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The Design of Future Central Receiver Power Plants Based on Lessons Learned from the Solar One Pilot Plant*

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Gregory J. Kolb
Sandia National Laboratories
Albuquerque, N. Mex. 87185-5800

ABSTRACT

The 10-MW_e Solar One Pilot Plant was the world's largest solar central receiver power plant. During its power production years it delivered over 37000 MWhrs (net) to the utility grid. In this type of electric power generating plant, large sun-tracking mirrors called heliostats reflect and concentrate sunlight onto a receiver mounted on top of a tower. The receiver transforms the solar energy into thermal energy that heats water, turning it into superheated steam that drives a turbine to generate electricity.

The Solar One Pilot Plant successfully demonstrated the feasibility of generating electricity with a solar central receiver power plant. During the initial 2 years the plant was tested and 4 years the plant was operated as a power plant, a great deal of data was collected relating to the efficiency and reliability of the plant's various systems. This paper summarizes these statistics and compares them to goals developed by the U. S. Department of Energy. Based on this comparison, improvements in the design and operation of future central receiver plants are recommended.

Research at Sandia National Laboratories and the U. S. utility industry suggests that the next generation of central receiver power plants will use a molten salt heat transfer fluid rather than water/steam. Sandia has recently completed the development of the hardware needed in a molten salt power plant. Use of this new technology is expected to solve many of the performance problems encountered at Solar One. Projections for the energy costs from these future central receiver plants are also presented. For reference, these projections are compared to the current energy costs from the SEGS parabolic trough plants now operating in Southern California.

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DISCLAIMER

Introduction

Solar One, located near Barstow, California, was the world's largest solar central receiver power plant (Figure 1). In this type of electrical power generating plant, large sun-tracking mirrors called heliostats reflect and concentrate sunlight onto a receiver mounted on top of a tower. The receiver transforms the solar energy into thermal energy that heats water, turning it into superheated steam that drives a turbine to generate electricity (Figure 2). Alternatively, energy can be stored in a thermal storage system for later use.

The Solar One project was a joint undertaking of the U.S. Department of Energy and the Associates, consisting of the Southern California Edison Company (SCE), the Los Angeles Department of Water and Power, and the California Energy Commission. SCE, the lead agency for the Associates, provided the plant's conventional equipment and was responsible for the plant's operation. The project was designed to demonstrate the feasibility of generating electricity with solar central receiver power plants. The plant came on line April 12, 1982, and was mothballed on September 27, 1988, after successfully achieving all technical objectives. Its nominal power rating was 10 MWe; the plant was designed to achieve this power level for at least 8 hours near the summer solstice, and for at least 4 hours near the winter solstice. After an initial 2-year testing and evaluation phase, the plant began a 3-year "power production" phase followed by an additional 14 months of 5-day per week operation. During these 50 months, the plant delivered 37,000 MWh net energy to SCE's electrical power grid. Radosevich presented a summary of the plant's 3-year power production phase [1,2].

Solar One was designed in the late 1970s and should be considered a first-generation plant. Since that time several industrial and government organizations have performed studies that define more advanced, second-generation designs. In addition, several small-scale experiments, which support these new concepts, have been conducted at the Central Receiver Test Facility in Albuquerque, NM [3,4]. Recently, design studies of second-generation plants were conducted by two U.S. utilities [5,6]. The current objective of the central receiver program in the U. S. is to demonstrate that a commercial-scale power plant is feasible for utility-scale power production. The principal difference between Solar One and more recent designs is the choice of heat transfer fluid---in the second-generation systems, molten nitrate salts rather than water/steam is pumped through the receiver's tubes. Use of salt offers numerous advantages over water/steam including a simpler and more efficient receiver (the salt is a single phase fluid that operates at low vapor pressure), more efficient turbine operation (steam conditions and flow rates are easier to control), and a more efficient energy-storage system (hot salt can be economically stored in tanks).

Before second-generation power plants are built, however, it is important that the lessons learned from Solar One be thoroughly digested so that the improvements can be incorporated into the next-generation plant. In this paper, we focus on methods for increasing the annual electrical energy produced by central receiver power plants. Annual energy can be increased by improving the efficiencies of the plant's systems and by bettering the plant's availability. The basis of our analysis is the actual performance data from the Solar One plant, a simulation of the plant using the computer code SOLERGY [7], and the plant's detailed records on maintenance and repair of individual components. The effect that these energy improvements have on the cost of electricity from central receiver plants is also presented and compared to existing solar thermal power plants.

Plant Design of Solar One

Figure 2 depicts the major systems at Solar One:

- The collector field, including the heliostats and supporting components
- The receiver
- Thermal storage
- Master control systems
- Electric power generating system
- Plant Support Systems.

Integration of the plant's systems was the responsibility of the McDonnell Douglas Corp.

Collector. The heart of the collector system was a field of 1818 heliostats positioned 360 degrees around the tower; the heliostats were designed and built by Martin Marietta [8]. Each heliostat was an assembly of 12 slightly concave glass mirrors mounted on a support structure and geared drive that could be controlled for azimuth and elevation. The total reflective area of each heliostat was 40 m^2 (430 ft^2). The controlling system consisted of a microprocessor for each heliostat, 64 field controllers (each for up to 32 heliostats), and two heliostat control computers, one controlling the entire field and the other acting as a backup. Also included were the associated power supply and the hardware for data transmission and control.

Receiver. The receiver system used the reflected sunlight to heat water directly, creating superheated steam. The system, designed by Rocketdyne, consisted of 6 preheating panels and 18 single-pass-to-superheat boiler panels [9]. External tubing, tower, pumps, piping, wiring, valves, and controls were all part of the system that provided steam to the turbine or to the thermal-storage charging system. Although the control-room operator could control delivery of steam, the system normally reacted automatically to changes in the amount of sunlight reaching the receiver.

<u>Thermal Storage.</u> The thermal storage system stored heat from solar-generated steam in a tank filled with rock and sand, using thermal oil as the heat transfer medium [10]. The system thus extended the plant's power-generating capability into the night or during cloudy periods. It also provided heat for generating low-grade steam to warm parts of the plant during off-hours and to start the plant the next morning. Components of the system, designed by Rocketdyne, were the charging subsystem, which heated the storage oil with steam from the receiver; the extraction subsystem, which transferred the stored heat to water, generating medium-pressure steam; a single thermocline storage tank; and an ullage maintenance unit. The storage system was typically not used to supply steam to the turbine generator because excess energy was not available from the receiver[1] and because the turbine ran most efficiently when operating on receiver steam.

