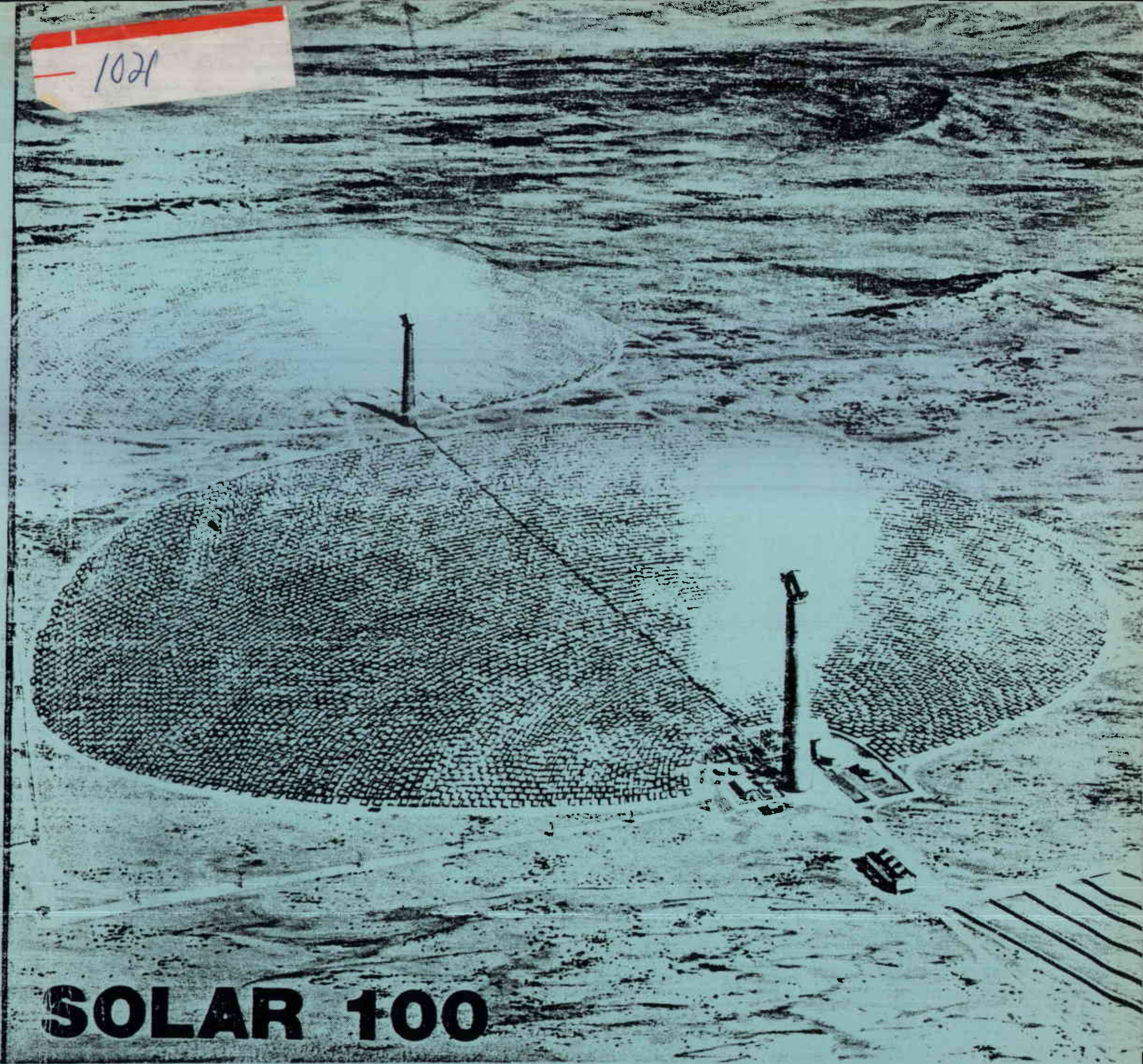

SOLAR 100

CONCEPTUAL STUDY
FINAL REPORT
(EXECUTIVE SUMMARY)

SCE Southern California Edison Company

BECHTEL POWER CORPORATION

MCDONNELL DOUGLAS CORPORATION

SOLAR 100

CONCEPTUAL STUDY

(Executive Summary)

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SOLAR 100 CONCEPTUAL STUDY

EXECUTIVE SUMMARY

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EXECUTIVE SUMMARY

SOLAR 100 CONCEPTUAL STUDY

I. INTRODUCTION

A. BACKGROUND

This study was conducted to determine the present day feasibility of designing and constructing a commercial size (100 MWe) solar thermal power plant, to be located in the southwestern United States. A conceptual design was developed and its financial aspects were explored; the study included consideration of:

- o Alternate systems
- o Capital operating and maintenance costs
- o Financing and tax implications
- o Ownership by private utilities, municipal or other public agencies, or private investors

This report describes the procedures, conceptual design, financial analysis and the conclusions and recommendations. Figure 1 is an artist's rendering of the central receiver solar plant, designated as the Solar 100 Project, which uses two separate heliostat fields and common power block.

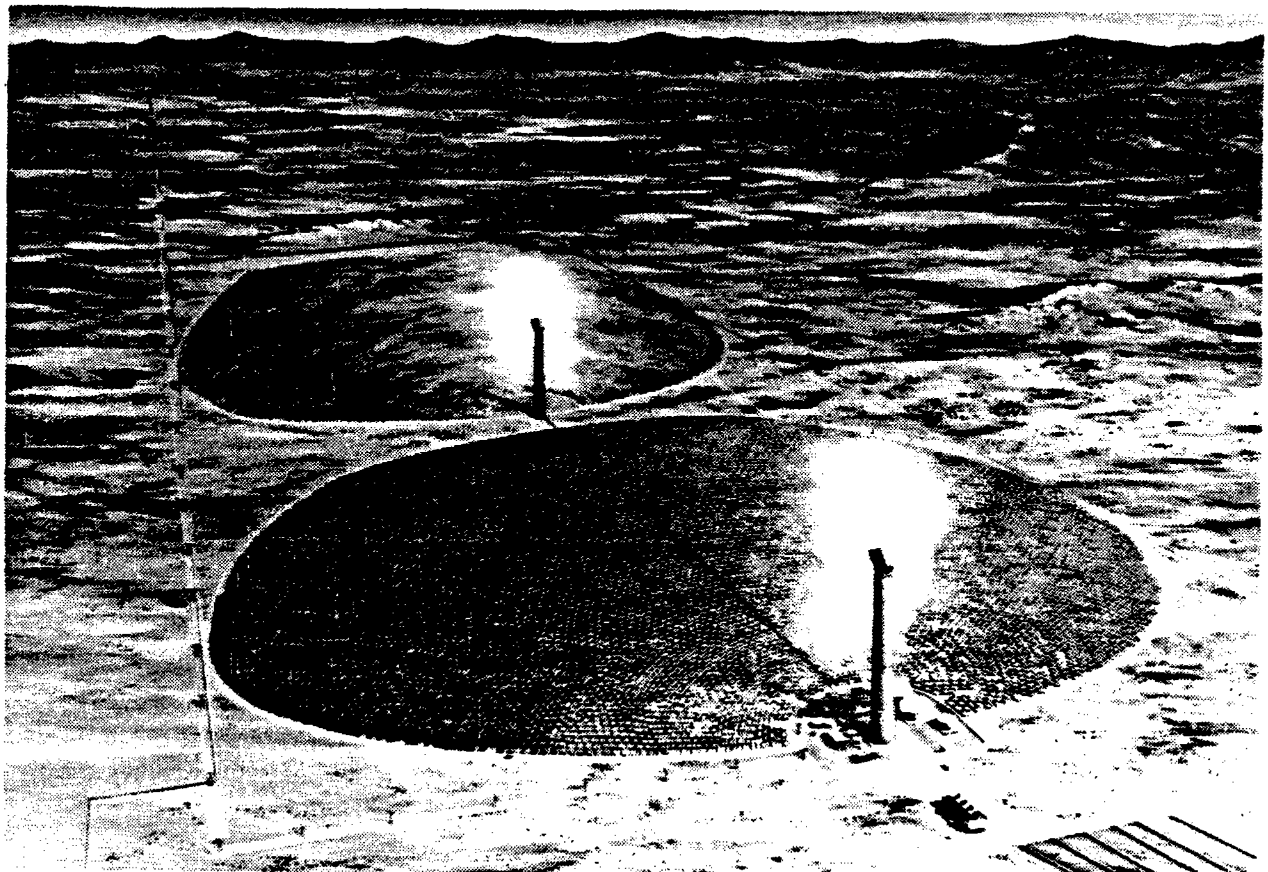


Figure 1. Solar 100

The further development of solar energy at this time is particularly desirable, in order to decrease the country's dependence on imported oil. For this reason, tax incentives are offered by the government for its development; these were examined during the study and their implications are explained in this report.

Three major corporations, each with its own expertise, pooled their resources as participants in the study. The three companies and their primary responsibilities in the study are:

Southern California Edison Company (SCE)

- Design and Selection Criteria
- Plant Value Analysis
- Siting and Regulatory Investigations
- Steam Cycle Process
- Overall Study and Report Responsibilities

McDonnell Douglas Corporation (MDC)

- Alternative System Evaluations
- Design of Collector Field and Receiver
- Design of Steam Generator
- Plant Control Design
- O&M Cost Estimate

Bechtel Power Corporation (BPC)

- Cost Estimate
- Process Flow Diagrams
- Project Schedule
- Thermal Storage and Transport
- Receiver Support Towers
- Turbine Generator Plant

In addition to the three major participants, other manufacturers and contractors cooperated in the study by providing conceptual designs and budget prices.

