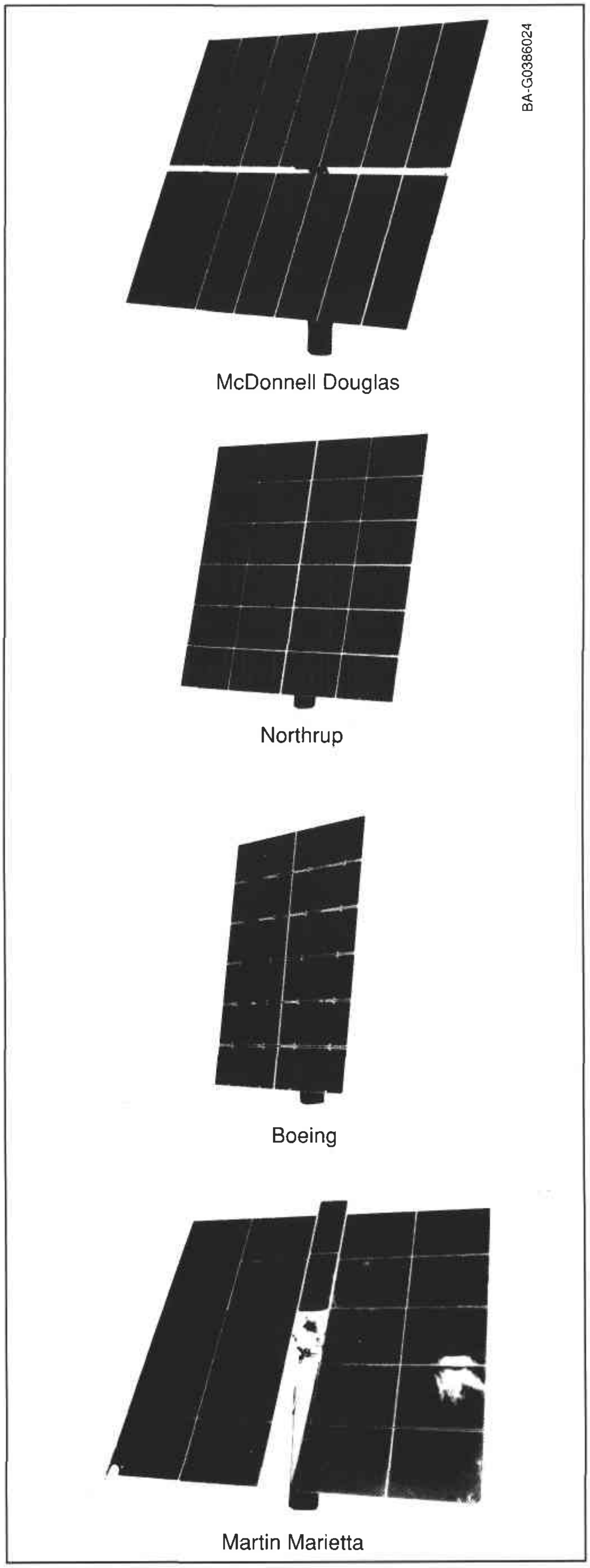


Figure 2.6. Second-generation heliostats

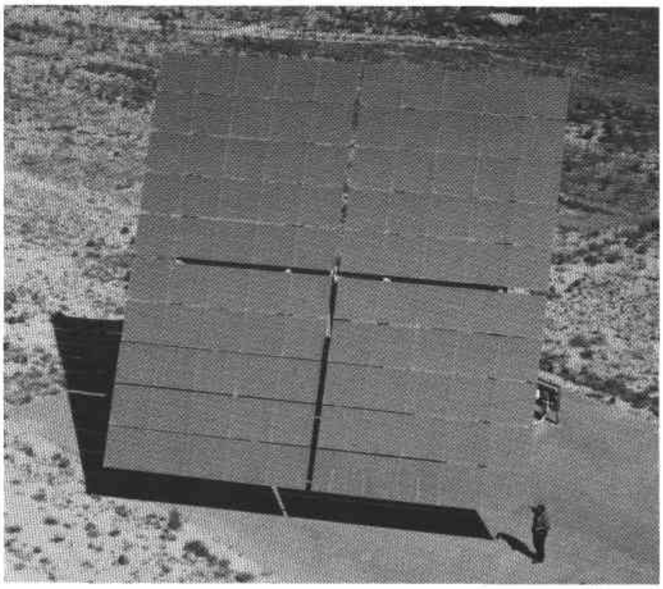


Figure 2.7. The 150-m ^{2} glass/metal heliostat

second-generation design. Solar Power Engineering Company produced a 200-m^2 unit, and ARCO produced 95-m^2 and 150-m^2 units both as tracking photovoltaic arrays and as heliostats. The 150-m^2 heliostat produced by ARCO and installed by Advanced Thermal Systems at the CRTF is shown in Figure 2.7. This large-area heliostat can be constructed and assembled cost-effectively in moderate quantities and still preserve its high-performance operational characteristics. Studies indicate that the optimum heliostat size is about 150 m^2 for minimum life-cycle costs. Larger than this, costs increase disproportionate to the area because wind loads affect the structure and drives. Design features of the first- and second-generation heliostats are listed in Table 2.1.

Stretched-Membrane Heliostats

The stretched-membrane heliostat, shown in Figure 2.8, consists of a ring, a front-silvered polymer membrane, a back thin-metal membrane, a tensioning system, and an active-focus control system that becomes a large, focused, reflecting mirror. By placing a slight vacuum in the plenum between the two membranes, the mirror module can be focused onto the receiver. The radius of curvature can be set at a range that allows this single-mirror module to focus the sun at exactly its slant range from the tower. By placing a slight pressure, with respect to atmosphere, in the plenum, the mirror module can be unfocused.

The adjustable-focus mirror module is supported by the structural ring that binds it. This ring, in turn, is supported by trusses that come from the azimuth and elevation drive actuators.

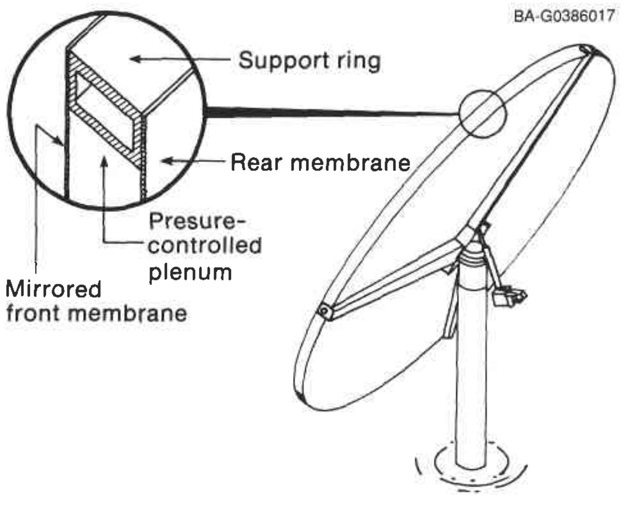
Solar Kinetics, Inc. (SKI), and Science Applications International Corporation (SAIC) were contracted in 1985 to develop the stretched-membrane heliostats. Both contractors produced 50-m^2 prototypes of their 150-m^2 commercial designs that were installed on existing pedestal/drive units at the CRTF for testing in late 1986. The SAIC design used thin, stainless steel back membranes; SKI used aluminum. Both used a silvered polymer as the reflector on the front membrane. The SKI heliostat is shown in Figure 2.9.

Both contractors also prepared designs for low-cost, commercial, stretched-membrane heliostats with a reflective area of 150 m^2. The major cost benefits for these heliostats are

- Large area (common with glass/metal technology and learned from that development program)
- Low weight (mirror modules can be one-fourth the weight of glass/metal designs)

Table 2.1. Glass/Metal Heliostat Evolution

	First Generation		Second Generation	
	CRTF	Solar One	McDonnell Douglas	Large Area
Period	1977–78	1978–81	1979–81	1981–86
Area (m^2)	37	39	57	95 and 150
Support	Yoke	Pedestal	Pedestal	Pedestal
Reflector	Glass/glass laminate	Glass/foam core/steel sandwich	Glass/glass laminate	Glass/steel laminate
Drives				
Azimuth	Gear-driven base-mounted gimbal	Worm/gear, helical pinion/gear	Helicon gear, harmonic spur	Worm and gearing
Elevation	Yoke-mounted gimbal	Same as azimuth	Helicon gear, ball screw/nut	Same as azimuth
Structure	Yoke, channels	Torque tube, truss beams	Box beam channels	Torque tube trusses, braces



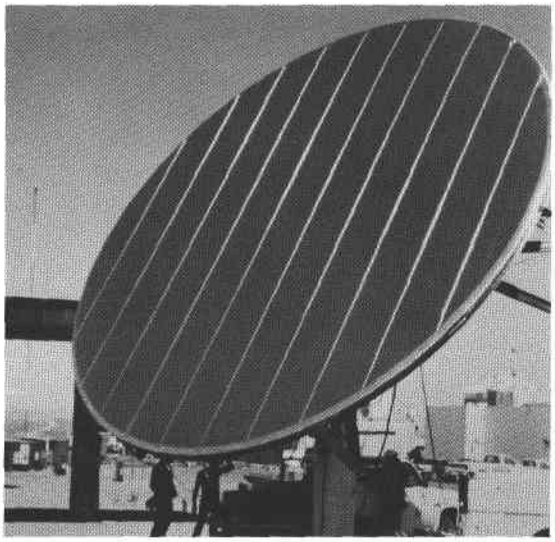


Figure 2.8. Stretched-membrane heliostat design

- Fewer parts and pieces than glass/metal heliostats
- Potential for drive and foundation cost reductions with advanced rim drives.

Although substantial development issues remain to be resolved, testing of the 50-m^2 prototypes indicates performance comparable to glass/metal designs. Cost estimates for a commercial design offer the possibility of reducing costs to less than $100/$m^2$. An overview of heliostat evaluation from the first-generation designs to the stretched-membrane design is shown in Figure 2.10.

Receivers

Although the collector field represents the major cost element of a central receiver plant, the receiver is the major technical challenge. The receiver must absorb the concentrated solar radiation reflected from the collector field and transfer it to the heat-transfer fluid. Technical requirements that can challenge the state of the art include the following:

- Because small receivers lower costs and maximize efficiency, they must accept high heat-flux levels.
- High power-conversion efficiency dictates high heat-transfer-fluid temperatures.
- Clouds passing cause very rapid operating transients.
- Many temperature cycles result from daily start-up and shutdown and intermittent cloudiness.
- Placement on top of a tower limits space and access.

Solar receiver designs and development have progressed through the early water/steam concepts to those using the advanced receiver coolants in a conventional tube configuration and finally to an even more advanced concept where the coolant absorbs the solar radiation directly. Receiver panels and full prototype receivers have been designed, built, tested, and evaluated as part of this development. Lessons learned and the resulting effect on the full

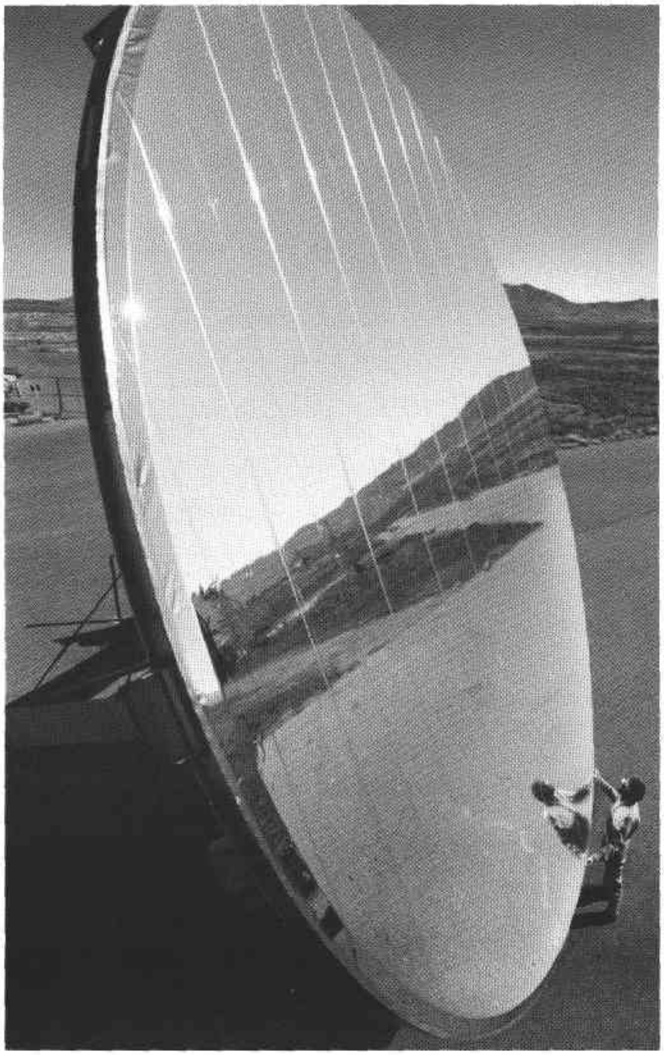


Figure 2.9. The 50-m^2 stretched-membrane heliostat developed by Solar Kinetics, Inc.

