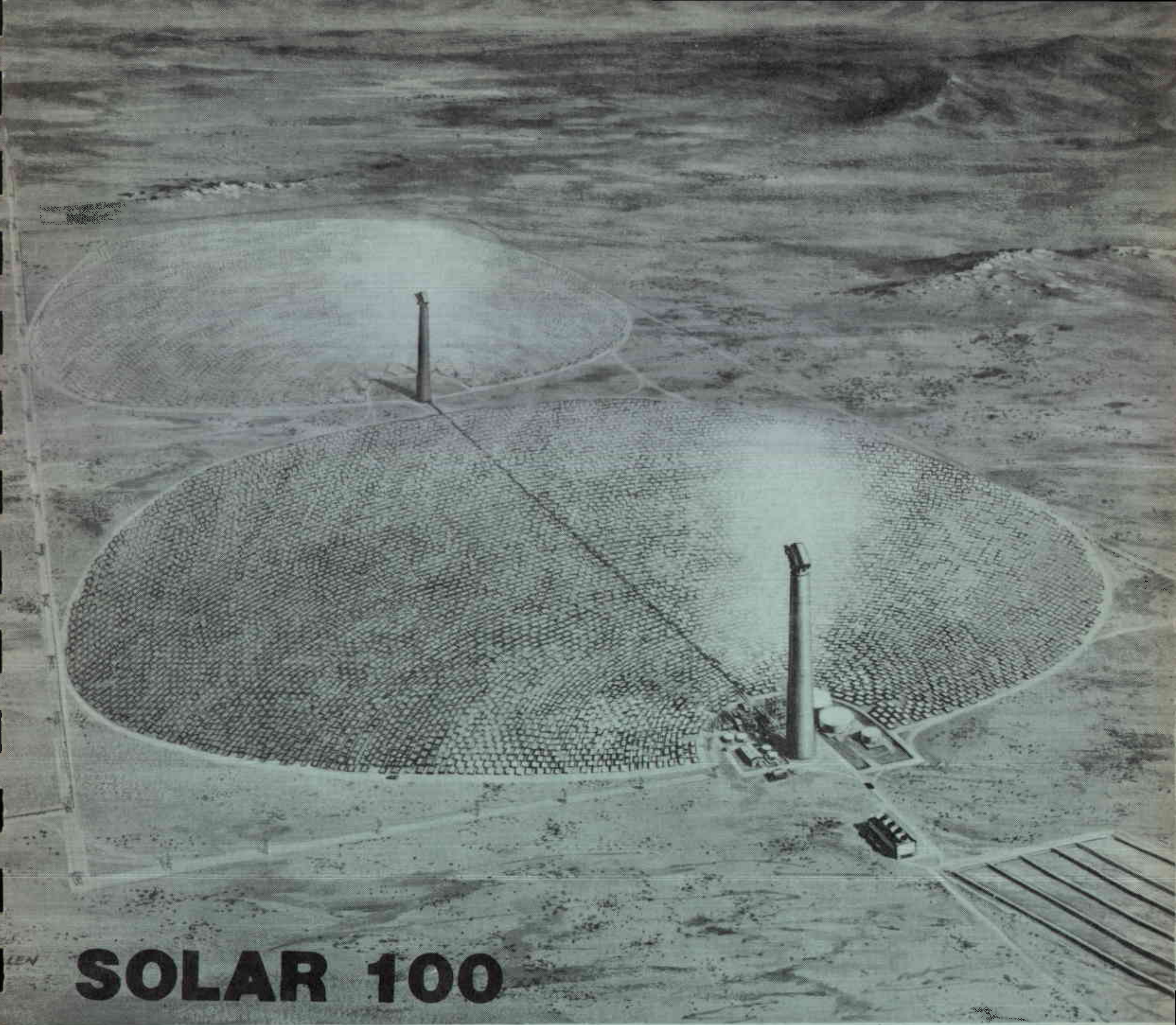

SOLAR 100

CONCEPTUAL STUDY
FINAL REPORT

1022

SCE Southern California Edison Company

BECHTEL POWER CORPORATION

MCDONNELL DOUGLAS CORPORATION

SOLAR 100

CONCEPTUAL STUDY

August 3, 1982

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SOLAR 100 CONCEPTUAL ENGINEERING STUDY

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SOLAR 100 CONCEPTUAL STUDY

I. INTRODUCTION

I-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 I.A.1 is an artist's rendering of the central receiver solar plant which uses 2 heliostat fields to produce a nominal 100 MWe net at a 60% capacity factor.

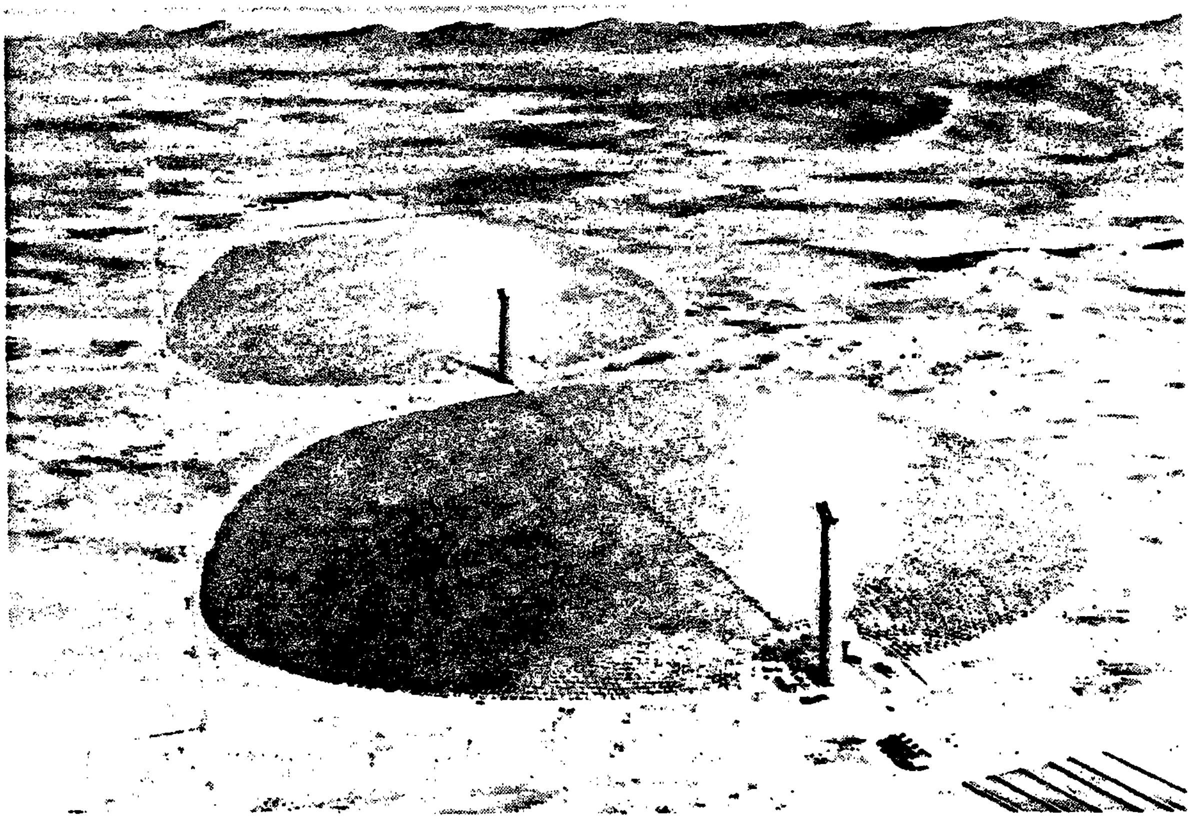


Figure I.A.1. Solar 100

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)

- Receiver Design
- Steam Generator Design
- Alternative System Evaluations
- Collector Field Design
- Storage System Design
- Plant Control Design
- O&M Cost Estimate
- Performance Analysis

Bechtel Power Corporation (BPC)

- Capital Cost Estimate
- Thermal Transport and Storage
- Process Flow Diagrams
- Tower Design
- Project Schedule
- Turbine Plant Design
- Balance of Plant Design

I-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 was 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 1988 should the Project demonstrate viability.

I-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. In order to achieve cost-effective power production, 75,000 heliostats must be sold and a prospective market for purchase of these heliostats are the southwest utilities.

The participants presented two status reports and will make a final presentation of the study's conclusion and recommendation in connection with the Solar 100 Project. Further action by the UAB as a group or as individual identities will be contingent on the development of large scale commercial solar power.

I-D. REPORT FORMAT

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

The full report is comprised of the following twelve chapters:

- I Introduction
- II Project Critiera
- III Alternate System Concept
- IV Description of Selected Plant
- V Performance
- VI Siting
- VII Regulatory Analysis
- VIII Economics/Cost
- IX Risks and Constraints
- X Schedule
- XI Utility Advisory Board Input
- XII Conclusions/Recommendations

In addition, a Reference List is also provided at the end of the report. The Reference List is in lieu of an appendix and represents both a technical source and documentation to the study.

II. PROJECT CRITERIA

The Solar 100 plant will be the world's largest solar thermal power station rated at 110 MWe (gross). The purpose of this chapter is to present the plant requirements, design criteria and an overview description of the solar control receiver power plant systems and processes.

II-A. REQUIREMENTS

The Solar 100 plant was conceptually designed to be integrated into Edison's electrical grid system. Presently, the system consists of approximately 15,000 MW of installed capacity and is comprised of various generation mixes, principally oil/gas, hydro, coal and nuclear generating units. In addition, Edison purchases substantial amounts of energy from the Pacific northwest and the southwest. It is also understood, that a generic type of plant is required to permit installation by different utilities anywhere in the southwest United States. As such, the plant was designed based on the following requirements:

1. The plant will be designed to delivery 110 MWe gross (net to the Edison grid is assumed at 100 MW). The plant will be capable of providing maximum load when operating solely from insolation for a period of four hours on the least favorable solar day of the year. The plant will be a stand alone design.

2. 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.

3. Insofar as possible, the plant will be designed generically to provide a common design suitable for use anywhere in the southwestern part of the United States (including Hawaii).

4. The plant will have a mechanical availability factor of 96% (1.0 - forced outage rate) inclusive of turbine-generator, condenser, boiler, collector field and balance of plant. This mechanical availability is consistent with other oil/gas units on the Edison system. It is understood, of course, that weather conditions may preclude operation from time to time. However, since Edison is a summer peaking utility (due to air conditioning loads) on those days when the solar plant is not operating, the plant will not be required for peaking (i.e., Edison does not peak on cloudy or stormy days).

5. Maintenance and warehouse facilities will be kept to a minimum; Edison's division maintenance will provide all major maintenance support.

6. The plant will be designed with no consideration for capacity enlargements (i.e., no provisions for a second unit on same site).

7. The capacity factor will be that which produces the lowest bus bar energy costs as determined by:

   - number and cost of heliostats
   - amount of land required
   - receiver cost
   - storage cost
   - cost of generation equipment

This capacity factor was found to be 60%. However, due to the dispatching requirements of the Edison system, it is advisable to produce the same amount of annual energy in a shorter period. Accordingly, although further analysis is required, Edison will probably require a capacity factor of 25-40% with a generating capacity of 240 to 150 MW's (see Section III-E).

II-B. DESIGN CRITERIA

The plant was designed based on the following criteria:

1. All systems will be designed in accordance with Edison's Standard Design Criteria (Reference II.B.1) insofar as they are applicable to solar design. The design criteria include guidelines on:

   - architecture/design of control/administration/warehouse facility
   - security/fencing
   - landscaping
   - codes and standards
   - concrete/steel criteria
   - foundations
   - piping
   - equipment
   - protection
   - switchgear & MCC's
   - lighting/roadways
   - control criteria

2. The plant will be designed to withstand flooding consistent with a risk/cost analysis.

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

4. The plant will be designed in accordance with the seismic criteria of the Uniform Building Code.

5. The plant will be designed in accordance with the environmental conditions (e.g., temperature, insolation, winds, etc.) as specified in the Aerospace Report No. ATR-78 (7695-05)-05 (Reference II.B.2).

6. The following codes and standards as applicable will apply as applicable:

   - American National Standards Institute (ANSI)

- American Society of Mechanical Engineers, Boiler and Pressure Vessel Codes
- American Society for Testing and Materials
- Heat Exchange Institute
- National Fire Protection Association
- National Electrical Code
- Cal OSHA (Title 24)
- National Electric Manufacturer's Association
- Institute of Electrical and Electronic Engineers
- Uniform Building Code
- American Institute of Steel Construction
- American Welding Society
- American Concrete Institute
- American Water Works Association

7. The plant will be capable of normal load additions of 3 MW per minute and emergency load additions of 5 MW per minute.

8. The unit will be base loaded.

9. The plant's minimum load capability will be 25% of base load.

10. The staffing of the plant, inclusive of solar equipment, for each shift (total of two shifts) will be 67 operating and maintenance personnel.

    One control operator will be onsite during periods of no generation.

11. Turbine maintenance will be 6 weeks every 4 years (assuming 1,800 PSIG operating pressure).

12. Storage capability will be sufficiently large to carry Edison's winter peak (8:00 P.M. evenings).

II-C. SYSTEM SELECTION CRITERIA

The following criteria were used in determining design selection:

1. Performance
2. Capital Cost
3. Technology Readiness
4. Technical Risk
5. Nonrecurring Costs
6. Operating and Maintenance Costs

7. Reliability, Maintainability, Availability
8. Safety Hazards
9. Operability
10. Schedule
11. Generic Adaptability

II-D. ECONOMIC SELECTION CRITERIA

The Solar 100 plant feasibility was evaluated based on the following criteria:

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

a. Economic Factors

Base Year for Present or Future Worth Calculations	1987
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%
Present Worth of Facilities Carrying Charges	1.64
Annual Capital Escalation Rate (1981 - 1987)	9%
Annual O&M Escalation Rate	
(1987 - 1990)	10%
(1990 - 2017)	9%
Levelized In-Plant Fuel Cost	Not Applicable

b. Annual Avoided Cost Escalation Rate

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

c. System Incremental Cost (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

d. Maturity Factor

In order to assess the economic value of the plant, the amount of energy produced is, of course, of paramount concern. However, to assume that the plant will be capable of operating at its design capacity factor the first year of operation is unfounded. All plants, and especially one of a new or unique design, will have operating "bugs" for several years. Consequently, "Maturity Factors" have been applied in an attempt to quantify the energy produced during the first five years of operation. A review of recent years fossil plant startup indicates industry average Maturity Factors of:

1st Year - 81.7%
2nd Year - 94.6%
3rd Year - 97.9%
4th Year - 99.4%
5th Year - 100.0%

When applied to the entire Solar 100 plant on a modular startup basis (i.e., Module 1 in services 7-86 and Module 2 in services 7-87), these Maturity Factors result in the following percentages of mature plant annual energy output:

1986 ------ 21%
1987 ------ 66%
1988 ------ 93%
1989 ------ 98%
1990 - Beyond - 100%

Prior to developing this maturity schedule, it was assumed that the solar plant would have modular Maturity Factors of 50% in the first six months followed by 100% thereafter. This assumption, with modular startup, resulted in the following percentages of mature plant annual energy output:

1986 ------ 12.5%
1987 ------ 62.5%
1988 - Beyond - 100.0%

The latter maturity schedule penalizes the plant in the first two calendar years of operation and provides 375% of the mature annual energy in the first five years while the former provides 376% of the mature annual energy in the same five years of operation. Therefore, the 12.5%, 62.5% and 100.0% mature profile results in a slightly more conservative annual energy and was selected for use in the financial analysis.

II-E. SCOPE LIMITATIONS OF ASSUMPTIONS

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

1. Siting

At the beginning of study, a specific location had not yet been selected for the Project, and accordingly, it was assumed that the site would be a "generic" Barstow-type environment. Probably, the most important site specific parameter which was assumed for the Project was the solar insolation data. Barstow, being the site of Solar I (a 10 MWe solar thermal demonstration facility, see Reference II.E.1) had a significant amount of solar insolation 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:

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

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

Capacity Factor is defined as: Annual kWh divided by maximum capacity rating X 8,760 hours.

The study determined 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 nominal peak capacity from 100 to 150 MWe). For purposes of this study, a generic 100 MWe, 60% capacity factor plant was assumed with a determination made of cost sensitivity to variations in capacity factor.

3. Stand Alone Design

For costing purposes, a complete stand alone design was assumed. However, since the plant is contemplated on a site adjacent to a peaker park, certain cost benefits through the dual use of systems could be expected (e.g. service air and water, firewater, instrument air, etc.).

4. Existing Data

Existing data was used as much as possible. Aside from the Barstow insolation data, substantial information from Sandia National Laboratory and other DOE sponsored agencies were also used. Data and information used in the report is compiled in Chapter XIII, "References."

II-F. CENTRAL RECEIVER CONCEPT

The Southern California Edison Company has a corporate goal to achieve approximately 300 MWe of solar power by 1990. This power is presumed to be developed from a variety of energy sources:

Solar Salt Pond
Photovoltaic (PV)
Solar Thermal (Trough, Heliostat and Dish)

The Edison Company is presently studying (in-house) the benefits of a solar salt pond and PV's. Both the salt pond concept and the PV's will have demonstration facilities in the 1985-1987 time frame. The DOE, in conjunction with Sandia Laboratories, has studied the relative cost of producing heat using troughs, heliostats and dishes. As a result of these analyses, the DOE funded (with Edison as one of the minority partners) the 10 MW central receiver located at Barstow, California. The Barstow Project, while not intended to be an economically viable plant, will demonstrate solar techology and will be an invaluable learning tool for the 100 MW solar plant.

The central receiver concept has been studied by others and there is a general consensus that the central receiver is the most cost-effective method of large-scale power production. Work is continuing on the other types of solar thermal processes (dish and trough). However, it is expected that the ultimate uses of these alternatives will be different from the heliostat system. The parabolic dish is probably best suited for remote power generation in those areas not served by a central grid. Power production is expected to be on the order of about 25 kW per dish. The parabolic trough will probably be relegated to collection of process heat (400°F-600°F) although several trough manufacturers are proposing large centralized systems for power production.

The Solar 100 plant will be the largest solar thermal powered generating plant in the world and will represent an order of magnitude scale up from the 10 MW Barstow plant. There is, of course, inherent risk in the magnitude of size increase and these risks will be discussed later in this report. The 100 MW size and the determination of the 60% capacity factor were by calculated methods to produce the lowest bus bar energy costs. Sensitivity analyses were also made to determine the penalty associated with decreasing the capacity factor and increasing the capacity while holding the annual energy production constant. In other words, the solar components, (i.e., collector field and receiver) were held constant and the storage, steam generator and turbine cycle are varied in size. Essentially, the analysis showed only marginally higher bus bar energy costs if the capacity is increased proportionally to a decrease in storage capability. Accordingly, the central receiver concept will be suited for a wide range of dispatch requirements with little costs incurred if the capacity factor is varied and annual energy production is constant.

II-G. OVERALL PROCESS - GENERAL

The solar thermal power plant is sized to produce a nominal 100 MWe net when operating at rated conditions. The selected receiver fluid is molten nitrate salt; however, further consideration of alternate fluids may be desired before a final selection is made. 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 is estimated at 60% which therefore requires a solar multiple of 2.4 (i.e., ratio of total solar power to thermal input to steam generator). The steam cycle uses one standard reheat utility turbine of approximately 110 MWe gross rated capacity.

The concept of solar thermal electric power is relatively simple and is illustrated in Figure II.G.I. Solar radiation is collected at the receiver by the use of reflective mirrors called heliostats. The heliostats track the sun (by computer control) and reflect the sunlight 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 MW Solar Plant at Edison's Cool Water Generating Station at Daggett) 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 which means it is designed to minimize re-radiation losses. Molten salt (or other fluids) used as the receiver fluid will be heated by the solar insolation and cooled

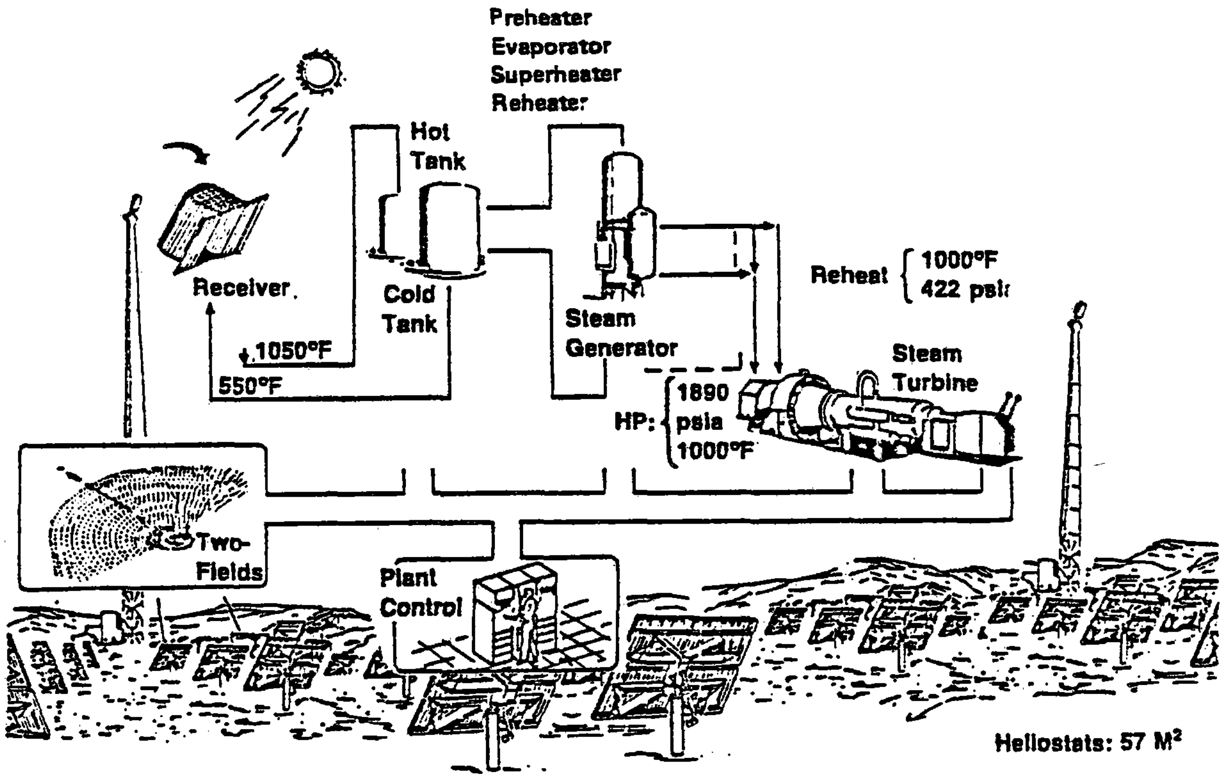


Figure II.G.I. 100 MWe Solar Central Receiver Plant

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, the 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. Therefore, a heat storage system is used to store excess heat produced during the day for use at night or on days with no sun. There is an economic point of diminishing returns, however, as any storage system which could store sufficient heat to run the plant at full load for greater than twelve hours could be counterproductive. In other words, if there is heat in storage at the beginning of a sunny day, towards the end of the day there may be insufficient storage capacity for all the heat collected (i.e., the storage system is filled too early since the system did not start at empty). Accordingly, studies indicate approximately 8-1/2 hours of storage are required to minimize bus bar energy costs. Further analysis and optimization were also required to better define the "worth" of capacity and energy to the Edison system which would also affect the determination of capacity factor. Worth of capacity and energy to the Edison system are described in Section VII.C.

The study was site specific with location of the solar plant at the proposed Lucerne Valley peaker park. Originally, the park was to have 20 gas turbines/generators each rated at 65 MW's. With the addition of the 100 MW solar plant, the peaker park has been reduced to 18 gas turbines. The solar power plant layout is illustrated in Figure IV.A.1. As noted, the solar plant is located in the northern two thirds of the site with the peaker park (not shown) occupying the southwest corner. For all practical purposes, the solar plant represents a stand-alone design; however, minor sub-systems (e.g., service and fire water, instrument and service air) are planned to be interconnected with the peaker park.

The major systems of the solar thermal power plant as illustrated in Figure II.G.1 can be 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 1.6 square miles of land area (0.8 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 towers will be approximately 585 feet to the base of the receiver structure. The receiver centerlines will be approximately 675 feet above ground level.

Storage and Transport System - The storage and transport system includes all receiver fluid piping to the receiver and steam generator, two (hot and warm storage at 3.6 million gallons and 3.3 million gallons, respectively) storage tanks, and the associated pumps, valves, controls, receiver fluid maintenance, and cover-gas systems. Total salt flow to each tower 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 665,000 lbs/hr.

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 startup and shutdown 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 7,988 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 (e.g., firewater, service air and water).

Site Preparation and Facilities - The maximum allowable net soil bearing pressure will be 3-5 ksf for foundation design for the general field (actual value will depend on site boring analysis). For areas which are backfilled and compacted, a bearing pressure up to 7.5 ksf will be used.

The collector field site will be graded as required to provide for drainage in the collector field area. Grading for foundations is required at the steam cycle, balance of plant, steam generator, and thermal storage tank areas. In addition, grading will also be required for access and clearance of combustible materials from areas of potential salt spill. Paved roads will be built to the steam cycle/balance of plant portion of the site, and connecting to the tower locations. These roads will be capable of supporting heavy duty construction vehicles.

III. ALTERNATE SYSTEM CONCEPTS

III-A. SELECTION OF SOLAR CENTRAL RECEIVER PLANTS TO STUDY

This conceptual engineering study focused entirely on solar central receiver technology. Central receiver plants are perceived as being technically ready for implementation, economically viable after the cost reductions associated with the collector field volume production are achieved, and capable of the ranges of capacity factors and sizes desirable to electrical utility companies.

1. Types Of Central Receiver Plants

Central receiver plants can be categorized by hybrid or stand-alone, use of thermal storage, power conversion cycle, and receiver fluid. The following paragraphs discuss the alternatives for each of these.

Hybrid vs. Stand-alone

A hybrid plant utilizes fossil fuel to generate electricity during periods when demand for electricity exists, but sunlight is inadequate to provide energy to meet the demand. Plants may also be hybridized to buffer solar operation, as in the case of air-Brayton cycle systems (discussed in this section), where fossil fuel is used to maintain constant output regardless of insolation level.

Stand-alone plants are designed to operate without the use of fossil fuel. However, a small fossil source may be required for cold startup, supplying blanketing and sealing steam, and thermal conditioning. The stand-alone plant draws its auxiliary electric power load from the grid during non-operating hours.

A stand-alone plant is recommended to reduce the complexity of licensing, design, and operating of this first-of-a-kind plant.

Thermal Storage

Storage-coupled plants accumulate energy to significantly extend operating hours of the plant. Storage is potentially valuable because it:

- Increases the capacity factor of the plant; hence, increases the capacity credit which can be allowed for the plant.
- Provides the capability of carrying the winter peak load, which normally occurs after sundown throughout the southwest.
- Lowers the revenue requirements of the plant (energy cost in mils/kWh) by increased utilization of the fixed-cost portions of the plant.
- Buffers system operation and plant output during periods of variable insolation.

Capacity credit is not highly valued for this project because SCE capacity is adequate for the 1990s, in fact, several older oil-fired plants will be decommissioned. However, the remaining benefits of storage still cause a storage-coupled plant to be preferred. The single exception of water/steam without storage is considered for this project because of the Solar I background.

Power Conversion Cycle

Three power conversion cycles have been studied for central receiver plants. These are the air-Brayton, steam-Rankine, and combined Brayton-Rankine cycles. In the Brayton cycle, or gas turbine, the combustion chamber is replaced by a solar heater. The turbine/ generator is located at the tower top, near the receiver, to minimize pumping losses. By using high turbine inlet-temperatures and regeneration, Brayton machines can be made to operate at high thermal efficiency. When using air, the rejected heat remains in the working fluid and is exhausted to the atmosphere. Cooling towers and related equipment are not required.

The Brayton cycle has disadvantages of:

- All major equipment is at the tower top.
- High operating temperature leads to higher losses and lower overall efficiency for the receiver.
- Tower and receiver costs tend to be high because of the poor heat transfer characteristics of the working fluid, the extra weight at tower top, and extra tower height required to minimize receiver losses by reducing aperture size.
- Storage is impractical.
- Off-design cycle efficiency is poor.
- Hybridization is usually required to insure system operation with diurnal and cloud induced insolation variations.

The steam-Rankine cycle is a utility standard. Efficiency is high when reheat and regeneration can be utilized. In general, the antithesis of the air-Brayton cycle comments apply to the steam-Rankine cycle for solar plants.

The combined cycle plant, with a Brayton engine rejecting heat to a Rankine engine, holds promise because of its high efficiency. However, it is encumbered with most of the disadvantages of both the Brayton and Raykine cycles, separately.

Prior studies by Sandia Laboratories (Ref. III.A.1) have shown the Brayton and combined cycle plants to be less cost effective than Rankine plants. In addition, operational flexibility is severely constrained. Therefore, the steam-Rankine system was chosen for conceptual engineering.

Receiver Fluid

Within the steam-Rankine systems, there are three promising receiver fluids: water/steam, liquid sodium, and molten salt. These commonly used heat transfer fluids all have high temperature capability, good heat transfer properties, and high enthalpy gain per unit mass. Table III.A.1 provides a comparison of these fluids for some properties important to central receiver systems.

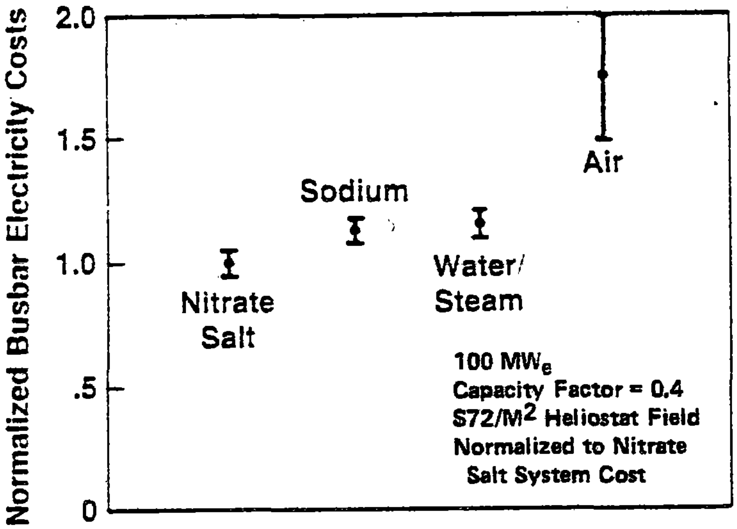
TABLE III.A.1
COMPARISON OF RECEIVER FLUIDS

	Water/Steam	Liquid Sodium	Molten Salt
Maximum temperature (^oF)	~1100 Limit imposed by tube materials)	~1200	~1100
Heat Gain (Btu/lb)	~1000	~200	~220
Volumetric heat capacity ρc (Btu/ft^3 ^oF)	58.0 (water) ~1.5 (steam)	16.6	42.6
Thermal conductivity (Btu/hr ft ^oF)	0.35 (water) 0.031 (steam)	41.8	0.33
Kinematic viscosity, ft^2/sec	0.148×10^{-5} (water) 0.722×10^{-5} (steam)	0.352×10^{-5}	0.123×10^{-4}
Density, lb/ft^3	~40.5 (water) ~2.86 (steam)	49	~115
Specific heat, Btu/lb^oF	1.17 (water) 0.745 (steam)	0.31	~0.37
Freezing point (^oF)	32	208	430

Maximum temperature is significant in the implied ability to operate a 1000^oF main steam Rankine cycle. All are capable of this. Heat gain relates directly to pump work required to collect a unit of energy. The remaining properties relate to heat transfer and storage. The effects of these are discussed in the following sections on these fluid alternatives. Note that freezing can occur in any of the fluids, but it is a more constant concern for design and operation with sodium and molten salt.

2. Selection of System Configurations to Study

Sandia Laboratories (Reference III.A.1) estimated the comparative cost of electricity produced by systems based on the three types of receiver fluids discussed above. Key results are shown in Figure III.A.1 and III.A.2. The comparison is made at constant capacity factor in Figure III.A.1. Molten nitrate salt, liquid sodium and water/steam appear to be close in cost. Based on Sandia Lab investigations, Liquid sodium is about 10% more costly than molten salt, and water/steam is about 15% more costly than molten salt. Note that air-Brayton systems are from 50 to 100% more costly than molten salt. With increased capacity factor, even more significant advantage accrues to molten salt, as shown on Figure III.A.2. For example, at 0.5 capacity factor, liquid sodium is 20% more costly than molten salt, and water/steam is about 15% more costly, but beginning to lose by comparison.



Ref. "1980 Solar Central Receiver Technology Evaluation," SAND 80-8235

Figure III.A.1. Relative Cost/Performance Comparison of Solar Central Receiver Technologies

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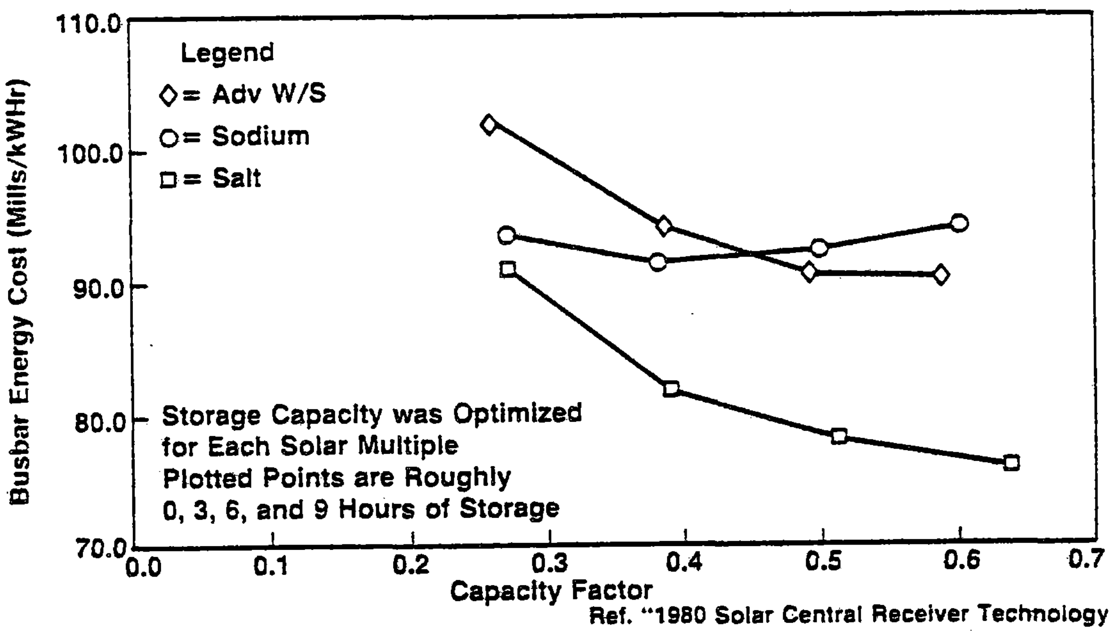


Ref. "1980 Solar Central Receiver Technology Evaluation." SAND 80-8235

Figure III.A.2. Busbar Electricity Cost as a Function of Capacity Factor for Solar Central Receiver Technologies

SCE faces a situation in the late 1980s and early 1990s in which low-cost bulk purchases of electricity will be available in the low-demand portions of the night. High capacity-factor may be of limited value during the summer when the solar plant operating day, with storage, can be over 20 hours. During the fall and winter, the operating day will be shorter, and the period of minimum load should not coincide with solar operation. This impact on system size selection is discussed in the value analysis, Section VIII.C.