The thermal storage system at Solar One operated through August 30, 1986. On that date the storage tank was damaged by a fire, which was caused by the inadvertent injection of water into the hot oil, causing an explosion [1]. Because it was possible to run the plant without storage, and evaluation of the system had been completed, the system was not repaired.

<u>Master Control System.</u> Solar One was the first power plant in the U.S. to employ a fully distributed process control system. It consisted of several computers responsible for monitoring and controlling the plant's individual systems and for collecting data about the plant's operation and performance [11]. Most of the plant's functions were fully automatic, with operator override capabilities, which made it possible for one operator to control the entire facility. The system had access to approximately 2500 channels of information from all over the plant and displayed operating data and alarms on consoles and other graphic means within the control room. Three Beckman MV8000 distributed-process controllers were used to operate the receiver, thermal storage, and electric power generation systems. An interlock logic system consisting of three Modicon 584 programmable logic units contained the plant permissives required to operate safely. Two red-line units, also Modicon 584 programmable logic units, provided safety monitoring and control of the receiver and thermal storage systems to assure shutdown of the systems when criteria for safe operation were exceeded. Five remote stations processed information between the operational control room and the operating equipment.

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[1]Due to a cost-saving measure during plant construction, the number of heliostats was reduced and thus little excess energy was available to deliver to storage.

Turbine Generator. The General Electric turbine-generator was a single-case design for cyclic duty, rated at 12 MW. The turbine admitted high-pressure steam generated by the receiver through one port and lower pressure steam generated by the thermal storage system through another [12]. Circulating water from an evaporative cooling tower condensed the spent steam into water, which was routed back to the receiver through a full-flow demineralizer and a series of feedwater heaters. Two other functions supported the power-generating system: water chemistry control facilities and an uninterruptible power-supply battery system in case the main and back-up power supplies to the control system failed.

Plant Support Systems. The plant's auxiliary systems provided raw water, fire protection, water treatment, cooling water, nitrogen, compressed air, liquid waste disposal, auxiliary steam, and air conditioning.

Performance Simulation of Solar One

We used the SOLERGY computer code [7] to simulate Solar One's performance during calendar year 1985, because a reasonably complete set of data from the plant's data acquisition system was available for that year. The objective of the simulation was to determine energy conversion efficiencies for each of the plant's systems on an annual basis. These results can be used to assess the impact of alternative plant designs or operating strategies on annual energy production, the final objective being to optimize the design of central receiver power plants.

SOLERGY simulates the operation of a solar central receiver power plant using insolation recorded at 15-minute intervals. The relatively short intervals are needed to model plant start-up and the effects of cloud-induced transients. The code has subroutines for each major plant system, i.e., heliostat field, receiver, thermal-energy storage, and turbine-generator. For each 15-minute time step, SOLERGY determines the plant's operational state (shutdown, starting up, etc.) and calculates steady-state power flows through each plant system. The annual performance is found by summing the performance at every 15-minute time step. Complete details of the simulation of Solar One using SOLERGY can be found in a report by Alpert and Kolb [13].

We developed the data used as input to SOLERGY from actual experiments performed at the plant, curve fits of data collected by the plant's data acquisition system, or from examination of the design and specifications of individual components. We validated the model by comparing the plant's actual and predicted performance on 153 days; the weather on these 153 days covered a broad range of possibilities: clear skies, hazy skies, various types of partly cloudy weather, and completely overcast days. The basis for selecting these 153 days was that the plant's data acquisition system was operating, there were no outages, and thermal storage was not charged.

Figure 3 is a scatter plot relating the actual net energy produced by Solar One on these 153 days to SOLERGY's predictions. The predictions are very reasonable for about 90% of the 153 days; for the remaining days, SOLERGY significantly overpredicted energy production. The overpredictions tended to occur on days with intermittent clouds, in part because 15-minute average insolation was used, which eliminates short cloud-induced transients, and because of unpredictable actions taken by the plant's operator, who could not predict if future insolation levels would be sufficient to allow operation of the plant. However, relatively little energy is produced on these days, so that an overprediction has little impact on the total annual energy production. The total net energy produced by Solar One on the 153 days was 6140 MWh---SOLERGY predicted 6910---a difference of 12%.

To determine the energy-conversion efficiency of each of the systems, the plant's performance for all of calendar year 1985 was simulated with SOLERGY. The annual energy flows calculated by the program are summarized in Figure 4. The actual net energy produced for the year was 8625 MWh; an annual efficiency of 4.8%. SOLERGY predicted 10050 MWh, a difference of 16%. The annual SOLERGY-calculated efficiency of each system is presented in Table 1, and these values are compared with the efficiency goals established by DOE [14]. In the next section, we discuss the performance of each system and make recommendations for improving the design and/or operation of future central receiver plants to more nearly attain DOE's long-term goals.

Recommendations for Improving The Efficiency and Availability of Central Receiver Systems

The following sections discuss the performance and efficiency of the plant's systems; the availability of each system is discussed in a later section.

Heliostats. This category concerns the reflectivity of the heliostats. When clean, the heliostats had an average reflectivity of 90.3% [8]; however, continuous exposure to the environment caused them to become dirty over time. During calendar year 1985, for example, the cleanliness[2] of the heliostat field averaged 90.6% [13], which gave an average reflectivity value of 82%. To approach the goal of 92%, improvements in both the clean reflectivity and in cleanliness are necessary.

Since Solar One's heliostats were designed, DOE's solar thermal program has made significant improvements in heliostats [15]. Glass-mirror heliostats with reflective areas up to 150 m^2

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[2]Cleanliness is the measured reflectance divided by the reflectance when the mirror is clean.

have been built, and their good optical performance and high reflectivity (up to 94%) are indicative of the maturity of the technology [16]. Currently, in the United States, the Department of Energy and Sandia National Laboratories are developing a new type of heliostat that should be lower in cost than current glass mirror designs. Called a stretched-membrane heliostat, its reflector is a silvered-polymer film laminated to a thin metal foil, which is stretched over a large-diameter metal ring (Figure 5). The solar-averaged reflectivity is about 92%. Fifty-square-meter prototype heliostats have been built and tested [17-19], and designs for heliostats up to 150 m^2 in area have been prepared [20,21]. Because of its simplicity and light weight, a stretched-membrane heliostat could cost up to one third less than comparable glass-mirror designs [15]. A key uncertainty about membrane heliostats is the durability and cleanability of silvered-polymer films; research in this area is continuing. Stretched-membrane heliostats are expected to be commercially available in the U.S. by 1992. Development of stretched-membrane heliostats is also underway in Spain [22] and Germany [23].