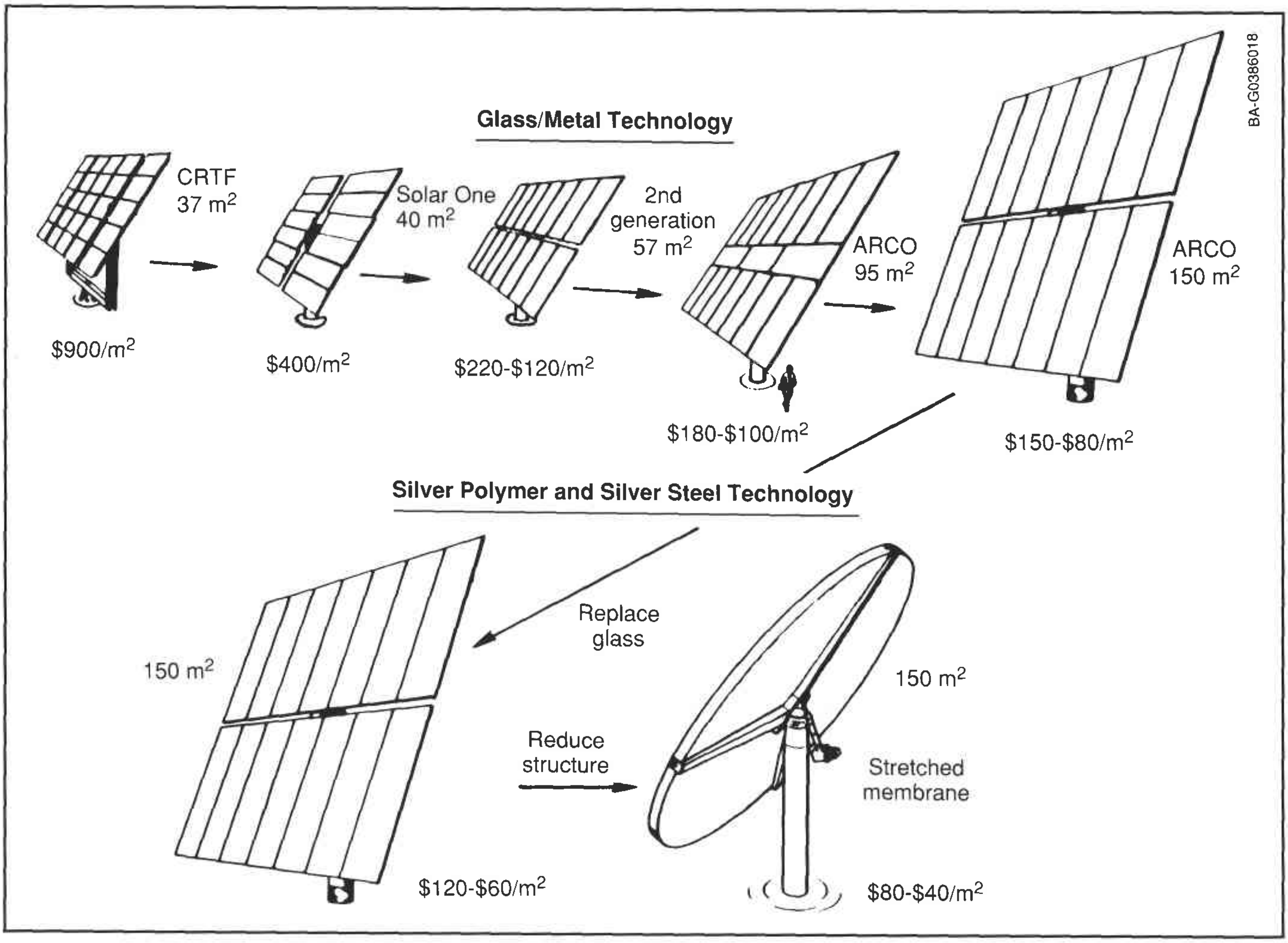


Figure 2.10. Pictorial representation of heliostat development

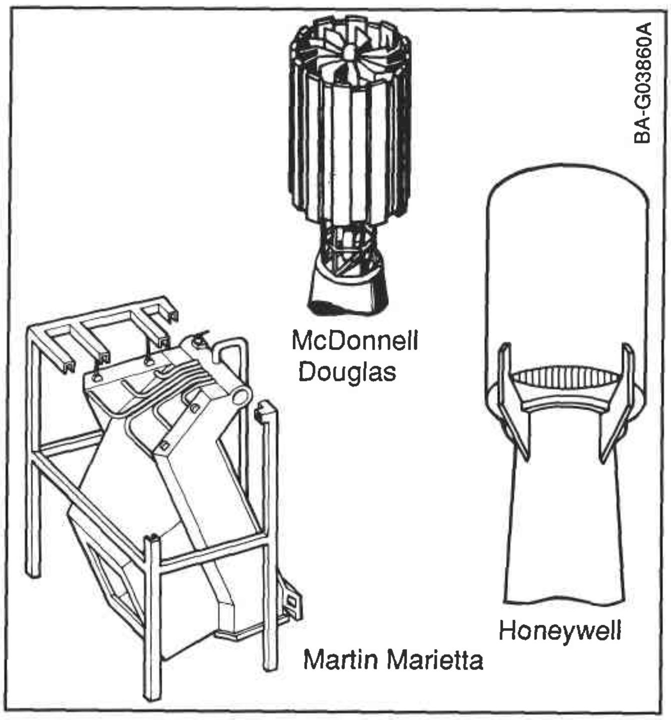


Figure 2.11. Solar One receiver designs

central receiver system have been used to select the preferred receiver designs for future central receiver power plants.

Receivers Using Water/Steam

Three quite different water/steam receiver designs (shown in Figure 2.11) were developed from 1975 to 1977 by the three contractors designing Solar One. The Honeywell design used a downward-facing cavity mounted on a high tower within the heliostat field. The Martin Marietta design used a side-opening cavity mounted on a tower located to the south of the heliostat field. McDonnell Douglas used an external receiver with the panels heated from the side by the surrounding heliostat field. Both Honeywell and Martin Marietta used recirculating boilers, a steam drum water/steam separator, and a separate superheater. McDonnell Douglas used the once-through-to-superheat principle.

A 1-MW_t model of the Martin Marietta receiver was built and tested at the Odeillo solar furnace in France. Panels of the McDonnell Douglas receiver and a prototype of the Honeywell receiver were built and tested with radiant heaters in the United States.

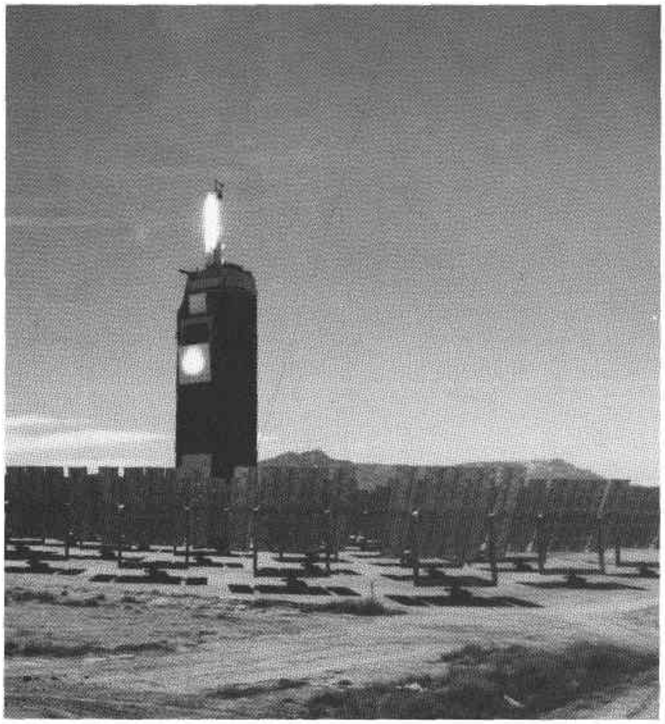


Figure 2.12. Solar One panel test at the Central Receiver Test Facility

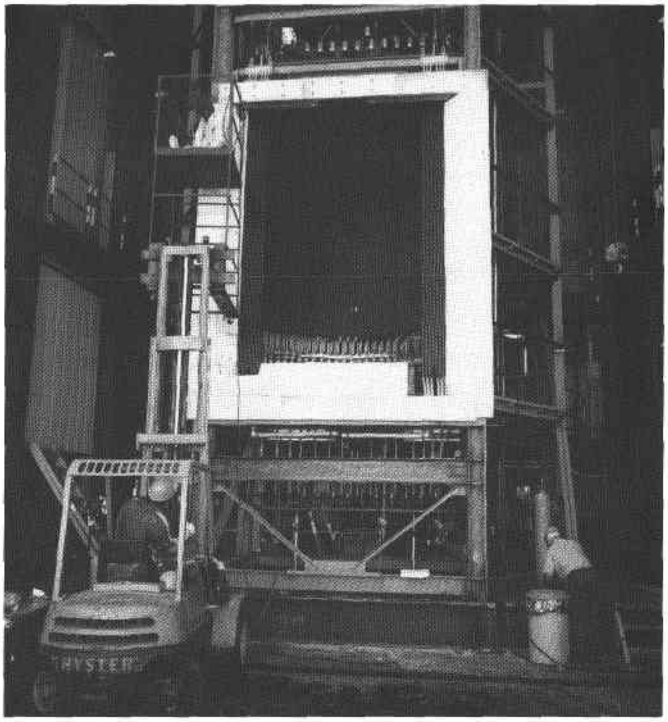


Figure 2.13. 5-MW_t molten-salt receiver

The McDonnell Douglas design was selected because of its low cost, good performance, low weight, short tower, responsiveness (low thermal inertia), simple design, and easy receiver panel replacement.

A full-scale Solar One receiver panel with supporting control and instrumentation was tested at the CRTF during late 1979 and early 1980 (see Figure 2.12). Testing included receiver operation under all solar radiation and operating conditions anticipated for the plant. Receiver steady-state and transient operating characteristics and performance were investigated during normal start-up, mode transitions, and shutdown sequences; intermittent cloud conditions; and simulated emergency situations. The test program successfully validated the design of the Solar One receiver panel and controls.

Water/steam receivers were used for five full-system experiments, which are discussed later in this chapter.

Receivers Using Advanced Heat-Transfer Fluids

The two major advantages of sodium and salt as receiver coolants (described in Chapter 1) are their ability to decouple power production from solar transients and power conversion at full-efficiency when operating from thermal storage. Receivers using air, liquid sodium, and molten salt as heat-transfer fluids were tested at the CRTF. This document only describes molten-salt and liquid-sodium systems because this is the direction of the U.S. program. Note, however, that a recent study completed by the Phoebus project in Europe suggests that a second-generation air system holds promise and may be competitive with the molten-salt system.

The objective of the molten-salt-cooled receiver experiment, shown in Figure 2.13, was to test the model under conditions similar to those a commercial receiver would experience, including

- Salt temperatures
- Heat-flux levels
- Fluid heat-transfer coefficients
- Start-up, shutdown, and cloud transients
- Power rise rates.

The receiver was constructed as a single panel within a cavity enclosure with a door. Salt circulated through the receiver in 18 vertical passes with 16 tubes per pass. The panel dimensions were 3.4 m (11 ft) high by 5.5 m (18 ft) wide, and the tubes were 19 mm (0.75 in.) in diameter with 1.7-mm (0.065-in.) thick walls constructed of Incoloy 800.

For the test, a vertical cantilever pump circulated molten salt through the receiver system, entering at 288°C (550°F) and exiting at 566°C (1050°F). A control valve regulated the outlet temperature. The salt then entered a forced-convection heat exchanger where it was cooled by air to 288°C (550°F). Varying the pitch of the fan blades controlled this outlet temperature. Salt leaving the cooler returned to the sump. A schematic of the receiver and test loop is shown in Figure 2.14.