To the extent possible, previous studies and work were used as a basis for this study and provided the direction of effort, i.e., a solar thermal central receiver station offers the best chance for solar technology to compete with energy produced from oil.

B. PURPOSE

The purpose of this conceptual study is to quantify the technical and cost feasibility of constructing a commercial solar thermal power plant. The bus bar energy costs will have to be below that of Edison's "avoided cost" in order to demonstrate cost feasibility. The demonstration of technical feasibility will be investigated through design analysis and risk assessment of the scheme chosen. It is the intent of the Edison Company to engineer, construct and start-up the Solar 100 plant by 1987 should the Project demonstrate viability.

C. UTILITY ADVISORY BOARD

In order to disseminate information on the Solar 100 Project and to solicit comments on the conceptual study, the Utility Advisory Board (UAB) was formed. The UAB consists of various southwest utilities which would have a commercial interest in a cost-effective solar thermal power plant. The binding parameter which is common to all members of the UAB is the availability of solar sites; the southwestern portion of the United States is recognized as one of the best areas in the world for solar development.

D. REPORT FORMAT

This report is comprised of two stand alone documents; this "Executive Summary" and the full report entitled "Solar 100 Conceptual Study." The latter document provides detail methodology and results of the study while this Executive Summary provides an overview.

II. CONCLUSIONS AND RECOMMENDATIONS

This conceptual study investigated the technical and financial feasibility of a commercial 100 MWe solar thermal power plant. The conclusions of this report are:

1. It is technically feasible to build the Solar 100 thermal central receiver plant by 1988 which would have the following characteristics:

   a) 98.3 MWe net average output

   b) 489 million kWh's annual energy production

   c) 60% capacity factor and 94.5% availability (excluding meteorological conditions)

2. Further receiver prototype testing and operational experience with Solar One will minimize technical risks associated with Solar 100.

3. The plant has an estimated capital cost of $580 million and average operating expenses of $5.5 million (nonlevelized 1981 $).

4. Utility ownership would result in an energy cost that exceeds avoided costs (i.e., energy cost of Solar 100 exceeds Edison's incremental rate).

5. Of the three ownership alternatives considered, third party ownership appears to offer the most promise. However, under the present provisions of PURPA such a plant would be subject to federal and state regulation.

6. Although this conceptual study was essentially site specific to Edison's requirement, the analysis also shows the technical and financial concepts developed to be applicable to most southwestern U.S. utilities.

To further pursue Edison's corporate objective's of having 300 MWe of solar capacity by 1990, Edison released a Solar Program Opportunity Announcement (SPOA) on May 3, 1982 to solicit proposals for a third party ownership of Solar 100; proposals are due September 17, 1982. Edison, therefore, expects to have a minimum of one large solar central receiver by 1990 at or below avoided cost to its rate payer. In order to expand the use of central receiver type power stations to lower the unit cost of heliostats (which accounts for 40% of total plant cost), Edison recommends other utilities to solicit proposals via an SPOA to compare this technology to present day alternatives. While it is understood that other utilities have a different generation mix and rates, the incremental rate structure is probably based on oil and therefore similar to Edison's.

III. PROJECT DESCRIPTION

The Solar 100 plant, rated at 110 MWe (gross) and 60% capacity factor, will be the world's largest solar thermal power station. The design concept of the plant, is flexible such that the plant may operate in most southwestern areas, i.e., a generic design was chosen to produce the least bus bar energy cost.

A. REQUIREMENTS AND DESIGN CRITERIA

The Solar 100 plant was conceptually designed to be integrated into Edison's electrical grid system. Presently, the SCE system consists of approximately 15,000 MW of installed capacity and is comprised of various generation mixes, principally oil/gas units. This design was also generic in nature to permit installation by different utilities anywhere in the southwest United States and was based on the following requirements and design criteria:

1. Requirements

a. The plant will be designed to deliver 110 MWe gross (net to a system grid is assumed at 100 MWe) and will be a stand alone design.

b. The plant will be capable of providing the maximum load for a period not less than eight hours when operating solely from insolation on the most favorable solar day of the year.

c. The plant will have a mechanical availability factor of 96% (exclusive of meteorological limitations) and will have loading and unloading characteristics similar to a fossil power plant.

d. Minimum thermal storage shall be required to allow operation of the turbine generator during cloud transients. Additional thermal storage shall be added consistent with plant economy.

2. Design Criteria

a. All systems will be designed in accordance with Edison's Standard Design Criteria insofar as they are applicable to solar design.

b. The plant will have a 30-year design life.

c. The plant's seismic design criteria will be designed in accordance with the building criteria of the Uniform Building Code.

d. All applicable codes and standards will apply.

e. The plant will be designed in accordance with the environmental conditions similar to those of Solar One (e.g., temperature, insolation, wind, etc.), foundation data was, however, site specific.

f. The unit will be base loaded on a daily startup and shutdown basis.

B. SYSTEM EVALUATION CRITERIA

The Solar 100 Project was evaluated using the following major assumptions:

Initial Operating Dates	
Module 1	July, 1986
Module 2	July, 1987

1. Economic Factors

Plant Economic Life	30 Years
Cost of Money (for utility ownership)	15%
Cost of Money (for entrepreneur ownership)	20%
Annual Carrying Charges (for utility ownership)	25.0%
Annual Capital Escalation Rate (1981 - 1987)	10%
Annual O&M Escalation Rate (1987 - 2017)	9%

2. Annual Avoided Cost Escalation Rate

1982 - 1985	11.0%
1986	10.0%
1987 - 1990	9.6%
1991 - 2017	9.3%

3. System Incremental Costs (1988)

	Levelized	Present Worth
Capacity	$240/kW-yr.	$930/kW
Fuel	271 mills/kWh	$15,571/kW*
O&M	$21/kW-yr.	$136/kW

*based on 100% capacity factor

4. Maturity Factors

All new and unique power plants generally have a reduced capacity factor during the first few years due to operating and design "bugs". The assumed availability factors for the first three years are:

1st Year = 11.89%
2nd Year = 59.1%
3rd Year = 94.5%

C. SCOPE LIMITATONS

This conceptual study had several limitations due to time and funding restraints. The major limitations identified are:

1. Siting

The most important site specific parameter which was assumed for the Project was the insolation data. Barstow, being the site of Solar I, had a significant amount of solar radiation and meterology data already recorded. Accordingly, this data with minor modifications was used at the nearby selected site in Lucerne Valley.

2. Capacity Factor

It was the intent of the study to determine the size and loading of the solar plant to meet two different criteria:

a) a generic plant design which would be applicable to location anywhere in the southwestern United States and Hawaii, and

b) a plant which would best suit Edison's requirement.

The study indicated that a 100 MWe plant operating at a 60% capacity factor would produce the least bus bar energy cost. However, Edison's initial investigation into dispatch requirements indicated a plant of 25-40% capacity factor would be optimum. Further analysis indicated only a slight cost penalty associated with reducing the capacity factor from 60% to 40% assuming a constant energy production (i.e., by reducing the capacity factor from 60% to 40% and raising the peak capacity from 100 to 150 MWe). For purposes of this study, a generic 100 MWe, 60% capacity factor plant was assumed; a determination was also made of cost sensitivity to variations in capacity factor.

D. PROCESS DESCRIPTION

The solar thermal power plant is sized to produce a nominal 100 MWe net when operating at rated conditions. The selected receiver fluid for this conceptual study is molten nitrate salt; however, further consideration of alternate fluids may be desired before a selection is made for final design. A two-module collector field is used, each with a separate tower, however, the power block will be common to both fields. The capacity factor was designed at 60% which therefore requires a solar multiple of 2.4 (i.e., ratio of total solar power to rated steam generator power) and heat storage of approximately 8-1/2 hours. The steam cycle uses one standard reheat utility turbine of approximately 110 MWe gross rated capacity with 6 extraction points for feedwater heating.