It was decided to do a detailed trade study of the three receiver fluid alternatives because of uncertainty in reported system cost and performance, as well as varying degrees of technical risk and operational suitability. This is discussed in the following subsections.

III-B. WATER/STEAM SYSTEM DEFINITION

1. Functional Description and Key Attributes

The system, shown schematically on Figure III.B.1, consists of a tower-mounted water/steam cooled receiver heated by a field of MDC Model 50 heliostats (DOE/Sandia second generation). 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 pressure steam directly, the portion of steam routed to storage flows through a heat exchanger 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. The condensate from the electrical generation system is routed back to the receiver or the storage steam generator for further steam production. It was considered impractical to generate reheat steam with this system; therefore, a lower efficiency nonreheat turbine must be used.

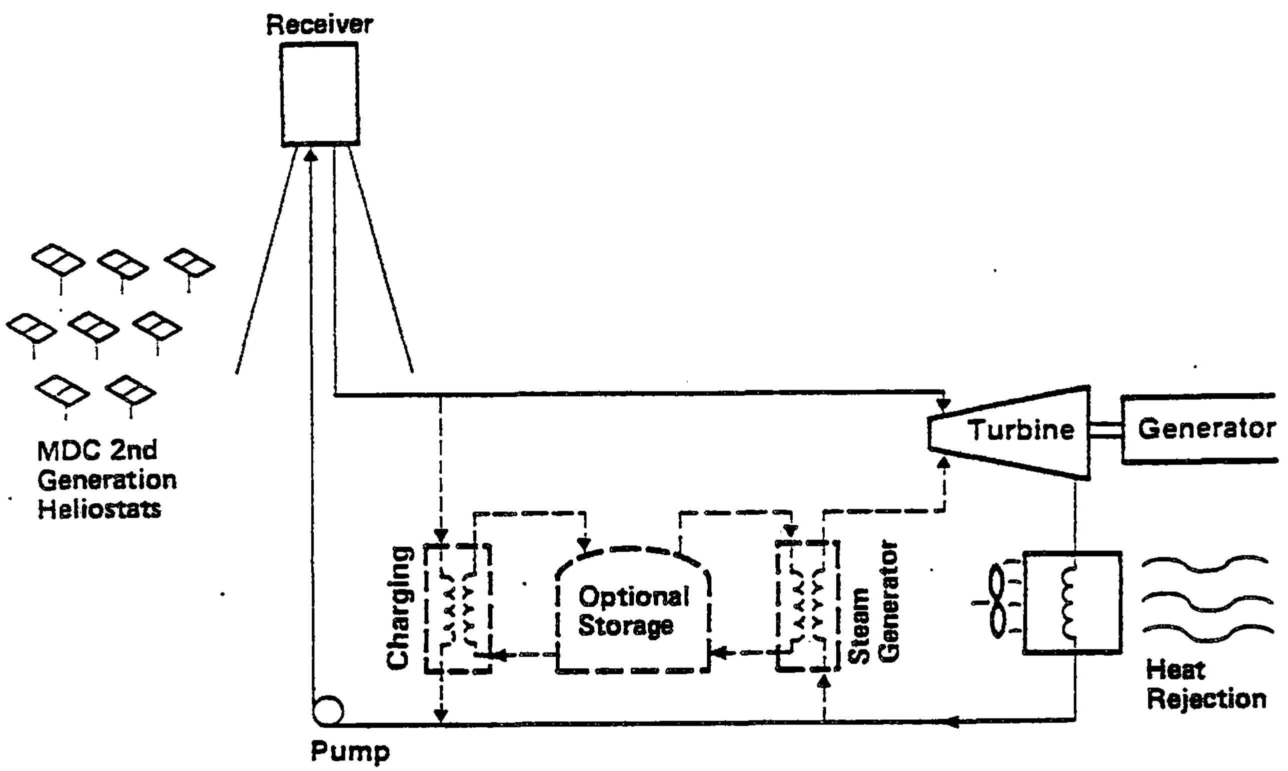


Figure III B-1 Solar Central Receiver System — Water Steam

Water/steam is the most conventional heat-transfer fluid in use in the electric utility industry. The direct production of steam in a solar receiver would appear to be the most natural transition from fossil-fired plants to solar thermal plants. However, the transient nature of solar energy makes it difficult to directly couple total solar receiver output to a standard utility turbine. Also, storage of large amounts of high pressure steam to buffer a turbine from receiver output and increase plant capacity 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 a somewhat unique 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. In addition, the requirements for high fluid pressure and two-phase heat transfer in the receiver have significant consequences on receiver design, operation and control. However, all of these problems have been addressed in the design of the Solar I, 10 MWe plant at Barstow and workable solutions have been found. This study addresses the economic viabilty of these solutions for a 100 MWe commercial size plant.

2. Options for Trade Studies

Three different water/steam receiver configurations have been studied or developed under DOE/Sandia central receiver programs. Therefore, it was decided to conduct a trade study to select one for the baseline water/steam system. Two of the receivers are external cylinders and differ by their flow philosophy. One is the MDC/Rockwell, Solar I single phase to superheat (once through design (Reference III.B.1); another is a B&W forced recirculation, screened-tube design (Reference III.B.2); and the third is an MMC/FW natural recirculation quad cavity design (Reference III.B.3). These are shown on Figure III.B.2.

In the trade-off, collector fields for each of the receivers were configured geometrically to the shape originally defined in previous studies of these receivers. This was to maintain the flux distributions originally used on the receivers, as each has its own peculiar flux distribution requirements.

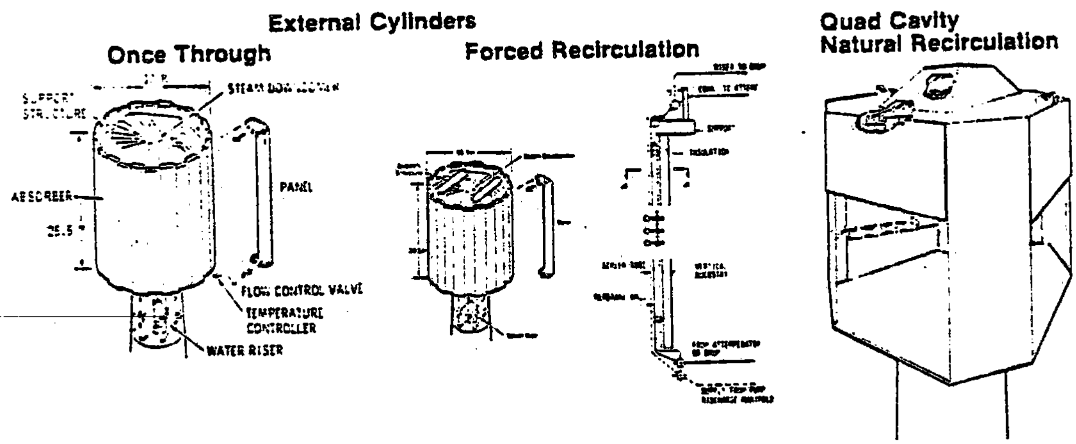


Figure III.B.2. Candidate Water/Steam Receivers

An oil-rock thermocline system based on the Solar I design and a higher operating temperature two-stage alternative (based on Reference III.B.4) were considered for thermal storage in the water/steam system. The oil-rock system is charged by desuperheating 950°F steam from the receiver to heat a heat-transfer oil (Caloria HT-43) in a heat exchanger. The hot oil is circulated through a tank of rocks, heating the rocks and establishing a thermocline in the tank of oil/rock mixture (25% oil and 75% rock by volume). The system is discharged by routing hot oil from the tank through a steam generator where feedwater is converted to steam. The maximum temperature limitation of the oil (approximately 600°F) requires this process to be conducted at reduced steam temperature and results in the output steam being derated at 565°F, as opposed to the 950°F steam from the receiver. This derated steam is introduced to the turbine through a special admission port in the turbine. The system is schematically illustrated on Figure III.B.3. The result of using this lower temperature derated steam is a low turbine gross cycle efficiency of 27.5%.

The other option is a two-stage storage concept which takes advantage of the higher temperature capability of molten salt to store energy, thus providing higher temperature steam to the EPGS. This is also illustrated on Figure III.B.3. The system is charged with superheated steam from the receiver. Salt is heated in a heat exchanger between a warm salt tank and hot salt tank. The energy transferred to the salt desuperheats the steam and reduces its temperature to near saturation value. The lower temperature energy available from condensing the steam is transferred to an oil/rock storage system. The oil/rock stored-energy is used to generate saturated steam, which is then superheated in a salt/steam heat exchanger. The higher temperature capability of this system generates steam which is less derated (750°F) than in the previous option, thus providing a higher turbine gross cycle efficiency (32.2%).

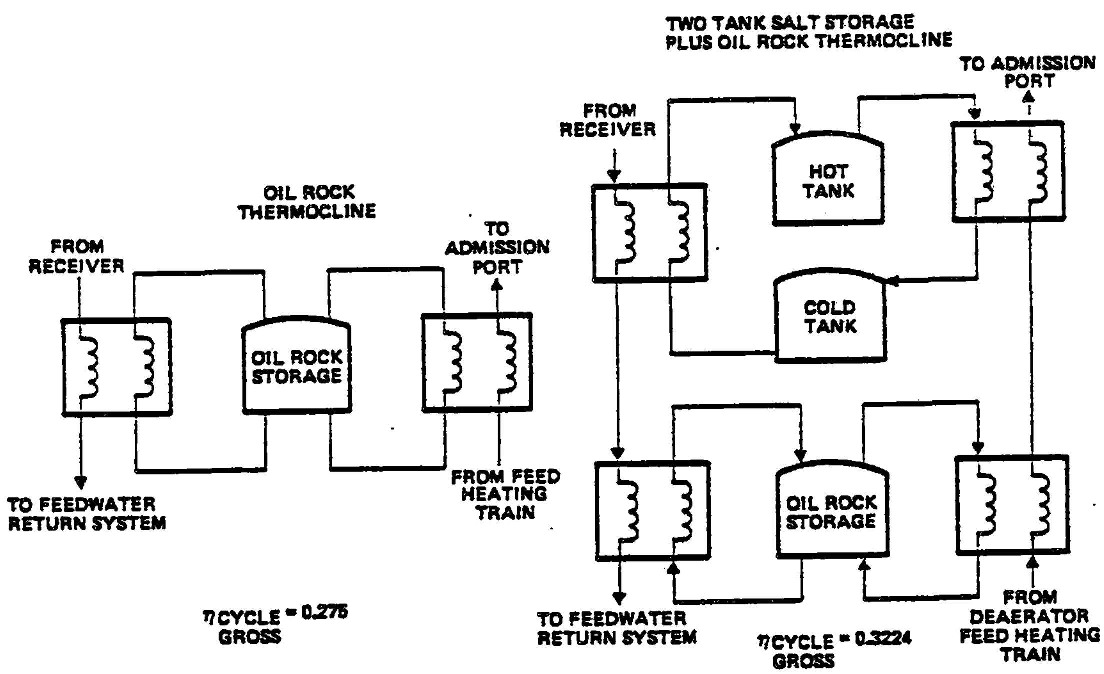


Figure III.B.3. Candidate Water/Steam Storage Systems

As a point of comparison for a minimum capital investment alternative, a no-storage option was also considered. However, as previously stated, the problem associated with this option is the control difficulty of directly coupling total solar receiver ouput to a standard utility turbine.

In addition, receiver tower selection was based on the steel versus concrete tradeoff conducted for the baseline molten salt system definition (Section III-C.).

Economics, performance, operational characteristics and relative technical risk were evaluated for these alternatives to select the system for use in the final plant concept selection.

3. Trade Studies

c. Key Inputs, Assumptions and Results

The isolation model used in all the trade studies is the SOLINS Barstow model. This model is discussed in detail in Section V.A of this report.

All of the trade studies were based on using the MDC second generation heliostat. A detailed description of the heliostat is given in Section IV.C of this report.

A slipform concrete tower was selected for the water/steam system as a result of cost trades done in conjunction with selecting the baseline salt system and other reported studies. The rationale for its selection is discussed in Section III-C of this report.

Receiver

To make comparisons of the candidate receiver configurations, estimates were made of receiver performance, in terms of absorptivity and combined radiation and convection losses, for each receiver. The performance estimates were based on performance data in the previously referenced publications. Table III.B.1 summarizes the performance parameters in the

TABLE III.B.1
WATER/STEAM RECEIVER PERFORMANCE FACTORS

Receiver Type	Once Through	Screened Tube Forced Recirc.	Quad. Cavity
Reference	MDC	B&W	MMC
Absorptivity Fraction	0.950	0.972	0.983
Radiation and Convection Losses (KW_t/m^2)	19.1	23.7	30.4

trade studies for each receiver. The absorptivity values are expressed as the fraction of incident power which is absorbed. The B&W screened-tube receiver has slightly better performance than the once-through because the front tubes absorb a portion of power reflected by the back tubes. The cavity receiver has an even higher value because the cavity provides further enhancement of absorptivity by capturing more reflected radiation. The radiation and convection losses are presented in the form provided in the reference sources, which is the form required for analysis. It's worthy to note that the relative receiver efficiencies are actually the inverse of these unit area loss factors. The published power levels are nearly identical and the areas vary such that the quad cavity receiver has the highest convective and radiation efficiency, and the once-through has the lowest efficiency.

Receiver irradiated area was scaled linearly with design point power as shown in Figure III.B.4. Receiver cost was from the published sources updated to current year dollars and adjusted by MDC and Foster Wheeler to assure consistency. In addition, for the once-through receiver, a reduced allowable peak flux on the receiver was considered because of uncertainty that developed after publication. Therefore, both the published value of 0.85 MW/m^2 and a reduced value of 0.6 MW/m^2 were used in the study.

The average system cost spread for the three alternatives is approximately 3%. Reduction of peak flux on the once-through receiver causes an increase in receiver area with resulting increases in radiation and convective losses. This requires more heliostats and a corresponding increase in system cost, as shown on Figure III.B.5 and Figure III.B.6, respectively.

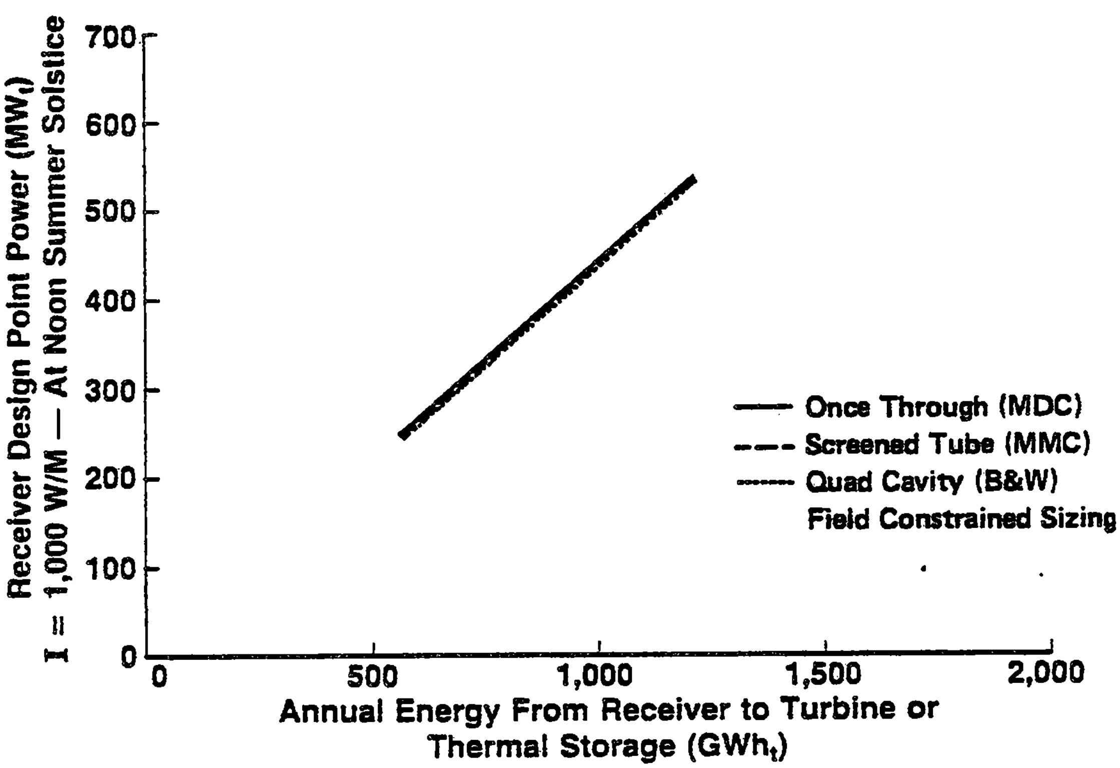


Figure III.B.4. Typical Delsol Results Comparison of Water/Steam Configurations

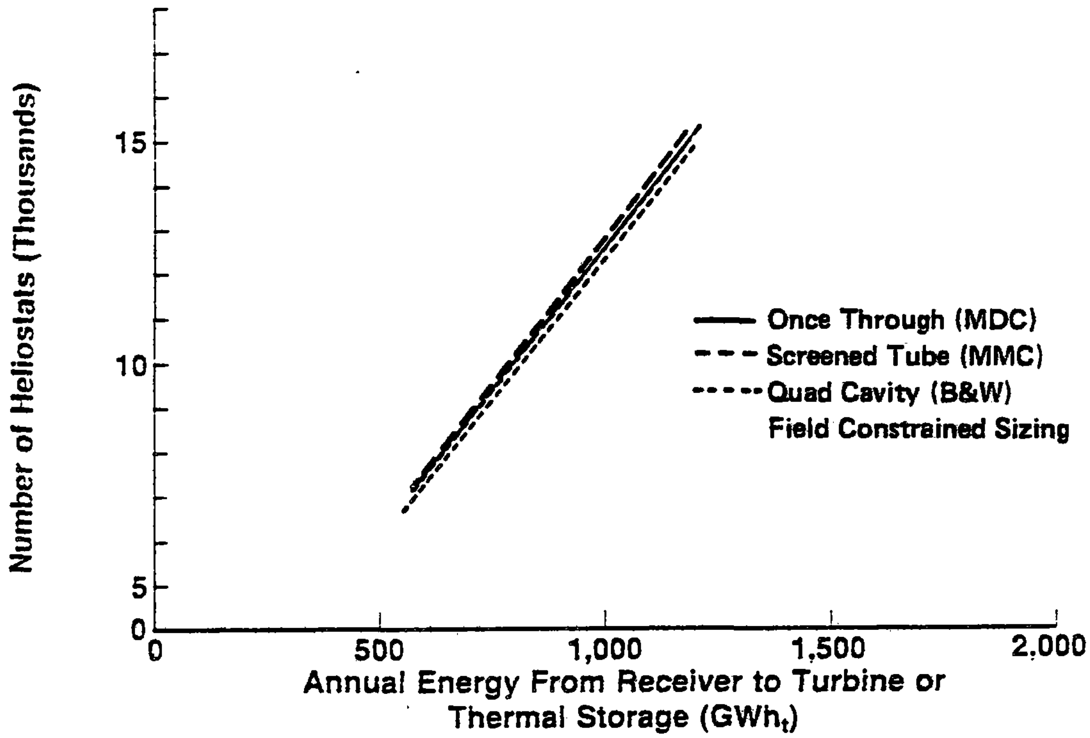


Figure III.B.5. Typical Delsol Results Comparison of Water/Steam Configurations

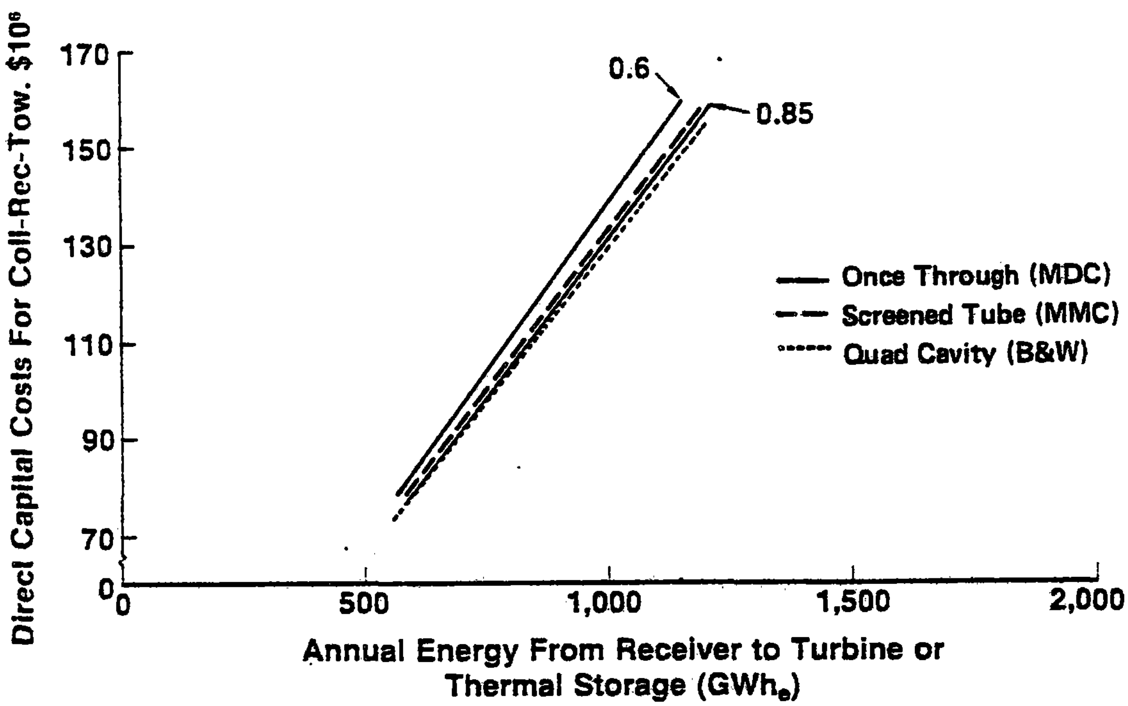


Figure III.B.6. Typical Delsol Results Comparison of Water/Steam Configurations

Storage

Data on cost and performance for the two storage options are from the published sources. For both systems, the following conditions were assumed:

- 110 MWe gross turbine power from primary steam supply
- Primary steam supply at 1465 psia, 950°F
- Non-reheat with five stages of feedwater preheat.

In the two-stage system, the topping storage cycle improves the efficiency of operation from storage by producing higher pressure steam with greater superheat. But the system complexity and cost are increased to achieve this. Hence, the trade study focuses on cost and performance. But system complexity and attendant problems of operation, reliability and availability are also considered.

Cost estimates for the two systems are shown on Table III.B.2. The two-stage system costs are greater because the salt equipment is added and the

TABLE III.B.2
STORAGE SYSTEM COST ESTIMATES

(MILLIONS 1981 $)

Item	Single Stage System	Two Stage System
Oil Storage Tank	8.79	14.71
Oil Circulation Equipment	4.62	7.07
Oil Heat Exchangers	5.76	5.19
Salt Tanks	—	1.39
Salt Circulation Equipment	—	1.35
Salt Heat Exchangers	—	2.13
Control	0.98	0.98
Foundation + Site Prep.	1.00	2.13
Engineering	1.58	2.37
Rock Medium	0.93	2.34
Oil Medium	3.64	9.16
Salt Medium	—	4.86
Transportation and Handling	2.16	5.44
TOTALS	29.46	59.12

oil/rock thermocline system is much larger. The oil/rock thermocline portion of the two-stage system is much larger because it has a much smaller oil temperature difference than the oil/rock thermocline system alone (55°F vs 160°F). This can be explained by examination of the diagrams for the two systems, Figure III.B.7(a) & III.B.7(b).

As intended, the admission steam superheat temperature is higher for the two-stage system. Its corresponding higher admission steam saturation temperature limits the oil temperature difference available for storing the heat (note the slope of the oil curve). Thus, much more oil is required for the heat stored in the oil/rock stage of the two-stage system than for that stored in the oil/rock only system. This accounts for about half the increased cost, which must be paid for the performance improvement of the two-stage system. It is, therefore, an important factor in the value analysis of this system. The performance of each system was determined assuming both had the same annual energy input available from the collector/receiver system. These results are given on Table III.B.3 with the total system costs and derived value parameters. This shows that cost of energy from the two-stage system is nearly twice that of the single stage system. The marginal cost of the additional energy is more than three times that for the single-stage system.

b. Risk Considerations

There is no significant difference in technical risk for the storage options, although there is greater operational complexity with the two-stage system,

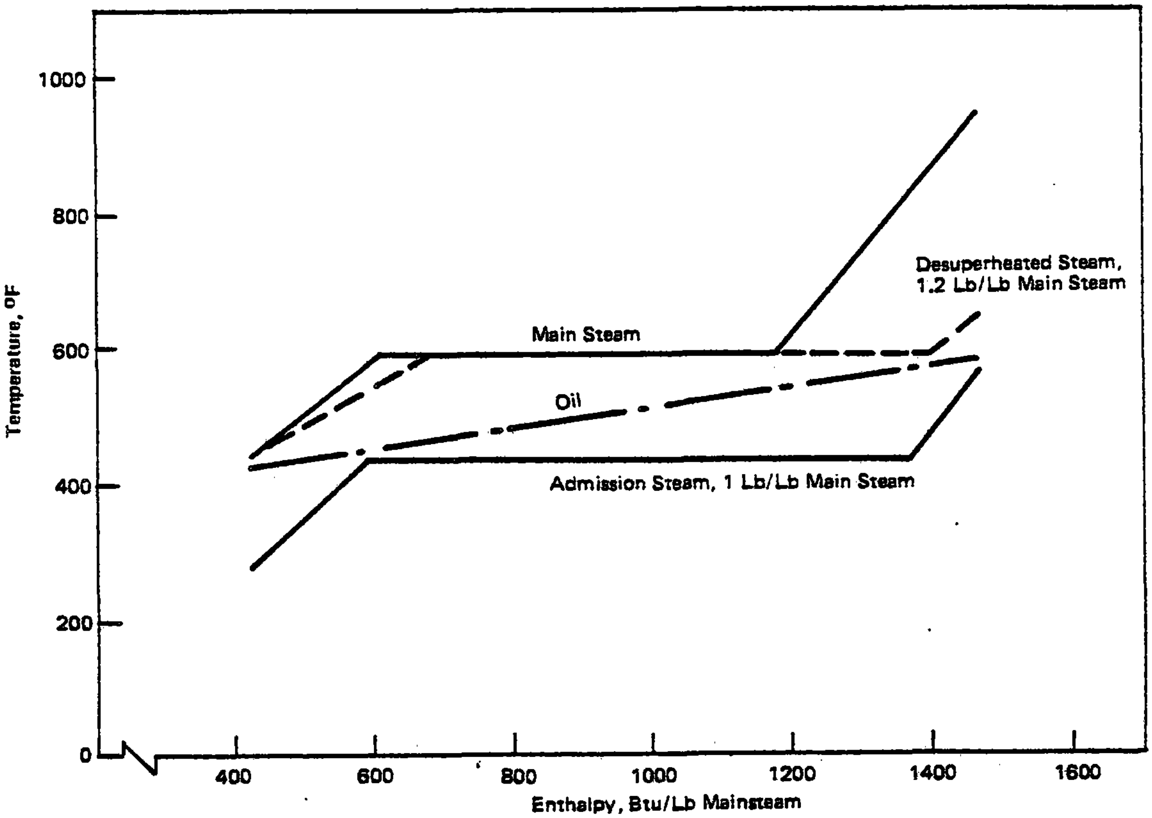


Figure III.B.7(a). Pinch Point Diagram of Single Stage Storage Unit

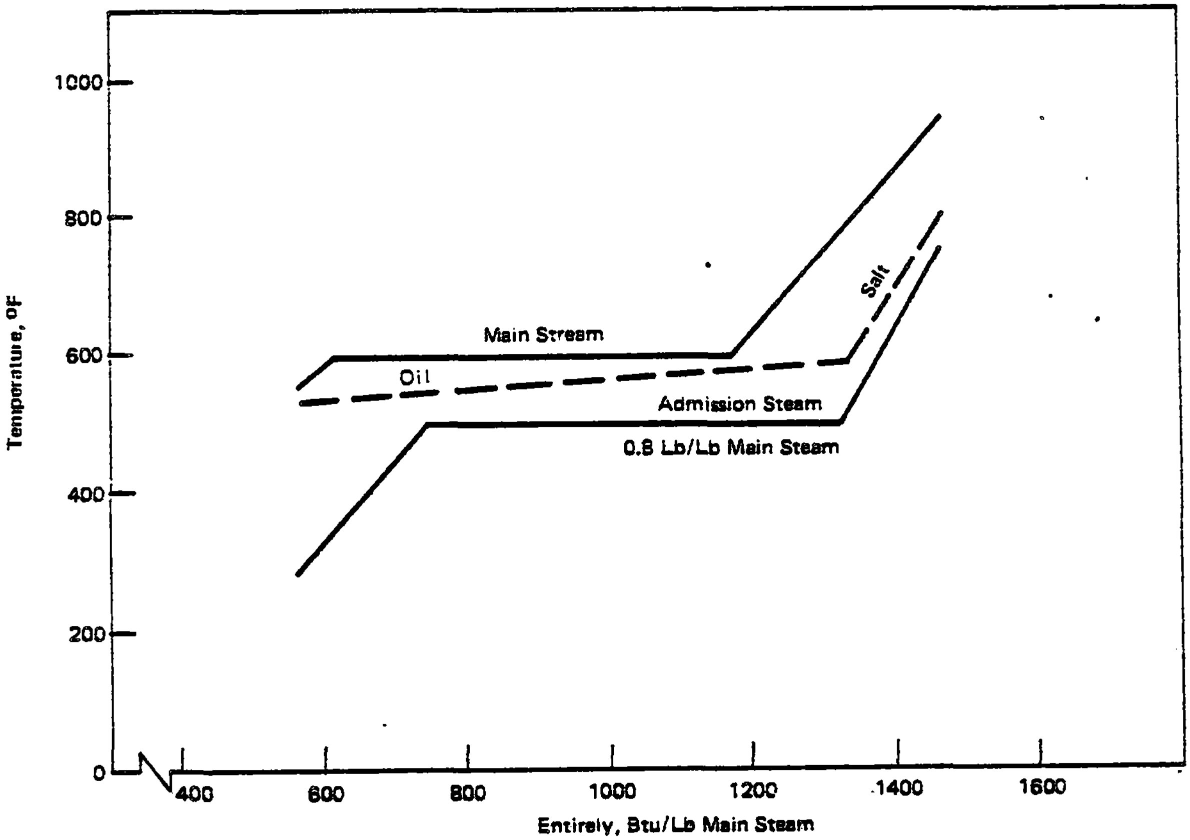


Figure III.B.7(b). Pinch Point Diagram for Two Stage Storage

due to the additive equipment and heat transfer processes. There are some differences in risk, however, for the receiver options. Three factors of the solar environment affect the degree of risk for receiver designs. These are daily cycling, cloud induced transients and clear day insolation variations.

Daily Cycling - Overnight shutdown, gradual change in insolation due to sun position during clear days, and variation of collector field efficiency due to sun position cause daily complete and partial cycling of receiver power level.

Cloud Induced Transients - Clouds cause insolation changes ranging from rapid momentary drop-outs to diffused or complete shading for tens of minutes followed by rapid return to full power. These can affect localized portions of the collector field and thus localized portions of the receiver surfaces.

Clear Day Insolation Variations - Atmospheric water vapor and turbidity affect the clear day insolation levels to the extent of about 20% variation in receiver power levels. In addition, seasonal changes in sun position can vary the power level by a factor of two or more.

These factors influence the receiver structural, control and operational requirements. The impact is most significant for the quad cavity receiver as discussed in Section III-C.3b, primarily due to two-sided receiver tube heating, which results in complex flow control requirements with cloud transients. This is even more difficult for the water/steam case because of the potential for two-phase flow.

TABLE III.B.3
WATER/STEAM STORAGE SYSTEM COMPARISON

	Single Stage	Two Stage
Temperature Range (^oF)	Oil - 160	Oil - 55 Salt - 230
Gross Cycle Efficiency	0.275	0.322
Gross Heat Rate (BTU/KWh)	12,410	10,590
Estimated Capacities (KW_e)	3,770	4,000
Gross Power Output (KW_e)	77,000	93,500
Net Power Output (KW_e)	73,230	89,500
Mainstream Capacity Factor	0.344	0.344
Annual Energy Delivered From Admission Steam (GW_ehr)	127	150
Total Installed System Costs (Millions $)	29.5	59.1
$/Annual kW_ehr	0.23	0.39
¢/kWhr @ Levelized Fixed Charge Rate of .0250	5.8	9.8
Marginal Cost of Additional Energy (Δ\$/Δ Annual kW_ehr)	0	0.78
Marginal Levelized Cost (Δ¢/Δ KW_eHR)	0	19.5

The quad cavity configuration presents an untried, questionable design for a potential devastating environment. The once-through system has been demonstrated to a limited degree for Solar I. The external, forced-recirculation screened-tube system presents a potential improvement in controllability over the once-through system, but it introduces some additional question of tube support suitability.

c. Conclusions

The B&W forced-recirculation, screened-tube external receiver was selected for the water/steam concept. Although there was no clear-cut cost advantage for any of the receivers, the B&W receiver concept was judged the best design for controllability.

The single stage oil/rock thermocline storage system was selected on the bases of cost for the water/steam concept. As previously mentioned, it was decided to continue with a no storage option as well. Thus, two water/steam concepts were defined for consideration in the final plant concept selection. This was done so the economics of reduced efficiency for operation with storage could be compared with a higher cycle efficiency, though lower capacity factor, potential available without storage in a water/steam system.