Major test results were

- Total solar test time: 495 hours
- Total solar test time at full power (200 heliostats): 240 hours

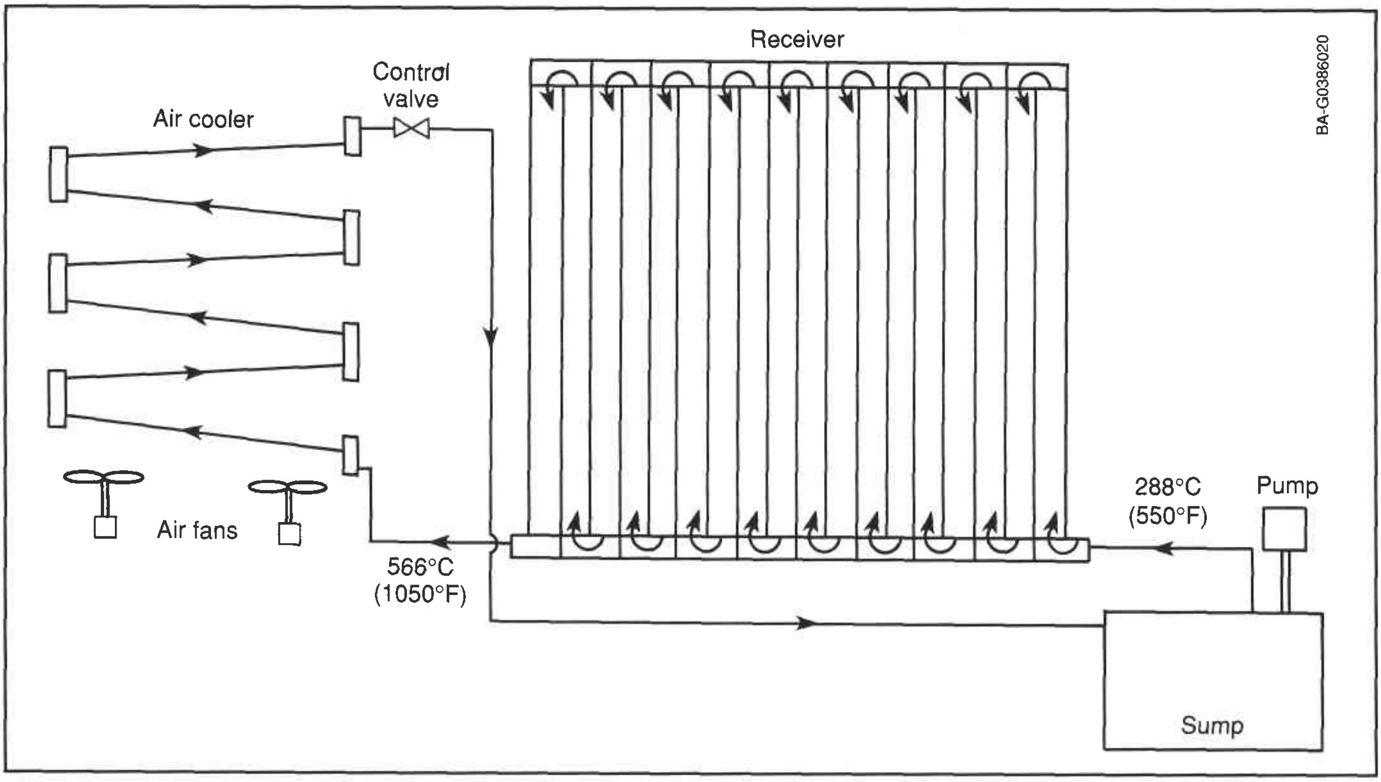


Figure 2.14. Molten-salt receiver schematic

- Total solar test time at full power and temperature: 130 hours
- Peak power output (measured): 4.7 MW_t
- Peak incident heat flux (measured): 0.756 MW/m^2.

This very successful test program achieved its objectives and provided confidence to proceed with using the molten-nitrate-salt technology for central receiver systems. After the test, the receiver was refurbished and used for the Molten Salt Electric Experiment (MSEE) described later in this chapter.

The sodium-cooled receiver panel tested consisted of three subpanels made up of 316 stainless steel tubes operating in parallel. An artist's concept of the panel, test fixture, and sodium loop mounted on top of the CRTF tower is shown in Figure 2.15.

Major test results were

- Total test time: 70 hours
- Maximum power: 2.86 MW_t
- Maximum incident solar flux: 1.53 MW/m^2
- Panel inlet temperature: 288°C (550°F)
- Panel outlet temperature: 593°C (1100°F)
- Start-up time to full power: 29 minutes.

The panel test met all of the program goals and objectives and provided development experience leading to the design of a commercial liquid-sodium receiver panel. Other receivers using advanced coolants were tested as full-system experiments and are described later in this chapter.

Direct Absorption Receiver

The DAR is a significant departure from the conventional fluid-in-tube receiver technology and offers substantial promise for improving performance and reducing costs in future receiver generations. In the DAR, the concentrated solar radiation is absorbed directly into a film of molten salt that is flowing over a nearly vertical plate. Because the film absorbs most of the radiation directly, the radiation limits associated with tubular receivers can be relaxed substantially. This high flux density allows the use of smaller and lighter receivers, which results in better thermal performance and lower capital costs. An external DAR is shown in Figure 2.16.

Experiments on a small prototype DAR (620 mm [24 in.] long, 150 mm [6 in.] wide) using concentrated solar radiation were run during 1985 at the Advanced Components Test Facility at the Georgia Tech Research Institute (GTRI) in Atlanta. Carbonate salts were used instead of nitrates to examine very high temperatures. Data gathered supported the analysis of the film stability at high and low flow rates, thermal efficiency, and heat transfer between the salt and the absorber plate. Comparing the data with the analytical predictions of thermal efficiency and heat transfer suggested a thermal efficiency of 80% to 90%, depending on operating temperature and solar radiation, and high heat-transfer coefficients. This test information suggests that the DAR concept is technically feasible.

Following this test, the DAR concept was evaluated on its effect on system performance and energy cost. A central receiver system with a DAR receiver was compared with the same system using a conventional salt-in-tube receiver.

Cavity and external receiver designs were included. In the comparison, the heliostat fields, towers, and all ground-based components were assumed to be identical. The annual energy delivered by each of the two systems was calculated using a computer code capable of simulating a year's operation through 15-min time steps. The DAR cost was obtained through a detailed category-by-category comparison with the cost of a tube-type receiver.

The study concluded that the DAR could reduce the cost of a central receiver system significantly and improve its performance. A cavity DAR may reduce the receiver cost by more than half (56%) because it can use a smaller absorber area for the higher radiation levels and because it does not require the expensive tubing and many of the welds, valves, and pumps required by a tube receiver. The performance increase is achieved through reduced thermal losses from the smaller receiver (9.6%), increased absorptance of the doped salt (2.9%), and reduced parasitic pumping power (3.7%). The lower receiver cost, coupled with a 16% increase in annual energy delivered, yields a combined 20% reduction in levelized energy cost. The relative complexities of the DAR and a comparable tube receiver with a rating of 190 MW_t are compared in Table 2.2.

Two additional characteristics of the DAR concept could further reduce the cost of energy below these estimates. First, reducing the number and complexity of components and eliminating the flow tubes should increase the reliability of the receiver. Second, the reduced mass may yield less sensitivity to radiation transients and a quicker start-up time. These significant potential DAR advantages warrant further quantification and analysis.

The validity of the assumptions made in the systems analysis described here is being investigated in a joint test

