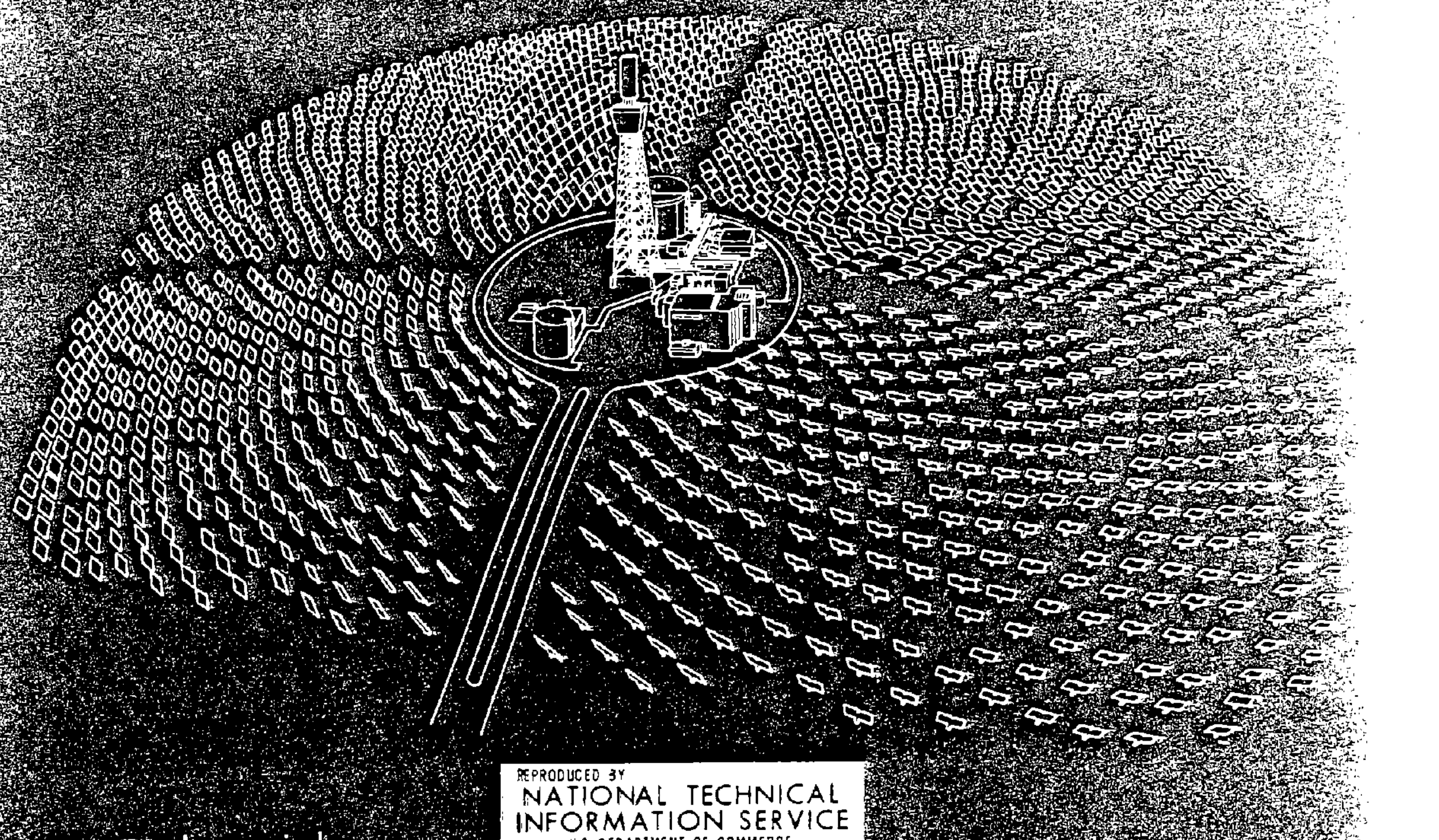
Final Report on the Power Production Phase of the 10 MW_e Solar Thermal Central Receiver Pilot Plant



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FINAL REPORT ON THE POWER PRODUCTION PHASE OF THE 10 MW_e SOLAR THERMAL CENTRAL RECEIVER PILOT PLANT

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ABSTRACT

This report describes the evaluations of the power production testing of Solar One, the 10 MW_e Solar Thermal Central Receiver Pilot Plant near Barstow, California. The Pilot Plant, a cooperative project of the U. S. Department of Energy and utility firms led by the Southern California Edison Company, began a three year period of power production operation in August 1984. During this period, plant performance indicators, such as capacity factor, system efficiency, and availability, were studied to assess the operational capability of the Pilot Plant to reliably supply electrical power. Also studied was the long-term performance of such key plant components as the heliostats and the receiver.

During the three years of power production, the Pilot Plant showed an improvement in performance. Considerable increases in capacity factor, system efficiency, and availability were achieved. Heliostat operation was reliable, and only small amounts of mirror corrosion were observed. Receiver tube leaks did occur, however, and were the main cause of the plant's unscheduled outages. The Pilot Plant provided valuable lessons which will aid in the design of future solar central receiver plants.

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FOREWORD

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

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

This report is a summary of evaluation efforts performed for the three-year Power Production Phase of the 10 MW_e Solar Thermal Central Receiver Pilot Plant. The report is the last in a series of evaluation reports that describes the performance of the Pilot Plant over its five-year test period that began in 1982 and ended on July 31, 1987. The report supplements information in SAND85-8015, which summarizes the data evaluations for the earlier two-year Experimental Test and Evaluation Phase.

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ACKNOWLEDGEMENTS

The data evaluation for the Power Production Phase of Pilot Plant operation was performed by the following organizations:

Sandia National Laboratories (SNL)

Southern California Edison

McDonnell Douglas Astronautics Company (under contract to SNL).

The efforts of numerous individuals from these organizations are summarized in this report. I am particularly indebted to my colleagues, A. F. Baker, C. L. Mavis, D. N. Tanner, and A. C. Skinrood at Sandia National Laboratories; R. L. Gervais and J. Raetz of McDonnell Douglas Astronautics Company; and C. W. Lopez of Southern California Edison for their contributions.

ACRONYMS

BCS	Beam Characterization System
CS	Collector System
DARMS	Data Acquisition Remote Multiplexer Systems
DAS	Data Acquisition System
DF	Dual Flow Operating Mode
DOE	Department of Energy
EPGS	Electric Power Generation System
EPRI	Electric Power Research Institute
HAC	Heliostat Array Controller
I	Inactive Operating Mode
ILF	In-Line Flow Operating Mode
ILS	Interlock Logic System
LADWP	Los Angeles Department of Water and Power
MCS	Master Control System
MDAC	McDonnell Douglas Astronautics Company
METRO	Meteorological
MMC	Martin Marietta Corporation
MW_e	Megawatt-electric
MW_e-hr	Megawatt-hours-electric
MW_t	Megawatt-thermal
MW_t-hr	Megawatt-hours-thermal
OCS	Operational Control System
O&M	Operations and Maintenance
PM	Preventive Maintenance
R&D	Research and Development
RLU	Red Line Unit
RS	Receiver System
SB	Storage-Boosted Operating Mode
SC	Storage Charging Operating Mode
SCE	Southern California Edison
SD	Storage Discharging Operating Mode
SDPC	Subsystem Distributed Process Controller
SNL	Sandia National Laboratories
SNLA	Sandia National Laboratories Albuquerque
SNLL	Sandia National Laboratories Livermore
TBD	To Be Determined
TD	Turbine Direct Operating Mode
TD&C	Turbine Direct and Charging Operating Mode
TSS	Thermal Storage System
TSU	Thermal Storage Unit

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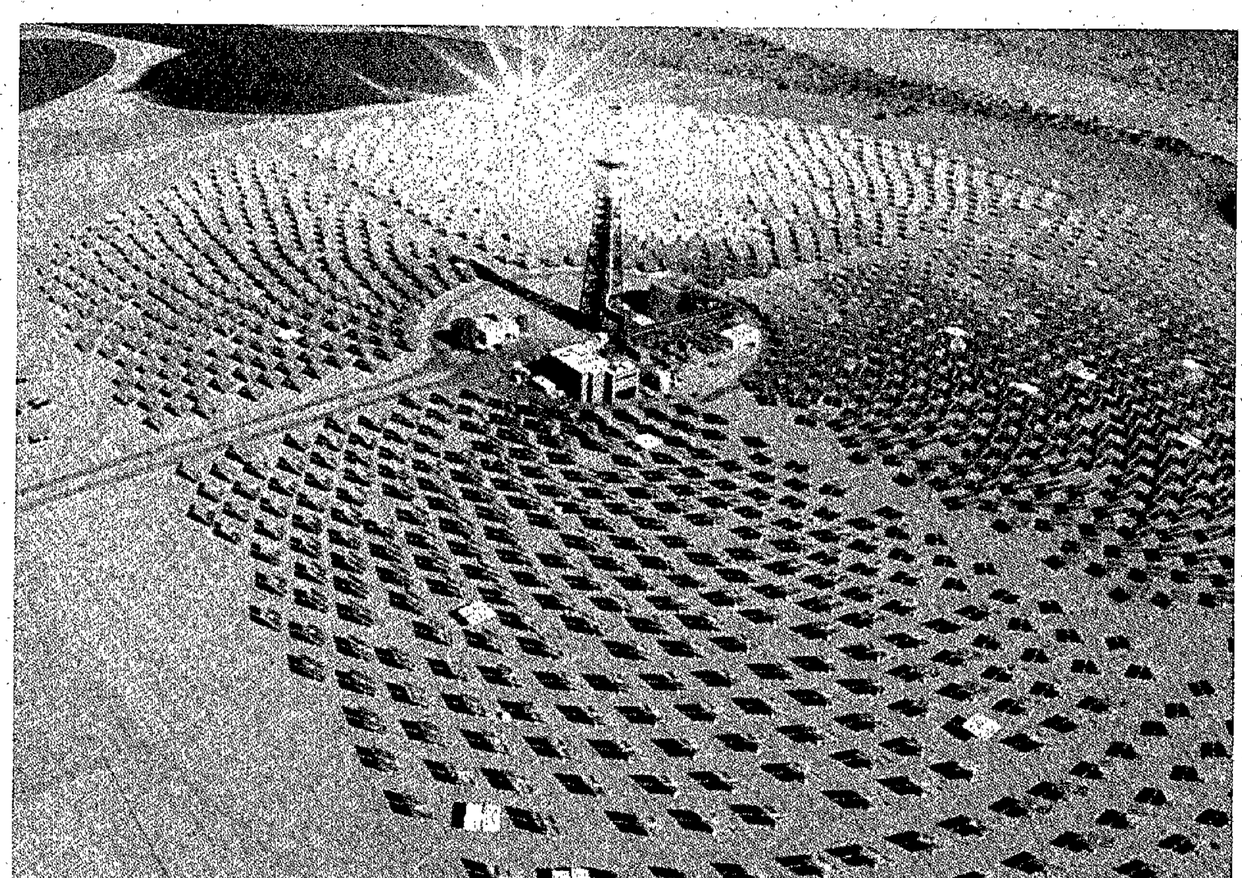
Executive Summary



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Photograph of Solar One, the 10 MW_e Solar Thermal Central Receiver Pilot Plant, near Barstow, California. Solar One is the world's largest solar central receiver electric generating plant.

EXECUTIVE SUMMARY

Overview

The power production operation of the Pilot Plant was characterized by many successes. First and foremost, the plant operation demonstrated the feasibility of reliably supplying electrical power from the Pilot Plant to the Southern California Edison utility grid. Plant availabilities of 80% or greater (disregarding weather effects) were achieved during each year of power production. Power production operation was routinely carried out under a wide range of plant conditions.

The three years of power production operation provided valuable data on the long–term performance of key plant components, such as the heliostats and the receiver. These data included changes in mirror module corrosion and the effects of thermal cycling the receiver. The data will be useful to designers of future central receiver plants.

The Pilot Plant operation demonstrated that a solar central receiver plant could be operated by utility personnel with skills similar to those needed to operate conventional power plants. Southern California Edison personnel successfully operated and maintained the plant for over five years The plant operators adapted well to the plant's distributed digital control system, even though the system was a departure from conventional control systems typically used in utility power plants.

Almost all of the Pilot Plant performance goals were met. Design goals pertaining to power output (megawatts of electricity) were all met or exceeded. Parasitic power needs were successfully reduced during the course of testing and were significantly less than the plant design values.

The Pilot Plant did not meet its energy production (megawatt-hours of electricity) goals for individual winter and summer days. Annual energy production was also less than predicted. The goals were not met because actual insolation levels and actual plant conditions such as plant availability and mirror cleanliness were less than the plant's design values. The plant operating data showed that some design assumptions were too optimistic for this first-of-a-kind plant, at least during its early years of operation.

The plant conditions experienced at the Pilot Plant can be improved. For example, the more frequent washing of the heliostats will increase the mirror cleanliness, and a preventive maintenance program should enhance the plant availability. The implementation of these and other improvements in future plants, along with the use of advanced central receiver technologies like molten salt and liquid sodium, should significantly improve the annual energy production of future power plants relative to the Pilot Plant (Reference ES–1).

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Introduction

In 1978 the Department of Energy (DOE) and the Associates (Southern California Edison, Los Angeles Department of Water and Power, and the California Energy Commission) entered into a Cooperative Agreement to design, construct, and operate a solar thermal central receiver pilot plant near Barstow, California. The Pilot Plant, named Solar One, can supply ten megawatts of electrical power to the Southern California Edison grid, making it the world's largest solar central receiver electric generating plant.

Solar One uses a large number of computer-guided tracking mirrors, called heliostats, that reflect the sun's energy to a receiver mounted on top of a tower. The receiver absorbs the solar energy in water that is boiled and converted to high-pressure steam. This steam powers a turbine-generator for the generation of electrical energy. Steam from the receiver, in excess of the energy required for the generation of 10 MW_e net power to the utility grid, is diverted to thermal storage for use when output from the receiver is less than that needed for rated electrical power.

Construction of Solar One was completed in 1981, and the plant then underwent a five-year Operational Test Period. The Operational Test Period consisted of a two-year Experimental Test and Evaluation Phase followed by a three-year Power Production Phase.

The Experimental Test and Evaluation Phase, which began in mid-1982, was completed on July 31, 1984. During this phase, the Pilot Plant demonstrated its technical feasibility. The Pilot Plant achieved operating experience in all the plant's operating modes, and the plant's system and component performances were evaluated. Results are documented in Reference ES–2.

The Power Production Phase for the Pilot Plant began on August 1, 1984, and concluded on July 31, 1987. The objective of this phase was to demonstrate the operational capability of the Pilot Plant to reliably supply electrical power. The evaluation activities for the plant included analyses of the overall plant operation and the operation of key plant systems and components. The major findings from these power production evaluations are summarized below.

Power Production

Both power production goals of generating 10 MW_e net from receiver steam and 7 MW_e net from thermal storage steam were met. The Pilot Plant generated a peak output of 11.7 MW_e net from receiver steam on February 26, 1986. In addition, the plant generated 10 MW_e net on numerous occasions throughout the course of testing.

When operating from thermal storage, the plant achieved a peak output of 7.3 MW_e net. Using thermal storage steam the plant also sustained a 7 MW_e net output for over 4 hours, generating 43.4 MW_e-hr net and easily surpassing the design goal of 28 MW_e-hr net.

Annual Energy Production and System Efficiency

A considerable improvement in the plant's annual energy production characterized the Power Production Phase of the Pilot Plant. Plant output increased from 7,024 MW_e-hr net during the first year of power production operation to 10,465 MW_e-hr net during the second year of power production operation. Plant output during the third year was slightly less than the second year.

The plant's energy output during the second year of power production operation correlates to an annual system efficiency of 5.8%. Since system efficiencies in the 11-15% range are the goal for commercial-size central receiver plants, additional improvements in efficiency and annual energy output need to be made for future central receiver plants.

These improvements can be achieved. For example, commercial-size plants will use turbine-generators with higher thermal-to-electric conversion efficiencies than the Pilot Plant turbine-generator. Future plants will achieve improved efficiencies when operating from thermal storage by using alternate working fluids, such as molten salt and liquid sodium.

A higher heliostat clean-mirror reflectance and higher receiver efficiency should also be achievable in future plant designs. The clean-mirror reflectance can be improved by using thinner low-iron glass than that used in the Pilot Plant mirrors or by using thin plastic-coated mirror designs. The use of receiver designs and working fluids which can accept higher incident flux densities than the Pilot Plant water/steam receiver, as well as periodic repainting of the receiver absorbing surface, will be required to achieve higher receiver efficiencies.

Further improvements will be needed in other areas affected by the operating and maintenance procedures for the plant. The areas include plant availability and heliostat cleanliness. These improvements should be achievable with refined operating procedures and vigilant maintenance activities.

Plant Availability

The design goal for the Pilot Plant availability, including only the effects of equipment outages but not the effects of weather, was an annual average value of 90%. Good plant availabilities were achieved during power production testing, but the 90% goal was not reached. The Pilot Plant availability averaged 80, 83, and 82%, respectively,during the first, second, and third years of power production operation.

Leaks caused by the thermal cycling of plant equipment were a major reason why the 90% goal was not met. In particular, receiver tube leaks were a prime cause of unscheduled plant shutdowns. Numerous modifications were made to the receiver operating conditions, tube welds, and tube attachments with some degree of success, but tube leaks continued to plague plant operation during power production testing.

The Pilot Plant experience emphasizes the need to use realistic conditions for determining the expected output from a plant. A plant availability of 100%, which was used to derive some early annual energy predictions, is unrealistic. The Pilot Plant design availability of 90% is probably achievable given the benefits of learning experiences and a preventive maintenance program. However, the 90% value was too high for this first-of-a-kind plant during its infant years of plant operation when more unexpected events are likely to occur.

Preferred Modes of Operation

During the daytime hours of operation, the Pilot Plant was run almost exclusively in Mode 1 (receiver-to-turbine direct) or Mode 5 (storage charging). Mode 1 was the preferred mode for power production operation because it was the most efficient method of converting the collected thermal power into electrical power. Mode 1 also provided simplicity of operation compared to other power production operating modes because it minimized the quantity of equipment that had to be operated and monitored simultaneously. Finally, Mode 1 operation was preferred because no consideration was given to maximizing plant revenues by generating power when it would be most valuable to Southern California Edison. The latter consideration would have led to the use of thermal storage for nighttime power production at the expense of daytime Mode 1 operation (see discussion under the Use of Thermal Storage).

Mode 5 was used to charge the thermal storage system so that thermal energy was available for the plant's auxiliary steam needs at night. Mode 6 (storage discharging) was almost never used for power production operation since this mode is less efficient than Mode 1.

The thermal storage system was charged about every tenth day and then partially discharged each night until it required recharging. The reasons for operating the plant in this manner were: (1) the strategy allowed increased daily operation in Mode 1, the preferred mode for power production; (2) the strategy simplified plant operations since it reduced the number of mode transitions that the plant operators would have to perform on a daily basis; and (3) excess energy was never available to charge thermal storage on a daily basis because the collected thermal energy in the receiver was insufficient to simultaneously run the turbine at or near full load and charge thermal storage. The insufficient energy condition occurred because of a lack of heliostats, soiled reflecting surfaces, and a degraded receiver surface absorptance. (During the design of the plant, 150 heliostats were eliminated, and at any given time, some number of heliostats in the field would be down for repairs.)

This operating strategy would not be used in future power plants. Future plants will likely use working fluids like molten salt or liquid sodium which can serve as both the receiver coolant and thermal storage medium. For these plants all the collected thermal energy can be directed to the storage system, and there is no penalty in efficiency when operating from storage.

Staffing Levels

The Pilot Plant achieved a large reduction in staff during the course of operation as a result of learning experiences, automation capabilities added to the plant control system, and a reduction in the plant's test and evaluation activities. In 1982 the Pilot Plant staff numbered 40 persons, not including the McDonnell Douglas test engineers. A reduction in the number of plant equipment operators and security officers, as well as changes in the required skills of the maintenance staff, lowered the number of overall staff to 34 persons in 1984. The staff was reduced to 17 persons near the end of the Power Production Phase in anticipation of going to five-day-a-week, two-shift operation in August 1987. Southern California Edison indicated that a staff of 20 persons (12 operating and 8 maintenance persons) would have been adequate to continue the satisfactory operation and maintenance of the plant on a seven-day-a-week, three-shift basis.

The staff for a commercial plant, 100 MW_e in size, is projected to be only 60–70 persons. Considerable economies of scale should be possible for a commercial plant since the number of plant operators will not be significantly different from the Pilot Plant operating staff. The major differences between the Pilot Plant and a commercial plant would occur in the maintenance, equipment operator, and security areas. The additional maintenance personnel would be required primarily for the additional heliostats and the addition of heavy maintenance capabilities. The additional plant equipment operators and security personnel would be needed for the larger plant facilities and around-the-clock surveillance.

Heliostat Availability

The average heliostat availabilities during the first, second, and third years of power production operation were 96.7, 96.0, and 98.8%, respectively. The desired availability for power production operation was 99% and was based on Sandia analyses which indicated that the additional maintenance costs required to achieve a 99% value were less than the additional plant revenue resulting from the increased availability. Heliostat availability improved during power production testing as a result of increased maintenance efforts. The high availability achieved during the third year of operation is indicative of a successful SCE heliostat maintenance program and shows that a 99% availability should be achievable.

Heliostat Cleaning

Mirror cleanliness (expressed as a percent of the clean field reflectance) was an important factor in Pilot Plant operations since it had a significant impact on the overall plant performance. Periodic mechanical washings of the Pilot Plant heliostats were required to achieve a high mirror cleanliness. The average annual mirror cleanliness was 89.5 and 93.0% during the first and second years of power production operation, respectively. (No value was derived for the third year due to insufficient data.) Sandia analyses for the Pilot Plant suggested that it was desirable to strive for an average annual cleanliness of 97%. The 97% value was based on the costs of a biweekly mechanical washing and the increased plant revenue that would result from having cleaner mirrors. Equipment breakdowns on the wash truck and infrequent washings were the major reasons why higher annual cleanliness values were not achieved during power production operation.

Future solar plants are likely to use much larger glass/metal heliostats or stressed membrane heliostats whose reflective surface may be more susceptible to scratching than glass. The mechanical washing of these heliostats will be more difficult than the washing of the Pilot Plant heliostats. Consequently, particular attention should be paid to analyzing the washing equipment effectiveness during the design of the heliostats and the overall plant.

Mirror Module Corrosion

Silver corrosion has occurred on the Pilot Plant mirrors. The corrosion is caused by water inside the mirror modules that penetrates through the protective paint layers and dissolves the copper; water and oxygen then corrode the silver.

Corrosion surveys of the entire heliostat field were performed during the summers of 1983, 1984, and 1985. During the summer of 1986 a survey was made of 98 randomly selected heliostats. This limited survey was done instead of a full field survey since it had been determined that these heliostats accurately represented the field. The surveys indicated that only 0.061% of the total reflective surface of the heliostat field had corroded by July 1986. This percentage is equivalent to the surface area of about 1.1 heliostats. Thus, although mirror corrosion had been a concern at the Pilot Plant, to date, the overall impact upon collector performance has been small.

The Need for a Beam Characterization System

The need to accurately and quickly measure tracking errors for a large number of heliostats will dictate that future solar central receiver plants also have a beam characterization system. Once the Pilot Plant system started, it was fully automatic, and very little operator time or skill was needed to run the system and make heliostat tracking error corrections. Because there was a need for morning, noon, and afternoon tracking measurements to correct for errors that vary with the time of day, the Pilot Plant system performed a complete alignment on about 50 heliostats per day. Therefore, to perform an alignment of the Pilot Plant's 1,818 heliostats required about 36 clear weather days.

The measurement speed for future solar plants will depend on several factors, including the number of heliostats and the frequency at which heliostats must be re-checked for tracking errors. A fast measurement speed is desirable to reduce checkout costs during heliostat installation, but once in operation the need for fast measurements will be reduced. A high measurement speed can also impact the heliostat costs since fast speeds will require high slew rates. These factors, as well as specific design features like video digitizing, image analysis, and data presentation, should be considered in the beam characterization design for future solar plants.

Receiver Performance

The Pilot Plant receiver operation confirmed that several important receiver design characteristics could be achieved. First, the measured peak receiver efficiency was comparable to the design efficiency. Prior to repainting the receiver absorbing surface, the receiver efficiency was measured to be about 77% at an absorbed power of 34 MW_t (the power level at the 2 p.m., winter solstice design point). After repainting the receiver to bring the surface absorptance value closer to its design value, the measured efficiency increased to about 82%. The predicted efficiency at the winter solstice design point was 81%. Although differences besides the surface absorptance existed in the "actual" and "design" receiver physical and operating characteristics (for example, differences in the active heat absorbing areas and the operating temperatures), these results generally confirm the design point performance of the Pilot Plant receiver. The results also lend credence to the computational methods used to estimate the efficiency of external receiver designs.

The receiver operation demonstrated a receiver responsiveness that exceeded expectations. The receiver was able to start-up quickly in the morning and operate to near sunset. The receiver also responded well to cloud-induced changes in insolation levels. Some limitations on receiver operation resulted from the inability of the collector field to reflect sufficient energy on certain panels during start-up and shutdown. Other limitations resulted from constraints on the receiver temperature ramping rate, which can be severe during cloud transients.

The receiver operation showed that several early concerns about the receiver boiler design were unwarranted. Flow stability problems which some had predicted for this single-pass-to-superheat design were prevented by orificing many of the receiver tube inlets. Also, the small-diameter receiver tubes with orifices did not foul or plug because of an effective upstream filtering system.

The main problem with the receiver operation resulted from the diurnal and cloud-induced thermal cycling. Cracks appeared in the receiver tubes after eighteen months of service, and several panels warped as a result of thermal expansion constraints (described below under Receiver Life). These led to frequent outages so repairs could be made. All the repairs of the receiver tube leaks were successfully carried out in the field. The repairs were made without removing the receiver panels from the tower.

Surface Absorptance

The receiver panels were coated with Pyromark paint, a black paint that was used to increase the absorption of solar energy by the receiver surface. In December 1985, the receiver was repainted with Pyromark since the absorptance of the paint on the receiver panels had decreased from 0.95 (the design value) to about 0.86. Solar absorptance measurements made on the receiver in March and August 1986 showed that the average solar absorptance of the receiver was about 0.97 and did not change, within experimental accuracy, between March and August. A measurement in October 1987 showed that the average absorptance had decreased to about 0.96.

The Pilot Plant experience showed that it was possible to successfully repaint the receiver in the field and improve the receiver's thermal performance. The Pilot Plant receiver was completely repainted only once during its five years of operation. For future solar plants, projections should be made regarding the expected rate of degradation in receiver coatings and the economic intervals for repainting.

Receiver Life

During plant operations, tube leaks occurred on several of the receiver boiler panels. The leaks were associated with cracks at two distinct locations on the panels. After eighteen months of service, the leaks occurred at the top of the panels at the interstice weld between subpanels (Type I cracks) and on the edge tube bend (Type II cracks). The second location, which first occurred in July 1985, was on the back of the panels at the panel support assembly (Type III cracks).

Panel structural modifications at the top of the panels and changes in the receiver operating conditions eliminated the Type I and II cracks. Start-up procedures were revised to control temperature during start-up and shutdown, and repairs of the receiver tube leaks were carried out successfully.

Analyses indicated that the Type III cracks were caused by thermal stresses due to temperature gradients through the panel tubes and the panel support clips welded to the back of the tubes. The panel supports were modified to relieve the thermal stresses, but the modifications did not eliminate the occurrence of the Type III cracks. The receiver experience concerning tube leaks has shown that designs need to be improved to account for thermal cycling, and manufacturing techniques need to be changed to eliminate the amount of welding required on the receivers. Almost all tube leaks, except Type II, were associated with welds on the tubes. Simpler manufacturing techniques with less welding should be used in the future receiver designs.

Use of Thermal Storage

During the Power Production Phase, thermal storage use was limited to providing auxiliary steam for the plant's nighttime steam needs. The use of thermal storage for power production operation was minimal. This operating strategy was employed at the Pilot Plant because (1) Mode 1 (receiver-to-turbine direct) was a more efficient way of producing electrical power than Mode 6 (storage discharging) for the water/steam central receiver technology used in the Pilot Plant; (2) a lack of heliostats and soiled mirror surfaces limited the amount of excess thermal energy that was available to charge storage; (3) no consideration was given to maximizing plant revenues by producing power when it would be most valuable to Southern California Edison; and (4) this strategy allowed operating experience to be obtained for the thermal storage system without incurring a significant reduction in plant performance.

The strategy of using thermal storage for only auxiliary steam production would not likely be used in commercial power plants. The auxiliary steam demand for a power plant is small and would make a cost-effective thermal storage system difficult to achieve. A good portion of the annual thermal energy directed to the Pilot Plant thermal storage system was lost through tank and heat exchanger heat losses. Thermal storage operation was restricted by the lack of thermal energy needed to charge storage on a daily basis (discussed under Preferred Modes of Operation). The restriction limited the amount of thermal energy directed to storage and caused the relatively constant heat losses to become a large fraction of the energy input to thermal storage. This does not mean that the Pilot Plant thermal storage system worked poorly. In fact, it met or exceeded its design expectations with respect to extractable energy, charging and discharging rates, and heat losses.

Directing additional thermal energy from the receiver to thermal storage at the expense of the receiver–to–turbine direct operation was not performed during power production due to the reduced turbine thermal–to–electric conversion efficiency when operating from storage. The reduced efficiency is a consequence of using different receiver and thermal storage working fluids and the need to transfer heat between the fluids. Future plants will likely use working fluids which serve as both the receiver coolant and storage medium. For these plants it is desirable to direct all the thermal energy to the storage system because storage provides an excellent buffering capability for the turbine, and there is no penalty in the thermal–to–electric conversion efficiency when operating from storage.

The goal of the Pilot Plant Power Production Phase was to maximize energy production while obtaining some operational experience with the thermal storage system. The goal was not to maximize plant revenues. In a recent study at Sandia, we concluded that to maximize revenues would have dictated greater use of the Pilot Plant thermal storage for power production.

Thermal Storage Fire

The thermal storage system was routinely used during power production operation to supply the plant's auxiliary steam needs. Routine operation was interrupted on August 30, 1986, early into the third year of power production operation. On that day, an overpressurization and rupture of the thermal storage tank occurred and was followed by a fire at the top of the tank.

An investigation of the accident determined that oil containing significant quantities of water had been pumped into the tank. The hot oil inside the tank vaporized the water and caused the overpressurization. When the tank ruptured, hot volatile gases escaped and ignited on contact with air.

The rupture in the thermal storage tank was repaired, but the thermal storage system was not returned to service. Sandia had completed the test and evaluation of the thermal storage system prior to the accident. Moreover, the system was being used only for auxiliary steam production and not for electric power production. After the accident the plant's auxiliary steam needs were supplied with an electric boiler. Parasitic power needs for the plant increased about 10% due to the use of the electric boiler.

The thermal storage shutdown resulted in increased Mode 1 operation since thermal energy no longer was sent to the thermal storage system. The power production from the increased Mode 1 operation more than offset the increased parasitic power from the use of the electric boiler. This result is not apparent from the actual power production data before and after the fire because other plant conditions such as insolation and availability also affected plant output and were not the same during these periods.

Distributed Digital Control System

The Pilot Plant control system, a distributed digital control system with several automatic features, demonstrated that modern computer control technology can be successfully utilized in the electric utility industry. The Pilot Plant control system was a significant departure from a conventional power plant control system. Nevertheless, utility personnel with typical skills were able to successfully operate the plant without difficulty. The Pilot Plant operations and maintenance personnel came from within the utility without any special job descriptions.

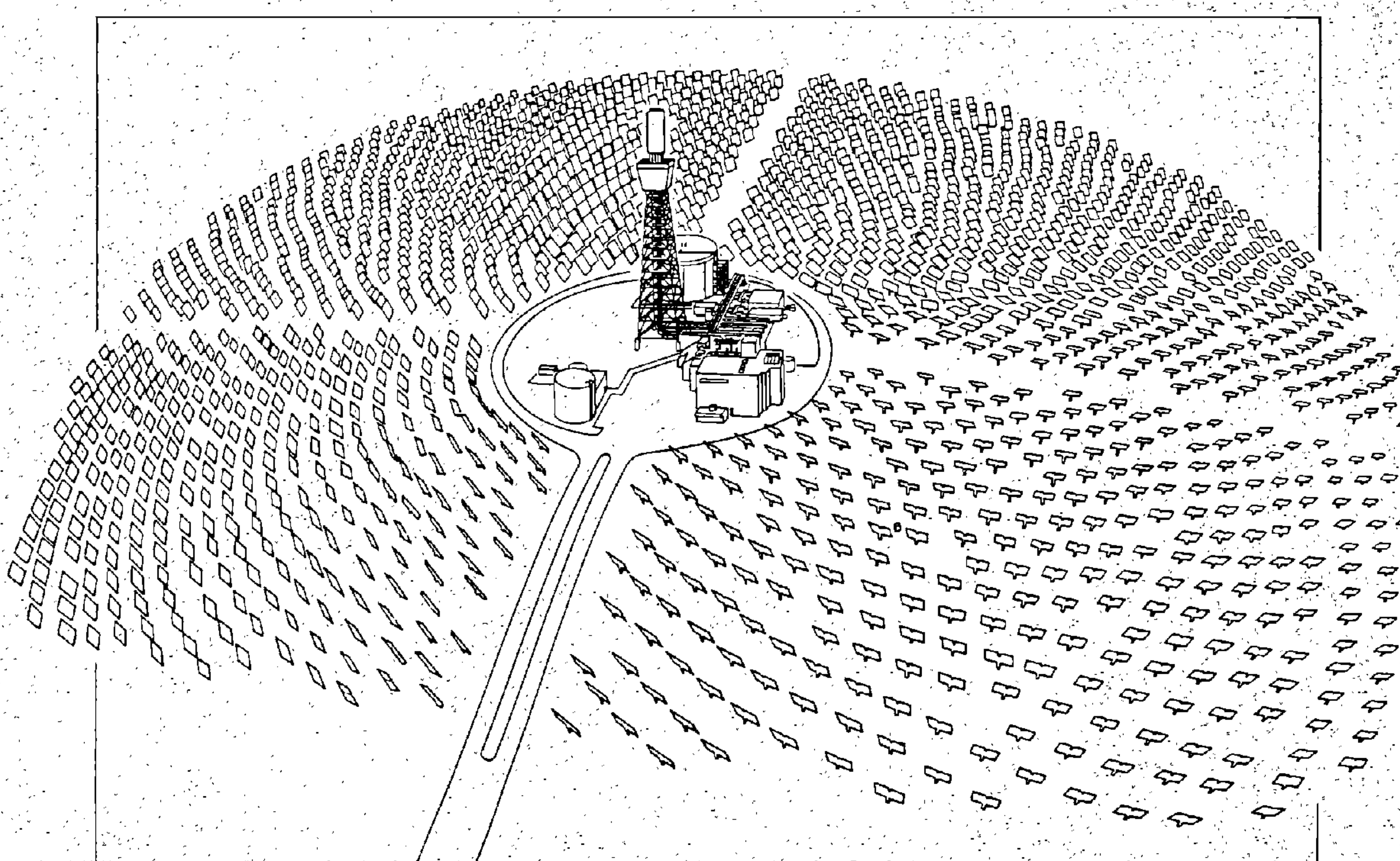
The Pilot Plant control system functioned well and operated reliably. Although the plant's control system was designed for controlling a water/steam solar central receiver plant, the basic functions and operating philosophy are readily adaptable to other power plants. A distributed digital control system with some modifications that reflect Pilot Plant learning as well as state-of-the-art equipment is recommended for future solar central receiver plants.

References

ES-1. P. K. Falcone "A Handbook for Solar Central Receiver Design," Sandia National Laboratories, SAND86-8009, 1987.

ES-2. L. G. Radosevich, "Final Report on the Experimental Test and Evaluation Phase of the $10MW_e$ Solar Central Receiver Pilot Plant," Sandia National Laboratories, SAND85-8015, 1985.

Introduction



Schematic Illustration of the Pilot Plant

FINAL REPORT ON THE POWER PRODUCTION PHASE OF THE 10 MW_e SOLAR THERMAL CENTRAL RECEIVER PILOT PLANT

I. Introduction

In 1978 the Department of Energy (DOE) and the Associates* entered into a Cooperative Agreement to design, construct, and operate a solar thermal central receiver pilot plant near Barstow, California. The Pilot Plant, named Solar One, was completed in 1981 and has been operated over a five-year Operational Test Period. The Operational Test period consisted of a two-year Experimental Test and Evaluation Phase followed by a three-year Power Production Phase. The plant is capable of supplying ten megawatts of electrical power to the Southern California Edison grid, making it the world's largest solar central receiver electric generating plant.

The Experimental Test and Evaluation Phase began on August 1, 1982, and ended on July 31, 1984. During this time, operating experience was achieved for all the plant's operating modes, and the performance of the plant's system and components was evaluated. Reference 1-1 contains a summary which evaluates the Pilot Plant performance for the Experimental Test and Evaluation Phase.

The Power Production Phase began on August 1, 1984, and ended on July 31, 1987. During this period the Pilot Plant was routinely operated in a power production mode to assess the capability of the plant to reliably supply electrical power. Plant performance indicators, such as annual energy output, availability, and capacity factor, were monitored and analyzed. Key plant components, such as the heliostats and the receiver, were studied to deduce the effects of their long-term operation Reference 1-2 describes the objective and the approach for each evaluation activity of the Power Production Phase.

Near the end of the Power Production Phase, the DOE and Southern California Edison agreed to continue operation of the Pilot Plant for at least another year. The plant will continue to be operated in a power production mode but on a five-day-a-week basis rather than the seven-day-a-week basis used in previous years.

* Southern California Edison, Los Angeles Department of Water and Power, and the California Energy Commission

The overall evaluation of the Pilot Plant for the Power Production Phase was performed by three organizations. Sandia National Laboratories Livermore (SNLL), on behalf of DOE, analyzed and evaluated the data obtained from the power production operation. Southern California Edison (SCE) operated the plant, recorded data for the plant and its systems, and evaluated the plant from a utility perspective. McDonnell Douglas Astronautics Company (MDAC) also performed evaluations in specific areas, under contract to SNLL.

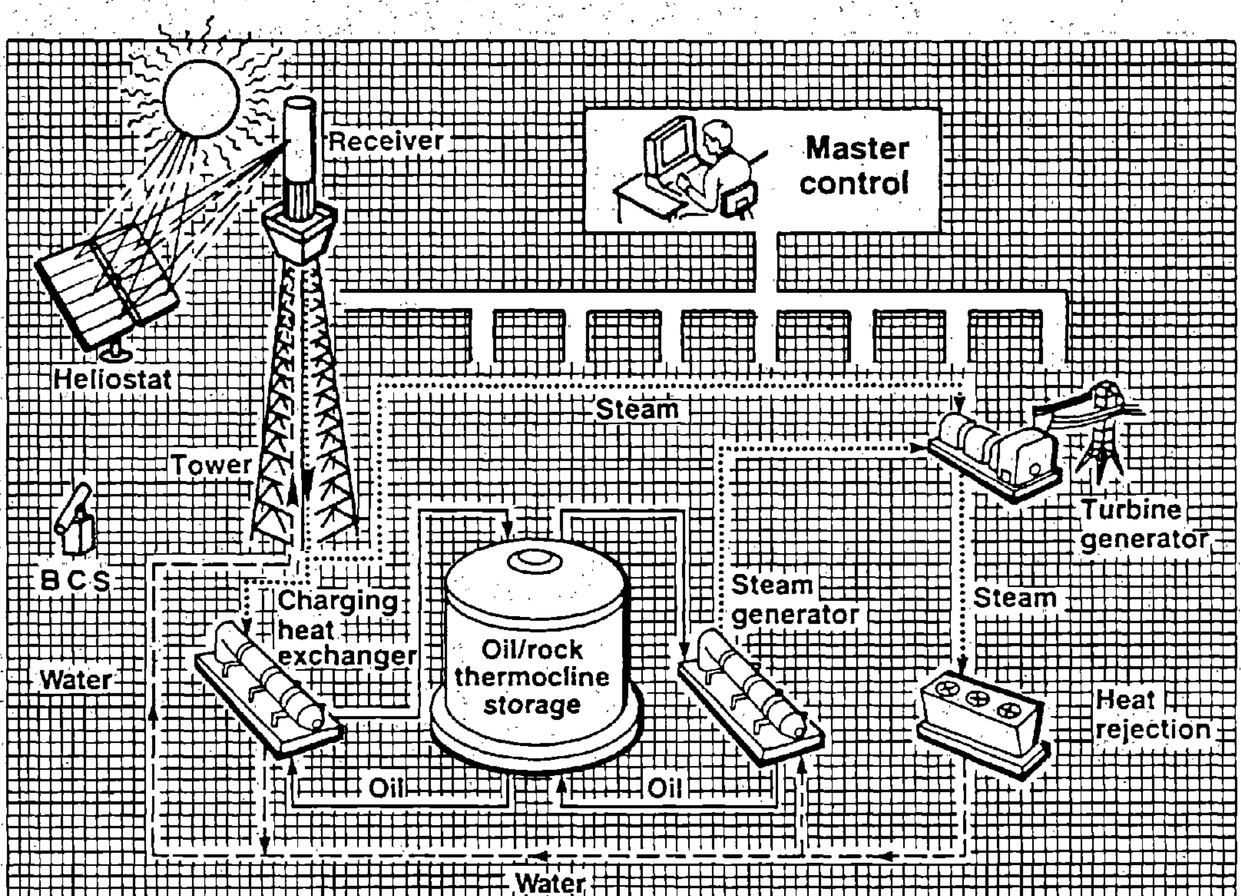
This report presents a summary of the data evaluations performed for the Power Production Phase. The report contains previously unpublished results as well as a compendium of information from work reported in several references. The references are cited in each chapter, as appropriate. Chapter 2 describes the Pilot Plant and its operating modes. Chapter 3 describes the operating data for the plant during the Power Production Phase. Chapters 4 to 7 summarize the performance of the overall plant and the plant's collector, receiver, and thermal storage systems. Chapter 8 describes the major lessons learned during power production operation. Finally, Chapter 9 presents a bibliography of all reports pertaining to the evaluation of the Pilot Plant.

References

1-1. L. G. Radosevich, "Final Report on the Experimental Test and Evaluation Phase of the 10 MW_e Solar Thermal Central Receiver Pilot Plant," Sandia National Laboratories, SAND85-8015, 1985.

1-2. L. G. Radosevich, "Data Evaluation Plan for the 10 MW_e Solar Thermal Central Receiver Pilot Plant Power Production Phase," Sandia National Laboratories, SAND84-8237, 1984.

Plant Description



Schematic Illustration of the Pilot Plant Major Systems

2. PLANT DESCRIPTION

Siting and General Design Data

The Solar One Pilot Plant is located in the Mojave Desert about 12 miles east of Barstow, California, near Daggett. The site is on 130 acres of land, directly adjacent to Southern California Edison's Cool Water Generating Station.

The Pilot Plant is designed to produce at least 10 MW_e net for a period of 7.8 hours on the plant's "Best Design Day" (summer solstice) and for a period of 4 hours on the plant's "Worst Design Day" (winter solstice). The plant is also designed to produce 7 MW_e net for a period of 4 hours when operating from thermal storage.

Plant Systems

The Pilot Plant, based on the central receiver concept, uses a large number of computer-guided tracking mirrors, called heliostats, that reflect the sun's energy to a receiver mounted on top of a tower. The receiver absorbs the solar energy into water that is heated and converted to high-temperature, high-pressure steam. This steam powers a turbine-generator for the generation of electrical energy. Steam from the receiver, in excess of the energy required for the generation of 10 MW_e net power to the utility grid, is diverted to thermal storage for use when output from the receiver is less than that needed for rated electrical power. The Pilot Plant consists of seven major systems (shown on interleaf):

- the **collector system**, which includes 1,818 heliostats that reflect solar energy onto the receiver;
- the **receiver system**, which consists of tubes welded into twenty-four panels mounted on a central tower. The receiver is analogous to a boiler in a conventional steam power plant;
- the **thermal storage system**, which stores energy as sensible heat in a bed of heat transfer oil, sand, and gravel;
- the **plant control system**, including computers that monitor and control the plant;
- the **beam characterization system**, which is used for correcting the alignment of the heliostats and evaluating the collector system performance;
- the **electric power generation system**, including the turbine-generator and its auxiliaries; and

- the **plant support system**, consisting of site structures, buildings, and facility services, such as raw water, fire protection, demineralized water, bearing cooling water, nitrogen, compressed air, oil supply, liquid waste, and electrical distribution equipment.

Reference 2–1 contains detailed descriptions of each system.