During 1985, rain provided the only source for cleaning the heliostats at Solar One. Subsequently, it was determined that it would be cost effective to mechanically clean the heliostats [24], and in the latter phase of operation, the heliostats were washed with water and chemical sprays using a truck designed for that purpose [25]. Depending on local soiling rate, biweekly cleaning of heliostats should improve cleanliness to greater than 95% [15].

<u>Field.</u> The locations of the heliostats in the field were chosen to produce optimum field performance on an annual basis. Computer codes developed by the University of Houston determined the layout of the field [26]. The 30% loss in the Solar One field was primarily because of cosine effects, which are due to the fact that the heliostats do not point directly at the sun. The energy incident on the heliostat's reflective surface is thus reduced by the cosine of the angle defined by the sun's location and a vector that is normal to the mirror.

Since the annual field efficiency meets DOE's goal, significant changes in this area are not recommended; moreover, only small improvements are likely to be possible.

<u>Receiver.</u> As indicated in Table 1, the Solar One receiver absorbed 69% of the annual solar energy incident upon it. The 31% lost was primarily due to reflection, thermal losses (radiative and convective), and start-up inefficiencies. Reflection losses occur because the high-absorptance paint does not absorb all the incident energy. Thermal losses are caused by radiative and convective heat transfer between the receiver and environment and are a function of the external temperature of the receiver and wind speed. To start up Solar One's receiver, several MWh of thermal energy must be absorbed to achieve rated steam conditions. To approach the 90% goal, a

significant improvement in receiver efficiency is needed.

As mentioned previously, the next generation of central receiver power plants will likely use a molten salt heat transfer fluid rather than water/steam. Receivers using molten salt will have a higher thermal efficiency because they use higher average incident solar fluxes and thus can be smaller. Higher fluxes are possible because the salt is at lower pressure, which allows thinner walled tubes to be used in the receiver. The smaller receiver size reduces both radiative and convective losses. Molten salt receivers have been tested at the Central Receiver Test Facility in Albuquerque, New Mexico. [3,4].

Reflection losses were reduced from 13% to 6% at the end of 1985 after a second coat of Pyromark paint was applied, indicating that much was learned at Solar One regarding the application of absorptive coatings [1,9].

Efforts in the U.S. are underway to improve the design of receivers. For example, the development of a third-generation receiver using the falling-film, direct-absorbtion (DAR) concept could further increase the receiver's performance by reducing start-up losses, lowering thermal losses, and improving absorptance [27]. Instead of having the salt flow in tubes as in second-generation designs, the direct absorption receiver has a darkened salt flowing in a thin film down a flat, nearly vertical plate, with the solar energy directly incident upon it. The annual efficiencies projected for second- and third-generation receivers are approximately 80% [5,6] and 90% [27,28], respectively. The direct absorption receiver is currently being tested at Sandia National Laboratories.

<u>Master Control.</u> Solar One demonstrated that modern computers, distributed process controllers, and programmable logic units can be successfully used in the electrical utility industry. These systems are now being installed in non-solar power plants.

<u>Thermal Storage.</u> Solar One successfully demonstrated the additional flexibility thermal storage affords a solar power plant. Thermal storage allows the generation of power to be shifted to periods of peak demand and provides a buffer between the plant's receiver and turbine, allowing the turbine to operate during cloud-induced transients. However, Solar One's thermal storage system used an intermediate heat transfer fluid that significantly compromised its efficiency. There were energy losses associated with warming up both the charging and discharging heat exchangers, increased parasitic energy required to pump the fluid, as well as a decreased turbine efficiency because of the lower inlet temperature of steam produced from stored energy [29]. It was because of these inefficiencies that Solar One's thermal storage system was generally used only to provide auxiliary steam. A plant using molten salt for the heat transfer fluid can economically store the salt heated by the receiver in a large tank [30]. In fact, current designs often oversize the plant's receiver and heliostat field to provide

sufficient energy to operate the turbine at full power and simultaneously charge the storage system[3]. In addition, molten-salt thermal storage is simple, because there is no charging heat exchanger, and highly efficient (>99% [31]).

Turbine. At Solar One's design point, the turbine-generator efficiency is approximately 33% [32]. However, on an annual basis, the efficiency is approximately 30% because of energy losses from starting up the turbine in the morning and following cloud-induced transients. Moreover, because the heliostat field was slightly undersized compared to the receiver, it was necessary to operate the turbine at less than full capacity for a large part of each day, and the turbine's efficiency was lower than 33% during part-load operation.

The design-point efficiency of 33% for Solar One's turbine is low compared to modern power plants because its size was relatively small (12 MWe) and thus, it did not use a reheat cycle. A commercial-scale central receiver plant would be much larger than Solar One, employing a turbine rated at 100 to 200 MWe [5,6]. Turbines of this size typically use reheat cycles and provide efficiencies close to 42%. In addition, with a properly sized molten-salt thermal storage system it is possible to operate the turbine at full load and highest efficiency even though the receiver is operating at less than its capacity. In addition, thermal storage provides a buffer between the plant's receiver and turbine generator, which reduces energy losses associated with restarting the turbine, as occurred at Solar One.

Support Systems. The support system at Solar One consists of the balance-of-plant system hardware and includes all site structures. The support system's equipment and buildings require electric power to operate while the plant is on line and during shutdown each night. The energy consumed by this equipment, known as parasitic power, reduces the net amount of electricity delivered by Solar One to the grid. During the power production phase, parasitic power consumption was about 33% of the gross electricity produced by the turbine-generator [1], and in 1985 it was 39% (Table 1). Parasitic power consumption was relatively high because Solar One was a small plant, and because some of the non-solar support equipment was oversized (the support systems were not optimized because Solar One was meant to demonstrate the performance of only the solar-unique portions of the plant). In a commercial-scale plant, the parasitic loss fraction would be much smaller because it would use roughly the same size equipment that Solar One used during shutdown, yet should produce much more electric power. In a recent study of a 100-MWe molten-salt plant, parasitic power consumption was estimated to be approximately 10 to 12% on an annual basis [5,6]. In a third-generation plant, parasitic

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[3]In this case the solar multiple is greater than one -- the solar multiple is the ratio of the receiver power to the thermal power required by the turbine.

power consumption would be further reduced, because a direct-absorption receiver requires about half the pumping power needed by a tubed receiver [27].