4. Candidate Water/Steam System Description

a. General

Two options are considered for the water/steam system plant; one with storage having a capacity factor of 0.48, and one with no storage, having a capacity factor of 0.26. The water/steam system plant includes a single collector field surrounding the tower, and receiver, storage tanks (storage option), turbine generator and balance of plant, all located in an area at the base of the tower.

b. Collector System

The 1068-acre (storage) or 524-acre (no storage) collector field is approximately circular, as indicated on the plot plan, Figure III.B.8. The collector system contains 17,250 MDC Model 50 heliostats with

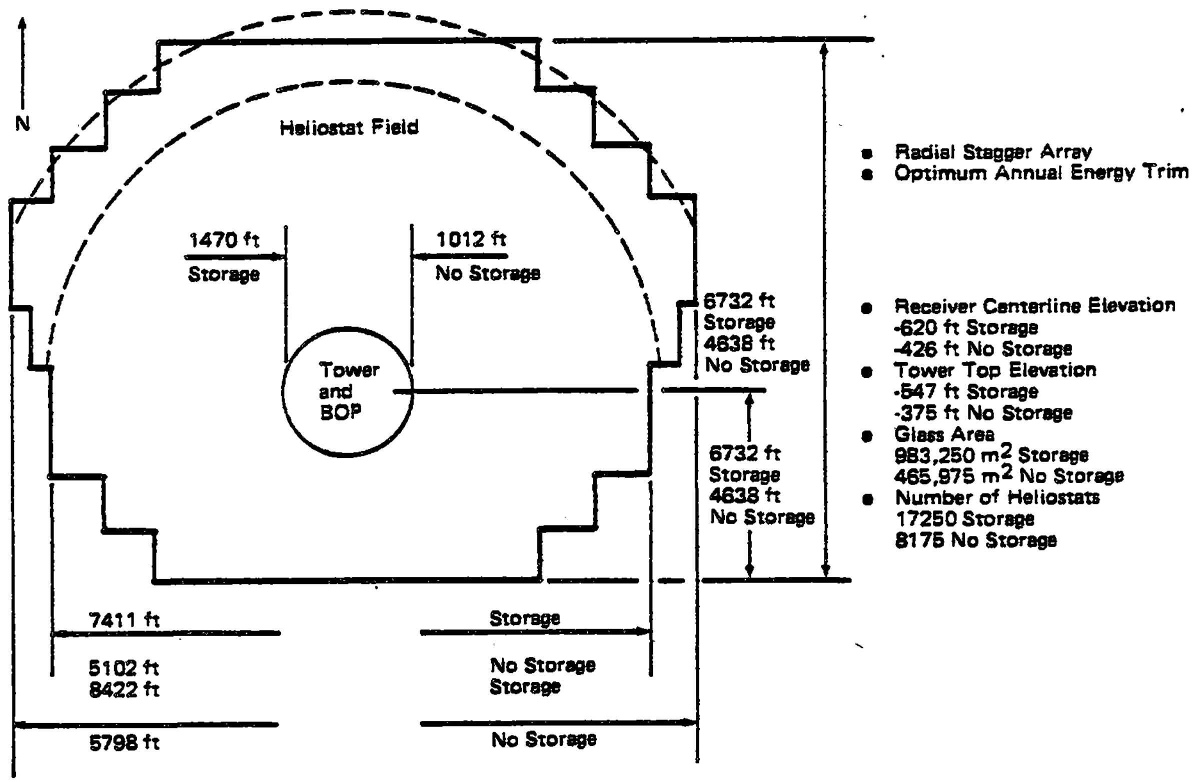


Figure III.B.8. Commercial System Field Layout approximately 57 m^2 each of glass area for a total mirror area of 983,250 m^2 (storage) and 8,175 heliostats with a total mirror area of 465,975 m^2 (no storage). The heliostats are arranged in a radial staggered array around the tower.

c. Receiver System

The receiver system consists of a cylindrical screened-tube, forced-recirculation absorber unit with its support structure, control elements, interconnecting piping, and a receiver tower.

The receiver tower is a tapered, slip-formed concrete structure which supports the receiver at an optical height of 620 ft. for the storage option and 547 ft. for the no-storage option. Approximate scale and dimensions for the receiver tower are shown on Figure III.B.9. The receiver support structure attaches to the tower top.

The tower will contain an internal elevator running up the center of the tower. This elevator will go from the ground level through intermediate work station stops, and will terminate at the top deck level.

Refer to Section IV.D for details of the tower structure and features.

The main water riser and steam downcomer are supported on the inside of the tower shell and include expansion loops at the appropriate intervals. Piping size and materials are shown in Table III.B.4.

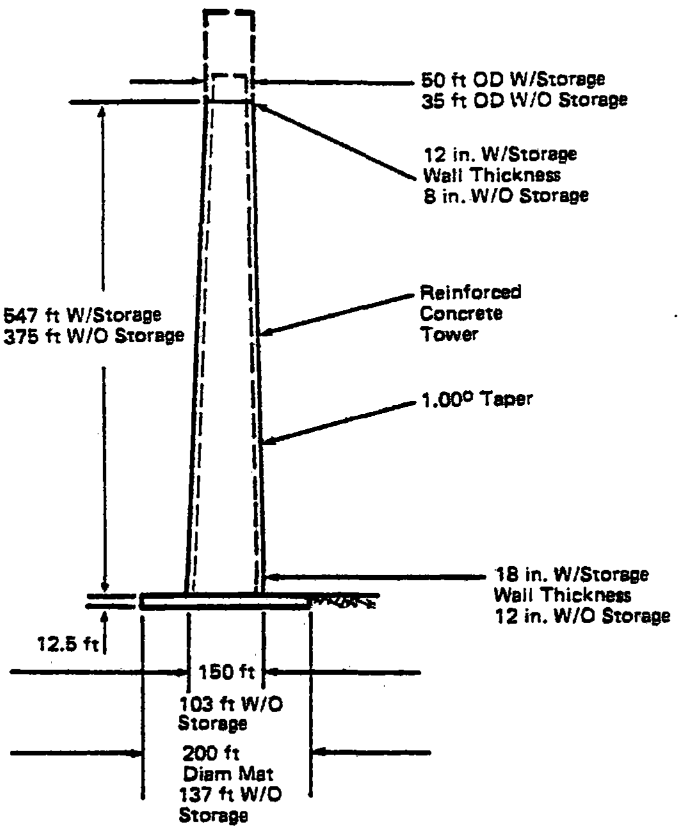


Figure III.B.9. Receiver Tower

TABLE III.B.4
PIPING MATERIALS AND SIZES

Pipe	Material	Size: Storage Option	Size: No Storage Option
Main Steam Downcomer	A335 - p22 2-1/4 Cr - 1 Mo.	26" Schedule 160	12" Schedule 160
Feedwater Riser	ASTM A106 Gr. C	12" Schedule 160	10" Schedule 160
Admission Steam	ASTM A106 Gr. B	20" Schedule 40	None
Steam Generator Feedwater	ASTM A106 Gr. B	9" Schedule 40	None
Oil	ASTM A106 Gr. B	6" Schedule 40	None

The receiver is constructed of 24 factory-assembled absorber panels (made of Incoloy 800), arranged in cylindrical configuration, as illustrated on Figure III.B.10. Each panel is complete with strong-back, insulation and lagging, instrumentation, structural attachment points, piping, and piping attachments points.

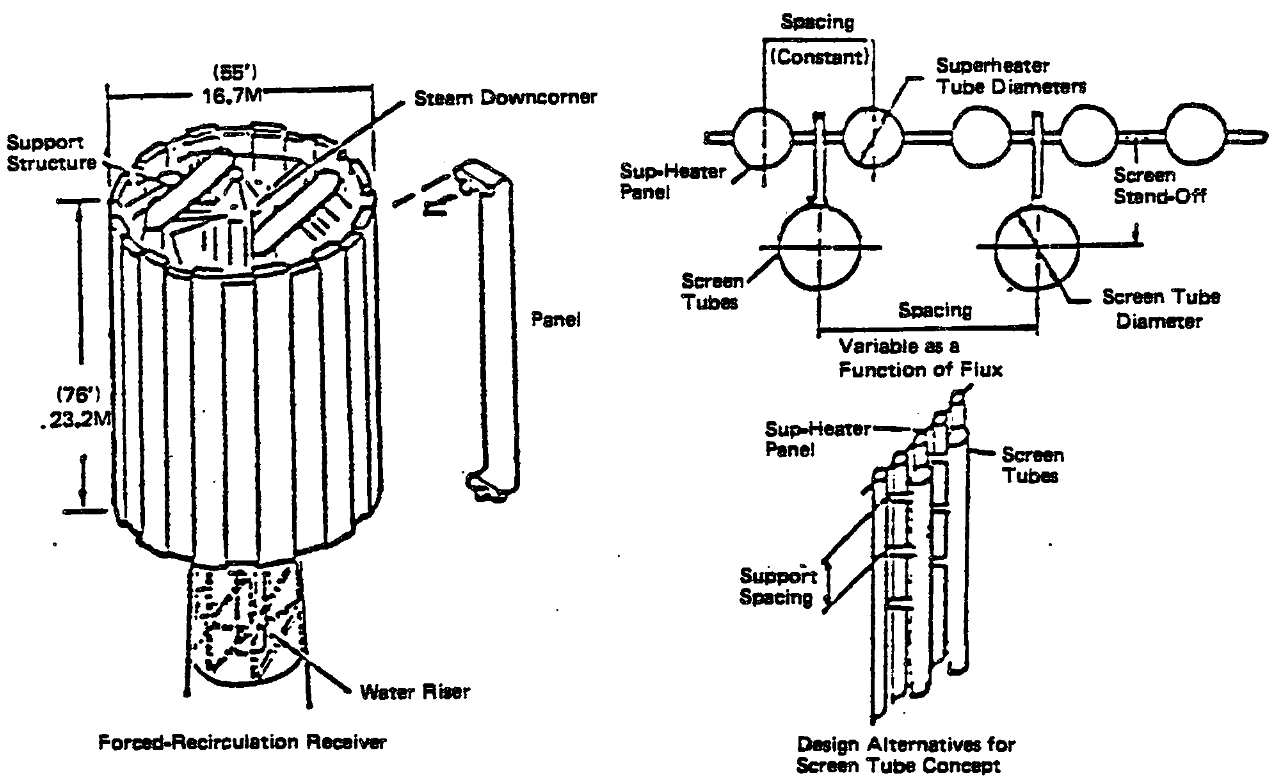


Figure III.B.10. Receiver Design Features

Screen tubes on the panels provide the phase change in forced-recirculation flow from two drum separators, one for each side of the receiver. Steam from the drums flows through the superheater screened tubes in three series passes of two parallel panels for each side of the receiver. Attemporation between passes controls outlet temperature, while balance valves control the flow distribution between panels.

A schematic of the receiver main components is shown on Figure III.B.11. Water enters the receiver at 2250 psig and 459°F. The maximum receiver fluid flow rate is 1.7×10^6 lb/hr. The receiver is controlled to maintain an outlet steam temperature of 960°F. The outlet temperature and steam mass flow rate (for feedwater control) are measured continuously. Flow rate to the attemporators is adjusted (with appropriate logic to respond properly to transients) to correct any error detected in receiver outlet temperature.

The receiver power level at the system design point is 603 MW_{th} (absorbed) for the storage case and 292 MW_{th} for the no-storage case. However, the receiver will be designed to function up to 110% power. The peak heat flux on the absorber surface is limited to less than 0.6 MW/m^2 and tube metal temperature is limited to less than 1200°F.

No minimum steam flow rate is required. During startup or when the receiver fluid temperature drops below 900°F, the fluid is diverted to a flash tank. Steam from the flash tank goes to the primary steam line, and condensate flows through a separate downcomer to a deaerator.

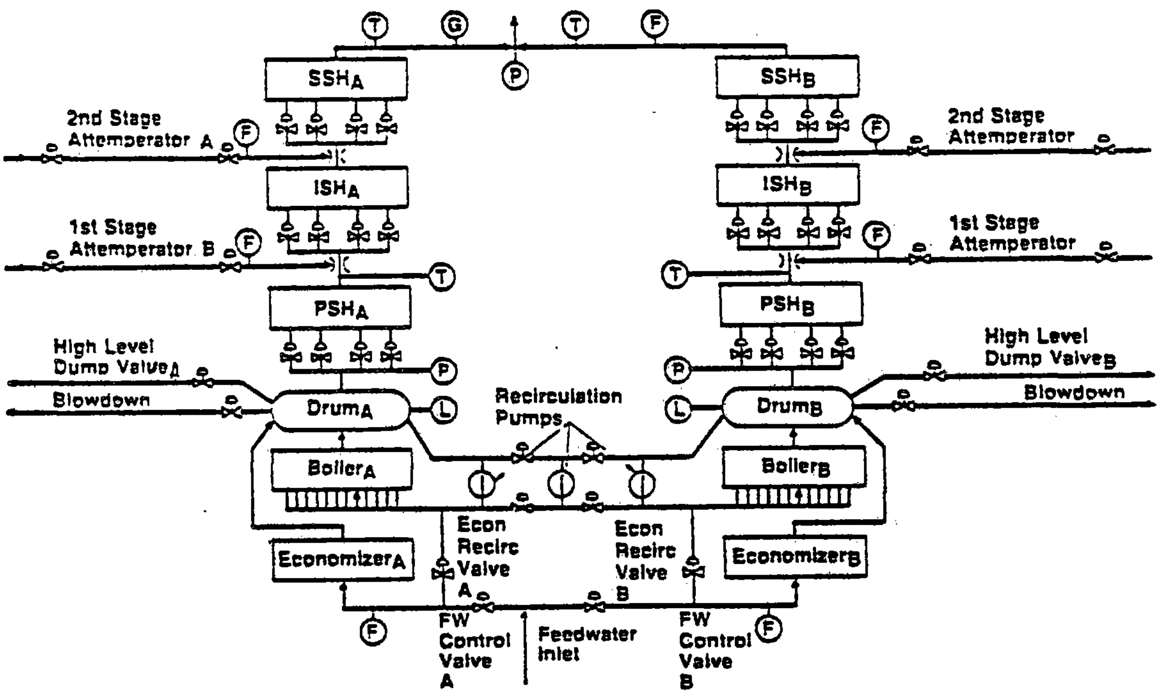


Figure III.B.11. Water/Steam Receiver Schematic

d. <u>Storage and Transport System</u>

The storage and transport system includes the thermal storage tanks, heat exchangers, and all of the piping to and from the receiver and the associated pumps, valves and control instrumentation.

A schematic of the storage system is shown on Figure III.B.12.

Thermal energy is absorbed into the system (charging process) by circulating a heat transfer oil through charging heat exchangers while condensing receiver steam which is desuperheated. The heat transfer oil (Caloria HT-43) enters at about 425°F and exits at about 585°F. The high temperature Caloria flows to either the storage tank (thermal storage option) or to the inlet of the steam generating heat exchangers. The desuperheater is a direct contact mixing chamber with feedwater injected through multiple atomizing nozzles. The maximum steam flow rate is 700,000 lb/hr into the desuperheater. The spray is controlled to provide 650°F steam at the outlet.

Five heat exchangers are used to heat the thermal storage fluid. Each has a removable U-tube bundle. Each is made of carbon steel and has a heat transfer area of 18,000 ft^2.

Condensed steam from the storage heater flows to a flash tank. The steam flows to the deaerator and the condensate to the second stage feedwater heater. Pipe sizes and materials are included in Table III.B.4.

The thermal storage unit (TSU) is a vertical cylindrical tank filled with a sand/rock mixture. Hot Caloria is introduced at the top of the TSU through a distribution manifold and passes downward through the tank. As the oil

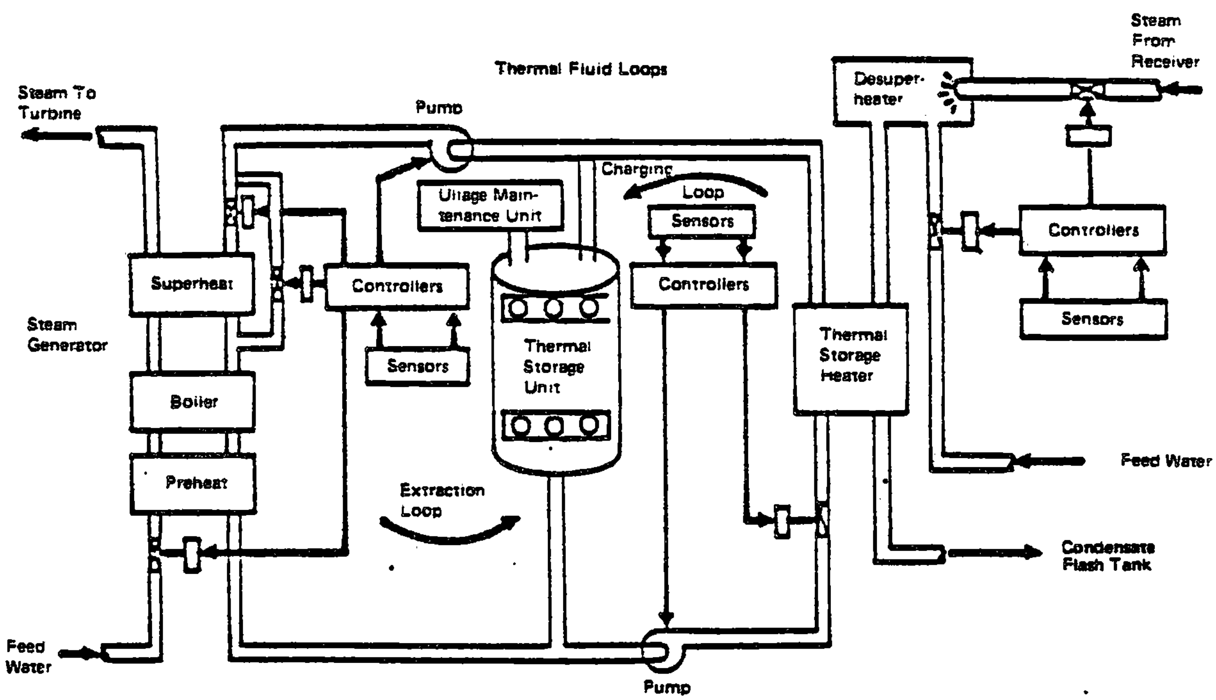


Figure III.B.12. Thermal Storage Schematic

passes through the rock/sand mixture, it transfers its heat to the sand and rock and is cooled to the low temperature (425°F) condition. The zone of heat transfer within the tank (thermocline) occurs over a small fraction of the entire tank height. As energy is added to the TSU, the thermocline moves downward, thereby increasing the thermal charge.

During the energy extraction process, high temperature Caloria is circulated to the steam generators either flowing directly from the outlet of the charging heat exchangers or from the top manifold in the TSU. The cooled oil then flows to either the TSU bottom manifold where it is reintroduced into the tank or directly to the charging heat exchangers where it absorbs additional charging energy.

Five modules of steam generator are used. Each includes a preheater, boiler, and superheater. The preheater is a straight tube, floating head, counterflow exchanger with 4684 ft^2 heat transfer area. The boiler is a horizontal U-tube, kettle boiler with 13,000 ft^2 heat transfer area. The superheater is a horizontal, U-tube, cross-flow exchanger with 6390 ft^2 heat transfer area.

The Caloria introduced into the TSU bottom manifold flows upward through the sand/rock mixture. As the Caloria passes through the thermocline region, it absorbs heat from the high temperature rock and continues to flow upward until it passes out of the tank top at a nominal temperature of 585°F.

During this period, thermocline is moving toward the top of the TSU which results in a net energy extraction from the TSU. Charging and extraction functions for the TSU must be terminated when the thermocline reaches the bottom or top manifold, respectively.

The storage tanks (Figure III.B.13) have approximately 0.6 height-to-diameter ratio to resist over-turning during earthquake. Four thermal storage tanks are used in parallel. Each tank is 97.5 ft. in diameter and 56 ft. high. The total volume per tank is 2,890,000 gal. Each tank is filled with 22,300 tons of granite rock and sand and 503,000 gals. Caloria HT-43. The tanks are made of ASTM A537-70, Grade B carbon steel. The wall thickness is stepped to reflect the hoop stress resulting from hydrostatic pressure and settling of the rock bed.

The tank foundation is insulating concrete over lightweight concrete and is designed for stability in a seismic environment. The inner tank shell is not restrained by the anchor bolts; hence, it is relatively free of thermal stresses. An outer shell serves as lagging and provides attachment to the anchor bolts. Expanded perlite insulation absorbs compressive strains resulting from expansion of the inner tank shell.

An ullage maintenance unit controls nitrogen flow to pressurize the TSU to a safe level and removes any volatile degradation products of the heated Caloria. The TSU is maintained at a slightly positive pressure to prevent air from leaking into the tank. This prevents oxygen from entering the tank to increase the degradation rate of the Caloria.

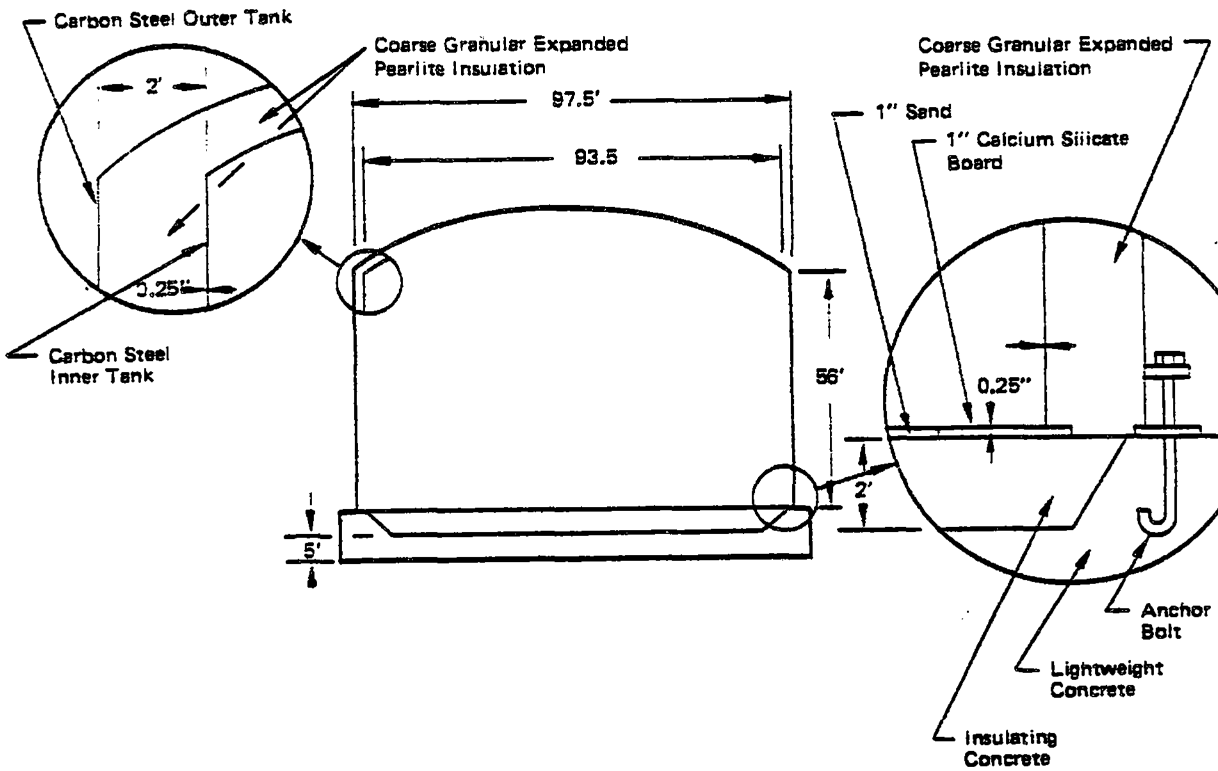


Figure III.B.13. Thermal Storage Tank

The warm oil is circulated through the charging heat exchanger by five 4000 gpm centrifugal, high temperature pumps. Each pump requires 190 kWe power at the maximum charging rate.

Hot oil is circulated through the steam generator by five 6000 gpm centrifugal, high temperature pumps. Each pump requires 190 kWe.

Two receiver feed pumps, operating at half capacity, boost feedwater the number one heater (600 psi, 454°F) to receiver feed pressure of 2550 psi at a total flow rate of 2.0×10^6 lb/hr. Each pump requires a 1500 kWe motor power (storage option). For the no-storage option, the total flow rate is 960,000 lb/hr with a 790 kWe electrical power requirement for each pump.

e. EPGS and Balance of Plant

The EPGS and balance of plant for the water/steam systems are similar to that described for the molten salt system (Section III-C). The turbine is a nonreheat turbine. The turbine for the storage option also has an admission port to accept the derated steam from storage. The turbine for the no-storage option was assumed to be a variable pressure turbine.

f. Plant Control System

The plant control system provides coordinated control of all of the plant systems. Its characteristics and operation are basically the same as describecd for the molten salt system (Section III-C) except for differences in storage system control (where applicable) and more complicated turbine controls due to the closer coupling between receiver and turbine and the operation on admission steam for the storage option.

g. Final Baseline Water/Steam Systems Sizing

The baseline water/steam systems component sizes and capacities are summarized on Table III.B.5 for both the storage and no-storage options.

TABLE III.B.5
BASELINE WATER/STEAM
SYSTEMS CHARACTERISTICS

	No Storage	Storage
Capacity Factor	0.264	0.480
Annual Energy to Steam ($GW_e hr$)	663	1377
Land Area km^2/acres	2.12/524	4.32/1068
Heliostats	8175	17250
Glass Area m^2	464,667	980,490
Tower Height (m)		
Optical	130	189
Rec ℄	133.7	192.7
Top of Tower	110.7	165.5
Receiver Design Pt. Power MW_t	292	603
Rec. Geometry H X D (m)	19.4 x 14.0	27.8 x 20.1
Rec. Area (m^2)	856	1760
Design Pt. Flow Rate (lb/hr)	960,000	2.0×10^6
Cold Water Pipe ASTM A106 GrC (m)	520 10" Sched 160	520 12" Sched 160
Hot Steam Pipe 2-1/2 Cr - 1 Mo (m)	520 12" Sched 160	520 26" Sched 160
Receiver Pump		
Number	2	2
Size Each (HP)	1060	2120
Storage Size ($MW_t hr$)	0	1796
Type		Oil Rock Thermocline

h. Baseline Water/Steam Systems Costs

The estimated costs of the two water/steam systems are shown on Table III.B.6. These costs are based on the two systems (with and without storage) as described in the preceding text.

TABLE III.B.6
WATER/STEAM
RELATIVE COST ESTIMATE FOR 100 MW SOLAR POWER PLANT

		0.264CF 1 Field Without Storage		.480 0 CF 1 Field With Storage	
1.0	Solar Steam Supply System				
	.1 Collector				
	.11 Collector Purchase Price	$68.3m	-	$144.1m	-
	.11 Collector Erection	11.7	-	24.7	-
	.2 Major Solar Steam Supply Hardware	15.4	-	25.3	-
	.3 Solar Process Mechanical Equipment	0	-	30.7	-
	.4 Solar Electrical	1.8	-	2.2	-
	.5 Solar Civil and Structural	3.4	-	6.9	-
	.6 Solar Piping and Instrumentation	3.1	-	10.1	-
	.7 Solar Yardwork and Miscellaneous	3.4	-	6.6	-
2.0	Turbine/Generator	-	$8.4m	-	$8.9m
3.0	Process Mechanical Equipment	-	9.1	-	10.3
4.0	Electrical	-	6.1	-	6.1
5.0	Civil and Structural	-	4.2	-	4.2
6.0	Process Piping and Instrumentation	6.1	3.2	6.1	3.7
7.0	Yardwork and Miscellaneous	-	0.6	-	0.6
8.0	Switchyard	-	0	-	0
70.0	Distributable Construction Costs (CM&SU)	3.8	5.8	8.6	6.0
80.0	Engineering & Home Office				
	- A&E	1.2	5.0	3.2	5.0
	- Solar Integrator	4.0	-	9.1	-
	Contingency	-	8.5	-	8.9
	Subtotal (MDC, Bechtel)	$122.2m	$50.9m	$277.6m	$53.7m
	Total	$173.1m		$331.3m	
	Dollars Per MW_ehr	$747		$785	

i. Baseline Water/Steam Systems Performance

The overall system performance at the design point and annual average are shown in waterfall format for both systems on Figures III.B.14 through III.B.17. The auxiliary power requirements at the design conditions and the corresponding annual energy consumption for system parasitics are given for each water/steam system on Tables III.B.7 (without storage) and III.B.8 (with storage).

5. Technology Readiness

The majority of large, baseload and intermediate load electric generation plants operate with steam cycles. The major difference between plants is the source of energy (different fuels) used to produce the steam. In a simplistic sense, a water/steam solar system is but another energy source with the collector field and receiver replacing the conventional fossil-fuel fired boiler. All other components in the water/steam solar system, with the exception of the thermal storage system (where applicable), are essentially identical to those in a conventional steam plant. These components represent little or no risk associated with their design, construction, and operation. The receiver is the only hardware item which requires further validation of the design. Also, because of the transient nature of solar energy, there is some operational complexity due to the close coupling of receiver outflow and turbine inflow. The use of storage also adds a degree of control complexity associated with use of derated steam in an admission turbine.

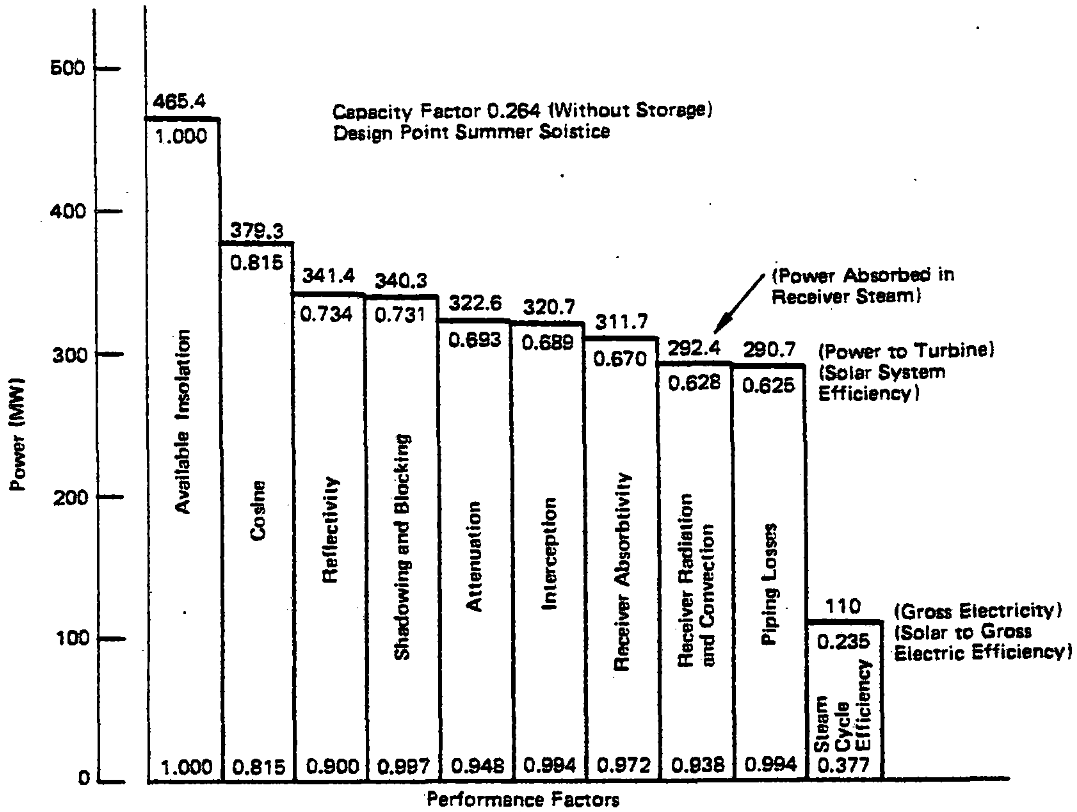


Figure III.B.14. Baseline Water/Steam System Performance

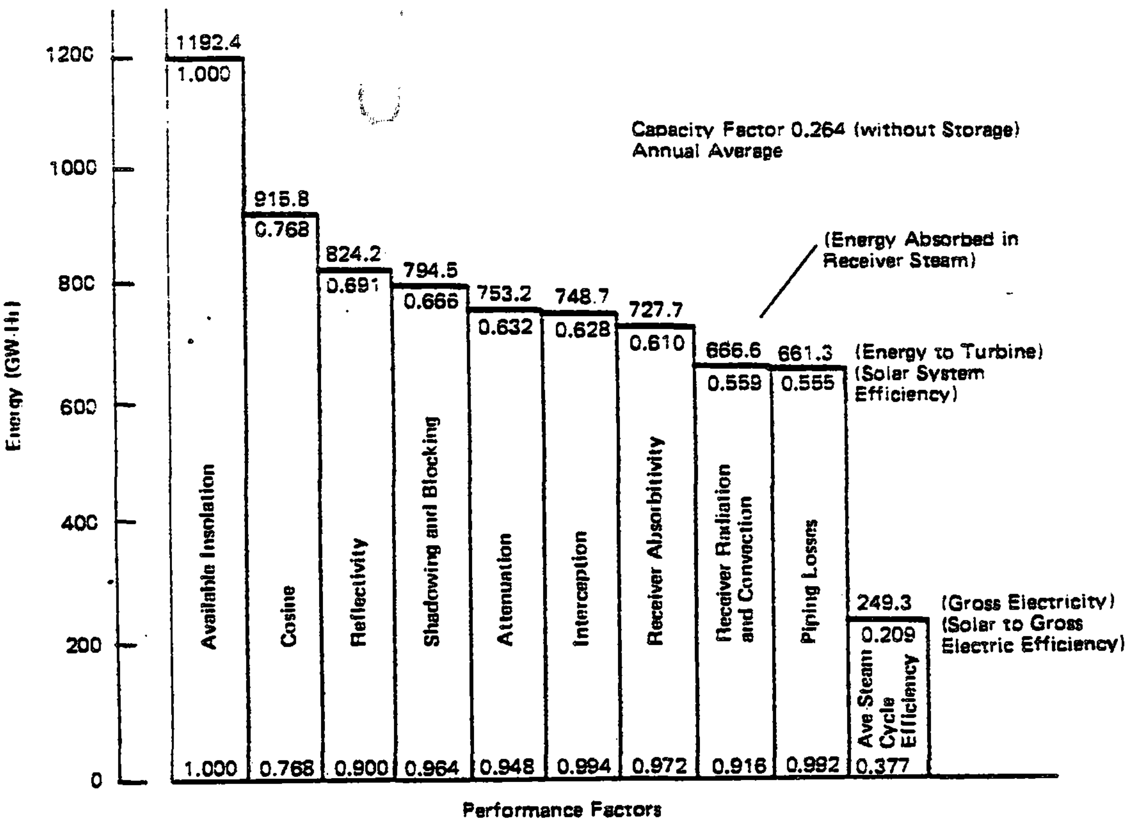


Figure III.B.15. Baseline Water/Steam System Performance

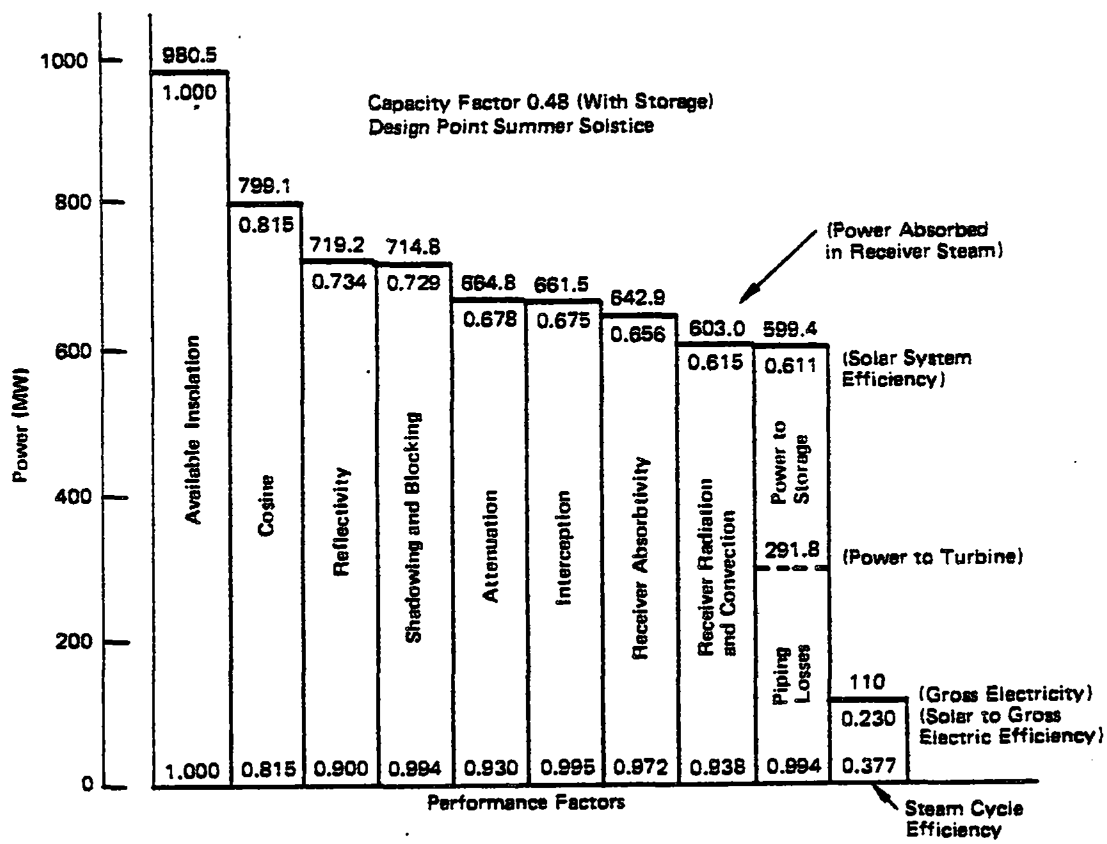


Figure III.B.16. Baseline Water/Steam System Performance

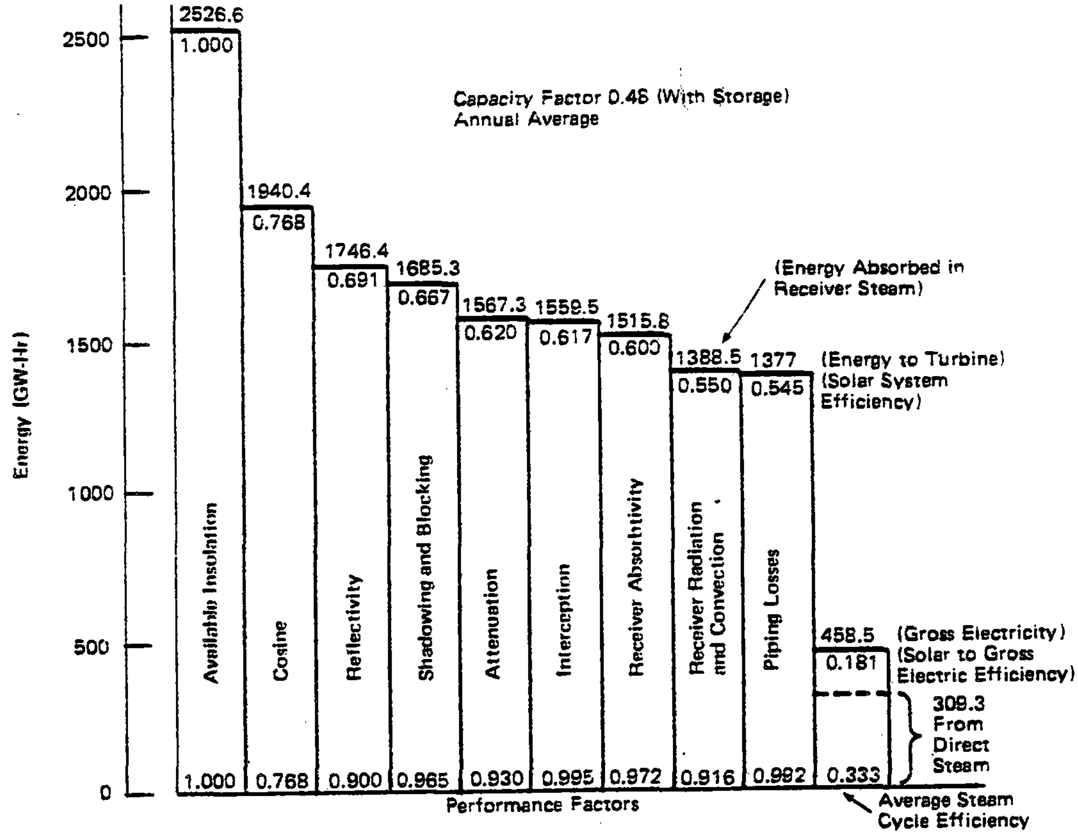


Figure III.B.17. Baseline Water/Steam System Performance

Several government and industry studies and test programs have been directed toward this technology development over the past several years. During the preliminary design of the Barstow Solar I plant, several receiver tube test panels were constructed and tested. Initial tests of these panels were made using artificially generated radiant energy (heat lamps). Both a Rockwell (the Solar I receiver manufacturer) panel and a Foster Wheeler/Martin receiver were tested this way. These tests verified the feasibility of producing superheated steam in tubular receiver panels heated with radiant energy. Peak fluxes up to 1 MW/m^2 were achieved with outlet steam temperatures approaching 1000°F. One unit (FW/MMC-1 MW_t) was installed at the solar test facility at Odeillo, France, where it was tested using concentrated solar energy as a heat source.