Collector System

The collector system consists of an array of 1,818 Martin Marietta heliostats of the type shown in Figure 2–1. The heliostat field, which has a total reflective area of 765,400 ft^2 (71,140 m^2), surrounds the central receiver tower, with 1,240 of the heliostats in the north portion of the field and 578 in the south portion of the field. The heliostat field occupies 72 acres of the 130–acre plant site.

Each heliostat has twelve slightly concave mirror panels totaling 421 ft^2 (39.13 m^2) of reflective surface. The mirrors have an average clean reflectance of 0.903; this average is area-weighted for the mixture of low– and high–iron glass used in the field. Each mirror assembly attaches to a geared drive unit for azimuth and elevation control. The drive unit is mounted on a fixed pedestal. The total weight of each heliostat is 4,132 lb. (1,875 kg), including the reflective assembly, drive unit, pedestal, and electronics but excluding the poured–in–place concrete pile foundation.

The collector control system consists of a micro–processor controller in each heliostat, a field controller for control of groups of up to 32 heliostats, and redundant central computers called the heliostat array controllers. The sun position information for aiming each heliostat is calculated within this control system. The heliostats can be controlled individually or by groups in either manual or automatic modes through the heliostat array controller which is located in the plant control room. The heliostats are designed to operate in winds up to 45 mph (20 m/s) and will withstand winds up to 90 mph (40 m/s) when stowed in a mirror–down position.

Receiver System

The receiver system consists of a single–pass–to–superheat boiler with external tubing, support tower, valves, piping, and controls necessary to provide the required amount of steam to the turbine (see Figure 2–2). The receiver is approximately 45 ft (13.7 m) high and 23 ft (7 m) in diameter. The top of the receiver is approximately 300 ft (90 m) above ground level.

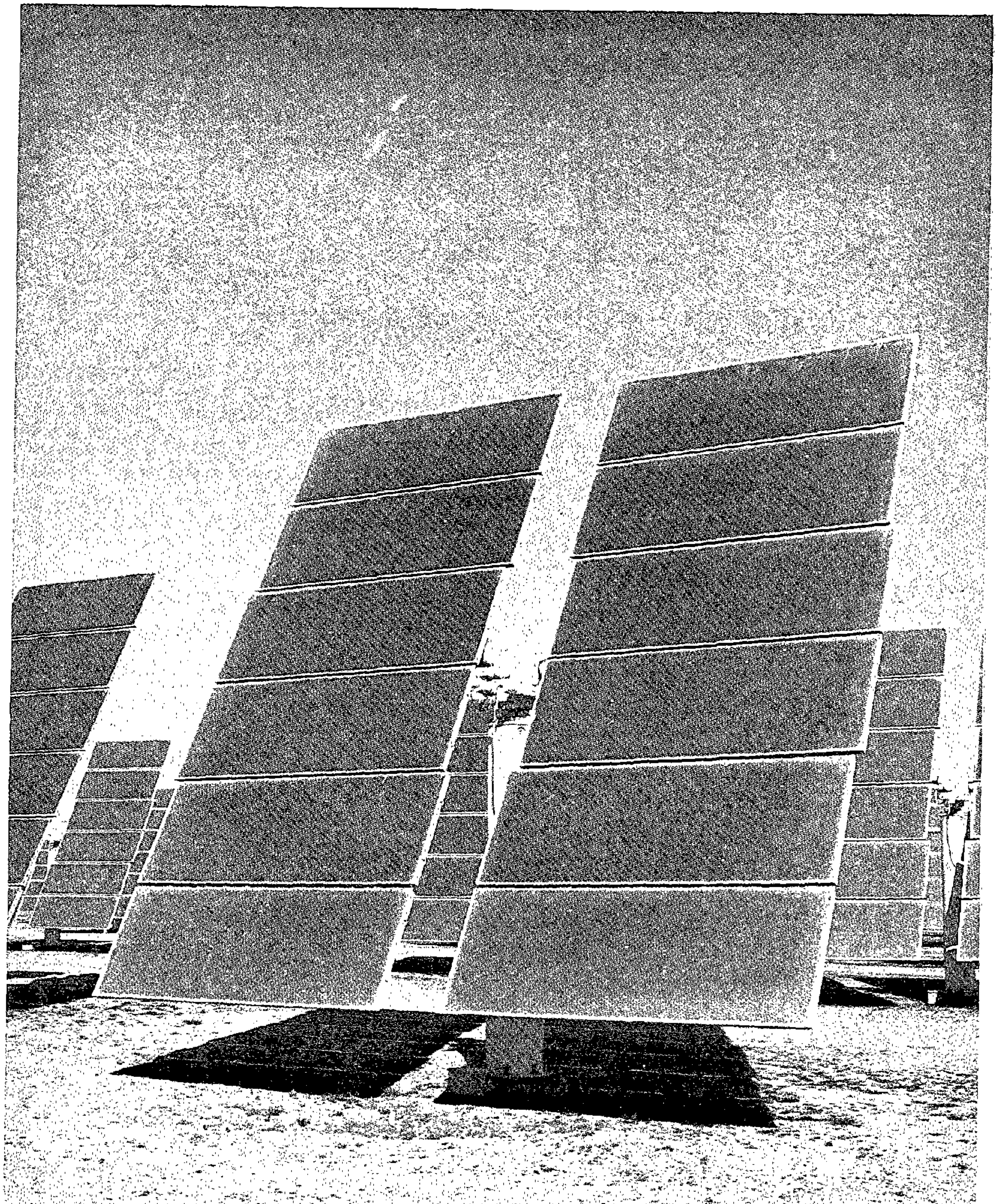


Figure 2-1. Pilot Plant Heliostat

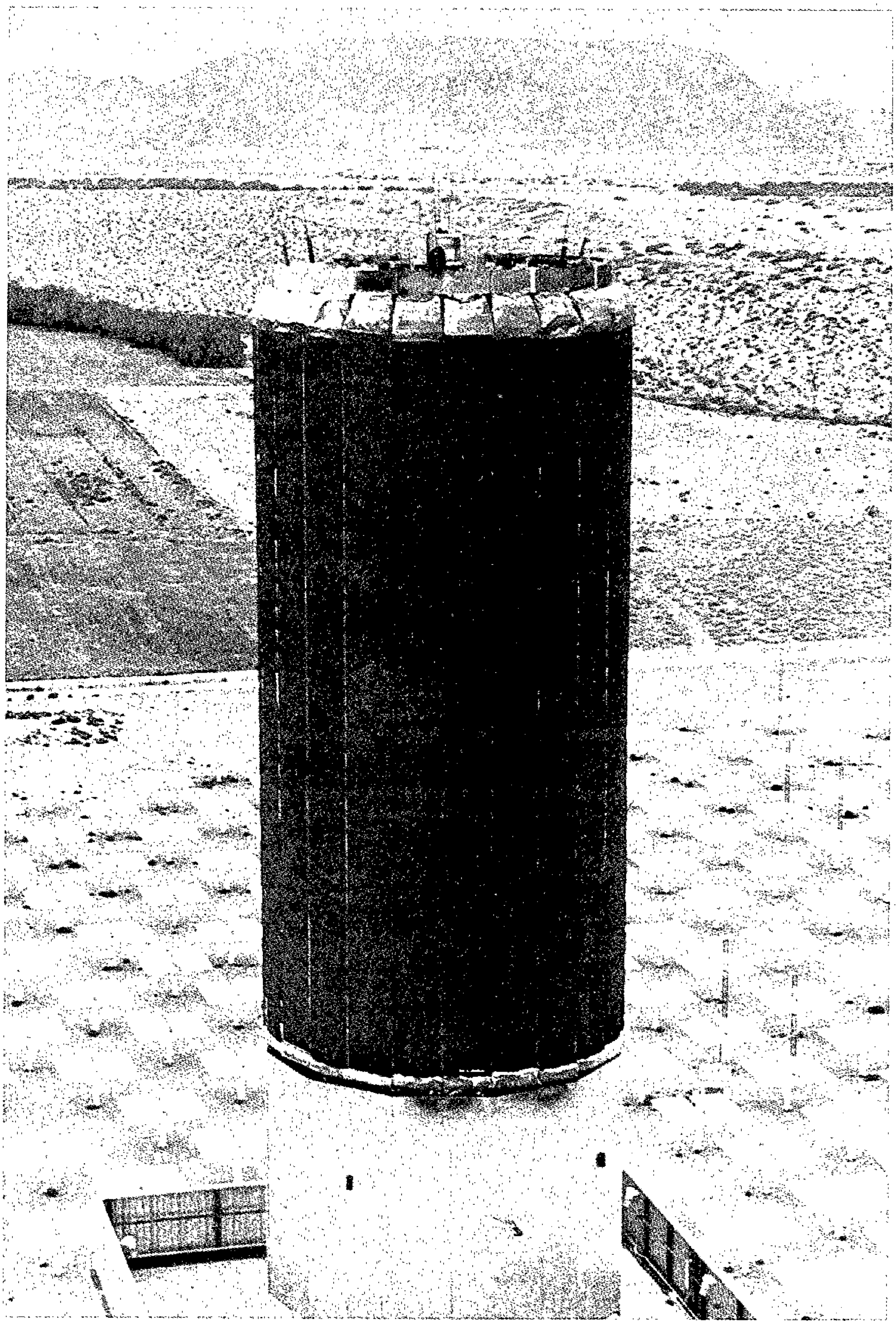


Figure 2-2. Receiver Panels with Boiler Tubes

The receiver has twenty-four panels, each approximately 3 ft (0.9 m) wide and 45 ft (13.7 m) long. The panels have a total surface area of 3,252 ft^2 (302 m^2). Six panels on the south side of the receiver are feed-water preheat panels while the remaining eighteen are boiler panels.

Each panel consists of seventy tubes (0.5 in or 1.27 cm OD, 0.27 in or 0.69 cm ID) through which the feedwater is pumped and, in the boiler panels, converted to steam. These thick-wall tubes are made of Incoloy 800, an alloy which can withstand the effects of daily heat cycling as well as cloud transients. Within each panel the tubes are welded to each other over their full length and the panel is coated with a special black paint (Pyromark) to increase thermal energy absorption. The back surface of each panel is heavily insulated and sealed against light leaks.

The receiver is designed to produce 112,000 lb/hr of steam at 960°F (516°C) and 1,465 psia (10.1 MPa). The receiver tubes are designed for a peak external surface temperature of approximately 1,150°F (620°C) under normal operating conditions.

The receiver support tower includes receiver piping, supports, personnel access equipment, and controls required for operation and monitoring. The piping lines in the tower include: feedwater, main steam, flash tank steam, flash tank water, panel drain, instrument air, nitrogen, and service water. The lattice steel tower stands on four 25 ft (7.6 m) deep footings attached to a 1,500 ton (1,360 metric ton) concrete base. The flared area of the tower immediately beneath the receiver is formed by four white aluminum sheet metal targets used for the beam characterization system. The tower space inside these targets houses air-conditioned rooms where the receiver computer and some of the beam characterization system controls are located. The receiver including panels, panel support structure, wiring, and piping weighs 165 tons (150 metric tons). The structural steel tower weighs an additional 202 tons (183 metric tons).

Thermal Storage System

The thermal storage system consists of a tank, heat exchangers, pumps, valves, piping, and controls required for operation and monitoring. The thermal storage system provides for storage of solar energy to extend the plant's electrical power generating capability into nighttime or periods of cloud cover. The system is sized to provide 7 MW_e net for a period of four hours. It also provides steam for maintaining selected portions of the plant in a warm status during non-operating hours and for starting up the plant the following day.

The thermal storage system employs dual liquid and solid storage media with the thermocline principle applied to store both hot and cold storage media in the same tank. In operation, heating of the media is achieved by removing colder fluid from the bottom of the tank, heating it in a heat exchanger with steam from the receiver, and returning the fluid to the top of the tank. The process is reversed for heat extraction.

The thermal storage system consists of three major elements: (1) the thermal storage tank, (2) the thermal charging loop, and (3) the thermal discharging loop. Figure 2-3 is a schematic flow diagram of the Pilot Plant thermal storage system showing these major elements.

The thermal storage tank (see Figure 2–4) contains a packed bed of rock/sand and Caloria HT–43 heat transfer fluid. The fluid flows through the bed to deposit or withdraw energy. An ullage unit provides a pressurized heptane atmosphere above the bed to prevent air from entering the tank and oxidizing the fluid. The unit also prevents the presence of a combustible environment in the tank and provides for the disposal of excess gas through an outside combustion system. The thermal storage tank is 45 ft (13.7 m) high (at outside edge) and 60 ft (18.3 m) in diameter. It sits on a lightweight, insulating concrete foundation that reduces heat loss to the ground. The walls are made of steel plate with one foot of external insulation, and the roof is made of steel with two feet of insulation. The tank is filled with about 6,800 tons (6,180 metric tons) of rock and sand and about 240,000 gal (908,000 liters) of Caloria HT–43.

The thermal charging loop consists of a desuperheater, condenser and subcooler heat exchangers (two parallel trains), pumps, piping, and valves. The desuperheater lowers the temperature of the receiver steam from 950°F (510°C) to 650°F (343°C) to avoid overheating of the Caloria HT–43. This steam is then used in the charging heat exchangers to heat the heat transfer fluid from 425°F (218°C) to 580°F (304°C).

The thermal discharging loop consists of preheater, boiler, and superheater heat exchangers (two parallel trains), pumps, piping, and valves. Caloria HT–43 fluid is pumped from the storage tank through the heat exchangers and back to the storage tank, converting feedwater to steam at a temperature of 530°F (277°C) and a pressure of 400 psia (2.76 MPa).

Plant Control System

The plant control system includes the master control system (MCS) equipment, system distributed process controller (SDPC) equipment, and interlock logic system (ILS). The equipment is located in the control room (see Figure 2–5) and at four distributed sites throughout the plant.

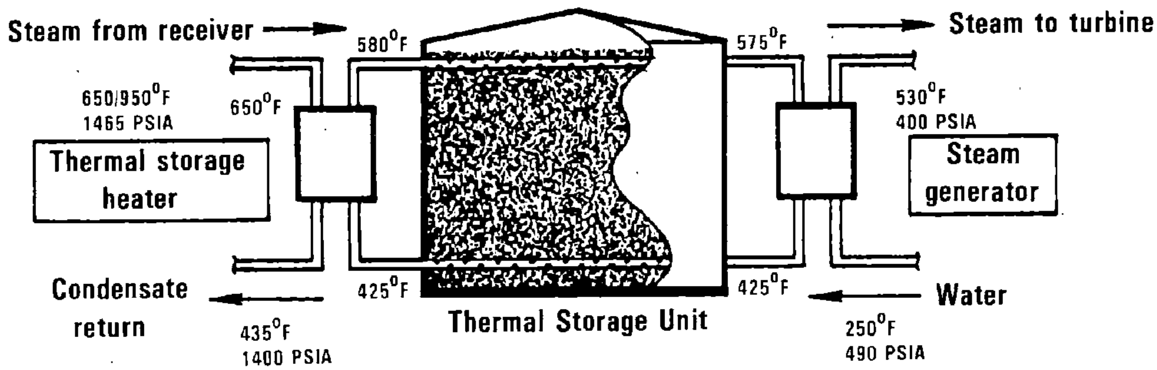


Figure 2—3. Storage System Schematic

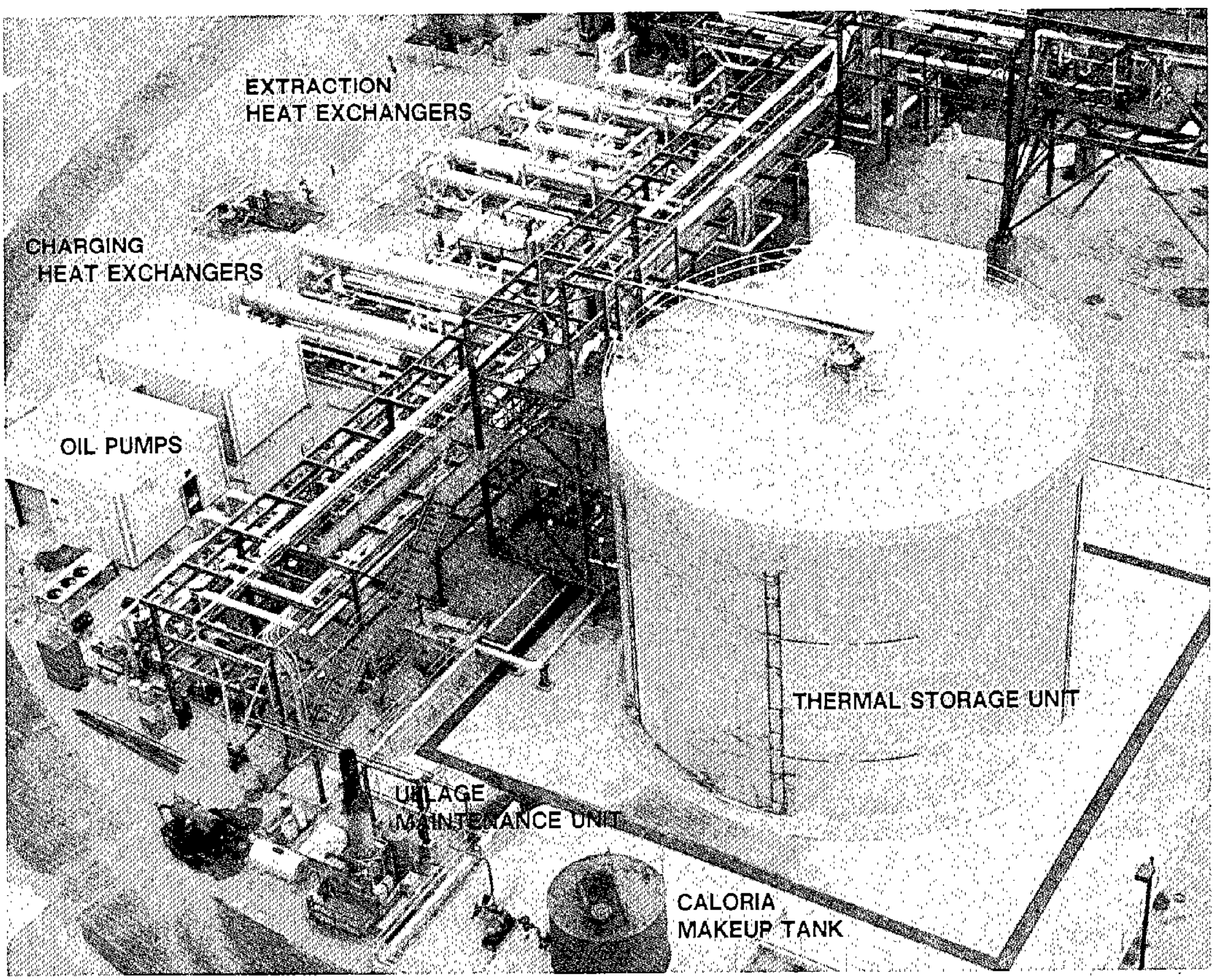


Figure 2—4. Thermal Storage Tank and Heat Exchanger Equipment

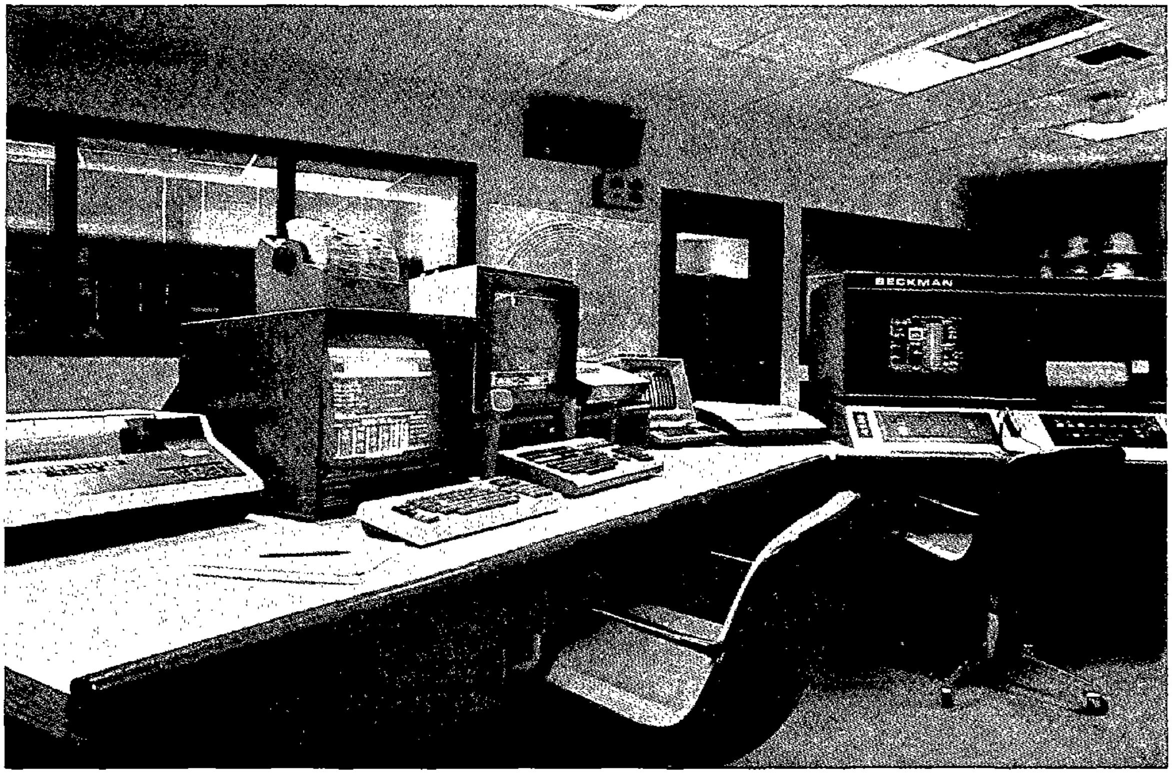


Figure 2—5. Control Room

The MCS is an overall command, control, and data acquisition system that performs control management and supervision functions as well as data collection and display functions. Its purpose is to integrate the independent controls of the other four primary operating systems (collector, receiver, thermal storage, and electric power generation) with the balance of plant to achieve effective single–console control and evaluation capability. Plant operating commands can be initiated either from the operator or directly from plant operating software contained in the operational control system computer.

About 2,000 continuous, discrete measurements from throughout the plant are transmitted to the MCS and recorded. Operating data and alarms are displayed on control consoles and on graphic displays (CRTs). Additionally, plant piping and instrumentation diagrams are displayed with live–time process parameters and valve operating configurations indicated for system status.

The MCS consists of five Modcomp Classic 7863 computers:

OCS —Operational Control System which provides a console for single operator control;

DAS —Data Acquisition System which records selected control and monitoring data;

HAC —Heliostat Array Controller which supervises the collector field. Two Modcomp units are utilized. One provides full redundancy for the other; and

BCS —Beam Characterization System which is used for heliostat alignment and evaluation.

The SDPC consists of three Beckman MV–8000 distributed digital control systems which are located in the control room. The balance of the hardware includes twenty-one Beckman analog/digital controllers which are located in remote stations. The SDPC allows the operator to manually control systems on an independent basis.

The ILS contains the interlock logic and plant permissives required to safely operate the plant. This computer will verify the plant and/or selected equipment status prior to executing a command. The ILS will also shutdown equipment in the event certain permissives are not satisfied. Red Line Units (RLU) provide safety monitoring and control of the receiver and thermal storage systems to assure shutdown of the systems when criteria for safe operation are exceeded.

Figure 2–6 is a schematic of the principal elements of the plant control system and its interfaces with other plant elements.

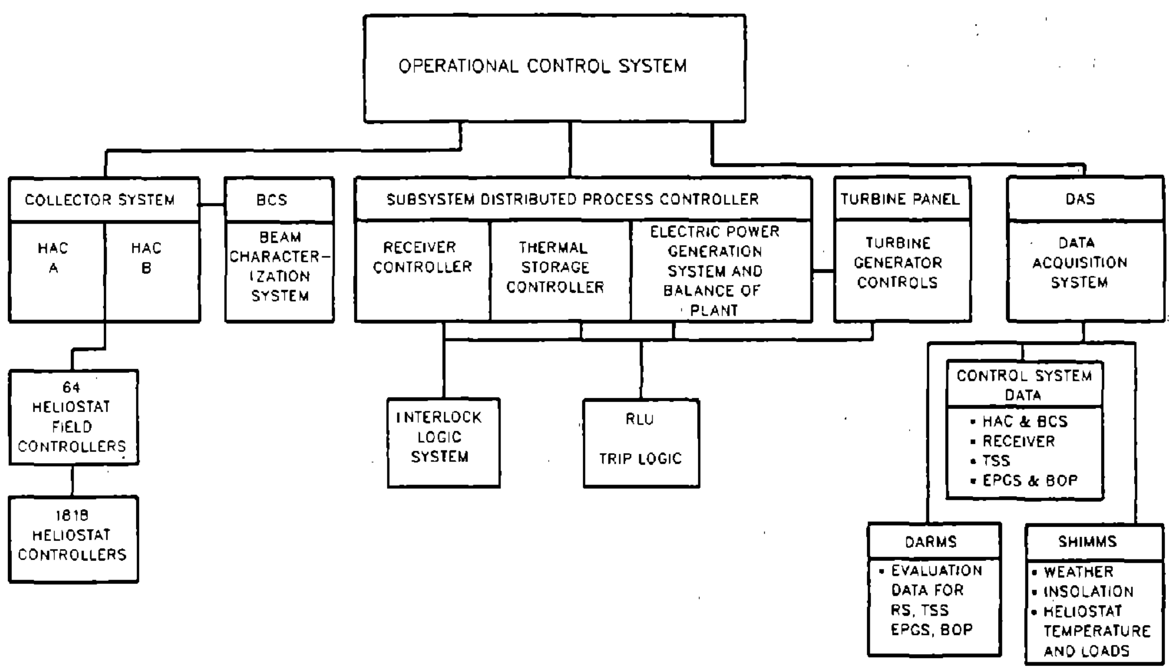


Figure 2—6. Plant Control System Elements

Beam Characterization System

The beam characterization system consists of tower–mounted targets, video cameras, heat flux sensors, and supporting and display equipment. The system measures the location, shape, and brightness of the reflected image and compares the data to an expected image for each heliostat. The resulting data are used for heliostat alignment, updating the heliostat tracking equation, evaluating the performance of the collector field, and the detection of heliostat anomalies.

The system includes four television cameras which view the heliostat beam images on target panels. These cameras are located along each of the four spoke roads in the heliostat field as shown in Figure 2–7. There are four target panels located on the tower, directly beneath the receiver. Controls for the beam characterization system permit individual heliostats (determined from a preselected list) to be focused on target panels at three times during the day. The camera detects the reflected image on the target. The system is designed to evaluate the entire heliostat field in about one month.

Electric Power Generation System

The electric power generation system is made up of steam Rankine cycle power plant equipment, including the turbine–generator, condensate/feedwater equipment, circulating and cooling water systems, auxiliary steam system, condensate polishing system, chemical analysis/feed system, compressed air system, sampling system, and electrical distribution network.

The turbine is a single casing, single–flow, automatic admission condensing unit produced by General Electric. It is rated at 12.5 MW_e at a 2.5 in Hg back pressure when operating with inlet steam conditions (from the receiver) of 1,465 psia (10.1 MPa) and 950°F (510°C). When operating on admission steam at 385 psia (2.65 MPa) and 525°F (274°C),the turbine will generate 7.8 MW_e at a 2.5 in Hg back pressure. The rated turbine cycle, thermal–to–electric efficiency is 35% from receiver steam and 25% from thermal storage steam.

The cycle includes four feedwater heaters for regeneration purposes and three major pumps: the condensate pump which draws from the hotwell, and the receiver and thermal storage feed pumps, both of which draw from the deaerator.

Heat rejection is accomplished by means of a wet cooling tower located beyond the southern edge of the collector field. Circulating water absorbs heat from the condenser and cooling water heat exchanger and rejects it to the atmosphere through the cooling tower. The heat rejection equipment is designed to dissipate 95×10^6 Btu/hr (27.8 MW_t).

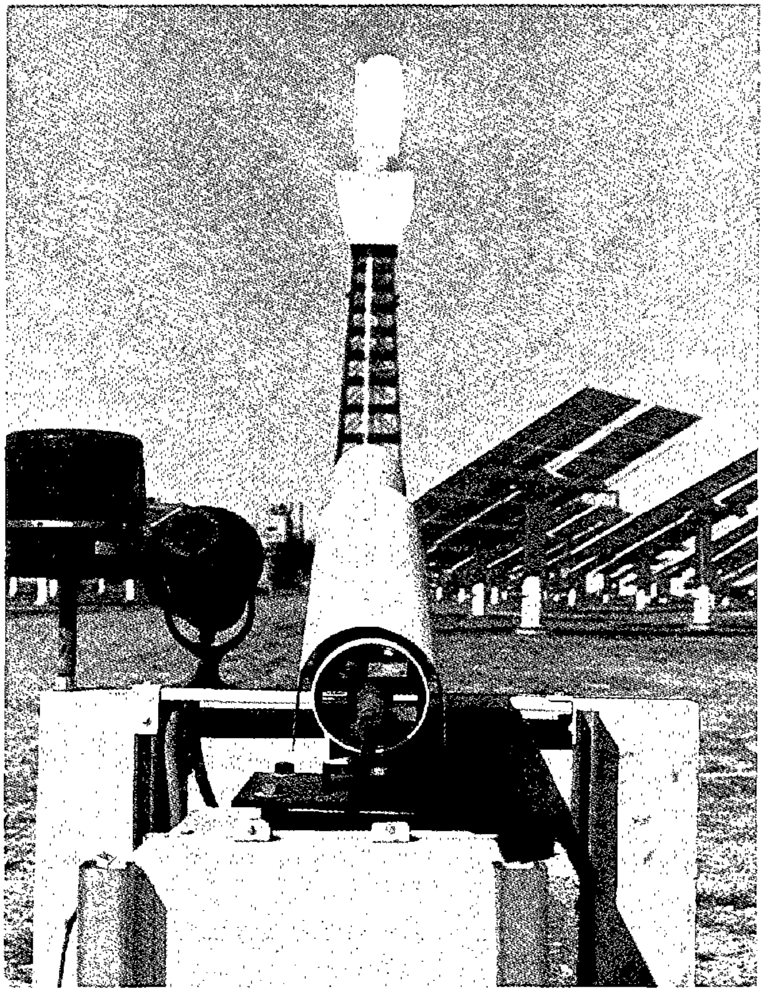


Figure 2—7. Beam Characterization System Camera

Plant Support System

The plant support system includes most of the balance of the plant hardware including site structures, buildings and facilities, and facility services as follows:

Site Structures:

- pipe racks and equipment foundations required for component support.

Major buildings and facilities:

- an administration building, which contains areas and facilities for plant management, visitor control, and technical support for the Pilot Plant;

- a turbine–generator area, which contains the turbine–generator, associated steam, feedwater and electrical equipment and a control building which contains the necessary consoles and electronic equipment to permit centralized control of the plant through the MCS;
- electronic termination shelters and electrical equipment building;
- a warehouse building for the receiving and storage of equipment, spare parts and materials for plant servicing;
- a guardhouse for plant security;
- weather monitoring equipment used for operating information and to supply data for historical records;
- a pump house, which contains the primary fire pump, water treatment pumps, a motor control center, and foam tanks;
- a diesel fire pump building;
- a visitor's center near the plant site; and
- a heliport near the plant site.

Support systems:

- raw water
- fire protection
- demineralized water
- cooling water
- nitrogen
- compressed air
- liquid waste
- oil supply, and
- lightning protection.

Operating Modes

The Pilot Plant can be operated in eight steady-state operating modes. Different operative process flow paths between the plant's collector, receiver, thermal storage, and electric power generation systems characterize each mode (see Figure 2-8). The modes are described as follows:

Mode 1 – Turbine Direct

In the turbine direct mode, all steam generated by the receiver passes directly to the turbine-generator, bypassing the thermal storage system. The turbine direct mode is the most efficient mode for power production, and it is used on clear days when thermal storage unit charging is not required.

Mode 2 – Turbine Direct and Charging

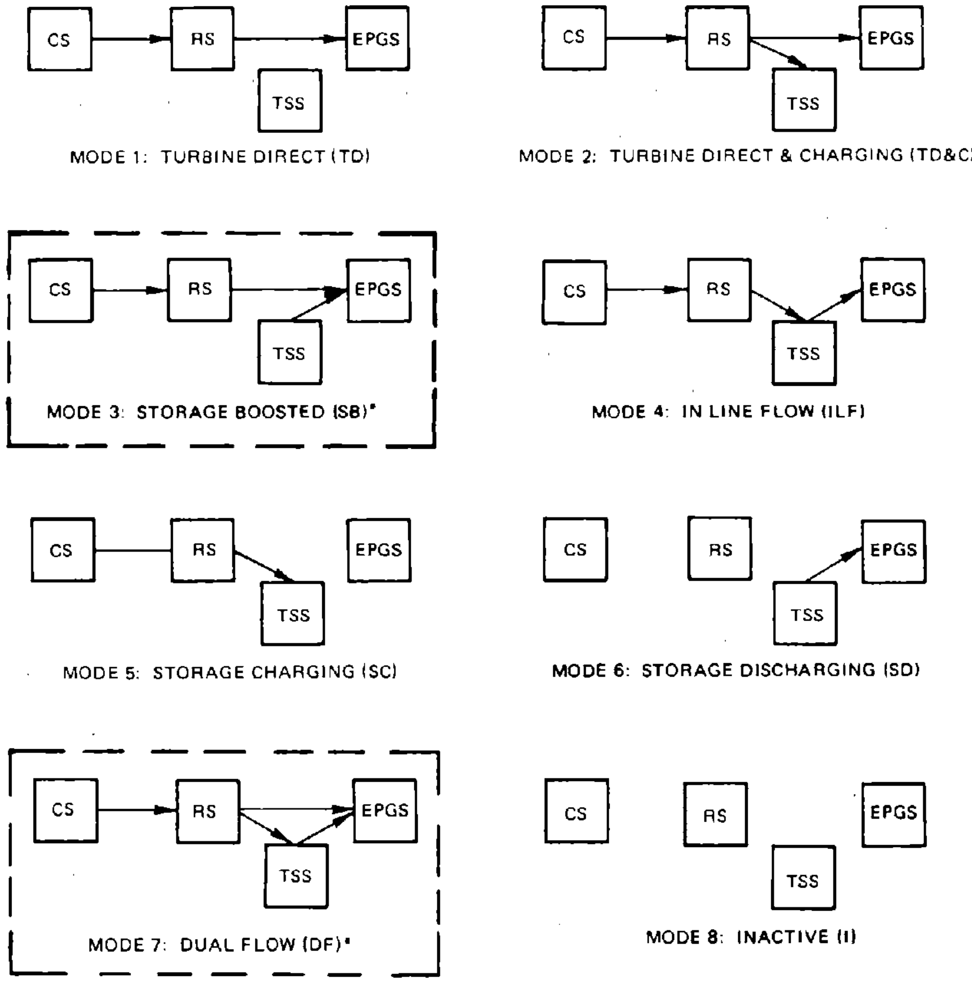
In the turbine direct and charging mode, receiver steam is directed simultaneously to the turbine-generator and to the thermal storage system. This operating mode would be used at midday on a clear day when the available solar energy exceeds the maximum capability of the turbine.

Mode 3 – Storage-Boosted

In the storage-boosted mode, steam generated by the thermal storage system is used to supplement the steam generated in the receiver. This mode could be used on a clear day during early morning and late afternoon, when the available solar energy is less than the maximum capability of the turbine.

Mode 4 – In-Line Flow

In the in-line flow mode, steam from the receiver is used to charge the thermal storage system, which then generates steam for the turbine-generator. Operating in the in-line flow mode enhances the unit's tolerance of cloud transients. Due to limitations on the temperature of the heat transfer oil and the temperature differences across the heat exchangers, plant efficiency and maximum power output are less than for Mode 1.



Mode 1	Turbine Direct:	Receiver-generated steam directly powers the turbine.
Mode 2	Turbine Direct and Charging:	Receiver-generated steam powers the turbine and charges storage.
Mode 3	Storage Boosted:	Steam from the receiver and storage powers the turbine.
Mode 4	In-Line Flow:	Receiver steam charges storage, while storage steam is stimultaneously discharged powering the turbine.
Mode 5	Storage Charging:	Receiver steam charges the storage system.
Mode 6	Storage Discharging:	Steam generated by the storage system is used to power the turbine.
Mode 7	Dual Flow	A combination of Modes 2 and 3 (probably only achieved during transitions).
Mode 8	Inactive	Major systems are standing by for operation.

*Engineering Test and Transitory Modes

Figure 2—8. Operating Modes

Mode 5 – Storage Charging

In the storage charging mode, the turbine–generator is not in operation. All steam generated in the receiver is delivered to the thermal storage system.

Mode 6 – Storage Discharging

In the storage discharging mode, the heliostats and receiver are not in operation and the thermal storage system generates steam for use in the turbine–generator. This mode would be used on overcast days or at night.

Mode 7 – Dual Flow

In the dual–flow mode, the receiver delivers steam to both the turbine–generator and the thermal storage system. Simultaneously, the thermal storage system directs steam to the turbine–generator. This mode can be used on cloudy days since it allows the thermal storage system to dampen transients caused by passing clouds.

Mode 8 – Inactive

In the inactive mode, none of the systems, except those used for the generation of auxiliary steam, are in operation.

References

2-1. "Pilot Plant Station Manual (RADL Item 2-1), Volume 1, System Description," prepared by McDonnell Douglas Astronautics Company under Department of Energy Contract DE-AC03-79SF10499, revised September 1982.

Operating Data

Pilot Plant Operating Data Display

3. OPERATING DATA

Overview

During the Power Production Phase, operating data were compiled for the Pilot Plant site insolation, plant availability, gross electrical output, net electrical output, and plant load. Plant availability was determined both with and without the effects of weather. The Pilot Plant achieved increases in availability and annual energy output during power production testing.

Barstow insolation data for 1976, used to establish the plant's design performance, were compared to the available data for 1984 to 1987. The data show that the annual direct normal insolation for 1984 to 1987 was always less than the 1976 insolation. The annual insolation improved during power production testing, however, and contributed to an improvement in annual energy output.

Overall availabilities, which include the effects of both weather and equipment outages, averaged 52, 60, and 54% during the the first, second, and third years of power production operation, respectively. A second availability value, named plant availability, because it only includes the effects of equipment outages, averaged 80, 83, and 82% over the same periods, respectively. The latter values are less than the design plant availability of 90%. Plant availability improved slightly during power production testing as the frequency of planned inspection periods was reduced and maintenance procedures were refined.

The gross energy productions for the first, second, and third years of power production operation were 11,754, 15,345, and 15,305 MW_e–hr, respectively. April to September were generally the best months for energy production.

The net energy productions for the first, second, and third years of power production operation were 7,024, 10,465, and 9,982 MW_e–hr (based on a 24-hr plant load).* The annual net energy production increased by 49% from the first to second year of power production operation. Energy production during the third year was slightly less than the second year production.

The plant loads for the first, second, and third years of power production operation were 4,731, 4,880, and 5,323 MW_e–hr, respectively. The monthly plant load averaged 394, 407, and 444 MW_e–hr, respectively, over the same periods. Plant load remained relatively constant during the first two years of power production operation even though the plant's gross output increased significantly. The plant load increased about 10% during the third year because an electric

* Net energy production is obtained by subtracting the 24–hour plant load from the gross energy production. The 24–hour plant load is the energy needed to supply the plant's parasitic load for twenty-four hours per day.

boiler rather than the thermal storage system was used to generate auxiliary steam. Overall, the plant load has decreased since Pilot Plant testing began, reflecting successful efforts by SCE to reduce the plant's parasitic power requirements.

Introduction

During power production operation, data were compiled for the site insolation, plant availability, gross electrical output, net electrical output, and plant load. Plant availability was determined both with and without the effects of weather.

This chapter presents monthly and annual values for the data. The next chapter discusses the effect of actual plant conditions, such as insolation, plant availability, heliostat cleanliness, etc., on the annual plant electrical output.

Direct Normal Insolation

Daily averages of the direct normal insolation have been tabulated for 1976 SCE Barstow data,* 1984, 1985, 1986, and 1987 Pilot Plant data, and a set of 25-year average values that were estimated from total global data (see Table 3-1). The SCE Barstow and Pilot Plant data were obtained by integrating the value of direct normal insolation from horizon to horizon, as recorded by a normal incidence pyrheliometer. (For a detailed discussion of the Pilot Plant meteorological equipment and instrumentation and the data for 1982 to 1984, see References 3-1 to 3-4.)

For 1984, insolation was lower than the 1976 values for all months except September and was lower than the 25-year average values for all months except January, February, and October. A comparison of 1984 and 1976 indicates that the total available direct normal insolation for 1984 was 17% less than 1976.

For 1985, insolation was lower than the 1976 values for all months except September and was lower than the 25-year average values for all months except January, February, August, October, and December. A comparison of 1985 and 1976 indicates that the total available direct normal insolation for 1985 was 11% less than 1976.

For 1986, insolation was lower than the 1976 values for all months except July and September and was lower than the 25-year average values for all months except January and November. A comparison of 1986 and 1976 indicates that the total available direct normal insolation for 1986 was 12% less than 1976.

* These data were used originally to derive the performance goals for the Pilot Plant and are thus a baseline for evaluating plant performance based on the actual insolation data for 1984 to 1987.

Table 3-1
Daily Average Direct Normal Insolation Data

		Daily Average Insolation (kW-hr/m²)				
Month	1976[a]	25-year[b] average	1984	1985	1986	1987
JAN	7.10	4.87	5.61(31)[c]	5.40(30)	5.16(31)	5.44(30)
FEB	6.15	5.51	5.86(29)	6.04(28)	5.47(28)	5.17(28)
MAR	7.33	6.60	6.27(31)	5.52(31)	5.94(31)	6.35(31)
APR	8.00	8.01	7.39(30)	7.65(30)	7.36(30)	7.14(30)
MAY	8.95	8.69	8.57(31)	8.35(31)	8.56(31)	7.13(31)
JUN	10.56	9.39	8.11(30)	8.96(30)	8.91(30)	8.62(30)
JUL	8.23	8.76	5.76(31)	7.11(31)	8.27(31)	8.49(31)
AUG	10.13	8.32	6.82(30)	9.21(31)	7.52(31)	NA[d]
SEP	5.78	7.59	7.15(30)	7.29(30)	7.38(30)	NA
OCT	7.47	6.65	6.77(31)	6.72(31)	6.58(31)	NA
NOV	7.19	5.52	5.21(30)	5.52(30)	6.23(30)	NA
DEC	6.40	4.83	3.61(31)	5.13(31)	4.45(31)	NA
ANNUAL	7.78	7.07	6.42	6.91	6.82	NA

a. C. M. Randall, "Barstow Insolation and Meteorological Data Base," The Aerospace Corporation, Report ATR-78(7695-05)-2, March 13, 1978.

b. "Direct Normal Solar Radiation Data Manual," Solar Energy Research Institute, SERI/SP-281-1658, October 1982. (These direct normal insolation values are estimated from total global data.)

c. The number in parenthesis is the number of days that data were recorded and analyzed. Comparable numbers for 1976 are not available.

d. Not available.

A comparison of 1987, 1976, and the 25-year average data, considering only the 1987 days when data were recorded and analyzed, indicates that the 1987 insolation was lower than the 1976 average values for all months except July. The 1987 values were lower than the 25-year average values for all months except January. Considering the time period of January through July where 1987 data were available and comparing these data to 1976 data for the same number of days, the 1987 total available direct normal insolation was 14% less than 1976 insolation.

The data in Table 3-1 were combined to derive daily average values for the first, second, and third years of power production operation. The daily average insolation was 6.55, 6.97, and 6.72 kW-hr/m² for the first, second, and third years of power production operation, respectively. Figure 3-1 shows these data along with the values for 1976 and the 25-year average. The insolation values for the second and third years of power production operation were greater than the first year value but remained below both the 1976 design and 25-year average values. The insolation values recorded during the first, second, and third years of power production operation are 16, 10, and 14%, respectively, less than the 1976 insolation value.