The concept of solar thermal electric power is relatively simple and is illustrated in Figure 2. Solar radiation is collected at the receiver by the use heliostats; the heliostats track the sun (by computer control) and reflect the radiation back to the receiver. The layout of the heliostat positions is called a collector field which may completely surround the tower (similar to the 10 MWe Solar One

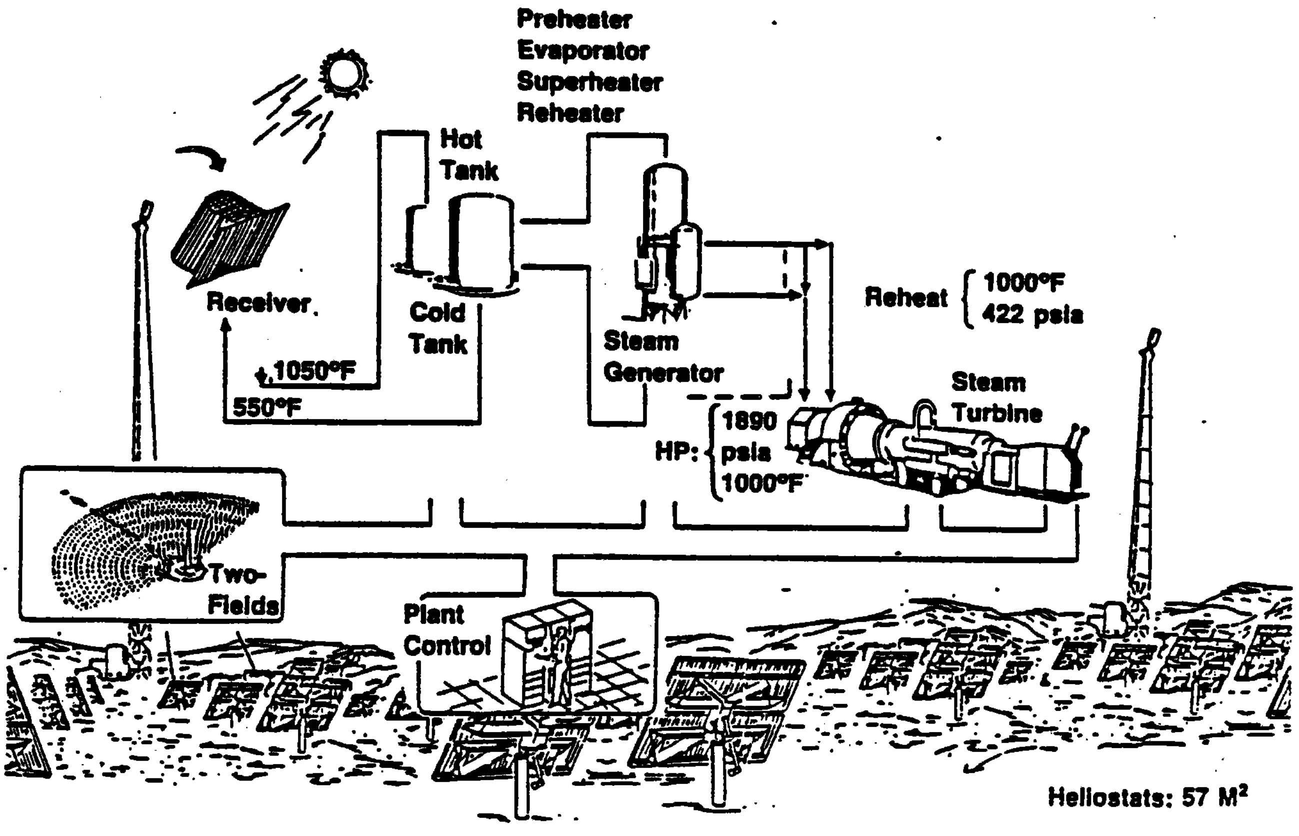


Figure 2. 100 MWe Solar Central Receiver Plant

plant) or the entire heliostat field may be located north of the tower which is the case for this study. The receiver is a partial cavity type to capture the solar radiation with minimal losses. Molten salt (or other fluids) used as the receiver fluid will be heated by the solar radiation and cooled by water/steam in the steam generator. The receiver fluid circulation is therefore a closed loop, constantly circulating the molten salt to provide heat to the steam cycle. Once steam is produced, electric power is produced using a conventional Rankine cycle.

An important aspect of solar thermal electric power is the requirement for heat storage. In order to reduce the cost of electricity produced by the plant, the facilities must be used as much as possible. Studies indicate approximately 8-1/2 hours of storage are required to minimize bus bar energy costs. Specific analysis of energy and capacity worth would have to be performed by each prospective owner/utility since the generic worth of energy from Solar 100 (or any power plant) should not exceed the energy worth of alternative sources.

The study was site-specific with location of the solar plant at the proposed Lucerne Valley peaker park site located approximately 30 miles southeast of Barstow, California. The Solar Plant layout is illustrated in Figure 3; the peaker park (not shown) would be located in the southern tip of the property.

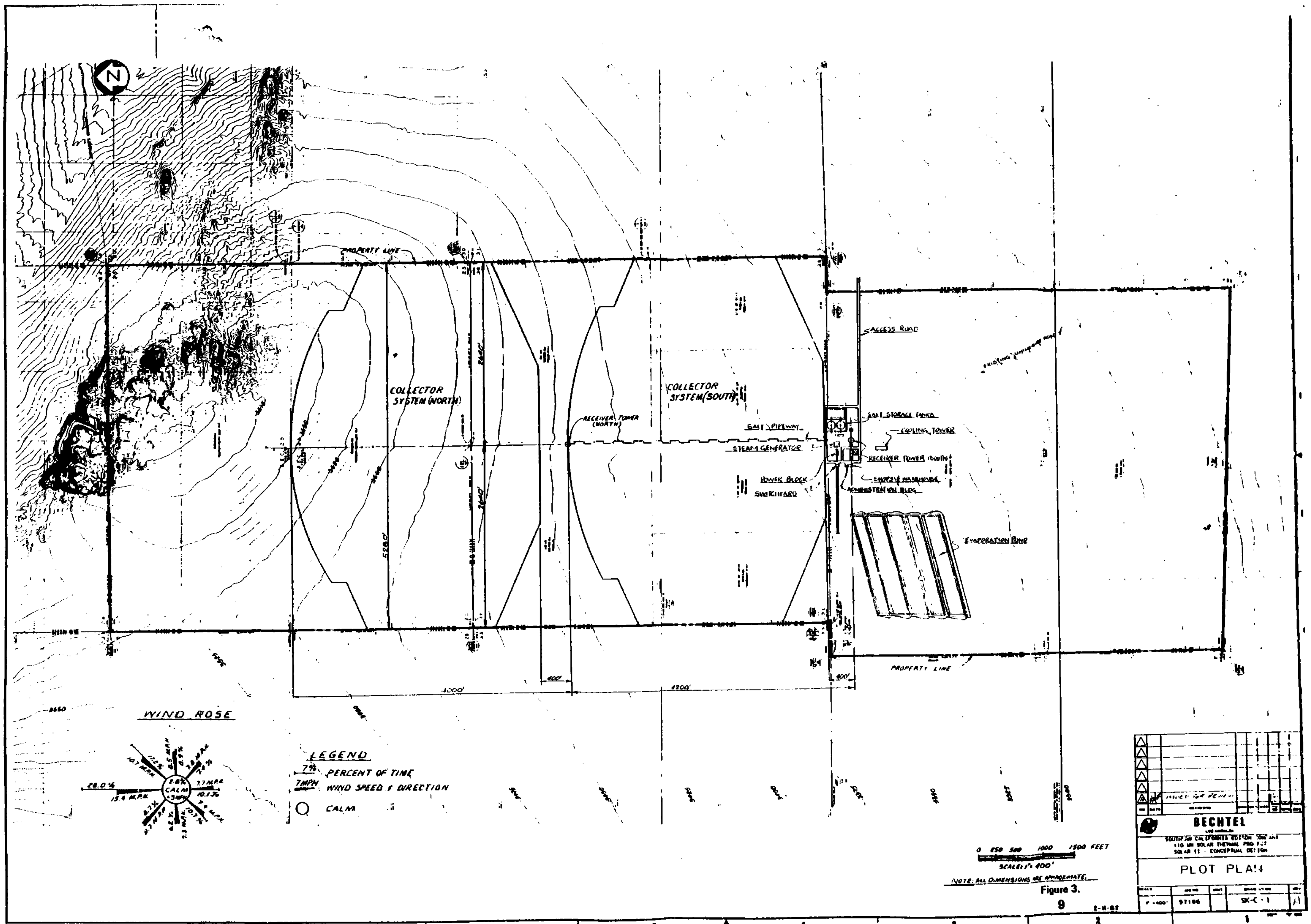
The major systems of the solar thermal power plant are summarized as follows:

Collector System - The two-module collector system is arranged in a north-south alignment. The collector system consists of heliostats, field wiring and electrical equipment, collector control and alignment equipment. The two fields will have a total of approximately 15,400 heliostats (assuming MDC Model 50 design) and will require about 1.4 square miles of land area (0.7 square mile for each field).

Receiver System - There is a receiver and tower for each collector module. The receiver system consists of the tower and the receiver unit (partial cavity type) with its control, surge tanks, door, and support structure. The top of the towers will be approximately 585 feet from the base of the receiver structure. The midpoint of the receiver aperture will be approximately 675 feet above grade.

Storage and Transport System - The storage and transport system includes all receiver fluid piping to the receiver and steam generator, two storage tanks (hot and warm storage at 3.6 million gallons and 3.3 million gallons, respectively), and the associated pumps, valves, controls, and cover gas systems. Total salt flow will be approximately 6,500 gpm per receiver; salt leaving the tower will be 1,050°F and will return at 550°F from the warm storage tank after leaving the steam generator.

Steam Generator System - The steam generator system includes the preheater, boiler, superheater, and reheater heat exchangers, and their associated piping, valves and controls. Main steam superheat will be approximately 1,000°F at 1,800 psia with a flow rate of 742,000 lbs/hr. Reheat steam will be approximately 1,000°F at 442 psia with a flow rate of 653,000 lbs/hr.