A subsequent phase of panel testing was accomplished using a full-size panel from the Barstow Solar I project installed at CRTF. These tests, conducted during February 1979 to March 1980, provided full-scale demonstration of a once-through to superheat receiver design. The test objective of operating at the Solar I peak flux requirement of 0.3 MW/m^2 was easily met and flux levels in excess of 0.4 MW/m^2 were experienced without difficulty.

At the time of this report, the world's largest (10 MWe) solar powered electrical generating plant (Solar 1) is virtually completed and is undergoing final checkout prior to beginning rated operation in the near future. The successful testing and operation of this facility provides a quantum step in the verification of the solar thermal electric generation in general and solar water/steam systems specifically, with a corresponding improvement in technical readiness of solar systems.

TABLE III.B.7
WATER/STEAM SYSTEM AUXILIARY POWER REQUIREMENTS
WITH NO STORAGE - CAPACITY FACTOR 0.264

	Direct Operation (kW_e)	Storage Operation (kW_e)	Shut Down (kW_e)	Annual Auxiliary Energy (GWhr)
Collector	531	N/A		2.31
Receiver				
Feed Pumps (Variable)	3038			6.67
Thermal Storage & Transport				
Thermal Storage Drain Pumps	0			
Circulating Pumps	0			
Master Control	50		30	0.33
Steam Cycle				
Variable Load*	63			0.20
Cooling Tower Fans	292			0.92
Circulating Water Pumps	477			1.50
Heating/Air Conditioning	440		300	3.07
Misc. Fixed Load	320		260	2.47
Totals	5211	0	560	17.47

*Feedwater and Condensate Pumps

Key areas to be validated in the Solar I operation are integrated plant control (including receiver/turbine control interaction), for water/steam systems, in particular, and receiver panel operational life in the solar thermal cycling environment.

Receiver panel operational life remains to be validated in the real environment, although analyses and panel tests place high confidence that the 30-year objectives can be realized. Unique residual concerns applicable to a water/steam system for this plant are the extrapolation to higher receiver flux and modification of panel tube supports to accommodate the screened tube concept. Extrapolation of results to a larger scale plant is a concern common for all central receiver concepts, but no unique problems are anticipated that would not apply also for other technologies.

TABLE III.B.8
WATER/STEAM SYSTEM AUXILIARY POWER REQUIREMENTS
WITH STORAGE - CAPACITY FACTOR 0.480

	Direct Operation	Storage Operation	Shut Down	Annual Auxiliary Energy (GWhr)
Collector	1120			4.90
Receiver				
Feed Pumps (Variable)	3490			8.80
Thermal Storage & Transport				
Thermal Storage Drain Pumps	2240			3.50
Circulating Pumps	750	930		2.70
Master Control	50	30	30	0.33
Steam Cycle				
Variable Load*	130	620		1.41
Cooling Tower Fans	600	600		4.75
Circulating Water Pumps	980	980		4.67
Heating/Air Conditioning	440	300	300	3.07
Misc. Fixed Load	320	260	260	2.47
Totals	10,120	3720	590	36.60

*Feedwater and Condensate Pumps

III-C. MOLTEN SALT SYSTEM DEFINITION

1. Functional Description and Key Attributes

The system, shown schematically on Figure III.C.1, consists of a tower-mounted molten-salt-cooled receiver heated by a field of MDC Model 50 heliostats (DOE/Sandia second generation). The molten salt used in these systems is typically a mixture of 60% (weight) sodium nitrate and 40% potassium nitrate. Molten salt heated in the receiver is routed through a molten salt/water steam generator, through the thermal storage system. The steam is then used in a conventional manner to power a reheat turbine generator set to produce electricity. The cooled salt is returned through the thermal storage system 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). The use of a high temperature storable fluid, such as molten salt, in the receiver and

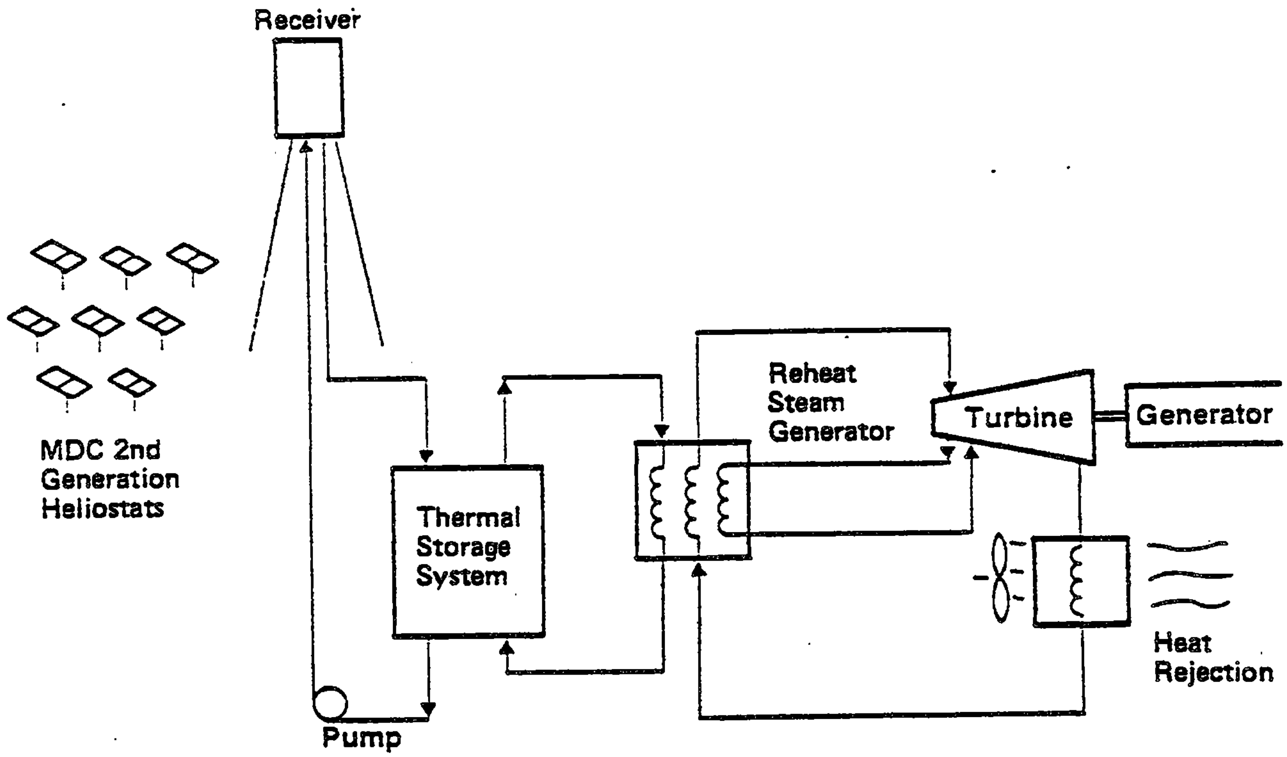


Figure III C-1. Solar Central Receiver System — Molten Salt

thermal transport loop not only decouples steam generation from solar transients, but permits a high efficiency reheat steam cycle at temperatures and pressures standard to utility practice.

The molten salts suitable for use as a heat transfer fluid in a solar system are of the same family of molten salts used in commercial heat-treating and industrial process plants. Extensive operational experience has been accumulated with these salt mixtures over the last 20-30 years. The exact composition of the molten salt fuild is balanced between operating temperature requirements of the process and cost of the mixture. Usual mixtures will provide a freeze point in the 430-480°F range. With the addition of some sodium nitrite, the freezing point can be depressed even further, but mixtures with lower freeze points have somewhat less compositional stability at operating temperature of more than 1000°F, and are more costly. The molten salts are nonexplosive, nonflammable and nontoxic, and when properly protected from the environment, are compositionally stable over an extended period of time. These salts have a low vapor pressure at high temperature and do not react with water/steam; hence, no unusual safety hazard is encountered, as with the reacting of liquid sodium with water. The low hazard characteristics of this fluid permits the design of the solar receiver, storage tanks and steam generator to be made to less stringent ASME codes and in some cases the use of uncoded equipment would be legal.

The low safety hazard, low cost and ready availability of the molten salt make this fluid most suitable for use with solar central receivers. Hence, these fluids have been selected by the DOE for continued extensive development testing at the CRTF facility in Albuquerque, New Mexico.

2. Options for Trade Studies

Two different receiver configurations have been selected for continued development under the DOE/Sandia central receiver program. These are a four-sided "quad" cavity receiver and a partial-cavity "omega" receiver. The arrangement of these two receivers are shown on Figure III.C.2. The "quad" configuration is a basic design of a cavity type receiver suitable for use with a 360° surround collector field. The "quad" arrangement is essentially four separate cavity receivers installed in a single housing and oriented at 90° intervals. The common receiver walls at the intersections are heated on both sides. The "omega" partial-cavity receiver is designed for use with a north-field collector layout.

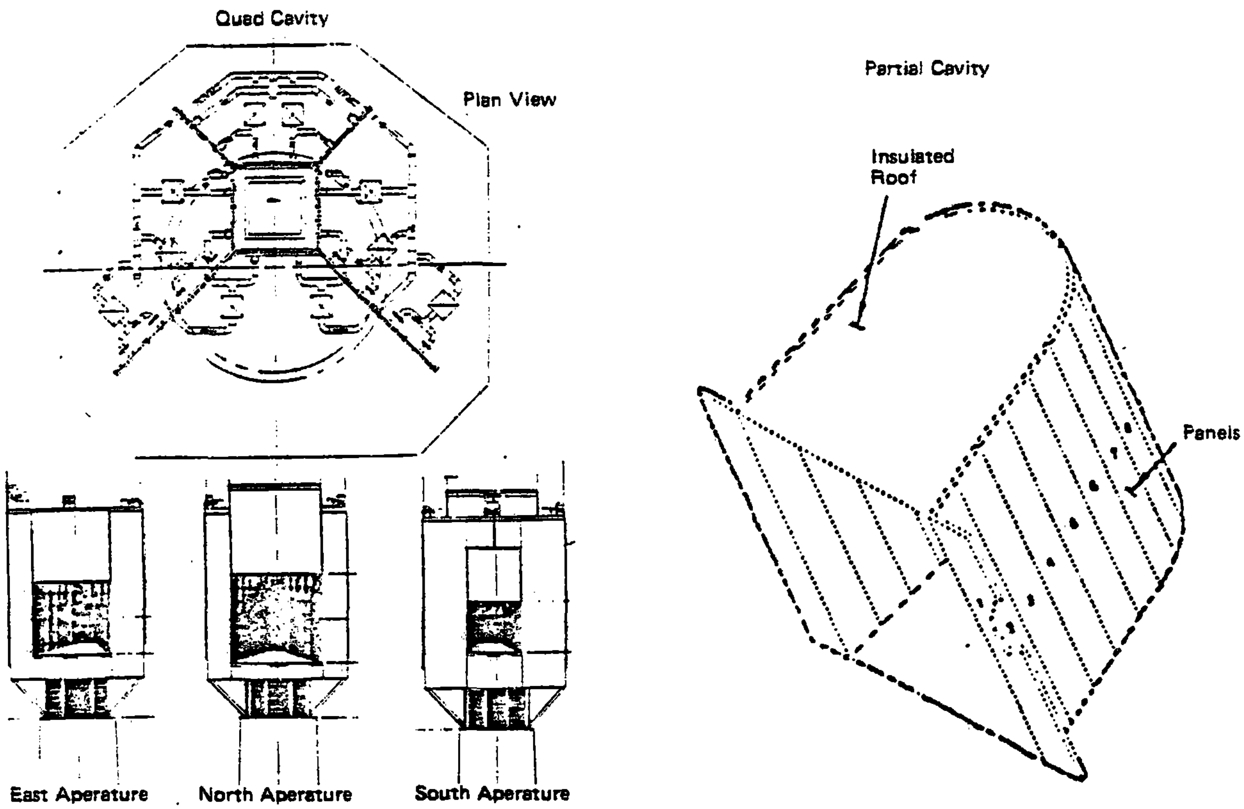


Figure III.C.2. Candidate Molten Salt Receivers

These two configuration approaches have been defined in previous studies of central receiver repowered utility plants. The "omega" partial-cavity receiver, north field, configuration has been developed by MDAC for use on the Sierra Pacific Power Company Ft. Churchill Unit No. 1 near Reno, Nevada (Reference III.C.1). The "quad" cavity receiver surround field was considered by Martin Marietta for the Arizona Power Company's Saguaro Unit No. 1 near Tucson, Arizona (Reference III.C.2). In general, the two systems optimize for different latitudes. The north-field design gets progressively better the farther north the plant is located (in the northern hemisphere), while the surround field becomes better farther south. Therefore, it was decided to trade off these configurations for the near Barstow, California location of this project.

A second trade study was conducted to select the number of collector field modules which should be used in the final design. This addresses issues such as performance, cost, hardware physical size limitations (fabrication and transportation) and available land geometry constraints. Therefore, the study considered a single large collector field as well as two modules (two half-size fields) and three modules (three third-size fields). A sample two-module field arrangement is shown on Figure III.C.3.

Economics, performance and relative technical risk were evaluated for these alternatives to select the system for use in the final plant concept selection.

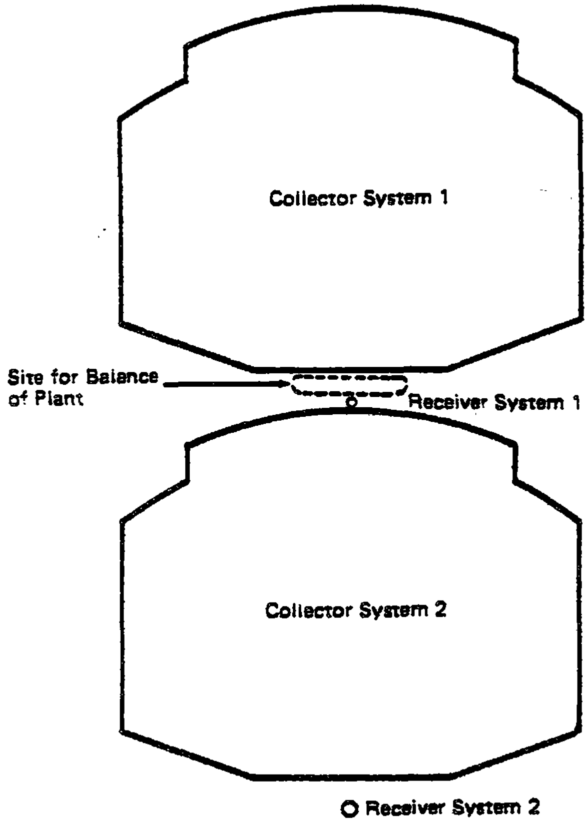


Figure III.C.3. Plot Plan – Molten Salt System, North/South Arrangement

3. Trade Studies

a. Key Inputs, Assumptions and Results

The insolation model used in all the trade studies is the SOLINS Barstow model (see Section V-A.).

The trade studies were based on the MDC Model 50 heliostat characteristics (see Section IV-C).

Receiver/Collector Field Configuration

The study was conducted for plant sizes ranging from 160 MW_t to 700 MW_t. Receiver irradiated area was scaled linearly with power and the quad receiver cavity power ratios were held constant. Receiver costs were derived by Foster Wheeler to provide completely comparative breakdowns from reported values in the previously referenced studies of these concepts. Receiver efficiency factors were scaled linearly with power from the reported values. The collector field size, shape and performance are based on SNLL DELSOL collector field computer code optimization runs for the system.

A typical result is shown on Figure III.C.4 at a design-point power rating of about 330 MW_t. As in this case, the results for the entire range of sizes studied were essentially equal costs for all annual energy outputs at the Barstow latitude. The slightly lower heliostat and receiver cost for the partial-cavity receiver in this case is more than offset by the higher tower and associated piping and pumping costs. In any event, the differences are well within the margin for error in the estimates.

In this study, both configurations used a slip form concrete tower. Data to compare a free standing steel and concrete tower, as shown on Figure III.C.5, was generated by evaluating both in the computer runs for the north-field configurations. These results are shown on Figure III.C.6. A significant cost advantage exists for the concrete tower in large plant sizes such as this (height of about 200 meters).

Collector Field Modularization

The study was conducted for the partial-cavity, north-field configuration using the same inputs and assumptions as the previously discussed trade study.

Plants of one full-size, two half-size, and three third-size collector field with a 0.6 capacity factor were evaluated. Specific land geometry

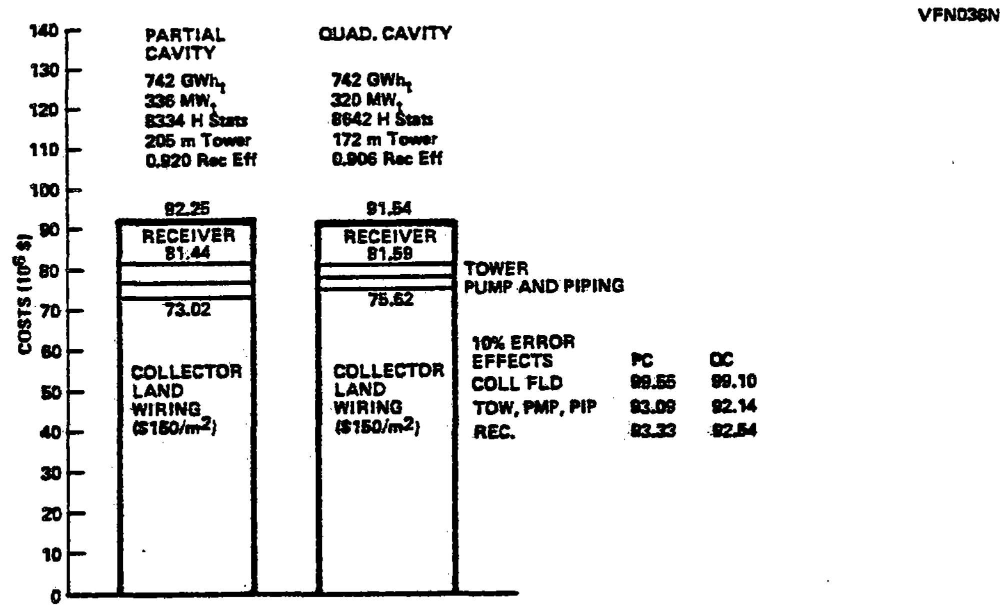


Figure III.C.4. Molten Salt Receiver Cost Breakdown Comparison

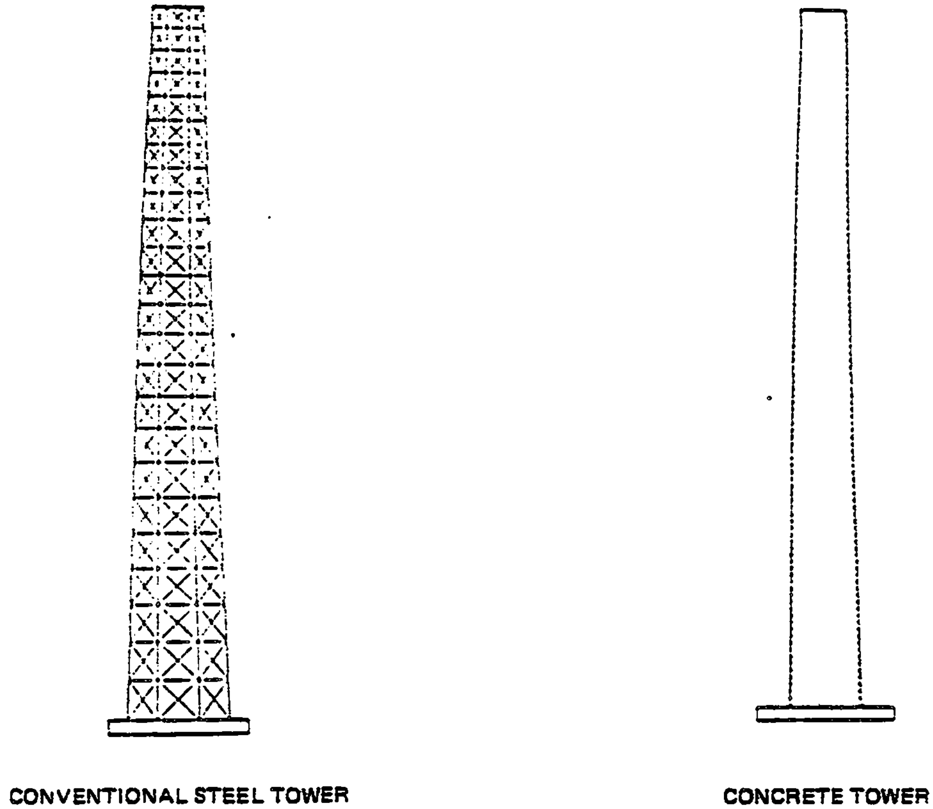


Figure III.C.5. Candidate Tower Concepts

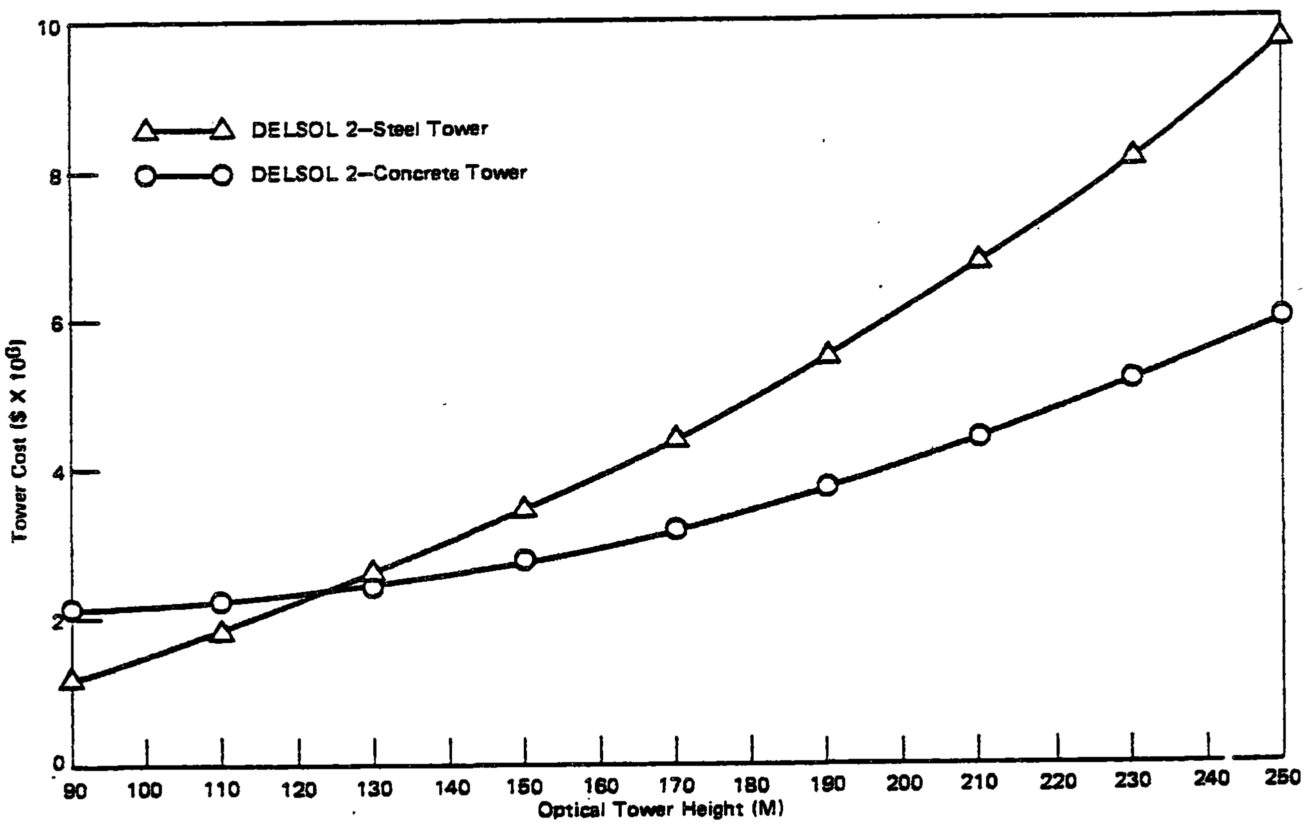


Figure III.C.6. Tower Cost Models

constraints were not included in the tradeoff. Comparison of the capital costs for the three configurations is shown on Figure III.C.7. The following observations were made:

- o The cost difference is not significant for one, two, or three modules.

- o The physical size of the receiver for the single field configuration could result in additional complications in fabrication, shipping, and operation. For practical considerations, receiver panel length (approximately 85 feet) for the two-module size plant is more in line with shipping constraints and less divergent from experience in fabrication and structural support for thin wall tube panels.

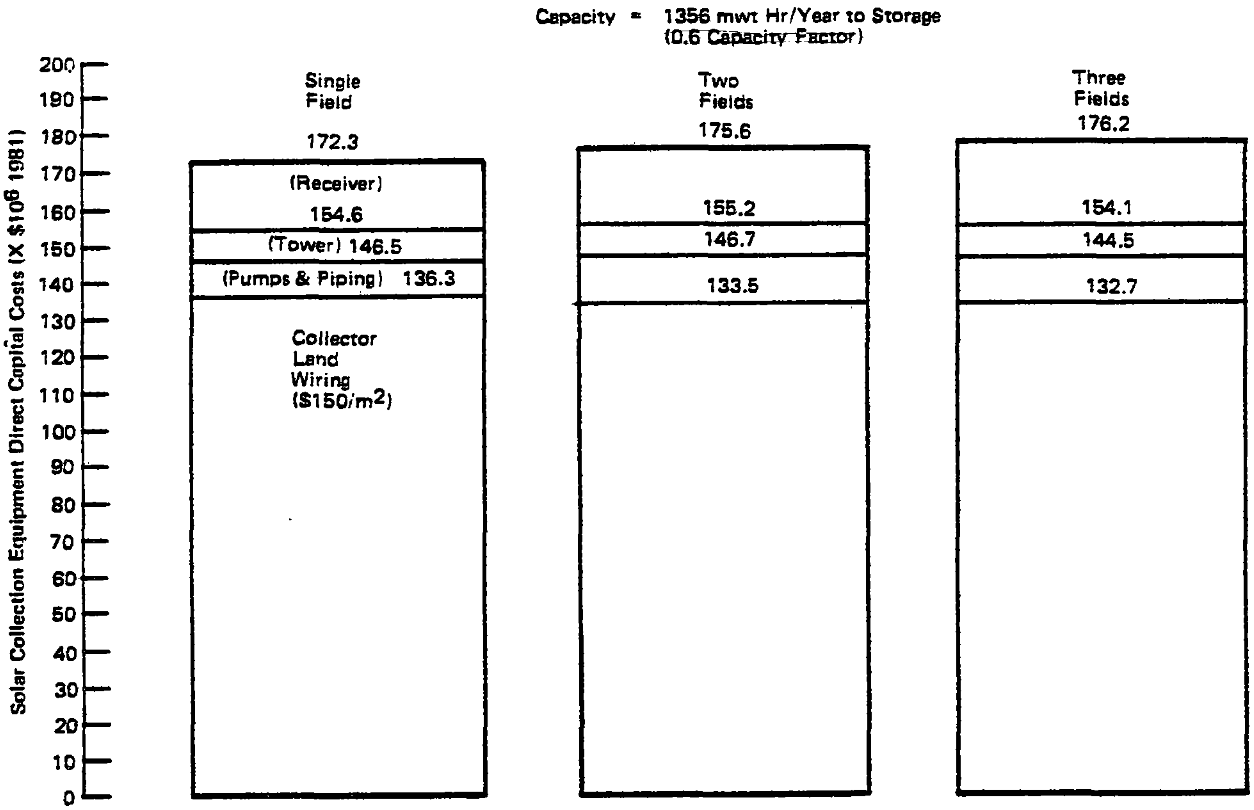


Figure III.C.7. Molten Salt Modularity

b. Risk Considerations

Consideration of technical risk applies primarily to the receiver selection. The partial-cavity receiver is strongly favored at this time because it has tube-panels supported and heated from one side, as has been demonstrated, while the quad cavity receiver has several significantly different design and operational difficulties, including two-sided heating of panels. The one-sided heating is similar to a molten salt receiver demonstration test in a Sandia CRTF experiment. The partial-cavity receiver design builds on this successful experience and makes improvements to obviate the minor problems experienced in the demonstration. On the other hand, the quad cavity introduces a new set of significant issues, as follows:

- o Structural - Difficult, untried design is required to provide lateral support for the panels heated on both sides and subject to wind loading.
- o Performance - Increased tube surface area and total aperture area is likely to yield higher losses.
- o Cavity enclosure - Four doors are required for emergency and overnight protection instead of one.
- o Operation and Control
  - Two-sided panel heating is subject to more complex cloud transient impact on flow control to maintain wall and coolant temperature.
  - Difficult, untried design required to provide feed-forward control sensors that can survive two-side heated panels.
  - Difficulty in pre-heating panels for startup.

c. Conclusions

The selected configuration for the baseline molten salt system is a two-module configuration with a partial-cavity receiver on a slip-form concrete tower in each north-field. There is no significant cost consideration in the selection, but technical risk, ease of fabrication, handling and shipping for the receiver and flexibility to meet potential available land geometry constraints for the selected site supports this choice.

4. Candidate Molten Salt System Description

a. General

The following molten salt system description was used for the alternate system concept evaluations only. The system is similar but not identical to the system adopted in this study for Solar 100 (described in Section IV).

The baseline molten salt system plant operates at a capacity factor of 0.6 and includes two collector fields, each with a tower and receiver (each collector field is located north of its tower) ~~and one set of thermal storage~~ tanks, steam generator, turbine generator and balance of plant, all located ~~at the south tower~~.

b. Collector System

The collector system is divided into two independent systems occupying a total of about 909 acres. The selected north-south orientation is shown on Figure III.C.3. Each field contains 7,620 MDC Model 50 heliostats with approximately $57 m^2$ each of glass for a total mirror area of $433,000 m^2$ each of glass for a total mirror area of $433,000 m^2$. The heliostats are arranged in a radial-staggered-array concentric to the north of the tower.

c. Receiver System

A receiver system is provided for each collector system. Each receiver system consists of an omega, partial-cavity absorber unit with its support structure, doors, control elements, interconnecting piping and a receiver tower.

The receiver tower is a tapered, slip-formed concrete structure which supports the receiver at an optical height of 663 feet. Approximate scale and dimensions for the receiver tower are shown on Figure III.C.8. The receiver support structure attaches to the tower top. Refer to Section IV.D for details of tower construction and features.