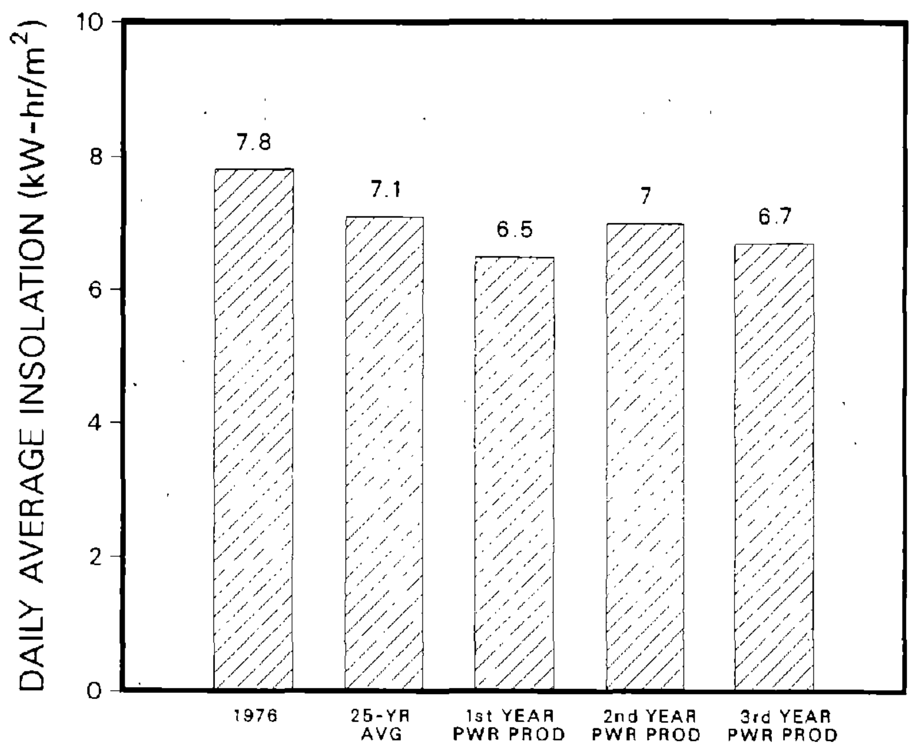


Figure 3–1. Daily Average Direct Normal Insolation

Plant Availability

Availability was assessed to determine the effects of weather outages and mechanical equipment outages on system performance. Two availabilities were calculated: (1) an overall availability which includes the effects of both weather and equipment outages; and (2) a plant availability which only includes the effects of equipment outages.

Availability Definitions

The availability calculations for the Power Production Phase were based on the following definitions:

$$OA(PWR) = \frac{PWRHR + TSSHR}{PWRHR + TSSHR + SCHED + UNSCHED + WEATH - OVER}$$

$$PA(PWR) = \frac{PWRHR + TSSHR}{PWRHR + TSSHR + SCHED + UNSCHED - OVER}$$

where

- OA(PWR): overall availability for the Power Production Phase
- PA(PWR): plant availability for the Power Production Phase
- PWRHR: power hours, that is, the time during which the turbine was connected to the grid
- TSSHR: storage charging hours, that is, the time during which the thermal storage system was being charged
- SCHED: scheduled maintenance outage hours, that is, the daylight hours during which scheduled maintenance prevented power production or storage charging
- UNSCHED: unscheduled maintenance outage hours, that is, the daylight hours during which unscheduled maintenance prevented power production or storage charging
- WEATH: weather outage hours, that is, the daylight hours during which weather prevented plant operation
- OVER: overlap outage hours, that is, the overlap in weather and maintenance outages

For the purpose of tabulating these hours, the following procedures were used: (1) for days in which an early morning or sunrise start-up was planned, maintenance and weather outage hours were recorded over a daylight time period that begins 45 minutes after sunrise and ends 45 minutes before sunset. The 45 minute periods at the start and end of the day were not used because operating experience showed that these periods had little effect on the plant operations. That is, to say, during these periods the insolation levels were too low and collector field cosine and blocking and shadowing losses were too high to have much effect on the start-up and shutdown characteristics of the plant. The 45 minute periods were not used for days with planned mid-day starts since insolation levels are much higher during mid-day. In general, all clear day start-ups initiated later than 2 hours after sunrise were of the mid-day type; (2) for days in which maintenance and weather outages overlap, the overlapping period of the outage is considered to be a weather outage; and (3) for days in which the power production and storage charging hours overlap the overlapping period is considered to be a power production period. The overlapping rarely occurred because the plant was primarily operated in Modes 1 and 5.

Availability Results

Figure 3-2 shows the overall and plant availabilities for the Experimental Test and Evaluation Phase and the first, second, and third years of power production operation. The overall availabilities averaged 44, 52, 60, and 54%, respectively. The combined effects of bad weather and equipment outages were evident for the winter months, the months generally with the lowest overall availabilities. The

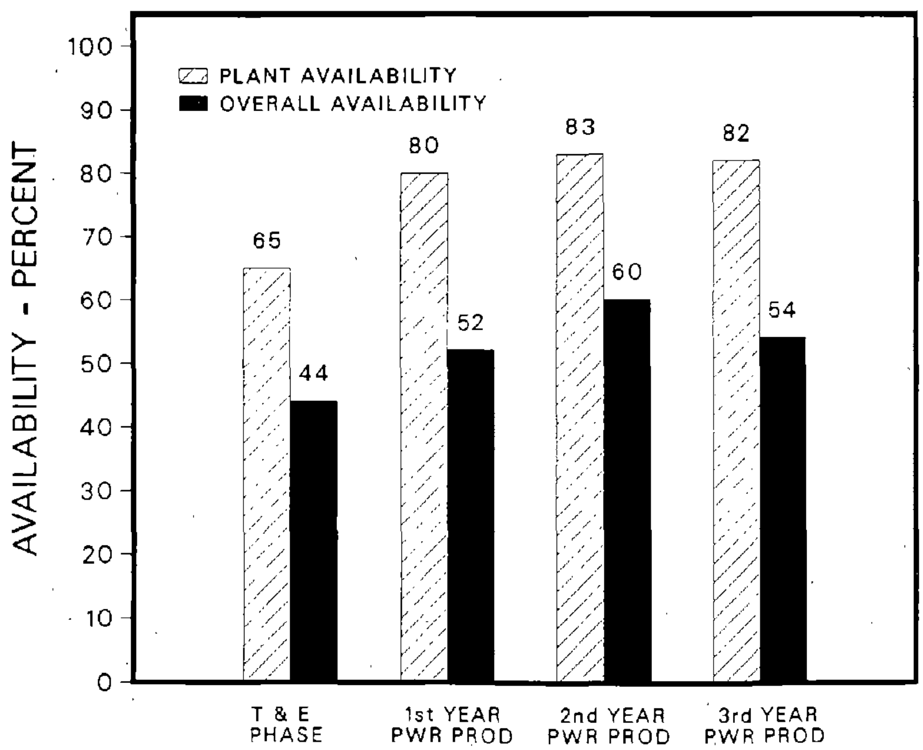


Figure 3—2. Pilot Plant Availability With and Without the Effects of Weather

contribution of bad weather is evident from these values because plant availability is considerably higher: over the same time periods, plant availability averaged 65, 80, 83, and 82%, respectively. The values for power production operation are only slightly less than the design plant availability of 90%. The improvements in the overall and plant availabilities resulted from better weather, fewer planned inspections, and improved maintenance procedures during Pilot Plant testing.

Plant Generating Statistics

The monthly and cumulative gross MW_e–hr, net MW_e–hr, and 24-hour plant load in MW_e–hr have been compiled for the first, second, and third years of power production operation (see Figures 3–3 to 3–8).

Gross Energy Production

The cumulative gross energy productions for the first, second, and third years of power production operation were 11,754, 15,345, and 15,305 MW_e–hr, respectively. Generally, the best months for production were April to September due to favorable weather conditions and long operating days. A peak monthly output of 2,262 MW_e–hr was achieved during August 1985. Energy output for February 1985 was nearly zero due to a scheduled maintenance outage. Energy output was low in June 1986, a good weather month, due to an unscheduled maintenance outage for receiver tube leak repairs.

Net Energy Production

The cumulative net energy productions for the first, second, and third years of power production operation were 7,024, 10,465, and 9,982 MW_e–hr, respectively, (based on a 24-hr plant load). Net energy production increased by 49% from the first to second year of power production operation. Energy production during the third year was slightly less than the second year production. The net energy productions for December 1984, February 1985, March 1985, and January 1987 were negative due to maintenance outages or poor weather.

Plant Load

The cumulative 24-hour plant loads for the first, second, and third years of power production operation were 4,731, 4,880, and 5,323 MW_e–hr, respectively. The monthly plant load averaged 541 MW_e–hr during the Experimental Test and Evaluation Phase and 394, 407, and 444 MW_e–hr during the first, second, and third years, respectively, of the Power Production Phase. Plant load remained relatively constant during the first two years of power production operation even though the plant's gross output increased significantly. The plant load increased about 10% during the third year because an electric boiler rather than the thermal storage system was used to generate auxiliary steam. Overall, the plant load has decreased since Pilot Plant testing began, reflecting successful efforts by SCE to reduce the plant's parasitic power requirements.

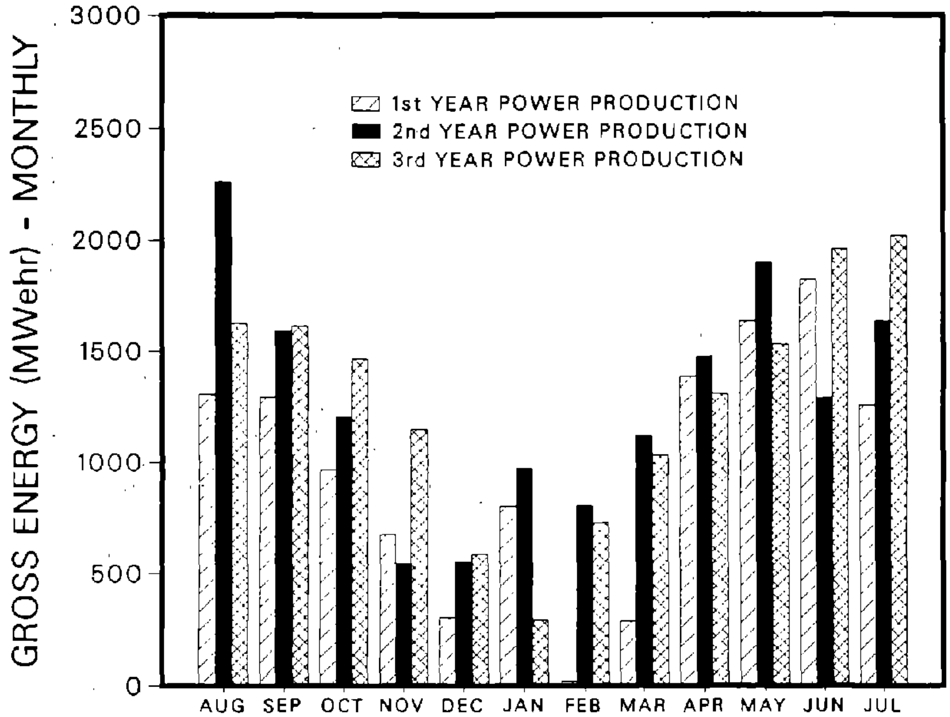


Figure 3—3. Pilot Plant Monthly Gross Energy Production

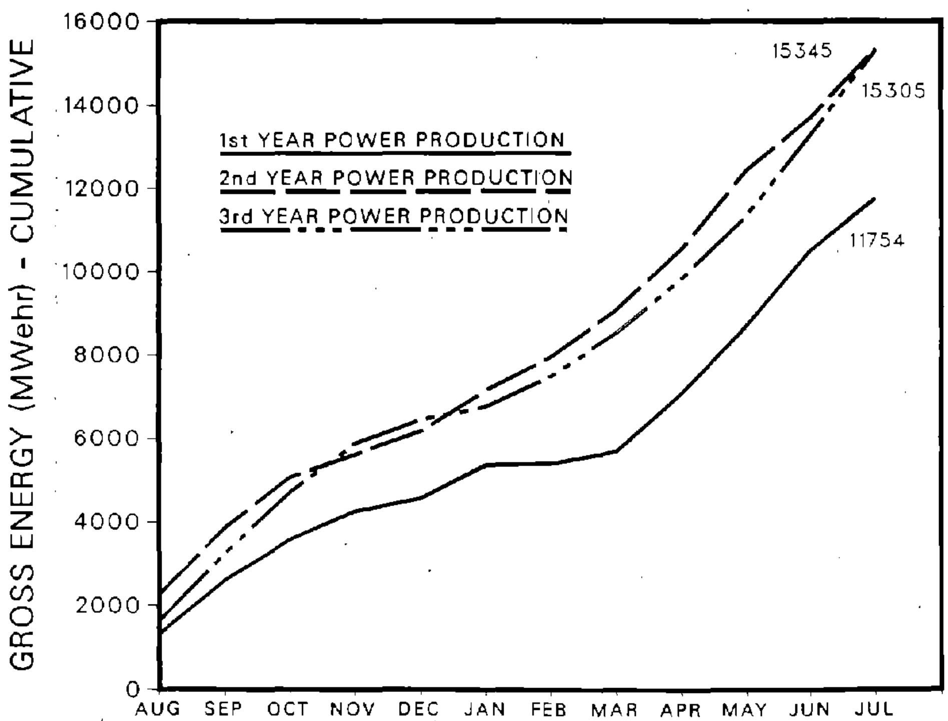


Figure 3—4. Pilot Plant Cumulative Gross Energy Production

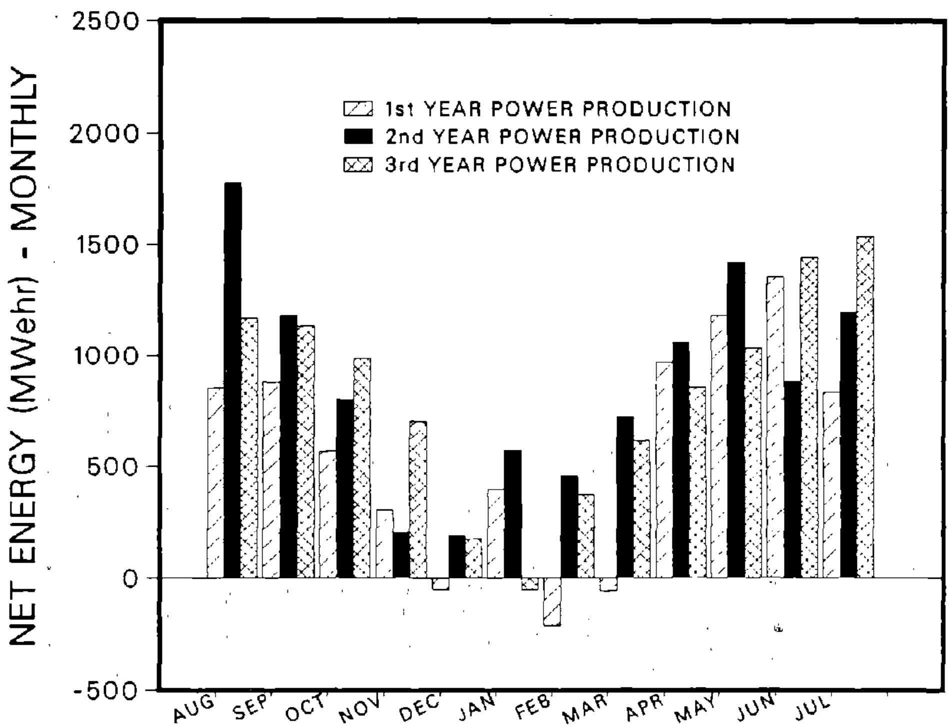


Figure 3—5. Pilot Plant Monthly Net Energy Production

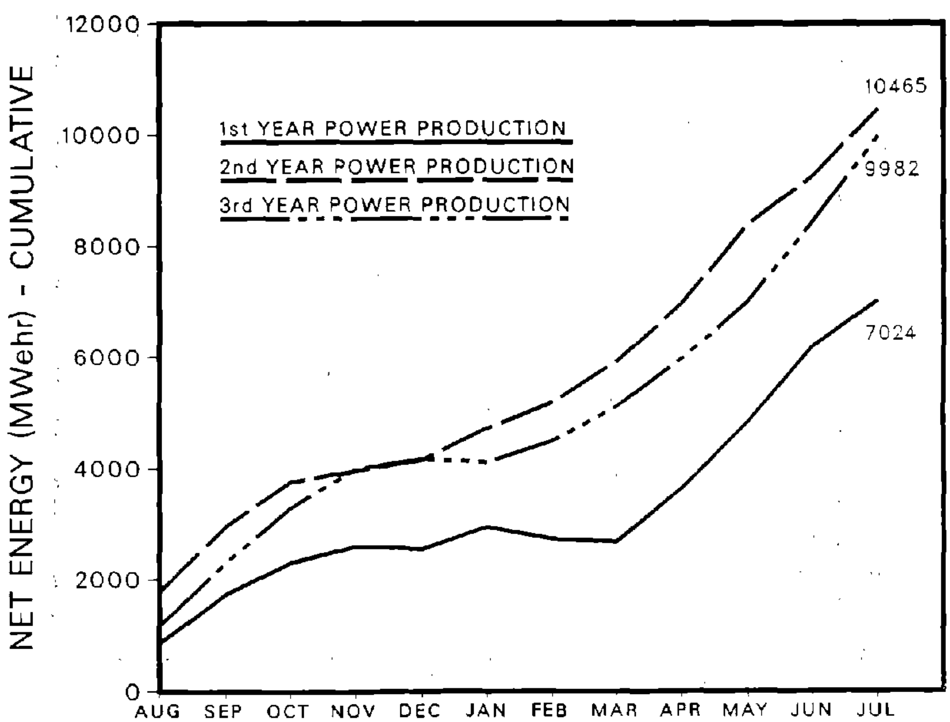


Figure 3—6. Pilot Plant Cumulative Net Energy Production

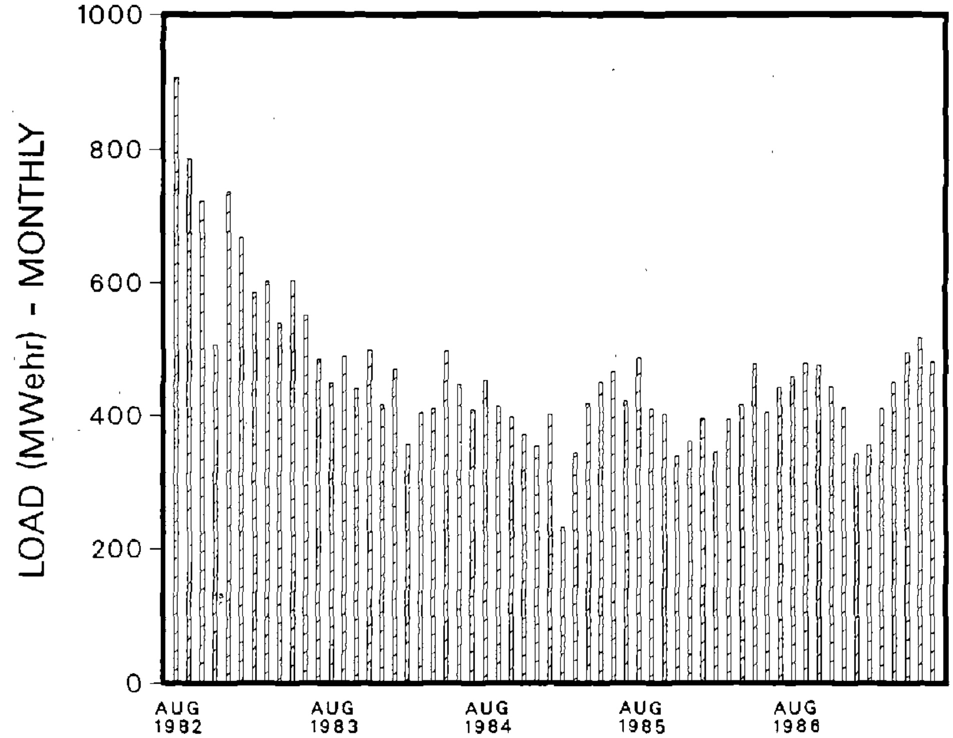


Figure 3—7. Pilot Plant Monthly 24-Hour Load

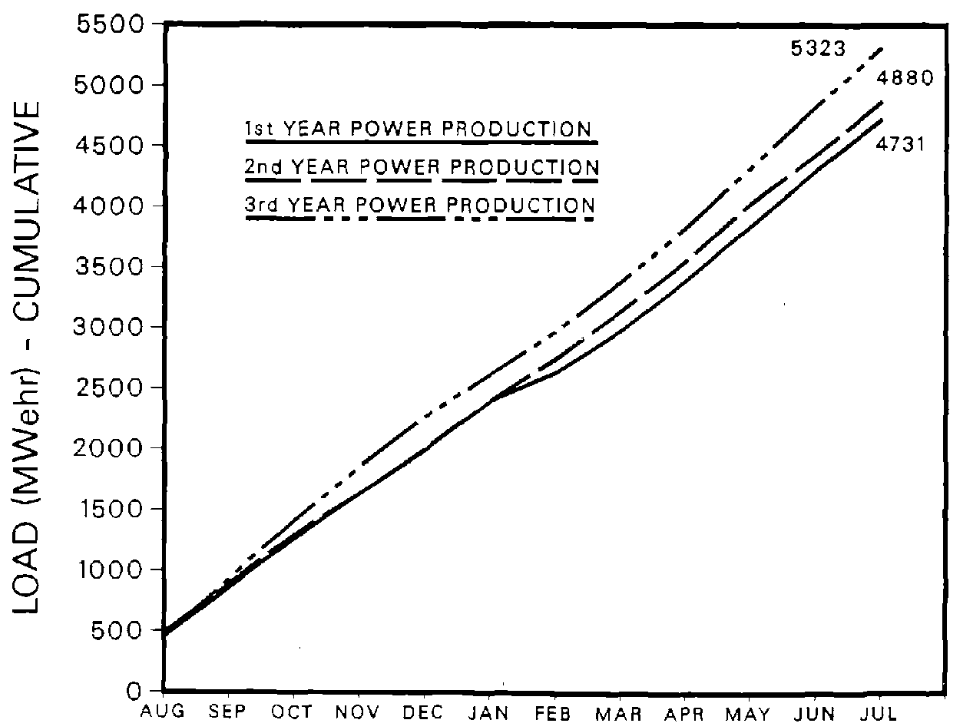


Figure 3—8. Pilot Plant Cumulative 24-Hour Load

References

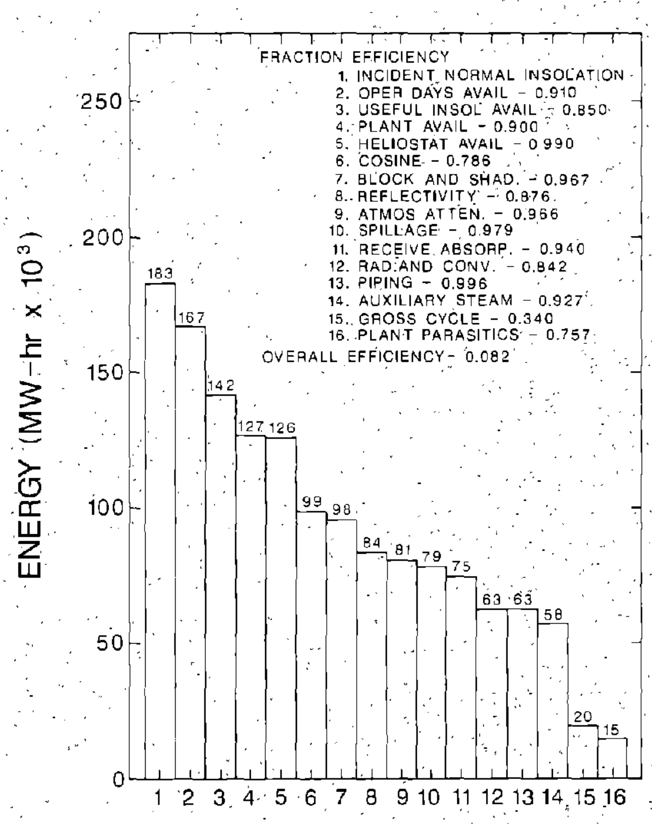
3–1. L. G. Radosevich, "Final Report on the Experimental Test and Evaluation Phase of the 10 MW_e Solar Thermal Central Receiver Pilot Plant," Sandia National Laboratories, SAND85-8015, 1985.

3–2. "Solar One Solar Thermal Central Receiver Pilot Plant 1982 Meteorological Data Report," McDonnell Douglas Astronautics Company, contractor report SAND83-8216, 1983.

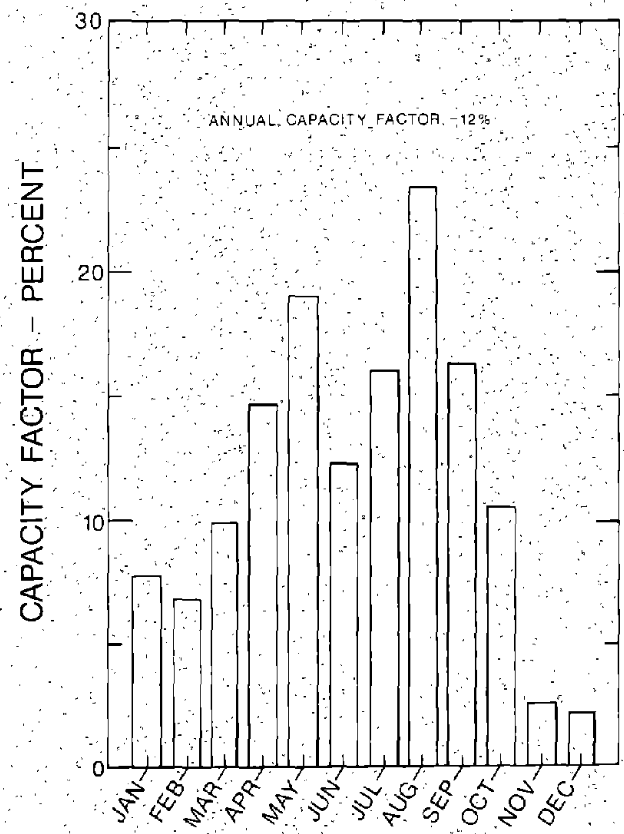
3–3. "Solar One Solar Thermal Central Receiver Pilot Plant 1983 Meteorological Data Report," McDonnell Douglas Astronautics Company, contractor report SAND84-8180, 1984.

3–4. "Solar One Solar Thermal Central Receiver Pilot Plant 1984 Meteorological Data Report," McDonnell Douglas Astronautics Company, contractor report SAND86-8181, 1986.

System Performance



PILOT PLANT SYSTEM EFFICIENCY AND ANNUAL ENERGY GOALS



PILOT PLANT MONTHLY CAPACITY FACTOR FOR THE 2nd YEAR OF POWER PRODUCTION

Typical Pilot Plant System Performance Indicators: (1) Stairstep Annual Energy Production and System Efficiency Goals; and (2) Actual Monthly and Annual Capacity Factors for the Second Year of Power Production Operation

4. SYSTEM PERFORMANCE

Overview

During power production operation system performance data were recorded and analyzed for the plant's daily, monthly, and annual operation. The data show that almost all of the Pilot Plant performance goals were met. Performance goals pertaining to power output (megawatts of electricity) were all met or exceeded. Parasitic power needs were successfully reduced during the course of testing and were significantly less than the plant design values.

The Pilot Plant did not meet its energy production (megawatt–hours of electricity) goals. The system performance goals for the Pilot Plant are an annual capacity factor of 17% and an annual system efficiency of 8.2% (corresponding to an annual energy output of 15,000 MW_e–hr net).* The plant's capacity factor averaged 8, 12, and 11% during the first, second, and third years of power production operation, respectively. The system efficiency was 4.1, 5.8, and 5.7% over the same periods. The two performance factors increased considerably during power production testing, but further increases are desirable.

The plant operating data showed that some design assumptions used to derive the system performance goals were too optimistic for this first–of–a–kind plant, at least during its infant years of operation. Additional operating and maintenance improvements in the areas of plant availability and heliostat cleanliness, as well as improved insolation, are required to reach the performance goals. The implementation of these improvements in future plants, along with the use of advanced central receiver technologies like molten salt and liquid sodium, should significantly improve the annual energy production of future power plants relative to the Pilot Plant.

* The annual capacity factor and annual energy production are not independent variables. Specifying one of these automatically defines the other. Values for both terms are often presented here.

Introduction

The Pilot Plant's actual and predicted performances were analyzed to identify areas where further improvements in performance may be made. Three measures of system performance were analyzed: capacity factor, system efficiency, and output factor. This chapter describes monthly and annual values for the three factors during power production operation. The actual annual values are compared to predicted values, and the impact of actual plant conditions on the values is analyzed. Procedures are identified to improve system performance and reach the predicted values.

System Performance Predictions

Daily Operation

When the Pilot Plant was being designed several performance goals were specified pertaining to its daily power and energy production. The goals were:

(1) the delivery of 10 MW_e net when operating solely from insolation for a period of at least 4 hours on the least favorable day of the year (winter solstice–December 21);

(2) the delivery of 10 MW_e net when operating solely from insolation for a period of at least 7.8 hours on the most favorable day of the year (summer solstice–June 2l);

(3) the delivery of 7 MW_e net when operating from thermal storage; and

(4) the delivery of 28 MW_e–hr net when operating from thermal storage.

Annual Operation

In addition to the performance goals specified for the Pilot Plant's daily operation, predictions were made for the plant's capacity factor and system efficiency. These predictions were derived to provide an indication of the plant's expected annual performance.

Capacity factor is the plant's actual net electrical output divided by its rated net output over a 24–hour period. Capacity factor is a commonly used electric utility term and is a measure of the energy generating potential of the plant. A plant which experiences a capacity factor significantly less than its design value will be unable to generate sufficient revenue to recover its capital and operating and maintenance expenses, as well as providing a profit for its investors.

The capacity factors for several solar central receiver electric plant designs have been estimated to be 20–70%. The low end of this range corresponds to plants with little or no thermal energy storage while the high end corresponds to plants with significant storage (e.g., greater than 10 hours) and/or a fossil–fueled backup energy source.

System efficiency is the plant's actual net electrical output (based on a 24–hour plant load) divided by the direct insolation incident on the collector field reflective surface. System efficiency is a measure of a plant's capability to convert sunlight into electrical energy.

Plant designs with high system efficiencies are desirable in order to maximize the use of the solar energy resource. The annual system efficiencies for several solar central receiver electric plant designs have been estimated to be 11–15% (Reference 4–1). The low end of this range is typical for a small plant like the Pilot Plant which, because of its size: (1) uses a relatively large portion of its output for parasitic energy needs; and (2) cannot use a more efficient turbine technology. The more efficient reheat steam turbines are only available in large plant sizes.

The high end of the range is an estimate for a large solar central receiver plant, typically 100 MW_e in size. Such a plant would use advanced technologies, such as molten salt or liquid sodium working fluids, as well as the high–efficiency, reheat, steam Rankine cycles.

Early predictions of the annual capacity factor and system efficiency were made at the beginning of the Pilot Plant's preliminary design (Reference 4–2). These predictions were optimistic values because they were based on the design value for the receiver absorptance and assumed a 100% annual availability of plant equipment. With these ideal assumptions and others, an annual capacity factor of 30% (corresponding to an energy production of 26,000 MW_e–hr net) and a system efficiency of 13% were predicted for the plant, based on an available incident insolation of 202 x 10^3 MW–hr (1976 insolation data).

Recent predictions of the two performance factors have been made using more realistic plant conditions (Reference 4–3). The substitution of these plant conditions for the values used in the early predictions lowers the capacity factor and system efficiency considerably. The current predictions for the Pilot Plant are a capacity factor of 17% (corresponding to an energy production of 15,000 MW_e–hr net) and a system efficiency of 8.2%. A comparison of the initial and current predictions for these performance factors is described below.

Initial and Current Predictions

The initial and current annual efficiency and annual energy predictions are summarized for the Pilot Plant in Table 4-1 and Figure 4-1. The initial predictions for efficiency and energy production are taken from Reference 4-2. The current predictions are based on measured plant data or projected improvements to several key plant factors, such as plant availability, mirror reflectance and receiver absorptance, which affect efficiency and energy output. The initial and current values for each factor are discussed below.

<u>Incident Normal Insolation</u>—The initial annual energy value of 202 x 10^3 MW-hr is based on insolation data collected in Barstow during 1976. The current value of 183 x 10^3 MW-hr is based on a 25-year average value. The 25-year value, which is 9.4% less than the 1976 insolation value, was selected to derive the current prediction because it is more representative of a typical operating year.

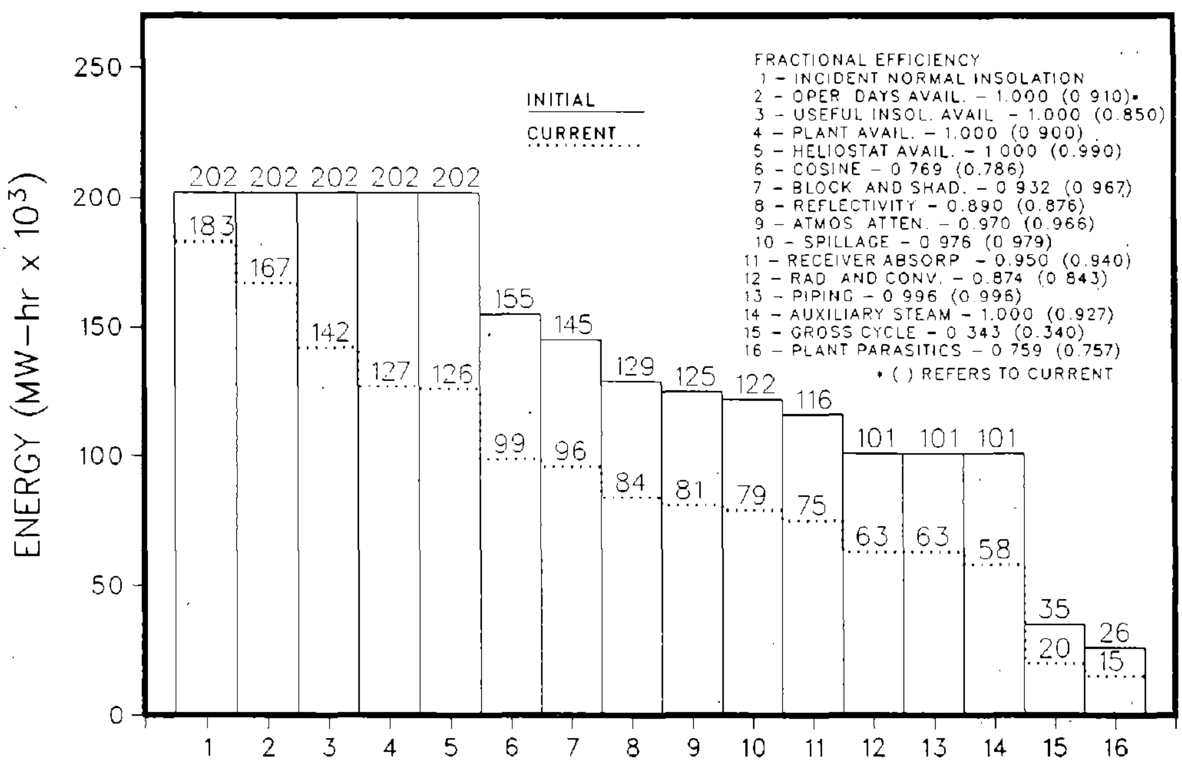


Figure 4-1. Comparison of Initial and Current Pilot Plant System Efficiency and Annual Energy Predictions

Table 4-1
Comparison of Initial and Current Pilot Plant System Efficiency and Annual Energy Predictions

Item	Initial Efficiency (Fraction)	Initial Energy (MW-hr x 10^3)	Current Efficiency (Fraction)	Current Energy (MW-hr x 10^3)
Incident Normal Insolation		202		183
Operating Days Availability	1.000	202	0.910	167
Useful Insolation Availability	1.000	202	0.850	142
Plant Availability	1.000	202	0.900	127
Heliostat Availability	1.000	202	0.990	126
Cosine	0.769	155	0.786	99
Blocking and Shadowing	0.932	145	0.967	96
Reflectance	0.890	129	0.876	84
Atmospheric Attenuation	0.970	125	0.966	81
Spillage	0.976	122	0.979	79
Receiver Absorptance	0.950	116	0.940	75
Radiation and Convection	0.874	101	0.843	63
Piping	0.996	101	0.996	63
Auxiliary Steam	1.000	101	0.927	58
Gross Cycle	0.343	35	0.340	20
Plant Parasitics	0.759	26	0.757	15
Overall	0.130	26	0.082	15

Operating Days Insolation Availability—Operating days insolation availability refers to the fraction of the annual horizon-to-horizon insolation that is available on the days when the plant was operating or could have operated. The difference between the total (365 day) horizon-to-horizon insolation and the operating days insolation is the insolation occurring on the plant's non-operating days — that is, days when insolation levels were too low or wind speeds were too high. For 1984, the operating days insolation was estimated to be 2080 kW-hr/m^2 (Reference 4-4). This value corresponds to an operating days insolation availability of 0.887. A slightly higher availability of 0.91, which was assumed to be representative of a better weather year, was used for the current prediction, while an availability of 1.0 was assumed for the initial prediction.

Useful Insolation Availability—Useful insolation is the insolation above 500 W/m^2 that is available on the plant's operating days. An insolation level of at least 500 W/m^2 is desirable for Pilot Plant operation although the plant has operated at levels less than this level. For 1984, the useful insolation was estimated to be 1733 kW-hr/m^2 (Reference 4-4). This corresponds to a useful insolation availability of 0.833. A slightly higher availability of 0.85, which was assumed to be representative of a better weather year, was used for the current prediction, while an availability of 1.0 was assumed for the initial prediction.

Plant Availability—In this analysis, plant availability refers to the fraction of daylight hours that the plant is available to operate, assuming good weather conditions. Thus, plant availability reflects scheduled and unscheduled plant maintenance outages but does not reflect weather outages. (Any overlap between maintenance and weather outages is considered to be a weather outage.) A plant availability of 1.0 was used for the initial annual energy prediction reported in Reference 4-2. The current value is based on a Pilot Plant design goal of 0.90 (Reference 4-5). Actual plant availability for power production operation has been slightly less than this value.

Heliostat Availability—Heliostat availability refers to the fraction of the heliostat field that is operational. For the initial prediction, a heliostat availability of 1.0 was used since all 1,818 heliostats were assumed to be operational for the entire year. The current value of 0.990 is based on an average daily outage of 18 heliostats which should be achievable with a vigilant maintenance program.

Cosine, Blocking and Shadowing—The current values for these factors were derived from MIRVAL computer calculations because no experimental confirmation of the values exists at this time. See Reference 4-6 for a description of MIRVAL.

Reflectance—Heliostat reflectances of 0.890 and 0.876 were used for the initial and current predictions, respectively. The actual average reflectance of the Pilot Plant heliostat field is 0.903 if the heliostats are perfectly clean. A reflectance of 0.876 corresponds to an average cleanliness of 97% (expressed as a percent of the clean field reflectance) and should be achievable with a bi-weekly wash program.

Atmospheric Attenuation and Spillage—The current values for these factors were derived from MIRVAL computer calculations because no experimental confirmation of the values exists at this time.

Receiver Absorptance—The design receiver absorptance is 0.95. The receiver absorptance was measured to be: November 1982 – 0.92; December 1983 – 0.90; September 1984 – 0.88; March 1986 – 0.97 (after repainting in December 1985); and October 1987 – 0.96. In this analysis a current value of 0.94 was assumed to be representative of the average effective absorptance which could be achieved by periodic repainting of the receiver surface.

Radiation and Convection—The radiation and convection efficiency in the initial prediction is based on a constant radiation and convection loss of 4.7 MW during receiver operation. The loss corresponds to an annual energy loss of about 15 x 10^3 MW–hr. An annual loss of 11.8 x 10^3 MW–hr was used for the current prediction. This loss was based on an annual receiver operation of 2350 hours and a 5 MW loss during operation. A comparable estimate of the receiver radiative and convective losses was reported in References 4–7 and 4–8.

Piping—The current value for this factor was assumed to be equal to the initial value because no experimental confirmation of the value exists at this time.

Auxiliary Steam—In plant operation a portion of the receiver steam flow is used periodically to charge thermal storage. The stored energy is used to provide auxiliary steam during the plant's shutdown periods but has not been used to generate electrical power. An annual input to storage of 4,600 MW–hr was estimated based on data analyzed for the first two years of power production operation.

Gross Cycle—A gross cycle efficiency of 0.343 resulted from the initial annual energy calculation reported in Reference 4–2. The current efficiency of 0.340 was based on the design turbine cycle performance characteristics (Reference 4–9) for an average gross output of about 8.5 MW_e while on line. An average gross output of 8.24 MW_e was achieved during the second year of power production operation.

Plant Parasitics—The plant parasitic values are based on the 24–hour plant load. The current value of 4.8 x 10^3 MW_e–hr is less than the initial value of 9 x 10^3 MW_e–hr. The current value is an average annual load for the first two years of power production operation and reflects a successful effort to reduce the parasitic power requirements for the Pilot Plant.

Overall—Weather data for 1976 and design plant conditions resulted in a predicted annual system efficiency of 13% and a plant output of 26,000 MW_e–hr net (corresponding to a capacity factor of 30%). In contrast, the use of 25-year average weather data and the substitution of more realistic plant conditions for some design conditions resulted in a predicted annual system efficiency of 8.2% and a plant output of 15,000 MW_e–hr net (corresponding to a capacity factor of 17%).

System Performance Data

Daily Operation

The power production goals of generating 10 MW_e net from receiver steam and 7 MW_e net from thermal storage steam were both met. The Pilot Plant generated a peak output of 11.7 MW_e net from receiver steam on February 26, 1986. In addition, the plant generated 10 MW_e net or more on numerous occasions throughout the course of testing.

When operating from thermal storage the plant achieved a peak output of 7.3 MW_e net. Using thermal storage steam the plant also sustained a 7 MW_e net output for over 4 hours, generating 43.4 MW_e–hr net and easily surpassing the design goal of 28 MW_e–hr net.

The two design goals which were not met are the delivery of 10 MW_e net for 7.8 hours on the most favorable day of the year (summer solstice) and for 4 hours on the least favorable day of the year (winter solstice). The Pilot Plant did achieve a 10 MW_e net output for 2.8 hours on December 19, 1985 (close to winter solstice) and for 5.3 hours on March 21, 1986 (spring equinox). Additional attempts were made to meet the two goals during the Power Production Phase, but the attempts were also unsuccessful.

An analysis of plant conditions and plant output for the solstice days was performed and showed that the combined effects of low direct insolation, heliostat outages, mirror soiling, receiver efficiency, and turbine efficiency were sufficient to preclude the plant from meeting the two design goals (Reference 4–10). The results indicate that the design conditions used to derive the two goals were too optimistic and did not adequately reflect actual operating conditions.

Monthly and Annual Operation

Capacity Factor—Figure 4-2 shows the monthly capacity factors for the three years of Pilot Plant power production operation. A negative value means that the plant consumed more power than it produced during the month, due to poor weather or scheduled and unscheduled plant outages. The best capacity factors generally occurred during the months of April to September. The Pilot Plant achieved a maximum monthly capacity factor of about 24% during August 1985.

The Pilot Plant's capacity factor averaged 8, 12, and 11% during the first, second, and third years of power production operation, respectively. A considerable improvement in capacity factor was observed during the second and third years of power production operation as a result of better weather conditions and improved operating and maintenance procedures. Better insolation permitted more hours of operation at or near full load. Improved operating and maintenance procedures resulted in increased plant availability, heliostat availability, heliostat cleanliness, receiver absorptance, and reduced start-up times. These factors all contributed to an increased steam flow to the turbine and more hours of full-load operation.