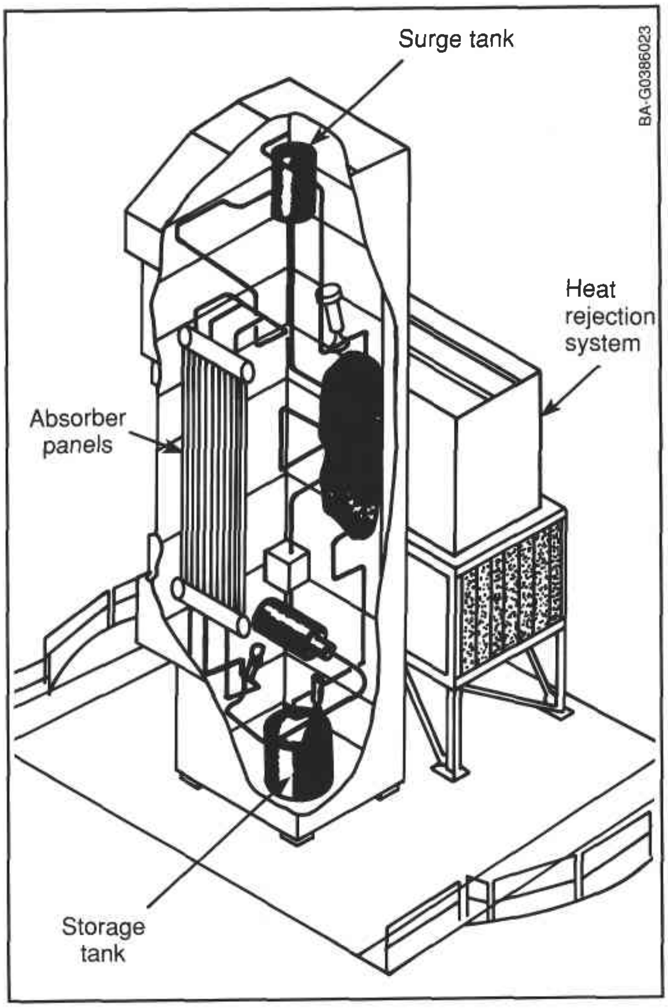


Figure 2.15. Liquid-sodium receiver panel test

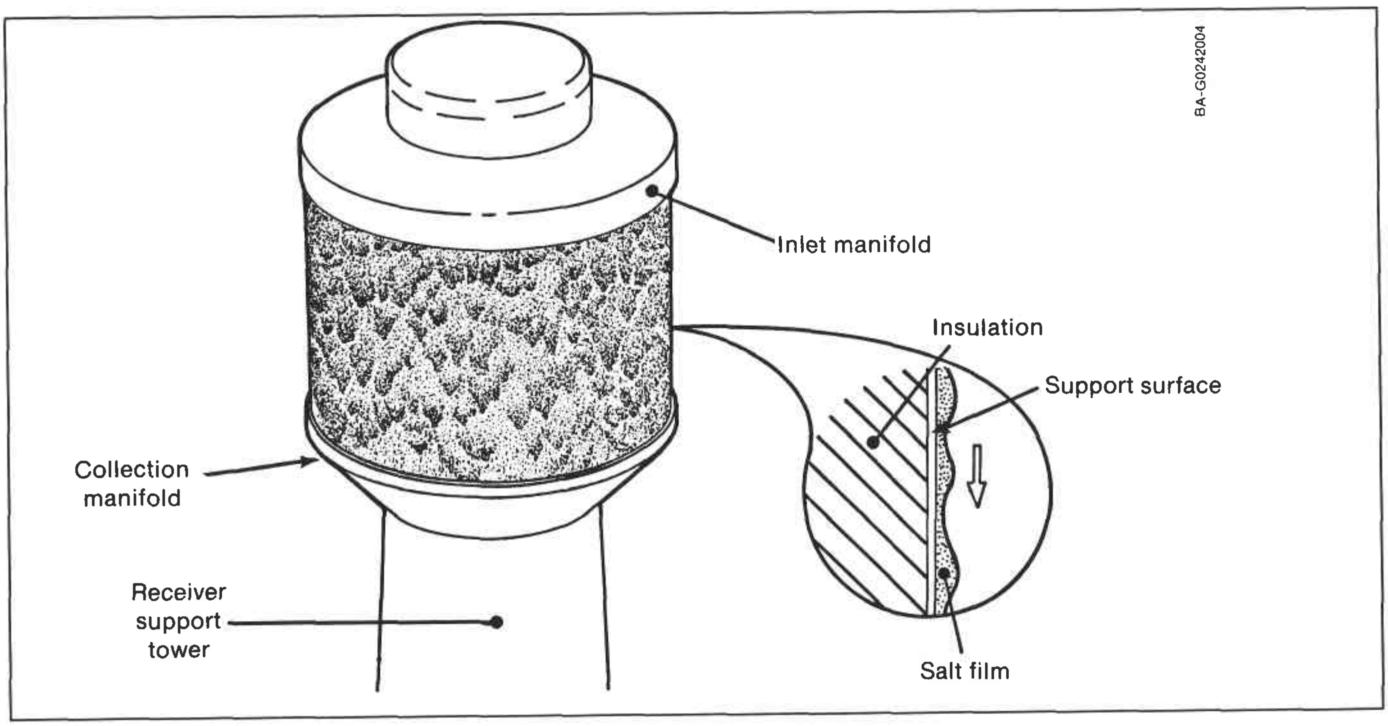


Figure 2.16. Direct absorption receiver concept

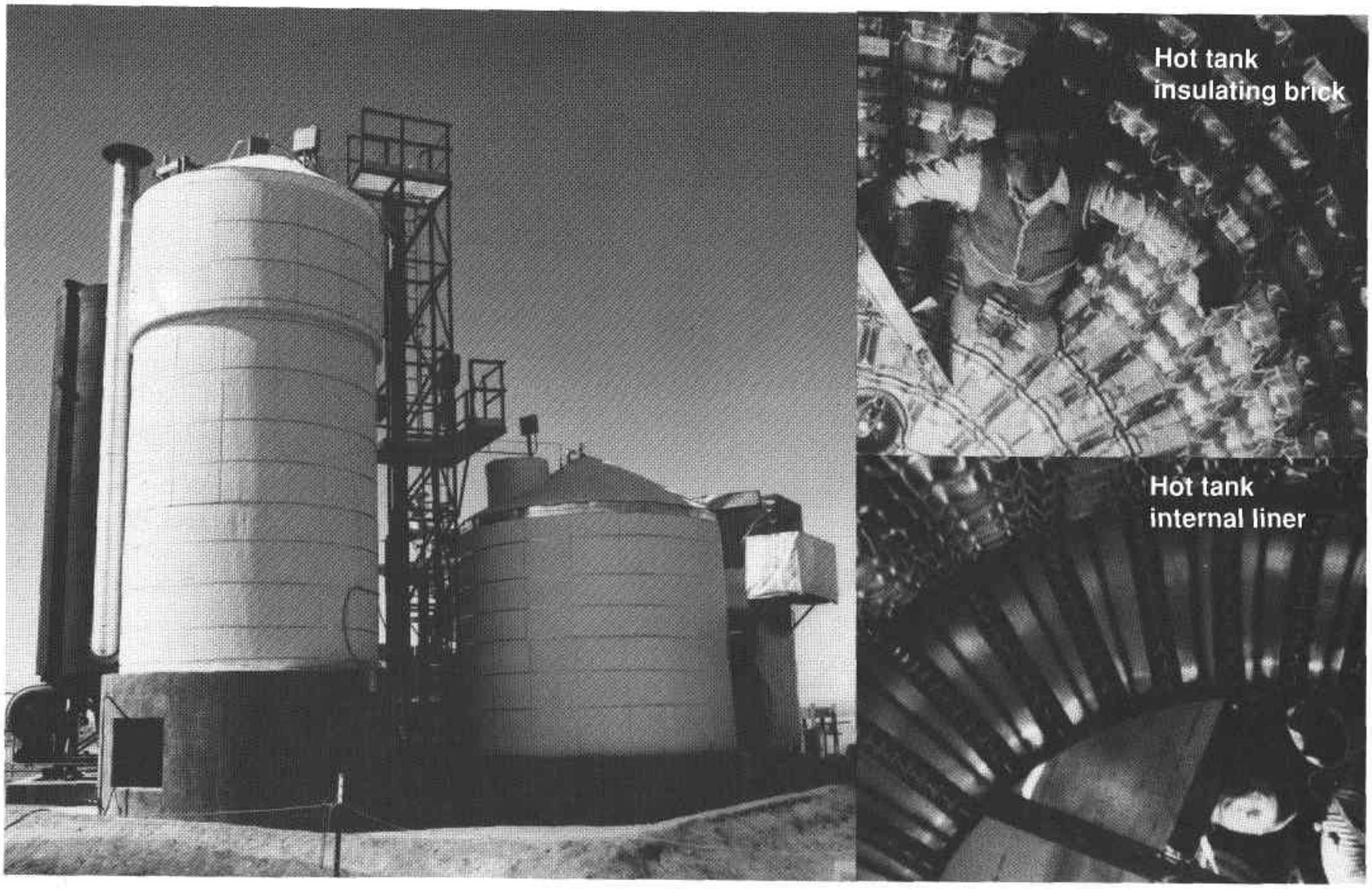


Figure 2.17. Molten-salt thermal storage test

program being conducted by Sandia National Laboratories and the Solar Energy Research Institute. Preliminary work suggests that flow stability will be the primary issue for a commercial-scale DAR. This issue was not identified during the GTRI experiments because the DAR panel was only 620 mm (2 ft) long. In contrast, a commercial-scale DAR would be about 10 m (33 ft) long. Recent experiments at the CRTF indicate that the flow instabilities can cause fluid to be ejected from a vertical panel after traveling about 5 m (16.5 ft). A near-commercial-scale DAR panel will be tested at the CRTF in 1990 to determine whether flow instabilities can be controlled by varying the panel tilt or using other methods.

Table 2.2. Receiver Circulation System Complexity

Tubular Receiver	Cavity DAR
2000 tubes with 10,000 welds and 14,000 welded attachments	No tubes or welds
48 fluid manifolds	10 atmospheric manifolds
44 drain and purge valves	No drain and purge valves
4 control valves	8 flow controllers

Thermal Storage

Although thermal energy storage development is not as critical as either heliostat or receiver development, both the water/steam and the molten-salt storage systems were evaluated.

Rock/Oil Thermocline Storage Experiment

McDonnell Douglas and Rockwell International tested the thermal storage concept that they proposed for Solar One at Rockwell's Santa Susana Test Facility in California. The system had a 4-MWh_t storage capacity and used dual liquid (oil) and solid (rock/sand) storage media, applying the thermocline principle to store hot and cold fluid in the same tank. The receiver steam for charging storage was simulated by heating the oil directly with a fossil-fuel-fired heater. For discharging storage, a steam generator heat exchanger was used.

Because these tests successfully demonstrated the principle of the oil/rock thermocline concept, it was selected for Solar One. The thermal storage tank at Solar One contained Caloria HT 43 heat-transfer oil, 1-in. gravel, and sand. The oil was distributed over the rock and sand bed by the diffuser manifolds to ensure a sharp and uniform thermocline. The system operated over a range of 218° to 304°C (425° to 580°F) and was sized to deliver heat equivalent to 7 MW_e over a 4-hour period. Because the temperature and pressure of steam generated from storage were less than that available from the receiver, the power derived was less.

Molten-Salt Thermal Storage Experiment

Martin Marietta Aerospace, in association with American Technigaz, Inc., Arizona Public Service Company, and Stearns-Roger, conducted a thermal storage research experiment at the CRTF from January through August 1982. The design was based on a central receiver system concept that used molten salt (60% sodium nitrate, 40% potassium nitrate by weight) for the heat-transfer and thermal storage fluid.

The experiment contained a hot tank; a cold tank; a fossil-fuel-fired heater to simulate a solar receiver; an air cooler to simulate a steam generator; and all of the pumps, sumps, and controls necessary to simulate a complete system. The hot tank was constructed of carbon steel with internal insulation and a corrugated membrane liner to contain the hot molten salt. The liner also prevented the salt from penetrating the insulation or contacting the tank. The cold tank was constructed of carbon steel and had external insulation. The installed thermal storage subsystem, which had a 7-MWh_t storage capacity, together with views of the hot tank internal insulation and liner is shown in Figure 2.17.

The test sequence began by loading 79,314 kg (174,000 lb) of molten salt into the cold tank at a nominal temperature of 315°C (600°F). The molten salt was then circulated through the entire system at 315°C (600°F) until all components were brought up to this temperature. The propane heater and air cooler were used when the actual testing began. The performance tests included a daily cyclic test of charge and discharge, steady-state conditions for the tank, and a transient cooldown of the tanks. The test program demonstrated that a solar thermal energy storage subsystem using molten nitrate salt could operate efficiently, reliably, and safely in both steady-state and transient modes, which is representative of what would be experienced in a large solar power plant.

These two experiments established the technology base for thermal storage with either a water/steam system or an advanced system concept. The poorer performance of the lower temperature oil/rock storage subsystem is a major reason for choosing the advanced concepts that have storage at the higher receiver outlet temperature.

Full-System Central Receiver Experiments

Eight full-system experiments were conducted for central receiver systems, five using water/steam as the receiver coolant and various types of thermal storage, and three using molten salt or liquid sodium as the receiver coolant. These experimental plants allowed a comparison between the operations of the water/steam systems and the advanced system concepts. Four of the water/steam systems produced electricity as the product, and one produced steam for enhanced oil recovery. The three advanced system plants produced electricity.

Solar One

Solar One, the 10-MW_e central receiver located near Barstow, Calif. (shown in Figure 1.1), was a joint venture between DOE and several associates, including Southern California Edison, the Los Angeles Department of Water and Power, and the California Energy Commission. Southern California Edison operated and maintained the facility during the plant start-up, 2-year test and evaluation phase, and the 4-year power production phase. After 6-1/2 years of successful operation, the plant was taken off line on September 27, 1988.

The program objectives were to

- Establish the technical feasibility of central receiver systems as solar thermal power plants, which included collecting information on retrofitting solar boilers to existing power plants fueled by oil or natural gas
- Obtain sufficient development, production, and operating and maintenance information to identify potential economics of commercial solar plants of similar design, including retrofit applications on a comparable scale
- Determine the effects of solar thermal central receiver plants on the environment
- Gather operational data to determine system operating and safety characteristics
- Develop utility company and commercial acceptance of solar thermal central receiver systems
- Stimulate industry to develop and manufacture solar energy systems
- Enhance public acceptance and familiarity with solar energy systems.

The plant produced its first electric power on April 12, 1982. After 2 years of testing, the power production phase began. During this phase, Solar One was operated to maximize electric power output so it could be evaluated as a viable resource for electric power production. Operating procedures and equipment modifications were developed to optimize plant performance. Monthly power production during the first 3 years is shown in Figure 2.18. Performance data were also being evaluated to define plant design parameters for future solar power generation facilities.

Heliostat availability (shown in Figure 2.19) was excellent and averaged 95.0% in the first year, 96.3% in the second, and 98.9% in the third. A heliostat availability of 99.6% was demonstrated. Overall plant availability was also excellent. During these first 3 years, the plant averaged 82% availability during the hours the sun shone. Also, during this time, any recurring problems were gradually corrected, and operating and maintenance practices were improved. The result was 96% plant availability during the fourth and final year.

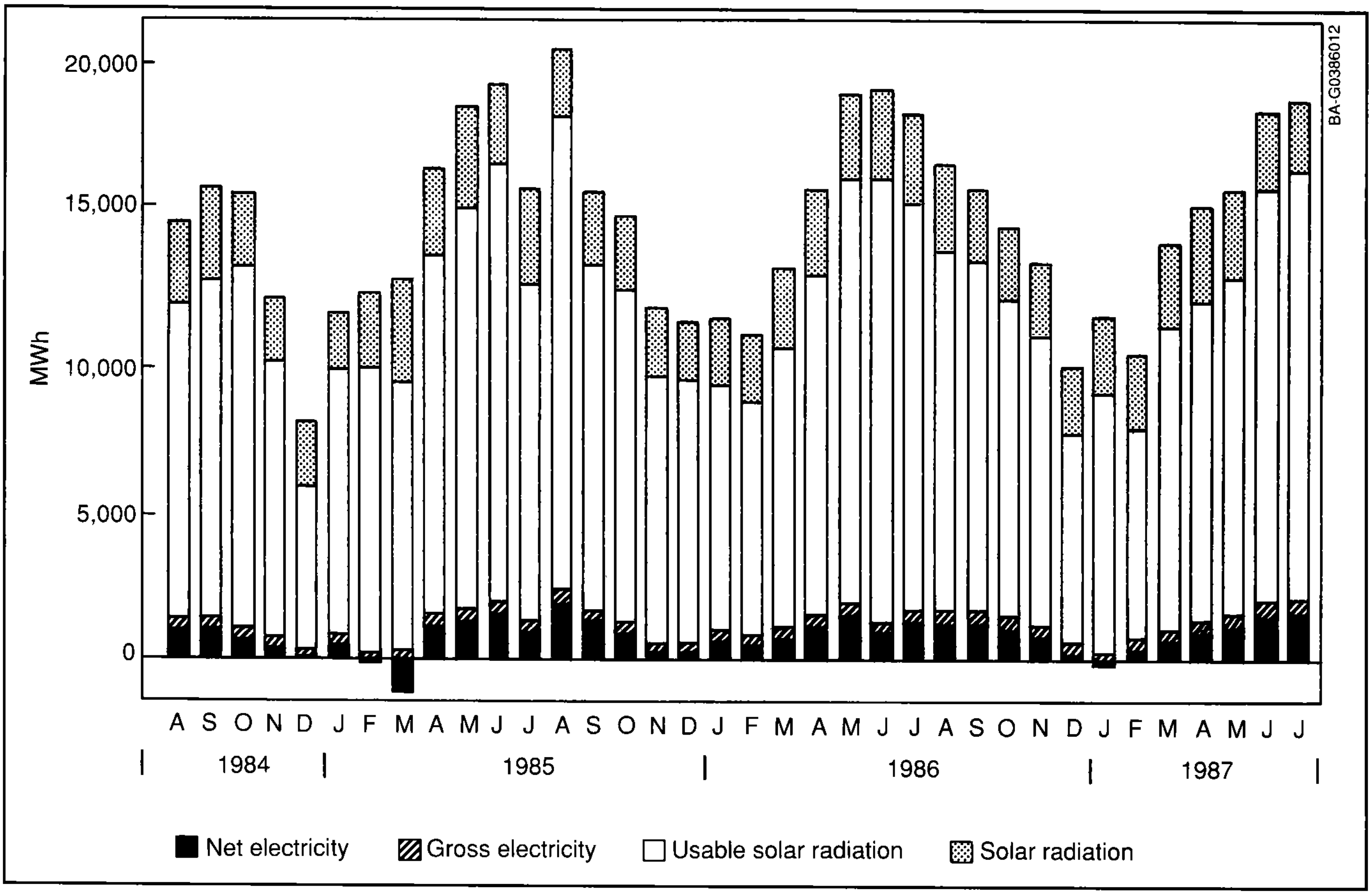


Figure 2.18. Solar One monthly power production

The plant system drawing (Figure 2.20) shows how Solar One operated. Solar radiation was reflected by the 1818 heliostats located in the collector field onto a tower-mounted receiver (boiler) that absorbed the solar radiation and converted the water to superheated steam. This steam was directed to a conventional turbine generator, which produced electric power, or to the storage system, where it was used to heat oil, rocks, and sand. Later, the energy would be extracted from the oil to produce steam with moderate pressure and temperature that would go directly to the turbine generator, which produced electric power. Plant characteristics are given in Table 2.3.