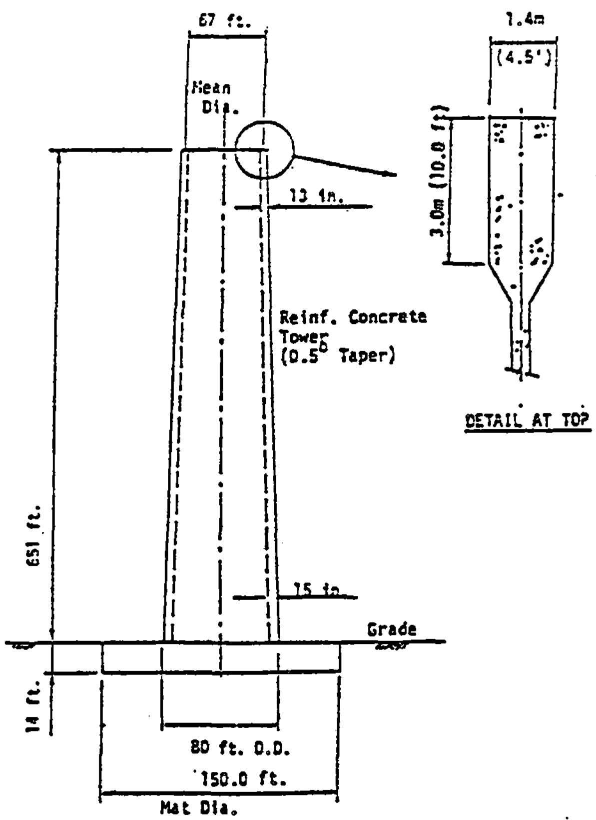


Figure III.C.8. Receiver Tower

The main salt riser and downcomer are supported on the inside of the tower shell and include expansion loops at the appropriate intervals. The downcomer is 12-inch diameter stainless steel and the riser is 16-inch carbon steel (ASTM, A106). Both are insulated with calcium silicate insulation (8 inch on downcomer, 6 inch on riser).

Each receiver is constructed of factory-assembled absorber panels (made of Incoloy 800) and arranged in a partial-cavity configuration. Each panel is complete with strongback, insulation and lagging, instrumental, structural attachment points, piping, and piping attachment points.

The general arrangement and components of the receiver are shown on Figure III.C.9.

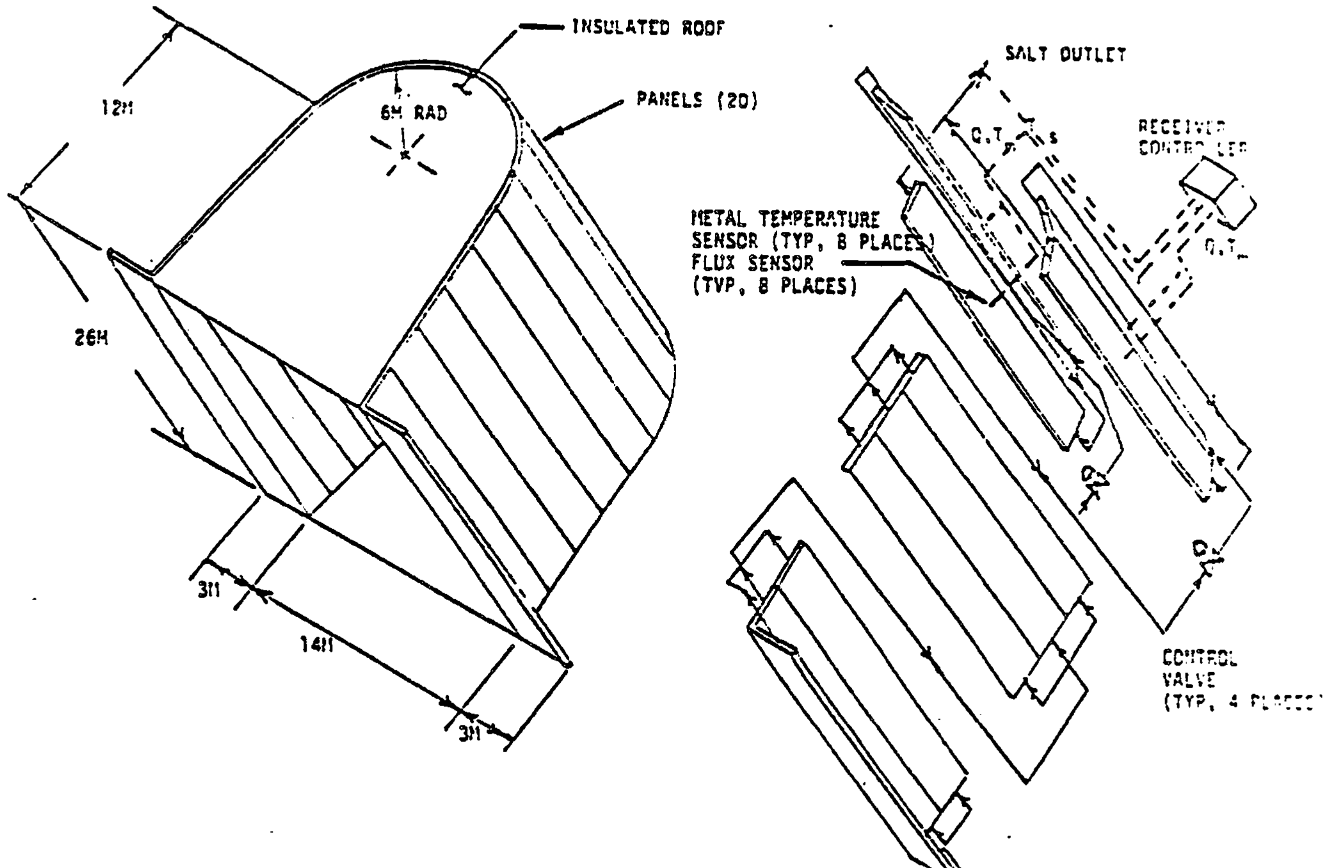


Figure III.C.9. Partial Cavity Receiver

The receiver design point power level (absorbed) is 306 MW_{th}. It is designed to operate at a peak heat flux of less than 0.6 MW/m^2 and metal temperature less than 1200°F with a peak salt film temperature less than 1100°F.

The design point flowrate is 5.63 x 10^6 lb/hr. The minimum flowrate capability is 25% of rated flow. Hot salt flows from the receiver to the hot storage tank except at startup or when the receiver fluid temperature drops below 1000°F. In this case, the fluid is recirculated to the warm storage tank. Each receiver is fitted with doors to close the aperture and limit heat losses during overnight and extended daytime shutdown. The doors counter-balance each other and are weighted to automatically shut if electrical power is lost. The doors have an ablative outer coating to prevent structural damage in the event of a total loss of electrical power to both the receiver and collector.

d. <u>Storage and Transport System</u>

The storage and transport system includes the thermal storage tanks and all piping between the receivers, steam generator, and the tanks, and the associated pumps, valves and control instrumentation.

A Schematic is shown on Figure III.C.10. A drag valve (LCV-I) controls the fluid level in a receiver outlet surge tank. ~~A bypass from the receiver to the warm storage tank permits receiver circulaton during startup and low insolation periods without degrading storage temperature.~~

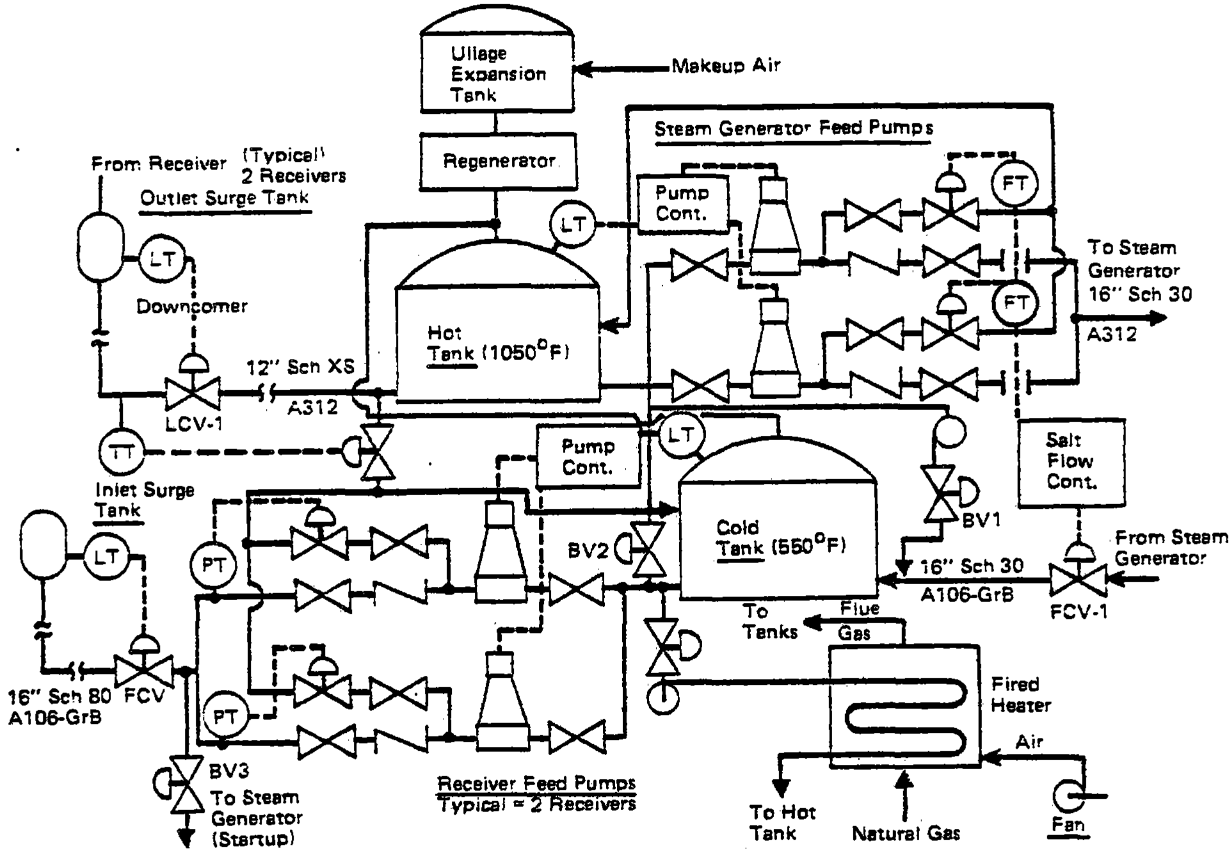


Figure III.C.10. Storage and Transport System Schematic

The hot storage tank accumulates the salt flow from the receivers for use on demand by the steam generator system. ~~An ullage expansion tank and transfer line is used to transfer dry air cover gas between the hot and warm storage tanks, allowing for temperature changes.~~

Two pumps operating at half capacity each feed salt to the steam generator. Each multistage, cantilever pump is capable of delivering 2950 gpm at 250 psi (300') head. Each pump operates at 75% efficiency and requires 380 kW when running at full capacity.

Bypass dump lines to the hot tank provide pump flow control. A bypass around the steam generator through BVI (Figure III.C.10) permits salt circulation to the ~~warm tank~~ to maintain warm tank temperature. Another bypass line through BV2 is provided to the warm tank outlet for blending with salt from the hot tank during startup and overnight temperature maintenance of the receiver.

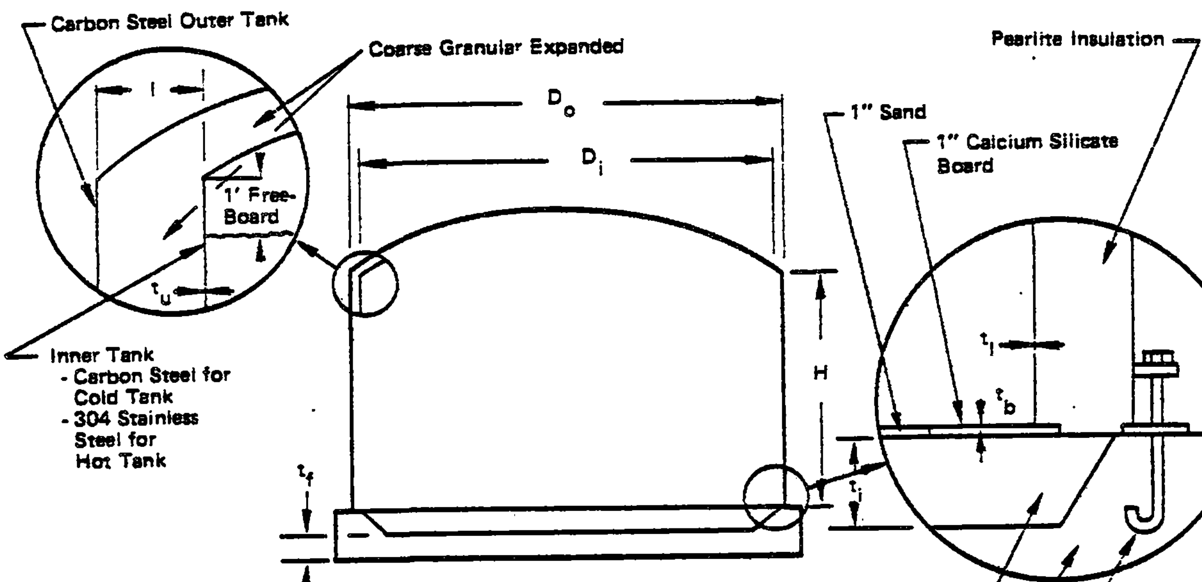
Salt returns from the steam generator to the ~~warm tank~~ where it accumulates for on-demand circulation to the receiver. A flow control valve

(FCV-1) regulates total salt flow. This valve is analogous to the burner control in a fossil fired unit. Opening FCV-1 increases the heating rate and steam production rate in the evaporator. A line from the warm tank circulates salt to a natural gas-fired heater to aid initial system charging, startup and temperature maintenance during long-term shutdown. Salt heated in this manner flows to the hot storage tank.

Two pumps operating at half capacity each feed salt to each of the receivers. Each multistage, cantilever pump is capable of delivering 3250 gpm at a 900 psi (1100') head. Each pump operates at 75% efficiency and requires 1403 kW when running at full capacity. Bypass dump lines to the warm tank provide pump control. A bypass line through BV3 permits gradual temperature increase during steam generator startup. A flow control valve regulates fluid level in a receiver inlet surge tank.

The drag valve is a 12-inch angle valve which is preferred for its self-draining capability.

The hot and warm tanks are illustrated on Figure III.C.11 and are similar in design. The tanks have an 0.6 height-to-diameter ratio to resist overturning during earthquake. ~~The hot tank is made of 304 stainless steel~~, and the warm tank of carbon steel. The wall thickness of each is stepped to reflect the hydrostatic pressure.



Dimensions	Hot Tank	Cold Tank
D_o	84'	79'6"
D_i	80'	77'
t_u	0.306"	0.398"
t_l	1.45"	1.5"
t_i	4'	2'
t_f	5'	5'
t_b	0.25"	0.25"
l	24"	24"
H	50'	50'

Figure III.C.11. Thermal Storage Tanks

The tank foundations are an insulating-concrete over lightweight-concrete and are designed for stability in a seismic environment. The inner tank shell is not restrained by the anchor bolts; hence, it is relatively free of thermal stresses. An outer shell serves as lagging and provides attachment to the anchor bolts. Expanded perlite insulation absorbs compressive strains resulting from expansion of the inner tank shell.

e. Steam Generation System

The steam generator system includes the heat exchangers (preheater, evaporator with integral steam drum, superheater, and reheater) and the interconnecting piping, valves, and control instrumentation.

A schematic of the sytem is shown on Figure III.C.12. A mixing valve blends the hot and warm salt for gradual warming of the steam generator heat exchangers during startup.

Molten salt flow follows three paths. One path flows through the superheater. The valve, FCV-3, on the superheater outlet is used primarily to fine tune superheater pressure drop and regulate superheater steam outlet temperature. The single pass superheater does not provide any convenient entry points for spray attemporation of outlet temperature. ~~The nominal salt inlet conditions are 160 psig, 1050°F.~~

Another path flows through the reheater. The valve FCV-2, is the primary point of regulation of salt flow between the superheater and the reheater.

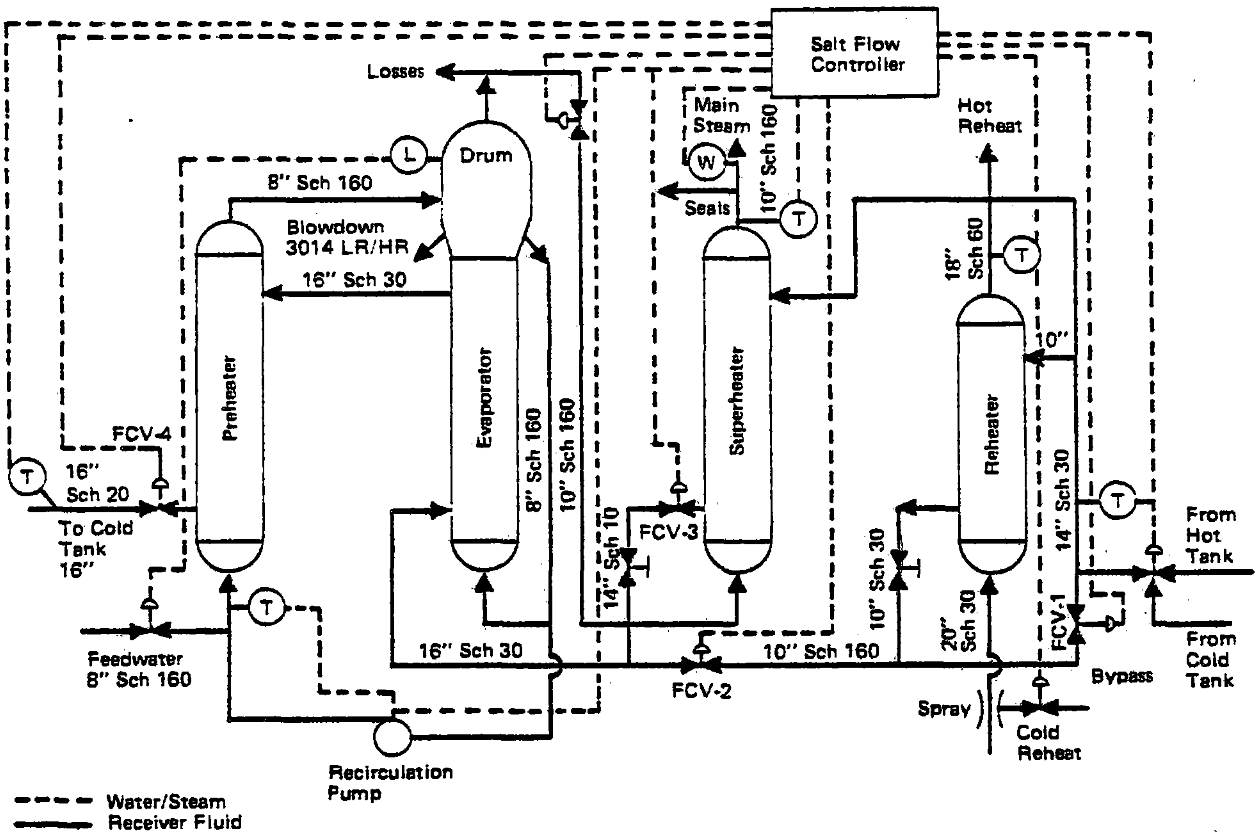


Figure III.C.12. Steam Generator System Schematic

The hot reheat steam temperature is controlled primarily by regulating salt flow. Secondary control is provided by spray attemporator at the inlet to the reheater.

The third path is a bypass line around both the reheater and superheater. This path merges with the salt outlet flow from the reheater and superheater. The valve, FCV-4, regulates the amount of bypass flow. FCV-4 will be operated to minimize the amount of attemporation required on the reheater. The valve will be positioned according to total steam flow, with a slow response correction for attemporator flow.

All these flow paths merge, and a single path flows through the evaporator and preheater, in series. The valve, FCV-1, on the preheater outlet, regulates total salt flow. This valve is analogous to the burner control in a fossil fired unit. Opening FCV-1 effectively increases the firing rate and the steam production rate in the evaporator.

All feedwater flows to the preheater and exits to the steam drum of the evaporator. A recirculation pump draws water from the drum to blend with the feedwater and ensure a feedwater inlet temperature safely above the freezing temperature of the salt.

Water flows through the evaporator by natural circulation. Steam from the drum flows through the superheater, and warm reheat steam from the turbine flows through the reheater.

All heat exchangers are vertical, with water/steam flowing upward. ~~Water/steam tubes in the heat exchangers are straight. A bellows on the shell side provides for expansion. The preheater, superheater, and reheater are counterflow and the evaporator is parallel flow.~~

f. EPGS and Balance of Plant

The EPGS and balance of plant for the molten salt system is as described in description of the selected plant, Secton IV.

g. Plant Control System

The plant control system is a computerized system capable of semi-automatic operation. The basic schematic diagram for the control system is shown on Figure III.C.13. The collector control systems for the two modules (north and south fields) are identical. They share a single additional redundant Heliostat Array Controller (HAC) in the main plant control. The main plant control equipment and the collector field HACs are located in the main control building. Heliostat Field Controllers (HFCs) are located on each individual heliostat pedestal. The control and power wiring for each HC, HFC and the leads to the HAC are connected with buried underground cables.

The receiver controls are located in the control building and are connected to the respective equipment with cabling which is carried in cable racks in the plant area and with underground cables in the field areas. The two receiver controls provide identical control of salt flow rate to maintain salt outlet temperature. Combined signals from the two receiver controls are

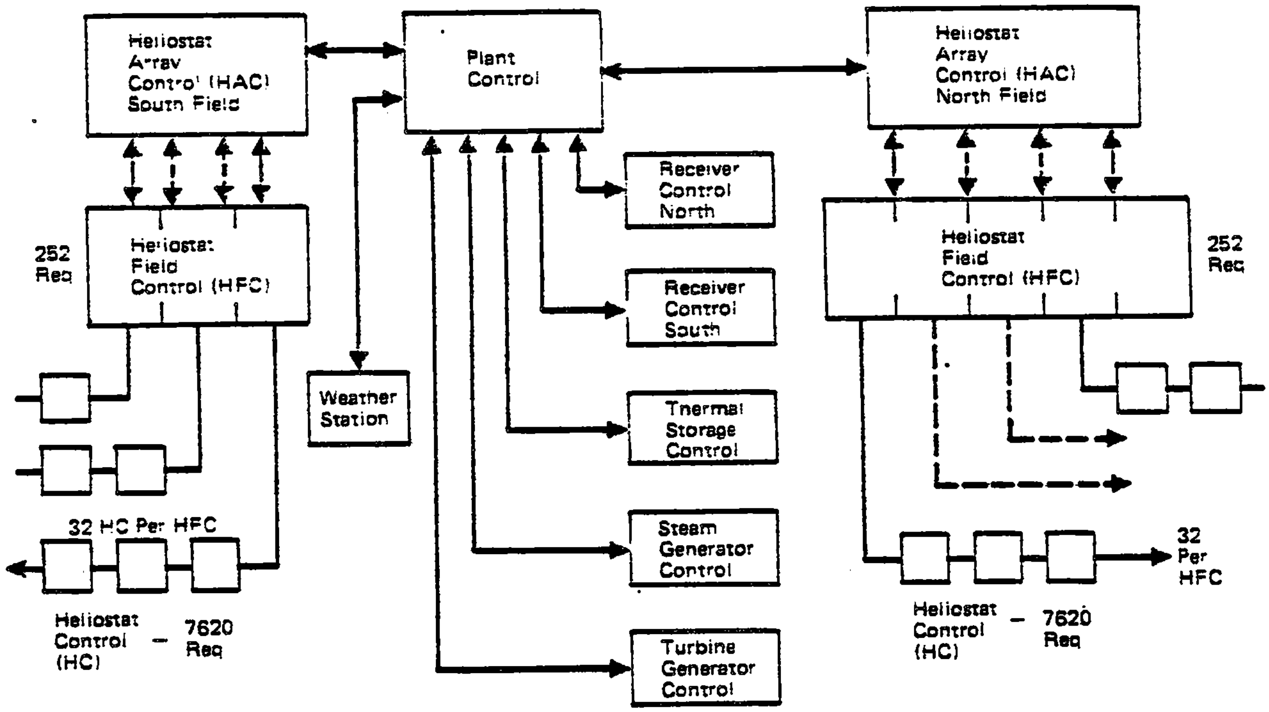


Figure III.C.13. Plant Control System — Molten Salt Configuration

supplied to the thermal storage controller. The thermal storage controller controls the mass flow rate and distribution of molten salt to the receivers. Thermal storage control is located in the control building. The cabling between the thermal storage controller and the thermal storage system is carried on instrument trays in overhead pipe racks.

The steam generator control is located in the control building. This controller controls salt and water flow to the steam generators. The cabling for the steam generator system control is carried on instrument trays in overhead pipe racks. The turbine-generator control controls steam flow through the turbine, excitation and cooling for the generator and interfaces with the grid. The turbine-generator control is located in the control room. The connecting cabling is carried on the instrument trays in overhead pipe racks.

The plant control system is assembled from commercially available minicomputers and microprocessors. The operator's control panel is equipped with color CRT displays and hardline printers. The operational software for the control system is stored on disks.

h. Final Baseline Salt System Sizing Data

The baseline molten salt system component sizes and capacities are summarized on Table III.C.1.

i. Baseline Salt System Costs

The estimated costs of the baseline molten salt system are shown on Table III.C.2. These costs were based on the system as described in the preceding text.

TABLE III.C.1
BASELINE MOLTEN SALT
SYSTEM CHARACTERISTICS

Capacity Factor	0.6
Annual Energy to Steam ($GW_e hr$)	
Land Area	909
Heliostats	15,240
Glass Area m^2	866,400
Tower Height (m)	
Optical	202 662'
Rec ℄	205
Top of Tower	180 590'
Receiver Design Pt. Power MW_t (each)	306
Rec. Geometry H X W (m)	24.6 x 19
Rec. Area (m^2)	470 - aperture
Design Pt. Flow Rate (lb/hr)	5.63×10^6
Cold Salt Pipe (A106GrB)	
Riser (m)	260
Horizontal (m)	1920
Total (m)	2180
Hot Salt Pipe (304H)	
Downcomer (m)	260
Horizontal (m)	1920
Total (m)	2180
Receiver Pump	
Number	4
Size = .75	5 MW_e
Head (ft)	900
Storage Size ($MW_t hr$)	2510
Type	Two Tank

TABLE III.C.2
BASELINE MOLTEN SALT SYSTEM COSTS

0.6 Capacity Factor
(1981 $ Millions)

1.0	Solar Steam Supply System	
	.1 Collector	
	.11 Collector Purchase Price	$127.0
	.12 Collector Erection	21.8
	.2 Major Solar Steam Supply Hardware	34.1
	.3 Solar Process Mechanical Equipment	12
	.4 Solar Electrical	2.0
	.5 Solar Civil and Structural	10.1
	.6 Solar Piping and Instrumentation	~~22.9~~
	.7 Solar Yardwork and Miscellaneous	3.3
2.0	Turbine/Generator	9.1
3.0	Process Mechanical Equipment	9.5
4.0	Electrical	6.2
5.0	Civil and Structural	4.2
6.0	Process Piping and Instrumentation	8.7
7.0	Yardwork and Miscellaneous	.6
8.0	Switchyard	0
70.0	Distributable Construction Costs (CM&SU)	13.9
80.0	Engineering & Home Office	
	-A&E	8.3
	- Solar Integrator	12.0
	Subtotal 305.7	
	Contingency	8.8
	Total $314.5	
	$MWhr_e$ 519,000	
	Dollars per $MWhr_e$	$606

j. Baseline Salt System Performance

The baseline molten salt system performance is shown on Figures III.C.14 and III.C.15. The first figure shows the performance on a waterfall chart for the design point conditions. The second figure shows the corresponding annual average data. The auxiliary power requirements at the design conditions are shown on Table III.C.3. Table III.C.4 gives the annual energy requirements for system parasitics.

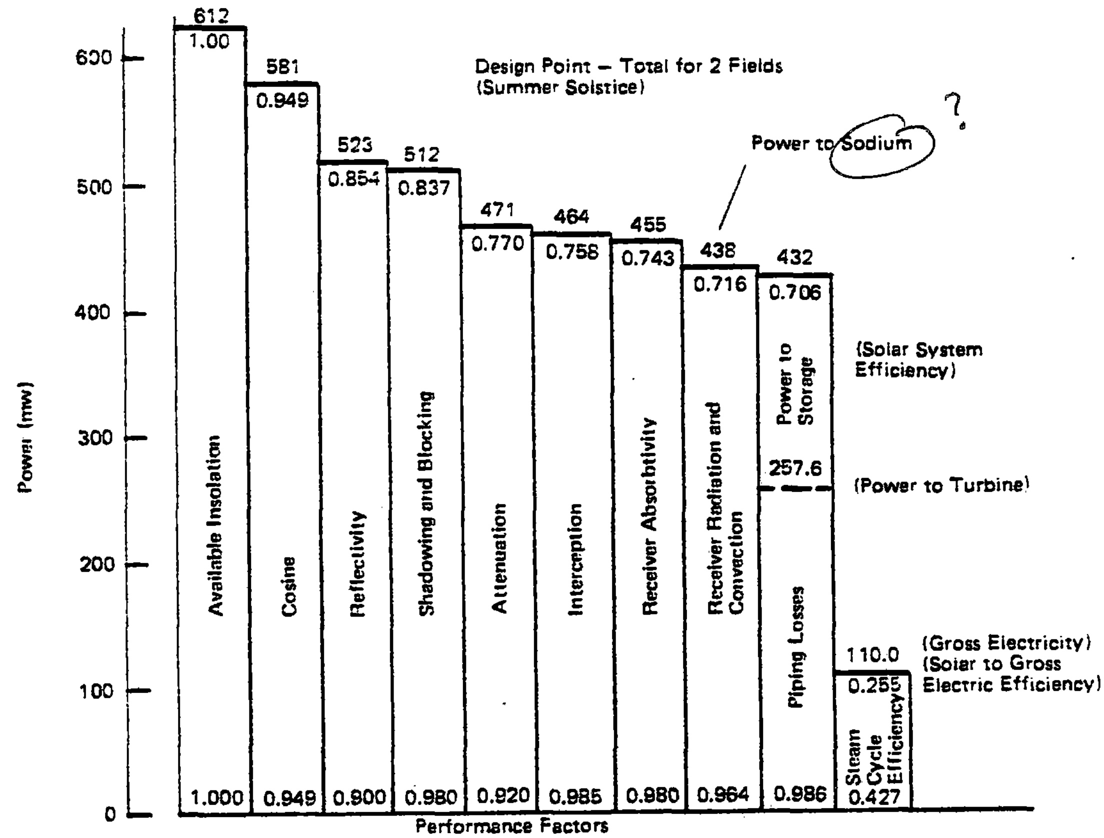


Figure III.C.14. Baseline Molten Salt System Performance

5. Technology Readiness

Molten salt has been used in industry for more than ~~40 years as a metal heat treating solution and a heat transfer medium~~. Extensive design and operational experience has been gained with the material and the equipment used to handle and control it. This industrial experience and the comprehensive DOE technology development programs already completed or underway have been instrumental in advancing molten salt system technology for solar plants. The additional technology data required to build large commercial molten salt systems in the near term are being generated now and are scheduled to be completed within the time frame of Solar 100.

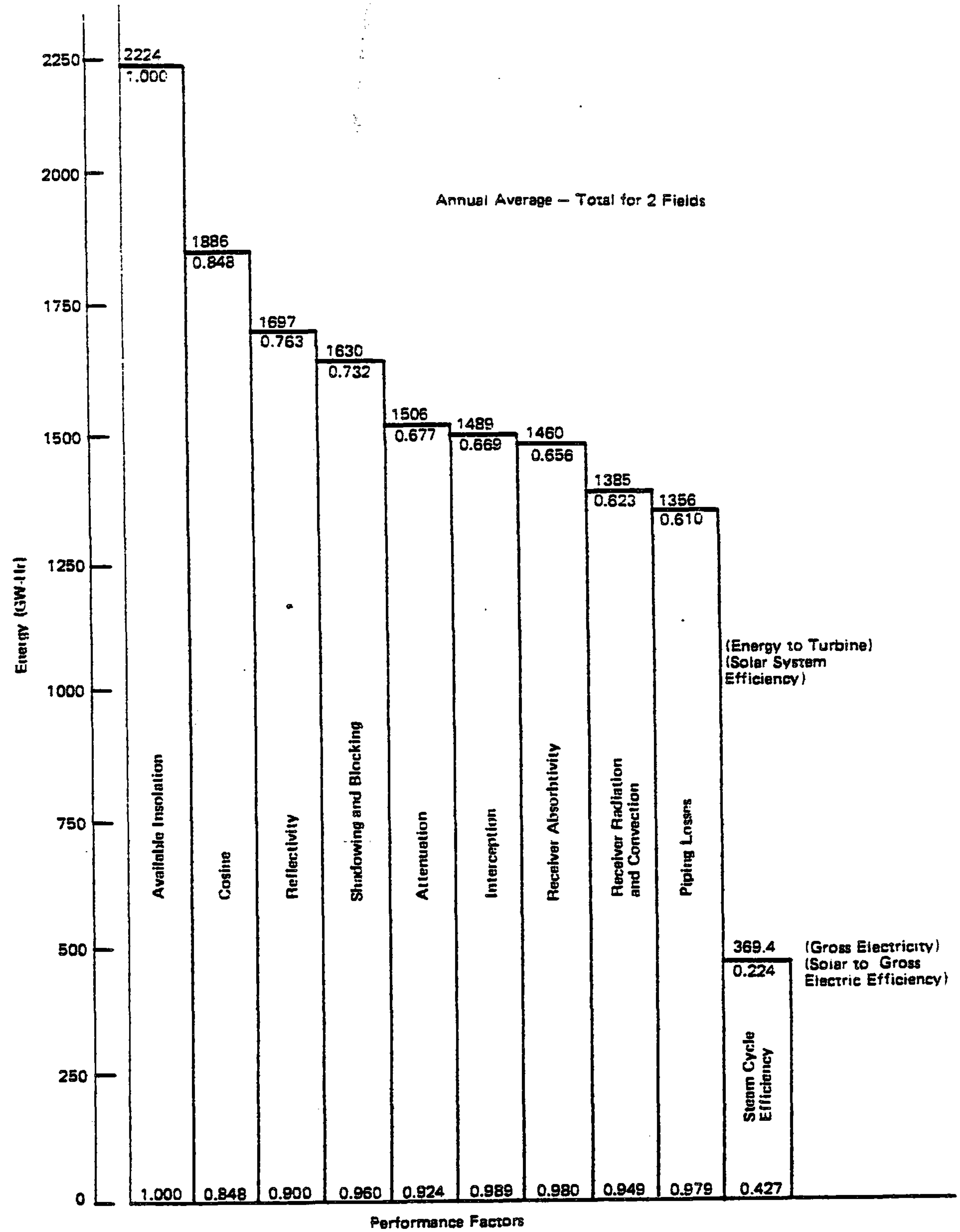


Figure III.C.15. Baseline Molten Salt System Performance

TABLE III.C.3
MOLTEN SALT SYSTEM AUXILIARY POWER REQUIREMENTS
(LOADS IN KW_e)

		0.6 Capacity Factor			
		Collector/Receiver		Steam Cycle	
	PG&E UTIL STUDY	Design Point	Shutdown	Design Point	Shutdown
Collector	672	1100	610	—	—
Receiver					
Feed Pumps	6010	5612	—	—	—
Heat Tracing		—	1000	—	—
Thermal Storage & Transport					
Heat Tracing		—	1000	—	—
Steam Generator	HOT PUMPS				
Circulating Pump	712	914	—	430	—
Master Control		50	30	—	—
Steam Cycle				PG&E 2600	210 → 1350
Variable Load*		—	—	3020	—
Cooling Tower Fans		—	—	550	—
Circulating Water Pumps		—	—	900 1650	— DRY COOL PG&E
Heating/Air Conditioning		—	—	440	300
Misc. Fixed Load		—	—	300	260
Totals		7676	2640	5640	560

*Feedwater and Condensate Pumps

The programs which have been completed or are underway for molten salt include the following:

- o Completed testing at CRTF of a molten salt cavity receiver which achieved the test goals of producing a 1050°F outlet salt temperature, operating at a ~~peak flux of .75 MW_t/m^2~~ (well over the design flux of .63 MW/m^2), operating a receiver in transient insolation conditions, demonstrating overnight shutdown and next day startup, and operating a closed loop molten salt system.