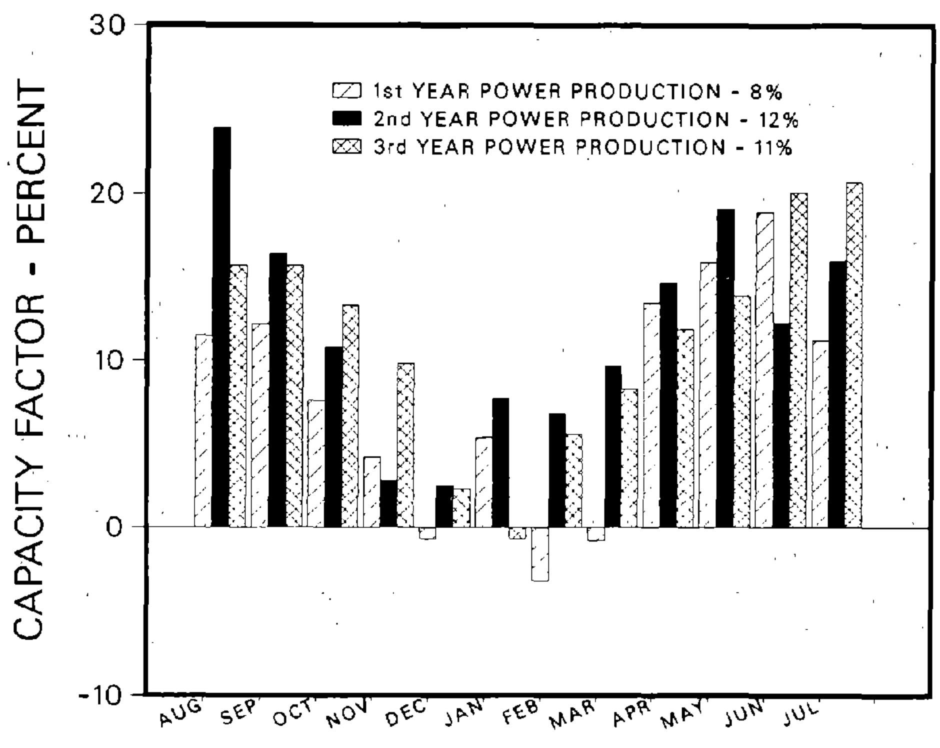


Figure 4-2. Pilot Plant Monthly Capacity Factor

System Efficiency—The monthly system efficiencies for the three years of power production operation are shown in Figure 4-3. A negative value again indicates that the plant consumed more power than it produced during the month. The Pilot Plant achieved a maximum monthly system efficiency of about 8.7% during August 1985.

The system efficiencies for the first, second, and third years of power production operation were 4.1, 5.8, and 5.7%, respectively. System efficiency, like capacity factor, increased considerably during the second and third years of power production operation and for the same reasons.

Output Factor—Monthly and annual values for a third performance factor, called the output factor, were also obtained during power production operation. Output factor is the plant's actual net electrical output divided by its rated net output while on line. The output factor is an indicator of the plant's average power output when it is connected to the grid. A low output factor indicates that the plant is operating under off-design plant conditions most of the time and is thus experiencing a reduction in performance.

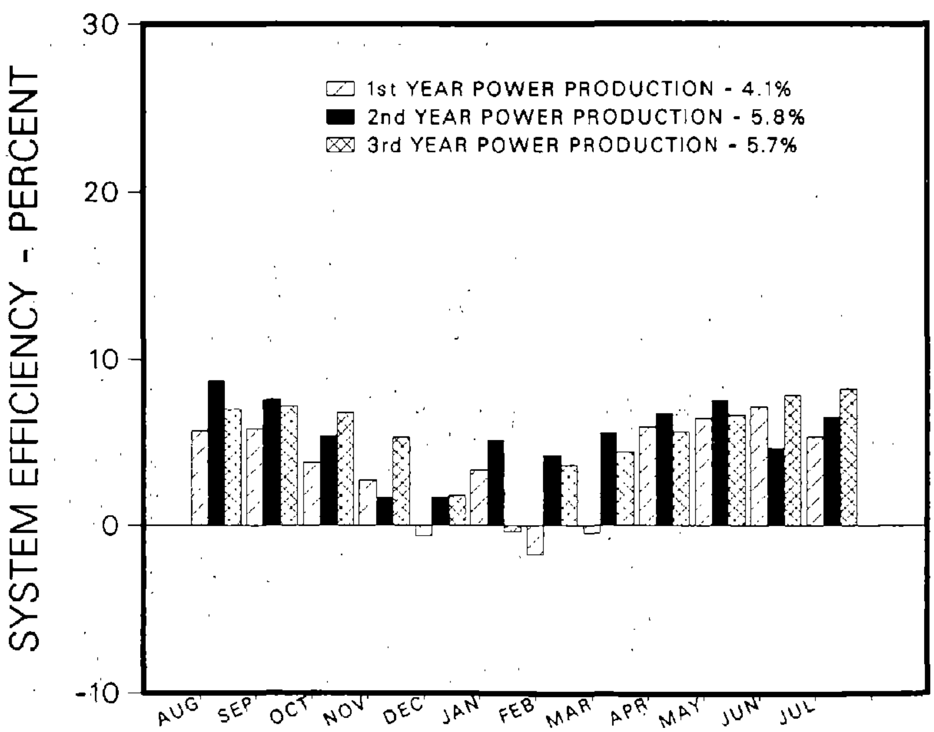


Figure 4-3. Pilot Plant Monthly System Efficiency

The output factors experienced during the three years of power production operation are shown in Figure 4-4. Monthly output factors for the plant ranged from a high of 85% in February 1986 to a low of 47% in February 1985. The high and low values correspond to average power outputs of 8.5 and 4.7 MW_e net while the plant was on line. A design output factor was not specified for the Pilot Plant, but the values reported here would be less than a value based on design plant conditions. Actual plant conditions had a significant effect on the plant output.

The Pilot Plant has experienced an increase in output factor since testing began in 1982: the plant's output factor averaged 52% during the Experimental Test and Evaluation Phase and 66, 73, and 70% during the first, second, and third years of the Power Production Phase, respectively. During the Experimental Test and Evaluation Phase the plant was sometimes operated under part-load conditions to test and evaluate the operating characteristics of the plant. Part-load operation resulted in a reduced turbine efficiency and contributed to a reduced output factor. During the Power Production Phase no part-load testing was performed. In addition, improved maintenance procedures, which resulted in improved heliostat availability, cleanliness, etc., increased the steam flow to the turbine and contributed to increased operation at or near full-load conditions. The

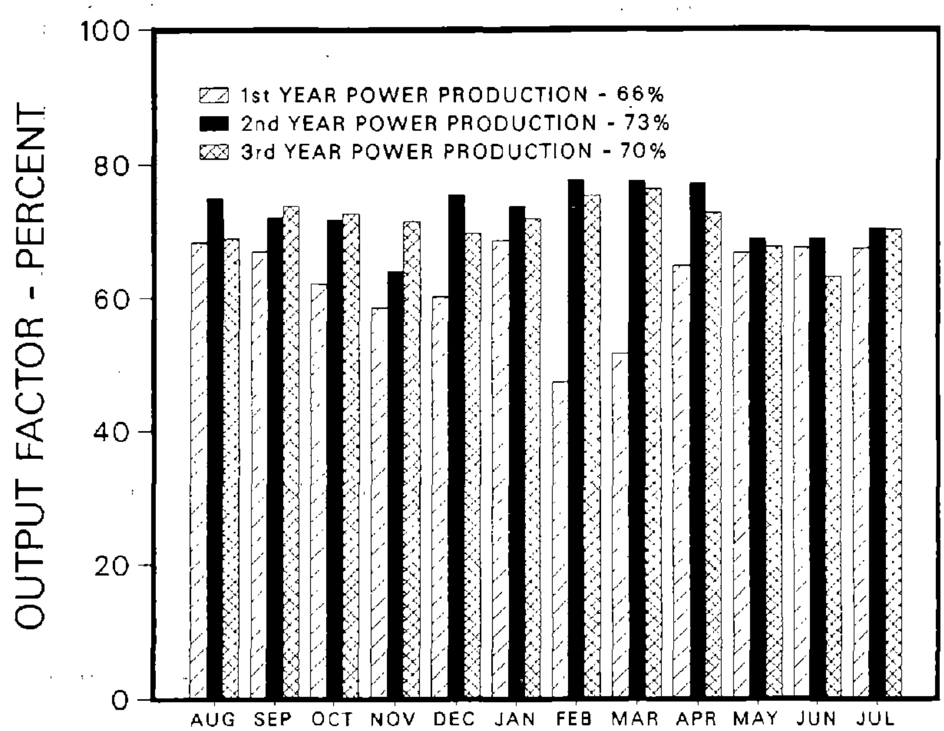


Figure 4-4. Pilot Plant Monthly Output Factor

higher output factors during power production operation resulted from this increase in power production operation and an attendant increase in turbine efficiency (resulting from decreased operation under part-load conditions) that occurred over this period.

Comparison of Actual and Predicted Performance

Analysis of Plant Data

The actual plant capacity factors, system efficiencies, and energy outputs for power production operation were less than either their initially or currently predicted values. The effects of actual plant conditions on these values were analyzed to determine where further operating and maintenance improvements are needed to achieve the currently predicted values. The analysis results are shown in Table 4-2 and described below.

Incident Normal Insolation—The current predictions for plant performance are based on an annual insolation of 183 x 10^3 MW-hr, the 25-year average value. The measured values for the three years of power production operation, which are shown in the Table, are all lower than this value.

Operating Days Insolation Availability—For 1984, the operating days insolation was estimated to be 2080 kW-hr/m^2 (Reference 4-4). This value corresponds to an operating days insolation availability of 0.887. An operating days availability of 0.90 was assumed for the three years of power production operation since the weather was slightly more favorable over these periods compared to 1984. However, the availability value is slightly less than the predicted availability of 0.91, which is based on better weather than was observed during the years of power production operation.

Useful Insolation Availability—For 1984, the useful insolation was estimated to be 1733 kW-hr/m^2 (Reference 4-4). This value corresponds to an useful insolation availability of 0.833. An useful insolation availability of 0.84 was assumed for the three years of power production operation since the weather was slightly more favorable over these periods compared to 1984. Again, the availability value is slightly less than the predicted availability of 0.85, which is based on better weather than was observed during the years of power production operation.

Plant Availability—The current predictions for plant performance are based on a plant availability of 0.90, the Pilot Plant design goal (Reference 4-5). Actual plant availabilities for the first, second, and third years of power production operation were 0.80, 0.83, and 0.82, respectively.

Table 4-2
Effects of Actual Plant Conditions on Pilot Plant System Efficiency and Annual Energy Output

Item	First Year Efficiency (Fraction)	First Year Energy (MW-hr x 10^3)	Second Year Efficiency (Fraction)	Second Year Energy (MW-hr x10^3)	Third Year Efficiency (Fraction)	Third Year Energy (MW-hr x10^3)
Incident Normal Insolation		170		181		174
Operating Days Availability	0.900	153	0.900	163	0.900	157
Useful Insolation Availability	0.840	129	0.840	137	0.840	132
Plant Availability	0.800	103	0.830	114	0.820	108
Heliostat Availability	0.967	99	0.982	112	0.988	107
Cosine	0.786	78	0.786	88	0.786	84
Blocking and Shadowing	0.967	76	0.967	85	0.967	81
Reflectance	0.808	61	0.840	71	0.790	64
Atmospheric Attenuation	0.966	59	0.966	69	0.966	62
Spillage	0.979	58	0.979	67	0.979	61
Receiver Absorptance	0.880	51	0.910	61	0.940	57
Radiation and Convection	0.803	41	0.812	50	0.812	46
Piping	0.996	41	0.996	50	0.996	46
Auxiliary Steam	0.886	36	0.909	45	0.998	46
Gross Cycle	0.328	12	0.335	15	0.333	15
Plant Parasitics	0.600	7	0.676	10	0.652	10
Overall	0.042	7	0.056	10	0.057	10

Heliostat Availability—The current predictions for plant performance are based on a heliostat availability of 0.990. Actual availabilities for the first, second, and third years of power production operation were 0.967, 0.982, and 0.988, respectively. The heliostat availability for the second year of power production operation excludes a collector field outage in November 1985 that shut down the entire plant. This outage, however, is accounted for in the plant availability of 0.83 for the second year of power production operation. The heliostat availability, including the November 1985 outage, would be 0.960, as reported in the next chapter.

Cosine, Blocking and Shadowing—The values for these factors were derived from MIRVAL computer calculations because no experimental confirmation of the values exists at this time.

Reflectance—The current predictions for system performance are based on a heliostat reflectance of 0.876. The measured reflectances of the heliostat field averaged 0.808 and 0.840 for the first and second years of power production operation, respectively. The reflectance value for the third year was selected to "fit" the data, that is, to give the measured net energy output for the third year. An average measured value of the reflectance was not available for the third year because the reflectometer was inoperable for six months during the year.

Atmospheric Attenuation and Spillage—The values for these factors were derived from MIRVAL computer calculations because no experimental confirmation of the values exists at this time.

Receiver Absorptance—The current predictions for plant performance are based on a receiver absorptance of 0.94. The receiver absorptance was measured to be: November 1982 - 0.92; December 1983 - 0.90; September 1984 - 0.88; March 1986 - 0.97 (after repainting in December 1985); and October 1987 - 0.96. The consideration of these measured values, as well as the tubular geometry and the inactive absorbing area of the receiver (discussed in Chapter 6), led to effective absorptance values of 0.88, 0.91, and 0.94 for the first, second, and third years of power production operation, respectively.

Radiation and Convection—The current predictions for plant performance are based on an annual radiation and convection energy loss of 11.8×10^3 MW-hr. This loss assumed an annual receiver operation of 2350 hours and a 5 MW loss during operation. Losses for the three years of power production operations were based on: (1) actual hours of plant operation, which includes on-line hours, thermal storage charging hours, and an estimate of effective start-up and shutdown hours; and (2) a 5 MW loss during operation.

Piping—The actual values for this factor were assumed to be equal to the predicted value because no experimental confirmation of the values exist at this time.

Auxiliary Steam—The current predictions for system performance are based on an annual input to storage of 4,600 MW–hr. Storage input for the first and second years of power production operation was estimated to be 4,650 and 4,525 MW–hr, respectively. These amounts were determined from the actual hours of thermal storage charging and estimates of the average receiver output power. The input to thermal storage was negligible for the third year of power production. A fire knocked out the thermal storage system in August 1986 and led to the use of an electrically heated boiler for supplying auxiliary steam needs during the third year.

Gross Cycle—The current predictions for system performance are based on an annual gross cycle efficiency of 0.340. This efficiency was estimated from the design turbine cycle performance characteristics (Reference 4–9) for an average gross output of about 8.5 MW_e while on line. Similarly, efficiencies were estimated for power production operation from the design turbine cycle performance characteristics and actual average gross power outputs for each year. The average gross outputs while on line were 7.34, 8.24, and 8.00 MW_e during the first, second, and third years of power production operation, respectively.

Plant Parasitics—The current predictions for system performance are based on an annual plant load of 4.8×10^3 MW_e–hr, the average annual load for the first two years of power production operation. Actual measured loads were substituted for analyzing the first, second, and third years of power production operation.

Overall—The current predictions for system performance are an annual system efficiency of 8.2% and a plant output of 15,000 MW_e–hr net (corresponding to a capacity factor of 17%). The actual performance values achieved during power production operation were less than these values. The best performance occurred during the second year of power production operation when the plant achieved an annual system efficiency of 5.8% and a plant output of 10,465 MW_e–hr net (corresponding to a capacity factor of 12%). Further operating and maintenance improvements are needed to achieve the predicted values and are discussed below.

Potential Improvements

An examination of Tables 4–1 and 4–2 shows several areas where system performance can still be improved. The major areas for further improvement are plant availability and heliostat reflectance.

Plant availability, although improving during power production operation, remained below the plant design value of 0.90. Leaks resulting from the thermal cycling of plant equipment, in particular, the receiver tubes, pumps, and valves, were the primary contributors to a reduced availability. An improvement in availability from 0.83 to the design value of 0.90 would increase the plant net electrical output by about 2,000 MW_e–hr.

Heliostat cleanliness, which affects the heliostat reflectance, also improved during power production operation. The best annual average cleanliness, 93%, was achieved during the second year of power production operation. This value although good remained well below the 97% value used to develop the predicted system performance. An increase in cleanliness from 93 to 97% would increase the plant net electrical output by about 900 MW_e–hr.

Significant improvements in heliostat availability and receiver absorptance were achieved during power production operation. Increased maintenance activities brought the heliostat availability to 0.988, close to the desired value of 0.99. Repainting the receiver restored the receiver surface absorptance to 0.97. As a result, the effective receiver absorptance averaged 0.91 and 0.94 during the second and third years of power production operation, respectively. The latter value is equal to the value used to derive the current predictions of annual system performance.

Improvements in the heliostat reflectance, heliostat availability, and receiver absorptance also have a synergistic effect. The improvements result in the turbine–generator operating more at full load than part load, thereby increasing the average turbine cycle efficiency.

Analyses for the Pilot Plant indicated that it was cost effective to strive for these three improvements. The benefit, in the form of increased plant revenues, exceeds the cost of making the improvements.

An improvement in plant availability is also most desirable but is probably the most difficult to implement. Plant availability is governed, to a large degree, by unscheduled outages. Preventive maintenance, equipment redesign, or the addition of equipment redundancy could improve plant availability, but the costs of these activities are unknown.

The implementation of the above improvements in future plants, along with the use of advanced central receiver technologies like molten salt and liquid sodium, should significantly improve the annual energy production of future power plants relative to the Pilot Plant. Commercial-size plants will use turbine-generators with higher thermal-to-electric conversion efficiencies than the Pilot Plant turbine–generator. Improved efficiencies when operating from thermal storage will be achievable in future plants through the use of working fluids, such as molten salt and liquid sodium, that serve as both the receiver coolant and storage medium.

A higher heliostat clean-mirror reflectance and higher receiver efficiency should also be achievable in future plant designs. The clean-mirror reflectance can be improved by using thinner low-iron glass than the Pilot Plant mirrors or thin plastic-coated mirror designs. The use of receiver designs and working fluids which can accept a higher incident flux than the Pilot Plant water/steam receiver, as well as periodic repainting of the receiver absorbing surface, will be required to achieve higher receiver efficiencies.

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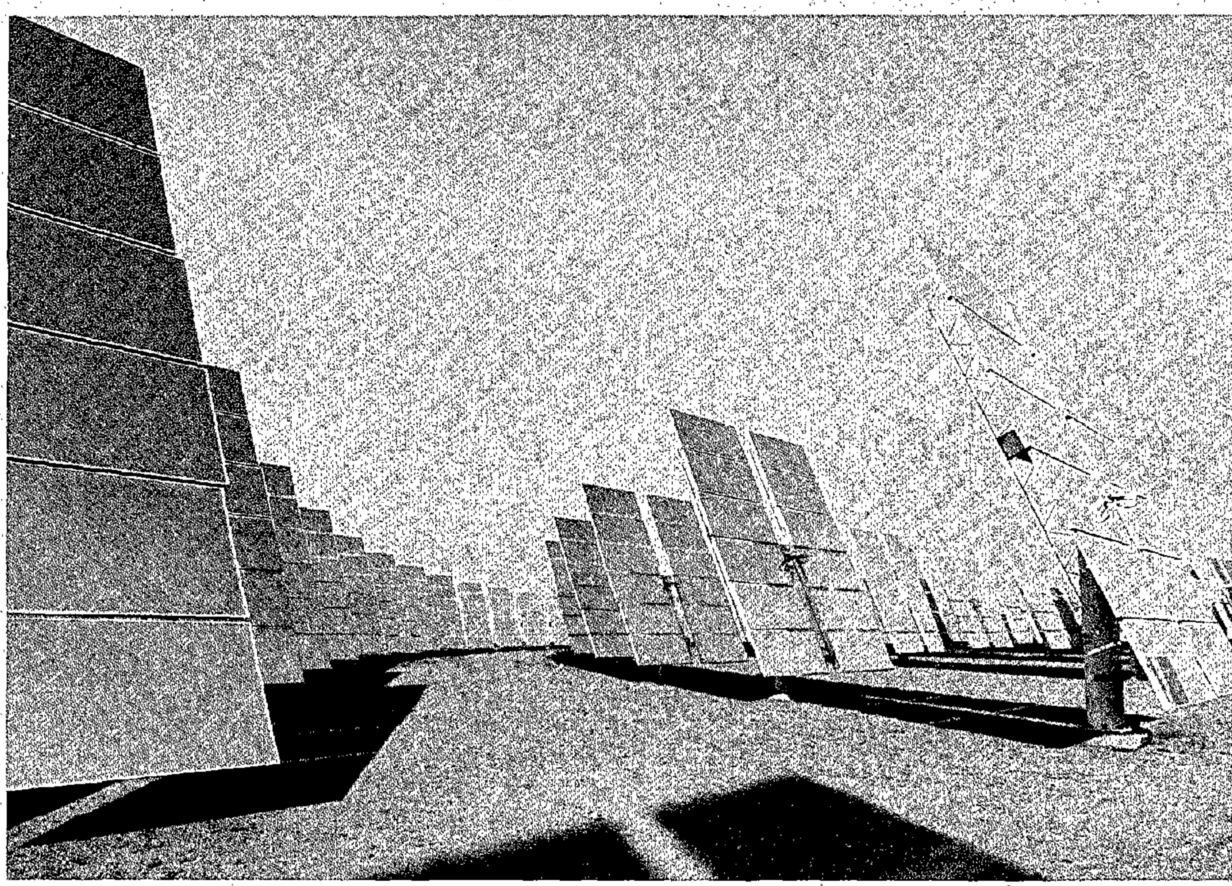
Collector Performance



Pilot Plant Heliostat Field

5. COLLECTOR PERFORMANCE

Overview

During power production operation, the collector system performance was evaluated in several areas. Heliostat availabilities were determined, and mirror cleanliness data were gathered. Mirror corrosion surveys were performed, and heliostat tracking accuracy and wind load data were analyzed.

A comparison of maintenance costs and plant revenues that result from an improved heliostat availability suggested that it would be cost-effective to attain an annual average availability of 99%. The annual average heliostat availabilities during the first, second, and third years of power production operation were 96.7, 96.0, and 98.8%, respectively. The annual average availability for the last year of power production operation is very close to the 99% goal and demonstrates a successful maintenance effort by SCE.

Mirror cleanliness data and analyses indicated that an average annual cleanliness of 97% (expressed as a percent of the clean mirror reflectance) was desirable for Pilot Plant operation. The best annual cleanliness, 93.0%, was achieved during the second year of power production operation. Achievement of a 97% cleanliness remained an elusive goal during power production testing, because of repeated breakdowns of the heliostat wash equipment and too infrequent washings.

Corrosion surveys of the heliostat field, performed during the summers of 1983, 1984, 1985, and 1986, showed that after five years of operation, mirror corrosion had a negligible effect on collector and overall plant performance. At the conclusion of the 1986 survey 0.061% of the total reflective surface of the collector field was corroded. This percentage is equivalent to the surface area of only 1.1 heliostats.

Heliostat tracking data taken with the beam characterization system in 1985 and 1986 indicated that heliostats were tracking accurately; therefore, the system required few tracking error corrections. The data showed that there were no significant changes in the tracking errors over a six-months measurement period.

The wind load analyses indicate a need for further long-term test data which can be subjected to a statistical analysis. This is due to the large and frequent changes in wind speed and direction. However, the first-of-a-kind tests at the Pilot Plant verified that the method used to calculate heliostat wind loads is adequate for design and errors on the conservative side. Additional data will probably justify reducing the heliostat wind load requirements.

Introduction

During power production operation, data were compiled for the heliostat availability, heliostat cleanliness, heliostat tracking accuracy, heliostat wind loads, and mirror corrosion. The results of the first four evaluations are reported in Reference 5-1 while the mirror corrosion results are reported in References 5-2 to 5-4.

Heliostat Availability

Heliostat availability is defined as the fraction of the heliostat field that is operational. To achieve a high heliostat availability one might anticipate a high level of maintenance since the collector field is equipment intensive. However, software development for the Pilot Plant significantly minimized operational requirements, and reliable equipment design reduced maintenance manpower expenditures.

Figure 5–1 shows the heliostat availabilities for power production operation. The monthly values ranged from a high of 99.7% in June 1985 (6 heliostats out of service) to a low of 66.7% in November 1985 (606 heliostats out of service). The average availabilities over the first, second, and third years of power production operation were 96.7, 96.0, and 98.8% (60, 72, and 22 heliostats out of service), respectively.

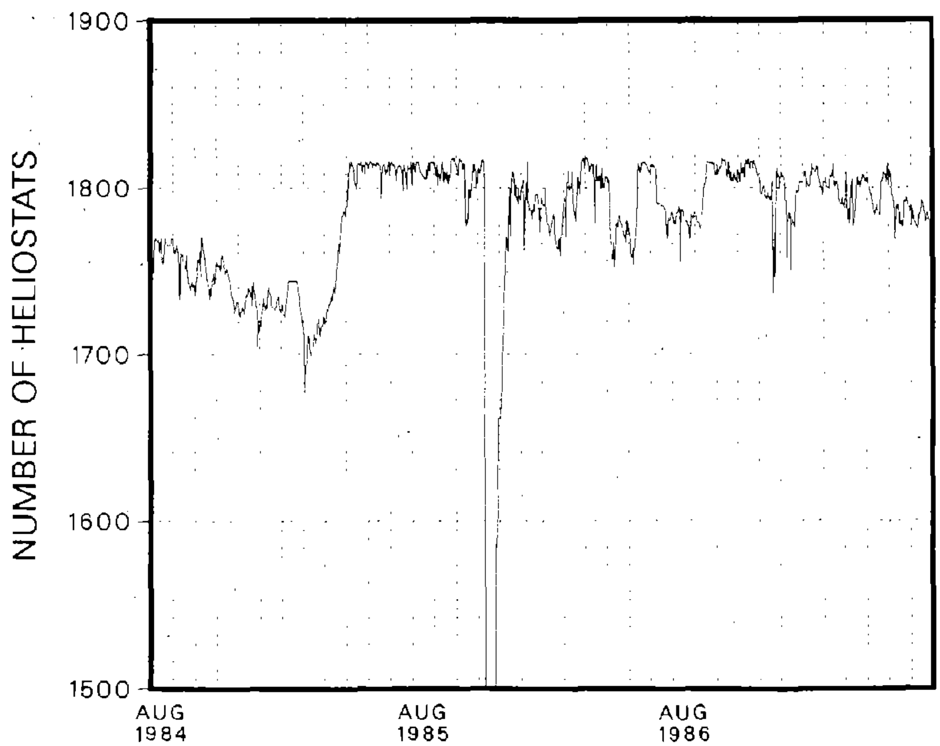


Figure 5–1. Pilot Plant Heliostat Availability

Figure 5–1 shows that a significant improvement in heliostat availability was made in March and April 1985, when a concerted effort was made to improve the plant's power output There was a power transformer failure in November 1985, which damaged several hundred heliostats because of power surges to the heliostat controllers. The malfunction caused a loss of power to and control of the heliostat field. Numerous heliostat control boxes were affected by the transformer failure and were repaired or replaced. The plant resumed operation after a nine-day shutdown although initially only 1320 heliostats were available for operation. Without this outage the heliostat availability would have exceeded 98% for the second year of power production operation.

In 1986 and 1987, heliostat drive motor repairs were performed in batches during several periods. The work consisted of seal replacement, motor bearing replacement and motor shaft welding. The motor work contributed to the declines in heliostat availability during 1986 and 1987.

The most significant problems with the operation of the collector field were caused by the electrical transmission grid to which the plant is connected and the computer interface communication. The plant was connected electrically to a 33KV "bug line," approximately 32 miles long, originating in Barstow and terminating in Newberry, California. This line was subject to undervoltage conditions and occasional power interruptions because of a combination of lightning, wind, heavy equipment electrical loads, and on one occasion, vehicle impact with a supporting power pole. The undervoltage or power interruptions resulted in a loss of collector field power, cutting off power to both the heliostat motors and the heliostat controllers that share common power supplies. Although field digital communications are on an uninterruptible power source, the microprocessor-based heliostat controllers, on being de-energized, lost their volatile memories and required reprogramming through the Heliostat Array Controller (HAC).

People with conventional skills have maintained the heliostats. An electrician and instrument repair technician performed most of the repair with minimal help from machinists and mechanics. Approximately one man-year of labor has been expended each year for heliostat repair.

Studies indicate that it would be cost effective to increase the annual average heliostat availability to 99% (18 heliostats out of service). The maintenance costs to achieve this availability were estimated to be less than the increase in plant revenues that results from an increased plant energy output. The high heliostat availability for the last year of power production operation indicates that the 99% goal should be achievable.

Heliostat Cleanliness

The average reflectance of the Pilot Plant heliostat field is 90.3%* if the mirrors are perfectly clean and there is no mirror corrosion. The actual reflectance is less, however, due primarily to the effect of mirror soiling.

It is convenient to express the reflective performance of the heliostat field in terms of a cleanliness factor. This factor, expressed as a percent of the clean reflectance, is a measure of the cleanness of the heliostat field. A portable specular reflectometer was used to measure mirror cleanness at the Pilot Plant. Measurements were generally made at intervals of about two weeks although no data were obtained over a six-month period in late 1986 and early 1987 due to a breakdown of the reflectometer

Figure 5-2 shows the Pilot Plant mirror cleanliness and rainfall for the years of power production operation. The rainfall values in the figure are from the Daggett, California, airport, about 2.5 miles (4 km) from the Pilot Plant site. The occurrence of reasonable amounts of rainfall, as recorded at the airport, is almost always accompanied by an improvement in mirror cleanliness. This result was the basis for drawing the cleanliness lines through the data points in the figure. The

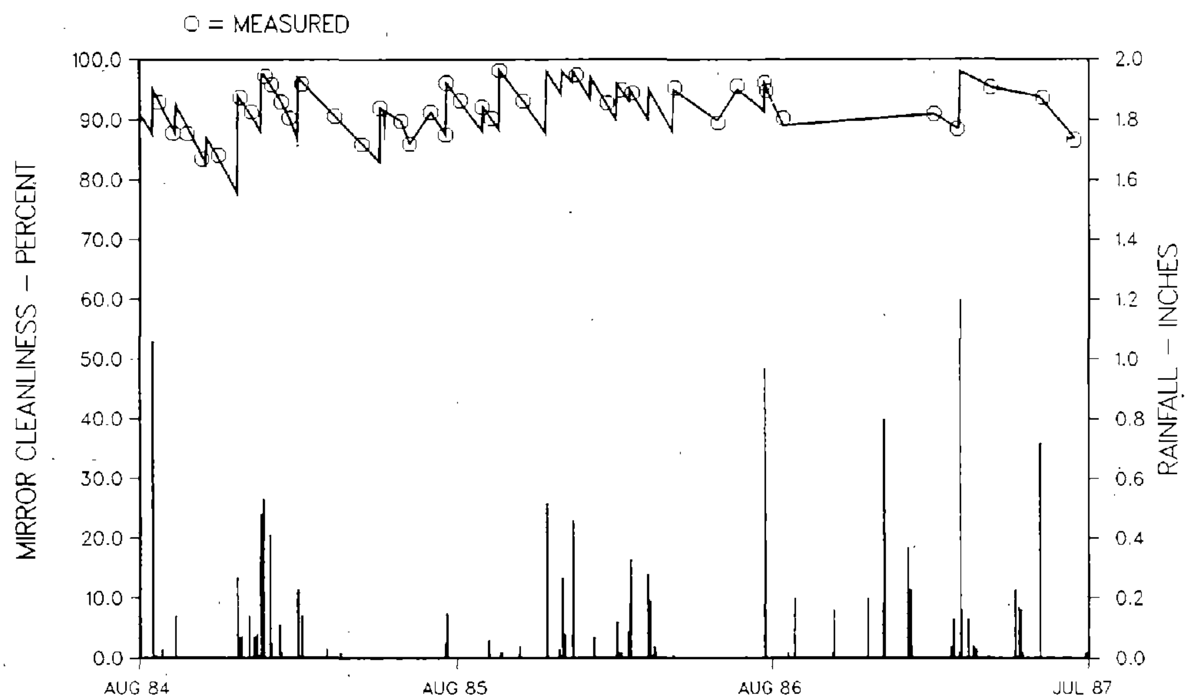


Figure 5-2. Pilot Plant Mirror Cleanliness and Rainfall

* The heliostat field is comprised of two mirror types: a low-iron glass with a reflectance of 91% and a high-iron glass with a reflectance of 79.8%. The resultant average field reflectance is 90.3%.

cleanliness lines were drawn through two or more data points and were extrapolated in both directions until rainfall occurred and an increase in cleanliness was observed. When only one data point was available, the line was drawn through this point approximately parallel to the neighboring lines.

The data indicate a decrease in cleanliness of about 0.25%/day (8%/month) for months with little rainfall and 0.1%/day (3%/month) for months with frequent rainfall. The heliostats mirrors regained about 97% of their clean reflectance when there was 0.5 in (12 mm) or more of rain. To maintain this recovery behavior, however, several artificial washes per year are required to remove dirt buildup that cannot be washed away by rainfall.

The data on rainfall, washing, and mirror cleanliness indicate that the most effective washing technique is to use a water spray with a brush. A spray rinse without brushing was less effective because it could not remove the build-up of small dust particles on the mirror surfaces.

Figure 5–3 shows the water-spray-with-brush heliostat wash truck that was used to wash the heliostat field. The truck requires one operator and washes 150-170 heliostats per eight hour shift. Using a biodegradable washing solution, the truck can restore the mirror cleanliness to 99% of the clean value reflectance.

Analyses of the soiling data and washing costs indicated that it would be cost effective to wash the heliostat field bi-weekly. For a soiling rate of 0.28%/day, the average rate in 1984, bi-weekly brush washing would achieve an average mirror cleanliness of 97% The benefit–an increase in plant energy output and plant revenues–that results from increased washing was estimated to be 2-3 times the costs of carrying out the additional washings.

The data in Figure 5–2 were analyzed to derive cleanliness values for the first two years of power production operation. No value was derived for the third year because the breakdown of the reflectometer limited the data gathered for this year. The cleanliness averaged 89.5 and 93.0% over the first and second years of power production operation, respectively. Based on the rainfall data and washing frequency for the third year the cleanliness value for the third year was probably less than 93.0%.

The bi-weekly washings needed to achieve an average cleanliness of 97% were not performed during power production operation because of breakdowns of the heliostat wash truck and assignment of personnel to higher priority maintenance activities. The wash truck was an experimental piece of equipment which was sent to the Pilot Plant for evaluation after it had been designed and fabricated under a Sandia contract with Foster–Miller Associates. Modifications to the truck and its washing equipment were made at various times, but the equipment continued to experience breakdowns during power production testing.

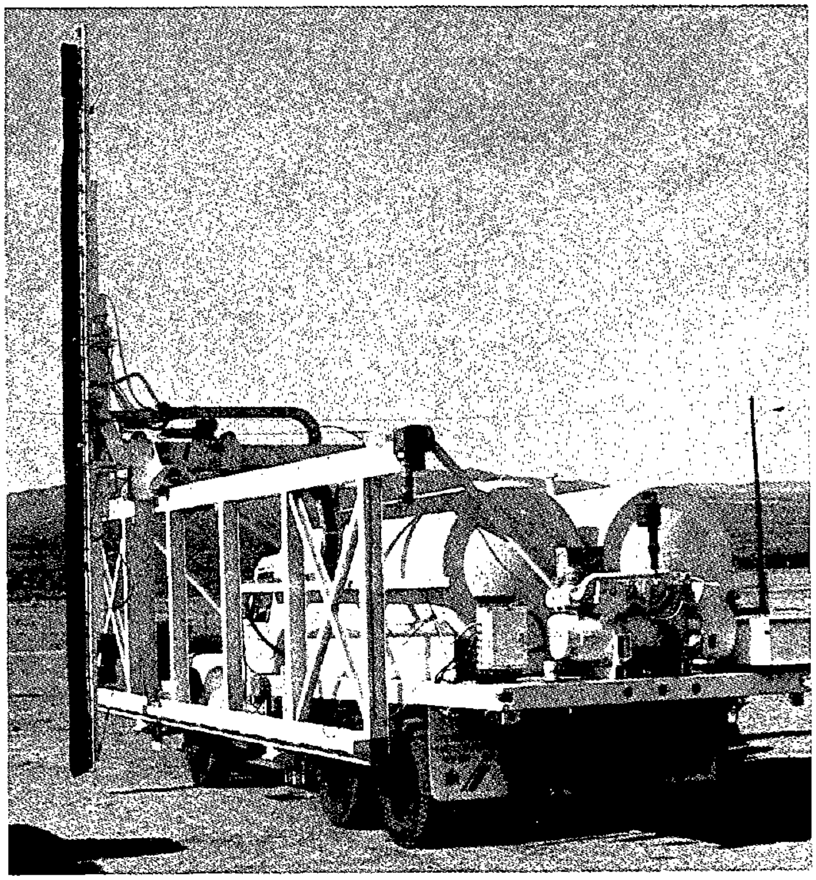
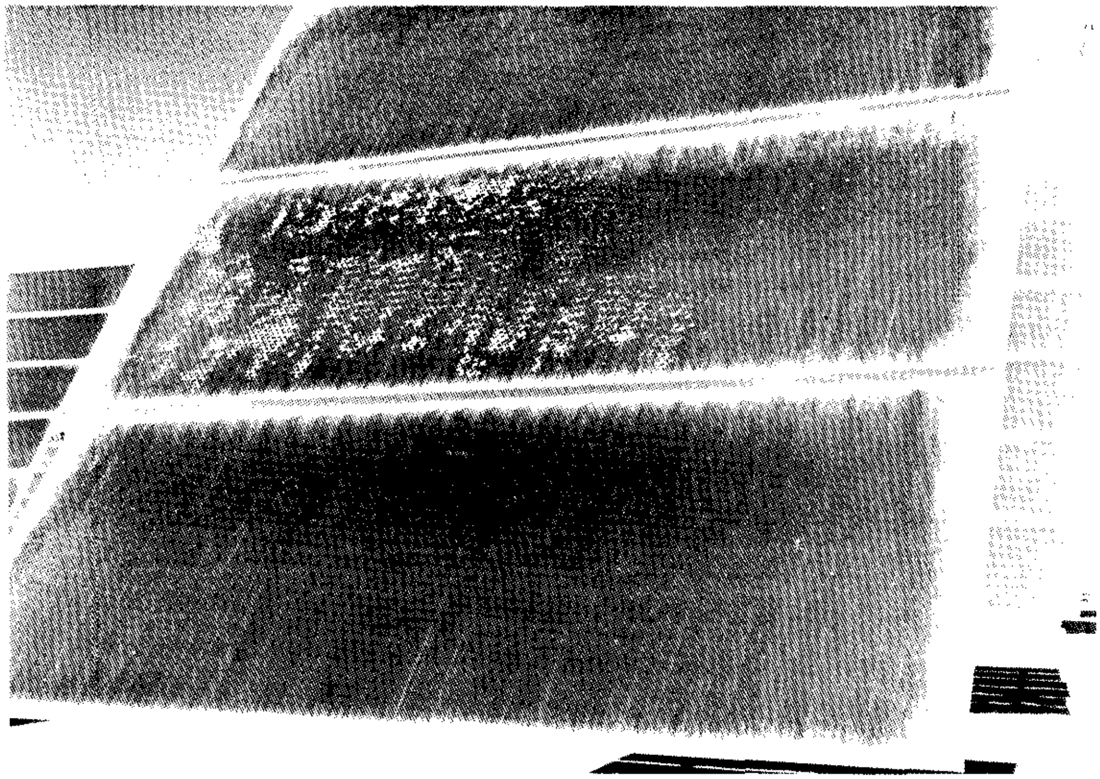


Figure 5—3. Photograph of Water-Spray-With-Brush Wash Truck

Mirror Corrosion

Silver corrosion was first observed on some of the mirror modules in the collector field in February 1982, approximately one year after the heliostats were installed (Figure 5–4). The corrosion forms as a result of water penetration through the paint and copper backing layers to the silver layer of the mirrors, causing the uniform silver layer to agglomerate.

When the corrosion was detected, several randomly selected mirror modules were first analyzed and then monitored for changes in the amount of corrosion. Beginning in 1983 this monitoring was expanded to include the entire collector field. Corrosion surveys of all 1,818 heliostats were performed during the summers of 1983, 1984, and 1985. The purpose of the surveys, which were performed by SCE, was to inspect all 21,816 mirror modules in the collector field, to document their condition, and to identify trends and/or patterns in the corrosion so that steps could be taken to halt the growth rate.



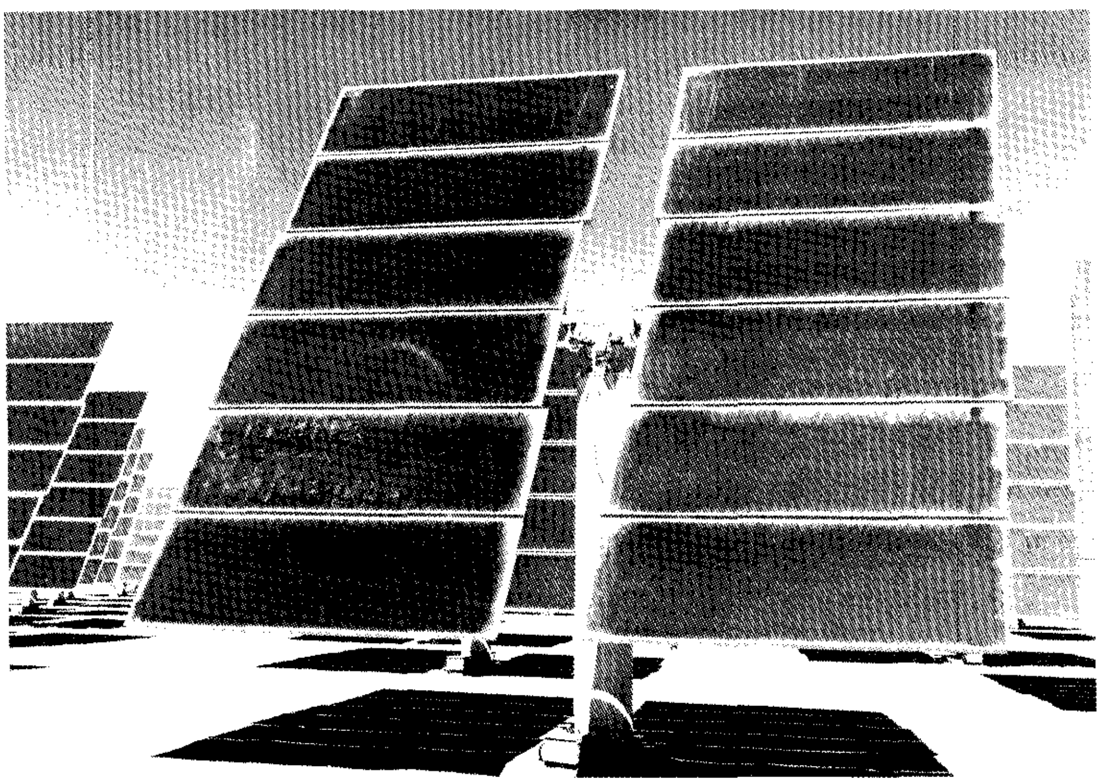


Figure 5–4. Photographs of a Corroded Mirror Module

During the summer of 1986 a survey was made of 98 randomly selected heliostats. The limited survey was done instead of a full field survey since it had been determined that these heliostats accurately represented the field.

The results of the surveys are shown in Table 5-1. The collector field corrosion area increased by a factor of about four during the period, July 1983 to July 1986. In terms of the total collector field reflective area, however, the corroded area is quite small: 0.015% and 0.061% of the total reflective area are equivalent to the surface area of about 0.3 and 1.1 heliostats, respectively. Thus, after almost five years of plant operation, mirror module corrosion had a negligible effect on collector system and overall plant performance.

Table 5-1
Results of Mirror Corrosion Surveys

Item	1983	1984	1985	1986
Percent of the Total Reflective Surface of the Collector Field That Was Corroded	0.015	0.029	0.052	0.061
Growth Rate of Mirror Module Corrosion (%/year)	1000	92	78	24
Most Prevalent Heliostat Field Location for Mirror Module Corrosion (quadrant)	NE	NE	NE	NE
Percent of Mirror Modules with Some Amount of Corrosion	15	27	48	57

The corrosion growth rate showed a significant decrease each year. A growth rate of 1000% per year was predicted in 1983 on the basis of the 1983 and earlier survey results. For 1986 the predicted growth rate had dropped to 24% per year.

This reduction may be partially due to a vertical stow position that was initiated in January 1983 and to mirror module vents that were installed in early 1984. Vertical stow was employed to minimize the build-up of water on the mirror module seals and to prevent water from reaching the mirror backing paint. Vent tubes were added to 10,036 mirror modules in order to "open-up" the air space inside the modules and enhance the drying of the module interiors. The vents also reduced the intake of water through imperfections in the mirror module seals by eliminating the slight vacuum formed inside the module as a result of a sudden cooling from rain or cold air.

The surveys indicated that mirror corrosion was most prevalent in the northeast quadrant of the field. This result can be correlated with the production and installation records for the mirror modules. The surveys and records showed that mirror modules manufactured after July 1, 1981, experienced less corrosion than modules manufactured before this time. The reduction was due to a change in the clamping procedure in the edge seal adhesive curing step. The production change improved the edge seal and reduced the leakage of moisture through edge seal imperfections into the interior of the mirror module. The northeast quadrant used a large share of the mirror modules manufactured before July 1, 1981.

Finally, the incidence of corrosion on individual mirror modules has increased. In July 1983, 15% of the mirror modules had some amount of corrosion on them. In July 1986, the figure had increased to 57%.