Solar One was a showcase for modern digital control system technology. At the time of its construction, it was unique in the electric utility industry in that a master

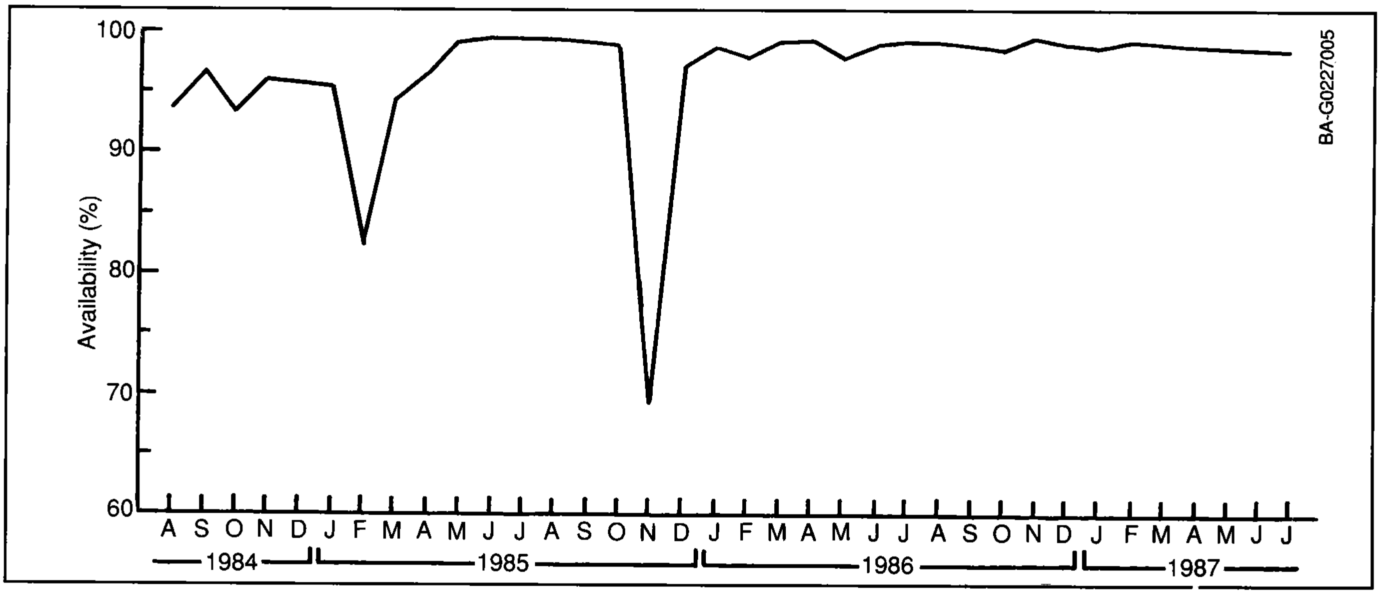


Figure 2.19 Solar One heliostat availability (August 1984–July 1987)

control system controlled the plant automatically. This system consisted of an operational control system computer that supervised the heliostat array controllers, three distributed process controllers that controlled the plant's main process loops, and five programmable logic process controllers that provided the plant's equipment and personnel protection logic. The master control system had four minicomputers that supervised the operation of the plant's 1940 microprocessors and one minicomputer that aligned the heliostats and evaluated performance.

The plant was operated during severe cloud transients that did not seem to upset the process. In a demonstration, the heliostat images were removed from the receiver for

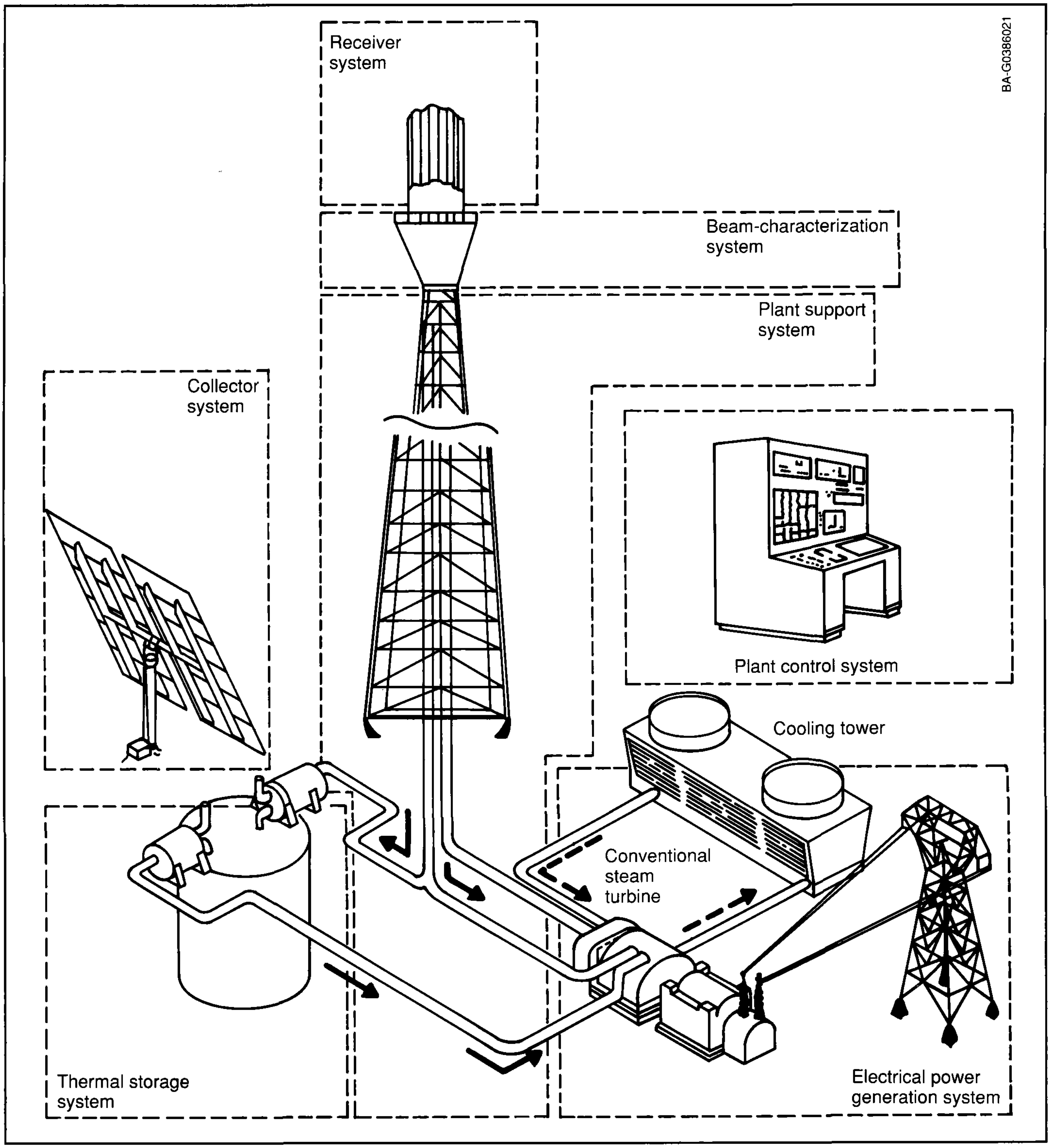


Figure 2.20. Solar One system schematic

Table 2.3. Solar One Plant Characteristics

Heliostats	
Number	1818
Size (each)	39.1 m^2
Total reflective area	71,084 m^2
Layout	Surround
Receiver	
Type	External
Coolant	Water/steam
Inlet temperature	175°C (347°F)
Outlet temperature	516°C (961°F)
Tower height	77 m (253 ft)
Thermal Storage	
Type	Single-tank thermocline
Media	Oil/rocks/sand
Rating	28 MWh_e
Power Conversion	
Type	Steam turbine
Rating, net	10 MW_e
Steam conditions	510°C (950°F), 100 bar (from receiver)
Heat rejection	Wet cooling tower

3 minutes and then redirected onto the receiver with a resultant steam outlet temperature excursion of only 8°C (46°F). The Solar One control system allowed the operator to devote more time to plant operational reliability and efficiency, thereby increasing energy output. Although the plant control system was designed to control a water/steam central receiver solar plant, the basic functions and operating philosophy are readily adaptable to other power plants.

Power production continued to increase during the more than 4 years of operation. Projections of energy production during the plant's final year indicated that the plant would have very nearly achieved the long-term annual average goal set for the plant. This extended period of production also provided extensive data for use in designing and operating future central receiver systems. Most notable were the operating time effects on component reliability, and operations and maintenance experience and costs. Many receiver problems did not become evident until after several years of operation.

The Solar One project was highly successful, achieving many significant technological milestones, such as:

- The plant could function in all operating modes.
- A water/steam once-through receiver could operate continuously through cloud transients without a thermal storage system as long as the available solar radiation remained above 300 W/m^2 of the rated value.
- The collector field availability was better than expected (98.9% during the 1986–1987 operating year).
- Plant availability exceeded the 90% design goal during the final year.
- The thermal storage system met its design requirements of capacity and efficiency.
- The thermal storage system provided a method of producing auxiliary steam.
- Plant automation significantly reduced the number of plant operations.
- Annual energy goals were very nearly achieved during the final operating year.
- The control system allowed a 24:1 turndown ratio of the plant output.
- A minimal number of operating and maintenance personnel were needed to operate the central receiver plant.

Solar One demonstrated the technical feasibility of the central receiver concept but not the economic feasibility, which was not a project objective. This will not be demonstrated until the cost goals are met.

ARCO Enhanced Oil Recovery Project

ARCO Power Systems designed, built, and tested a 1-MW_t pilot module Solar Thermal Enhanced Oil Recovery (STEOR) System at ARCO's Fairfield lease in Kern County, Calif. The plant produced steam to be injected into heavy oil fields to enhance the recovery of this viscous oil. It was designed as a 1/10 scale model of a commercial STEOR system. The major objective of the project was to gather operational and maintenance experience in an oil field environment. The plant, constructed in 1982, operated throughout 1983. Plant characteristics are given in Table 2.4.

The project demonstrated that the plant could operate virtually unattended with very little operation and maintenance expense. This is particularly crucial for the economics of smaller size plants. It also showed that all elements of a solar thermal steam-generation system are ready for full-scale applications such as enhanced oil recovery, process heat, or desalination.

Table 2.4. ARCO STEOR Plant Characteristics

Heliostats	
Number	30
Size	52.8 m^2
Total reflective area	1584 m^2
Layout	North
Receiver	
Type	Panel
Coolant	Water/steam
Outlet temperature (80% Quality)	285°C (545°F)
Tower height	19.8 m (65 ft)
Thermal Storage	None
Power Conversion	None

Table 2.5. Characteristics of Internationally Tested Central Receiver Plants

Components	Nio	Eurelios	CESA-1
Heliostats			
Number	807	70 (Cethel), 112 (MBB)	300
Size	16 m^2	52 m^2 (Cethel), 23 m^2 (MBB)	39.6 m^2
Total reflective area	12,912 m^2	6216 m^2	11,880 m^2
Layout	Surround	North	North
Receiver			
Type	Cavity (downward facing)	Cavity (side facing)	Cavity (side facing)
Coolant	Water/steam	Water/steam	Water/steam
Inlet temperature	115°C (239°F)	37°C (99°F)	200°C (392°F)
Outlet temperature	249°C (480°F)	512°C (954°F)	525°C (977°F)
Tower height	69 m (226 ft)	55 m (180 ft)	60 m (197 ft) to receiver
Thermal Storage			
Type	5 tanks	3 tanks	2 tanks
Media	Pressurized water	Molten salt and hot water	Molten salt
Rating	18 MWh_t	0.36 MWh_t	18 MWh_t
Power Conversion			
Type	Steam turbine	Steam turbine	Steam turbine
Rating, net	1.0 MW_e	1.0 MW_e	1.0 MW
Steam conditions	249°C (480°F), 40 bar (from receiver)	510°C (950°F), 62 bar	520°C (968°F), 98 bar (from receiver)
Heat rejection	Seawater	Wet cooling tower	Dry cooling tower

International Water/Steam System Experiments

Three full-system experiments using water/steam as the receiver heat-transfer fluid were conducted overseas. Major characteristics of these plants (referred to here as Nio, Eurelios, and CESA-1) are given in Table 2.5.

A 1-MW_e pilot plant, shown in Figure 2.21, was built at the Nio, Kagawa, prefecture on the north side of Shikoku Island, Japan. Sponsors were the Japanese Agency of Industrial Science and Technology and the Ministry of International Trade and Industry. Major participants were Electric Power Development Company, Ltd., Mitsubishi Heavy Industries, and the Electrochemical Laboratory, all of Japan.