- o Current DOE Subsystem Research Experiments (SRES) which are addressing the following areas in molten salt use and equipment:

  - ~~Large receiver absorber panel design, fabrication and operation.~~

TABLE III.C.4
BASELINE SALT SYSTEM AUXILIARY ENERGY REQUIREMENTS

	ANNUAL ENERGY ($GW_e hr$)
Heliostats	4.31
Receiver Feed Pump	10.99
Steam Generator Pumps	4.80
Master Control	.30
Variable Load*	15.9
Cooling Tower	2.9
Circulating Water Pump	4.73
HVAC	3.3
Miscellaneous**	12.36
Total	59.59 $GW_e hr$

142 GWhr

*Feedwater and Condensate Pumps
**Trace Heating and Miscellaneous Fixed Load

- Steam generator design, fabrication and operation.
- Thermal storage system design, fabrication and operation.
- Continued molten salt properties determination.

o Operation of a small (2.5 kWe) molten salt central receiver electric generating plant in France.

Data available from these programs materially improve technology readiness for design and operation of a near-term large power plant using molten salt.

Key results already available or being generated include significant data on a receiver design and operation, materials compatibility, and molten salt maintenance. These results, in addition to the extensive industrial background with molten salt and related equipment developments for use in liquid sodium service (pumps, valves and steam generators) provide a high level of confidence for technology readiness using this media.

The forthcoming Solar I operation, of course, also applies to a large measure to this plant for solar readiness independent of heat transfer medium considerations. Residual concerns requiring validation for this medium are the extrapolation of results to larger scale (common to all technologies) and extended operating times.

III-D. LIQUID SODIUM SYSTEM DEFINITION

1. Functional Description and Key Attributes

The system, shown schematically on Figure III.D.1, consists of a tower-mounted sodium-cooled receiver heater by a field of MDC Model 50 heliostats (DOE/Sandia second generation). Sodium heated in the receiver is routed through a sodium/water steam generator, through the thermal storage system. 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). The use of a high temperature storable fluid, such as sodium, in the receiver and thermal transport loop not only decouples steam generation from solar transients, but permits a high efficiency turbine reheat steam cycle at temperatures and pressures standard to utility practice.

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 this application. The vapor pressure at 1100°F is only slightly above

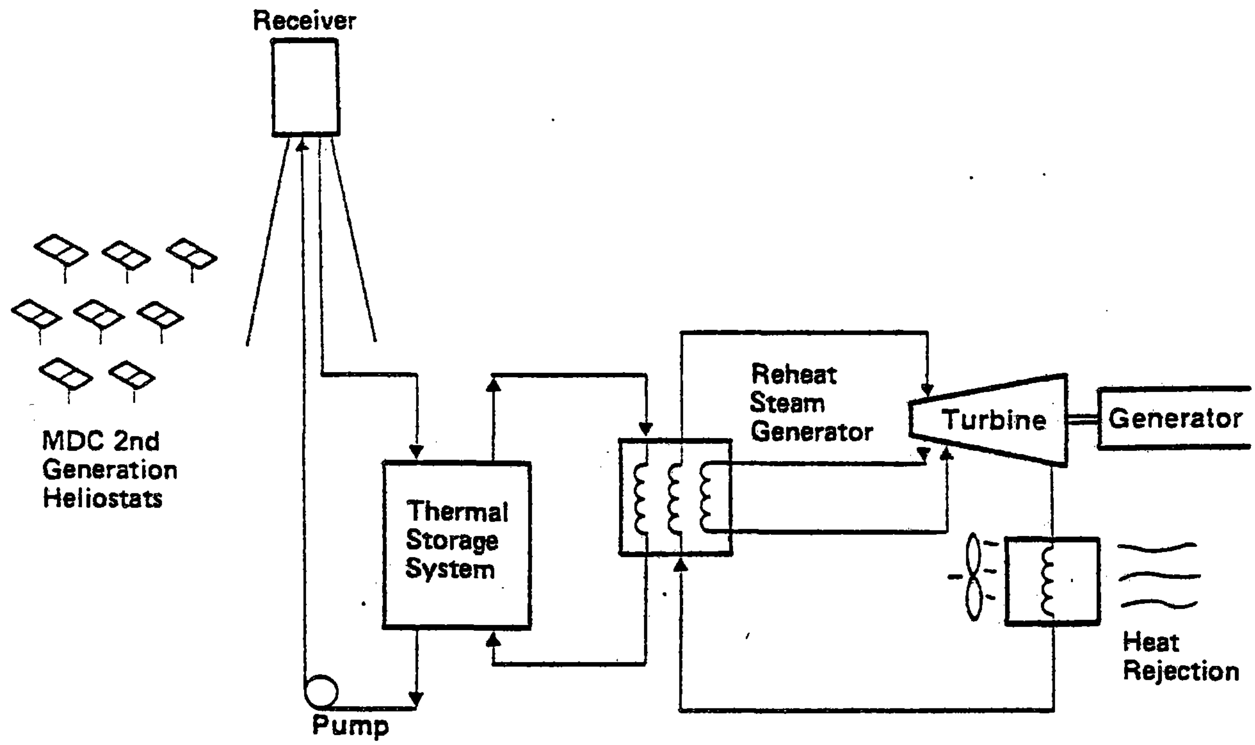


Figure III.D.1. Solar Central Receiver System — Liquid Sodium atmospheric pressure. Major sodium equipment, similar to that required for solar use, has undergone extensive development for use in breeder reactor systems. This includes pumps, valves, lines, and steam generators. Millions of dollars have been spent designing, building and testing these components.

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 in the sodium limits front-to-back receiver tube temperature difference 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 benfits are realized for external cylindrical receivers (externally heated), cavity receivers (internally heated) may be aperture size limited (heliostat spot size) 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 C_p) also drives up the cost of storage tanks.

Also, the highly reactive nature of sodium and water is important in the design of sodium components (primarily steam generator systems) and increases the cost of these components.

2. Options for Trade Studies

The foregoing discussion suggests several alternate configuration concepts for the receiver and thermal storage systems. In addition, receiver tower selection was based on the steel versus concrete tradeoff conducted for the baseline Molten Salt System definition (Section III.C). Economics, performance, and relative development status of these system configuration candidates were evaluated to select the system for use in the final plant concept selection.

The two candidate receivers are shown on Figure III.D.2. The external cylindrical receiver is a derivative of a Rockwell/ESG design (Reference III.D.1), while the partial cavity receiver is based on an MDC designed salt receiver (Reference III.D.2). The partial cavity operates with a collector field located north of the receiver (north field), while the external cylindrical receiver operates with a 360° surround field.

The external receiver design is based on 24 identical tube panels with single pass, parallel flow. Previous studies by Rockwell identified an operating problem for this receiver with an optimized surround field. The preponderance of heliostats are located in the better performing north portion of the field. This north biasing of the field yields an unacceptably high ratio of north to south incident power (order of 5:1) on the receiver, Unreasonably low flow in the south receiver panels is required to maintain the desired outlet temperature under this condition. Therefore, it is necessary to bias heliostats to the south portion of the field to reduce the north/south power ratio. This results in a lower efficiency collector field with more heliostats than an optimized field. This impact was included in the trade study.

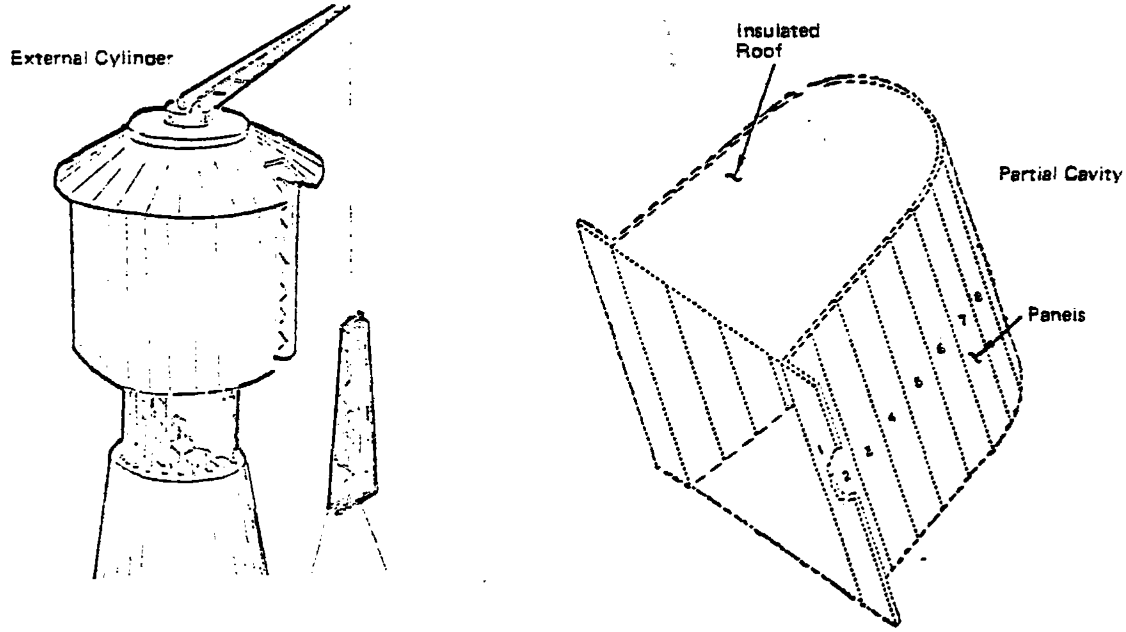


Figure III.D.2. Candidate Sodium Receivers

The sodium thermal storage options considered in the trade studies are shown schematically on Figure III.D.3. The two-tank system consists of two nearly equal-volume insulated steel storage tanks and appropriate plumbing to allow the alternate filling and draining of the tanks as the system operates. Hot (1100°F) liquid sodium flows from the receiver into the hot tank, from where it flows on demand through the steam generator to the warm (550°F) tank (after giving up heat to generate steam). The cold tank serves as a supply of sodium for the receiver during receiver operation. To provide the necessary operational flexibility, both tanks must be large enough to hold the entire sodium inventory. The amount of sodium available with any significant storage capacity is inherently adequate to buffer the steam generator from receiver transients. Low specific heat and high cost of sodium make this sytem costly at high storage capacities.

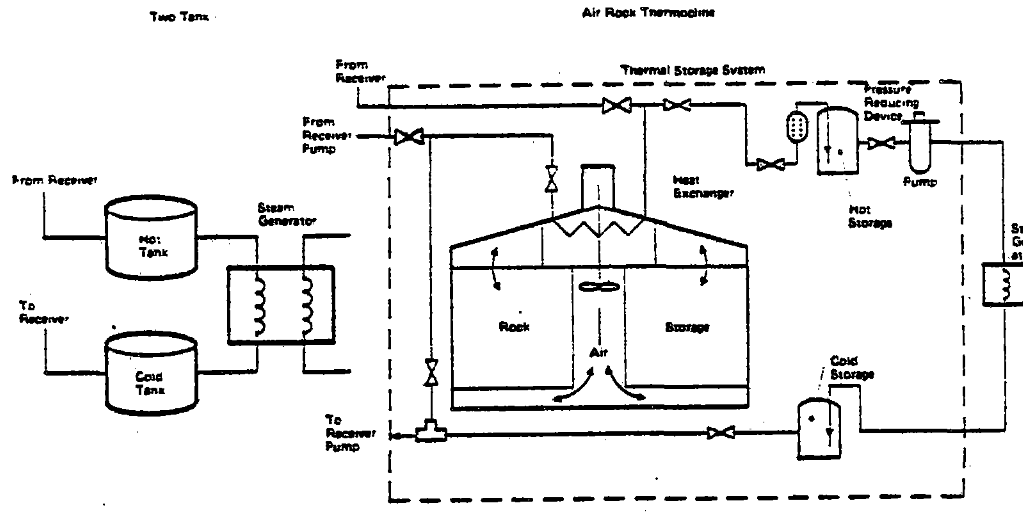


Figure III.D.3. Candidate Sodium Storage Systems

The alternate storage concept (air-rock thermocline) uses rock as a low-cost storage media. The thermocline rock bed is alternately heated and cooled by circulating air through the rock bed and a two-way sodium heat exchanger located above the rock bed. Because the heat is stored in rock, the sodium inventory is reduced from large storage tank quantities to small (order of 15 minutes operating time) hot and warm buffer tank quantities . An additional advantage of this concept is that the sodium operates in a closed loop, allowing recovery of the sodium static head in the downcomer, thus reducing the receiver pump head requirement. On the other hand, the cost of large pressurized storage tanks precludes this advantage for the two-tank system. The temperature differential required to transfer heat to and from air-rock storage reduces the sodium temperature entering the steam generator compared to that for the two-tank system. This involves trade-offs among steam generation size, electrical generation efficiency and storage size.

3. Trade Studies

a. Key Inputs, Assumptions and Results

The insolation model used in all the trade studies is the SOLINS Barstow model (see Section V-A.).

All trade studies were based on the MDC Model 50 heliostat characteristics (see Section IV-C).

A slipform concrete tower was selected for the sodium system as a result of cost trades done for the baseline salt system, which is discussed in Section III-C.

Receiver

Where necessary, receiver area was scaled directly with design-point power. Performance estimates for the external receiver were based on published performance data for the Rockwell hybrid system receiver. The value used for absorptivity is 0.95. The radiation and convection efficiency factor was derived from the published design-point value of 0.94, which was assumed to vary proportionally to receiver area. This resulted in an annual radiation and convection efficiency factor of 0.920 for the receiver size determined for this application. A first order analysis led to the conclusion that the radiation and convection losses from a sodium partial cavity receiver, on the basis of total receiver frontal area, would be equivalent to the more rigorously derived losses estimated for the molten salt partial cavity receiver. However, because the frontal area of the sodium receiver is smaller than the salt receiver, at the same design-point power level, the radiation and convection efficiency factor for the sodium partial-cavity receiver is slightly higher than that for salt (0.964 vs 0.940). Reduction in frontal area results from sodium's higher allowable flux. However, this reduction is limited by heliostat beam size to minimize spillage losses. The higher flux also allowed a reduction in the internal cavity area which translated to reduction in cavity depth, relative to the salt receiver. For this reason, the cavity effect of improving absorptivity by capturing first reflected energy is less for the sodium receiver. The assumed value for absorptivity was 0.975 compared to 0.980 for the salt receiver. Table III.D.1 summarizes the receiver performance factors (both design point and annual average) used in the trade studies.

TABLE III.D.1
SODIUM RECEIVER WATERFALL
PERFORMANCE FRACTIONS

	Receiver Type			
	External Cylinder		Partial Cavity	
	Design Point	Annual Ave.	Design Point	Annual Ave.
Absorptivity	0.95	0.95	0.975	0.975
Radiation and Convection	0.940	0.920	0.964	0.953
Overall	0.893	0.874	0.940	0.929

Receiver costs were derived from reported values from the previously referenced studies of these receiver concepts by MDC with consultation by Foster Wheeler.

The collector field size, shape and performance is based on SNLL DELSOL collector field computer code optimization runs for the system. DELSOL runs for the external receiver were constrained to limit the ratio of north to south receiver power to less than two to one.

The results of the receiver trade study are shown on Table III.D.2. The table shows about a 10% cost advantage in favor of a collector field with a partial-cavity receiver, due mostly to the reduction in heliostats caused by the field performance advantage of a north field over a constrained surround field. This advantage is offset somewhat by the higher cost of the receiver and taller tower of the partial-cavity system.

Storage

Both system concepts were sized to provide 923 MW_thr, corresponding to a plant capacity factor of 0.38. Costs for the two-tank system were estimated by MDC, based on a Stearns-Roger design reported in the Rockwell/ESG hybrid study. Bechtel estimated the costs for the air-rock system based on modification of system described by Rockwell/ESG (Reference III.D.3). The modifications, which involve reducing the capacity of the buffer tanks from 30 min. to 15 min. and resizing the fans and air/sodium heat exchanger capacity from 390 MW_t to 260 MW_t, were at the suggestion of Rockwell/ESG personnel contacted by Bechtel. The cost comparisons of these systems are summarized in Table III.D.3.

As shown on the table, potential savings are on the order of 7.4 million dollars (roughly 3% of total plant cost) with an air-rock system. The bulk of the savings comes from the reduction in sodium inventory. The savings in sodium storage tanks is more than offset by the cost of the air-rock peculiar

TABLE III.D.2
SODIUM RECEIVER COMPARISON DATA

Configuration	Capacity factor @ 110 MW_e = 0.38 External Cyl. Surround Field	Partial Cavity North Field
Annual Energy (GW_t/hr)	858	858
Overall Efficiency (annual)	.222	.257
Total No. of Heliostats	11,138	9,720
Number of Fields	1	1
No. of Heliostats per Field	11,138	9,720
Tower Height (Optical)	492 ft.	745 ft.
Receiver Des. Point Power	377 MW_t	387 MW_t
Receiver Area	6,734 ft^2	9,973 ft^2
Aperture Area	6,734 ft^2	5,382 ft^2
DELSOL Level Dir. Cap. Cost +	\$119.5M	\$108.5M
Dir. Cap. Cost / Ann. Energy to Base of Tower	\$.139/ kW_thr	\$.126/ kW_thr

+ Includes collector field, receiver, tower, receiver pump, and piping.
Based on heliostat costs of \$150/m^2.

equipment. Even greater savings can be obtained at higher plant capacity factors (larger storage capacity). The potential savings at a capacity factor of approximately 0.6 were estimated to be about 5% of total plant costs. This trade study did not include the cost impact of reduced sodium temperature at the steam generator inlet. This would negate a portion of the storage savings through cost increases in other parts of the plant.

b. Risk Considerations

Both candidate sodium receiver manufacturers (Rockwell and General Electric) have opted for external receiver configurations, so all design studies and test hardware to date support this approach. Although a sodium-cooled partial cavity receiver is not expected to present any sodium-peculiar problems, there is simply a lack of design definition and hardware fabrication for this approach.

TABLE III.D.3
THERMAL STORAGE COST COMPARISON

	Two Tank	Air Rock
Plant Capacity Factor	0.38	0.38
Capacity (MW_t hr)	923	923
Costs (1981 $ millions)		
Hot and cold tanks	6.90	0.47
Heat exchangers	-	5.97
Fans	-	1.37
Rocks	-	0.87
Rock containment	-	0.78
Rock foundation	-	0.35
Piping	1.08	1.08
Sodium	11.40	1.08
Total*	19.38	11.97

*Does not include allocations (distributables and solar int. + A&E).

Large-scale high temperature air-rock storage has been defined conceptually, but there are many basic technology issues which remain to be demonstrated. These include rock stability at elevated temperatures (1100°F), minimum operating temperature differential in the system, air pressure-drops and the corresponding fan parasitic power demand, and thermocline stability in an air-rock bed. Two-tank sodium storage does not involve these issues, although there is always the unknown of large-scale increases in size.

c. Conclusions

The selected receiver for the baseline sodium system is an external cylindrical receiver. The lack of design definition and demonstration for the partial-cavity sodium receiver outweighed its potential cost savings, considering the near-term first-of-a-kind plant for this project. If the sodium system appears attractive compared to alternate systems, then the savings for a partial-cavity receiver should be considered for future plants.

A two-tank sensible heat storage system is selected for the sodium system. The cost benefit of the air-rock system doesn't warrant introducing the uncertain technology issues in a near-term first-of-a-kind plant for this project.

4. Candidate Liquid Sodium System Description

a. General

The baseline liquid sodium system plant operates at a capacity factor of 0.38 and includes the collector field surrounding the tower and receiver, thermal storage tanks, steam generators, turbine/generator and balance of plant, all located in an area of the base of the tower.

b. Collector System

The 713-acre collector field is approximately circular, as shown on the plot plan (Figure III.D.4) and contains 11,261 MDC Model 50 heliostats with approximately 57 m^2 each of glass area for a total mirror area of 640,075 m^2. The heliostats are arranged in a radial staggered array around the tower.

c. Receiver System

The receiver system consists of a cylindrical absorber unit with its support structure, control elements, interconnecting piping and a receiver tower.

The receiver tower is a tapered, slip formed concrete structure which supports the receiver at an optical height of 505 ft. Approximate scale and dimensions for the receiver tower are shown on Figure III.D.5. The receiver support structure attaches to the tower top.

Refer to Section IV.D for details of the tower construction and features.

The main sodium riser and downcomer are supported on the inside of the tower shell and include expansion loops at the appropriate intervals. The downcomer is 12.75 inch diameter, stainless steel and the riser is 24 inch diameter, carbon steel. Both are insulated with calcium silicate insulation (5 inch on downcomer, 2 inch on riser).

The receiver is constructed of 24 factory-assembled absorber panels (made of Incoloy 800) and arranged in cylindrical configuration. Each panel is complete with strongback, insulation and lagging, instrumentation, structural attachment points, piping, and piping attachment points. The general arrangement and components of the receiver are shown on Figure III.D.6. The receiver design point power level is 377 MW_{th}. It is designed to operate at a peak heat flux of less than 1.5 MW/m^2 and tube metal temperature less than 1200°F.

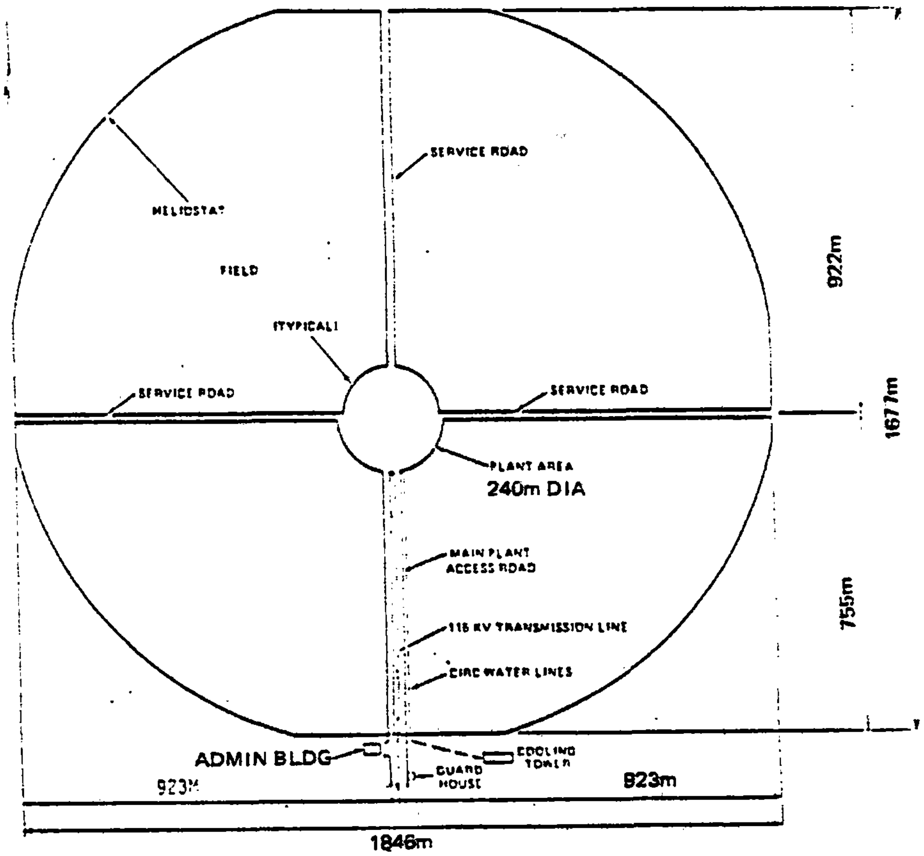


Figure III.D.4. General Plant and Heliostat Field Layout

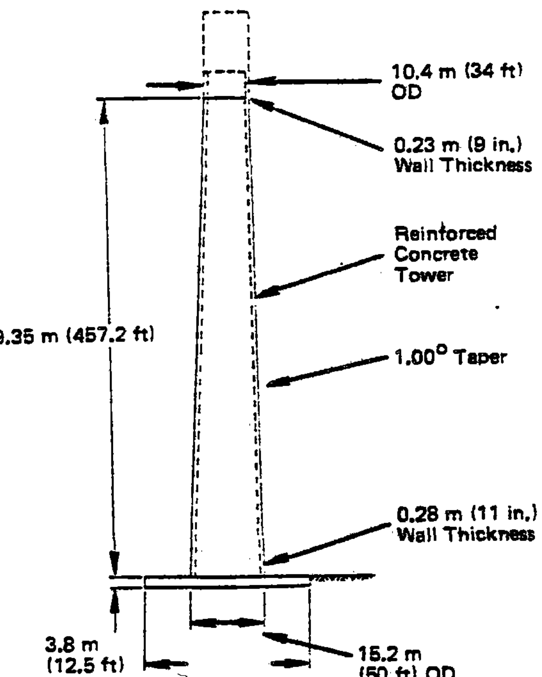


Figure III.D.5. Sodium Receiver Tower

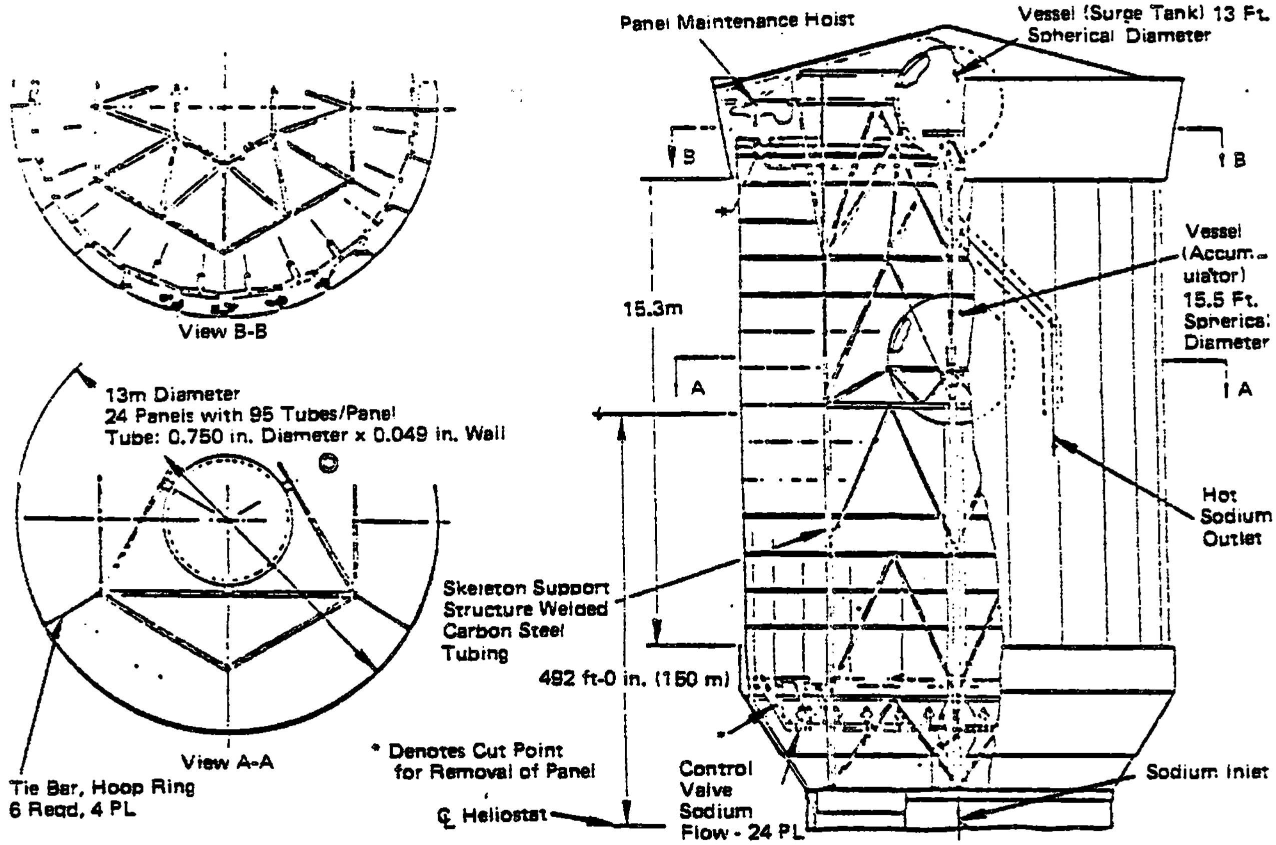


Figure III.D.6. Sodium Receiver General Arrangement

The design point flowrate is 7.9×10^6 lb/hr. The minimum flowrate capability is 60% of rated flow. Hot sodium flows from the receiver to the hot storage tank except startup or when the receiver fluid temperature drops below 1090°F. In this case, the fluid is recirculated to the warm storage tank. The receiver is drained for overnight shutdown.

d. Storage and Transport System

The storage and transport system includes the thermal storage tanks and all piping between the receiver, steam generator, and the tanks, and the associated pumps, valves and control instrumentation.

A schematic is shown Figure III.D.7. A drag valve (LCV-1) controls the fluid level in a receiver outlet surge tank. A bypass from the receiver to the warm storage tank permits receiver circulation during startup and low insolation periods without degrading storage temperature.

The hot storage tank accumulates the sodium flow from the receiver for use on demand by the steam generator system.

Two pumps operating at half capacity each feed sodium to the steam generator. Each multistage, cantilever pump is capable of delivering 6500 gpm at 100 psi (300') head. Each pump operates at 75% efficiency and requires 400 kW when running at full capacity. Bypass dump lines to the hot tank provide pump control. A bypass around the steam generator through BV1 (Figure III.D.7) permits sodium circulation to the warm tank to maintain

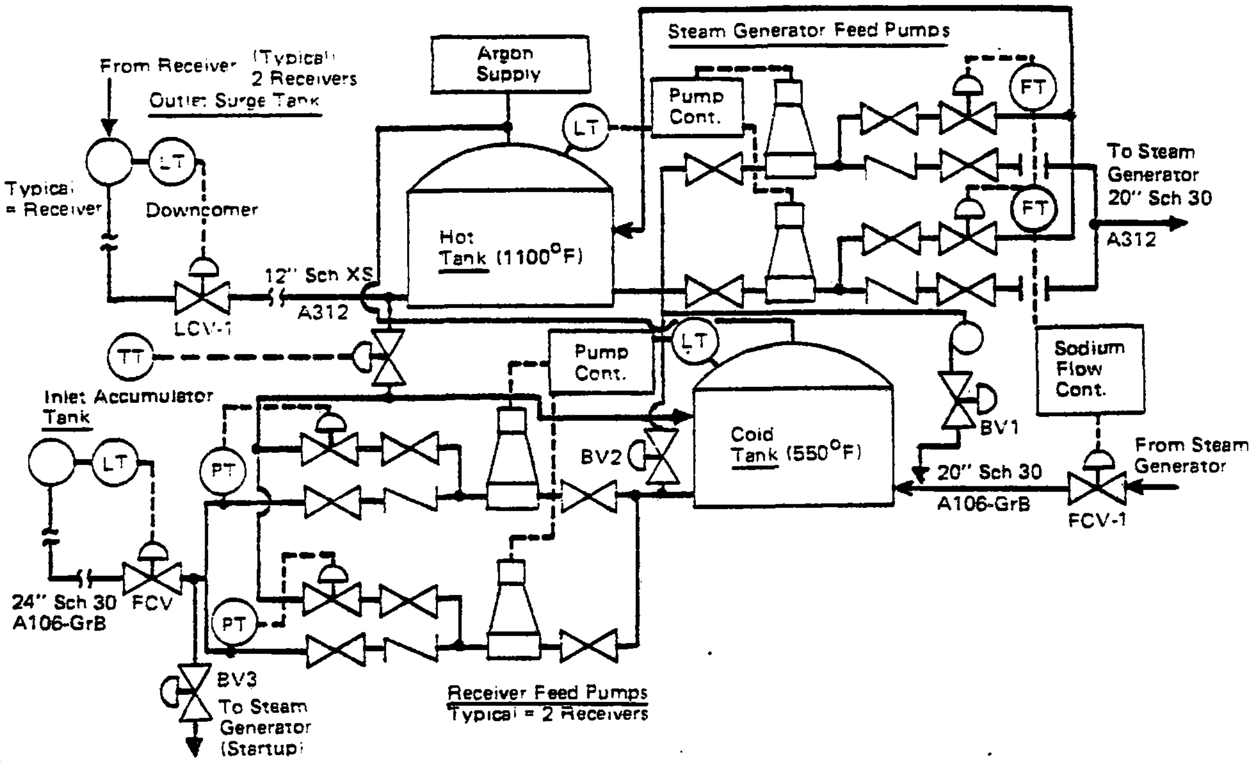


Figure III.D.7. Sodium Storage and Transport System Schematic

warm tank temperature. Another bypass line through BV2 is provided to the warm tank outlet for blending with sodium from the hot tank during startup and overnight temperature maintenance of the receiver.

Sodium returns from the steam generator to the warm tank where it accumulates for on-demand circulation to the receiver. A flow control valve (FCV-1) regulates total sodium flow. This valve is analogous to the burner control in a fossil-fired unit. Opening FCV-1 increases the heating rate and steam production rate in the evaporator.

Two pumps operating at half capacity each feed sodium to the receiver. Each multistage, cantilever pump is capable of delivering 9,300 gpm at a 310 psi (800') head. Each pump operates at 75% efficiency and requires 1650 kW when running at full capacity. Bypass dump lines to the warm tank provide pump control. A bypass line through BV3 permits gradual temperature increase during steam generator startup. A flow control valve regulates fluid level in a receiver inlet accumulator tank.

The drag valve is a 12 inch angle valve which is preferred for its self-draining capability. An Argon pressurization system provides a slight positive ullage pressure (1 psig) on both storage tanks. Storage tanks, interconnecting piping and valves are similar to those described for the molten salt system (Section III.C).

e. Steam Generator System

The steam generator system includes the heat exchangers (preheater, evaporator with integral steam drum, superheater, and reheater) and the interconnecting piping, valves, and control instrumentation.

The construction and operation of these is similar to the steam generator described for the molten salt system (Section III.C), except the steam generators are designed to contain any reactants of a sodium/water leak within the heat exchangers. This is accomplished through the use of appropriate relief valves, piping, and a reactants containment tank.

f. EPGS and Balance of Plant

The EPGS and balance of plant are common to the salt system.

g. Plant Control System

The plant control system provides coordinated control of all of the plant systems. Its characteristics and operation are the same as described for the molten salt system (Section III-C), except it is simplified for the single collector field and receiver of the sodium system.

h. Final Baseline Sodium System Sizing

The baseline sodium system component sizes and capacities are summarized on Table III.D.4.

i. Baseline Sodium System Costs

The estimated costs of the baseline sodium system are shown on Table III.D.5. These costs were based on the system as described in the preceding text.

j. Baseline Sodium System Performance

The overall system performance at the design point and for the annual average are shown in waterfall format on Figure III.D.8 and III.D.9. The auxiliary power requirements at the design conditions are shown in Table III.D.6. Table III.D.7 gives the annual energy consumption for system parasitics.