COLLECTOR SYSTEM (NORTH)
COLLECTOR SYSTEM (SOUTH)
RECEIVER TOWER (NORTH)
PROPERTY LINE
ACCESS ROAD
SALT STORAGE TANKS
COOLING TOWER
SALT PIPEWAY
STEAM GENERATOR
RECEIVER TOWER (SOUTH)
POWER BLOCK
SHOPS & WAREHOUSE
SWITCHYARD
ADMINISTRATION BLDG
EVAPORATION POND
400'
4000'
4200'
WIND ROSE
28.0%
13.4 M.P.H.
CALM
LEGEND
7% PERCENT OF TIME
7MPH WIND SPEED & DIRECTION
CALM
0 250 500 1000 1500 FEET
SCALE: 1" = 400'
NOTE: ALL DIMENSIONS ARE APPROXIMATE.
BECHTEL
PLOT PLAN
SK-C-1

Figure 3.

Steam Cycle - The steam cycle includes the turbine generator, condenser, feedwater heaters, and the associated pumps, valves and controls. The cycle is a conventional Rankine cycle of the type found in most fossil-fired plants and will have six stages of feedwater heating. The turbine operates with sliding or variable pressure during daily start-up and shut down for economic and maintenance reasons. The turbine will be rated at relatively low nominal pressure of 1,800 psig to reduce expected downtime and maintenance. The gross turbine heat rate is 7988 Btu/kWh.

Plant Control System - The plant control system includes hardware and software necessary to coordinate the control of the plant including the heliostat field and to provide operator interfaces and displays.

Balance of Plant System - The balance of plant system includes the facilities, utilities, switchgear, cooling tower, and other conventional equipment and structures necessary to complete the plant. Some of the subsystems may be shared with the peaker plant as planned for the Lucerne Valley (e.g., firewater, service air and water).

E. OPERATIONAL MODES

Plant operating modes are most easily described by separating the plant into a heat collection (including heliostat and receiver) and a power generation function. The heliostats collect the sun's direct insolation and concentrate the energy on the receiver. The receiver transmits its energy to the salt from the warm storage tank and the heated salt is returned to the hot storage tank. The power generation function uses a conventional Rankine cycle to produce power.

1. Heliostat Operating Modes

The heliostat or collector system operating modes can be commanded either automatically or manually through the plant control system, or manually in the field. The two operating modes are normal tracking and standby. There are additional non-operating modes (or stow positions) for night-time, high winds, and periodic maintenance (including cleaning).

Normal Tracking - Each operational heliostat tracks the sun so that its reflected beam strikes the receiver at its preassigned aim point. Tracking is by articulation of two axes (azimuth and elevation) to positions based on a computed, apparent sun position.

Standby - For emergency or planned reasons the heliostats can be directed to a standby position. The beam is directed off the receiver to a nearby safe position.

Normal Stow - The preferred heliostat stow position will be with its reflector surface nearly vertical or face up for high winds.

Cleaning and Maintenance - The heliostats will be able to be manually positioned, either singly or in groups, to positions which facilitate corrective maintenance and/or cleaning.

2. Receiver Operating Modes

The two operating modes for the receiver are normal operation (including startup and shutdown), and warm or overnight hold. There is an additional nonoperating mode of cold shutdown.

a. Normal Operation - In this mode, salt is supplied to the receivers at about 550°F with adequate pressure to maintain receiver flow and control. The salt flow is regulated by a throttle valve downstream of the receiver feed pumps. There are three half-capacity receiver feed pumps for each receiver.

Under most conditions of insolation transients, the feed-forward control on the receiver will maintain adequate salt outlet temperature control. When large, opaque clouds come over the field, a 20% rated flow minimum condition may be reached which results in receiver outlet temperature of less than 1050°F. The minimum flow constraint of 20% is applied under all insolation conditions.

b. Warm or Overnight Hold - During periods of no insolation, such as night time, the receiver is put in a warm hold mode. The receiver door is closed, and the collector system is stowed. Salt circulation is halted, and trace heaters are used on demand to maintain the salt in a molten state (above 430°F).

3. Power Generation Operating Modes

The two operating modes for power generation are normal operation (including sliding pressure operation and low power operation) and warm hold. There is also an additional nonoperating mode of cold shutdown.

a. Normal Operation - In this mode, salt is supplied to the steam generator at 1050°F. The steam generator produces primary steam at 1000°F and 1800 psi and reheat steam at 1000°F. The salt is returned to the warm tank at 550°F. Feedwater is supplied at 460°F.

During startup, the feedwater heaters operate at a reduced temperature and steam generator drum steam is fed to the salt preheater to peg feedwater temperature at 460°F. The pressure ramp rate is controlled to keep the superheater inlet temperature ramp rate below 150°F per hour due to metallurgical (thermal stress) limitations. Since the turbine is required to execute daily off-on cycling, sliding pressure is used to start up and shut down the turbine and minimize the thermal cycling effects on the turbine.

b. Warm or Overnight Hold - Under warm shutdown, the superheater and reheater are isolated by shutoff valves on both salt and steam sides. The temperature change is slow, and these units will not require the use of trace heating. The evaporator and preheater are similarly isolated with trace heating as required.

IV. PERFORMANCE

The performance analysis of the Solar 100 Plant is categorized into three parts: 1) insolation model; 2) plant output; and 3) availability analysis.

A. INSOLATION MODEL

Estimates for the insolation (sun energy) available for central receiver systems are generally developed in one of three ways: 1) measurement of direct normal insolation; 2) correlations based on measurements of global or total horizontal insolation and meteorological data; or 3) correlations based on models of the atmosphere and meteorlogical data. The DELSOL (developed by Sandia) and R-CELL (developed by University of Houston) computer programs generate insolation data by the latter method and these codes were used in Solar 100 modeling. The daily insolation profile was then adjusted based on measurements from the first and second types of estimates.

For Barstow, four years of direct normal insolation measurements are available through SCE and West Associates and approximately 30 years of data are available using the Jet Propulsion Laboratory SOLINS computer program with SOLMET data. Due to the extensive insolation data available from Barstow, it was assumed all Edison sites would, with minor variations, exhibit the same insolation. This resulted in a value of 2576 kWh/m^2 year with an average of 3,230 hours of usable sunlight per year. These values include the effects of weather and are based on using all sunlight for elevations greater than 10° above the horizon (i.e., usable insolation).

B. PLANT OUTPUT

The steam generator and turbine generator are sized for a gross output of 110 MWe. The net plant output during operations at full gross power rating (110 MWe) range from a minimum value of 96.6 MWe (collector fields and all receiver feed pumps operating) to a maximum value of 104.5 MWe (early evening storage operations before receiver trace heating is required). The annual average net power output is 98.3 MWe.

The annual energy delivered from the receivers to the storage tank is enough to operate the turbine generator at rated gross output for 5,325 hours per year, assuming 100% plant availability. The plant auxiliary loads are expected to consume 62 million kWH per year leaving a net annual production of approximately 524 million kWH* (assuming 100% plant availability). The annual output is 489 million kWH after accounting for planned and unplanned outages.

C. AVAILABILITY ANALYSIS

The availability calculation for this power plant was performed in two ways. The analysis for the solar portion of the plant (heliostat field, receiver, steam generators) was performed by estimating the predicted failure rate and recovery time for each component. The remainder of the plant was analyzed by utilizing industry-wide availability data for similar sized steam units. Table I compiles the summation of the availability analysis.

*Transformer losses and efficiency degradation in the turbine and auxiliaries over a 30 year life were not included in the production calculation.

TABLE I

AVAILABILITY ANALYSIS

System	*Expected Operating Time Hours/Year	System Downtime (Unplanned Outage) Hours/Year	System Unavailability %
Heliostat Field	3,313	0	0
Receivers (2)	3,313	104	0.59
Steam Generator	5,256	64	0.72
Turbine	5,256	220	2.51
Molten Salt Loop			
Receiver	3,313	20	.11
Steam Generator	5,256	10	.11
Control System	8,760	0	0
Unplanned Outage - Total			4.04
Planned Outage			1.45
Plant Availability			94.49% say, 94.5%

*Initial estimates of operating time: availability analysis was not revised to reflect final estimates of operating times.

V. ALTERNATIVE SYSTEMS

Two alternates to the molten salt receiver coolant were considered in the study; these are water/steam and liquid sodium. Previous study results left some uncertainty in cost and performance. This conceptual study examined the two alternates on a site-specific comparable bases.

A. WATER/STEAM

The system, shown schematically on Figure 4, consists of a tower-mounted water/steam cooled receiver heated by a field of heliostats. The receiver-generated superheated steam is routed directly to a steam turbine where it is used to produce electricity. A portion or all of the steam can be routed to the thermal storage system. Because of the impracticability of storing large quantity high temperature steam, a heat exchanger was used where a secondary fluid is heated and subsequently stored. The stored fluid is used to heat a separate storage steam generator. Lower temperature steam produced in this separate steam generator is routed to a lower pressure admission port on the dual admission turbine. It was considered impractical to generate reheat steam with this system; therefore, a lower efficiency nonreheat turbine must be used.