Tracking Accuracy

Heliostat tracking accuracy refers to the ability of a heliostat to maintain its reflected beam accurately upon a desired aimpoint. It is important to know if tracking errors change with time so that tracking corrections can be made before plant performance suffers.

Tracking error corrections are made by updating the reference settings of the heliostat azimuth and elevation angle encoders. Prior to 1985 the errors were evaluated and corrected once a year from visual estimates of the error on the beam characterization system target. The correction settings were based on a single observation of each angular error that was normally made between 10:00 a.m. and 2:00 p.m. Visual methods were used because the beam characterization system was experiencing operational problems and was not available for service.

In October 1985, the complete beam characterization system was used to detect, correct, and monitor the tracking errors for a group of 95 heliostats. The 95 heliostats were measured for tracking errors at three different times during the day. After the errors were determined, updates to the heliostat encoder reference settings were made to correct the errors. In order to determine any changes in the tracking accuracy with time, the tracking errors were then measured again on several occasions over a six-month period without any further bias updates.

The data show that there were no significant changes in the tracking errors during the measurement period. The mean errors were no larger than the beam characterization system resolution, and the one standard deviation error was well within the heliostat accuracy requirements.

Wind Loads

Heliostat wind loads are a major design concern because they are the primary contributor to heliostat costs. Wind loads determine the strength requirements of the drive mechanism, pedestal, mirror modules, and mirror support structure. To gain a better understanding of these requirements for future heliostat designs, the interaction of the wind with the Pilot Plant heliostats was studied. Wind speed and direction were measured at various locations in the heliostat field, and six heliostats were instrumented to measure wind loads. The wind data were analyzed to determine: (1) wind velocity profile versus height; (2) adequacy of ASCE flat plate wind load coefficients for heliostat design; (3) wind angle of attack for heliostats in a stow position; (4) potential reduction of wind loads within a heliostat field; and (5) suitability of peak wind speeds for heliostat design.

Considerable wind data were obtained during Pilot Plant testing. Nevertheless, additional data are required to perform valid statistical analyses of the test data. This is due to the large and frequent changes in wind speed and direction.

The results to date have verified that the method used to calculate heliostat wind loads was adequate for designing the Pilot Plant heliostats and erred on the conservative side. Additional data will probably justify reducing the heliostat wind load requirements for future heliostat designs. A summary of the test results is provided below.

Wind Velocity Versus Height

A wind velocity profile is used to determine the wind speed at heights other than the reference height, which is usually 32.8 ft (10m). The equation for wind speed versus height above the ground is:

$$
\begin{aligned}
V(h) &= V(refh)(h/refh)^{0.15} \\
V(h) &= speed\ at\ height\ (h) \\
V(refh) &= speed\ at\ the\ reference\ height\ (refh) \\
refh &= reference\ height,\ 32.8\ ft\ (10\ m) \\
h &= height\ above\ ground,\ ft\ (m)
\end{aligned}
$$

The exponent 0.15 gave the best fit to the data for the average wind speed at the Pilot Plant site. However, this does not mean that a speed profile like the one above should be used for a heliostat design since the peak wind speed, or some fraction of the peak, is what actually determines the load on the heliostat.

Wind Load Coefficients

The ASCE Paper 3269 provides the recommended wind load coefficients for heliostat design (Reference 5-5). Good agreement was obtained between the calculated and measured wind loads when the average wind speed incident on the field was used to calculate the heliostat wind loads. There was less agreement and a much wider spread in the results when the measured wind speed at the heliostat was used to calculate the wind load. The measured wind loads were not uniform across the heliostats, and they were not predictable from the wind speed profile because the speed varied widely with height and the direction was continuously changing.

Angle of Attack

The Pilot Plant data indicate that the maximum angle of attack for the wind was 4° from the horizontal. This measured angle of attack is significantly less than the 10° angle that was specified for the heliostat design. References 5-6 and 5-7 suggest that the maximum angle of attack for 90 mph (40 m/s) winds should be 4° for smooth terrain and 5.5 to 6° for outskirts of towns and suburbs. Therefore, until additional data are available, a 6° angle of attack is recommended for future heliostat designs.

Wind Loads Within the Heliostat Field

The Pilot Plant heliostats are all designed to survive a 50 mph (22 m/s) wind (heliostat in any orientation) or a 90 mph (40 m/s) wind (heliostat in the horizontal stow position). To investigate whether survival wind load requirements could have been reduced for heliostats within the field, wind loads were measured at several heliostat locations. The Pilot Plant wind load data showed that heliostat survival wind loads were not reduced as you move into the field. The peak loads on the inside heliostats were just as large as the loads on the outside heliostats when the rest of the heliostats in the field were in a stow position, as would be the case for a 90 mph (40 m/s) wind. Under thunderstorm gust front conditions, the field could be in any orientation; therefore, we could not depend on wind shielding from upwind heliostats. Any roads into the field would make this especially true. Therefore, unless wind shields are placed throughout the field, all heliostats should be designed for the same wind loads.

Suitability of Peak Wind Speeds for Design

The data showed that only a fraction of the peak wind speed was effective in loading the heliostat. The results indicate that the design wind speed survival requirement of 90 mph (40 m/s) could be reduced to about 75 mph (34 m/s). However, additional long-term statistical data are needed to confirm this finding.

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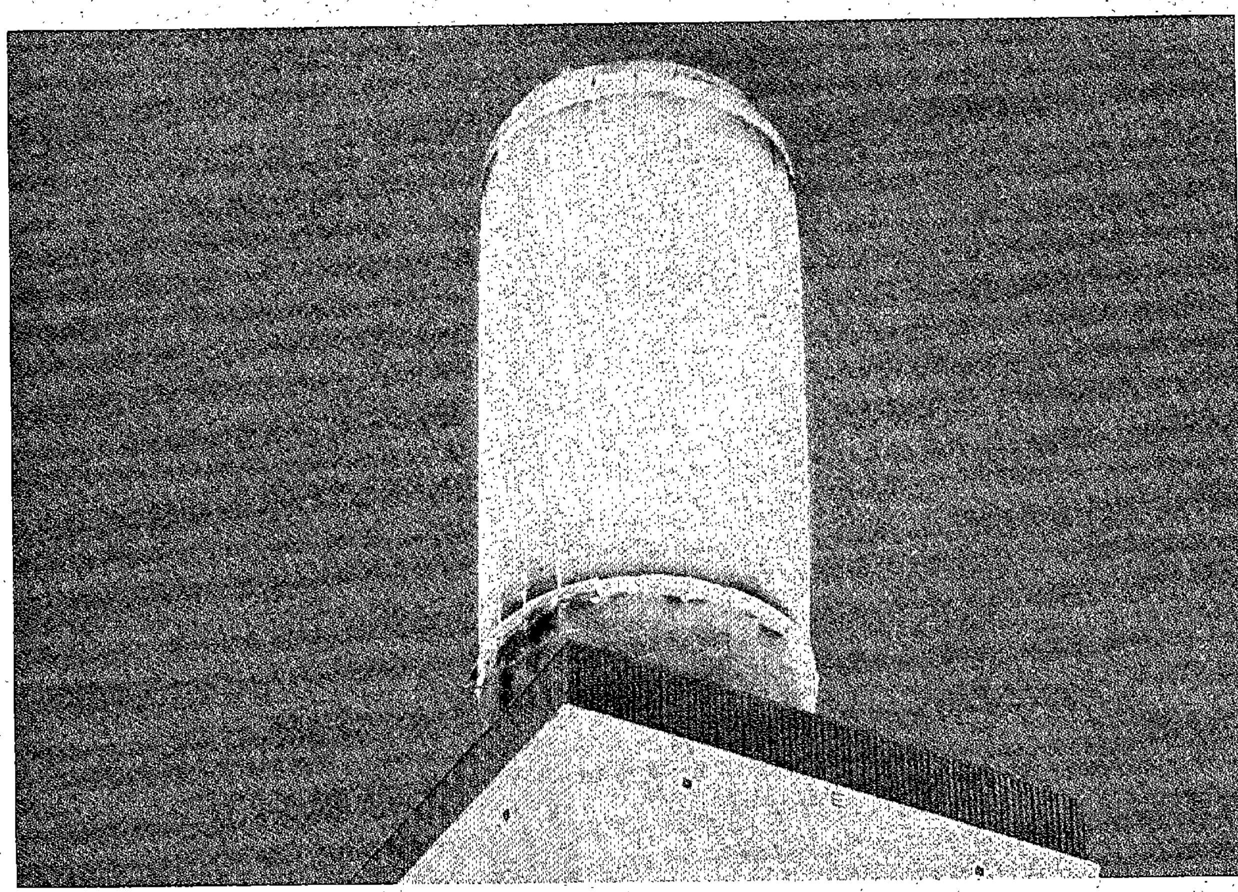
Receiver Performance



Pilot Plant Receiver

6. RECEIVER PERFORMANCE

Overview

The receiver evaluation during power production testing included analyses of receiver efficiency, thermal losses, receiver life, surface absorptance, and start-up times. Prior to repainting the receiver the receiver efficiency was measured to be about 77% at an absorbed power of 34 MW_t(the power level at the 2 p.m. winter solstice design point). After repainting the receiver to bring the surface absorptance closer to its design value, the measured efficiency increased to about 82%. The predicted efficiency at the winter solstice design point was 81%. Although differences besides the surface absorptance existed in the "actual" and "design" receiver physical and operating characteristics (for example, differences in the active heat absorbing areas and the operating temperatures), these results generally confirm the design point performance of the Pilot Plant receiver.

Receiver thermal loss data indicate that the total receiver radiation, convection, and conduction losses were about 4.5 to 5.0 MW_t. The results are comparable to the predicted losses and confirm the data previously obtained during the Experimental Test and Evaluation Phase.

Tube leaks were a recurring cause of plant outages during power production testing. Recurrences of leaks near the tops of the panels, which first appeared during the Experimental Test and Evaluation Phase, were eliminated through a combination of structural modifications at the tops of the panels and changes in the receiver operating conditions. However, leaks along the lengths of the panels appeared for the first time during power production operation. The leaks resulted from tube cracks that were caused by thermal stresses due to thermal gradients through the panel tubes and panel support clips welded to the back of the tubes. The panel supports were modified to relieve the thermal stresses but did not eliminate the occurrence of the cracks.

The solar absorptance of each panel on the receiver was measured annually from 1982 to 1987. The results showed a decrease in the solar absorptance with time. The decrease in solar absorptance correlated with the higher incident solar flux levels on the receiver panels and not with the operating temperature of the panels. Dirt on the panels did not appear to be a significant cause of the loss in solar absorptance. Repainting of the receiver panels was performed in late 1985, and the repainting successfully increased the solar absorptance of the panel surfaces to a value of about 0.97. An increase of almost five percentage points in the receiver efficiency was achieved by repainting the receiver surface.

New early morning and late afternoon heliostat aimpoints were developed for the Pilot Plant. The new heliostat aimpoints changed the circumferential distribution of the incident power on the receiver and increased the incident power on selected panels to reduce the early morning start-up time and extend the late afternoon operating time. Receiver morning start-up times were decreased by about 20 minutes with the new heliostat field aimpoints.

Introduction

During power production operation, the receiver was evaluated in several areas: receiver efficiency, receiver life, surface absorptance, and receiver start-up. Receiver efficiency was previously studied during the Experimental Test and Evaluation Phase. However, only limited data were generated for power production operation (Reference 6–1). During the Power Production Phase, additional data were analyzed to evaluate the receiver thermal performance under full- and part-load operating conditions (Reference 6–2).

Tube leaks, first observed after about eighteen months of plant service, continued to occur during power production operation (References 6–2 to 6–4). The causes of the leaks were analyzed, and methods to reduce the frequency of the leaks were studied and implemented. Surface absorptance was also measured, and the receiver absorbing surface was repainted (References 6–2 and 6–5). Finally, changes to the heliostat aimpoint strategies were studied and implemented in order to reduce the receiver start-up time (References 6–2 and 6–6).

Receiver Efficiency

Receiver efficiency is defined as the ratio of the power absorbed by the water/steam working fluid to the incident power supplied by the collector field. During power production operation receiver efficiency was evaluated on both a point-in-time (instantaneous) and average (average over time) basis. Point-in-time data were analyzed to derive the receiver efficiency as a function of the receiver absorbed power and the ambient wind speed. The data were also analyzed to derive values for the total receiver radiation, convection, and conduction losses. Finally, the average efficiency was evaluated for each year of plant operation.

The receiver efficiency data were gathered and analyzed for the time period, December 1982 to December 1986. The data base on receiver efficiency was thus extended to include almost the entire period of power production operation. The data supplement the efficiency data gathered during the Experimental Test and Evaluation Phase and provide a check on the early data.

Point-in-time Efficiency

The point-in-time receiver efficiency was analyzed in two ways. The first approach (Method 1) determined the receiver efficiency from a calculated value of the incident power on the receiver and a measured value of the absorbed power. The incident power could not be measured because of instrumentation limitations. It was, therefore, calculated using the MIRVAL heliostat field performance code (Reference 6–7). For each case studied, the heliostat beam pointing error, beam quality error, mirror module focal length (as a function of temperature), location of heliostats out of service, mirror reflectivity, insolation, sunshape, time of day, and other factors were input to MIRVAL. The output from each MIRVAL calculation was the incident power on the receiver surface for a particular day and time. The power absorbed by the receiver was determined from measured values of the water/steam flow rate and the water/steam inlet and outlet temperatures and pressures.

The second approach (Method 2) used an experimental technique that permitted the determination of the efficiency without knowledge of the actual value of the incident power on the receiver. The test procedure involved measuring the absorbed power under conditions of full and partial incident power. The experiments were performed by varying the number of heliostats directed at the receiver in a way that only the magnitude of the incident power was changed - not the flux distribution. This approach allows one to determine the receiver efficiency from the measured absorbed powers and calculated losses. The experimental and data analysis techniques for both methods are described in more detail in Reference 6–2.

Point-in-time Efficiency Versus Absorbed Power—The evaluation of point-in-time efficiency versus absorbed power was based on the following receiver conditions: (1) an inlet temperature of 240-375°F (115-190°C); (2) an outlet temperature of 780-860°F (415-460°C); (3) an outlet pressure of 1300-1500 psi (9.0-10.3 MPa); and (4) ambient wind speeds less than 15 mph (6.7 m/s). Only data from steady-state plant operation were studied in this analysis. The plant was considered to be in a steady-state condition if selected measured parameters did not change values within specified limits for a period of thirty-three minutes.

The efficiency as a function of absorbed power is shown in Figure 6–1. This figure displays 898 data points that are based on measured values of the absorbed power and calculated values of the incident power (Method 1). The data were gathered from December 1982 to December 1985, prior to the receiver repainting. The solid line is a least squares fit to the data while the "X"s are design point efficiencies calculated from Reference 6–8. The dashed lines show the 95% prediction interval: for a given value of the absorbed power there is a 0.95 probability that the efficiency will lie between the limits shown.

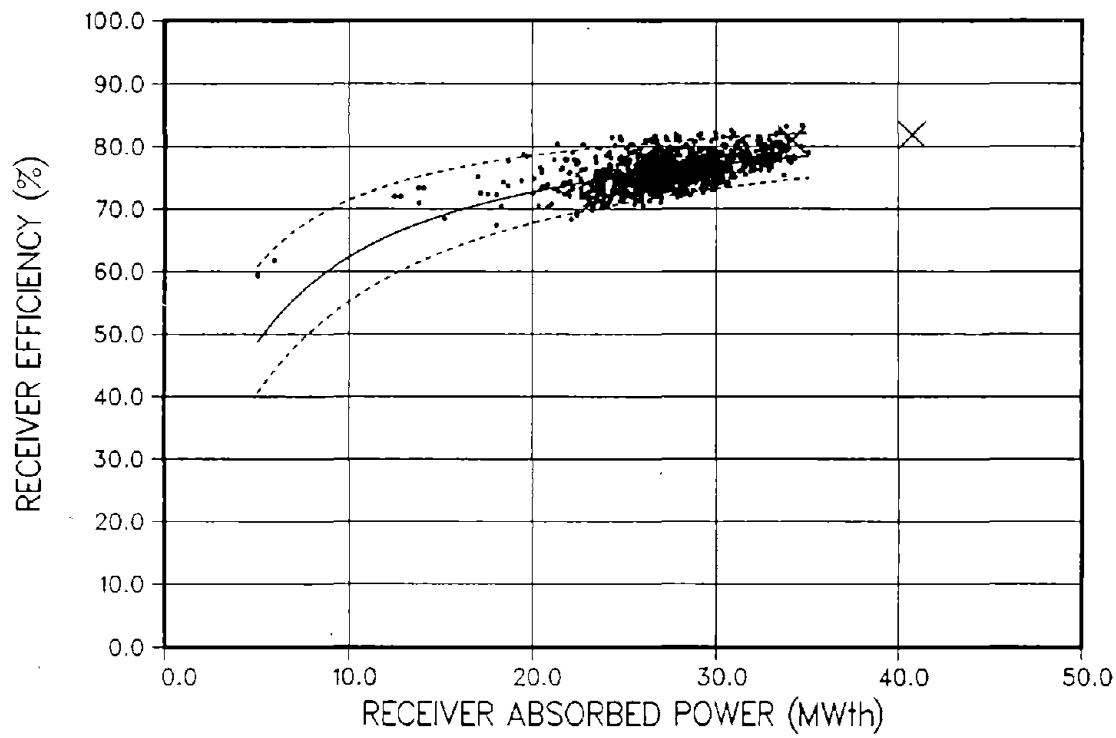


Figure 6–1. Receiver Point-in-time Efficiency Versus Absorbed Power (before Receiver Repainting)

The data show that the expected efficiency is 76.7% at an absorbed power of 34.0 MW_t with a 0.95 probability that the receiver efficiency will be between 72.9% and 80.8%. These results compare well with earlier test results (References 6–1 and 6–9) where the receiver efficiency was reported to be near 76.0% at the same absorbed power level.

The receiver efficiency decreases as the absorbed power decreases. The decrease in efficiency with a decrease in absorbed power occurs because the receiver losses are nearly constant. The losses depend on the receiver surface temperature which only changes slightly as the incident and absorbed powers change. The expected efficiencies at 25.5 MW_t (75% part load) and 17.0 MW_t (50% part load) are 74.7% and 71.4%, respectively. The drop in receiver efficiency of just 5.3 percentage points from the maximum absorbed power value to the half power value should be considered good since almost all the receiver operation was above the half power value.

The predicted design point efficiency is 81.2% at an absorbed power of 34.2 MW_t (Reference 6–8). This value is just about on the upper 0.95 probability curve. A second predicted design point value, 81.9% at an absorbed power of 40.8 MW_t, would lie near an extrapolated portion of the upper 0.95 probability curve.

A comparison of the measured and design values shows that: (1) the measured efficiency was slightly less than the predicted efficiency at the first design point; and (2) no measurements were made at the high absorbed powers needed to verify the second design point. Both results can be explained, with some qualifications, by the difference between the measured and design surface absorptance. The measured value of the surface absorptance was less than the 0.95 design value up to December 1985 when the receiver was repainted (see the discussion of Surface Absorptance later in this chapter).

The effect of repainting the receiver surface is shown in Figure 6–2. The data points at an absorbed power of about 37 MW_t, which were taken in March 1986, are 81.4% and 82.7%. Thus an increase of almost five percentage points was achieved by repainting the receiver surface.

The agreement between the measured and design efficiency values was better after the receiver was repainted. Although the better agreement is encouraging, some caution is required when comparing the results. The "actual" and "design" receivers, on which the values are based, were still different. First, the measured absorptance was 0.97 versus the design value of 0.95. Second, the measured active area of the absorbing surface was 96.2% of the measured exposed area, which in turn differed from the design area. Finally, the measured

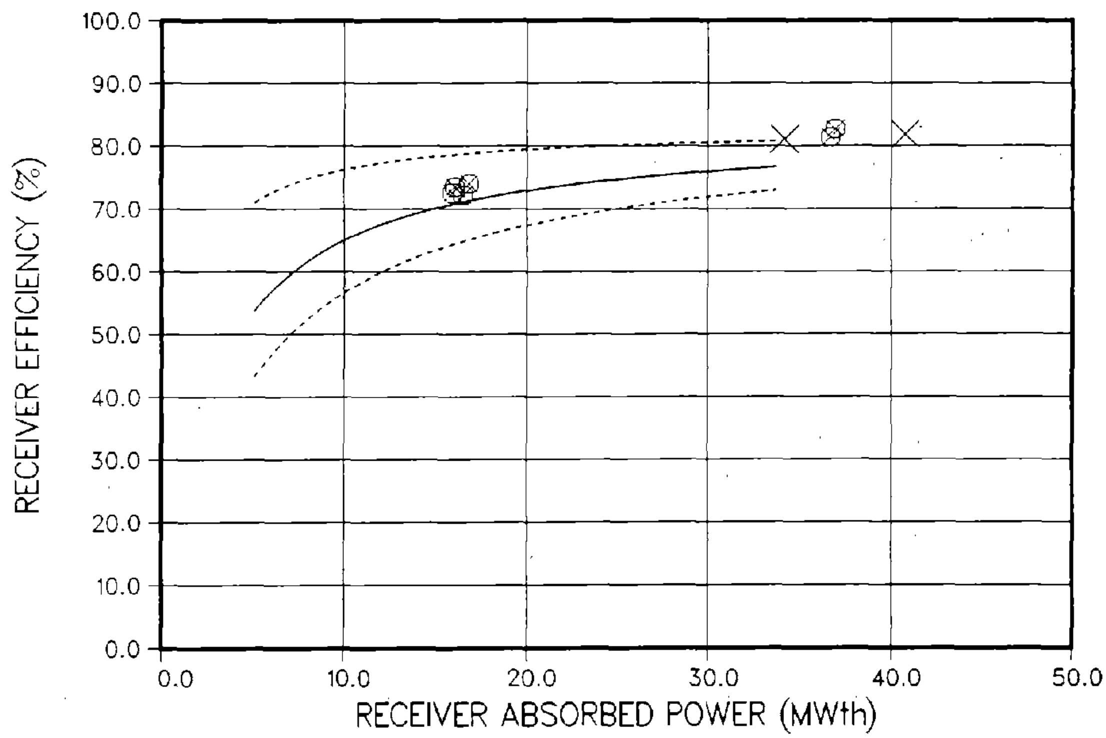


Figure 6—2. Receiver Point-in-time Efficiency Versus Absorbed Power (after Receiver Repainting)

receiver temperature conditions were different from its design conditions; for example, the measured outlet temperature on one test was 813°F (434°C) versus the design value of 960°F (516°C).

The absorbed power needed to verify the second design point could not be reached in spite of an increased surface absorptance. The reasons were due to soiled mirrors, low insolation, and some heliostats being out of service, all of which reduced the incident power on the receiver surface.

A final comment on the efficiency-versus-absorbed-power data concerns a comparison of results obtained with the two experimental methods described at the beginning of this section. Figure 6–2 shows data points that are based on test results from Method 2. These points, as well as others (not shown) generated by Method 2, fell on or within the 0.95 probability envelope that was generated from the tests using Method 1. The results indicate that the Method 1 receiver efficiency values agree well with those predicted from the Method 2 analysis.

Point-in-time Efficiency Versus Ambient Wind Speed —Receiver efficiency was calculated as a function of ambient wind speed for wind speeds up to about 27 mph (12 m/s). The point-in-time efficiency values were based on tests that satisfied the following receiver conditions: (1) an inlet temperature of 240-375°F (115-190°C); (2) an outlet temperature of 780-860°F (415-460°C); (3) an outlet pressure of 1300-1500 psi (9.0-10.3 MPa); and (4) a calculated incident power of 35-38 MW_t. Again, only data from steady-state plant operation were studied in the analysis.

The efficiency as a function of wind speed is shown in Figure 6–3. The figure displays 322 data points that are based on measured values of the absorbed power and calculated values of the incident power (Method 1). The solid line is a least squares fit to the data while the dashed lines show the 95% prediction interval: for a given value of the wind speed, there is a 0.95 probability that the efficiency will lie between the limits shown.

Wind speed was not considered in the calculation of the receiver incident power. If wind speed causes the heliostat's reflected beam to fluctuate on the receiver, the incident power on the receiver will decrease because of increased beam spillage. This will cause the efficiency values at the high wind speeds to be slightly higher than the values shown in Figure 6–3.

The data show that the expected efficiency is 76.5% at the lowest wind speed and 70.9% at the highest wind speed. Thus, the expected receiver efficiency dropped 5.6 percentage points over the range of wind speeds studied. The results show a slightly stronger dependence on wind speed than the early test results reported in Reference 6–1. The early results, which were based on limited test data, showed that the receiver efficiency decreased about one percentage point as wind speed increased from 0 to 20 mph (0 to 8.9 m/s).

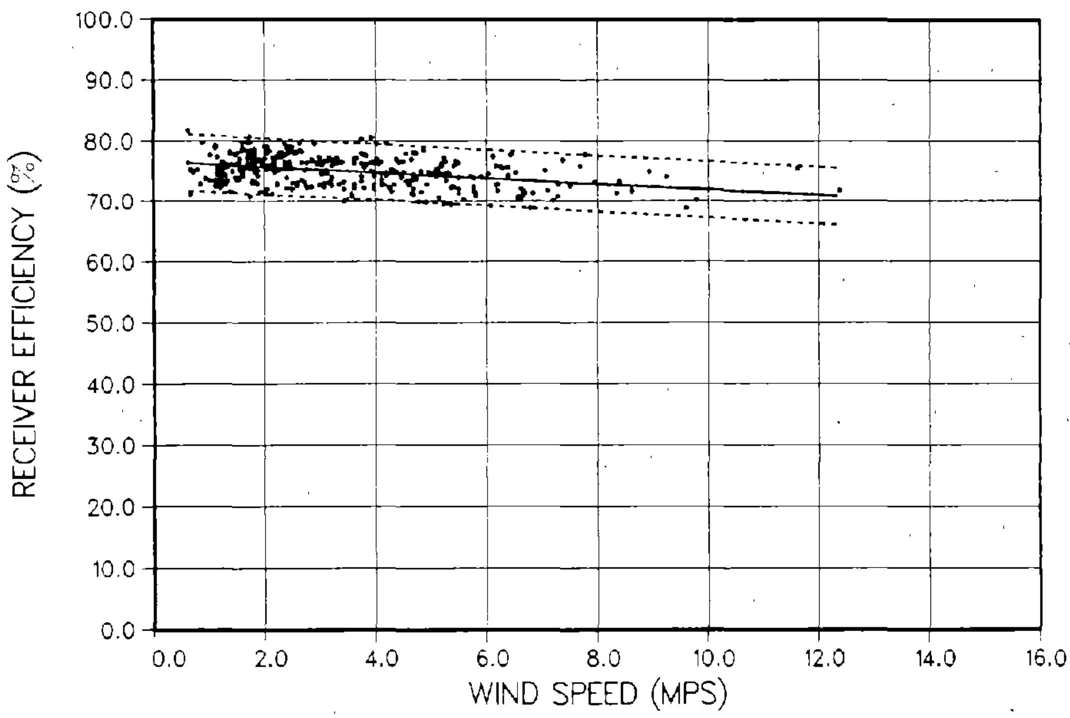


Figure 6—3. Receiver Point-in-time Efficiency Versus Wind Speed

The current results agree well with efficiency predictions described in Reference 6-10. In this reference the receiver efficiency as a function of wind speed was estimated from radiation loss calculations and convective loss data obtained on the Pilot Plant receiver. A reduction of 7.2 percentage points was estimated for the receiver as wind speed increased from 4.5 to 27 mph (2 to 12 m/s).

Receiver Losses

The point-in-time data obtained on the measured absorbed power and the calculated incident power were analyzed further to determine the frequency of occurrence of the receiver total losses. The receiver total losses include losses by emitted radiation, conduction, and convection.

The receiver total losses were calculated from the equation:

$$LOSS = (EFFABS * INC) - ABS$$

where

EFFABS: effective absorptance, that is, the measured flat surface value adjusted for the tube geometry and inactive, exposed receiver surface area

INC: calculated incident power

ABS: measured absorbed power

The data points in Figure 6–1 were analyzed by calculating an effective absorptance value for each point, taking into account the day of the year, the tube geometry, and the active receiver area. The incident power was obtained by assuming a linear relationship between the incident and absorbed powers (the solid line in Figure 6–4). The number of times the total loss was within 0.25 MW_t intervals from 0 to 10 MW_t was then tabulated.

The results of the tabulation are shown in Figure 6–5. The distribution of the frequency of occurrence of the receiver total losses has the general shape of a normal distribution. The mean value of the losses is 4.7 MW_t with an estimated standard deviation of 1.2 MW_t. The high estimated standard deviation for these data indicates that there would be a large uncertainty in determining the losses using just a few data points. Even now the best that can be said is that the receiver total losses are around 4.7 MW_t for the test conditions evaluated.

Receiver losses were also calculated using the Method 2 analysis. The total losses were calculated to be 4.4 MW_t from a test done prior to repainting and 4.9 MW_t and 5.6 MW_t from two tests performed after repainting. Considering the uncertainties involved, the agreement in the receiver loss values between Methods 1 and 2 is quite good.

Average Efficiency

The average efficiency is the energy absorbed by the receiver divided by the energy incident on the receiver over a number of operating days. The average efficiency is a measure of the receiver's performance under typical operating conditions. It includes the effects of receiver start-up energy needs as well as the effects of operating over a range of insolation conditions. It is important to note that average efficiency, by itself, can be misleading. A receiver that only operates for a short time during midday could have a high average efficiency but produce little annual energy. Thus operating times are also an important parameter in the evaluation of receiver performance.

The average efficiency was determined by first calculating the receiver absorbed and incident powers at three minute intervals during a given day. Both powers were then integrated over specified periods of time to obtain daily average energies and a daily average efficiency The daily energies were also added to determine the receiver average efficiency value over some number of days.

The specified time periods for the absorbed and incident energy calculations were not the same. The absorbed energy time interval began when the receiver

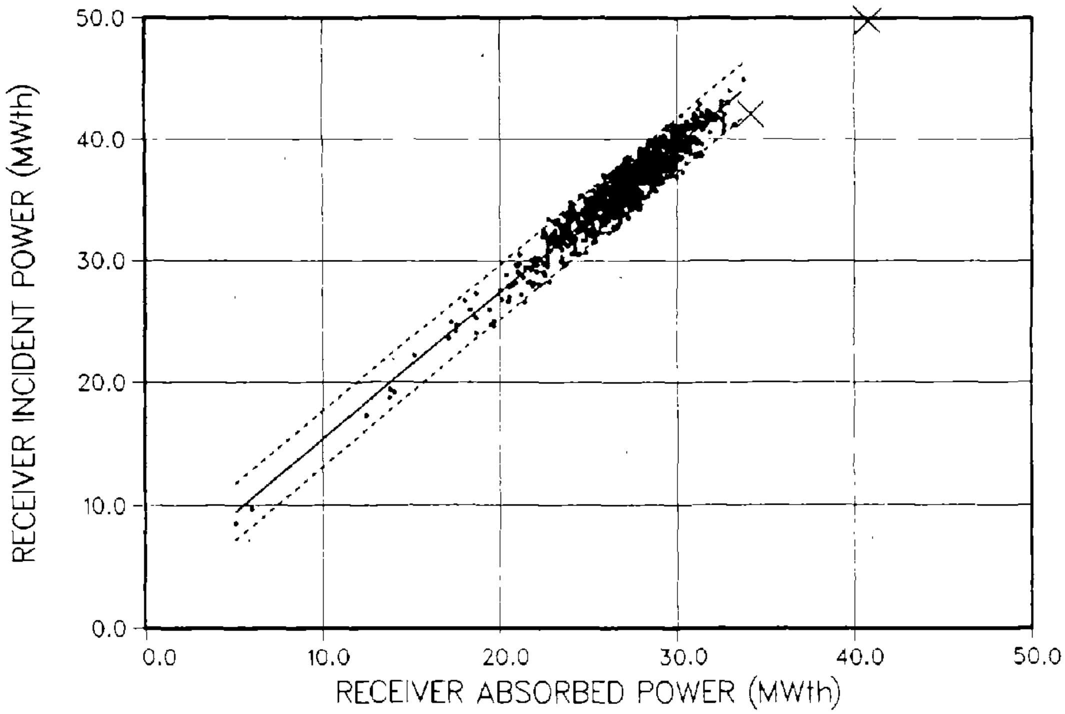


Figure 6—4. Receiver Incident Power Versus Absorbed Power

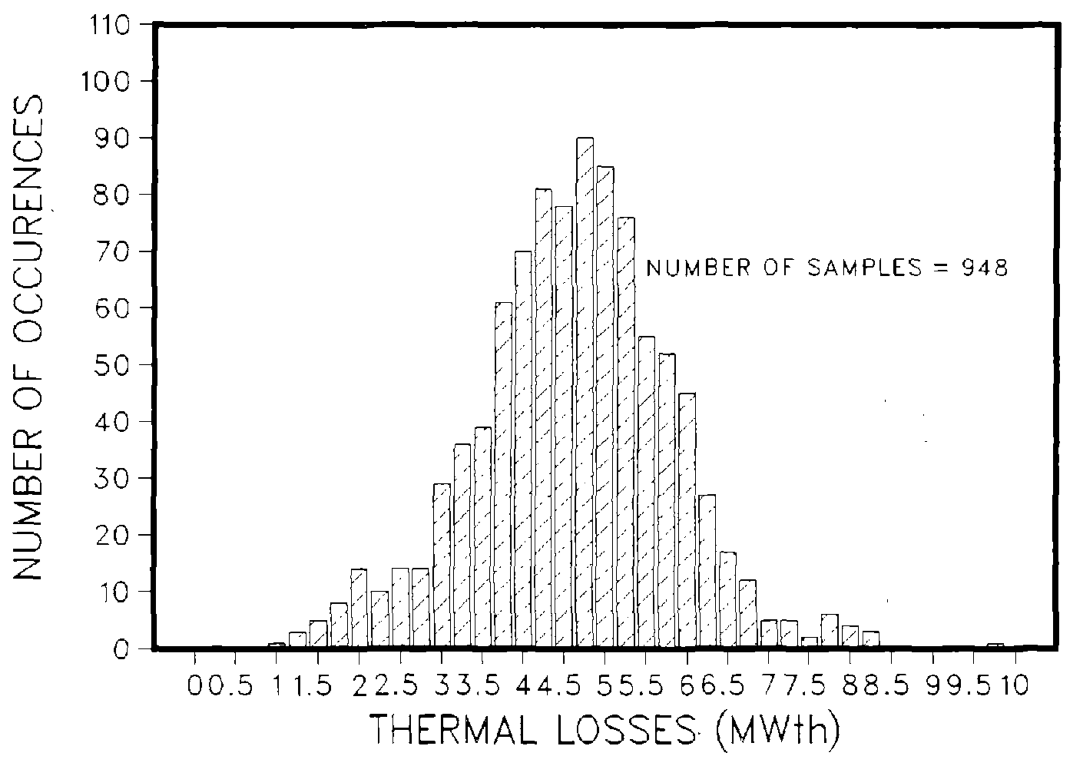


Figure 6—5. Receiver Losses

delivered superheated steam to the bottom of the tower. This definition for the receiver absorbed energy was selected because it is only when superheated steam is at the bottom of the tower that the steam can be used to drive the turbine/generator or charge thermal storage. The absorbed energy time interval ended when the receiver was shut down. The incident energy time interval included all times during which heliostats were tracking the receiver. Thus, the slower the receiver was at reaching its design outlet condition the lower its average efficiency would be.

Two year-by-year comparisons of the average receiver efficiency were made to assess trends in receiver performance. The first comparison was based on all operating days for which sufficient data were recorded to permit calculation of the absorbed and incident powers. In the second comparison "good days" were selected for each calendar year to assess trends on a more consistent basis. A good day was one where: (1) insolation was measured for at least all but one hour during the day; (2) the average insolation for the day was over 500 W/m^2; (3) the heliostat tracking of the receiver started within one hour of sunrise; (4) insolation was recorded within a half hour of sunrise; and (5) the receiver operated (absorbed power) for all but three hours during the solar day. In this context the term "good day" implies not only a good operating day but also a good data recording day.

Tables 6–1 and 6–2 show average efficiencies and some operating times of interest based on typical and good operating days for the years 1982 to 1986. The numbers of days selected for analysis are less than the actual number of plant operating days. The number of days that can be analyzed for each year is affected by several factors including adequate insolation for operation, scheduled and unscheduled maintenance outages, and a functioning data recording system. Some of the plant's data recording equipment, which was not essential to plant operations, was not always operating when the plant was operating. The values for 1982 are particularly low because they only included the month of December.

The average efficiency for the good days was 2-4 percentage points higher than the value for the typical days during each year. This increase largely reflects increased operation under full load conditions as a result of better insolation. The average efficiency for both typical and good days showed an improvement of 6.5 percentage points from 1985 to 1986. The increase reflects the receiver repainting that was done in late 1985 to improve the receiver's surface absorptance.

The point-in-time efficiency values prior to 1986 were measured to be 76.7% at full absorbed power and 71.4% at half absorbed power (see discussion under Point-in-time Efficiency Versus Absorbed Power). These efficiencies are for low wind speed conditions and would be even lower for high winds. The data in Table 6–1, which include operation under all wind conditions as well as the receiver start-up energy needs, show that the average efficiency for typical day operation

Table 6-1
Average Receiver Efficiency

Item	1982	1983	1984	1985	1986
Number of Days Analyzed	17	176	237	200	133
Average Efficiency (%)	60.2	66.8	67.9	67.5	74.0
Hours of Insolation	8.5	10.4	10.9	10.3	10.9
Hours of Incident Power	7.2	8.6	8.9	9.5	9.3
Hours of Absorbed Power	5.0	6.7	7.1	7.7	7.8

Table 6-2
Average Receiver Efficiency for "Good Days"

Item	1982	1983	1984	1985	1986
Number of "Good Days" Analyzed	2	32	74	64	48
Average Efficiency (%)	62.2	68.9	71.6	70.6	77.1
Hours of Insolation	9.4	11.7	11.9	11.8	12.2
Hours of Incident Power	8.8	11.2	11.2	11.4	11.6
Hours of Absorbed Power	6.9	9.2	9.7	9.9	10.4
Hours to Heliostats All Tracking	3.3	2.3	1.1	0.7	0.4
Hours to Steam to Downcomer	2.0	1.9	1.7	1.6	1.3

is within 10 percentage points of the peak point-in-time efficiency and 5 percentage points of the half power value. When the average efficiencies for the good days operation are compared to the point-in-time efficiencies the differences are even less. These results indicate that most receiver operation is near the peak power level. The 5 to 10 percentage point difference between the average and peak efficiencies that was observed at the Pilot Plant is good compared to other central receiver plants.

The average daily hours of insolation shown in Table 6–1 varied from year to year. The values depend on the relative number of days from each season and the relative number of good and not-so-good weather days that were included in the evaluation. The 1982 value is low because it only includes December, a month when the daylight hours are short and the weather is less favorable. The values for 1983 and 1985 are less than the ones for 1984 and 1986 because the plant was shut down for receiver repairs during portions of the summer months in 1983 and 1985.

The differences in the average daily hours of insolation from year to year are less pronounced, as expected, when the good days analysis is considered. The good days data, like the typical days data, illustrate the improvements in the receiver start-up with time: the difference in the hours of incident and absorbed power decreased from 1983 to 1986. This improvement is also shown by the last two entries in Table 6–2, which show the average number of hours to get all available heliostats tracking the receiver and the average number of hours to get steam to the downcomer. Both numbers are measured from the theoretical time of sunrise at the Pilot Plant site and both decreased over the years.

Receiver Life

The Pilot Plant's receiver life evaluation includes the performance of the panel mechanical supports and the occurrence of panel tube leaks since the start of receiver operations in February 1982. From February 1982 through July 1987 the receiver was operated seven days a week, from sunrise to sunset, except when weather or hardware problems limited operation. Thus over five years of operating data were available to assess the receiver's 30-year design life.

Receiver Design

The Pilot Plant's twenty-four receiver panels are all the same design. The only differences between the panels are the inlet orifices and instrumentation. The panels are designed to be flat in the vertical direction and have a radius of curvature equal to the receiver radius in the lateral direction.

A 70-tube receiver panel consists of seven subpanels of ten tubes each. During fabrication the subpanel tubes were first welded together along their entire length, and then the subpanels were welded together. Attachments were welded on the back of the panels to carry the panel loads. Figure 6–6 shows the locations of tube bends and manifolds at the top and bottom of the panels and the panel supports at levels 1-6. The weight of a panel is carried by supports under each subpanel at the top of the panel, level 7.

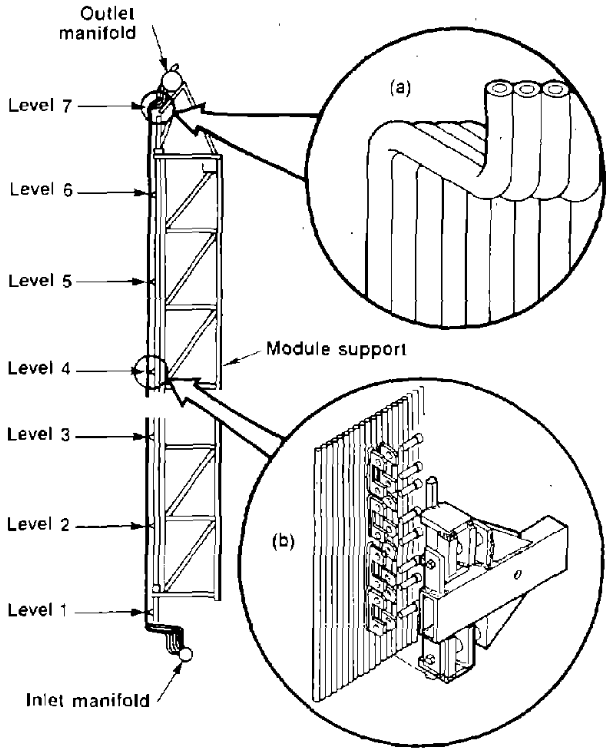


Figure 6—6. Receiver Panel Schematic

After the subpanel tubes were welded together, the tube ends were bent to an appropriate shape. The first bend at both the top and bottom was approximately a 90° bend toward the core or inside of the receiver with about a 1.5 in (38 mm) bend radius. The lengths of the subpanels and the tube shapes after the first bend on each end were different to allow the tubes to be welded to the panel inlet and outlet manifolds.

The welds between the subpanels are referred to as the panel "interstice welds". An interstice weld was terminated at the top and bottom of the panel by extending the weld along the shortest subpanel and wrapping it over about one inch on the front of the panel. A small portion of insulation at the top and bottom of the panel covers the interstice weld termination. Figure 6–7, a photograph of the top portion of a panel, shows the subpanels, supports under the subpanel first 90° bend, and interstice welds on the front of the panel. The insulation at the top of the panel has been removed to expose this area of the panel. The wires across the top of the subpanels are used to hold the insulation material above the subpanels in place.

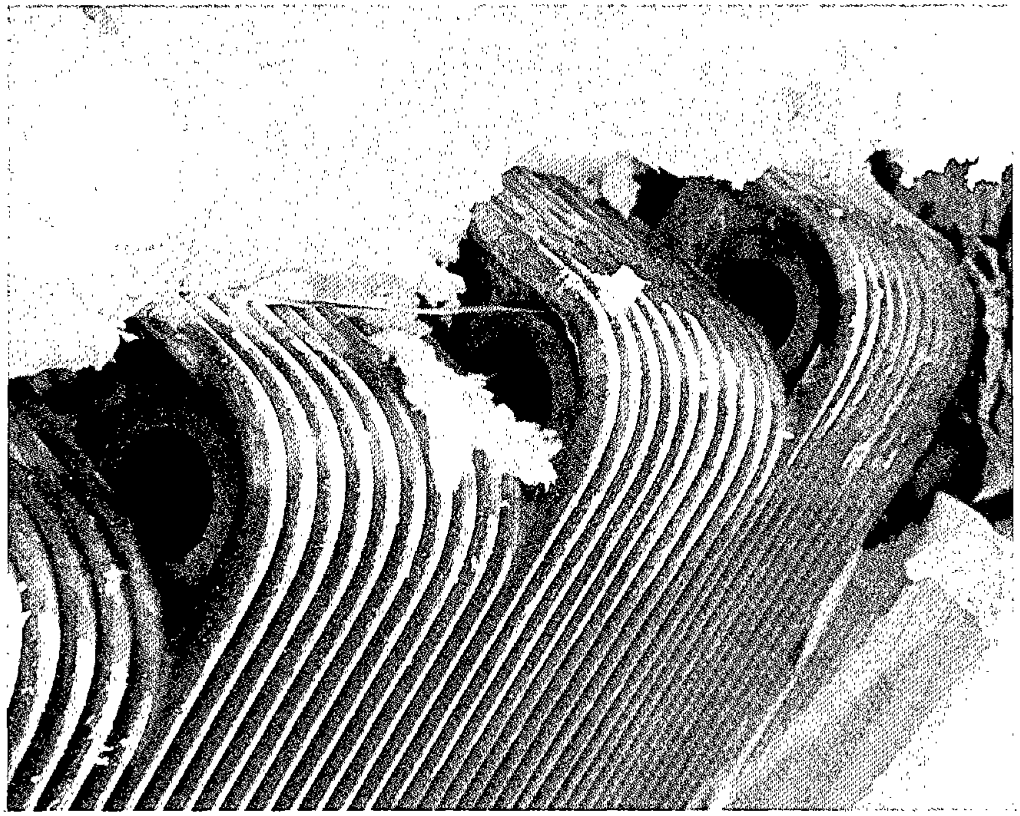


Figure 6—7. Photograph of Top Portion of a Receiver Panel

After the subpanels were welded together, the inlet and outlet manifolds were welded to the tubes. The panel was then connected to the panel module support. The attachment clips welded to the back of the panel, shown in Figure 6–6 at levels 1 through 6, were located on each side of the panel, around tube 10 on one side and tube 60 on the other side. The clips were connected to the panel module support with pins and rollers (not shown). The rollers were free to move as the panel changed temperature. Thus the panel, at levels 1 through 6, was free to move vertically on the panel module structure relative to level 7. The roller supports were designed to keep the panel from warping (radial deflection in and out along the panel normal) and bowing (decreased panel radius of curvature in the lateral or receiver circumferential direction). Level 7, the top subpanel tube bend supports, was fixed and carried the panel weight. The panel module structure supported the panel weight, lateral loads (side to side), and radial loads (in and out) of the panel.