The objective of the project, conducted from 1974 until 1984, was to investigate the technical and economic feasibility of solar-thermal electric-power generation with a central receiver. The technical objectives of the project were achieved; however, economical viability was not established because of the plant's small size. The lessons learned from this experiment will be applied to the next generation system.

Eurelios is a 1-MW_e pilot plant (Figure 2.22) sponsored by the Commission of the European Communities. A European industrial consortium designed and built the plant in Adrano, Italy. The consortium consisted of Ansaldo SpA and Ente Nazionale per l'Energie Elettrica, Italy; Cethel (combining Renault, Five-Cail-Babcock, Saint-Gobain Pont-a-Mousson, and Heurtey S.A.), France; and Messerschmitt-Boelkow-Blohm, Federal Republic of Germany.

The objective of the project, conducted from 1976 through 1985, was to demonstrate the feasibility of the full system. Net electrical energy production was rather disappointing mainly because of the poor quality and quantity of solar radiation at the site and inadequate designs of the receiver and the thermal circuit. The experience gained proved that electric power connected to a grid could be produced and that the plant could operate with standard procedures like those used for conventional thermal electric power plants.

The CESA-1 project covered the design, construction, operation, and evaluation of a 1-MW_e experimental central receiver solar power system. The CESA-1 plant, shown in

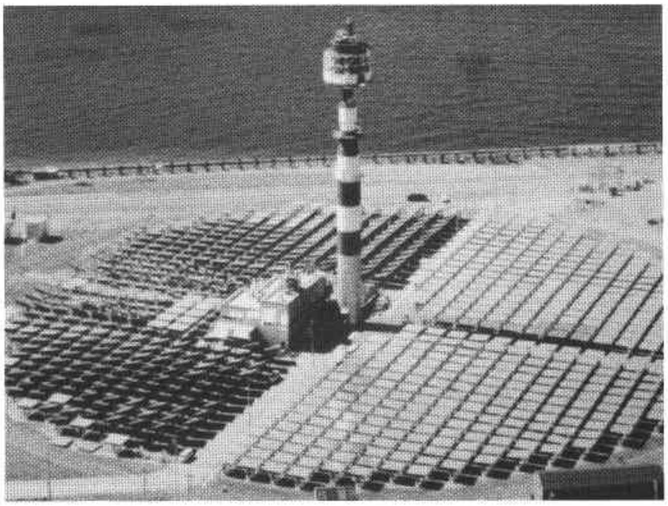


Figure 2.21. The 1-MW_e pilot plant at Nio, Japan

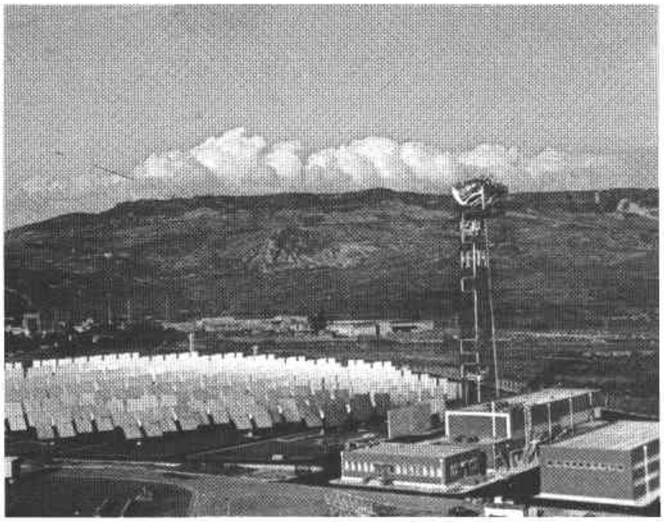


Figure 2.22. The I-MW_e pilot plant at Eurelios, Italy

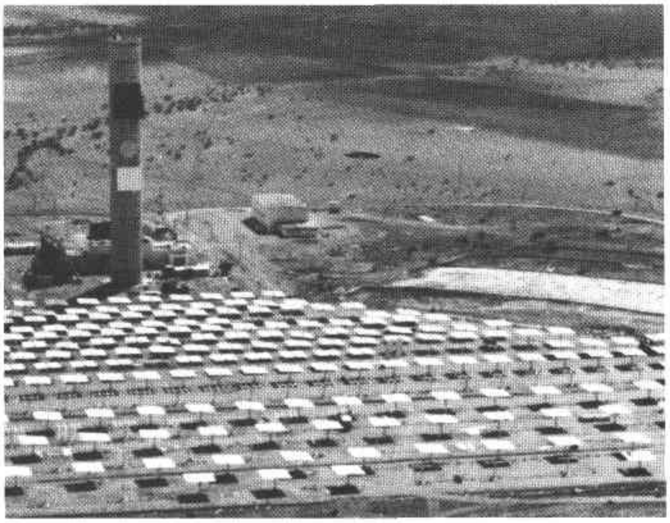


Figure 2.23. The CESA-1 project near Almeria, Spain

Figure 2.23, is located in Tabernas (Almeria), Spain. The Spanish Ministry of Industry and Energy sponsored the project, and the following Spanish companies participated: Sener, Initec, CASA, EISA, and Tecnicas Reunides.

The project ran from 1978 through 1984 but only operated from October 1983 through the end of 1984. Starting in 1985, the facility was dedicated to testing air Brayton-cycle components under the GAST program being conducted jointly with the Federal Republic of Germany.

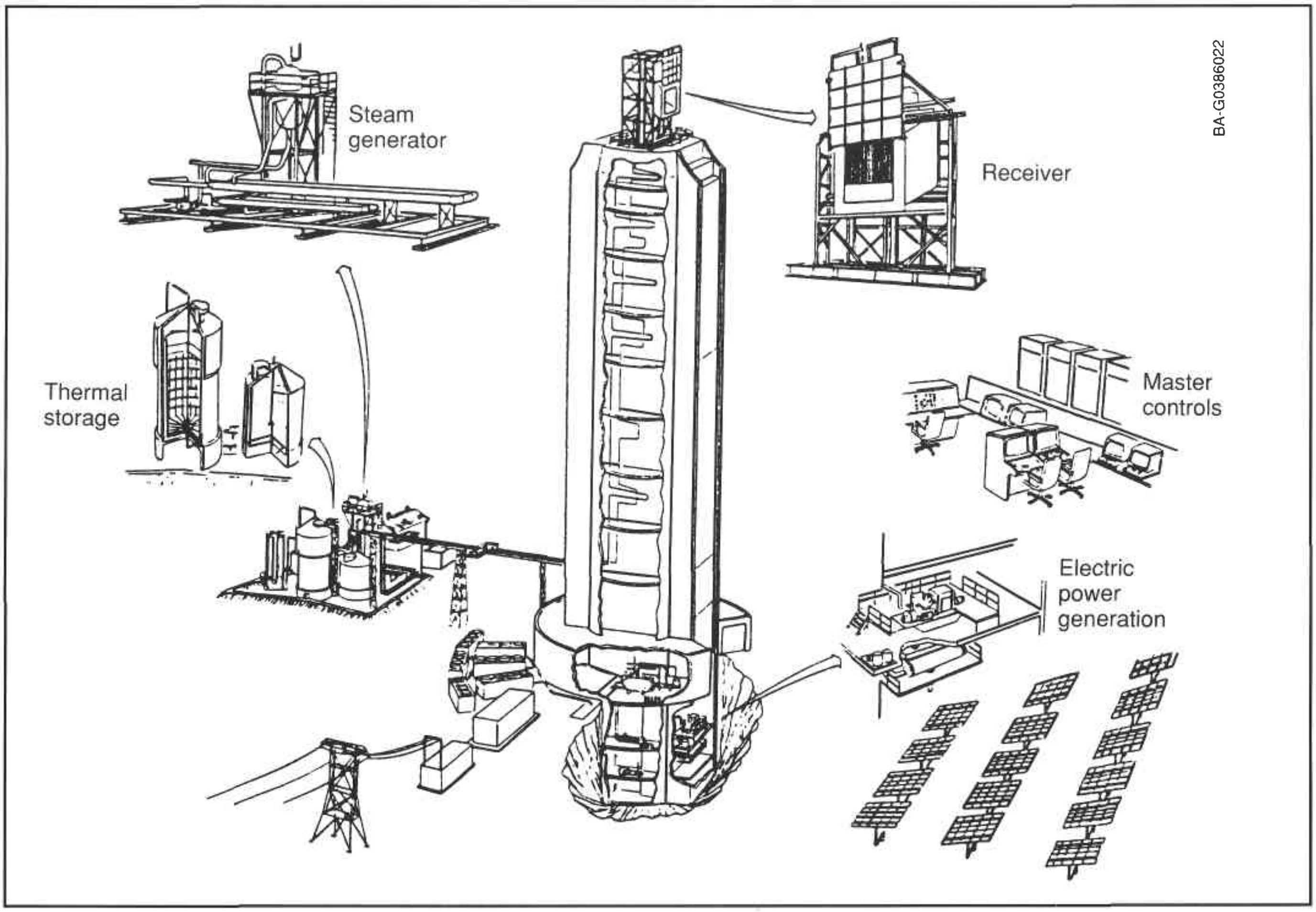


Figure 2.24. The Molten Salt Electric Experiment

Molten Salt Electric Experiment

The MSEE was a full solar-to-electric central receiver system that used molten nitrate salt as the heat-transfer and storage fluid. The project, built and tested at the CRTF in Albuquerque, N.Mex., between 1982 and 1985, demonstrated the technical feasibility of a molten-salt central receiver system. The MSEE consisted of two previously tested molten-salt subsystems, a 5-MW_t receiver, and a two-tank thermal storage system. In addition, it had a new steam generator, a rebuilt turbine-generator, and other existing equipment.

The MSEE objectives were to

- Verify the capability, flexibility, and simplicity of an advanced central receiver concept
- Provide performance information and operating experience on molten-salt systems and components for utility companies, system designers, component suppliers, and financial institutions
- Establish a test bed for component development and advanced controls.

A consortium of industries with solar technology experience, interested utility companies, and the Electric Power Research Institute (EPRI) was formed to help fund, design, construct, and operate the experiment. The consortium supplied half of the funding in the form of money and cost-shared engineering services. DOE supplied the other half plus project management and on-site construction and operations through Sandia National Laboratories.

The five major subsystems, shown in Figure 2.24, are the receiver, thermal storage unit, steam generator, electric power generator, and master control. The MSEE also used the existing CRTF components and equipment, including the heliostat field, 200-ft tower, data acquisition system, heat rejection and feedwater equipment, and control room. Plant characteristics are given in Table 2.6.

The MSEE demonstrated the feasibility of a full solar-to-electric central receiver system using molten nitrate salt as the primary working fluid. A large group of industry and electric utility company participants received hands-on experience in designing, operating, and verifying the performance of the hardware. The MSEE significantly advanced the technology of molten-salt central receivers in the following ways:

- Receiver controls were improved to accommodate cloud transients.
- Operating procedures were developed for rapid and efficient early morning start-up.
- An external receiver was demonstrated and compared with a cavity receiver.
- A prototypical steam generator was designed, built, and successfully operated.

Table 2.6. MSEE Plant Characteristics

Heliostats	
Number	211
Size	37.2 m
Total reflective area	7849 m^2
Layout	North
Receiver	
Type	Cavity
Coolant	Nitrate salts
Inlet temperature	310°C (590°F)
Outlet temperature	566°C (1050°F)
Tower height	61m (200 ft)
Thermal Storage	
Type	Two tanks
Media	Nitrate salts
Rating	7 MWh_t
Power Conversion	
Type	Steam turbine
Rating, net	750 kW_e
Steam conditions	504°C (940°F), 72 bar (from receiver)

- Techniques for designing and installing trace heaters and insulation were greatly improved.
- Extensive experience with pumps and valves operating under actual service conditions was obtained.

Furthermore, the MSEE demonstrated to designers and potential users of a central receiver system that its inherent flexibility enhances its use as a power plant. The system showed it could start up rapidly, operate through cloud transients, shift the electric-power production load, and buffer the uniform power output from solar transients. Finally, the MSEE gave a status report on the state of molten-salt central receiver technology to the solar community and helped define the next steps in technology development.

Molten Salt Subsystem/Component Tests Experiment

After the MSEE concluded, Arizona Public Service recommended a development plan to further reduce the technical risk of building a central receiver power plant. The Molten Salt Subsystem/Component Tests Experiment (MSS/CTE) program objective was to analyze, design, and test a molten-salt solar receiver prototypical of the commercial-size power plant designs to demonstrate to industry, utility companies, and the financial community the feasibility and efficiency of a molten-salt solar receiver. The technical objectives were to confirm the receiver's design, measure its performance, and define its capabilities. The MSS/CTE also included a full-scale molten-salt pump and valve test loop and a bench-scale test for evaluating valve packing materials. Several companies shared the program costs with DOE. The receiver was tested at the CRTF for about 10 months in 1987.