The direct production of steam in a solar receiver would appear to be the most natural transition from fossil-fired plants to solar thermal plants. However, the transient nature of solar energy makes it impractical to directly couple total solar receiver output to a standard utility turbine. Also, storage of large amounts of high pressure steam to buffer a turbine from receiver output and increase plant capacity

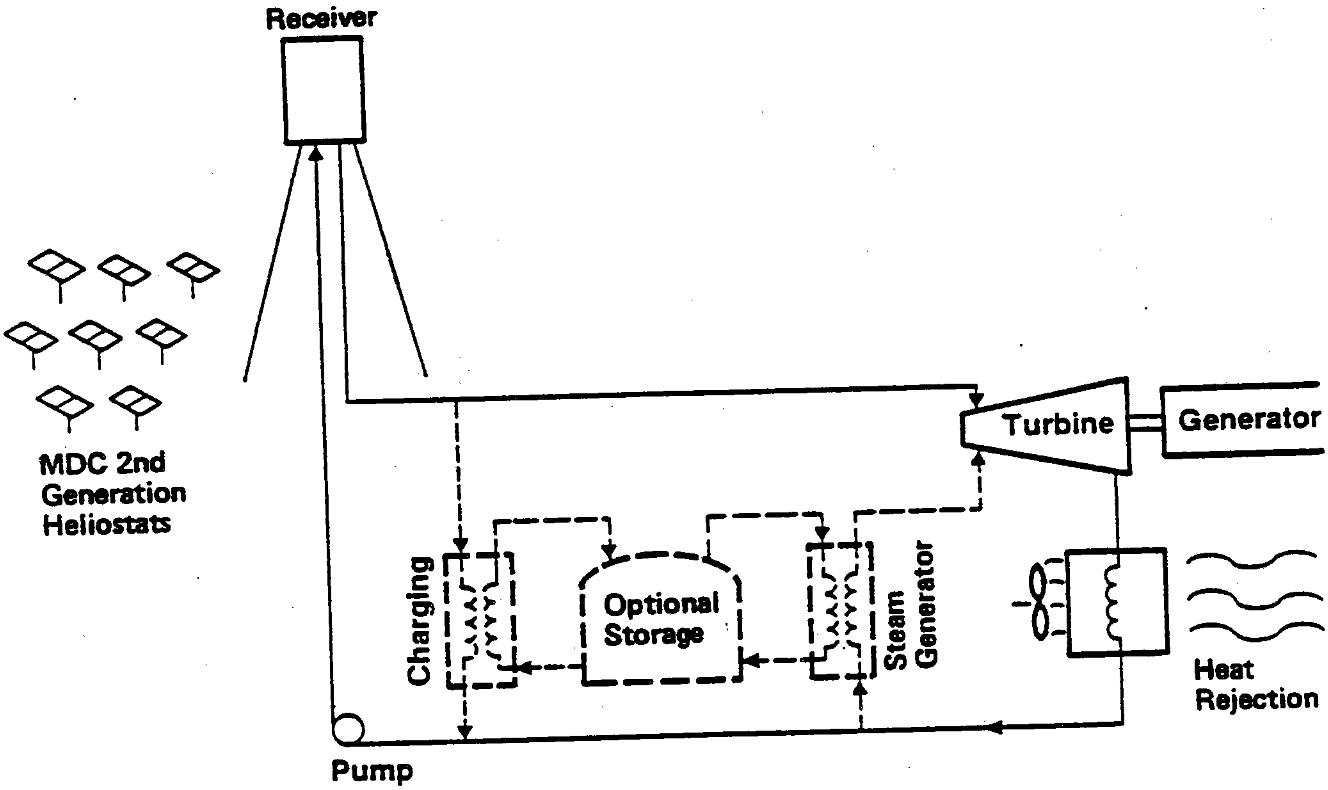


Figure 4. Solar Central Receiver System — Water Steam

factor is at best very costly and at worst virtually impossible. Therefore, it is necessary to consider the use of an intermediate fluid for energy storage. The transfer of heat from one fluid to another and back again results in losses which yield steam from storage at a lower temperature and pressure than that from the receiver. This necessitates the use of an admission turbine (one capable of accepting two different steam inputs; rated steam from the receiver and derated steam from thermal storage) and overall reduced electrical generating efficiency for the plant. The reduced efficiency translates to a larger, more costly solar collection system.

B. LIQUID SODIUM

The system, shown schematically on Figure 5, consists of a tower-mounted sodium-cooled receiver heated by a field of heliostats. Sodium heated in the receiver is routed through a sodium/water steam generator. The steam is then used in a conventional manner to power a reheat turbine generator set to produce electricity. The cooled sodium is returned through the thermal storage to the receiver. The thermal storage system buffers the steam generator from solar transients as well as supplying energy during extended periods of no insolation (i.e., after sunset).

Use of sodium as a high temperature heat transfer fluid had its genesis in the nuclear industry. Liquid sodium is thermally stable at the elevated temperatures required for pressurized water reactors and has certain characteristics which makes it suitable for a reactor coolant. Major sodium equipment, similar in size to that

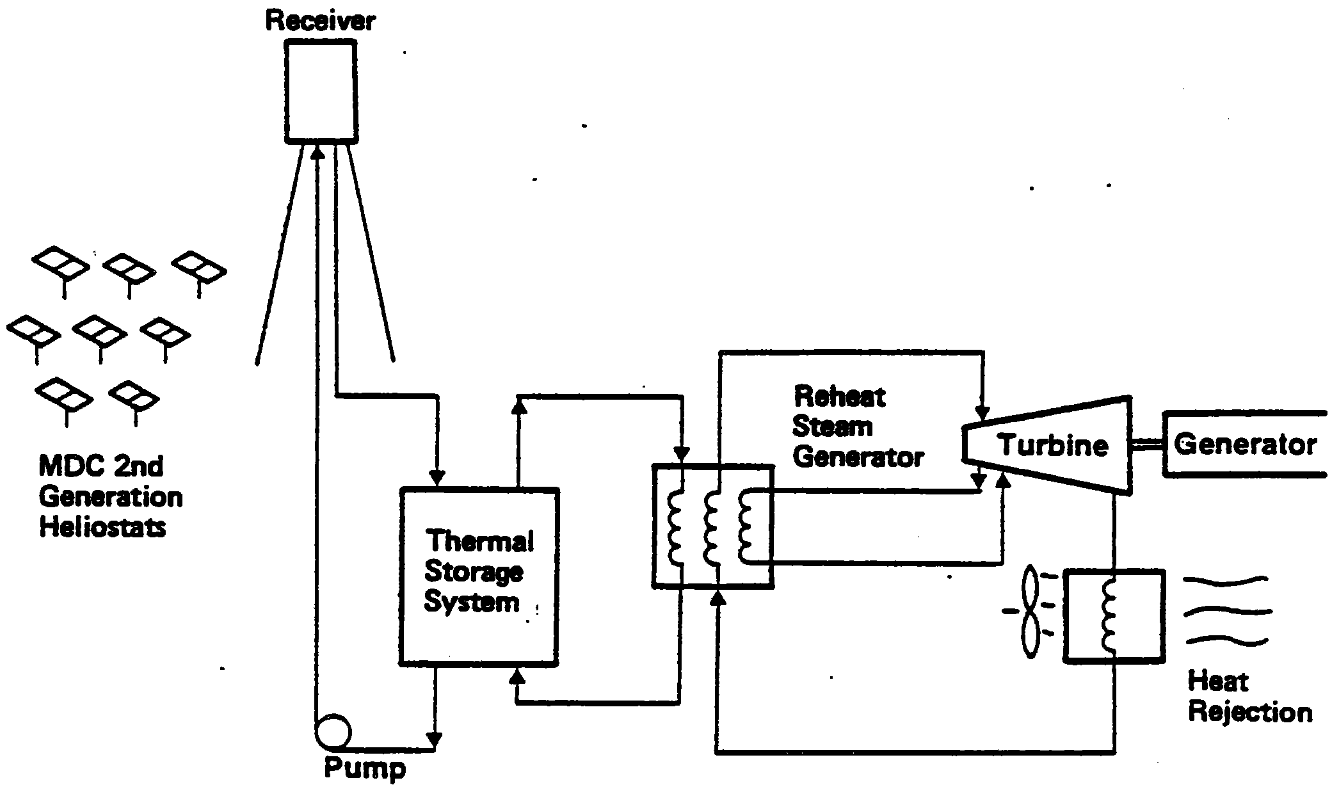


Figure 5. Solar Central Receiver System — Liquid Sodium

required for solar use, has undergone extensive development for use in breeder reactor systems. This includes pumps, valves, lines, and steam generator; the sodium receiver development is considered to be as far along as that of the salt receiver.

The relatively high thermal conductivity of liquid sodium permits receivers to operate at higher flux levels than with other fluids being considered for solar use. The high conductivity of sodium limits front-to-back receiver tube temperature differentials which permits higher flux for the same allowable stresses than could be permitted with other fluids. The major advantage of operation at high flux is a reduction in receiver size (area) for a specified power level. This theoretically reduces the cost of the receiver as well as improving its thermal efficiency (reduces area dependent losses, convection and radiation). Although these benefits are realized for external cylindrical receivers (externally heated), cavity receivers (internally heated) may be aperture size limited (i.e., the heliostats may require a larger target to minimize spillage losses) and may not realize this benefit. Relatively high cost and low specific heat limit the economical usefulness of liquid sodium as a sensible heat storage media. Sodium's lower volumetric specific heat (product of density and specific heat Cp) also drives up the cost of storage tanks. Accordingly, sodium based systems would probably be more cost effective only in the lower capacity factor ranges. Also, the highly reactive nature of sodium and water is important in the design of sodium components (primarily steam generator systems) and may increase the cost of these components.