Early Panel Warpage

A slight panel warpage was observed on several receiver panels in March 1982, two months after the receiver began operation. Figure 6–8 shows the top

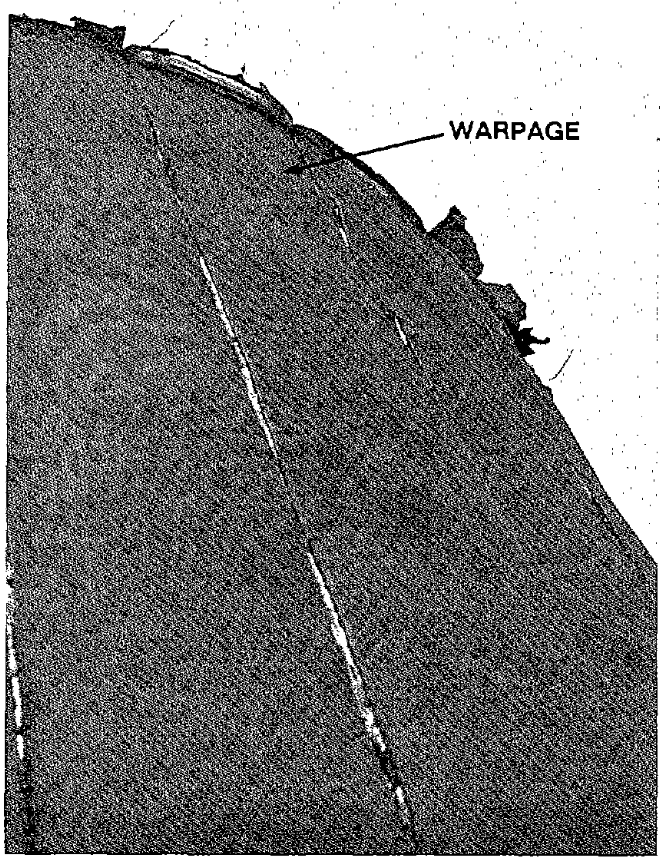


Figure 6—8. Photograph of Early Panel Warpage

portion of several receiver panels with the areas of warpage. Back surface metal temperature data at the top of each panel indicated that the north side of a panel was hotter than its south side. This lateral temperature gradient across a panel resulted from a lateral incident flux gradient on the panel since most of the heliostats in the heliostat field were north of the receiver.

As a result of the temperature gradient, the hot side of a panel expanded more than the cool side. But the tubes were welded together, so the cool tubes restrained expansion of the hot tubes and warpage occurred. The design of the panel supports and rollers may have contributed to panel warpage by constraining the uneven panel growth.

The panel temperature data also showed that a panel's north edge tube had the highest tube metal temperature. The space between adjacent panels allowed the panel edge tubes to be exposed to incident radiation over about 270° around the circumference of the tube while interior tubes were exposed over about 180°. The high temperatures in the edge tubes existed even though there were no orifices in the panel edge tubes to limit the water flow.

The slight warpage observed on the receiver panels had no effect on early receiver operation. Therefore, in 1982 no modifications were made to the panels to reduce the lateral temperature gradients or to the rollers to accommodate the uneven panel growth.

The warpage on one panel was apparently caused when the panel overheated from a loss of water flow. This panel expanded so much that it hit the bottom of the panel module support at level 1. To keep this from happening to other panels, the module support on each boiler panel was modified by extending its length to allow for more panel expansion.

Initial Tube Leaks

The first receiver tube leaks were observed in July 1983, eighteen months after receiver operation began. The leaks, named Type I leaks, occurred at the top, superheated section of one panel on each side of the center subpanel at the interstice weld. In August 1983, a second type of tube leak was observed. The new Type II leak was located on the top of a different panel on the panel north edge tube at the crown of the first 90° bend. This interstice weld and tube bend area of the panel is covered with insulation and is not exposed to the incident solar flux.

Figure 6–9 shows a drawing of the top portion of a panel and the location of the Type I and Type II leaks. The subpanel tube bends are toward the inside (core side) of the receiver and away from the incident solar radiation reflected from the heliostat field. The center subpanel interstice welds are between tubes 30 and 31 on one side and tubes 40 and 41 on the other side. The first interstice weld leaks were between tubes 30 and 31 and tubes 40 and 41. The panel edge tubes are tubes 1 and 70. The portion of the panel not shown in the figure, tubes 51 through 70, is a mirror image of tubes 1 through 20.

Several studies were performed to determine the cause of the two types of leaks and find a way to eliminate their occurrence. The studies were both analytical and experimental in nature. Until the cause of the leaks was understood, the maximum receiver steam outlet temperature was reduced from the design value of 960°F (516°C) to about 770°F (410°C). At first it was hoped that the leaks were exceptions and that there was not a generic problem with the receiver. After several receiver inspections, using dye penetrant and ultrasonics over a period of months, more interstice weld and tube bend cracks and leaks were found. The inspection data showed a tube leak problem affecting several receiver panels.

(a)

(b)

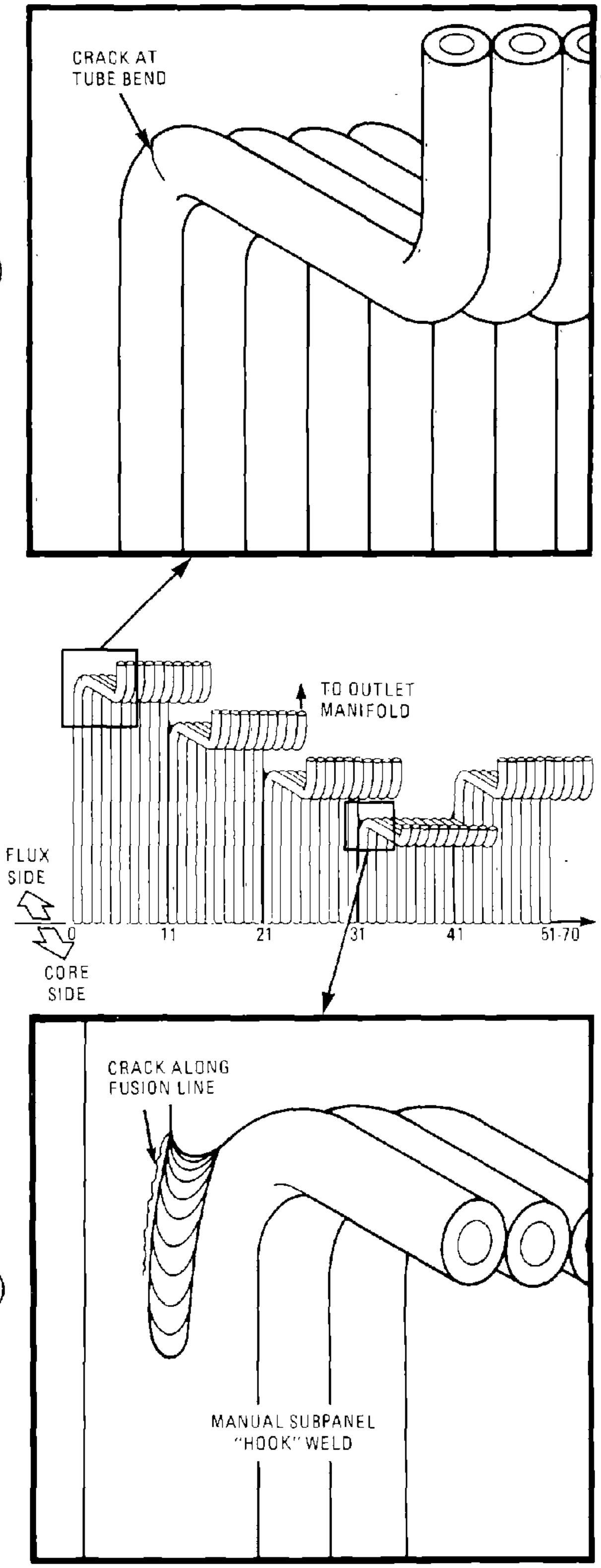


Figure 6—9. Locations of (a) Edge Tube Leaks (Type II) and (b) Subpanel Interstice Weld Leaks (Type I)

Interstice Weld Leaks—In August 1983, a small section of the interstice weld and tube from the panel with the Type I leak was removed and replaced with new tube material. Figure 6–10 is a photograph of the section of tube and weld removed from the panel with the interstice weld leak. Regions A and B show the termination of the crack next to the interstice weld. The crack is in the interstice weld fusion line between subpanels. The tube in the figure is tube 30, from the subpanel next to the center subpanel. The tube is longer than the tubes in the center subpanel and extends beyond the interstice weld between tubes 30 and 31. Region A in the figure is on the front side of the panel and region B is on the back. The crack extended only a short distance toward the front of the panel compared to the back. Detailed fractography of the crack showed that the crack initiated on the outside diameter of the tube near the weld heat affected zone and propagated into the tube. The crack surface striation spacing indicates that the failure was due to low cycle fatigue.

In October 1983, another panel was found that had a leak at the interstice weld, next to the center subpanel and between tubes 30 and 31. By the end of 1983 the dye penetrant inspections of the interstice welds between each subpanel showed numerous cracks on several panels. A summary of the inspection of the interstice welds, shows: (1) ten panels had cracks at one or more interstice welds; and (2) two panels had leaks at one or more interstice welds adjacent to the center subpanel. The distribution of the cracks at the interstice welds showed that 70% occurred between tubes 30 and 31 and tubes 40 and 41. No cracks were found on the water preheat panels, panels 1-3 and 22-24.

Analyses of the interstice weld area did not show conclusively the cause of the interstice weld failure. The results showed that the magnitude of the stresses due to constraining the expansion (temperature increase) or contraction (temperature decrease) in the lateral direction was low compared to the material yield strength. This represents the case where the supports under each subpanel restrained the lateral subpanel movement. The highest stresses predicted in the interstice weld between subpanels occurred when there was a large temperature difference between adjacent subpanels. This condition could occur during receiver shutdown if water at the saturation temperature flows to the top of one subpanel, still at the superheated steam temperature, before it flows to the adjacent subpanel. The data for the tube metal temperatures at the top of a panel showed occurrences where the tube 35 temperature, in the center subpanel, would drop before the tube 5 and tube 65 temperatures, in the exterior subpanels. We did not have data for adjacent subpanels.

In January 1984 modifications were made to all of the boiler panels to eliminate the occurrence of interstice weld cracks and leaks. Five of the seven supports for the subpanels at level 7 were removed. Supports were left under the two subpanels containing tubes 11-20 and tubes 51-60. The modifications also included the grinding out of all known cracks and weld filling the ones that were

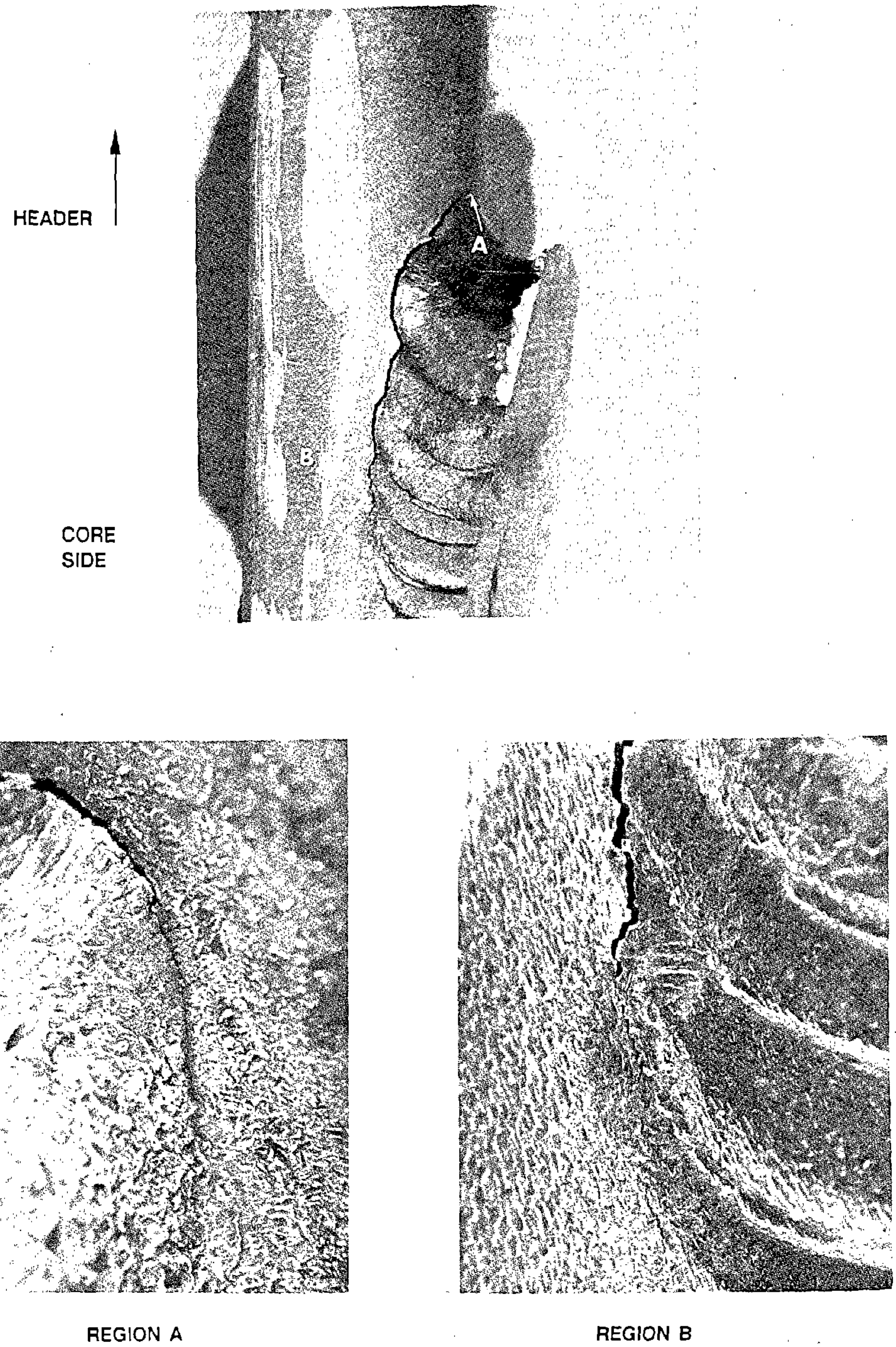


Figure 6—10. Photograph of a Tube and Weld Section Removed from a Panel with an Interstice Weld Leak

more than 0.004-0.008 in (0.1-0.2 mm) deep. The portion on the interstice weld which extended to the front of the panel and a small portion on the back of the panel were ground away. At the interstice welds on each side of the center subpanels, the interstice weld was ground away for a length of about 4 in (100 mm) down the panel. The termination of this grinding was tapered so that the weld was thin where the weld was removed and gradually thickened to its full thickness in about 1 in (25 mm). It was believed that if these modifications did not reduce the stresses in the interstice region, then any crack which did occur would be in the tapered weld and not in the tube.

No interstice weld leaks have occurred since these modifications and additional plant operational changes (discussed below) were made. However, cracks are visible in the tapered region of some interstice welds adjacent to the center subpanels. This indicates that the modifications did not relieve all of the loads in the interstice weld region of the panels.

Edge Tube Leaks—In August 1983 the leaking edge tube bend was removed and replaced with a new tube bend. The removed tube section extended from below the first 90° tube bend leak location to above the second 90° tube bend, shown in Figure 6–9. Figure 6–11 is a photograph of the Type II crack in the edge tube bend section removed from the panel. The crack is circumferential in direction, around the tube. The crack is located on the extrados, or outer curve, of the bend and wrapped around approximately 150° of the tube (see Figure 6-9 (a)).

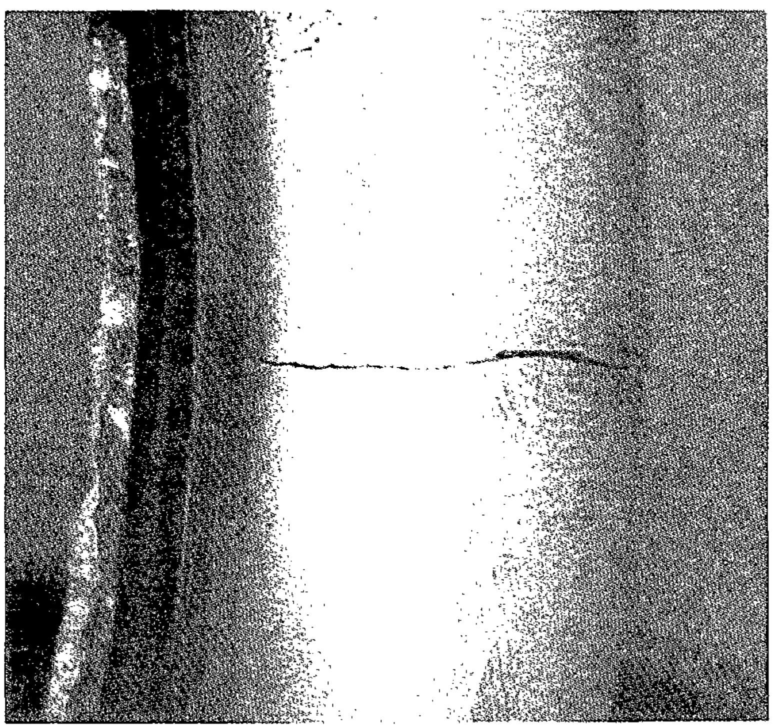


Figure 6—11. Photograph of a Crack in the Edge Tube Bend Section Removed from a Panel

By November 1983 ultrasonic inspections of the boiler panels first 90° tube bends showed that three panels had cracks in their edge tubes. One of the cracks was in the tube section that was replaced in August 1983. In December 1983, the edge tube bends with cracks were removed from two boiler panels. Material samples were also removed from tube bends without cracks from two other panels. The material samples were edge tubes from panels in which the edge tubes had operated at lower temperatures than the tubes which had cracked. A summary of the results from all the ultrasonic inspections shows that: (1) nine panels had cracks or crack indication in their edge tubes; and (2) five panels had leaks in their edge tubes. All of the cracks or leaks were in the north edge tubes which tend to operate at the highest temperature compared to other panel tubes. Also, the panel edge tubes with cracks had operated at higher temperatures than those panels without cracks.

A detailed metallographic evaluation was performed on the tube bend sections removed from the panels. The evaluation indicates that the tube bend cracks initiated on the inside surface of the tube. Figure 6–12 is a photograph of the cross-section of one of the edge tube bends removed from a panel. The crack began on the tube extrados inside surface and extended about 150° around the tube. Figure 6–13 is a low magnification photograph of the tube inside surface on the extrados, near the crack initiation site. The magnified photo shows many circumferential cracks, running perpendicular to the tube axis, and axial cracks, parallel to the tube axis. Further metallographic studies show that the circumferential cracks are much deeper than the axial cracks. The two material samples from tubes which operated at lower temperatures did not have any cracks. The major conclusions from these analyses are: (1) cracks initiate on the inside diameter in the extrados of the tube bend; (2) cracking occurs in both a circumferential and axial direction; (3) cracking is transgranular for both types of cracks; and (4) only circumferential cracks propagated to the outside of the tube.

The appearance of the inside surface at the tube extrados indicates that the tube has experienced high circumferential and axial tensile stresses. A high combined stress of these types could result if the inside surface of the tube is much cooler than the outside surface. This would be the case if during receiver shutdown water at the saturation temperature impinged on the tube bend inside surface while it was still at the superheated steam temperature. The thermal shock resulting from this condition would cause the cracks to initiate. Other types of loadings or repeated thermal shocks could then cause the crack to propagate through the tube wall.

The new tube section, which replaced a section of the first leaking edge tube, showed an ultrasonic indication of a tube bend crack within six months of being installed. The new tube section had a different mechanical environment than the old section since it was not welded to the adjacent tube. Yet, it still cracked. The appearance of cracks in the new tube section again suggests that thermal shock of the high temperature panel edge tubes is the cause of this type of crack.

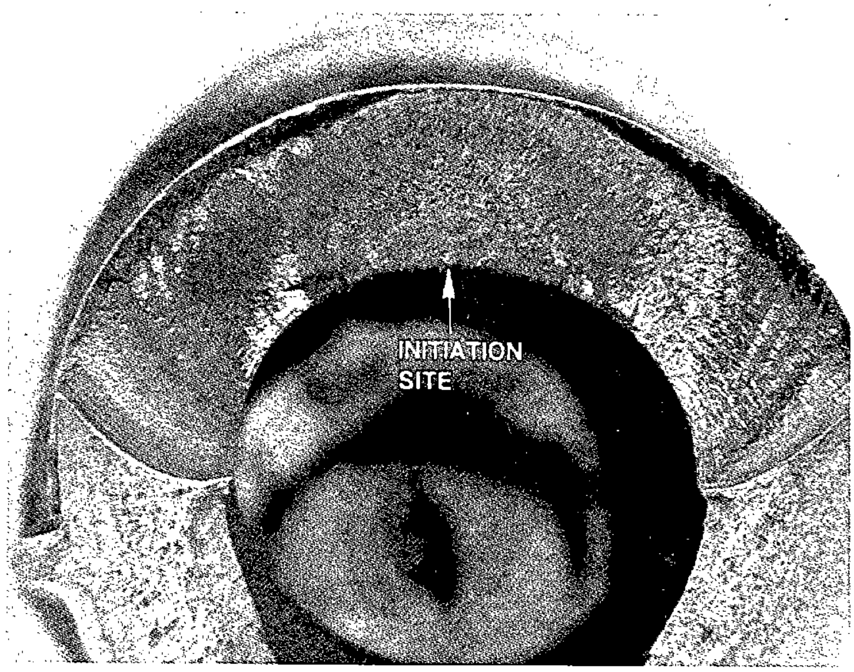


Figure 6—12. Photograph of the Cross-section of a Cracked Edge Tube Bend Section Removed from a Panel

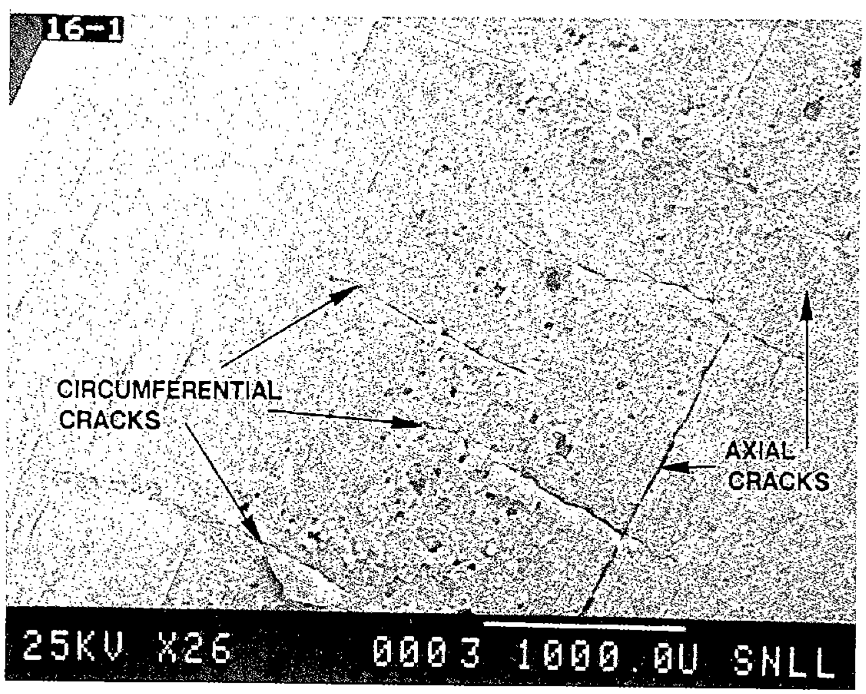


Figure 6—13. Low-magnification Photograph of Crack Initiation Site on the Tube inside Surface

The two material samples did not have inside surface cracks similar to those found in the other edge tube bends. However, these tube bend material samples had operated at lower temperatures than those where cracks were found.

Laboratory experiments were conducted to reproduce the type of cracking shown in Figure 6–13. Tube samples were heated to high temperatures, about 1200°F (650°C). Room temperature water was then injected into the tube at the extrados of the tube bend. The same types of cracks shown in Figure 6–13 were found on the tube inside surface.

A change in the receiver operating procedure and a modification to the receiver were made to eliminate the occurrence of tube bend cracks. The operating procedure was changed to reduce the outlet steam temperature to about 600°F (315°C), under controlled conditions, before receiver shutdown. Then, if water at the saturation temperature impinges on the tube bend inside surface during receiver shutdown, the temperature difference between the inside and outside of the tube will be less and cracks are less likely to occur. Also, radiation shields were installed between the panels on over half the receiver to reduce the north edge tube temperatures. The radiation shields keep the incident radiation from impinging on the side of the edge tubes, which makes their radiation environment similar to the interior panel tubes.

At the time of the operating procedure and radiation shield changes, three panels had edge tubes with known ultrasonic crack indications. The three tubes eventually developed leaks and were repaired. The tubes were repaired by grinding out the cracks and filling with weld material. No other edge tube bend leaks have occurred on the receiver panels since these changes were made.

In December 1983 a panel inspection revealed that more panels were warping. Also, several panels were beginning to bow in the superheating section. Bowing is a decrease in a panel's radius of curvature in the lateral direction. The panel back surface support brackets and rollers were inspected, and the bolts connecting the rollers to the panel module support were broken or bent. The bolt failures were found on nine panels with most failures at level 2. As the panel temperature increases the panels expand from the top, level 7, which is fixed. Thus, the bottom of the panels has the greatest vertical movement. If the rollers at level 2 bind and do not roll then the panel will warp to accommodate the thermal expansion. An inspection of the rollers showed considerable corrosion and seizing of the rollers onto their axles. The rollers were modified in February 1984 to increase the tolerance between the roller and its axle.

Later Tube Leaks

In July 1985, after about forty-two months of receiver operation, leaks were found on 3 panels at levels 5 and 6, where the attachment clips for the panel supports are welded to the panels. Figure 6–14 shows the location of the leaks, called a Type III leak. The "U" shaped clips are welded to the panel, and the support brackets are connected to the clips with pins. The leaks are located at the ends of the clips near the weld boundary and are circumferential in direction. Since the first clip weld leaks were found in 1985, 15 of the 18 boiler panels have had clip weld leaks at levels 5 and/or 6. Usually both sides of the panel at a given level have clip weld leaks. The clip weld leaks were repaired using the grind and weld fill method.

Initially, we thought the clip weld leaks were caused by the roller assembly binding and loading the clip. However, the leaks continued to occur even after the rollers were modified to increase their tolerance so that they would roll more freely. Also, the vertical movement of the panels at levels 5 and 6 is small compared to the movement at levels 1 and 2, and no clip weld leaks were found at levels 1 and 2.

Another possible cause could be the loads that are placed on the panel clips restraining the panels from bowing. With the panel front surface temperature higher than the back surface temperature, the panels will try to bow due to thermal expansion. The panel supports at levels 1 to 6 restrain the panels from bowing. The temperature difference between the front and back surfaces is greatest

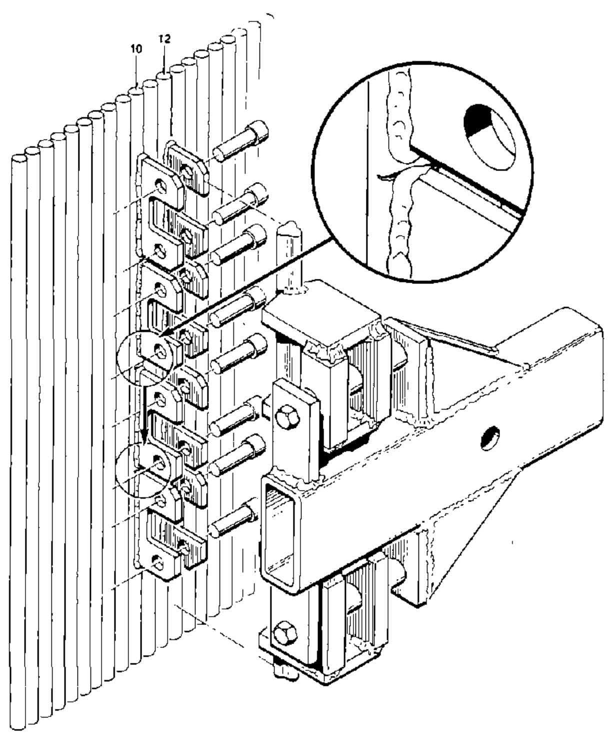


Figure 6—14. Location of Panel Clip Weld Leaks (Type III)

in the superheating section of the panels. Levels 5 and 6, the locations of the clip weld leaks, are in or near the superheated region: the level 6 support is in the panel superheated steam section, and the level 5 support is near the boundary of the saturated steam and superheated steam regions.

Analyses showed that high thermal stresses in the weld region between the panel tube and clip can result from the temperature gradient across the panel tube, weld, and clip material. The stresses are again highest in the high temperature region of the panels where the temperature gradients are the greatest. We believe that these stresses are the primary cause of the clip weld leaks.

Analyses of the clip stresses caused by the panel mechanical loads showed that the stresses were low compared to the material yield strength. The analyses also showed that the panel support at level 6 could be removed without a large increase in the clip stresses at level 5. As a result, the boiler panels were modified by removing the panel supports and clips at level 6. A modification of the panel supports and clips at level 5 was also attempted for two panels but did not work. The modification on the two panels removed all but a portion of two sets of clips and restrained the panel lateral movement with cables. Removing the clips reduced the clip weld leaks; however, the cable supports did not restrain the panel lateral movement. Clip weld leaks continued to occur after these modifications with some leaks now occurring at level 4. As long as these types of clips are welded to the panel, there is a chance of further clip weld leaks.

In June 1986, 53 months after the start of receiver operation, the north edge tube of one panel developed a leak (named Type IV) on the front side of the tube about 13 ft (4 m) below the top tube bend. An inspection of the tube revealed many circumferential cracks from 1.5 ft (0.5 m) above the leak to over 3 ft (1 m) below the leak. The appearance of the tube surface indicated that the tube experienced very high temperatures. Tube back surface metal temperature data confirmed this and showed that this edge tube operated at higher temperatures than any other panel edge tube. People with extensive experience in superheated boilers called this type of crack as "fire cracking". Cracking of the same type is found in superheated boilers when the tube has operated at high temperatures. The leak was repaired by replacing 19 feet (6 m) of the tube from above the top first 90° tube bend. At the end of 1987, only one other panel edge tube had had a fire cracking failure.

Summary

The Pilot Plant receiver has experienced four distinct types of tube leaks since testing began in February 1982. Table 6–3 summarizes the time of first occurrence and the location of each type. The causes of the leaks and possible solutions for eliminating their reoccurrence were studied for each leak type. Modifications to the receiver panel and changes to receiver operating procedures eliminated the interstice weld and north edge tube bend leaks, but clip weld leaks are still occurring. Since only two north edge tubes have had front surface leaks, no modifications were made to eliminate this type of leak. The radiation shields installed between panels to reduce the operating temperature of the north edge tubes should have a positive effect on limiting the front surface tube leaks. Also, it is hoped that a reduction in the maximum steam outlet temperature to below 840°F (450°C) will reduce the occurrence of clip weld leaks.

Table 6-3
Summary of the Receiver Tube Leaks

Type	Time of Occurrence (Months after Start-up)	Leak Location
I	18	interstice weld next to the center subpanel
II	19	north edge tube at the top 90° bend
III	42	panel back surface clip weld
IV	53	north ege tube front surface below tube bend

The severity of the panel warpage and bowing increased with time. Modifications to the panel roller supports to allow the supports to move more freely have not eliminated the warpage and bowing deformations. Figure 6–15, a recent photograph of the top portion of the receiver, shows how severe these deformations are compared to the earlier photograph in Figure 6–8. Panel warpage and bowing do not affect receiver operation other than exposing the panel supports behind the panel to incident solar radiation. However, such deformations may be reducing the receiver life and most likely will lead to additional tube leaks on the receiver. Additional insulation has been installed to protect the panel supports.

After more than seventy months of receiver operation, many things about receiver life have been learned. Most tube leaks have been associated with some type of weld on the panels. One need is to reduce the number of welds and be concerned with the relative size of materials welded to the tubes. Over constraining the panel thermal expansion can lead to high thermal stresses in the panel tubes. The severe thermal environment and exposure to weather can cause corrosion on the panel supports and restrict their movement. Temperature gradients due to lateral incident solar flux gradients and panel front-to-back surface temperatures during start-up, cloud transients, and shutdown can cause thermal creep-fatigue leading to panel warpage and bowing. Having the panel tubes welded together along their length when the panel has a lateral temperature gradient can lead to panel deformation. Overall, the Pilot Plant operation has provided valuable receiver life data for the designers of future receivers.

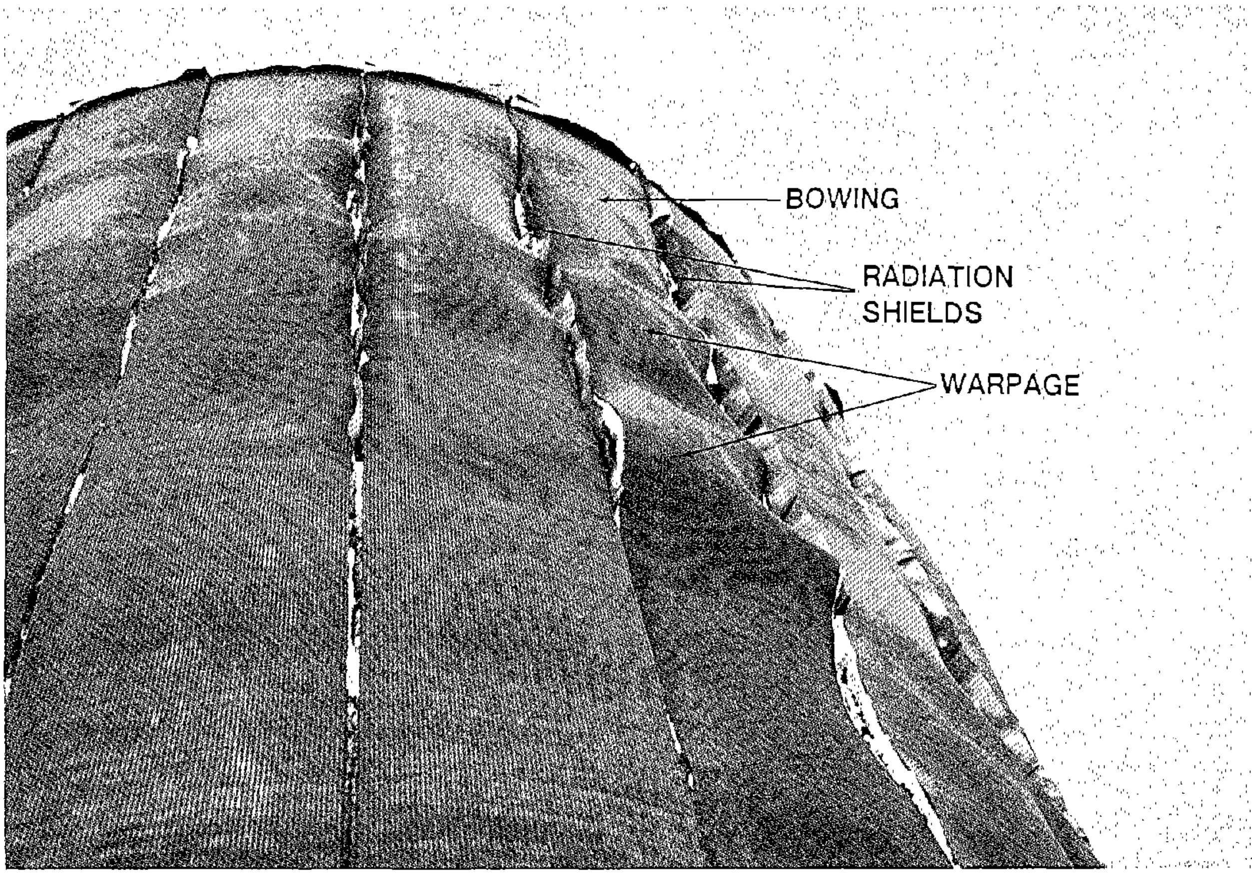


Figure 6–15. Photograph of Current Panel Warpage and Bowing

Surface Absorptance

The Pilot Plant receiver panels are coated with Pyromark, a black, nonselective, high-temperature paint. The paint increases the absorption of solar energy by the panels. In operation, water enters the receiver and flows in parallel through three low-temperature water preheat panels (Panels 1 to 3). The water then flows in parallel through three high-temperature water preheat panels (Panels 22 to 24), and finally in parallel through eighteen boiler panels (Panels 4 to 21), where it exits as superheated steam. Figure 6–16 shows the panel numbering system and the locations of the preheater and boiler panels.

The receiver is designed to operate with an inlet water temperature of about 350°F (175°C) and an outlet superheated steam temperature of about 960°F (516°C). In each panel the water flows from the bottom to the top of the panel. Thus the top of a panel is at a higher temperature than its bottom.

North panels receive the highest incident solar fluxes and south panels receive the lowest. Peak incident flux ranges from a low of 100 kW/m^2 on Panels 1 and 24 to a high of about 300 kW/m^2 on Panels 12 and 13. The incident flux distribution is nearly the same on all panels, and only the peak values change.

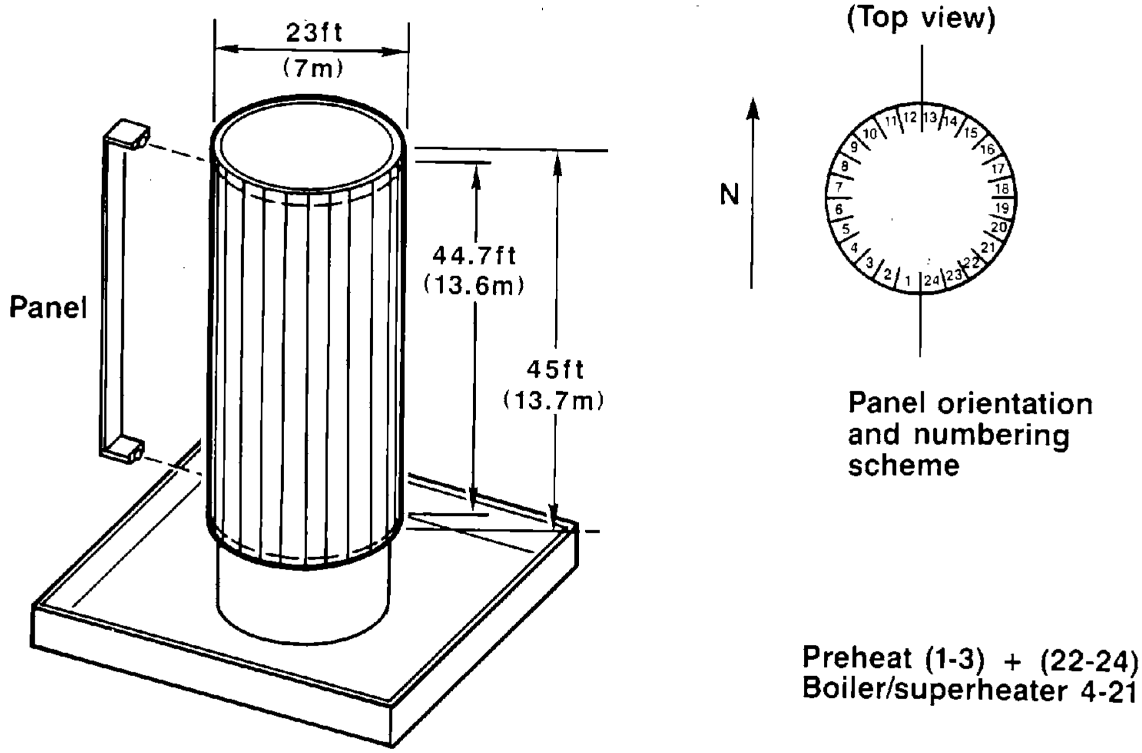


Figure 6—16. Receiver Panel Numbering System

Pyromark paint was applied to the panels in early 1981 and cured after the panels were installed on the tower in early 1982. The cure was carried out using the sun's energy reflected from the heliostat field to heat the panels. Nominal recommended cure temperatures and times were used to cure the panels except for 24 hours of the final temperature-time of 1000°F (535°C). The maximum cure temperature even when operating at the design superheated steam outlet temperature was below 725°F (385°C) over most panels. Only the top of the boiler panels experienced temperatures near the recommended final cure temperature.

The design absorptance of the receiver surface is 0.95. To determine the actual absorptance and any changes in absorptance with time, measurements of the absorptance of each panel and two spare panels were made from 1982 to 1987. The solar absorptance measurements were made using a solar spectrum reflectometer. For flat samples, the instrument was accurate to +/- 0.01 absorptance units; the necessity of generating correction factors for measurements on the small receiver tubes reduced the accuracy to about +/- 0.02 absorptance units. The instrument measured the solar spectrum reflectance, and the absorptance was calculated from the equation:

Absorptance = 1 - (Correction Factor) * (Measured Reflectance).

In most cases sufficient measurements were made so that the 90% confidence interval on the panel average solar absorptance was +/-0.005 absorptance units.

The average solar absorptance for the receiver was calculated using the individual panel averages, but each panel average value was weighted based on a representative noon time distribution of solar energy incident on the receiver. Thus, more weight was given to the average solar absorptance of the panels which have the most incident solar energy and less to panels with less incident solar energy.

The first measurements of solar absorptance were performed in November 1982. The measurements occurred about a week after the last measurable rain at the site. Measurements were next performed in December 1983. For these measurements there had not been any measurable rain for about two months at the site. The third measurements were performed in September 1984. The last measurable rain occurred three days before these measurements began. For this case, measurements were made on both "as-is" and washed panel surfaces.

In March 1985 one panel, Panel 12, was repainted in order to develop a repainting method for panels while they are on the receiver. In April 1985 the absorptance of this panel, two adjacent panels (Panels 11 and 13), and the two spare panels was measured. In December 1985 all receiver panels were repainted, including Panel 12. The cures for the March and December repaintings were carried out using the sun's energy reflected from the heliostat field to heat the panels. Finally, in March and August 1986 and October 1987 absorptance measurements were again performed on all panels.

Figure 6–17 shows the average absorptance data for the receiver. The results indicate that the receiver panels experienced a decrease in absorptance with time. The average receiver absorptance was measured as follows: November 1982 – 0.92; December 1983 – 0.90; September 1984 – 0.88. Repainting of the receiver in December 1985 successfully restored the absorbing characteristics of the panel surfaces. Solar absorptance measurements made on the receiver in March and August 1986 showed that the average solar absorptance of the receiver was about 0.97 and did not change, within experimental accuracy, between March and August. However, by October 1987 the absorptance decreased to 0.96.

Additional observations from the absorptance measurements follow:

(1) A slight increase in the measured solar absorptance was achieved after washing the panel surfaces, but dirt does not appear to be a significant cause of the loss in solar absorptance.