Availability. This category represents energy losses due to equipment outages. The overall availability listed in Table 1 is the product of the availability of individual heliostats (98%) and the plant's availability (80% [13]).

The reliability of the 1,818 heliostats was excellent during the plant's operating years, and it was found that the entire field could be maintained by only one person working 3/4 time [33]. Future plants would therefore be wise to adopt Solar One's heliostat maintenance practices.

Considering the fact that Solar One was a first-of-a-kind power plant, the plant's availability during 1985 (80%) and its 4-year average (85% [34]) were commendable. However, improvements are necessary to approach the goal listed in Table 1. We performed a detailed analysis of the frequency and causes of plant outages that occurred over a 3-year period and made recommendations regarding mitigation of these failures at future central receiver power plants [33]. Figure 6 groups the solar-outage times by system. It can be seen that approximately half of the outage hours were due to problems with the receiver, with additional significant contributions from the turbine and the plant's computers. These three problem areas are briefly presented below. A more detailed discussion of these and other outages can be found in Kolb and Lopez [33,34].

The receiver outages at Solar One were caused primarily by tube leaks; reasons for the leaks were described by Radosevich [1]. Failures of valves and process transmitters were also important. However, experience at the Themis molten salt receiver, a receiver with many similarities to a second generation receiver, indicated that tube leaks were not a problem in over 3000 hours of operation [35]. Adoption of the third-generation receiver should also improve reliability; the direct-absorption receiver does not have tubes and is less reliant on process transmitters.

The turbine outages at Solar One in 1985 were dominated by a single 5-week scheduled outage. This outage was preventive in nature, and nothing significantly wrong was found. The solar-outage time could have been reduced 25% if the maintenance had been scheduled around the winter solstice when there are fewer daylight hours.

Half of the computer related outages were caused by problems with the computers that controlled the heliostats. The majority of these problems were due to interface incompatibilities between the prime and back-up computers. Interfaces between these two vital computers and others that were non-vital also proved to be troublesome. The lessons learned from Solar One in this area are twofold: 1) interfaces between vital and non-vital computers should be avoided, and 2) analyses of failure modes and effects should be performed on computer interfaces to gain a clear understanding of subtle system interactions.

As a final note, the 90% availability goal listed in Table 1 was achieved at Solar One during its final operating year. The primary reasons for this improvement were the performance of more maintenance when the plant was closed (the equivalent of doing maintenance at night) and the reduced frequency of severe tube leaks. The reduced number of tube leaks is believed to be partially due to the use of a more conservative operating strategy during the final year; slower temperature ramp rates were used to reduce the frequency and severity of the receiver's thermal cycles. The improvement in availability allowed the plant to achieve an annual efficiency of 7.4%, which was close to the goal of 8.2% established for Solar One [1].

Energy Cost Projections for Molten Salt Central Receiver Technology

Solar One was a first-generation design. For the past 10 years Sandia National Laboratories has been developing the hardware for second generation central receiver technology. Virtually every component of the second generation power plant has been built and tested during that time. Most recently, we completed testing of molten-salt pumps and valves sized for a 60 MW_e power plant [36]. Testing of the pumps and valves was completed within the last year and represents the last major hurdle to successful demonstration of the technology. All components have exhibited acceptable levels of performance and reliability. Besides hardware development, we have recently completed a reliability study which integrates the reliability data from Sandia experiments and other solar power plant projects such as Solar One, Themis, and the 350 MW_e of solar electric generating stations installed by LUZ in Southern California. This analysis has indicated that the technology should be able to achieve the 90% availability goal required for economical power production [37].

In Figure 7 we present levelized-energy cost predictions for second and third generation central receiver power plants. For reference, these projections are compared to the most recent SEGS parabolic trough power plant now operating in California. The comparison was based on the central receiver utility studies [5,6], as well as economic and insolation assumptions commonly employed by LUZ [38]. These favorable projections are causing a renewed interest in the U.S. for a demonstration of a molten salt power plant at a 10 MW_e to 30 MW_e scale. Projects currently under consideration are a retrofit of the Solar One plant with a molten salt system [39] or the building of a new 30 MW_e plant.

Summary

Much has been learned from the operation of Solar One. The plant successfully operated as a power plant for over 4 years and proved the feasibility of generating electricity with solar central receiver power plants. Shortcomings with the design and operation of Solar One have been identified. Implementation of the second and third generation design discussed in this paper should help correct these shortcomings and increase the annual efficiency of future plants to more nearly meet DOE's goal for annual efficiency of 20%. These efficiency improvements (>15% for second generation and >17% for third generation) are predicted to cause a major reduction in the cost of energy from future central receiver plants.

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Table 1
Annual Efficiencies of Solar One's Systems in 1985 Versus DOE's Long-Term Goals

	Solar One (1985) [13]	DOE's Long-Term Goal [14]
Heliostats	0.82	0.92
Field	0.70	0.70
Receiver	0.69	0.90
Transport	0.99	0.99
Turbine	0.30	0.42[1]
Support System	0.61	0.92[1]
Availability	0.78	0.90[2]
Product	0.056	0.20
Product (Best Year)	0.074[3]	

[1] Inferred from information presented in [14]
[2] As assumed in reference [5,6]
[3] Goal for Solar One was 0.082 [1]

Figure 1. Aerial view of the Solar One pilot plant. The plant's rated capacity was 10 MWe.