C. SELECTION

The molten salt receiver system showed the best cost performance advantage (particularly at higher capacity factor). There was no substantial overall relative difference in other more qualitative parameters. Therefore, the molten salt system was selected as the baseline configuration.

VI. SITING

A siting study was performed to determine the best site for locating Solar 100. However, the Edison Company is presently in the process of licensing a 1290 MW peaker park at Lucerne Valley and decided to submit an application to include the Solar 100 project on the same site.

Accordingly, the Solar 100 plant is contemplated for the Lucerne Valley site notwithstanding its fourth place site ranking. The two most compelling reasons for siting at Lucerne Valley which were not addressed in the independent siting study were:

1) Time - By "piggybacking" on the Peaker Park licensing activity 6-12 months are saved in the licensing of Solar 100, and

2) Water - Negotiations for a water supply have essentially already been completed guaranteeing water availability for Solar 100. Location of Solar 100 at other sites may require lengthy (and possibly unfruitful) negotiations for water.

The siting analysis investigated potential solar plant areas located in Edison's service territory (principally Southern California), although one location in Nevada was also investigated. Initially 20 sites were determined to be suitable and this list was subsequently reduced down to 10 viable sites. Environmental investigations into most of the sites were somewhat limited due to time restraints. However, several of the sites (e.g., Cool Water and Lucerne Valley) had been previously studied in conjunction with other siting investigations and so, were more fully analyzed.

The ten viable sites were ranked and weighted according to the following:

Public acceptance	- 20%
Environmental impact	- 20%
Economics	- 20%
Seismicity	- 20%
Meteorology	- 10%
Road Access	- 5%
Land Aquisition/Cost	- 5%

The final summation of the overall ranking of the potential sites is shown in Table 2. A map showing the locations of the candidate sites is presented in Figure 6.

Table 2
OVERALL RANKING OF CANDIDATE SITES FOR A 100 MW SOLAR THERMAL STATION

Site Ranking	Candidate Sites	Overall Rating
1	Lockhart Ranch	7.40
2	Cool Water G.S.	7.05
3	Vidal Valley	6.99
4	Lucerne Valley	6.67
5	Midland/Big Marias	6.53
6	Ord Mountain	6.17
7	Camino	5.95
8	North Lucerne Valley	5.83
9	Alvord Well	4.60
10	Tenmile Well	4.55

VII. REGULATORY ANALYSIS

The permitting and regulatory cycle of the Solar 100 project can essentially be related to four agencies: California Energy Commission, California Public Utilities Commission, Federal Authorities, and Local Agencies.

A. CALIFORNIA ENERGY COMMISSION

The California Energy Commission (CEC) has the sole authority for the certification of thermal power plants within the state of California. The provisions governing the certification process are set forth in the Warren-Alquist Act (Cal Pub Res Code Sections 25500 et. seq.). Jurisdiction of the CEC is limited to licensing only those thermal power plants rated at 50 or more megawatts (MW).

Typically, the provisions require a 12-month Notice of Intention (NOI) proceeding and an 18-month Application for Certification (AFC) for licensing of a thermal power plant. The NOI is a statement prepared by the applicant containing a description of the proposed project, a statement of need for the project and a discussion of the relative economic, technological and environmental advantages and disadvantages of alternative sites and facility proposals. The AFC is the regulatory process by which a specific design at a specific location is evaluated. In addition, the Warren-Alquist Act also enables a thermal power plant with a generating capacity of up to 100 MW to be exempt from the NOI process. Under this statute only an AFC is necessary and the Commission is required to issue its final decision within 12 months of the filing date. Solar 100 qualifies for this exemption; an AFC was filed with the CEC on December 1, 1981 and a final decision is expected in December, 1982.

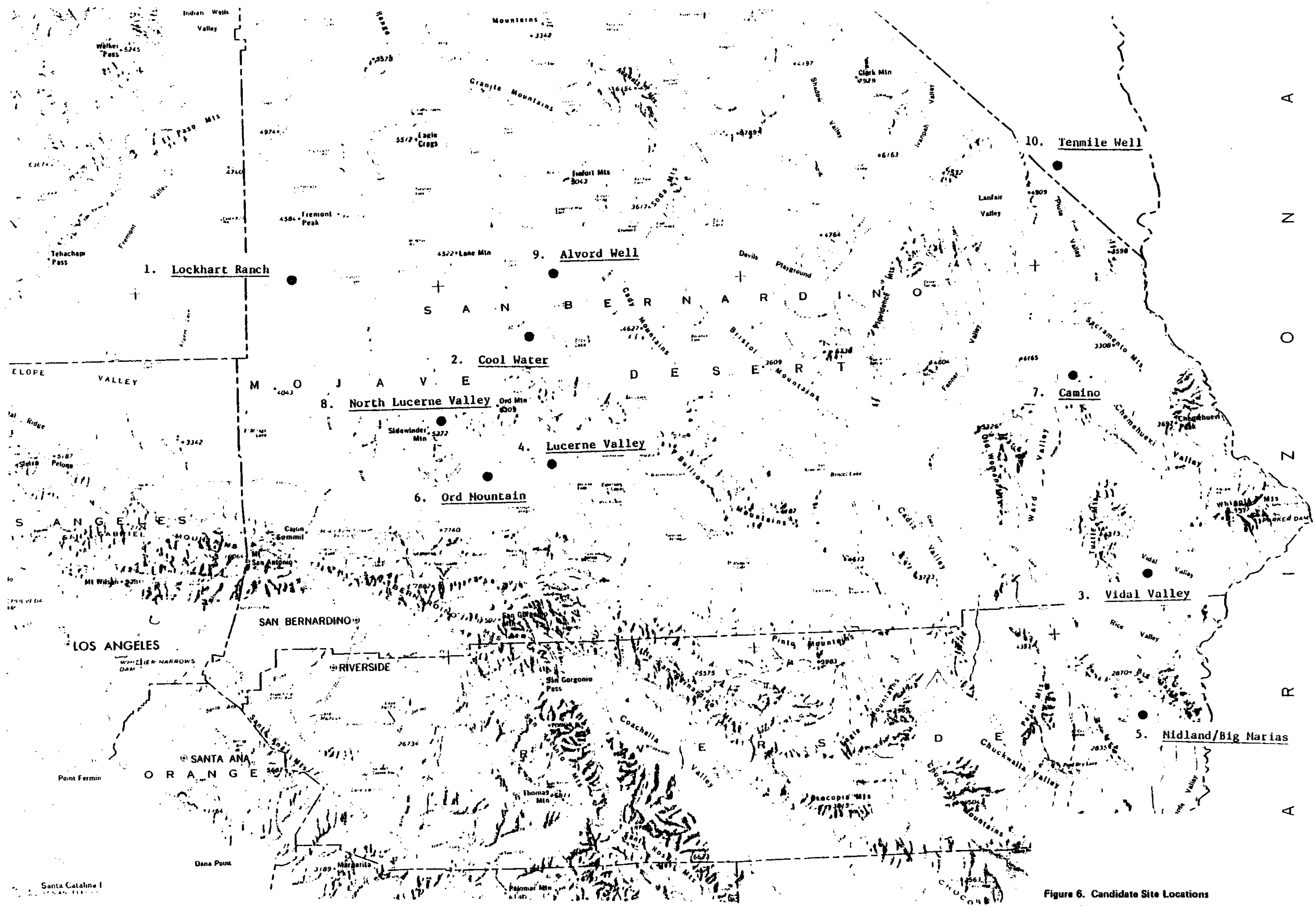


Figure 6. Candidate Site Locations

B. CALIFORNIA PUBLIC UTILITIES COMMISSION

In addition to certification by the CEC, Edison is required, if it is the plant owner, to obtain a Certificate of Public Convenience and Necessity from the California Public Utilities Commission. CPUC authority is limited to rate and system reliability issues. However, a third party owner does not have to file with the CPUC although CEC filing (AFC) would still be required.

C. FEDERAL AUTHORITY

Generation and transmission facilities that are to be sited on federal lands will require a permit from the appropriate landholding agency. No significant obstacles are anticipated at the Lucerne Site since it is already Edison owned.

D. LOCAL AGENCY CERTIFICATION

Generally, the CEC authority preempts local jurisdiction; however, local agencies' regulations must still be met. No significant obstacles are anticipated at the Lucerne Site.

VIII. COST/ECONOMICS/FINANCIAL

A. CAPITAL COST ESTIMATE

The Capital Cost Estimate is shown on Table 3. The estimate is based on a joint effort by the three participating companies: Southern California Edison Company (SCE), McDonnell Douglas Corporation (MDC) and Bechtel Power Corporation (BPC).

The estimate includes all additivies (ie., labor, fringe benefits and payroll taxes, field indirect costs for manual and nonmanual labor, field engineering and indirect material and equipment costs). Contingency, averaging approximately 20%, is also included.

Cash flow based on 1981 in-service dollars is shown in Table 4.

B. OPERATIONS AND MAINTENANCE COSTS

Operations and maintenance (O&M) costs have been estimated for plant operation during the first year and an average subsequent year. These are itemized in three categories: material, water and labor. The estimates are shown in Table 5.

C. FINANCIAL ANALYSIS

The financial analyses were performed from three different perspectives to reflect three different ownership possibilities; utility, municipal, or third party entrepreneur.