5. Technology Readiness

The development of sodium technology for cooling breeder-reactors and steam generation has brought about the design, construction and operation of a family of sodium components which are directly applicable to use in a sodium solar system.

Significant experience in this development includes:

- Argonne National Laboratory (Naval Reactors Program) power-plant-scale heat transfer and steam generator system, 1947 to 1954.

TABLE III.D.4
BASELINE SODIUM SYSTEM CHARACTERISTICS

Capacity factor		0.38
Annual energy to steam (GW_ehr)		865
Land area (km^2/acres)		2.88/713
Heliostats		11,264*
Glass area m^2		640,075
Tower height (m)		
Optical		147
Rec ℄		150.5
Top of tower		133.9
Receiver design pt. power MW_t		385
Rec. geometry H X D (m)		13.2 x 15.5
Rec. area (m^2)		642
Design pt. flow rate	(lb/hr)	7.883×10^6
	(gpm)	17,836
Cold sodium pipe (A106GrB)		24" Sched 80
Riser (m)		195
Horizontal (m)		195
Total (m)		390
Hot sodium pipe (304H)		12.75"
Downcomer (m)		195
Horizontal (m)		195
Total (m)		390
Receiver pump		
Number		2
Size η = .75		2200
Head (ft)		800
Storage size (MW_thr)		923
Type		2 tank

*Final heliostat quantity increased from trade study result in final computer performance run.

TABLE III.D.5
BASELINE SODIUM SYSTEM COSTS

0.38 Capacity Factor
(1981 $ Millions)

Account No.	Equipment		Costs
1.0	Solar Steam Supply System		187.2
	.1 Collector		
	.11 Collector purchase price	94.1	
	.12 Collector erection	16.0	
	.2 Major Solar Steam Supply Hdwe.	25.5	
	.3 Solar Process Mech. Equip.	10.4	
	.4 Solar Electrical	1.8	
	.5 Solart Civil & Structural	3.5	
	.6 Solar Piping & Instrumental	32.2	
	.7 Solar Yardwork & Misc.	3.7	
2.0	Turbine/Generator		*
3.0	Process Mechanical Equipment		*
4.0	Electrical		*
5.0	Civil and Structural		*
6.0	Process Piping & Instrumentation		5.1
7.0	Yardwork and Miscellaneous		*
8.0	Switchyard		*
70.0	Distributable Const. Costs (CM&SU)		6.5
80.0	Engineering & Home Office		
	- A&E		3.0
	- Solar Integrator		9.7
			24.3
	Subtotal Solar		211.5
Total BOP (Bechtel, 8/6/81)			50.9*
Total			$262.4
$MWhr_e$		332,600	
Dollars per $MWhr_e$		$789	

*50.9 is sum of asterisked items

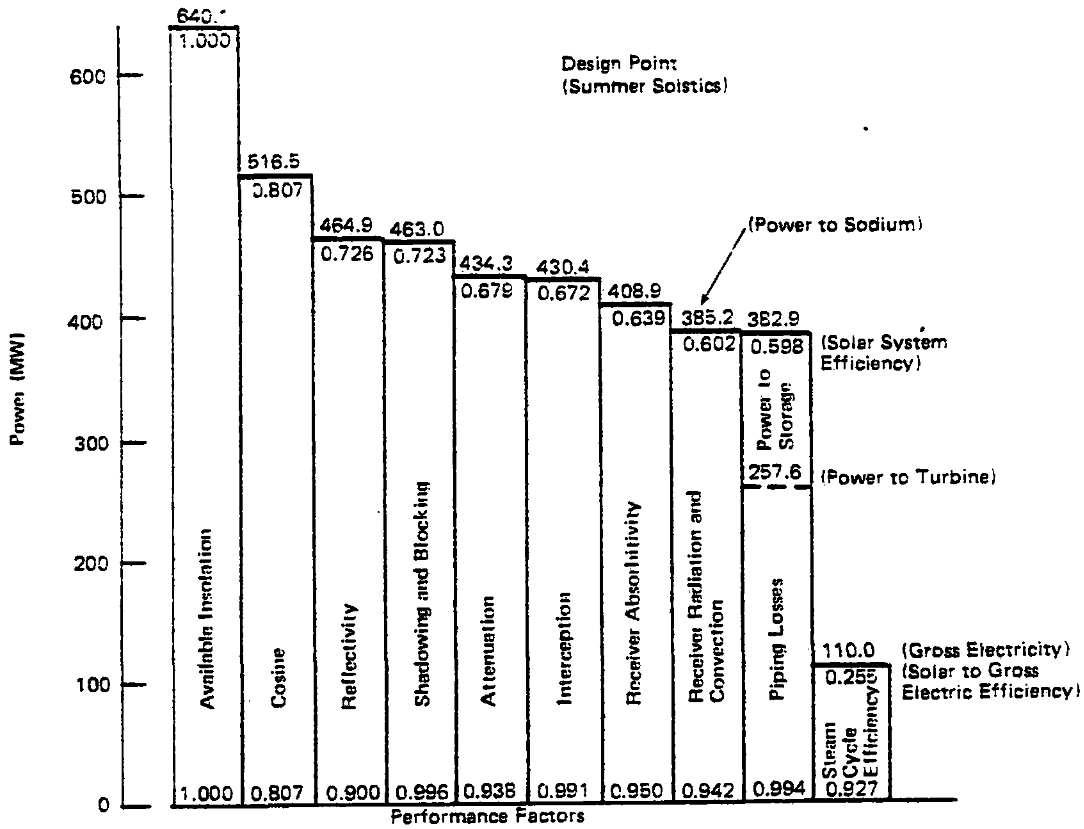


Figure III.D.8. Baseline Sodium System Performance

- Argonne National Laboratory Engineering Breeder Reactor (EBR-I), early 60's.

- The Sodium Reactor Experiment (SRE) experimental test facility to generate electric power, 1957 to 1965.

- Hallam Nuclear Power Facility generating electric power, from 1962.

- Argonne National Laboratory EBR-II 20 MW_e integrated fast breeder reactor and power plant, since 1965.

- Fermi nuclear plant, 1962 to 1966.

Successful operation of sodium-cooled reactors in the United States attracted the attention of several European countries, and sodium-cooled reactors were designed and constructed there. Second generation reactors are now operating in Russia, France, and U.K. The third generation of these concepts is being designed. It is interesting to note that all sodium-cooled reactors, taken together, have completed about 115 operating years to date.

Because of this vast experience with sodium as a heat transfer fluid, it has not been considered necessary to initiate separate sodium steam generator scientific research experiments for solar applications. In addition to numerous test loops involving steam generators, there are currently seven domestic reactors producing power using sodium steam generators.

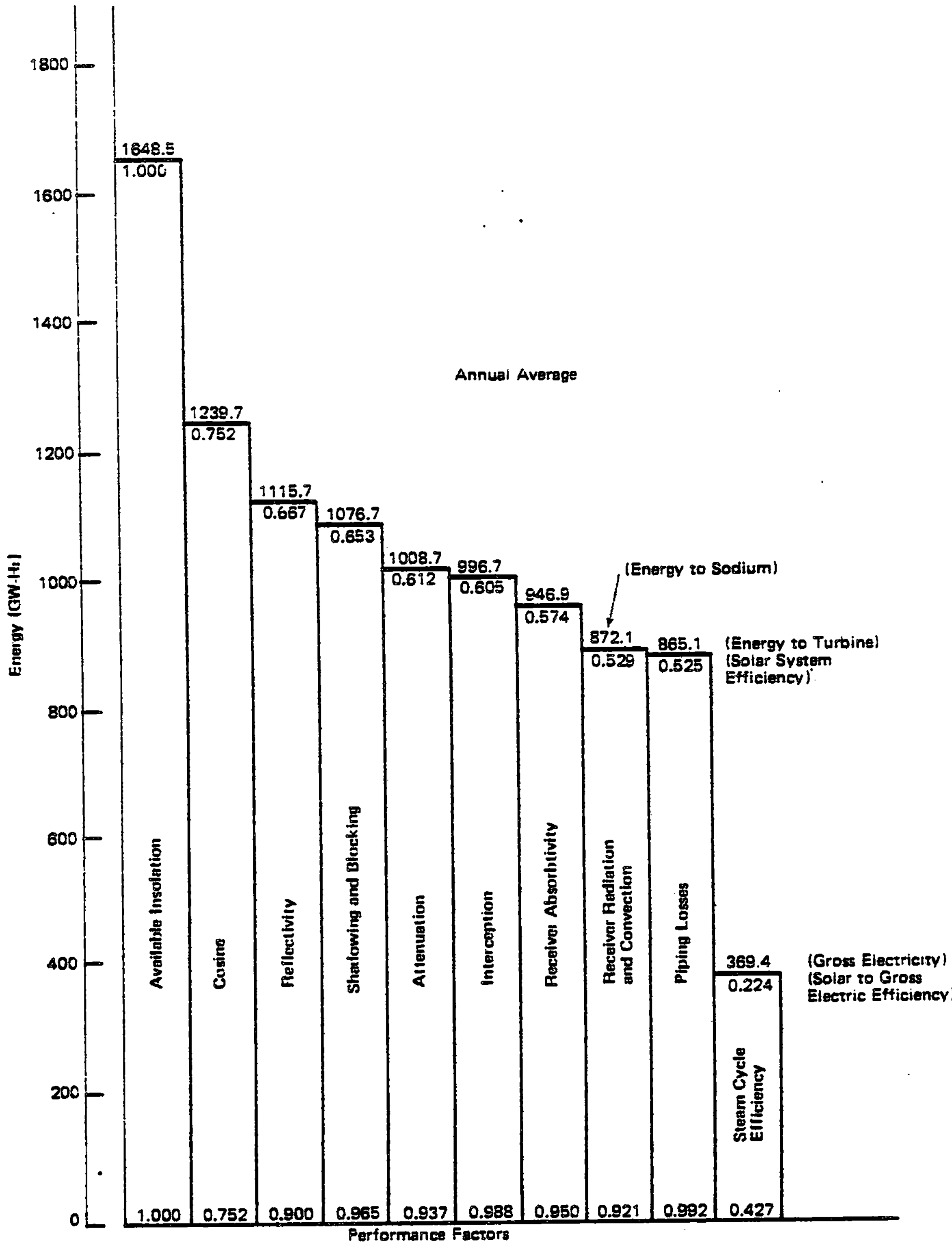


Figure III.D.9. Baseline Sodium System Performance

TABLE III.D.6
SODIUM SYSTEM AUXILIARY POWER REQUIREMENTS
(LOADS IN KW_e)

	0.38 Capacity Factor			
	Collector/Receiver		Steam Cycle	
	Design Point	Shutdown	Design Point	Shutdown
Collector	720	—	—	—
Receiver				
Feed Pumps	3530	—	—	—
Heat Tracing	—	320	—	—
Thermal Storage & Transport Heat Tracing	—	500	—	300
Steam Generator Circulating Pump	—	—	280	—
Master Control	50	30	—	—
Steam Cycle				
Variable Load*	—	—	3020	—
Cooling Tower Fans	—	—	550	—
Circulating Water Pumps	—	—	900	—
Heating/Air Conditioning	—	—	440	300
Misc. Fixed Load	—	—	320	260
Totals	4300	850	5510	860

*Feedwater and Condensate Pumps

The only major sodium solar component which does not have a counterpart in already developed reactor systems is the receiver. However, the vast experience gained in the development of high temperature sodium components in general lends credibility to sodium receiver designs. In order to verify the design further, a test of sodium-cooled receiver panels was started late last year and is currently under solar testing at CRTF. The panels are being tested at up to 2.5 MW_t and a peak flux of 1.5 MW/m^2 has been demonstrated.

Operational experience associated with overnight drain and next-day startup is being obtained along with transient solar operations. This test will provide the development experience leading to a commercial type receiver.

TABLE III.D.7
BASELINE SODIUM SYSTEM AUXILIARY
ENERGY REQUIREMENTS

	Annual Energy (GW_ehr)
Heliostats	3.10
Receiver feed pumps	5.61
Steam generator pumps	2.66
Master control	.33
Variable load*	10.13
Cooling tower	1.84
Circulating water pump	3.02
HVAC	3.10
Miscellaneous**	2.48
Total	32.27 GW_ehr

*Feedwater and condensate pumps.
**Trace heating and miscellaneous fixed load.

As for the previous concepts, the forthcoming Solar I operation also applies to a large measure to a sodium solar plant readiness independent of heat transfer medium considerations. Residual concerns requiring validation for this media are the extrapolation of results to a larger scale and extended operating time for the receiver.

III-E. SYSTEM SIZE/CAPACITY FACTOR SENSITIVITY

This study determined that a 110 MWe (gross) solar thermal power plant with a capacity factor of 60% would produce the lowest bus bar energy costs. This conclusion was based on cost analysis of various system sizes at different capacity factors. Another primary consideration is determining the size and capacity factor of the plant was the requirement that 75,000 heliostats would have to be built in order to produce a cost-effective design. Accordingly, six plants were assumed to be required and the number of heliostats assumed for one plant (assuming a molten salt design) was approximately 15,000; based on MDC's design, this number of mirrors would produce about 650 MW_t of heat. The plant size and capacity factor were therefore the variables and the size of the collector field and tower/receiver were fixed. The purpose of this section is to discuss the methodology used in determining plant size and capacity factor from both an Edison viewpoint and a generic perspective.

Edison System Dispatch

The Edison system consists of roughly 15,000 MWe of generating capacity consisting primarily of oil/gas units although coal, nuclear, hydro and purchased power also make significant contributions. Normally, a utility system is dispatched on economics. The unit which will produce the next increment of electrical power for the least cost is dispatched (or loaded) into the system grid first. However, Edison is unique in its dispatching system due to the air pollution problem indigeneous to the Los Angeles basin. In order to minimize NOx (nitrogen oxides), Edison must load the next increment of electrical power to produce the least amount of NOx.

The NOx dispatch applies only to those units located within the Los Angeles basin; the remaining system is then subject to economic dispatch. Due to this unique dispatch system, the Edison system evolved such that

a) the in-basin units were relegated to "swing load" units, and

b) the out-basin areas were used to site base load units (e.g., coal and nuclear)

c) ~~there is strong~~ pressure on Edison to purchase power from out-of-state to minimize ~~NOx production and siting of large~~ base ~~loaded units.~~

Accordingly, Solar 100 must be dispatched in such a way to produce maximum economic benefit to the Edison Company given the above restraints.

1. Dispatch Analysis - Edison

In order to analyze, the dispatch requirement of Solar 100, a computer simulation of the dispatch system was used. This "Simulation" program was not specifically developed for Solar 100 as the program is used by Edison for a variety of uses. Simulation is used by Edison's System Development Department to determine generation mix, forecast capacity factors and, for each unit on the system, projected fuel requirements. The program loads each unit on the system on a bi-hourly basis (based on inputted load and capacity forecasts) to minimize NOx emission in the basin. In other words, the program looks at each unit and calculates the incremental increase in NOx that would occur and choses that unit which produces the least NOx emission. The load is increased in increments until the forecast capacity is met. All out-of-basin units are "loaded" before basin units based on economic dispatch, i.e., those units which cost the least to load have priority.

There are various parameters which are inputted into the Simulation program which include:

- Maximum/Minimum unit loads
- Energy forecasts
- Capacity forecast
- Day shapes
- Starting sequence

- o Heat rates
- o NOx curves
- o Maintenance schedules
- o Forced outages expected
- o Fuel type and price
- o Purchased power

While there are various outputs of Simulation, this Solar 100 Study is primarily interested in the following:

a. Capacity factor
b. Oil displaced/fuel savings
c. NOx reduction

In performing the Simulation analysis, it became apparent that one of the governing criteria that affected capacity factor of Solar 100 was minimum load. Edison has built so much capacity in base load units and is able to purchase so much power (available at under avoided cost) that the in-basin units cannot be "backed off" sufficiently without unit shutdown. By shutting down a unit the ability to meeting the next days peak load is impaired. In order to avoid the risk of not meeting peak load, Edison must refuse the offer of purchased power and incur an economic penalty. Referring to Figure III.E.1, Edison's load duration curve for a typical week in May 1986 is illustrated with the various components of:

- o system load
- o load after sales/purchases
- o load after hydro
- o base load operation (coal and nuclear)

As noted, base load operation is forecasted to be backed-off in order to accommodate purchased power. Accordingly, when Edison evaluates the worth of power from Solar 100, it must evaluate the worth of the power that it replaces. In other words, by displacing economy or base load energy, the worth of Solar 100 power to Edison cannot exceed the value of energy that it is replacing. Therefore, the dispatch of energy must be at those times when Edison load is the highest. As in most other southwest utilities, maximum load occurs during the summer days, and accordingly, Solar 100 will have to be dispatched essentially during daylight hours in order for Edison Company to value its energy at its optimum. Since the amount of annual energy is constant (i.e., mirror capacity is fixed) the capacity factor varies as shown in Figure III.E.2. This figure was computed using the simulation program to ascertain the dispatch sequence. By restricting the hours of operation, the net result is that the capacity factor is reduced and the net output (during Edison's peak load) is increased. Contract purchase forecasts are not necessarily firm, consequently, more time and analyses are required before Edison specifies an actual design capacity factor. However, for purposes of this report it is anticipated that Edison would require a 40% capacity factor which therefore would dictate a capacity output of 150 MWe. A particular concern to prospective third party owners is the time of dispatch since Edison pays a premium for "on-peak" energy.

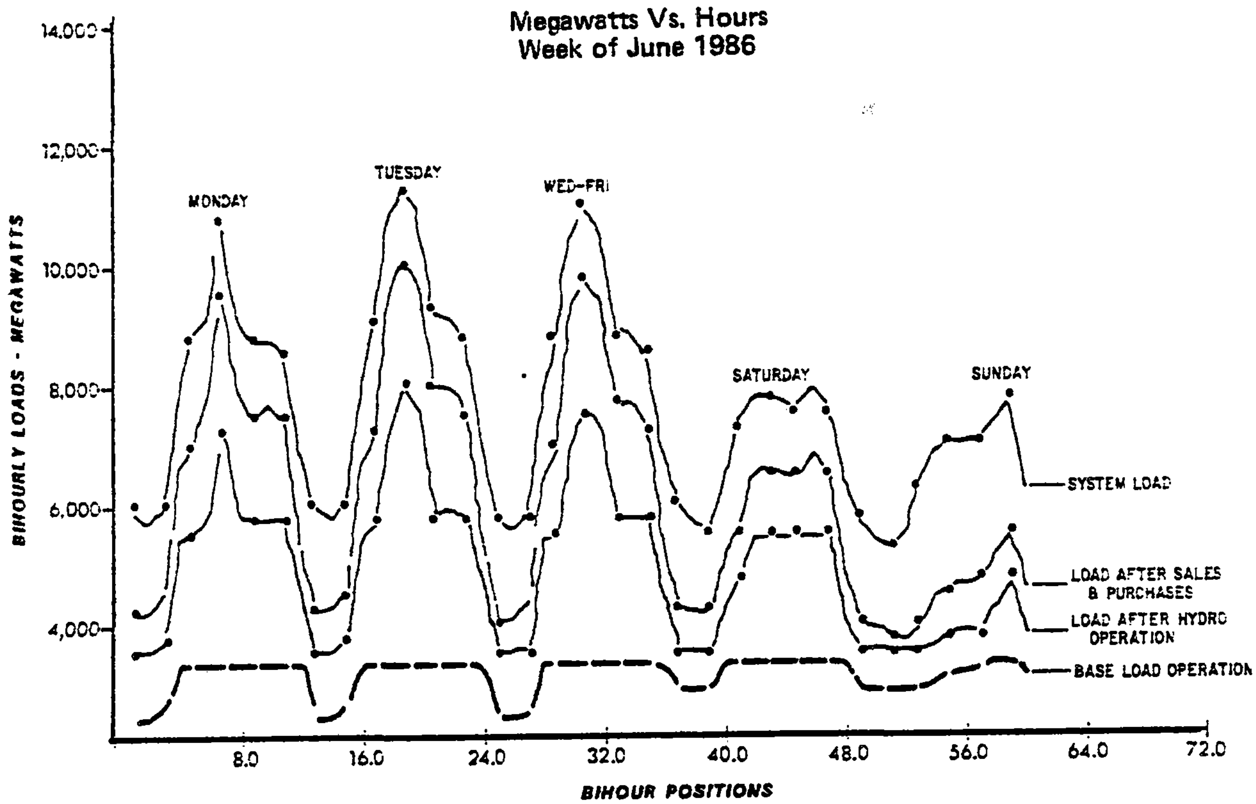


Figure III.E.1. System Simulation Results – Weekly Load Curve

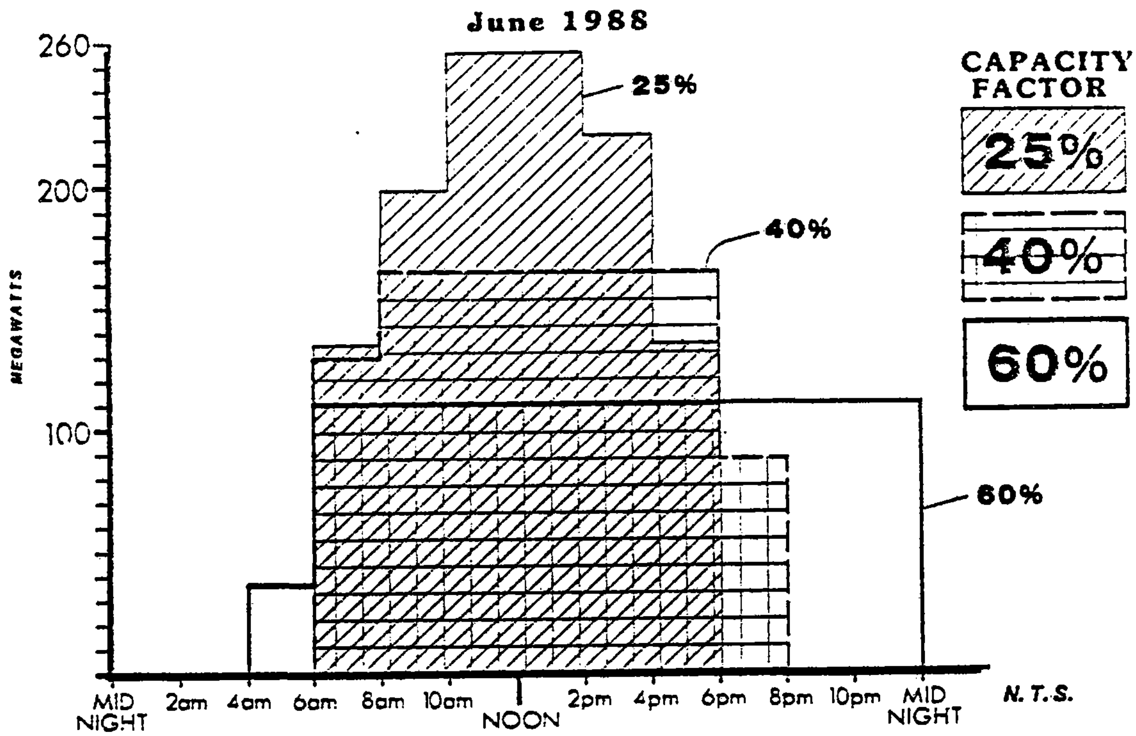


Figure III.E.2. Gross Energy Generation with Varying Capacity Factor

2. Dispatch Analysis - Generic

In determining the dispatch and capacity factor from a generic perspective, the worth of electricity is calculated from the amortization of capital. In other words, the annualized carrying charge (plus expenses) is divided by the annual energy output to derive costs in mills/kWh. It was from this perspective that the least bus bar energy costs were determined. All previous investigations into solar thermal use this methodology and it was also used in this report to determine the size and capacity factor of 100 MWe and 60%.

III-F. EVALUATION AND SELECTION

1. Introduction and Approach

Each of the alternative systems described in the foregoing sections were designed to conform to the requirements and criteria specified in Section II. The preferred plant concept was selected by an evaluation process that considered the system selection parameters specified in Section II.C. Some of these were evaluated quantitatively and others were evaluated qualitatively. The parameters evaluated quantitatively are:

- Performance
- Capital cost
- Ratio of capital cost to net annual output

The parameters evaluated qualitatively are:

- Technology readiness
- Technical risk
- Nonrecurring costs
- Operating and maintenance costs
- Reliability, maintainability, availability
- Safety hazards
- Operability
- Schedule
- Generic adaptability

Two parameters, levelized busbar electric costs and cash flow, which were originally identified for the evaluation, were not evaluated directly. The trade study scope did not include quantitative estimates of operating and maintenance costs for the alternative systems, so levelized busbar electric costs could not be calculated. However, because operating and maintenance costs can be generally estimated as a percentage of initial capital costs, the ranking of systems by ratio of capital cost to net annual output is equivalent to a ranking by levelized busbar electric costs. Therefore, this ratio is used in lieu of levelized busbar electric costs. Likewise, the trade study scope did not include definitive schedule estimates for the alternative systems, so meaningful cash flows could not be generated. However, within the relative accuracy of the evaluation, rankings based on the ratio of capital cost to annual net output should approximate a ranking by cash flow requirements. The system definitions and data presented in the preceding sections were used in the evaluations. The quantitative evaluation is presented in Section III.F.2. The qualitative evaluation is presented in Section III.F.3. A conclusion of the recommended baseline configuration is presented in Section III.F.4.

2. Quantitative Evaluation and Ranking

Tables III.F.1, 2, and 3 present the key sizing and system definition data, system performance data, and system cost data, respectively, for each of the alternative systems.

All systems data are derived from published literature and are based on the same insolation and computer performance models.

Figure III.F.1 presents data for system capital costs vs. net annual electricity output. The cost data do not include switchyard costs, because these were judged to be common to all systems.

Figure III.F.2 presents the ratio of capital cost to net annual energy output for all three candidate systems over a range of capacity factors and net annual electricity outputs.

Based on this data, it is apparent that the high capacity factor (0.6) molten salt system provides the best cost/performance ratio.

3. Qualitative Evaluation and Ranking

For the qualitative evaluation, the candidates were organized by major systems (collector, tower, receiver, energy transport and storage, steam generators or storage heat exchangers, EPGS, and plant control) and each of these systems were evaluated in terms of the qualitative parameters. In this evaluation, the qualitative relative rankings were developed by assigning a plus (+), zero (0), or minus (-) for each parameter. A plus is indicative of superior quality of a parameter for a particular candidate's system relative to the other candidates' systems; a zero is indicative of a norm for all candidates' systems; and a minus is indicative of inferior quality. For example, a Solar I once-through receiver was judged to be relatively superior to either salt or sodium receivers with respect to technology readiness and nonrecurring costs. This is based on the Solar I progress and demonstration status, as opposed to only single panel tests at CRTF for salt and sodium receivers. However, the water/steam screened-tube receiver (best choice primarily for improved controllability) represents too much of a departure to benefit to this degree from Solar I. And because it hasn't been subjected to even single panel tests at CRTF, it is judged inferior to the salt and sodium receivers. It should be noted that, although a single receiver configuration (screened-tube) was selected for the water steam system in Section III.B, the level of readiness exhibited by the Solar I receiver (once-through) forced consideration of it in this evaluation to the point of determining its influence on the system choice.

Table III.F.4 presents the results of the relative ranking between candidates for each system and qualitative evaluation parameter.

TABLE III.F.1
TRADE STUDY COMPARISON DATA - SIZING AND SYSTEM DEFINITION

	Water/Steam (Zero Storage)			Molten Salt				Liquid Sodium		
Capacity factor	0.264	0.397	0.482	0.299	0.396	0.514	0.594	0.250	0.380	0.594
Net. ann. elec. (GW_ehr)	231.8	348.0	421.9	262.1	347.3	450.2	520.6	219.1	332.6	520.1
Tot. No. of H-stats	8175	13420	17250	7620	10100	13217	15240	7376	11261	17688
No. of coll. flds.	1	1	1	1	2	1	2	1	1	1
H-stats/ coll. fld	875	13420	17250	7620	5050	13217	7620	7376	11261	17698
Tower ht. (ft)	363	484	543	597	475	783	597	358	446	560
Rec. des. pt. Pow (MW_t)	292	467	600	306	204	525	306	255	385	598
Rec. diam. (width)(ft)	46	58	66	63	52	83	63	35	43	54
Rec. height (ft)	64	81	91	81	67	107	81	41	51	64
Aper. area (ft^2)	9215	14726	18946	5123	3467	8790	5123	4560	6908	10881
Abs. area (ft^2)	9215	14726	18946	12939	8757	22199	12939	4560	6908	10801
Storage cap (MW_thr)	0	1396	2660	250	800	1700	2510	130	923	3046
Stor. cap (hrs at design power)	0	4.8	9.2	.97	3.1	6.6	9.72	0.5	3.6	11.8
Wt. of stor. media (lbs)	0	7.0×10^6/(1) 67000	13.0×10^6/(1) 125,000	4.6×10^6	14.7×10^6	31.3×10^6	46.0×10^6	2.7×10^6	18.9×10^6	62.4×10^6
Gross turb. rating (MW_e)	110	110/77(2)	11/77(2)	110	110	110	110	110	110	110
Gross turb. cycle eff.	.377	.377/.268(2)	.377/.268(2)	.427	.427	.427	.427	.427	.427	.427
Turb. type	Non reh.	Non-reh with adm.	Non-reh with adm	Reheat	Reheat	Reheat	Reheat	Reheat	Reheat	Reheat

(1) Gal. of oil/tons of rock
(2) Throttle operations/admission operations

TABLE III.F.2
TRADE STUDY COMPARISON DATA - SYSTEM PERFORMANCE
ANNUAL ISOLATION WITH WEATHER = 2576.4 kWhr/m^2 DELSOL PERFORMANCE DATA

Fluid	Water			Molten Salt				Liquid Sodium		
Rec. Type	Ext. Cyl. - Screened Tube			Partial Cavity				External Cylinder		
Fld. Type	Surround			North				Surround		
Cap. Factor	.264	.397	.482	.299	.396	.514	.595	.250	.380	.594
No. of Coll. Flds	1	1	1	1	2	1	2	1	1	1
Annual Avg. Perf. Factors										
Cos.	.768	.768	.768	.848	.849	.847	.848	.752	.752	.753
Refl.	.900	.900	.900	.900	.900	.900	.900	.900	.900	.900
Blk & Shad.	.964	.965	.965	.960	.959	.960	.960	.965	.965	.966
Atten.	.948	.933	.930	.924	.936	.906	.924	.948	.937	.926
Intercept	.994	.995	.995	.989	.989	.989	.989	.987	.988	.989
Recab	.972	.972	.972	.980	.980	.980	.980	.950	.950	.950
Rec. Rad/Conv.	9.5	.916	.916	.949	.950	.950	.949	.921	.921	.920
Piping	.992	.992	.992	.992	.980	.992	.979	.992	.992	.992
Subtotal	.544	.547	.545	.618	.619	.606	.610	.530	.525	.520
Turb. Cyc.	.377	.347*	.333*	.427	.427	.427	.427	.427	.427	.427
•	.928	.932	.920	.894	.898	.897	.896	.894	.900	.906
Overall	.194	.177	.167	.236	.237	.232	.233	.202	.202	.201
Gross Therm to Stor (GW_thr)	663	1075	1377	687	916	1175	1361	573	865	1346
Gross Elec. (GW_ehr)	249	374	459	293	391	502	581	245	369	575
Net Elec. (GW_ehrt)	232	348	422	262	351	450	521	219	333	521

*Average of .377 throttle cycle eff and .268 admission cycle efficiency weighted by fraction of energy to throttle and to admission

Discussion of the individual rankings is organized by both system and evaluation parameters. Of necessity, there is some duplication. However, in this way, a more comprehensive overview of the important issues is presented both with respect to any individual system and with respect to any single evaluation parameter.

a. Summary of Evaluations by System

Collector Field - Collector field rankings were generally zero because there are no qualitative differences that are dependent on system alternatives. The only nonzero rankings are in operating and maintenance costs and reflect the relative numbers of heliostats required for the different receiver fluids normalized to net annual output.

Tower - There are no fundamental differences in tower characteristics relating to system alternatives. Therefore, all tower entries are zero.