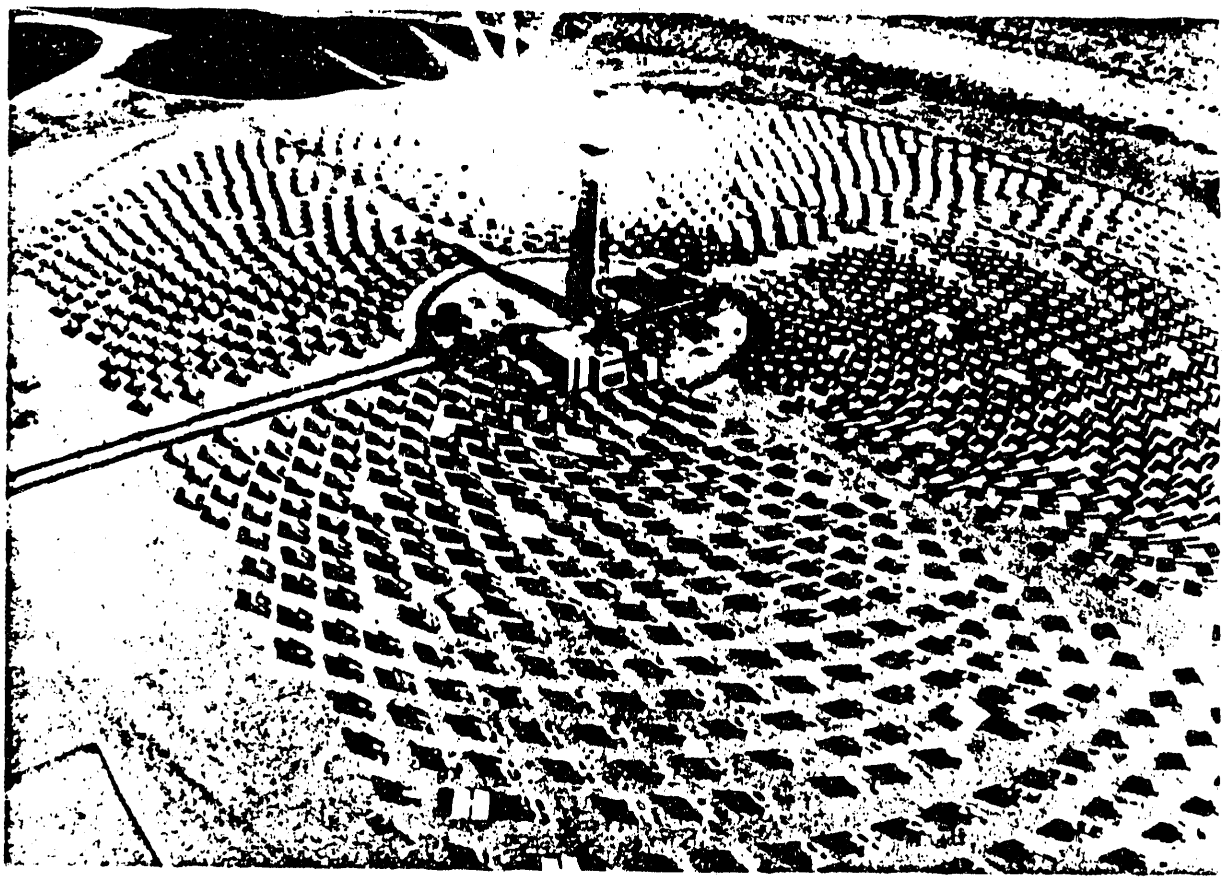
Figure 2. Schematic of the Solar One Pilot Plant.

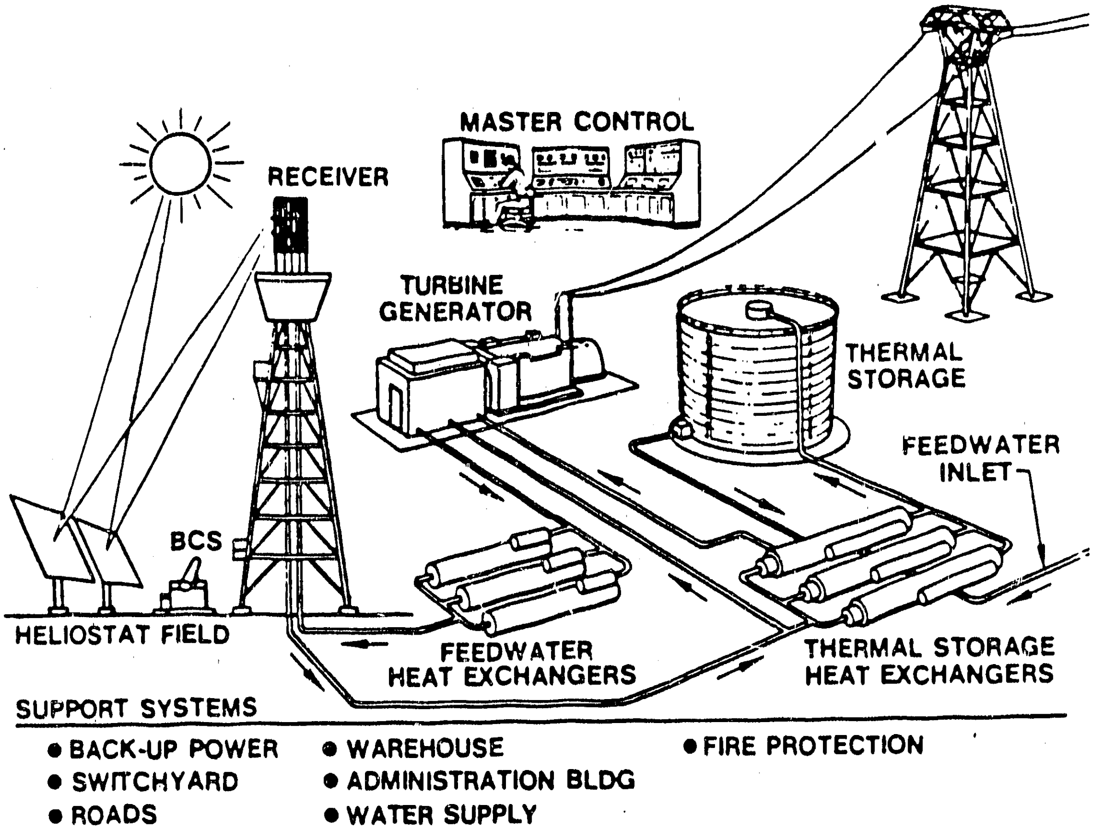
Figure 3. Scatter plot comparing the actual daily net energy produced by Solar One on 153 days with the SOLERGY prediction. The actual total energy produced on the 153 days was 6140 MWh---SOLERGY predicted 6910 MWh.