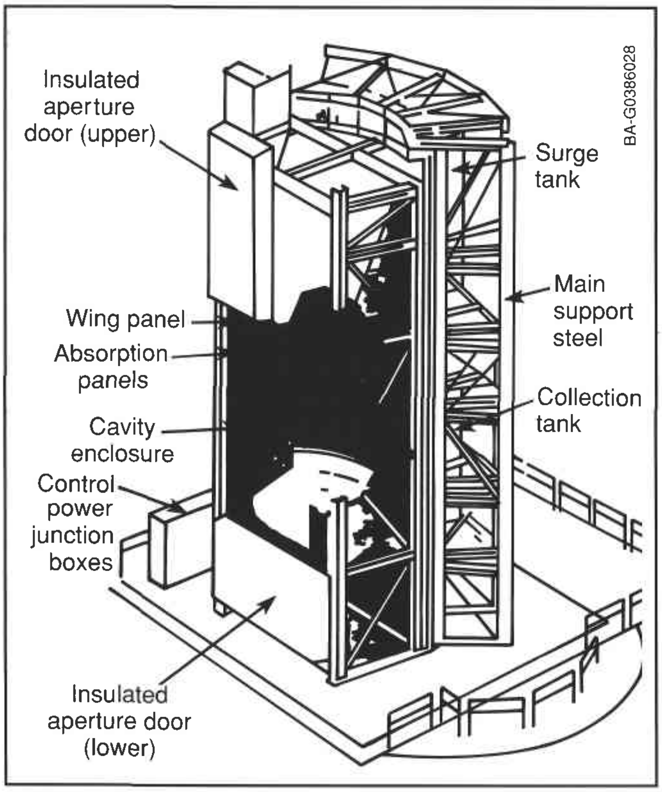


Figure 2.25. The 4.5-MW$_t$ cavity receiver

The 4.5-MW$_t$ cavity receiver, shown in Figure 2.25, used key features of the commercial receiver design, which included

- A C-shaped cavity
- Wing panels in the aperture plane
- Panels hung from the top with lateral supports
- Cavity doors to reduce heat loss
- Two flow control zones
- Automatic salt outlet temperature control.

Testing confirmed that the receiver design will work. Thermal performance testing confirmed a high design-point thermal efficiency of about 90%, showing that the receiver has a good capability for collecting energy during clear conditions. The receiver's ability to make maximum use of the solar radiation in nonsteady-state conditions was also demonstrated. This was made possible by the molten-salt storage system and the receiver controls strategy.

Overall, the MSS/CTE receiver test program was successful in demonstrating a mature salt-in-tube receiver design ready for scale-up to larger systems. The test also revealed several critical areas that must be addressed to ensure good performance and a long receiver life, thus protecting the investment of developers and operators of future solar thermal power systems.

European Advanced System Experiments

Two full-system experiments using advanced heat-transfer fluid were conducted in Europe. Characteristics of the plants are given in Table 2.7.

The Themis 2.5-MW$_e$ pilot plant using molten salt as the receiver coolant (Figure 2.26) was constructed at Targasonne, near the Odeillo solar furnace, in the French Pyrenees mountains. The objectives of this project were to

- Establish the technical feasibility of a solar-thermal central receiver plant at a size that can reasonably be scaled-up to a commercial size

Table 2.7. Characteristics of European Advanced-System Central Receiver Plants

Components	Themis	International Energy Agency
Heliostats		
Number	201	93
Size	53.7 m^2	39.3 m
Total reflective area	10,740 m^2	3655 m^2
Layout	North	North
Receiver		
Type	Cavity	Cavity
Coolant	Hitec salt	Sodium
Inlet temperature	250°C (482°F)	270°C (518°F)
Outlet temperature	430°C (806°F)	530°C (986°F)
Tower height	100 m (328 ft) (including receiver)	43 m (141 ft) (to receiver center)
Thermal Storage		
Type	2 tanks	2 tanks
Media	Hitec salt	Sodium
Rating	40 MWh$_t$	5.5 MWh$_t$
Power Conversion		
Type	Steam turbine	Steam motor
Rating gross	2.5 MW$_e$	500 kW$_e$
Steam conditions	410°C (741°F), 40 bar	500°C (932°F),100 bar
Heat rejection	Dry cooling tower	Wet cooling tower

Figure 2.26. The 2.5-MW_e pilot plant at Themis, France

- Test the solar thermal plant to improve the main components and collect technical data
- Indicate the export potential of solar plants to foreign countries.

Project results were limited by the inclement weather, low solar radiation, and construction deficiencies. Winds estimated at more than 100 mph blew during October and December 1980, damaging several heliostats. The entire heliostat field was strengthened after this.

The 3 years of operation confirmed the feasibility of the concept, demonstrated the advantages of decoupling solar energy collection from power generation, and provided a wealth of knowledge that could be incorporated into future plant designs.

A 500-kW_e experimental central receiver plant using liquid sodium as the receiver fluid was constructed adjacent to CESA-1 in Tabernas (Almeria), Spain. Shown in Figure 2.27, it is part of the Small Solar Power Systems Project, which is one of the joint tasks of the member countries of the International Energy Agency. Nine countries (Austria, Belgium, Germany, Greece, Italy, Spain, Sweden, Switzerland, and the United States) participated in designing, constructing, testing, and operating this plant.

The objectives of this project were to determine design viability, evaluate operational behavior, extrapolate for advanced commercial designs, and compare its performance with a distributed collector system located on the same site.

The German research agency, DFVLR, was the operating agent for the project, which was designed by an international consortium under the leadership of INTERATOM (Federal Republic of Germany) and Martin Marietta (United States). The Spanish utility company, Sevillana, operated the plant after the test phase.

The plant was operated like any utility during 1982. From 1983 until August 1986, the plant was operated under a

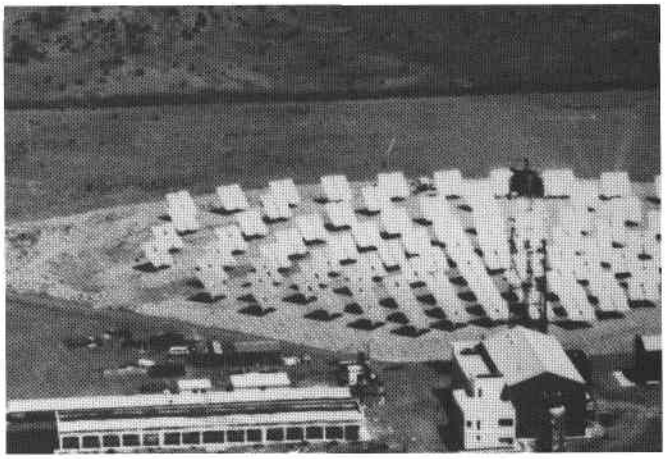


Figure 2.27. IEA 500-kW_e experimental central receiver plant near Almeria, Spain

Table 2.8. System Experiment Summary

System Test	Receiver Coolant	Field/Receiver Layout	Storage Media	Power Conversion	Plant Rating
Solar One	Water/ steam	Surround/ external	Oil/rock	Steam turbine	10 MW_e
ARCO STEOR	Water/ steam	North/ panel	None	None	1 MW_t
Nio	Water/ steam	Surround/ cavity	Pressurized water	Steam turbine	1 MW_e
Eurelios	Water/ steam	North/ cavity	Water, salt	Steam turbine	1 MW_e
CESA-1	Water/ steam	North/ cavity	Salt	Steam turbine	1 MW_e
MSEE	Salt	North/ cavity	Salt	Steam turbine	0.75 MW_e
Themis	Hitec salt	North/ cavity	Hitec salt	Steam turbine	2.5 MW_e
IEA CRS	Sodium	North/ cavity	Sodium	Steam turbine	0.5 MW_e

test and evaluation program to obtain detailed engineering data on its design, operation, and performance. In August 1986, a sodium fire destroyed part of the experiment, including the control room. The facility is now being devoted to research on other central receiver projects under the Spanish Ministry of Energy.

This project answered many questions regarding solar thermal technologies, including operational, technological, and economic areas, and allowed at least a qualitative assessment of the future application potential.

The experimental data base from all of the full-system experiments is summarized in Table 2.8.

Chapter 3
Status of Central Receiver Technology

As outlined in Chapter 2, solar central receiver systems have been extensively researched, and several generations of designs have been built and evaluated for the critical solar components. Most full-system experiments were first generation—exploratory rather than demonstrations of commercial technology. They did, however, confirm the feasibility of the central receiver concept and provide an adequate data base for selecting most of the features of a preferred central receiver system. The current status of the technology and the issues remaining to be resolved to produce a commercially workable system are summarized in this chapter.

Selecting the features that define the preferred system concept must be made on a full-system basis, as most selections are interdependent. Fortunately, a sufficient data base has been developed to make this selection.

A utility company-industry consortium concluded a study in 1988 that evaluated the system designs presented in this report and selected the preferred system design. This cooperative program among DOE, the consortium, and EPRI developed optimum full-system designs for each advanced system concept. Performance and costs for the alternative designs were developed and compared. The preferred system parameters selected in this study are given in Table 3.1; the system schematic is shown in Figure 3.1.

A major objective of the central receiver development program was to reduce the cost. The long-term DOE goal is to provide competitively priced power in the 1990s. The present cost status (shown in Table 3.2) can best be assessed from the utility study previously mentioned. The current technology column gives the costs for a first commercial 100-MW_e plant with contingencies applied as though it were being built in 1987 without further development. Both process contingencies, applied to the individual subsystems, and a project contingency are included. The second column is for a 200-MW_e commercial plant built after four previous plants have been built and operated. The third column gives the DOE long-range goals increased by 12% from their 1984 values to be more comparable with the utility company study results, which are given in 1987 dollars.

The DOE goals are overly conservative for the receiver, transport, storage, and balance-of-plant subsystems. The utility projection for power conversion is about 40% higher than the DOE goal; however, the excess, \$33.4 million for the 200-MW_e power conversion system, is counterbalanced by the savings in the balance-of-plant subsystem, \$52.2 million for the 1.8×10^6 m^2 heliostat field. The major target for reducing costs remains the heliostat field.

Because most of the experiments were very small, none of the advanced systems produced a positive net power output over a sustained period. The larger size of Solar One demonstrated a significant net output, but it was still lower than desired. Experimental verification of the predicted power production of the preferred system remains an open issue. The status of performance, expressed as the annual efficiency of converting direct-normal solar radiation to net electricity, is given in Table 3.3.

The major development requirements remaining for the central receiver system are

- Plant size—Because the preferred size for a utility-scale plant is about 200 MW_e, more than a tenfold scale-up from Solar One is required; the scale-up from the advanced system experiments exceeds 100 MW_e. This scale-up should include the receiver and the major components that will contact the molten salt. The scale-up to 200 MW_e will most likely require at least two intermediate sizes, e.g., 30 MW_e and 100 MW_e.
- Stretched-membrane heliostat development—The largest prototype built and tested was 50 m^2. The large area (150 m^2) heliostat needs to be developed and its performance and lifetime confirmed, which is essential for meeting the DOE cost goals.

Table 3.1. Preferred Central Receiver System Concept

Plant rating	200 MW_e
Plant type	Solar only (no fossil fuel)
Solar multiple[a]	1.8
Heliostat design	150 m^2 stretched membrane
Total reflective area	1.8×10^6 m^2
Field layout	Surround
Receiver type	External cylinder
Receiver coolant	Molten nitrate salt
Thermal storage type	Hot and cold tanks
Thermal storage medium	Molten nitrate salt
Storage capacity	Six hours
Power conversion	Reheat steam turbine
Control	Distributed digital with master control
Land area	1000 hectare (3.9 mi^2)

[a] Ratio of the maximum solar thermal power collection rating to that required to match the plant rating.