<u>TABLE 3</u>

CONCEPTUAL COST ESTIMATE SUMMARY BY SYSTEM
SOLAR 100 MW THERMAL PLANT
(Molten Salt)

SYSTEM DESCRIPTION	COST IN DEC. 1981 $ ($ x 10^6)		
Collector Field/Receiver/Tower	206.5*[1]		
Thermal Storage	52.5		
Steam Generator/Turbine-Generator	23.4*		
Plant Master Control	12.1*		
Balance of Plant	35.7		
SUBTOTAL		330.2	
Switchyard/Transmission	3.6		
SUBTOTAL		3.6	
TOTAL FIELD COST		333.8	
Spare Parts & Maintenance Equipment	.8		
Sales Tax	12.7		
SUBTOTAL		13.5	
Engineering and Home Office	29.0		
SUBTOTAL		29.0	
Additional Contingency		54.5	
Escalation		—	
TOTAL - Work Order Level (1981 $)			430.8
Allowance for Funds Used During Construction (AFUDC)			88.3
Cost of Capital (COC)		127.1	
Construction Overhead (without AFUDC or COC)			17.5
TOTAL CAPITAL COST (Without AFUDC or COC)			448.3
TOTAL CAPITAL COST (with AFUDC)			536.6
TOTAL CAPITAL COST (with COC)			575.4
	SAY	580.0	

*Part or all of the cost is MDC scope which includes their Assessment of Contingency.

1 Cost estimates are based on a price for 75,000 heliostats

TABLE 4
CASH FLOW

YEAR	%	CAPITAL COST $ X 10^6 (DEC 1981 $) WORK ORDER	W/ AFUDC	W/ COC
1982	0.5	2.3	2.7	2.9
1983	2.6	11.7	14.0	15.1
1984	18.4	82.8	99.4	106.7
1985	46.6	209.7	251.6	270.3
1986	28.9	130.0	156.1	167.6
1987	3.0	13.5	16.2	17.4
TOTAL	100.0	$450.0	$540.0	$580.0

TABLE 5
O&M SUMMARY
AVERAGE YEAR ($ in 1000's)

	SPARES, PARTS & CONSUMABLES	SERVICE CONTRACTS	TOTAL
MATERIALS			
COLLECTOR FIELD	383.	370	$753
TOWER	1.	-	1
RECEIVER	11.1	-	11
THER. STRG. & TRANSPT.	26.	-	26
STEAM GENERATOR	1.	-	1
TURBINE & BAL. OF PLANT	548.	-	548
PLANT CONTROL	-	202	202
			1,542
WATER COST (Expensed)			1,393
LABOR	MANNING		
SUPERVISOR	4		160
OPERATORS	27		1,138
MAINTENANCE	26		1,035
SECURITY	10		277
			2,610
TOTAL			5,545

1. Utility Ownership

Due to the regulatory nature of utility ownership, the basic parameter of concern is the cost to the ratepayer. For a facility constructed and owned by a utility, once operational, the ratepayer will be charged for the return of capital, return on capital, income taxes, all other taxes, administration costs, and all expenses incurred to operate and maintain the facility. For the purpose of this analysis perfect, instantaneous ratemaking was assumed; this implies that all costs are recovered as incurred. Additionally, full normalization of all tax timing differences was assumed. Assuming perfect and instantaneous ratemaking removes the only financial risk associated specifically with the solar project.

In the early years the largest components of the revenue requirement for a Solar facility are the return of capital and return on capital. Consequently, the annual revenue requirement declines until the year 2001. At that time the operating costs start to dominate the total revenue requirement causing it to increase by the end of the operating life. Avoided cost payments, under the study assumptions, would increase over the entire 30-year period. However, the annual revenue requirement and the avoided cost payment would equalize in the 1995-1996 time period. From 1996 on the annual avoided cost payment would exceed the annual revenue requirement.

For decision making, the total present worth of the annual revenue requirements and the total present worth of the avoided cost payment must be compared. Figure 7 shows that, because of the high revenue requirements in the early years, the cumulative present worth of the revenue requirement remains above the cumulative present worth of the avoided cost payment throughout the 30 years. Accordingly, for a private utility, Solar 100 does not appear to be a viable project.

2. Municipal Ownership

This scenario assumes that a city or other local public agency owns its own distribution system and wants to consider developing its own generating capacity to serve at least part of the needs of its customers rather than depending exclusively on purchased power.

The ownership of a 100 MW solar generating plant by a State or local government agency offers certain financing advantages:

- the facility can be financed with tax-exempt bonds thus reducing interest costs
- materials and equipment used in construction would not be subject to sales or use taxes
- the facility would be exempt from property taxes

On the other hand, the potential tax benefits associated with private financing and ownership which have been significantly enhanced in the last year, would be lost under this scenario.

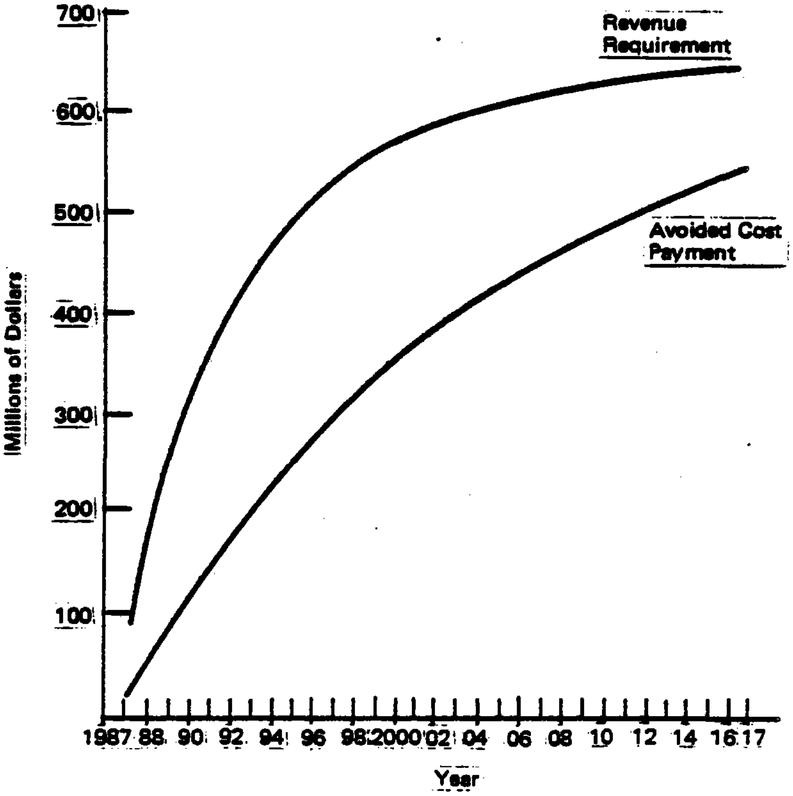


Figure 7. Utility Ownership — Cumulative Present Worth

The capital investment required by the plant is large and results in an initial solar generated power cost substantially higher than the cost of purchased power. The gap between the two costs narrows in future years as the cost of purchased power rises more rapidly than the cost of solar generated power. The cost of solar generated power compared to purchase power is shown on Figure 8.

The interest of a municipality or other public agency in the investment will depend upon how it evaluates the future savings in relationship to the present investment required and the risks perceived in the project.

3. Third Party Entrepreneur

The entrepreneur owner supports the utility's objective of minimizing ratepayer costs since the entrepreneur's income is determined by the utility's avoided cost as allowed by the energy supplied. The entrepreneur must determine whether the income received in meeting the utility's objective will earn a satisfactory return on the investment in the resources required to generate the energy. A satisfactory return must meet or exceed the marginal rate acceptable to the investor considering the perceived resource requirements and risks inherent in the project.

The acceptable marginal rate will vary with each investor, so that the analysis seeks to define the cash inflows and outflows, and then to determine values for the various financial figure of merits that an investor would employ in making an investment decision. In addition, financial sensitivity to various risks such as capital cost overruns and unrealized avoided costs are of interest to the investor.