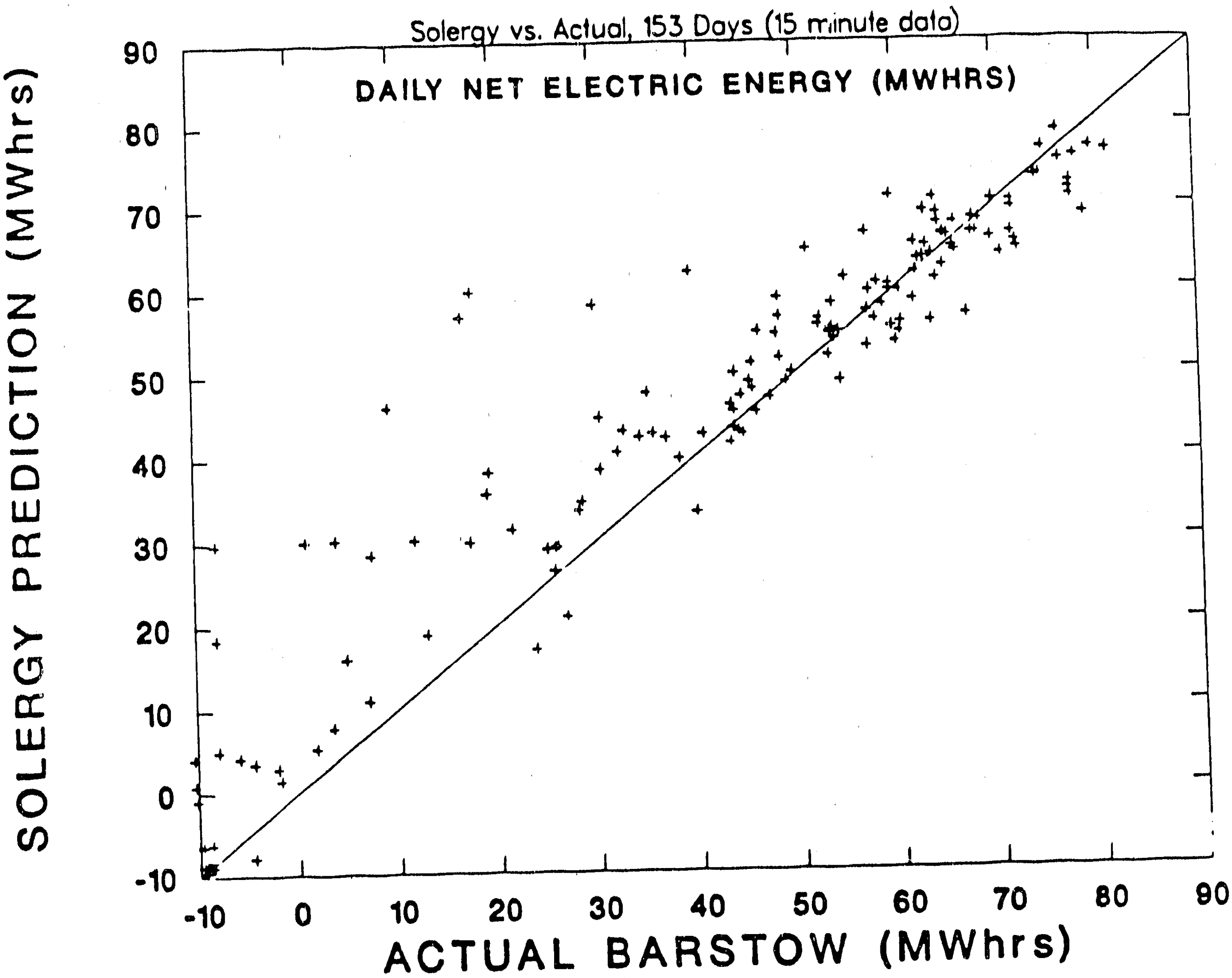
Figure 4. Waterfall diagram for Solar One during 1985 calculated using SOLERGY. The actual energy produced was 8625 MWh---SOLERGY predicted 10050 MWh.

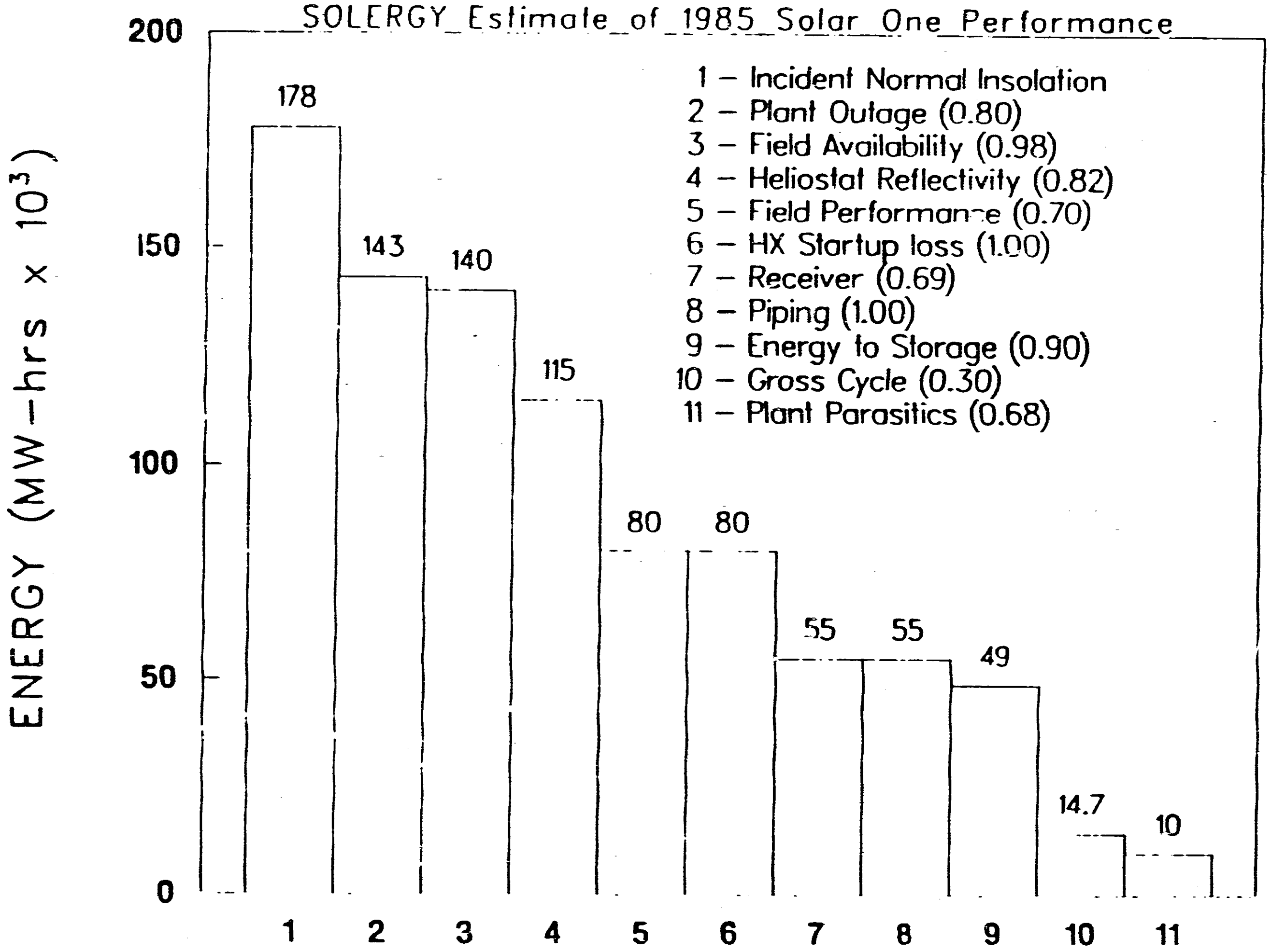
Figure 5. A stretched-membrane heliostat. Because of its simplicity and light weight, a membrane heliostat should cost about one-third less than conventional glass-mirror designs.