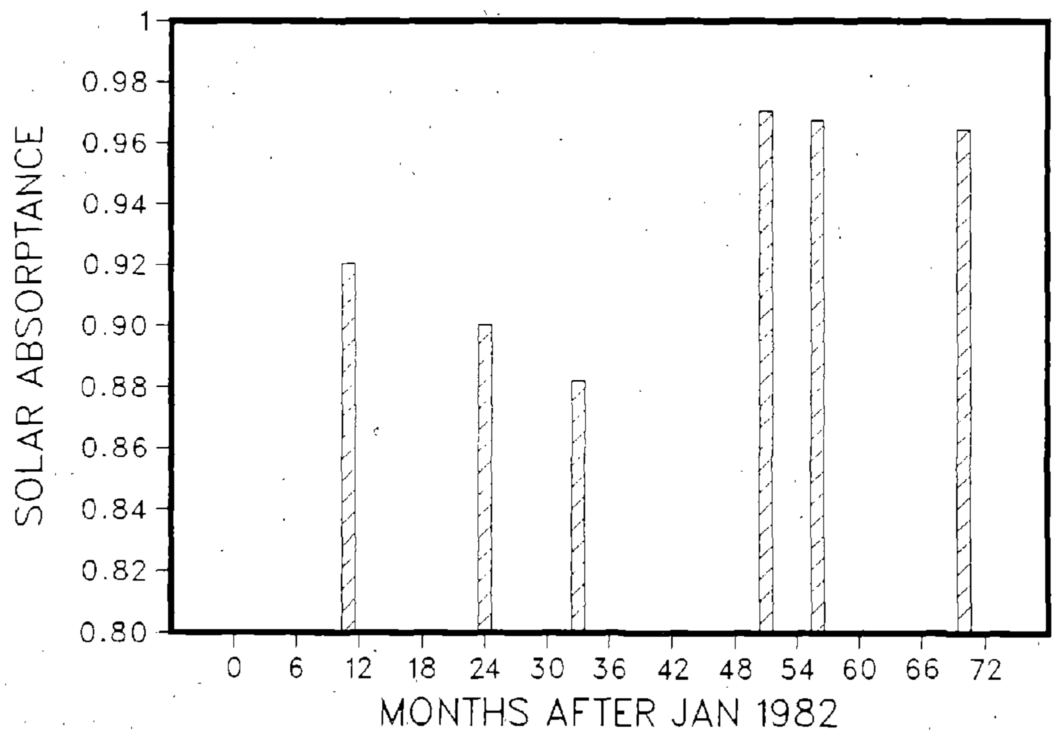


Figure 6—17. Receiver Absorptance

(2) The receiver panels with the lowest operating temperature, i.e., the low-temperature water preheat panels, consistently had the highest solar absorptance compared to the other receiver panels. However, by the second measurement period, the three high-temperature water preheat panels had a lower average solar absorptance than several boiler panels which operate at higher temperature and incident solar flux levels than the preheat panels.

(3) The panel to panel variation of the solar absorptance within each group of low-temperature water preheat panels, high-temperature water preheat panels, and boiler panels, that all operate within their group at about the same temperature distribution and outlet temperatures, showed a decrease in average solar absorptance and an increase in incident solar flux.

(4) The vertical solar absorptance distribution on the boiler panels changed with time. By September 1984 the lowest solar absorptance was near the bottom of the panel (low temperature and low incident solar flux) and in the middle of the panels (moderate temperature and highest incident solar flux). The highest solar absorptance usually occurred at the top of the boiler panels (high temperature and low incident solar flux).

(5) Whenever solar absorptance measurements were made on the receiver, they were also made on the two spare panels. These spare panels are at the Pilot Plant and are lying horizontal with the Pyromark surface facing up, uncovered. The Pyromark paint on these panels was not cured and was not exposed to high solar flux or temperature, but it was exposed to the normal weather at the site. Over the solar absorptance measurement time period, the two spare panels showed very little change in their average solar absorptance compared to the panels on the receiver.

Receiver Start-Up

The heliostat aimpoints used to direct the reflected solar energy onto the receiver worked well during the day. However, in the early morning and late afternoon, insufficient energy was directed to some panels, causing delays in start-up or changes in plant operations.

During an early morning start-up, some boiler panels (Panels 17 to 21 on the east side of the receiver) are slower than others in reaching the desired receiver outlet temperature. The receiver start-up procedures are such that the receiver cannot sequence through its start-up until each boiler panel has reached this temperature. The speed at which a boiler panel reaches the desired temperature is determined by the panel's low flow limit and the incident solar energy on the panel. Hardware changes were made to reduce the low flow limit on the boiler panels, and the changes did result in a faster early morning receiver start-up. However, some boiler panels were still slower than others to reach the desired outlet temperature.

Late afternoon operations, like early morning start-up, are a function of the low flow limit through the boiler panels and the incident solar energy. In late afternoon, water flow through some boiler panels (Panels 4 to 8 on the west side of the receiver) is so low that the flow control valves begin closing and then opening in trying to maintain a constant boiler panel outlet temperature. When this occurs, the receiver outlet temperature is reduced in order to increase the flow to the panels and prevent damage to the flow control valves. However, there is a limit on how low the receiver outlet temperature can be reduced and still operate the steam turbine.

It is more important to decrease the early morning start-up time than to extend the late afternoon operations. By decreasing the start-up time the receiver and plant are put in operation as the insolation is increasing. Extending late afternoon operations keeps the plant operating as the insolation is decreasing. At the Pilot Plant, more plant operation time would be gained by decreasing the early morning start-up time than by extending the late afternoon operations.

The problems of slow early morning start-up and afternoon low water flow through some panels could be solved by adding more heliostats in critical locations of the heliostat field. Another solution is to use different heliostat aimpoints so that the sun's reflected energy is increased on the panels which are slow to reach the desired outlet temperature in the morning or have low water flow in the afternoon. Reference 6–6 contains a study of the latter solution, also discussed below.

Initial Heliostat Aimpoints

Different heliostat field aimpoint files* were employed for morning start-up, midday, and afternoon operations. In addition, different start-up and afternoon aimpoint files were used for winter and summer operations, while the same midday aimpoint file was used over the entire year. The initial aimpoint files used at the Pilot Plant had one thing in common: the heliostats were all aimed at the vertical centerline of the receiver. The aimpoint files differed from one another in the elevation of the aimpoints along the centerline. Thus, changing from one aimpoint file to another changed the distribution of the aimpoints on a particular panel, but not the total number of aimpoints on the panel. Alternately stated, the changes in heliostat aimpoint elevations changed the vertical distribution of the solar energy incident on a panel, but not the total solar energy incident on the panel. The change from a morning start-up aimpoint file to the midday aimpoint file was usually done between 8:00 a.m. – 10:00 a.m. local time. Likewise, the change from the midday aimpoint file to an afternoon aimpoint file was done between 2:00 p.m. – 4:00 p.m. local time.

Improved Heliostat Aimpoints

To develop an improved morning start-up aimpoint file, some heliostat aimpoints from Panels 8 to 19 were shifted circumferentially in a clockwise direction toward Panel 21. For an improved afternoon aimpoint file, some heliostat aimpoints from Panels 5 to 17 were shifted circumferentially in a counter-clockwise direction toward Panel 4. Aimpoints from one panel were not moved circumferentially more than two panels, and the vertical elevation was not changed for any aimpoints. The number of heliostat aimpoints moved from each panel varied. The intent was to either reduce the early morning start-up time or extend late afternoon operation by increasing the number of heliostats aimed at the panels that needed more energy.

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* An aimpoint file is the array of aimpoints for the 1,818 Pilot Plant heliostats. The file is used by the plant computer to direct the reflected solar energy from each heliostat onto the receiver surface.

The effect of moving the heliostat aimpoints circumferentially was analyzed using the MIRVAL heliostat field performance code (Reference 6–7). The solar energy incident on the receiver panels was calculated for summer and winter solstice in one hour increments. To eliminate the insolation value as a variable in the calculations, the fraction of the total solar energy incident on the receiver was calculated for each panel. The assumption was that if the fraction of the total receiver energy incident on a panel at a given hour increased, then the new aimpoint file was an improvement over the old.

The calculations showed that the fraction of the total receiver energy could be increased on selected panels, by moving the aimpoints circumferentially. The increases in the fraction of the total receiver energy incident on Panels 17 to 21 and Panels 4 to 8 are shown below for representative times on summer and winter solstice.

	Panel Number				
Date (Time)	17	18	19	20	21
June 21 (0600)	17.0%	14.8%	22.2%	19.2%	16.9%
December 21 (0800)	5.9%	36.6%	68.1%	96.7%	89.2%

	Panel Number				
Date (Time)	4	5	6	7	8
June 21 (1800)	15.6%	10.0%	8.0%	13.0%	26.9%
December 21 (1600)	42.8%	66.6%	53.8%	45.7%	16.3%

Experience at the Pilot Plant revealed that during early morning start-ups in December, Panels 20 and 21 were the slowest to reach the desired panel outlet temperature. In June Panels 18 and 19 were the slowest. The large increase in incident solar energy on Panels 20 and 21 in December should reduce the time for these panels to reach the desired outlet temperature. However, the increase in June may be too small to have a significant effect on the panel start-up time. This result indicates that it may be better to have new start-up aimpoint files for at least two seasons of the year rather than just one.

Similar results are seen for late afternoon operation. The large increase in the solar energy incident on Panels 4 to 8 in December should delay the cyclic operation of the flow control valves of these panels. This would extend receiver operations at the desired outlet temperature until most of the boiler panel flows were near cyclic operation. At this time the receiver outlet temperature would be reduced or the receiver would be shut down. Since the increase in the fraction of the total receiver solar energy incident on Panels 4 to 8 is greater in December than in June, it would again indicate more than one new afternoon aimpoint file is needed.

The results of using the new morning aimpoint file can be seen by comparing receiver start-up times shown in Figures 6–18 and 6–19. Figure 6–18 shows a histogram of the receiver start-ups **before** the new aimpoint file was used. Figure 6–19 shows a histogram of start-up times **after** the new file was implemented. In both figures the start-up time is measured from a theoretical prediction of sunrise at the Pilot Plant site to the time when superheated steam is flowing in the downcomer.

Figure 6–18 shows that almost half of the receiver start-ups occurred in less than 1.8 hours after sunrise. The majority of the start-ups occurred around 1.6 hours after sunrise. Figure 6–19 shows that with the new start-up aimpoint file the majority of the start-ups occurred around 1.2 hours after sunrise. The new aimpoints,(along with the effect of receiver repainting), therefore, reduced the start-up time by about 20 minutes. Revising the heliostat aimpoints demonstrated the flexibility of using the heliostat field to improve the overall performance of an external receiver.

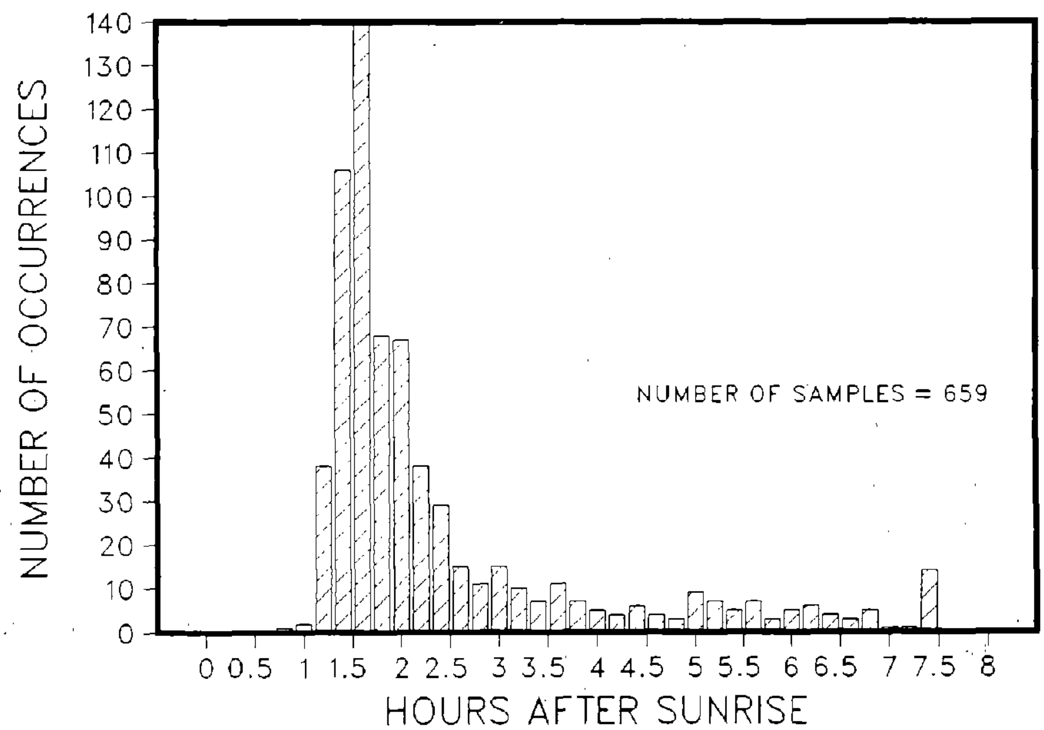

Figure 6—18. Receiver Start-up Times (January 1983 — November 1985)

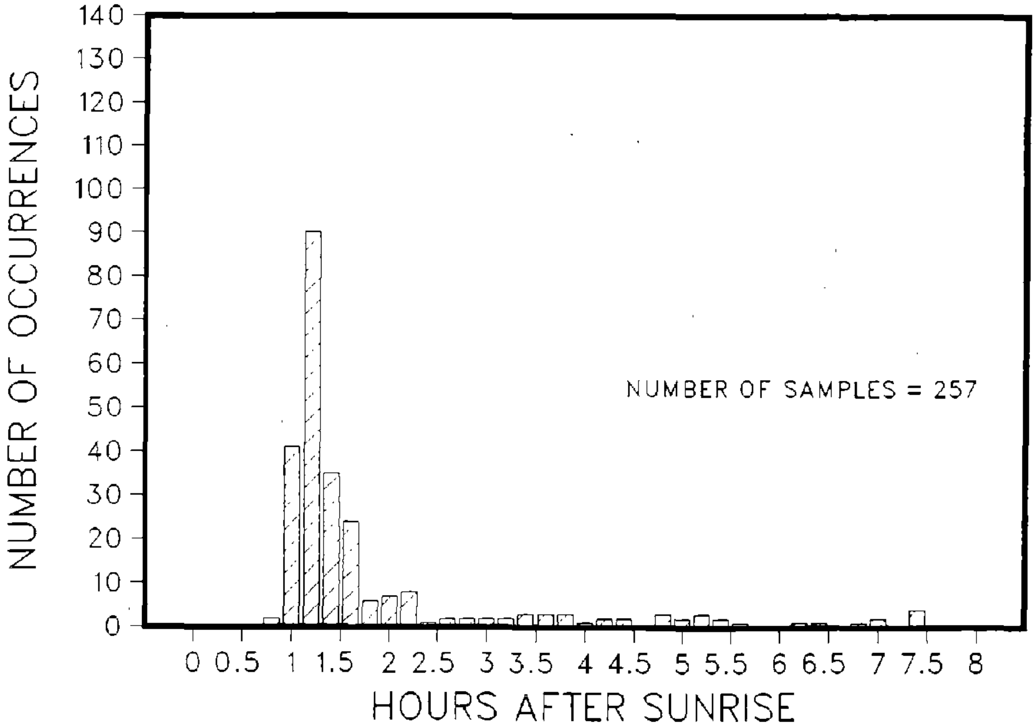

Figure 6—19. Receiver Start-up Times (January 1986 — December 1986)

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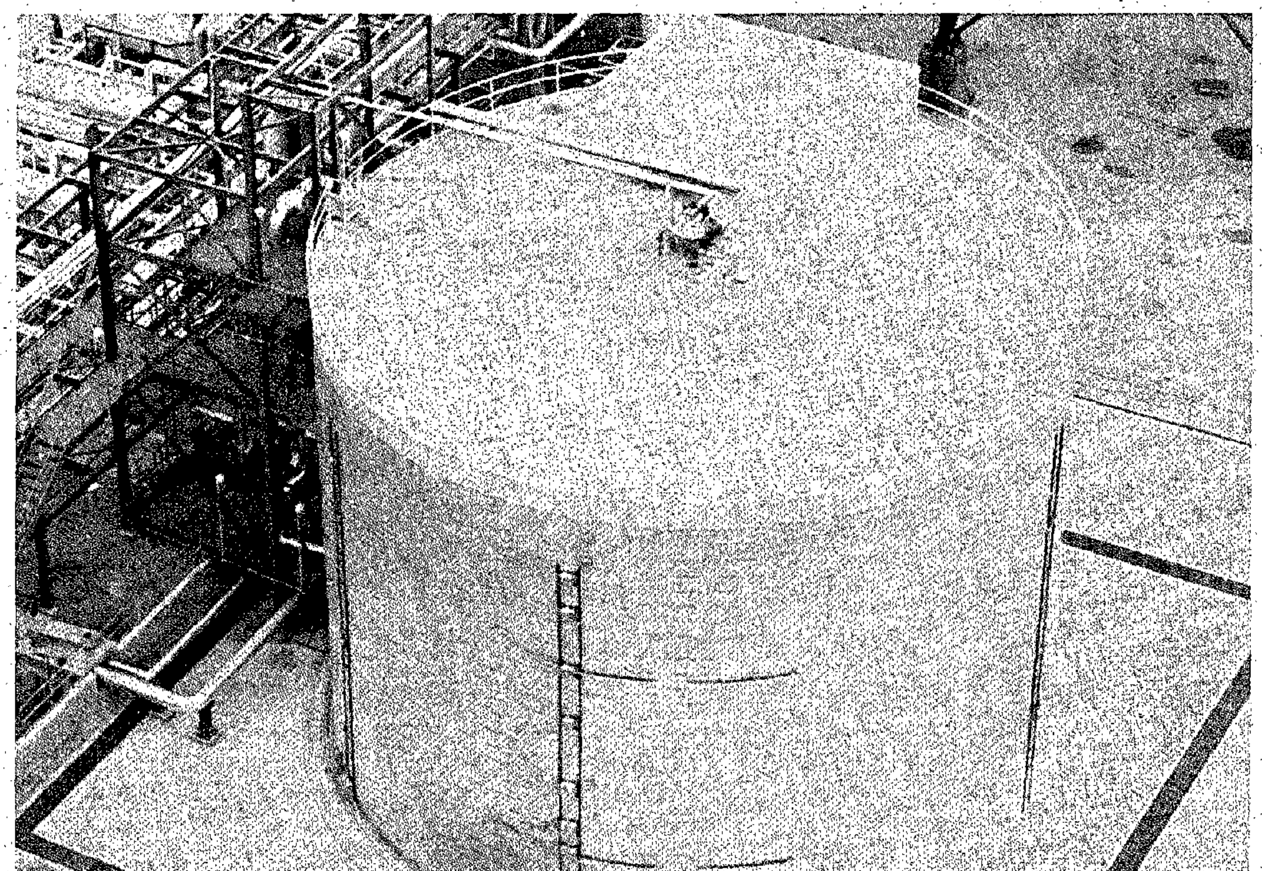
Thermal Storage Performance



Pilot Plant Thermal Storage Tank

7. THERMAL STORAGE PERFORMANCE

Overview

The thermal storage system, which was primarily used to satisfy the plant's auxiliary steam needs, operated uneventfully through late August 1986. During this period the storage system reliably supplied auxiliary steam, and the plant's staff gained valuable experience in thermal storage operations. However, on August 30, 1986, there was a fire at the top of the thermal storage tank.

The fire was observed at the top east side of the thermal storage tank. An internal overpressurization caused by water vaporizing to steam split the weld between the roof and wall of the tank on the east side. Shortly after the overpressurization, a fire ignited external to the tank and was eventually extinguished. No oil was spilled from the tank, and only vapors were emitted. There were no injuries or loss of life.

An investigation of the accident determined that oil containing significant quantities of water had been pumped into the tank. Procedural and design changes have been defined to minimize the possibility of this type of accident in future central receiver plants.

The Pilot Plant resumed operation three days after the fire using an electric boiler to generate auxiliary steam. Annual net electricity from the plant was not significantly affected because the additional electricity generated by not charging thermal storage more than offset the parasitic power consumed by the electric boiler. The electric boiler was operated only as required for short periods.

It was decided to not restore the thermal storage tank to operation. Sandia had completed the test and evaluation of the thermal storage system before the accident occurred. Moreover, the system was being used only for auxiliary steam production and not for electric power production.

Introduction

The thermal storage system was routinely used during power production operation to supply the plant's auxiliary steam needs. The routine operation was interrupted on August 30, 1986, early into the third year of power production operation. On that day, an overpressurization and rupture of the thermal storage tank occurred and was followed by a fire at the top of the tank. After the accident DOE appointed an investigating committee to determine the causes of the accident and to identify the procedures which should have, or could have prevented its occurrence.

In this chapter a brief summary of thermal storage operations prior to the fire is presented. The findings of the investigating committee, which are described in Reference 7–1, are also summarized.

Most of the thermal storage system evaluations were completed during the Experimental Test and Evaluation Phase and are not reported here. A summary of these evaluations is provided in Reference 7–2. Detailed information on the evaluations is given in References 7–3 and 7–4.

Thermal Storage Operation Prior to the Fire

The thermal storage system operated uneventfully through the first two years of power production operation. The system supplied the plant's auxiliary steam needs on a daily basis, but was almost never used for electric power production. Mode 1 operation, the receiver-to-turbine direct mode, was always preferred for power production because it was the most efficient mode for generating electrical power.

The thermal storage system was charged, on the average, about every tenth day. For charging, the plant almost always operated in Mode 5, the receiver-to-storage mode. Mode 2 operation, the simultaneous receiver-to-storage and receiver-to-turbine direct mode, was rarely used. The Mode 5 operation was preferred for two reasons. (1) it offered simplicity in operation because only one steam loop was in use; and (2) it allowed the plant to operate at all other times in Mode 1, the most efficient mode for power production. Mode 2 operation reduced the steam flow to the turbine and caused the turbine to operate at a flow far below its design point with a corresponding increase in the cycle heat rate.

Description of the Accident

On August 30, 1986, at 6:53 a.m., a fire was observed at the top east side of the thermal storage tank (Figure 7–1). An internal overpressurization caused by water vaporizing to steam split the weld between the roof and wall of the tank on the east side. Shortly after the overpressurization a fire ignited external to the tank. The fire burned for about three hours before it was extinguished. The fire broke out again at 12:50 p.m. and was extinguished at about 3:20 p.m. The tank fire went out shortly after cool oil from the bottom of the tank was pumped into the top of the tank, thus reducing the vapor pressure of the oil and reducing the combustible gasses leaking from the crack in the tank. The last firefighting unit left the Pilot Plant site on August 31. No oil was spilled from the tank, and only vapors were emitted. There were no injuries or loss of life.

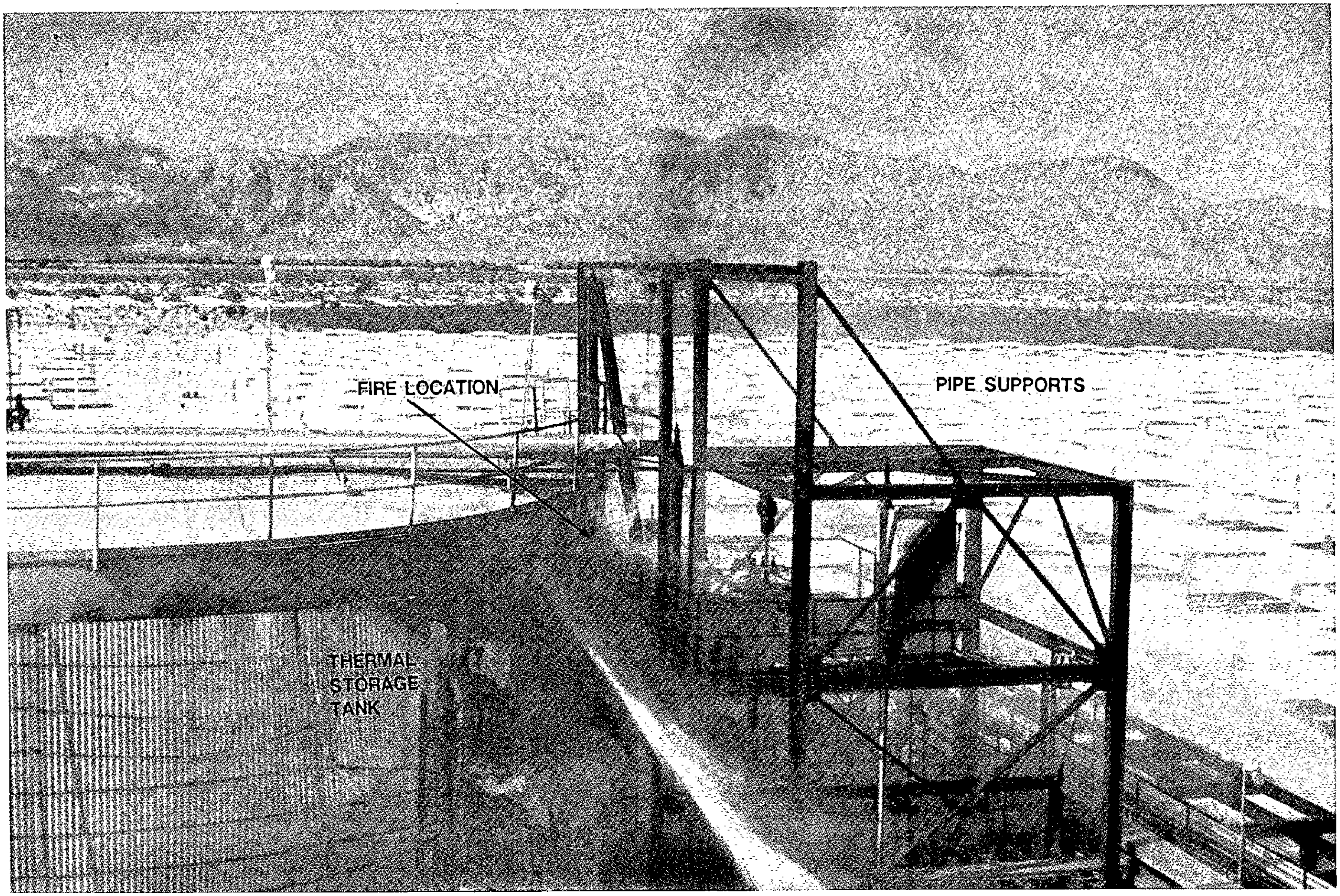


Figure 7—1. Thermal Storage Tank During the Fire

The major damage to the tank was roughly centered on a vertical axis passing through the main oil piping that penetrated the tank to connect to the upper and lower oil distribution manifolds. This axis is on the due east side of the tank. The weld seam between the tank roof plates (0.1875 in or 4.8 mm steel) and the stiffening ring at the top of the tank wall (0.75 in or 19 mm steel) separated for about 34 ft (10.4 m) on the due east side, but as can be seen in Figure 7–2, there was no gaping hole. There was also a 14–inch (0.36 m) crack on the due west side. Some fiberglass wall insulation was blown away from the tank wall on the east side down to approximately 10 ft (3 m) below the roof/wall weld and 20 ft (6.1 m) to either side of the due east point (Figure 7–3). The storage tank level gauge and instrumentation and control wiring and valve actuators in the vicinity of the fire were destroyed.

Cause of the Accident

Water turning to steam inside the tank caused the overpressurization and fire, which in turn caused the top of the tank to rupture. The fire resulted from hot volatile gases escaping from the tank and igniting on contact with atmospheric oxygen. Water was found in the bottoms of the storage tank and the Caloria make-up tank after the fire. Although it appears that the storage tank pressure relief

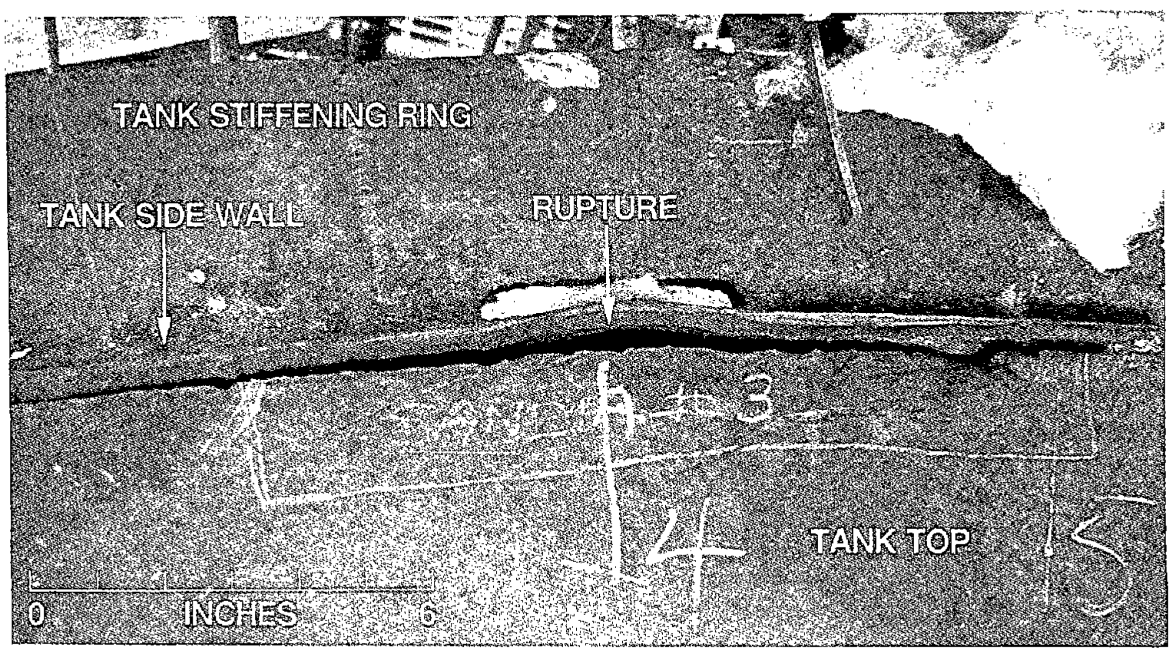


Figure 7—2. Thermal Storage Tank Wall/Roof Rupture Looking Down on the Roof

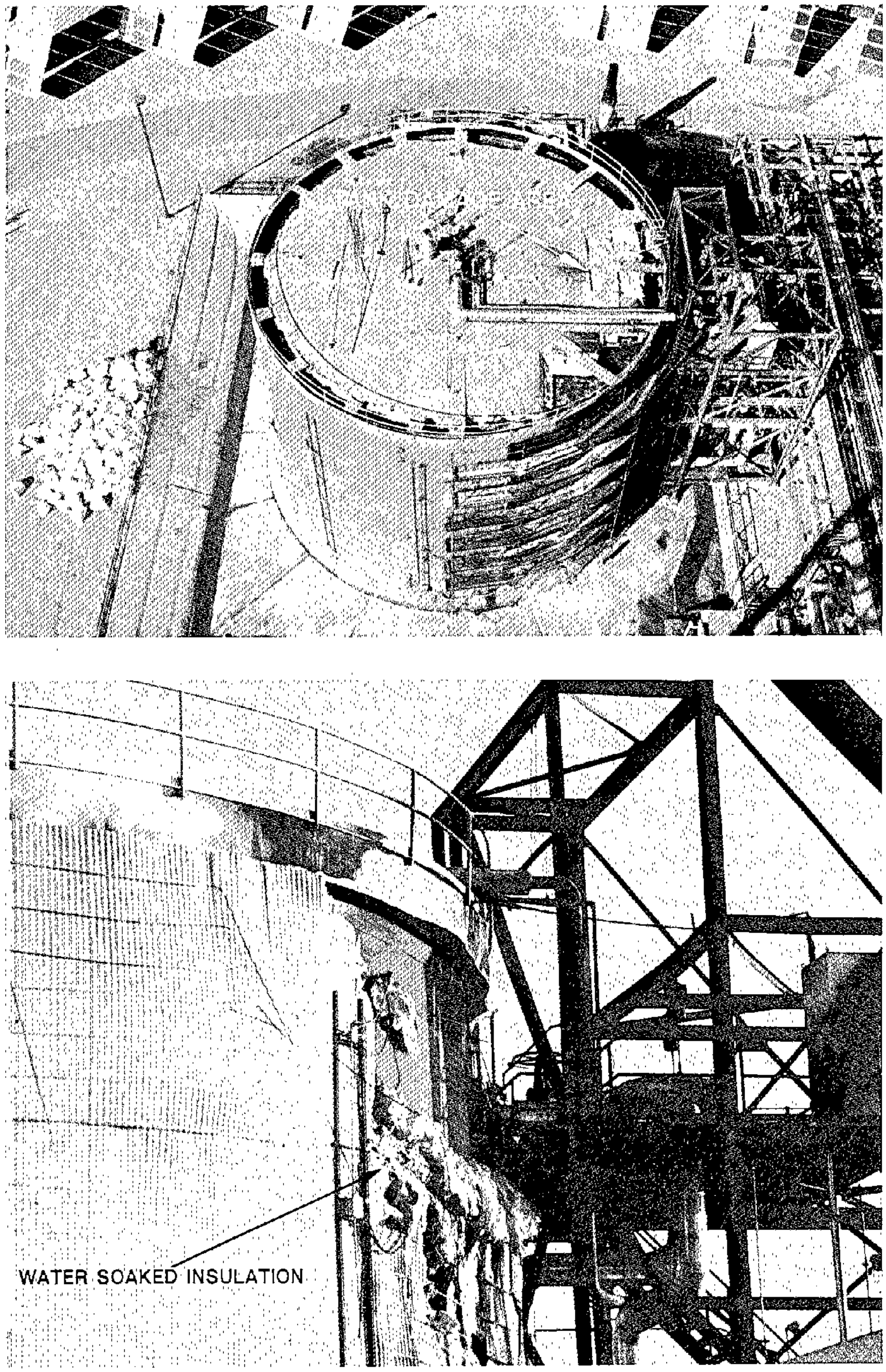


Figure 7—3. Thermal Storage Tank Damage

valves did operate, it is believed that the quantity of steam produced exceeded the valve venting capacity. Thus, the pressure in the tank rose to the tank roof rupture point.

Rocketdyne, the tank designer, stated that the tank pressure weak point was designed to be at the top so that if the pressure relief valves could not handle an overpressure, the tank top would relieve the pressure. The tank responded to the situation as designed.

The source of the water that caused the tank overpressurization was from water in the storage area sump which was pumped into the Caloria make-up tank and then into the storage tank on the day before the fire. It was noted that water may have already been suspended in the thermal storage tank prior to the incident. The water introduced into the tank on the day before the incident by itself or in combination with previously suspended water caused the overpressurization of the tank.

An investigation was conducted to determine how water would get into the storage tank. The investigation found that two rupture disk failure incidents had occurred during the year, and following the failures oil was pumped from the storage area sump into the make-up tank.

The first failure occurred in January. In this case hot oil was discharged into the sump, and it vaporized water contained in the sump. It is believed that no water was pumped into the make-up tank in January.

The second rupture disk failure occurred in May but was not discovered until August 28, two days before the fire. It is believed that the source of water was from this failure. Following a review of the plant records, a scenario was developed that explains how water was introduced into the tank. The significant events were as follows:

1. April 30, 1986. The thermal storage charging train was valved out, isolating the oil side of the charging train. The oil pressure relief valve was removed to allow re-adjustment of the valve pressure set point. The lines in the region of the valve were drained, and the valve opening of the relief valve was capped.
2. May 6, 1986. While operating charging train Number 2, a thermal storage system Red Line Unit trip occurred for charging train Number 1 as a result of an oil side overpressure. The rupture disk failed at this time, but was not noticed. The cause was steam that leaked through the steam inlet valve and into the steam side of the train. The steam heated the oil causing the oil pressure to increase until the disk ruptured. Since the train was valved out, little or no oil was spilled. However, any oil that might have spilled would empty into the maintenance oil sump and might not be detected.

3. In July there were two days of rain, sufficient to wash the heliostats and enough to leave water in the thermal storage area sump.

4. August 28, 1986. The charging train pressure relief valve was re-installed, and the train oil side was valved back into service. As the oil was admitted into the train, oil was observed overflowing the sump into the trough at the bottom of the storage tank berm. The rupture disk was found to have failed and it was replaced.

5. August 29, 1986. The oil in the trough and thermal storage area sump was pumped into the storage make-up tank. This sump could have contained as much as 160 gallons of water from rain in July and previous months. The oil and most likely water was pumped from the make-up tank into the thermal storage tank. Water was found in both the make-up tank and the thermal storage tank after the fire.

6. August 30, 1986. Following start-up of the thermal storage auxiliary steam system, the over-pressurization, tank rupture, and fire occurred.

Procedural and design changes have been defined to minimize the possibility of this type of accident in future central receiver plants. (See Chapter 8 for details.)

Post-Accident Plant Operation

The Pilot Plant resumed operation three days after the fire using an electric boiler to generate auxiliary steam. The effect of the electric boiler on plant performance can be estimated by comparing the storage use before the fire and the electric boiler use after the fire. Prior to the fire about 5000 MW_t–hr of thermal energy was directed annually to the thermal storage system. In contrast, the annual plant load increased about 500 MW_e–hr after the fire because of the use of an electric boiler for auxiliary steam production. Assuming a conversion efficiency of 30%, the 5000 MW_t–hr could have produced an additional electrical output of 1500MW_e–hr. Thus, the plant output was increased by about 1000 MW_e–hr (equivalent to about 10% of the annual plant output) by using an electric boiler rather than the thermal storage system for auxiliary steam production. (Note: the actual plant outputs for the second and third years of power production do not show this directly because other factors, such as insolation, also affect the annual plant output.)

It was decided not to restore the thermal storage tank to operation. Sandia had completed the test and evaluation of the thermal storage system before the accident occurred. Moreover, the system was being used only for auxiliary steam production and not for electric power generation. The repair of the tank was limited to welding the top of the tank and fire cleanup. The cost for this was about \$130,000. It would cost an additional \$60,000 to restore the thermal storage system to full operation.

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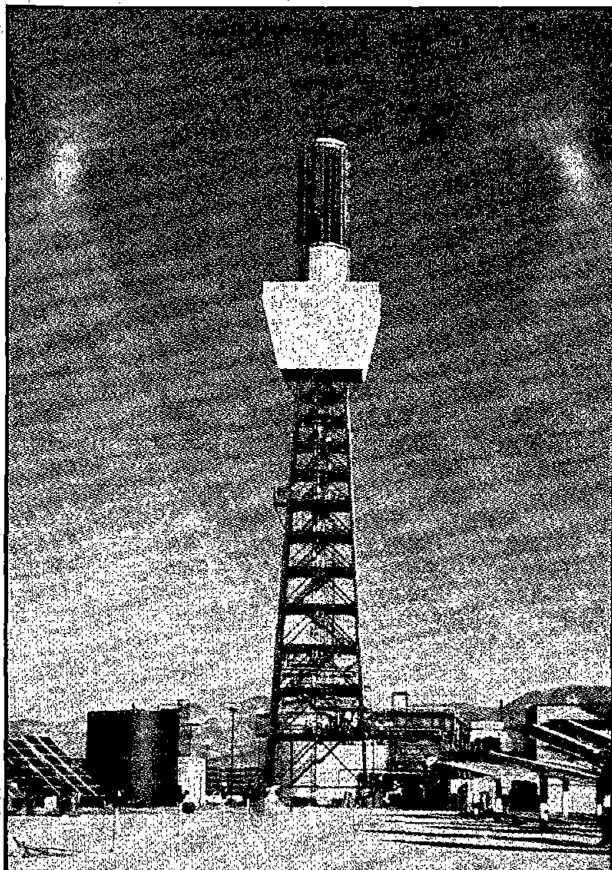
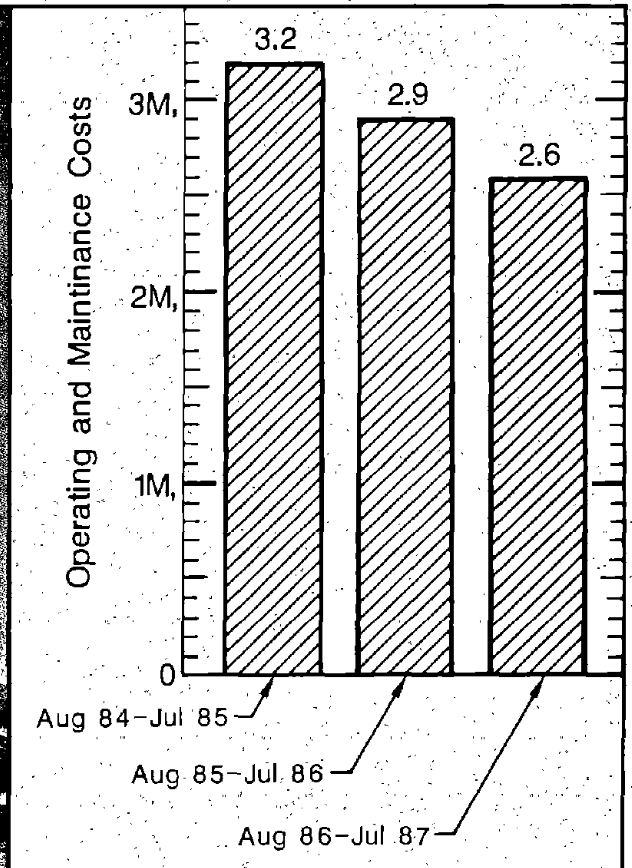
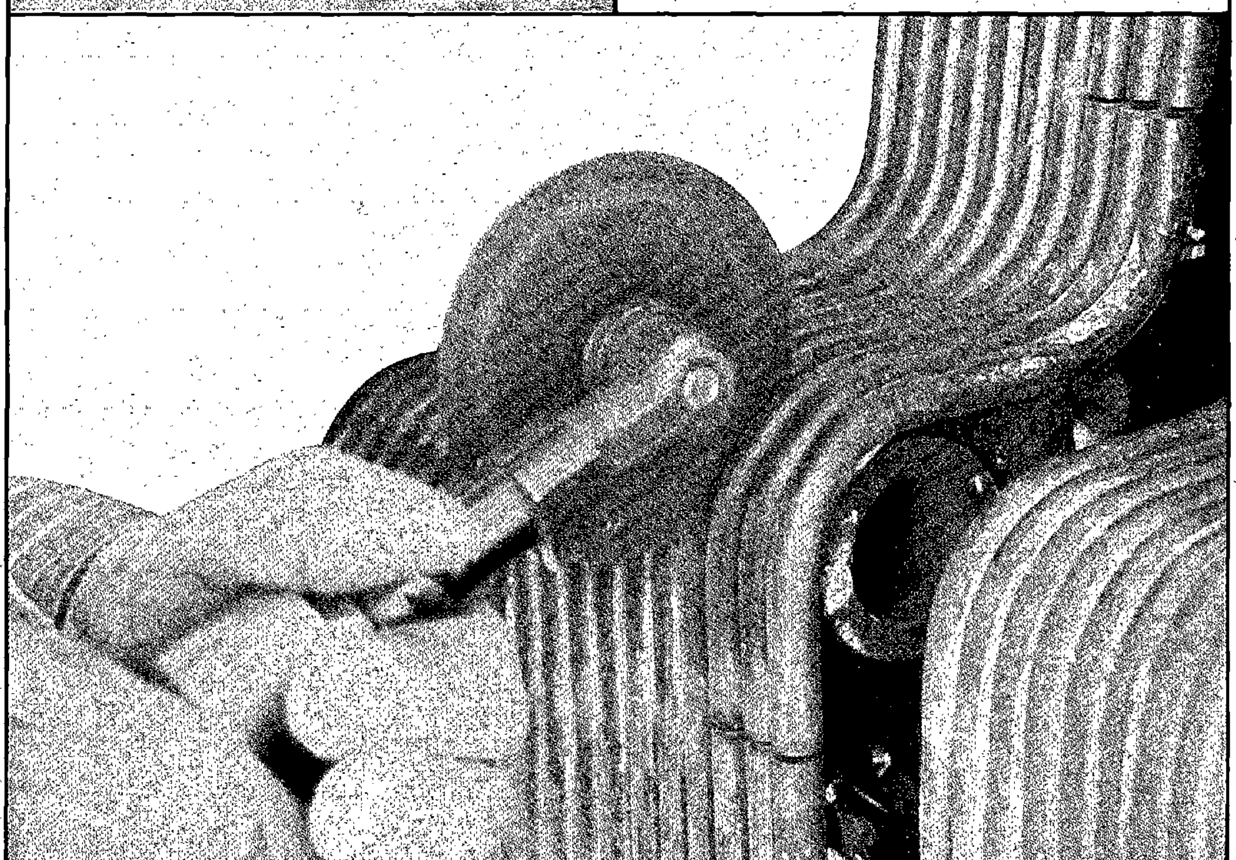
Lessons Learned







Some Pilot Operating Experiences: (1) Standby points provided safety for plant personnel and airplane pilots. When the plant started up in the morning, the heliostat beams were first focused on one of four standby points located about 115 feet (35 m) from the receiver. These bright standby points provided a safe location for the beams so that they did not converge on the ground, tower structure, or in the airspace above the plant; (2) Operating and maintenance costs were reduced; and (3) Receiver tube leaks were successfully repaired on the tower. The photograph shows a 3-tube section at the upper portion of a receiver panel edge being cut prior to its removal. The upper and lower horizontal cuts have already been made. The section was removed because the innermost tube had developed a crack. A new tube section was eventually welded in its place.