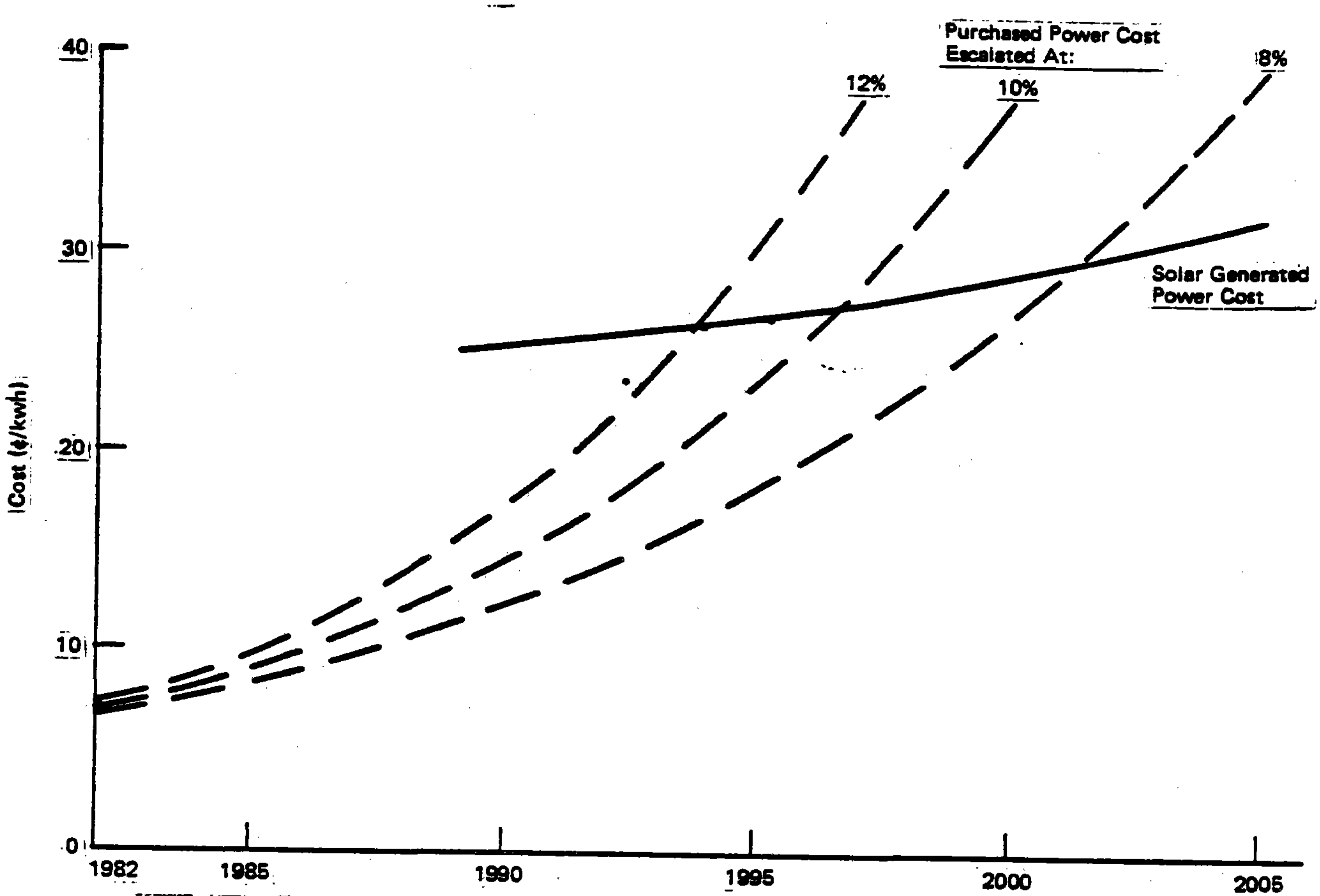


Figure 8. Estimated Cost of Solar Generated Power Compared to Estimated Purchased Power Costs

The analysis capitalizes all costs during construction except those in the first two years which are engineering related. The latter are expensed, and thus, not included in the tax credit and depreciation base. Federal energy tax credits are taken and the 5 year ACRS schedule is employed, but state energy credits are not taken, and 8 year depreciation is assumed for state taxes. The after tax results are summarized below showing variation to capital costs (±20%) and avoided cost (-20%) at 20% cost of money:

	Net Present Value* (20% Cost of Money)	"2000" Return on IRR	"2000" Return on Sales	"2000" Return on Capital
Baseline	$35 million	35%	35%	16%
80% Cost Multiplier	$50 million	43%	37%	21%
120% Cost Multiplier	$20 million	28%	34%	12%
100% Avoided Cost	$48 million	39%	36%	18%
80% Avoided Cost	$23 million	30%	34%	13%

*December 1981 Dollars

The detail reports show that, by the year 2000, the internal rate of return and the return on sales are within a few points of their final values. Figure 9 shows the cash flow cash analysis through the plant's 30 year life.

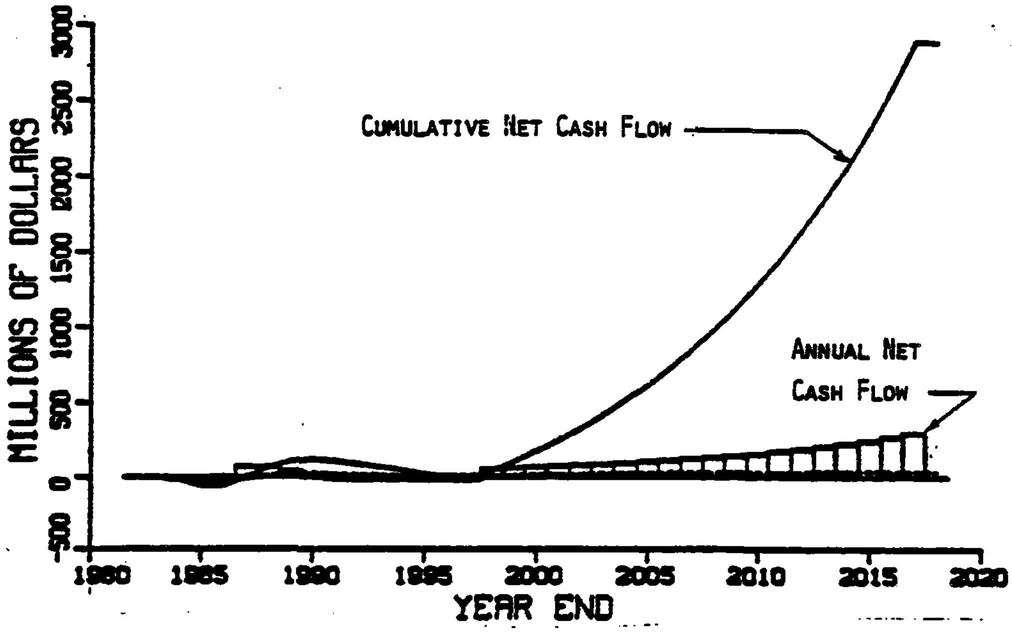


Figure 9. Entrepreneur Ownership — Baseline Cash Flow

D. COST SENSITIVITY

The impact of capital cost uncertainty has been assessed independently for three cost groups with the remaining portion of total plant cost held constant in each case. In addition, this cost uncertainty analysis reflects as constants the baseline plant location and performance characteristics.

These three cost groups are Collector Field, Balance of Solar Plant and Thermal Plant.

1. Collector Field - The collector field includes all delivered collector hardware, site preparation, foundations, installation, field wiring, and collector alignment and checkout. The cost risk estimated for the collector field is minus 7% to plus 12% variation from the baseline estimate of $170 million. This variation in collector field cost results in a minus 3% to plus 5% change in energy cost per kWh.

2. Balance of Solar Plant - The balance of solar plant includes tower, receiver, thermal storage and transport, steam generator, and plant control. The overall bounds for balance of solar plant again represent an estimated minus 15% to plus 20% cost risk range from the baseline estimate of $127 million. This variation in balance of solar plant cost results in a minus 5% to plus 6 1/2% change in energy cost per kWh.

3. Conventional Thermal Plant - The conventional thermal plant includes the turbine generator, condenser, feedwater and condensate trains, auxiliary mechanical equipment, auxiliary electrical equipment, other conventional plant equipment, and switchyard and transmission lines. The overall risk range for conventional thermal plant is estimated at ±5% variation from the baseline estimate of $62 million. This variation in conventional thermal plant cost results in a ±1% change in energy cost per kWh.

IX. RISKS AND CONSTRAINTS

The primary risks associated with the Solar 100 Project are technical. Solar I provides a solid basis for the readiness of solar control receiver technology for commercial application. However, it does not provide specific molten salt operational experience. Although there is extensive industrial process experience with molten salt for more than 40 years, there are specific equipment designs necessary to meet the unique requirements of the solar plant operation. The two most important items which must be addressed are the receiver and steam generator.

A. RECEIVER

The greatest technical risk is in the molten salt receiver. Some of the risk is inherent in the scale-up from previous equipment such as the 5 MW_t unit tested at CRTF and some is inherent in the high temperature, thermal cycling characteristic of the receiver operation. The primary risks are that performance may be lower than expected and receiver tubes may fail prematurely. This can be addressed by extra margins and redundancies as well as appropriate quality control and maintenance planning. It is believed that the background and experience available will permit design and construction of that equipment for Solar 100 to proceed without unusual problems.

B. STEAM GENERATOR

The technology of molten salt steam generators has not been fully proven, although there is extensive experience in design and fabrication of similar heat exchangers. The risk is inherent in the scale-up and extrapolation from other equipment. No specific risks have been identified. The perceived risks can be addressed by extra margins and redundancies as well as appropriate quality control and maintenance planning. It is believed that the background and experience available will permit design and construction of this equipment for Solar 100 to proceed without unusual problems.

C. OTHER RISKS

There are inherent risks associated with any type of new technology which must be tempered by the advantages of developing a new non-petroleum power source. The technical problems noted do not appear insurmountable; careful prototype testing and prudent and judicious engineering design should minimize the risks of nonperformance or reduced performance.

X. SCHEDULE

The following is a milestone schedule for the design, construction and startup of the Solar 100 Project assuming work begins in July 1982:

Tasks	Completion Date	South Module	North Module
Heliostat Factory	10-84		
Heliostat Production		11-85	11-86
Turbine Plant	7-86		
Thermal Storage System	4-86		
Steam Generator	4-86		
Heliostat Installation		4-86	4-87
Towers/Receivers		4-86	4-87
Plant in Service		7-86	7-87
Testing Complete		1-87	10-87