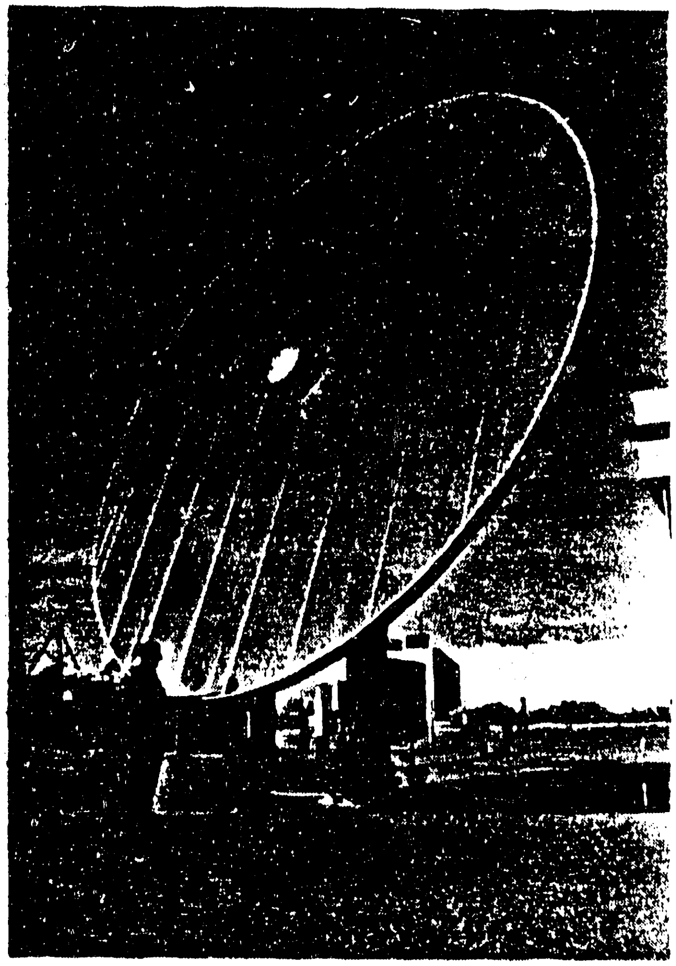
Figure 6. Plant outage hours by system. Half of all outage hours were related to problems with the receiver.

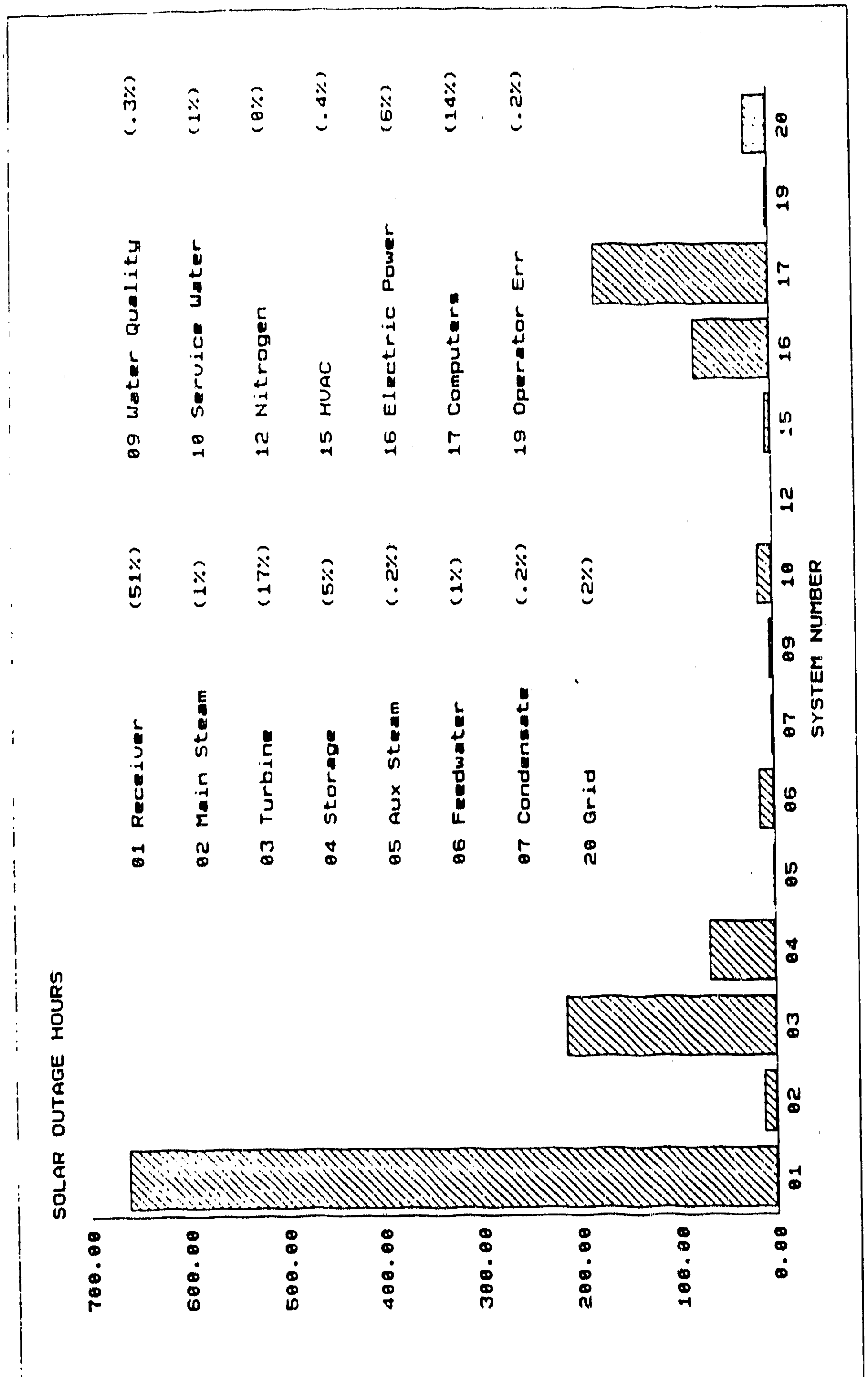



MASTER CONTROL
RECEIVER
TURBINE GENERATOR
THERMAL STORAGE
FEEDWATER INLET
BCS
HELIOSTAT FIELD
FEEDWATER HEAT EXCHANGERS
THERMAL STORAGE HEAT EXCHANGERS
SUPPORT SYSTEMS
• BACK-UP POWER
• SWITCHYARD
• ROADS
• WAREHOUSE
• ADMINISTRATION BLDG
• WATER SUPPLY
• FIRE PROTECTION