8. LESSONS LEARNED

Introduction

Lessons learned are an important element in the overall evaluation of the Pilot Plant. The lessons provide key information to guide decisions on the future development of central receiver technology and the design, construction, operation, and cost of future plants.

Lessons learned have been compiled throughout the course of the Pilot Plant project. The lessons learned during the design, construction, start-up, and early operation of the Pilot Plant were studied by Burns and McDonnell Engineering Company under contract to EPRI and are reported in Reference 8-1. A summary of these lessons, along with the lessons learned during the Experimental Test and Evaluation Phase, is reported in Reference 8-2.

In this chapter the lessons learned during the Power Production Phase are described. The lessons learned from power production operation are presented for the overall plant and the following plant systems: collector system; receiver system; thermal storage system; plant control system; beam characterization system; and electric power generation system. More detailed information on the topics presented here can be found in References 8-3 to 8-5, Chapters 3 to 7 of this report, and the references listed at the end of each chapter.

The decision to operate the Pilot Plant for at least another year will result in additional data on lessons learned. Updated data on receiver life and mirror corrosion and new data on the effects of five-day-a-week plant operation will be obtained and described in future reports.

Overall Plant Lessons Learned

Operating and Maintenance Costs

During the first, second, and third years of power production operation, the Pilot Plant had annual operating and maintenance costs of about \$3.2M, \$2.9M, and \$2.6M, respectively. The total operating costs and total maintenance costs for the three year period were similar.

Operating costs were reduced during each year of operation due to reductions in the plant operating staff. Maintenance costs fluctuated slightly but were highest during the first and third years. Maintenance costs for the first year were affected by a planned shutdown for a turbine inspection. Maintenance costs for the third year were affected by the thermal storage fire and heliostat drive motor repairs.

For the three years of power production operation the collector and plant control systems each accounted for about 25% of the total maintenance costs. The receiver and electric power generating systems costs averaged about 9% and 13% of the total maintenance costs, respectively. The thermal storage system showed the lowest maintenance costs with about 6% of the total. Supervisory/indirect and miscellaneous costs accounted for the balance of the maintenance costs.

The operating and maintenance cost data provide insights on the relative costs of Pilot Plant operations and maintenance and the breakdown of the plant's maintenance costs by system. However, caution must be used when scaling these costs to commercial-size plants. The Pilot Plant operating and maintenance costs were much greater than the revenue generated from the plant's power generation because the Pilot Plant was not an economic-size unit. The operating and maintenance costs expected for commercial-size plants are discussed below under Staffing Levels.

Staffing Levels

The Pilot Plant staff was comprised of a variety of operating and maintenance skills. Near the end of the Power Production Phase, the basic day shift operating crew at the plant consisted of four operations people: an operating shift supervisor, a control operator, an assistant control operator, and a plant equipment operator. The second shift consisted of two people: a control operator and an assistant control operator A caretaker crew, consisting of a control operator and an assistant control operator, also made up the third shift. These staffing needs translate to an operating staff of 12 persons on a seven-day-a-week basis.

The balance of the plant's staff performed administrative, material control, and maintenance activities. Maintenance staff skills included a maintenance foreman, instrument technician, electrician, boiler and condenser mechanic, and a heliostat washer. The maintenance staff size reflected the use of adjacent Cool Water Station personnel for some maintenance activities.

The Pilot Plant achieved a large reduction in staff during the course of operation as a result of learning experiences, automation capabilities added to the plant control system, and a reduction in the plant's test and evaluation activities. In 1982 the Pilot Plant staff numbered 40 persons, (not including the McDonnell Douglas test engineers). A reduction in the number of plant equipment operators and security officers, as well as changes in the required skills of the maintenance staff, lowered the overall staff to 34 persons in 1984. The staff was reduced to 17 persons near the end of the Power Production Phase in anticipation of going to five-day-a-week, two-shift operation in August 1987. Southern California Edison indicated that a staff of 20 persons (12 operating and 8 maintenance persons) would have been adequate to continue the satisfactory operation and maintenance of the plant on a seven-day-a-week, three-shift basis.

The staff for a commercial 100 MW_e plant is projected to be only 60–70 persons. Considerable economies of scale should be possible for a commercial plant since the number of plant operators will not be significantly different from the Pilot Plant operating staff. The major differences between the Pilot Plant and a commercial plant would occur in the maintenance, equipment operator, and security areas. The additional maintenance personnel would be required primarily because of the addition of heliostats and the addition of heavy maintenance capabilities. The additional plant equipment operators and security personnel would be needed for the larger plant facilities and around-the-clock surveillance.

Generating Statistics

The Pilot Plant's capacity factor averaged 8, 12, and 11% during the first, second, and third years of power production operation, respectively (corresponding to annual energy productions of 7,024, 10,465, and 9,982 MW_e-hr net). Capacity factor increased considerably during power production testing.

The current goal for the Pilot Plant is an annual capacity factor of 17% (corresponding to an annual energy production of 15,000 MW_e-hr net). Additional operating and maintenance improvements in the areas of plant availability and heliostat cleanliness, as well as improved insolation, are required to reach the goal.

Early predictions of the Pilot Plant performance that were developed at the start of preliminary design are based on overly optimistic plant conditions. For example, the early prediction of a 30% capacity factor (corresponding to an annual energy production of 26,000 MW_e-hr net) is based on 1976 direct insolation data and assumes a 100% annual availability of plant equipment. Actual insolation for 1984 to 1987 was lower than 1976, and actual plant and heliostat availabilities were less than 100%. The substitution of more realistic values for these factors and others reduces the plant's expected annual capacity factor from 30% to 17% and annual energy output from 26,000 MW_e-hr net to 15,000 MW_e-hr net. A capacity factor of 30% and annual energy output of 26,000 MW_e-hr net are not possible at the Pilot Plant with the current plant configuration.

The Pilot Plant experience shows that realistic design operating conditions should be used to establish the expected performance from a plant. The Pilot Plant design conditions were too optimistic in some cases. In particular, the assumed insolation levels and equipment availabilities were too high and did not reflect actual operating experiences.

Plant Availability

The plant availability (without the effects of weather) averaged 80, 83, and 82% during the first, second, and third years of power production operation, respectively. Plant availability improved from the first to second year as fewer scheduled maintenance outages were planned for the second year of power production operation. Near the end of the second year, the plant's unscheduled outage hours began to increase. This trend continued into the third year and resulted in a slight decrease in the plant availability for the third year of power production operation. The increase in unscheduled outage hours was due primarily to receiver problems. Tube leaks continued to occur, and thermal expansion problems with the panel supports caused some panels to buckle.

The Pilot Plant experience emphasizes again the need to use realistic conditions for determining the expected output from a plant. A plant availability of 100%, which was used to derive some early annual energy predictions, is unrealistic. The Pilot Plant design availability of 90% is probably achievable given the benefits of learning experiences and a preventive maintenance program. However, the 90% value was too high for this first-of-a-kind plant during its infant years of plant operation when more unexpected events are likely to occur.

Plant Safety

Safety procedures applicable to the solar central receiver technology in the Pilot Plant were effectively used during power production testing. The control of the heliostat reflected beams, the operation of the receiver boiler 300 ft (90 m) above ground level, and the containment of the hot heat transfer oil in the thermal storage system all presented new challenges for achieving personnel safety in a utility power plant.

The Pilot Plant achieved an excellent safety record. Strategies were developed for the control of the reflected heliostat beams, and the same strategies can be used in future solar plants. An accident prevention plan was prepared that described safety procedures to be followed for both the solar and conventional portions of the plant. Adherence to these procedures as well as personnel safety training resulted in a minimal number of personnel injuries during the course of Pilot Plant operation.

Preferred Operating Modes

During the daytime hours of operation the Pilot Plant was run almost exclusively in Mode 1 (receiver-to-turbine direct) or Mode 5 (storage charging). Mode 1 was the preferred mode for power production operation because it was the most efficient method of converting the collected thermal power into electrical power. Mode 1 also provided simplicity of operation compared to other power production operating modes (Modes 2, 3, 4, and 7) because it minimized the quantity of equipment that had to be operated and monitored simultaneously. Finally, Mode 1 operation was preferred because no consideration was given to maximizing plant revenues by generating power when it would be most valuable to Southern California Edison. The latter consideration would have led to the use of thermal storage for nighttime power production at the expense of daytime operation (see discussion under the Use of Thermal Storage)

Mode 5 was used to charge the thermal storage system so that thermal energy was available for the plant's auxiliary steam needs at night. Mode 6 (storage discharging) was almost never used for power production operation since this mode is less efficient than Mode 1.

The thermal storage system was charged about every tenth day and then partially discharged each night until it required recharging. The reasons for operating the plant in this manner were (1) the strategy allowed increased daily operation in Mode 1, the preferred mode for power production; (2) the strategy simplified plant operations since it reduced the number of mode transitions that the plant operators would have to perform on a daily basis; and (3) excess energy was never available to charge thermal storage on a daily basis because the collected thermal energy in the receiver was insufficient to simultaneously run the turbine at or near full load and charge thermal storage. The insufficient energy was due to a lack of heliostats, (During the design of the plant, 150 heliostats were eliminated, and at any given time a number of heliostats in the field would be down for repairs.) soiled reflecting surfaces, and a degraded receiver surface absorptance.

This operating strategy would not be used in future power plants. Future plants will likely use working fluids like molten salt or liquid sodium which can serve as both the receiver coolant and thermal storage medium. For these plants all the collected thermal energy can be directed to the storage system, and there is no penalty in efficiency when operating from storage.

Preferred Maintenance Procedures

The original concept for Pilot Plant maintenance was that much of the plant's maintenance would be performed at night while the plant was shut down. In actuality, most maintenance was performed during the day shift, with work being done at night only on an exception basis. Southern California Edison preferred day rather than night maintenance because higher labor productivity was achieved during the day. Maintenance personnel were occasionally called in early in the morning to correct minor problems so the plant would be ready to operate at sunrise. With stringent safety controls, access to the collector field during the day was not a problem, eliminating the principal reason for performing scheduled nighttime maintenance.

Planned maintenance shutdowns at the Pilot Plant were generally scheduled during the winter months (December, January, and February) when the daylight hours were shorter and the weather was less favorable for plant operation. This approach minimized the plant downtime for scheduled maintenance inspections and repairs. Annual shutdowns were of one to three weeks duration with the times devoted to maintenance activities like turbine inspection (February 1985) and receiver repainting (December 1985).

Miscellaneous Benefits

Several, mostly non-technical benefits surfaced during the Pilot Plant project that contributed, along with the technical accomplishments of the plant operation, to Southern California Edison's acceptance of central receiver technology as a viable energy alternative for power generation. First, the plant provided a good conduit for technology transfer into the utility's non-solar areas. It was shown, for example, that the distributed digital control technology at the Pilot Plant could be successfully operated by utility personnel without any special skills. This should enhance the utility's acceptance of this technology for its future solar and non-solar power plant projects.

Second, the Pilot Plant employed a new energy technology that proved to be an attractive utility project Quality personnel were attracted to the project. The personnel developed a strong esprit-de-corps and were dedicated to demonstrating the successful operation of the plant.

Finally, the Pilot Plant turned out to be a public relations bonanza for Southern California Edison. Over 250,000 people have been to the Solar One Visitor Center since the plant began operation. Many of the visitors also received tours of the plant site.

It is not unreasonable to expect that similar benefits would accrue to other utilities and organizations as a result of constructing and operating a solar plant. The generation of electric power using a renewable resource is appealing to almost everyone.

Collector System Lessons Learned

Heliostat Availability

The average heliostat availabilities during the first, second, and third years of power production operation were 96.7, 96.0, and 98.8%, respectively. The desired availability for power production operation was 99%, based on Sandia analyses which indicated that the additional maintenance costs required to achieve a 99% value were less than the additional plant revenue resulting from the increased availability. Heliostat availability improved during power production testing as a result of increased maintenance efforts. The high availability achieved during the third year of operation is indicative of a successful SCE heliostat maintenance program and shows that a 99% availability should be achievable.

Heliostat Maintenance

Heliostat maintenance costs for parts and labor were slightly less than the costs predicted by Martin Marietta when the heliostats were built. Approximately 160 hours per month were required to maintain the heliostats, including the controllers that are located in the field.

The heliostats were maintained using conventional maintenance skills. Most work was done by an electrician and an instrument technician while a machinist and a mechanic were used infrequently. The screened commercial parts in the heliostat controllers and a component burn-in have, undoubtedly, contributed to the favorable heliostat maintenance experiences at the Pilot Plant.

Heliostat Cleaning

Mirror cleanliness (expressed as a percent of the clean field reflectance) was an important factor in Pilot Plant operations since it had a significant impact on the overall plant performance (see Chapter 4). The average annual mirror cleanliness was 89.5 and 93.0% during the first and second years of power production operation, respectively. (No value was derived for the third year because of insufficient data.) Sandia analyses for the Pilot Plant suggested that it was desirable to strive for an average annual cleanliness of 97%. The 97% value was based on the costs of a biweekly mechanical washing and the increased plant revenue that would result from having cleaner mirrors. Equipment breakdowns with the wash truck and assignment of personnel to higher priority maintenance activities were the major reasons why higher annual cleanliness values were not achieved during power production operation.

Natural rainfall and even snow were used to clean the Pilot Plant heliostats, but mechanical washing was also required. The plant operators normally used rain to wash the heliostats whenever possible. For rainfall cleaning the mirrors were placed at 45 degrees facing up and into the wind. During the early years of Pilot Plant operation a 0.5 in (13 mm) rain restored the mirror cleanliness to a value of 97%. However, later, only a 95% cleanliness value was obtained. This reduction is believed to be due to the accumulation of very fine dust on the outside 6 in (15 cm) surface of the glass mirrors. The dirt was not removable by rain or a low-pressure spray rinse.

Snowfall is very infrequent at the Pilot Plant site, but a snowfall did occur in February 1985. During the snowfall the mirrors were face-up with about 2 in (5 cm) of snow on the mirrors and 4 in (10 cm) on the ground. The snow was dumped before it started to melt, and the mirror cleanliness was restored to 96%. It is believed that the cleaning would have been more effective if the snow had not been dumped until it started to melt.

A mechanical scrubbing with a brush and a biodegradable wash solution will restore the mirror cleanliness to a value of 99%, and this type of cleaning is required for the Pilot Plant environment. Additional experience is needed to determine if rain or a spray rinse will keep the mirrors clean for a period of time after a mechanical scrubbing. A heliostat wash truck using brushes and a wash solution cleaned the heliostat mirrors at the Pilot Plant.

The required heliostat cleaning frequency at future solar plants will depend upon soil and climatic conditions at that site, including rainfall, the concentration of airborne dust and particulates, wind conditions, and the mineral and chemical composition of the ambient dust. Also, the degree of installed redundancy in heliostats will affect the required cleaning frequency. More frequent cleanings will result in higher average reflectance and increased collector system performance. For a commercial solar plant, an economic analysis should be made to determine the frequency of heliostat cleaning by optimizing the cost of heliostat cleaning versus the value of increased heliostat reflectance.

Future solar plants are likely to use much larger glass/metal heliostats or stressed membrane heliostats whose reflective surface may be more susceptible to scratching than glass. The mechanical washing of these heliostats will be more difficult than the washing of the Pilot Plant heliostats. Consequently, particular attention should be paid to analyzing the effectiveness of washing equipment during the design of the heliostats and the overall plant.

Heliostat Alignment

Early procedures for heliostat alignment were based on visual estimates of the tracking errors because the beam characterization system was not available. The visual procedure did not provide the accuracy of the beam characterization system, but the errors could be approximated. In the visual procedure the operator directed the heliostat to track the beam characterization system target aimpoint and estimated the error. Only one measurement was made during a day so the tracking error correction could contain large errors. This is due to the fact that the tracking error is seldom constant over a day because of, for example, a tilted pedestal or a nonorthogonal heliostat axis.

When the beam characterization system became operational, morning, noon, and afternoon heliostat tracking measurements were performed. The data showed that the heliostats were tracking accurately, and few tracking error corrections were needed. The data also showed that there were no significant changes in the tracking errors over a six-months measurement period.

Mirror Corrosion

Silver corrosion has occurred on the Pilot Plant mirrors. The corrosion is caused by water inside the mirror modules that penetrates through the protective paint layers and dissolves the copper; water and oxygen then corrode the silver. The design of the Pilot Plant mirror modules lends itself to this problem because of the air volume inside the module and the very small vent pipe. The small vent pipe has a relatively large pressure drop which causes a small vacuum inside the module when the module is suddenly cooled by rain. This vacuum then draws in water through leaks in the adhesive seals.

Corrosion surveys of the entire heliostat field were performed during the summers of 1983, 1984, and 1985. During the summer of 1986 a survey was made of 98 randomly selected heliostats. The limited survey was done instead of a full field survey because it had been determined that these heliostats accurately represented the field. The surveys indicated that only 0.061% of the total reflective surface of the heliostat field had corroded by July 1986. This percentage is equivalent to the surface area of about 1.1 heliostats. Thus, although mirror corrosion had been a concern at the Pilot Plant, to date, the overall impact upon collector performance has been small.

The low mirror corrosion observed at the Pilot Plant after over five years of operation may be partially due to a vertical stow position that was initiated in January 1983 and to mirror module vents that were installed in early 1984. Vertical stow reduced the buildup of water on the mirror module seals, thereby reducing the possibility of leakage, while venting enhanced the drying out of the mirror module interiors.

Heliostat Operating Strategy

Normally, the heliostat field was moved from the mirror stow position to standby at some time before sunrise. There were four standby aimpoints located at the receiver elevation approximately 100 ft (30 m) out from the receiver surface. The heliostats were brought to the standby points by following an aimpoint up an imaginary line from a starting aimpoint that was below ground level. Motion from standby to stow was normally made after sunset, and it reversed the start–up path. The aimpoint moved from the focal point at ground level to the standby position adjacent to the receiver in about six minutes. When the reflected beams were directed onto the receiver from standby, the beam path was not controlled in any special manner.

For the first fifteen months of operation, the heliostats were always stowed horizontally with the mirrors face–down. However, since January 1, 1983, the heliostats have been stowed vertically except during high wind or severe dust conditions when they were again stowed mirror face–down horizontally. The mirror stow position was changed from horizontal to vertical in order to minimize water standing on the mirror module seals and on the mirror backing paint. There were no operational problems, and mirror cleanliness was not significantly different.

Heliostat Beam Safety

The control of the collector field's reflected sun images (beams) is important for site personnel safety and minimizing off–site personnel exposure to stray beams. The reflected beams were controlled to prevent high concentrations of the reflected light which could damage equipment or injure personnel. Although it was not necessary, the plant operators normally stowed and unstowed the heliostats when the sun was down. This reduced the number of occasions when a potential hazard exists near the ground; however, daylight stow was demonstrated many times. Heliostat beam safety was not a problem at the Pilot Plant as evidenced by the absence of any personnel injuries attributable to the collector field operation.

Operational Wind Speed

Initially, the maximum operational wind speed for the heliostats was 35 mph (16 m/s). Upon review of the heliostat design and site wind data, it was determined that sufficient design conservatism existed to increase the maximum operational wind speed to 45 mph (20 m/s). The increase resulted in an increased plant operating time since it reduced the plant outage time due to high winds. The plant continued to use this higher shutdown wind speed without any problems; however, the plant operators seemed to be very conscious of the wind speed and watched it closely when it was near the shutdown speed.

For future plants the frequency of occurrence of various wind speeds should be analyzed. A trade–off study between the heliostat cost and the benefit from operating at high wind speeds should be performed to determine the heliostat's maximum operational wind speed for a specific site.

Other Mirror Module Types

The occurrence of silver corrosion on the Pilot Plant mirrors led to the testing of alternate mirror designs at the Pilot Plant site. The alternate designs included the Second Generation heliostats developed by ARCO Solar, Boeing, Martin Marietta, and McDonnell Douglas and several laminated glass mirror module designs developed by Solar Kinetics.

One Second Generation heliostat from each company was installed at the Pilot Plant during 1984. Laminated glass mirror modules were substituted for the original Boeing and Martin Marietta module designs. The original designs, neither of which used laminated glass, showed evidence of corrosion and other problems during previous testing at the Central Receiver Test Facility (CRTF). The McDonnell Douglas module design also used laminated glass while the ARCO Solar design, the only non–laminated design, coupled the glass to a steel sheet with a grease that holds the glass on the steel by capillary forces. (The glass is prevented from sliding off the steel sheet by edge restraints.)

Solar Kinetics fabricated 150 mirror modules using five different types of laminated glass. The modules were installed in late 1985 and early 1986 as replacements for the Pilot Plant mirror modules. Laminated glass mirrors were chosen because of their resistance to water intrusion and the absence of oxygen on the back of the mirror. Laminated glass has been used for many years in automobile windshields without delamination, and since 1978, laminated glass mirrors have been in use at the Central Receiver Test Facility with no apparent silver deterioration. Laminated glass mirror modules have also been tested for several years by Martin Marietta and McDonnell Douglas as well as firms outside the U. S.

The alternate mirror module designs at the Pilot Plant site show no signs of corrosion at this time. However, the modules will continue to be monitored for signs of corrosion as long as the Pilot Plant continues to operate.

Receiver System Lessons Learned

Receiver Performance

The Pilot Plant receiver operation confirmed that several important receiver design characteristics could be achieved. First, the measured peak receiver efficiency was comparable to the design efficiency. Prior to repainting the receiver absorbing surface (described under Surface Absorptance), the receiver efficiency was measured to be about 77% at an absorbed power of 34 MW_t (the power level at the 2 p.m., winter solstice design point). After repainting the receiver to bring the surface absorptance value closer to its design value, the measured efficiency increased to about 82%. The predicted efficiency at the winter solstice design point was 81%. Although differences besides the surface absorptance existed in the "actual" and "design" receiver physical and operating characteristics (for example, differences in the active heat absorbing areas and the operating temperatures), these results generally confirm the design point performance of the Pilot Plant receiver. The results also lend credence to the computational methods used to estimate the efficiency of external receiver designs.

The receiver operation demonstrated a receiver responsiveness that exceeded expectations. The receiver was able to start-up quickly in the morning and operate to near sunset. The receiver also responded well to cloud-induced changes in insolation levels. However, some limitations on receiver operation resulted from the collector field's inability to reflect sufficient energy on certain panels during start-up and shutdown. Other limitations resulted from constraints on the receiver temperature ramping rate, which can be severe during cloud transients.

The receiver operation showed that several early concerns about the receiver boiler design were unwarranted. Flow stability problems which had been predicted for this single-pass-to-superheat design were prevented by orificing many of the receiver tube inlets. Also, the small-diameter receiver tubes with orifices did not foul or plug because of an effective upstream filtering system.

The main problem with the receiver operation resulted from the diurnal and cloud-induced thermal cycling. Cracks appeared in the receiver tubes after eighteen months of service and several panels warped as a result of thermal expansion constraints (described below under Receiver Life). These led to frequent outages so repairs could be made. All the repairs of the receiver tube leaks were successfully carried out in the field. The repairs were made without removing the receiver panels from the tower.

Receiver Maintenance

The maintenance experiences on the Pilot Plant receiver showed the importance of good accessibility for receiver repairs. The need to inspect, repair, or replace leaking tubes, leaking valves, and instrumentation on the receiver tower requires good maintenance access so that downtimes can be minimized. Night repair was found to be a practical approach for the Pilot Plant receiver, and it also offers the advantage of reducing the plant's downtime.

The replacement of both single and multiple tube sections was successfully carried out on the Pilot Plant receiver. Although no full panels were replaced, future plants should be designed with this capability in mind. The timely repair or replacement of tube sections and panels will require that multiple qualified welders be on call.

Surface Absorptance

The receiver panels were coated with Pyromark paint, a black paint that was used to increase the absorption of solar energy by the receiver surface. In December 1985 the receiver was repainted with Pyromark since the absorptance of the paint on the receiver panels had decreased with time from 0.95 (the design value) to about 0.86. Solar absorptance measurements, made on the receiver in March and August 1986, showed that the average solar absorptance of the receiver was about 0.97 and did not change, within experimental accuracy, between March and August. A measurement in October 1987 showed that the average absorptance had decreased to about 0.96.

The Pilot Plant experience showed that it was possible to successfully repaint the receiver in the field and improve its thermal performance. The Pilot Plant receiver was completely repainted only once during its five years of operation.

Repainting the receiver in the field required caution. The curing step was critical, and high–temperature ramp rate curing, using the reflected heliostat beams to heat the paint, resulted in macroscopic cracking of the paint surface. Painting during cold weather also resulted in long drying times. Receiver painting should only be performed by qualified painters. In addition, a good communications interface should be established with the paint manufacturer so that questions and concerns about painting procedures can be resolved in a timely manner.

For future solar plants, projections should be made regarding the expected rate of degradation in receiver coatings and the economic intervals for repainting, including the cost of any required paint stripping. With a need for periodic repainting the receiver design should include access for painters with provisions for convenient rigging of scaffolding.

Receiver Life

During plant operations, tube leaks occurred on several of the receiver boiler panels. The leaks were associated with cracks at two distinct locations on the panels. One leak, which occurred after about eighteen months of service, was at the top of the panels. The leaks at the top of the panels occurred at the interstice weld between subpanels (Type I cracks) and on the edge tube bend (Type II cracks). The second location, which first occurred in July 1985, was on the back of the panels at the panel support assembly (Type III cracks). Panel structural modifications at the top of the panels and changes in the receiver operating conditions were implemented and these eliminated the Type I and II cracks. Start-up procedures were revised to control temperature during start-up and shutdown, and repairs of the receiver tube leaks were carried out successfully.

Analyses indicated that the Type III cracks were caused by thermal stresses due to temperature gradients through the panel tubes and panel support clips welded to the back of the tubes. The panel supports were modified to relieve the thermal stresses, but the modifications did not eliminate the occurrence of the Type III cracks. The receiver experience concerning tube leaks has shown that designs need to be improved to account for thermal cycling, and manufacturing techniques need to be changed to eliminate the amount of welding required on the receivers. Almost all tube leaks, except Type II, were associated with welds on the tubes. For future receiver designs, simpler manufacturing techniques with less welding are needed.

Receiver Start-Up

The Pilot Plant receiver start-up procedures were such that the receiver could not sequence through its start-up until each receiver boiler panel reached a preset outlet temperature. The receiver operating experiences showed that one or two boiler panels were always slower to reach the preset value than the other panels.

To alleviate this problem and reduce the receiver start-up time, heliostat field aimpoints were changed for morning start-up. This changed the circumferential distribution of the incident power on the receiver and increased the incident power on the panels which were slow to reach their preset outlet temperature. Receiver morning start-up times were decreased by about 20 minutes with the new heliostat field aimpoints. The Pilot Plant experience demonstrated the flexibility of using the heliostat field to improve the overall performance of an external receiver.

Thermal Storage System Lessons Learned

Use of Thermal Storage

During the Power Production Phase, the use of thermal storage was limited to providing auxiliary steam for the plant's nighttime steam needs. The use of thermal storage for power production operation was minimal. This operating strategy was employed at the Pilot Plant for these reasons: (1) Mode 1 (receiver-to-turbine direct) was a more efficient way of producing electrical power than Mode 6 (storage discharging) for the water/steam central receiver technology used in the Pilot Plant; (2) a lack of heliostats and soiled mirror surfaces limited the amount of excess thermal energy that was available to charge storage; (3) no consideration was given to maximizing plant revenues by producing power when it would be most valuable to Southern California Edison; and (4) the strategy allowed operating experience for the thermal storage system to be obtained without incurring a significant reduction in plant performance.

Probably the strategy of using thermal storage only for auxiliary steam production would not be used in commercial power plants. The auxiliary steam demand for a power plant is small which would make a cost–effective thermal storage system difficult to achieve. A good portion of the annual thermal energy directed to the Pilot Plant thermal storage system was lost through tank and heat exchanger heat losses. Thermal storage operation was restricted by the lack of thermal energy needed to charge storage on a daily basis (discussed under Preferred Operating Modes). The restriction limited the amount of thermal energy directed to storage and caused the relatively constant heat losses to become a large fraction of the energy input to thermal storage. This does not mean that the Pilot Plant thermal storage system worked poorly. In fact, it met or exceeded its design expectations with respect to extractable energy, charging and discharging rates, and heat losses.

Directing additional thermal energy from the receiver to thermal storage at the expense of the receiver–to–turbine direct operation was not performed during power production operation because of the reduced turbine thermal–to–electric conversion efficiency when operating from storage. The reduced efficiency is a consequence of using different receiver and storage working fluids and the need to transfer heat between the fluids. Future plants will likely use working fluids which serve as both the receiver coolant and the storage medium. For these plants it will be desirable to direct all the thermal energy to the storage system because storage provides an excellent buffering capability for the turbine and there is no penalty in the thermal–to-electric conversion efficiency when operating from storage.

The goal of the Pilot Plant Power Production Phase was to maximize energy production consistent with obtaining some operational experience with the thermal storage system. The goal was not to maximize plant revenues. A recent study at Sandia concluded that maximizing revenues would have dictated a greater use of the Pilot Plant thermal storage for power production.

Thermal Storage System Fire

On August 30, 1986, there was a fire at the top of the thermal storage tank. (See Chapter 7 for additional details.) An investigation of the accident determined that oil containing significant quantities of water had been pumped into the tank. The hot oil inside the tank vaporized the water and caused overpressurization. When the tank ruptured, hot volatile gases escaped and ignited on contact with air. The following describes the procedures that should be followed to prevent a recurrence.

Operating Procedures—Following a review of the incident, it was concluded that operator training should emphasize the importance of water contamination of the heat transfer fluid. The training, coupled with revisions of operating procedures, would preclude recurrence of similar incidents. The recommended operating procedure revisions were as follows:

(1) Periodic water contamination tests of storage facility low points should be performed, and drainage of water should be carried out when it is detected in the thermal storage, heat transfer fluid make-up and heptane tanks.

(2) Water in the maintenance oil sump and the thermal storage area sump should be inspected weekly and pumped out whenever water is detected.

(3) New deliveries of heat transfer fluid should be checked for water contamination.

(4) The heptane tank should be monitored for water during and after thermal storage system operation. Any unusual water rate of accumulation should be investigated immediately and deficient equipment repaired.

(5) The transfer of heat transfer fluid into the thermal storage tank should be limited to thermal storage charging days to avoid accumulation of water in the normally cold bottom of the thermal storage tank.

(6) The thermal storage tank should be recharged completely (lower manifold temperature 400–450°F) once each month to ensure that the entire tank inventory is cycled above the water saturation temperature. This procedure will assure that water cannot accumulate in the tank's bottom.

(7) Semi-annual calibration of the thermal storage tank venting and pressurization system should be performed along with monthly verification that the system is working properly.

(8) When the heat exchangers are insolated, valve arrangements should be provided in order to control thermal storage expansion by an atmospheric vent rather than either the relief valve or the rupture disk.

(9) Operators should investigate the cause for any spurious trips, regardless of whether the trip occurs on active or inactive equipment systems.

(10) A fire fighting procedure should be established for the thermal storage tank, based on the experience gained in extinguishing the tank fire of August 30, 1986. Failure of a steam generator heat exchanger tube could still cause the tank to overpressurize because this newly defined "worst case" condition would require a tank venting rate in excess of the tank's pressure relief valve capacity.

Design Procedures—The thermal storage tank, if and when it is repaired to operate as designed, will remain susceptible to overpressurization as a consequence of thermal storage heat exchanger tube failures. The tank relief valves will control minor leakage, but they do not have the venting capacity for a complete failure of a single steam generator tube. Under this condition, the tank roof has been designed to separate from the tank wall per the tank's design. If the tank is returned to operation, consideration should be given to the following criteria:

(1) The tank should not be strengthened to prevent failure by overpressurization. Tank top failure shall be the last safeguard which protects the tank wall and bottom from failure during an overpressurization event.

(2) The thermal storage tank top circumferential weld should be designed so that failure will occur in a predictable zone.

(3) The predictable weld failure zone should be bounded by metal deflectors which flare escaping ullage gas and fire away from the tank in a controlled manner. The design should also minimize tank cover and insulation damage.

(4) The location of the predictable weld failure zone and flare deflector design should minimize damage to other equipment and structures such as piping, pipe supports, valves, instruments, cables and wires, and lighting.

(5) Water detection sensors should be included in the system design and be located at critical low points, which may be locations of water accumulation or at points where water may be introduced into the system.

In constructing new tanks to perform as a thermal storage unit, these considerations should be combined with the API tank design code.

Plant Control System Lessons Learned

Distributed Digital Control System

The Pilot Plant control system, a distributed digital control system with several automatic features, was an excellent demonstration of what can be achieved with modern digital control system technology. The Pilot Plant is unique in the U.S. electric utility industry because of its automatic controll by a master control system. This system includes an Operational Control System (OCS) computer that supervises two collector field computers, three distributed process controllers that control the plant's main process loops, and four programmable process controllers that provide the plant's safety and interlock logic. The master control system has five computers that supervise the operation of the 1940 microprocessors in the plant.

The Pilot Plant control room has very few analog controls, dedicated switches, control knobs, and meters. Information on plant operation is provided to the operator on color-graphic video displays, and the operator interacts with the system through keyboards, light pens, function keys, and function switches.

The majority of the information displayed on the video screens is in the form of functional diagrams Real time data are displayed near the graphics symbols which represent plant components such as pumps, valves, steam lines, etc. Plots of plant data can be displayed in real time and for the previous 24 hours. Process out-of-limit conditions are annunciated through the color-graphic displays rather than through dedicated annunciator panels that are common to conventional power plants.

The Pilot Plant control system was a significant departure from a conventional power plant control system. Nevertheless, utility personnel with typical skills were able to successfully operate the plant without difficulty. The Pilot Plant operations and maintenance personnel came from within the utility without any special job descriptions.

The Pilot Plant control system functioned well and operated reliably. Although the plant's control system was designed for controlling a water/steam solar central receiver plant, the basic functions and operating philosophy are readily adaptable to other power plants. The Pilot Plant demonstrated that modern computer control technology can be successfully utilized in the electric utility industry.

A distributed digital control system with some modifications that reflect Pilot Plant learning as well as state-of-the-art equipment is recommended for future solar central receiver plants. The next control system would be similar to the Pilot Plant system except that the functions at the top level would be integrated into one redundant master control system. The separate subsystem controllers at the Pilot Plant would become a single master control system that provides the man-machine interface, graphics, logging, top-level control integration, and communications with process controllers located elsewhere in the plant. There would be better cross communications between various process controllers and the master control system. A sensor output could be used by master control or any process controller without separate wiring. Interconnection would be via a high speed data highway.

The master control system should be able to maintain the characteristics of the process controllers. This means that there should be a capability for programming and verifying the data in each controller. The master data would be maintained in master control and would be sent to the process controller any time there is a need to re-initialize that controller. Data base maintenance would be in engineering units and not in internal format.

Plant Automation

Plant automation was implemented in the Pilot Plant solar equipment (the Electric Power Generation System was not included) at three levels: 1) the Subsystem Distributed Process Controller (SDPC); 2) the Operational Control System (OCS) process tasks; and 3) the OCS clear day supervisory control tasks. The addition of the OCS to the plant's control system was completed in 1984, prior to the start of the Power Production Phase. Up to that time the plant had been operated exclusively with the SDPCs.

Extensive automation that goes beyond set point or switch control was done at the SDPC level. Software "pushbuttons" were created which provided the equivalent of hardware pushbutton control, especially for the thermal storage system. Therefore, the majority of the plant automated sequences using the OCS computer dealt primarily with the manipulation of these SDPC pushbuttons.

The OCS integrated each of the subsystem control automation functions into one control point and coordinated the function of the subsystems. The level 2 automation was performed by the OCS and included subsystem start-up and shutdown, mode transitions, and functions which integrate more than one subsystem.

The level 3 functions were also performed by the OCS, and they included steady–state and mode transition management and clear day operation in Modes 1, 2 and 5:

> Clear Day Mode 1—Start–up, operation, and shutdown of the plant in Mode 1, receiver steam direct to the turbine
>
> Clear Day Mode 2—Start–up, operation in Mode 1, receiver to turbine, transition to Mode 2, receiver steam to turbine and to charge thermal storage, transition back to Mode 1, and shutdown of the plant
>
> Clear Day Mode 5—Start–up, operation, and shutdown of the plant in Mode 5, receiver steam to charge the thermal storage system.

The automatic clear day operating mode was designed for an almost fully automatic "hands–off" operation of the plant from sunrise to sunset on a clear day. Some operator interaction with the automatic sequence was required to perform manual functions, such as water chemistry tests, pump start–up, the fill and purge of the receiver, turbine roll, etc. The clear day scenario linked together in a logical sequence the automatic startup sequences, automatic mode transitions, and automatic shutdown sequences.

In spite of the availability of the OCS, the use of the OCS automatic control features decreased during power production operation. The primary reasons included the following: (1) considerable automation already existed in the plant's subsystem controllers, thus mitigating the plant operator's need for a more automatic system; (2) the OCS was brought on–line late – after the operators had already developed considerable experience controlling the plant with the subsystem controllers; (3) there was no formal OCS operator training; (4) there was a desire to maintain the plant operator skills using the subsystem controllers, in the event of an OCS failure; (5) the OCS lacked redundancy; and (6) a new receiver aimpoint strategy that shortened the receiver start–up times was used during power production operation. However, the new strategy was not programmed into the OCS.

The primary use of the OCS during power production operation was the monitoring of the plant systems. The response time to change a screen display, such as a piping and instrumentation diagram display, routinely took 10 seconds using the subsystem controllers. This seems long when an operator is preparing to give a command or desires equipment status information. The response time for the OCS screen display was much faster. The OCS display could be changed in about two seconds.

The Pilot Plant experience showed that automation can be effective in reducing the plant staffing levels (see discussion under Staffing Levels). However, automation does have some drawbacks. Plant automation can dull the operator awareness of individual system and equipment operating conditions, thereby depriving the operator of the knowledge needed to react quickly and correctly to an unforeseen event. This, undoubtedly, contributed to the Pilot Plant operators' preference for controlling the plant with the subsystem controllers rather than the OCS.

Computer Redundancy

A back-up computer for the OCS had been proposed for the Pilot Plant, but it was eliminated from the plant design as a cost-cutting measure. In retrospect, a redundant back-up for the OCS computer should have been retained as part of the overall plant control system. The availability of a redundant OCS back-up would have lessened operator concerns about the use of the OCS. A redundant back-up computer would also have facilitated the development of software changes like the revised heliostat aimpoint strategy - without affecting daily plant operations.

Future power plants should strive for a redundancy in the plant control system that is consistent with the cost of failures. The main point is that total redundancy may not be required or may not be cost effective. Components which would result in extended plant outages or are required for safety should be considered for redundancy. Analytic redundancy is another way of obtaining redundancy without extra hardware. If a sensor value can be calculated from other sensors in the plant, even if less accurate, this calculated value could be used to replace a failed sensor until it is repaired.

Sensor and Controller Degradation and Failure Detection

The Pilot Plant control system would have benefitted from a capability to detect and analyze sensor failures. The detection of sensor failures requires that expected values of the sensor output be known and that a time history of the sensor be kept. The control system computer would analyze this information and report actual and possible failures to the operator and the maintenance database (see below).

Alarm Analysis

The Pilot Plant control system generated excessive alarms. This was especially true when the plant was starting up or shutting down. Alarm limits were not tied to an operating mode. As a result, alarms that were not real occurred when there was a normal transition between operating modes. In future plants the control system should be designed to provide sensible information to the operator when alarms occur. Alarms should not occur when there are changes in the plant's operating mode or during start-up and shutdown. These are not abnormal conditions and should not be alarmed. The control system should be capable of analyzing an alarm and providing the operator with information on the source of the alarm. The following example illustrates the type of analysis needed.

A sensor in a control loop fails in the zero position. The process controller attempts to change the control device to restore the correct value from the sensor. This results in some other sensor value exceeding the limit. An alarm occurs and the plant protection system causes a trip. The alarm analysis would indicate that the failed sensor was the cause of all the rest of the alarms. Some alarms might be suppressed if they add no additional information.

Maintenance Data Base Integration

The Pilot Plant control system was not capable of tabulating and analyzing equipment failures as a means of defining and analyzing an effective maintenance program. In future solar plants consideration should be given to a control system with an integrated maintenance database or an off-line maintenance computer system. The system would provide an automatic means for posting maintenance orders for failures and would be used to look for failure trends and to issue preventive maintenance orders.

Beam Characterization System Lessons Learned

The Need for a Beam Characterization System

The need to accurately and quickly measure tracking errors for a large number of heliostats will dictate that future solar central receiver plants also must have a beam characterization system. The Pilot Plant system was fully automatic once it was started, and very little operator time or skill was needed to run the system and make heliostat tracking error corrections. Because there was a need for morning, noon, and afternoon tracking measurements to correct for errors that vary with the time of day, the Pilot Plant system performed a complete alignment on about 50 heliostats per day. Therefore, about 36 clear weather days were needed to perform an alignment of the Pilot Plant's 1,818 heliostats.

The measurement speed for future solar plants will depend on several factors, including the number of heliostats and the frequency at which heliostats must be re-checked for tracking errors. A fast measurement speed is desirable to reduce checkout costs during heliostat installation, but once in operation the need for fast mesurements will be reduced. A high measurement speed can also impact the heliostat costs since fast speeds will require high slew rates. These factors as well as specific design features like video digitizing, image analysis, and data presentation, should be considered in the beam characterization design for future solar plants.

Heliostat Diagnostics

The beam characterization system at the Pilot Plant could accurately measure tracking errors and beam quality (total reflected light and the size and distribution of the beam). However, it could not uniquely characterize the error sources which caused the tracking and beam quality to be poor. The beam characterization system could not be used by itself to determine what was wrong with a heliostat. A system that looks back at the heliostat, rather than at the reflected beam on a target, is required to evaluate the errors that contribute to beam quality.

Tower Shadow and Near-Singularity

Since a heliostat must be measured three times during a day, many heliostats were in the shadow of the tower or in near-singularity* during one or more of these times. This complicated the software required to schedule the beam characterization system measurements. Suitable software was not developed at the Pilot Plant to schedule the required measurements although the affected heliostats could be identified and dropped from the measurement list.

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* Near singularity refers to the condition whereby a heliostat mirror is nearly horizontal, and the azimuthal rate required for perfect tracking is greater than what the azimuthal drive is capable of producing. During normal tracking operations, this occurs at localized regions of the south field throughout the day.

Electric Power Generation System Lessons Learned

Thermal Cycling

The intermittent nature of the solar energy resource required the start–up and shutdown of the Pilot Plant equipment on a daily or even more frequent basis. To reduce the effects of this cycling on the electric power generation system operation and reliability, a receiver steam dump system diverted receiver steam to the condenser during start–up, allowing attainment of steam temperatures and pressures that were consistent with the turbine metal temperatures. This approach mitigated thermally induced turbine component failures and minimized the passage of steam line exfoliation products that erode turbine blades. A turbine inspection in 1985, which revealed only minor turbine wear, demonstrated the validity of this approach. The cyclic nature of Pilot Plant operation did not significantly increase the required maintenance for the electric power generation system.

Low–Pressure Admission Steam Operation

The Pilot Plant turbine–generator has dual steam admission ports —- one for high–pressure receiver steam and one for low–pressure steam from thermal storage. During the early testing at the Pilot Plant, we experienced problems with turbine start–up using low–pressure admission steam: an internal steam leak caused the turbine to overspeed uncontrollably. The problem was identified as a turbine design defect. Even though the turbine stop–valve was modified, some operator intervention was still required for the low–pressure admission steam start–up operation.

Little additional experience with the low–pressure admission steam operation was obtained during power production testing. The steam from thermal storage operation was never used for turbine start–up. This type of start–up proved to be unattractive for a variety of reasons in addition to the control problem mentioned above (References 8–2 and 8–6). In addition, thermal storage steam was almost never used to produce electrical power. Rather the steam was used to provide the plant's auxiliary steam needs.

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