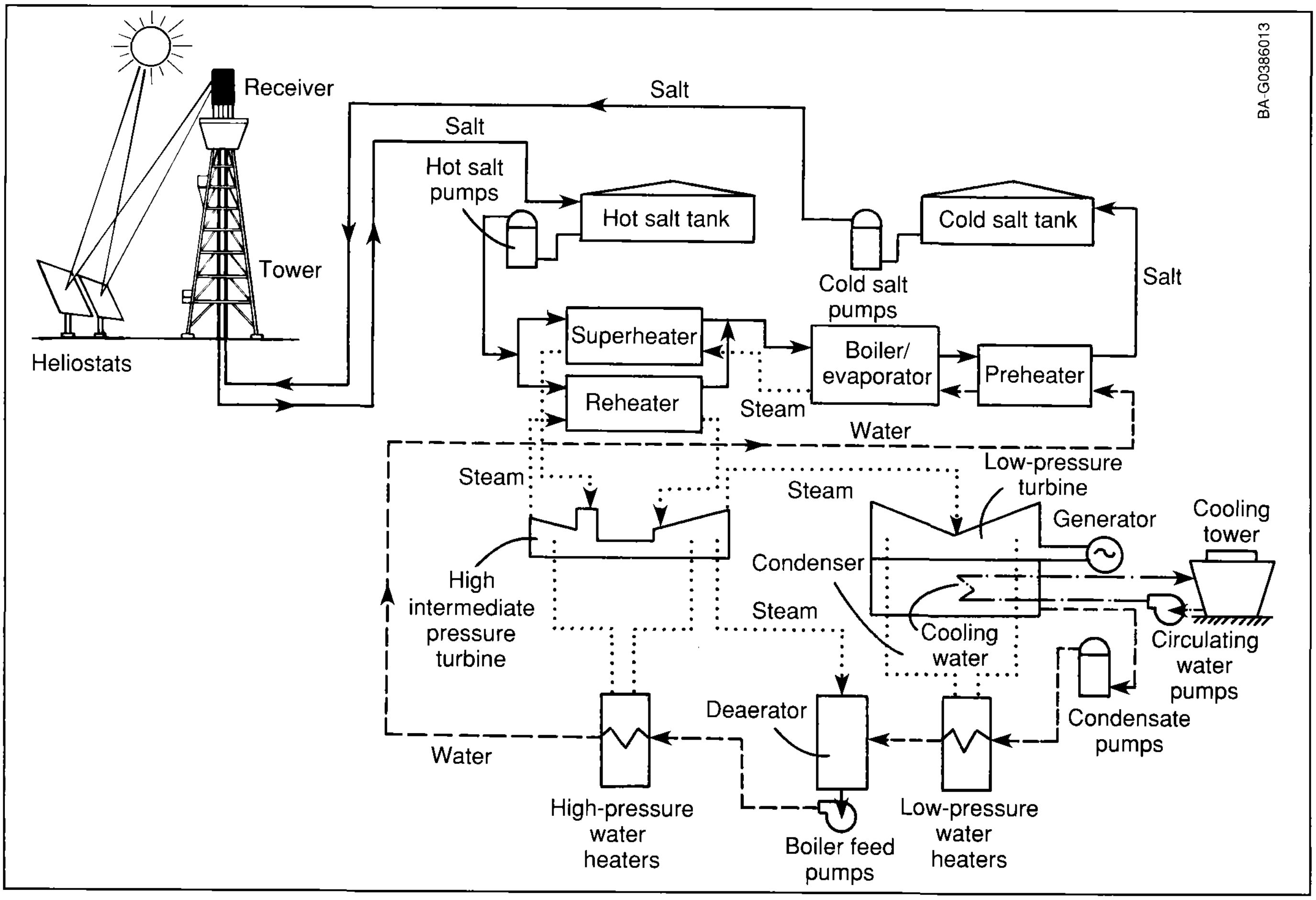


Figure 3.1. Schematic of preferred central receiver system

- DAR development—The DAR is still at the concept level. Development and performance verification is required to achieve the lower costs and system complexity inherent in this design.

Table 3.2. Cost Status and Projected Costs

	Current Technology (1987 \$)	DOE Projection	Long-Range Goals
Heliostat field (\$/m^2)	200	75	45
Receiver and transport (\$/m^2)	49	28	62
Storage (\$/kWh$_t$)	15.2	12.8	22.4
Power conversion (\$/kW$_e$)	718	559	392
Balance of plant (\$/m^2)	7	5	34
Operations and maintenance (\$/m^2 yr)	7.6	3.1	10.1
Indirect costs and contingency (% of capital)	47.5	15	20
Allowance for fund used during construction (% of total)	9.9	11.2	3.1

- Reliability—Tube receiving, instrumentation, and electric trace-heating under cyclic operation did not achieve the desired reliability. Development and qualification are required to meet the plant availability goals of greater than 90% and the operations and maintenance cost goals of less than \$10/m^2 of heliostat area. Extended operation of the components that contact the molten salt for more than several years is required to gain confidence in their reliability.
- Parasitic power reduction—The power generated and then consumed by the plant to run its own equipment is called parasitic power. Careful component design in a full-scale plant is needed to reduce the current estimate for parasitic power from 13% to 5%–10% of generated electricity.

Table 3.3. Annual Net Efficiency (%)

Solar One (best year)	7
Utility study prediction (200 MW$_e$ plant)	14.4
DOE long-range goal	22

Chapter 4
The Future of the Central Receiver System

Central receiver technology is a valuable resource and can supply a significant portion of our future energy needs as fossil fuels are depleted and further restrictions are imposed on nuclear reactors.

The development already completed confirms that DOE can achieve a levelized energy cost of 5¢/kWh, the long-term goal. This cost is competitive today with that of some power-generation plants that use conventional fuels. Central receiver systems will become increasingly attractive as fossil fuels become more scarce and costly.

Energy costs from a central receiver system using today's technology are two to three times higher than those for conventional power plants with the current depressed fuel prices. However, today's low-cost energy gives us time to finish developing this renewable resource, which will limit the rise in energy costs when fossil fuels are depleted. The technical development required to make central receiver systems cost-effective would take only 10 years if directed in the same way DOE's current development program is directed.

Research is also under way to increase the number of potential applications of concentrated solar energy. Thus far, nearly all solar thermal applications have converted the concentrated solar energy into electricity or into heat for industrial processes. The solar spectrum is very complex, however, consisting of moderately energetic photons in the infrared wavelengths and high-energy photons in the ultraviolet, opening the possibility of new uses for the high-energy portion of the spectrum.

A university research team found that concentrated solar energy can efficiently destroy certain hazardous-waste chemicals. Also, the properties of materials change, including making the materials stronger, when they are irradiated with solar energy. Other applications include renewable fuels, such as hydrogen derived from water by photolysis. Concentrated solar energy can produce strategic chemicals, such as ammonia used to make fertilizer, from air and water. Thus, concentrated solar energy, if it can be collected and converted economically, can satisfy many of our energy needs.

Much has been accomplished in developing the central receiver technology although several issues remain. At this stage of development, the role of research and development is to achieve cost and performance goals consistent with the 4¢–5¢/kWh of levelized energy costs. The research tasks remaining to meet these goals are to

- Develop a large-area stretched-membrane heliostat and confirm its cost and performance
- Develop an external DAR and confirm its cost, reliability, and performance
- Improve overall system reliability
- Scale-up system components to commercial (200 MW_e) size
- Reduce electrical parasitic power losses
- Confirm system performance with a prototype or system experiment of sufficient size.

The central receiver development program has produced a sound technical base for this renewable energy system, and DOE's long-term levelized energy costs appear to be achievable. The program has defined the preferred system design and identified what needs to be done to make it cost-effective. Beyond its development as a source for generating electricity, the central receiver system will be able to produce fuels and chemicals. At this point, the central receiver system should be fully developed.

Appendix
The Central Receiver Test Facility

The Central Receiver Test Facility (CRTF), rated at 5 MW_t, was the primary solar test facility for component and subsystem evaluations within DOE's solar central receiver development program. It is located in Albuquerque, N.Mex., and operated by Sandia National Laboratories (Figure A.1).

The heliostat field consists of 222 heliostats located to the north of the tower. Each heliostat contains 25 individual mirror facets, totaling 37.2 m^2 (400 ft^2) of reflective surface. Each facet is adjusted so that its reflected beam merges with the reflected beams from the other 24 heliostat facets to form a single image at the target. The ideal reflected energy concentration ratio per heliostat is 25:1. In addition, each facet is contoured so that it gives a concentration ratio of 1.5–2:1 at its focal length. The facets are mounted on a structure with azimuth and elevation gimbals that allow the reflected energy to be aimed at any target.

The CRTF tower is constructed of concrete and rises 61 m (200 ft) above the ground and extends 15 m (50 ft) below the ground. The tower cross section is circular with rectangular projections on the north and south. The tower has four major test locations: three on the north side and one on top of the tower. An elevator inside the tower with a 100-ton capacity is used to transport major experiments from the ground to the test location. When in the full raised position, the elevator roof becomes the floor of the tower-top test location; it is used for the largest experiments. Cranes of 3-ton and 5-ton capacity are used to lift smaller equipment to the test locations. A smaller interior elevator provides personnel access to all tower levels. Passive thermal protection is provided for the tower structure.

A control and data acquisition system, electrical utilities, compressed air, and a heat-rejection system are available. A heliostat characterization system is used to align CRTF heliostats and to test new prototype heliostats.

The CRTF can perform a variety of functions, including

- Evaluating prototype receivers
- Evaluating prototype heliostats
- Testing components and subsystems for advanced solar thermal systems, including heat or other energy storage systems
- Evaluating direct-energy-conversion cycles (such as photovoltaics or thermionics) that use concentrated solar radiation
- Developing and testing instrumentation and process control systems
- Training personnel to operate solar central receiver facilities
- Developing high-temperature solar chemical and metallurgical processes and determining high-intensity solar radiation effects on materials
- Performing thermal effects testing of materials and devices not related to solar energy development programs such as
  - simulation of chemical reaction or nuclear weapon heating
  - simulation of aerodynamic or reentry heating
  - simulation of nuclear reactor fault and accident events.

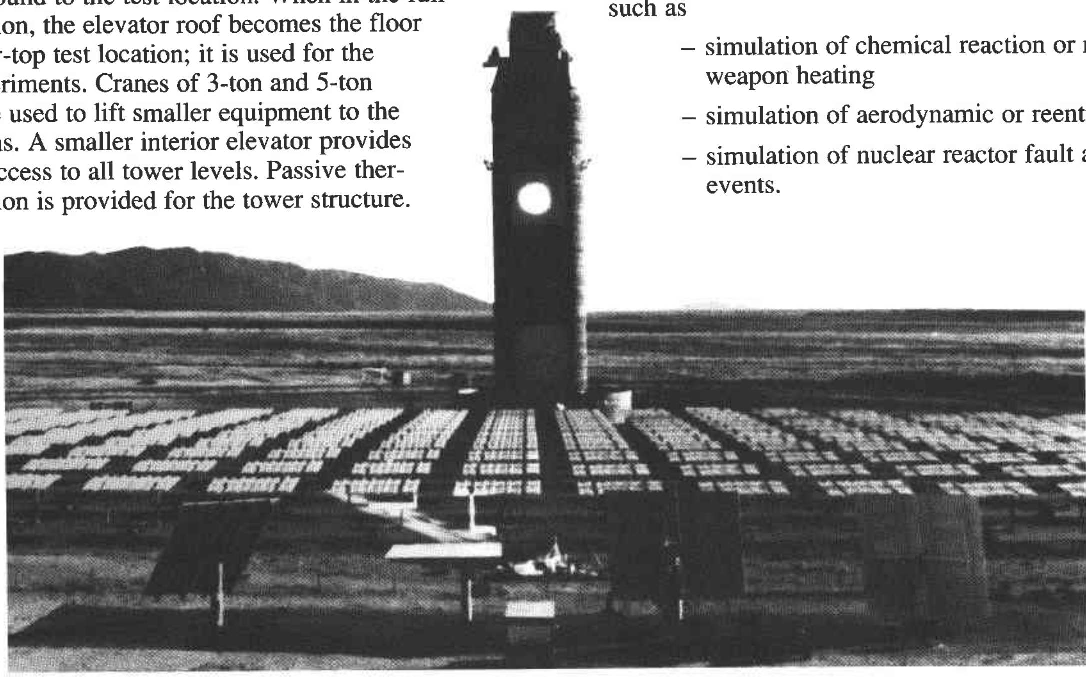


Figure A.1. The Central Receiver Test Facility in Albuquerque, N.Mex., operated by Sandia National Laboratories, where many of the U.S. central receiver test programs are conducted.

Technical Contacts

Dr. Robert San Martin
Deputy Assistant Secretary, Renewable Energy
U.S. Department of Energy
Forrestal Building
1000 Independence Ave. S.W.
Washington, DC 20585
(202) 586-9275

Mr. Clifton Carwile
Acting Director, Office of Solar Heat Technologies
U.S. Department of Energy
Forrestal Building
1000 Independence Ave. S.W.
Washington, DC 20585
(202) 586-5584

Dr. Howard S. Coleman
Director, Solar Thermal Technology Division
U.S. Department of Energy
Forrestal Building
1000 Independence Ave. S.W.
Washington, DC 20585
(202) 586-8121

Mr. Sigmund Gronich
Program Manager, Solar Thermal Technology Division
U.S. Department of Energy
Forrestal Building
1000 Independence Ave. S.W.
Washington, DC 20585
(202) 586-1623

Dr. Lawrence Murphy
Director, Solar Heat Research Division
Solar Energy Research Institute
1617 Cole Blvd.
Golden, CO 80401
(303) 231-1050

Dr. Billy W. Marshall
Manager, Energy Conversion and Science Department
Sandia National Laboratory
P.O. Box 5800
Albuquerque, NM 87185
(505) 844-2964

☆ U.S. GOVERNMENT PRINTING OFFICE: 1989—673-041/00,022 REGION NO. 8

A Product of the
Solar Technical Information Program

Solar Energy Research Institute
A Division of Midwest Research Institute

1617 Cole Boulevard
Golden, Colorado 80401-3393

Operated for the
U.S. Department of Energy

SERI/SP-220-3314
DE89009465
September 1989