Solergy vs. Actual, 153 Days (15 minute data)
DAILY NET ELECTRIC ENERGY (MWHRS)
SOLERGY PREDICTION (MWhrs)
ACTUAL BARSTOW (MWhrs)
90
80
70
60
50
40
30
20
10
0
-10
-10
0
10
20
30
40
50
60
70
80
90


SOLERGY Estimate of 1985 Solar One Performance
1 – Incident Normal Insolation
2 – Plant Outage (0.80)
3 – Field Availability (0.98)
4 – Heliostat Reflectivity (0.82)
5 – Field Performance (0.70)
6 – HX Startup loss (1.00)
7 – Receiver (0.69)
8 – Piping (1.00)
9 – Energy to Storage (0.90)
10 – Gross Cycle (0.30)
11 – Plant Parasitics (0.68)
178
143
140
115
80
80
55
55
49
14.7
10
ENERGY (MW-hrs x 10³)
200
150
100
50
0
1
2
3
4
5
6
7
8
9
10
11

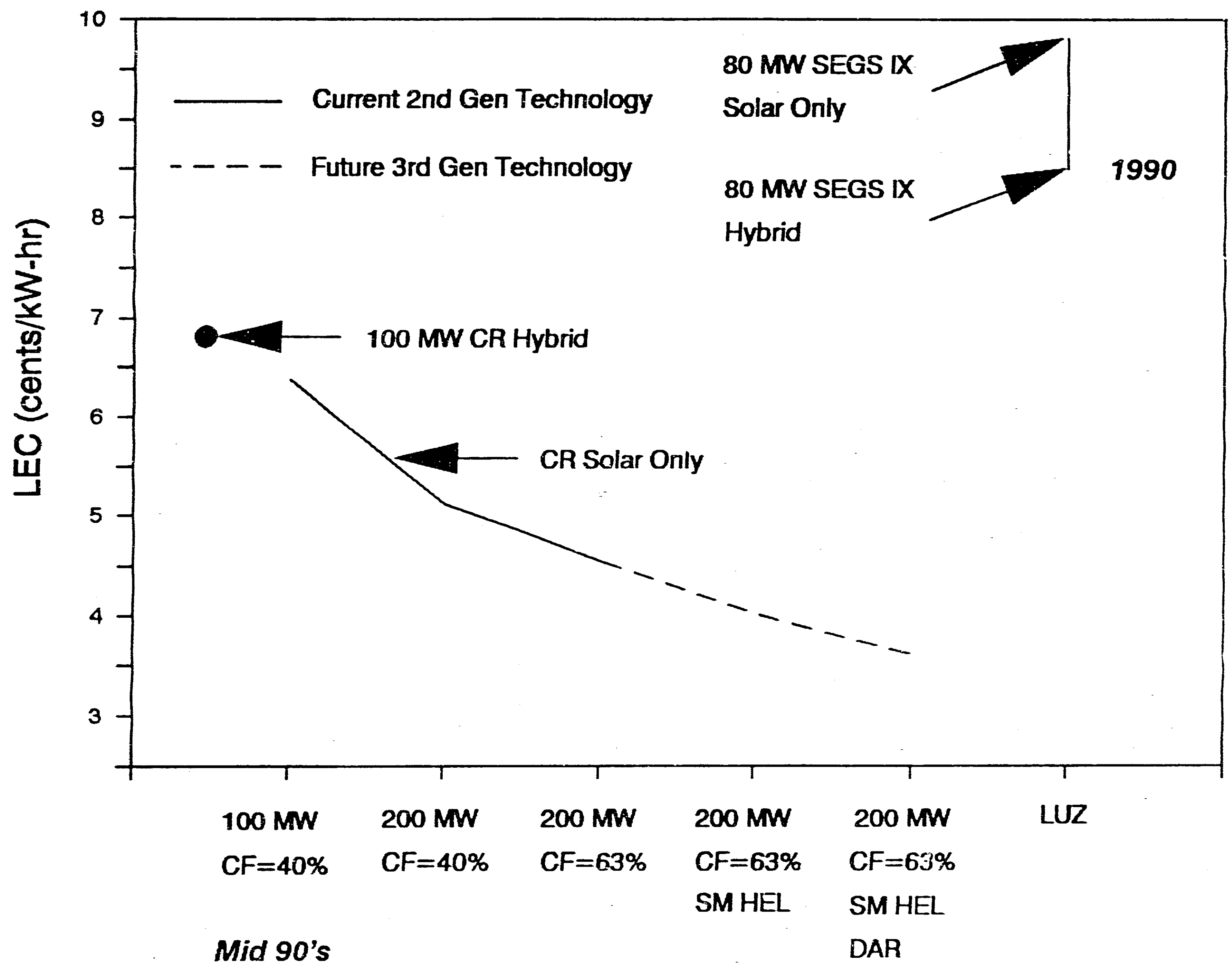



SOLAR OUTAGE HOURS
700.00
600.00
500.00
400.00
300.00
200.00
100.00
0.00
01 02 03 04 05 06 07 09 10 12 15 16 17 19 20
SYSTEM NUMBER
01 Receiver (51%)
02 Main Steam (1%)
03 Turbine (17%)
04 Storage (5%)
05 Aux Steam (.2%)
06 Feedwater (1%)
07 Condensate (.2%)
20 Grid (2%)
09 Water Quality (.3%)
10 Service Water (1%)
12 Nitrogen (0%)
15 HVAC (.4%)
16 Electric Power (6%)
17 Computers (14%)
19 Operator Err (.2%)

6

Figure 7 Prediction of Levelized Energy Costs For Central Receiver Technology With LUZ as a Reference

(For varying capacity factors (CF), given a fixed charge rate equal 5.4%.)



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