TABLE III.F.3
TRADE STUDY COMPARISON DATA - CAPITAL COST ($M - 1981)

Receiver Fluid	Water/Steam (Zero Storage)			Molten Salt				Liquid Sodium		
Capacity factor	0.264	0.397	0.482	0.299	0.396	0.514	0.594	0.250	0.380	0.594
Code of accts.										
1.0 Solar stm. sup.	107.1	192.6	250.6	119.5	164.8	190.5	233.1	128.6	187.6	298.1
2.0 Turb. gen.	8.4	8.9	8.9	9.1	9.1	9.1	9.1	9.1	9.1	9.1
3.0 Process mech. equipment	9.1	10.3	10.3	9.5	9.5	9.5	9.5	9.5	9.5	9.5
4.0 Electrical	6.1	6.1	6.1	6.2	6.2	6.2	6.2	6.2	6.2	6.2
5.0 Civil & structural	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
6.0 Process pip. & intsr.	9.3	9.8	9.8	8.7	8.7	8.7	8.7	8.6	8.6	8.6
7.0 Yardwork & Misc.	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
8.0 Switchyard	9.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
70.0 Distr. constr. costs	9.6	12.7	14.6	10.1	11.6	12.5	13.9	10.4	12.4	16.1
80.0 Eng'r. & home ofc.	10.2	14.5	17.3	13.2	16.2	17.3	20.3	14.0	17.7	25.1
Subtotal	164.6	259.7	322.4	181.1	230.9	258.6	305.6	191.2	255.9	377.5
BOP contingency*	8.5	8.9	8.9	8.8	8.8	8.8	8.8	8.8	8.8	8.8
Total	173.1	268.6	331.3	189.9	239.7	267.4	314.4	200.0	264.7	386.3
Ann. Eneregy (MWhr)	232	348	422	262	351	450	522	219	333	520
Cap. cost/net ann ($/MW$_e$hr)	747	772	785	725	683	594	604	913	796	743

*Solar plant contingency is distributed among individual items

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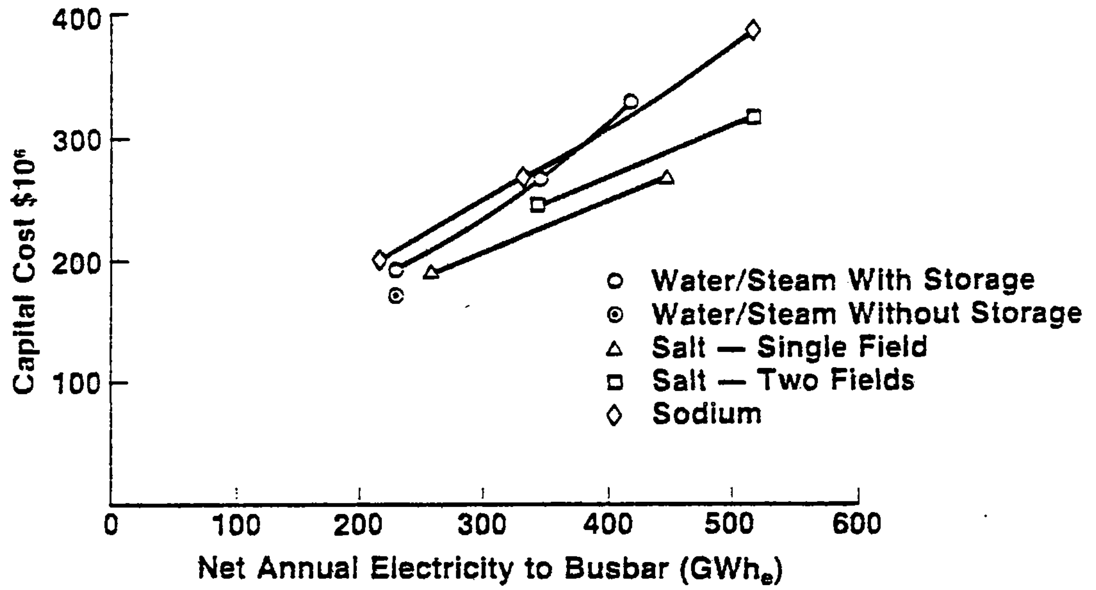


Figure III.F.1. System Costs Vs Net Annual Electricity Produced

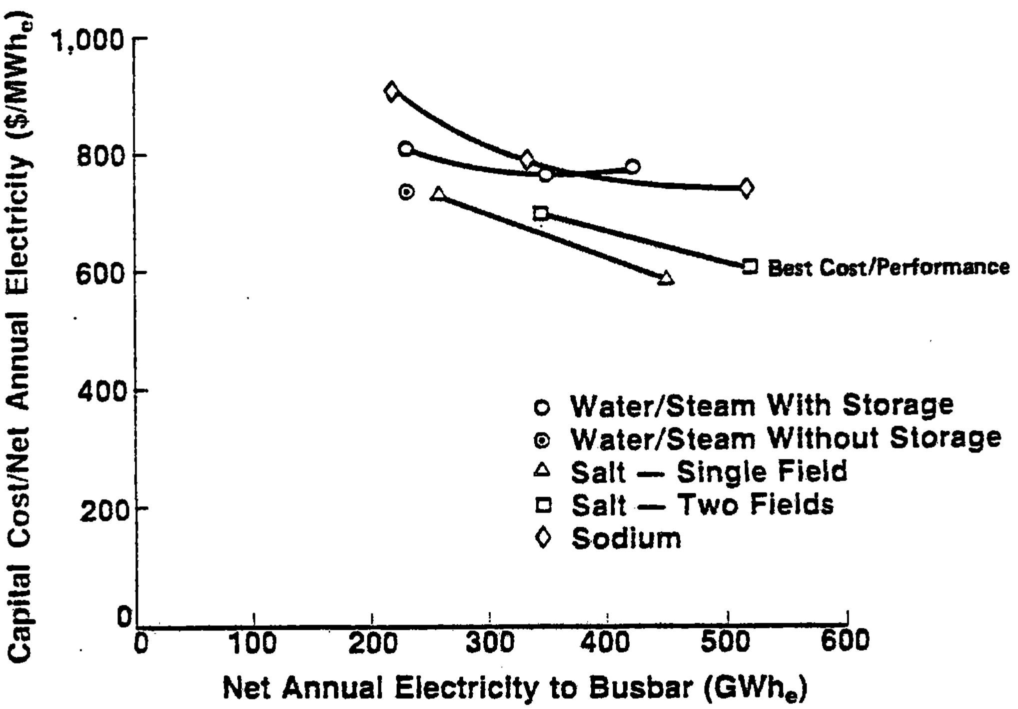


Figure III.F.2. Cost/Net Annual Electricity Vs Net Annual Electricity

TABLE III.F.4
COMPARISON MATRIX - CRITERIA NOT QUANTIFIED

	Receiver Fluids																				
	Water/Steam							Molten Steam							Sodium						
	Collector	Tower	Receiver	Transp. & Stor.	Heat Exchangers	EPGS	Plant Control	Collector	Tower	Receiver	Transp. & Stor.	Stm. Generator	EPGS	Plant Control	Collector	Tower	Receiver	Transp. & Stor.	Stm. Generator	EPGS	Plant Control
Technology Readiness	0	0	=(1)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Technical Risk	0	0	-	0	0	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Non-recurring Costs	0	0	±(1)	-	+	0	0	0	0	0	0	0(2)	0	0	0	0	0	0	+	0	0
Operating Costs (3)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Maintenance Costs	-	0	0	0	0	0	0	+	0	0	0	0	0	0	0	0	0	0	0	0	0
Reliability Maintainability Availability	0	0	-(1) / 0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Safety Hazards	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-	-	-	0	0
Operability	0	0	0	+	-	-	-	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Schedule	0	0	±	0	0	0	0	0	0	0	0	0(2)	0	0	0	0	0	0	0	0	0
Generic Adaptability	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Totals																					
Plus	0	0	3/0(1)	2	0	0	0	1	0	0	0	0	0	0	0	0	0	0	1	0	0
Zero	9	10	4/6(1)	7	8	8	8	9	10	10	10	10	10	10	10	10	9	9	9	10	10
Minus	1	0	3/3(1)	1	1	2	2	0	0	0	0	0	0	0	0	0	1	1	1	0	0

(1) Top numbers for once-through (Barstow receiver); bottom numbers for either forced circulation or natural circulation. Forced circulation used for cost/performance comparison.

(2) Assumes successful completion of molten salt steam generator SRE Phase II under government funds.

(3) Does not include auxiliary electricity; this is included in estimate of net annual output.

Receivers - The parameters with significant differences for receivers are technology readiness and technical risk, nonrecurring costs, reliability, maintainability, availability, and safety hazard.

Molten salt and liquid sodium receivers are judged equivalent in technology readiness and technical risk based on their comparable level of demonstration in CRTF panel testing and DOE/Sandia receiver SRE progress. The once-through water/steam receiver is judged superior in technology readiness because of its Solar I demonstration.

The other water/steam receivers are inferior based on lack of any demonstration. Complications of multiple phase-of-state heat input distribution requirements and direct coupling of variable steam flow to turbine throttle lead to the conclusion that all water/steam receivers have a higher technical risk than salt and sodium receivers.

Based on the degree of design and testing of receiver panel hardware to date, the molten salt and sodium receivers were ranked as the norm in requirements for further development and thus nonrecurring cost. The Solar I receiver is judged superior (that is, less nonrecurring costs) and the other water/steam receivers are judged inferior (that is, more nonrecurring costs).

Due to stringent water-quality requirements and orificing, the Solar I once-through receiver was judged much more likely to have maintainability and availability problems than the other receivers. To a degree, panel removal and replacement capability for the Solar I receiver will offset this disadvantage, especially relative to quad-cavity receiver configurations.

The fire hazard associated with sodium in contact with water leads to a rating below the norm set by water/steam and molten salt. Extensive experience in process industries and solar central receiver system component testing has verified the benign nature of molten salt.

Direct coupling of steam flow from the receiver to the turbine leads to all water/steam receivers being judged as significantly less desirable from the standpoint of operability. However, this disadvantage for water/steam receivers is offset by freeze protection requirements for molten salt and sodium and the added requirements for safe handling of sodium. Overall, no relative advantage or disadvantage was perceived. The Solar I once-through receiver has a substantial schedule advantage over all receivers because of the extensive design, fabrication, and testing already completed.

No relative advantage or disadvantage is seen for any receiver with respect to generic adaptability.

Transport and Storage - All candidates were judged equal for all parameters, except as follows. With respect to technology readiness and technical risk, the Solar I advantage for water/steam was offset by the limited experience with dual-media thermocline, so water/steam was judged approximately equal to molten salt two-tank storage. The sodium air-rock storage is judged lower in readiness and risk for lack of demonstration and uncertainty in performance, respectively.

However, the construction status of Solar I and the extensive utility operating experience at temperatures, pressures, and flow rates of interest, give the water/steam transport and storage systems an advantage with respect to nonrecurring costs. Additionally, this operating experience and the lack of freezing or other handling problems give the water/steam transport and storage systems an advantage with respect to operability. Because of the fire hazard, liquid sodium was judged to have a relative disadvantage as a safety hazard.

Steam Generators and Thermal Storage Heat Exchangers - All candidates were judged equal for all parameters except as follows. Solar I and the breeder reactor program developments give water/ steam and sodium a relative advantage in nonrecurring costs compared to molten salt. However, the work planned in the DOE/Sandia Steam Generator SRE program was considered in setting the molten salt steam generator as a norm to avoid an interpretation that would fail to account for this significant development.

The fire hazard associated with the sodium-water reaction gives liquid sodium a substantial disadvantage as a safety hazard.

With respect to operability, direct coupling of the storage charging heat exchanger with the receiver gives water/steam systems a definite disadvantage in operability.

Electric Power Generating System (EPGS) - The only substantial difference in EPGS characteristics relates to the potential problems associated with coupling receiver steam output directly to the turbine throttle. Therefore, water/steam EPGS is considered to have a relative disadvantage with respect to technical risk and operability. There are no other relative advantages among any of the receiver fluids.

Plant Control - Control complexity associated with multiple phase-of-state flow in the receiver and direct flow of receiver steam to the turbine throttle and to the thermal storage charging heat exchanger gives plant control for water/steam a clear disadvantage with respect to technical risk and operability. For all other parameters, there were no clear-cut relative advantages.

b. Summary of Evaluations by Evaluation Parameters

Technology Readiness - The extensive Solar I progress for a water/steam system with a once-through receiver gives it a relative advantage compared to other water/steam candidates, as well as molten salt and liquid sodium receivers.

Technical Risk - Higher technical risk for water/steam is associated with receivers, EPGS, and plant control and relates to direct steam flow from the receiver to the turbine throttle.

Nonrecurring Costs - Solar I once-through receiver water/steam transport and storage (including heat exchangers) and sodium steam generators are considered to have relative advantages in nonrecurring costs. These advantages relate directly to the work already accomplished on the Solar I program and the breeder reactor program.

Operating and Maintenance Costs - Excluding auxiliary electrical costs which are considered in plant net annual output, the only clear-cut relative differences in these costs is for the collector field. The smaller north-field molten salt collector system has a relative advantage on a per unit power basis.

Reliability, Maintainability, Availability - Stringent water quality requirements and receiver panel orificing give the Solar I receiver a disadvantage with respect to reliability, maintainability, and availability.

Safety Hazards - Only liquid sodium containing elements (that is, receiver, transport and storage, and steam generator) were considered to have a relative disadvantage due to the sodium fire and water/steam reaction hazards.

Operability - Water/steam transport and storage is judged superior with respect to operability because of the minimal requirements for freeze protection or special handling of media as required for sodium. However, this relative advantage is more than offset by the control complexity due to the direct flow of steam from the receiver to the charging heat exchangers and turbine.

Schedule - A water/steam system with a Solar I once-through type receiver has a significant schedule advantage. Lack of any receiver testing to date gives the other water/steam approaches a relative disadvantage with respect to schedule.

The two key schedule drivers are receiver development and heliostat commercial production. Heliostat production developments are clearly independent of system candidates.

Generic Adaptability - No relative advantages are perceived for any candidates.

c. Recommended Baseline Configuration

Based on the cost performance advantage of the molten salt receiver (particularly at high capacity factor) and the lack of substantial overall relative differences in the qualitative evaluation, the molten salt system has been selected as the baseline configuration.

On reflection of discussions in the preceding sections, it can be summarized that a molten nitrate salt system was chosen for Solar 100 because of a number of unique advantages. Among these are:

- o Low media cost allows efficient thermal energy storage to be used to maximize the plant's cost effectiveness.
- o Salt stability at high temperature allows operation of a reheat steam turbine.
- o A conventional utility turbine and turbine control can be used because solar transients are decoupled from steam generation.

- Low pressure and good heat transfer characteristics of molten salt permit an economic, efficient and easily controlled receiver design.
- These same heat transfer characteristics permit a very compact, low cost and easily controlled steam generator system.
- High energy density (Btu/ft^3) of the molten salt helps keep the storage concept and tank size within the state-of-the-art.

IV. DESCRIPTION OF SELECTED PLANT

The molten salt system which was functionally described in Section III-C was chosen as the system with the lowest bus bar energy cost. The purpose of this section is to physically describe (via P&ID's, heat balance and general arrangement drawings) the selected molten salt system and to functionally describe the plant's operating characteristics. In addition, those systems which are solar related (and therefore innately unique) have a comprehensive system description; those systems which are more conventional designs (e.g. tower design, cooling water, service air, etc.) are only briefly described.

IV-A. PHYSICAL DESCRIPTION

The plant can best be described by reviewing the Flow Diagrams which were generated for each system and also the physical drawings (e.g. site arrangements, elevations, etc.). In addition, a heat balance and one line diagram were developed. The drawings included in this report are:

Figure Number	Title
IV.A.1	Plot Plan
IV.A.2	Basic Flow Diagram
IV.A.3	Thermal Transport and Storage System
IV.A.4	Steam Generator and Steam Cycle
IV.A.5	Receiver System
IV.A.6	Service and Demineralized Water System
IV.A.7	Cooling Water System
IV.A.8	Circulating Water System
IV.A.9	Compressed Air System
IV.A.10	Chemical Feed System
IV.A.11	Heat Balance
IV.A.12	One Line Drawing
IV.A.13	Power Block - General Arrangement
IV.A.14	General Arrangement (Sections)
IV.A.15	Molten Salt Piping
IV.A.16	Receiver Support Towers Interior Arrangement and Details
IV.A.17	Pump Pit
IV.A.18	1050°F Molten Salt Tank (Hot Tank)
IV.A.19	550°F Molten Salt Tank (Warm Tank)

These drawings were generated not only to provide plant description to the reader, but also to more accurately define design for cost estimating purposes.

IV-B. OPERATIONAL DESCRIPTION

The Solar 100 plant is designed to be operated by a single control operator from the Control Room. All startup, shutdown, normal and emergency operations are automated. The actual operating crew will include additional personnel, as indicated in Section VIII.B.

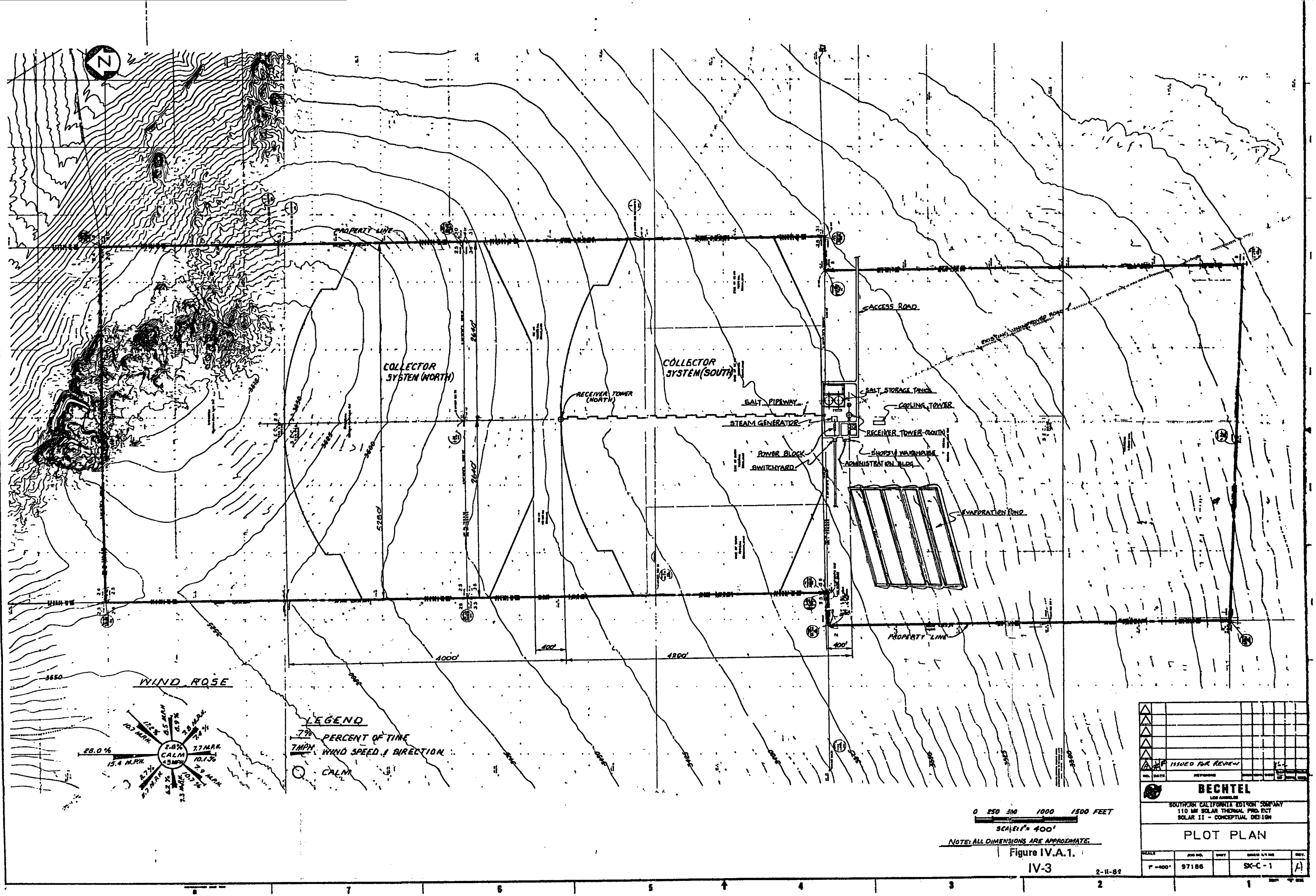

PROPERTY LINE
ACCESS ROAD
EXISTING UNIMPROVED ROAD
COLLECTOR SYSTEM (NORTH)
COLLECTOR SYSTEM (SOUTH)
RECEIVER TOWER (NORTH)
SALT PIPEWAY
STEAM GENERATOR
POWER BLOCK
SWITCHYARD
SALT STORAGE TANKS
COOLING TOWER
RECEIVER TOWER (SOUTH)
SHOPS & WAREHOUSE
ADMINISTRATION BLDG
EVAPORATION POND
5280
2640
2640
400'
4000'
4200'
400'
WIND ROSE
28.0%
15.4 M.P.H.
2.8% CALM 4.5 MPH
LEGEND
7% PERCENT OF TIME
7MPH WIND SPEED & DIRECTION
CALM
0 250 500 1000 1500 FEET
SCALE: 1" = 400'
NOTE: ALL DIMENSIONS ARE APPROXIMATE.
ISSUED FOR REVIEW
BECHTEL
LOS ANGELES
SOUTHERN CALIFORNIA EDISON COMPANY
110 MW SOLAR THERMAL PROJECT
SOLAR II - CONCEPTUAL DESIGN
PLOT PLAN
1" = 400'
97186
SK-C-1
A
2-11-82

Figure IV.A.1.

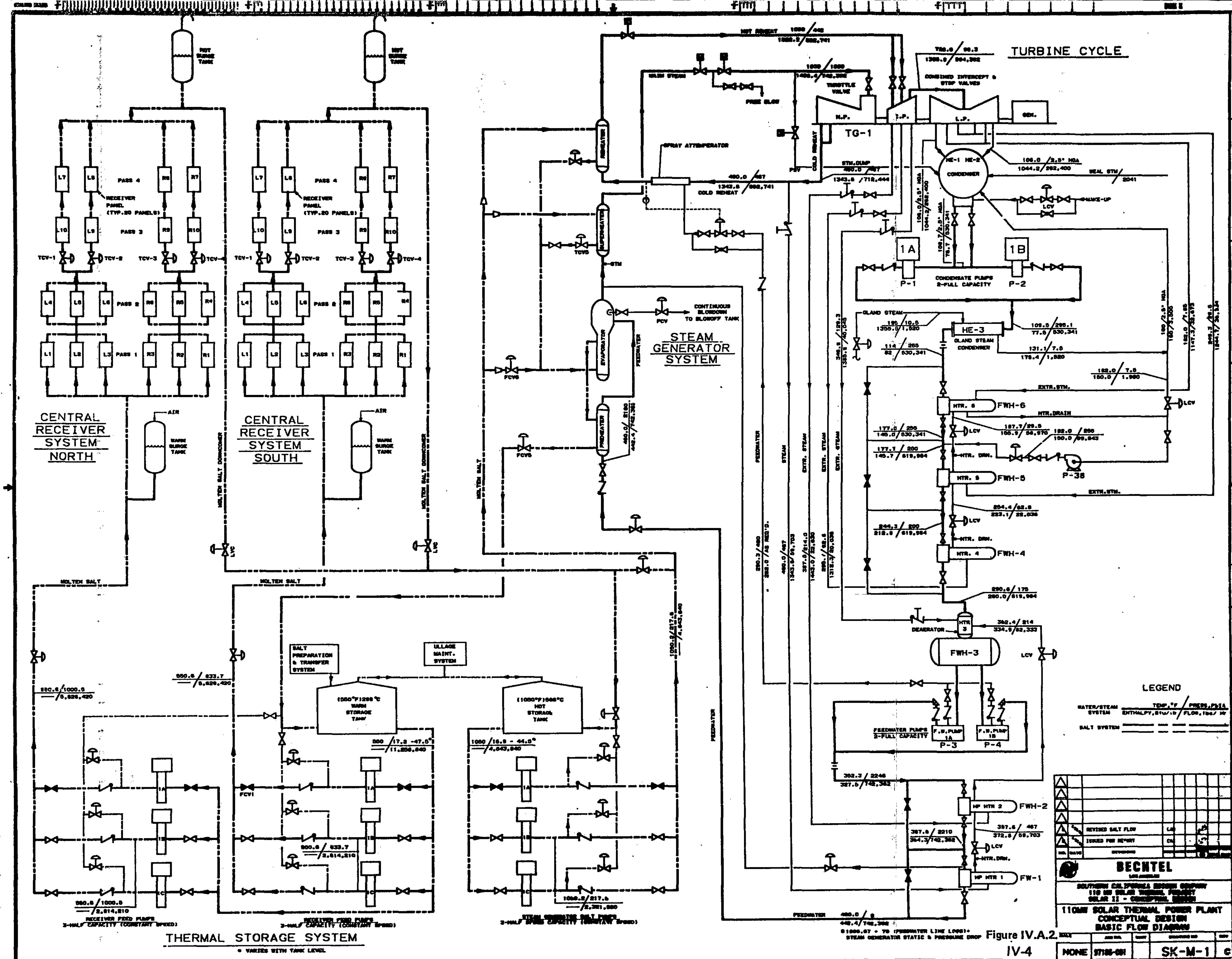

TURBINE CYCLE
HOT REHEAT
MAIN STEAM
THROTTLE VALVE
COMBINED INTERCEPT & STOP VALVES
H.P.
I.P.
L.P.
GEN.
TG-1
SPRAY ATTEMPERATOR
COLD REHEAT
CONDENSER
MAKE-UP
CONDENSATE PUMPS 2-FULL CAPACITY
P-1
P-2
1A
1B
GLAND STEAM
HE-3
GLAND STEAM CONDENSER
EXTR. STM.
HTR. DRAIN
FWH-6
FWH-5
FWH-4
FWH-3
FWH-2
FW-1
P-38
DEAERATOR
FEEDWATER PUMPS 2-FULL CAPACITY
P-3
P-4
LEGEND
WATER/STEAM SYSTEM
SALT SYSTEM
CENTRAL RECEIVER SYSTEM NORTH
CENTRAL RECEIVER SYSTEM SOUTH
HOT SURGE TANK
WARM SURGE TANK
RECEIVER PANEL (TYP. 20 PANELS)
PASS 4
PASS 3
PASS 2
PASS 1
MOLTEN SALT
MOLTEN SALT DOWNCOMER
REHEATER
SUPERHEATER
EVAPORATOR
PREHEATER
STEAM GENERATOR SYSTEM
CONTINUOUS BLOWDOWN TO BLOWOFF TANK
FEEDWATER
STEAM
EXTR. STEAM
SALT PREPARATION & TRANSFER SYSTEM
ULLAGE MAINT. SYSTEM
(550°F)288°C WARM STORAGE TANK
(1050°F)566°C HOT STORAGE TANK
RECEIVER FEED PUMPS 3-HALF CAPACITY (CONSTANT SPEED)
STEAM GENERATOR SALT PUMPS
THERMAL STORAGE SYSTEM
* VARIES WITH TANK LEVEL
BECHTEL
110MW SOLAR THERMAL POWER PLANT
CONCEPTUAL DESIGN
BASIC FLOW DIAGRAM
NONE
SK-M-1

Figure IV.A.2

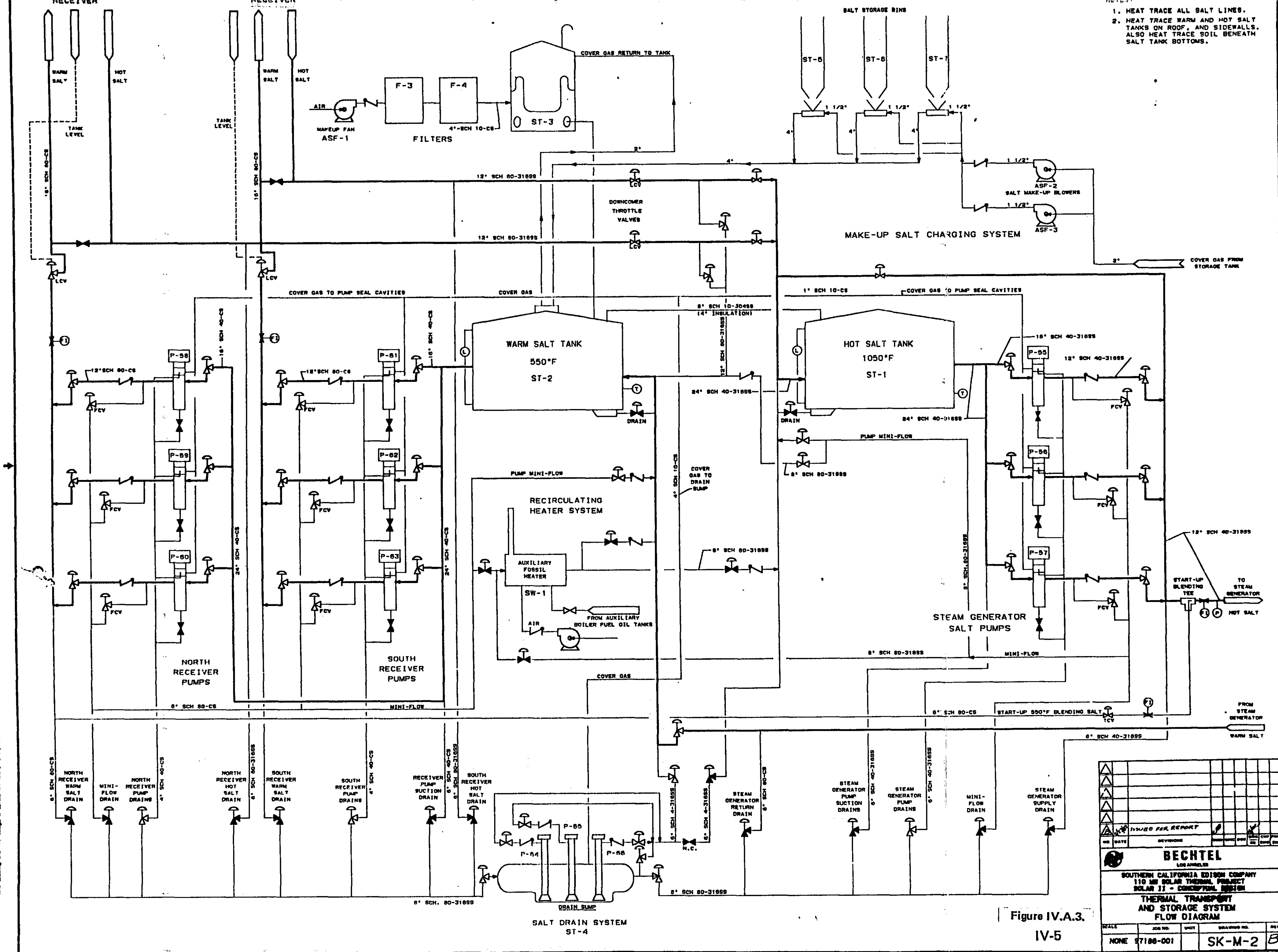
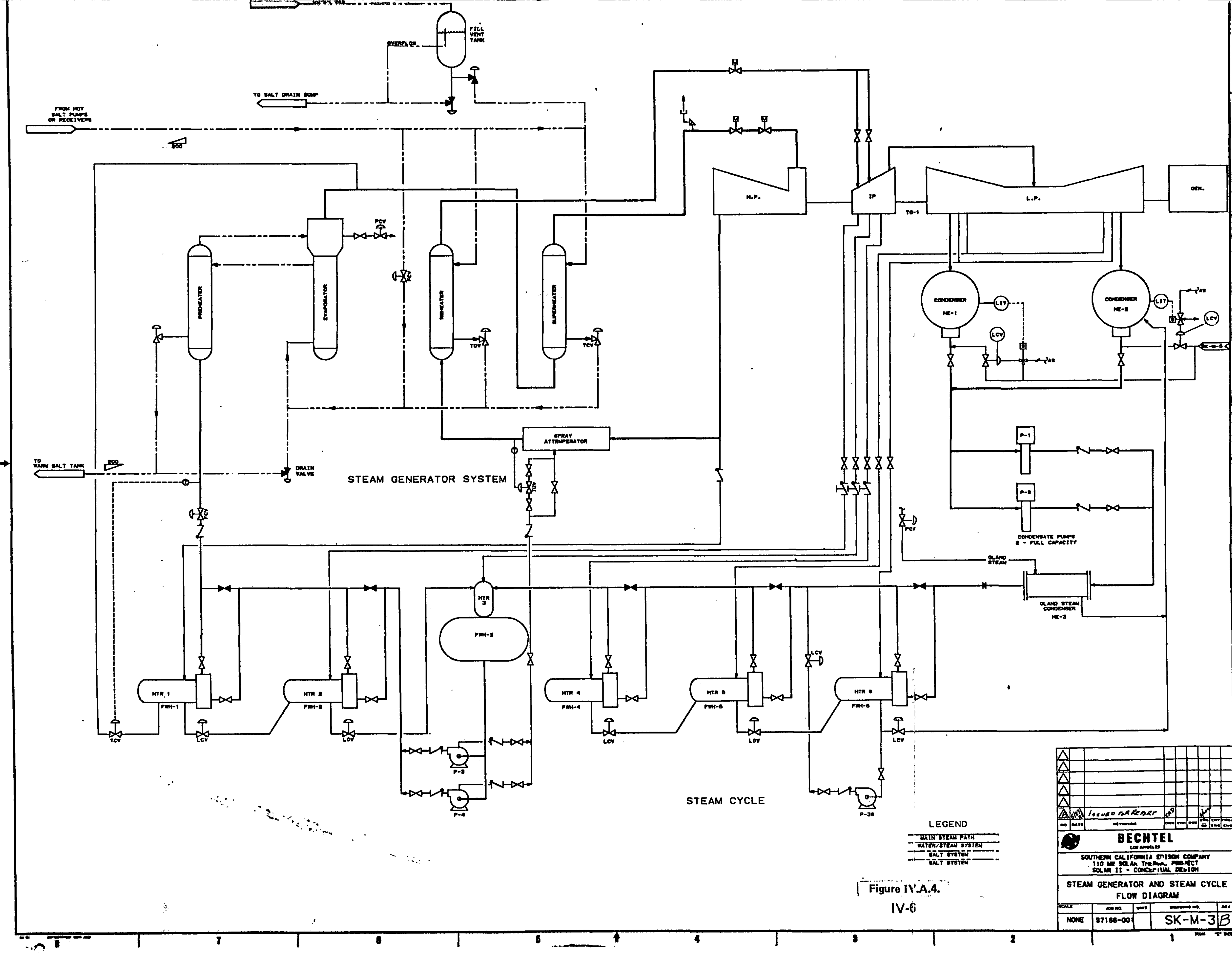

NOTES:
1. HEAT TRACE ALL SALT LINES.
2. HEAT TRACE WARM AND HOT SALT TANKS ON ROOF, AND SIDEWALLS. ALSO HEAT TRACE SOIL BENEATH SALT TANK BOTTOMS.
SALT STORAGE BINS
ST-5
ST-6
ST-7
MAKE-UP SALT CHARGING SYSTEM
ASF-2
ASF-3
SALT MAKE-UP BLOWERS
COVER GAS FROM STORAGE TANK
COVER GAS RETURN TO TANK
MAKEUP FAN
ASF-1
F-3
F-4
FILTERS
ST-3
WARM SALT
HOT SALT
TANK LEVEL
DOWNCOMER THROTTLE VALVES
COVER GAS TO PUMP SEAL CAVITIES
COVER GAS
WARM SALT TANK
550°F
ST-2
HOT SALT TANK
1050°F
ST-1
P-58
P-59
P-60
P-61
P-62
P-63
P-55
P-56
P-57
NORTH RECEIVER PUMPS
SOUTH RECEIVER PUMPS
RECIRCULATING HEATER SYSTEM
AUXILIARY FOSSIL HEATER
SW-1
FROM AUXILIARY BOILER FUEL OIL TANKS
PUMP MINI-FLOW
COVER GAS TO DRAIN SUMP
STEAM GENERATOR SALT PUMPS
START-UP BLENDING TEE
TO STEAM GENERATOR
HOT SALT
FROM STEAM GENERATOR
WARM SALT
START-UP 550°F BLENDING SALT
MINI-FLOW
NORTH RECEIVER WARM SALT DRAIN
MINI-FLOW DRAIN
NORTH RECEIVER PUMP DRAINS
NORTH RECEIVER HOT SALT DRAIN
SOUTH RECEIVER WARM SALT DRAIN
SOUTH RECEIVER PUMP DRAINS
RECEIVER PUMP SUCTION DRAIN
SOUTH RECEIVER HOT SALT DRAIN
STEAM GENERATOR RETURN DRAIN
STEAM GENERATOR PUMP SUCTION DRAINS
STEAM GENERATOR PUMP DRAINS
MINI-FLOW DRAIN
STEAM GENERATOR SUPPLY DRAIN
P-64
P-65
P-66
DRAIN SUMP
SALT DRAIN SYSTEM
ST-4
ISSUED FOR REPORT
BECHTEL
LOS ANGELES
SOUTHERN CALIFORNIA EDISON COMPANY
110 MW SOLAR THERMAL PROJECT
SOLAR II - CONCEPTUAL DESIGN
THERMAL TRANSPORT AND STORAGE SYSTEM FLOW DIAGRAM
NONE
97186-001
SK-M-2
B

Figure IV.A.3.



FILL VENT TANK
OVERFLOW
TO SALT DRAIN SUMP
FROM HOT SALT PUMPS OR RECEIVERS
PREHEATER
EVAPORATOR
REHEATER
SUPERHEATER
PCV
TCV
LCV
DRAIN VALVE
TO WARM SALT TANK
SPRAY ATTEMPERATOR
STEAM GENERATOR SYSTEM
H.P.
IP
L.P.
GEN.
TG-1
CONDENSER HE-1
CONDENSER HE-2
LIT
P-1
P-2
CONDENSATE PUMPS 2 - FULL CAPACITY
GLAND STEAM
GLAND STEAM CONDENSER HE-3
HTR 3
FWH-3
HTR 1
FWH-1
HTR 2
FWH-2
HTR 4
FWH-4
HTR 5
FWH-5
HTR 6
FWH-6
P-3
P-4
P-3B
STEAM CYCLE
LEGEND
MAIN STEAM PATH
WATER/STEAM SYSTEM
SALT SYSTEM
SALT SYSTEM
BECHTEL
LOS ANGELES
SOUTHERN CALIFORNIA EDISON COMPANY
SOLAR II - CONCEPTUAL DESIGN
STEAM GENERATOR AND STEAM CYCLE FLOW DIAGRAM
NONE
SK-M-3

Figure IV.A.4.

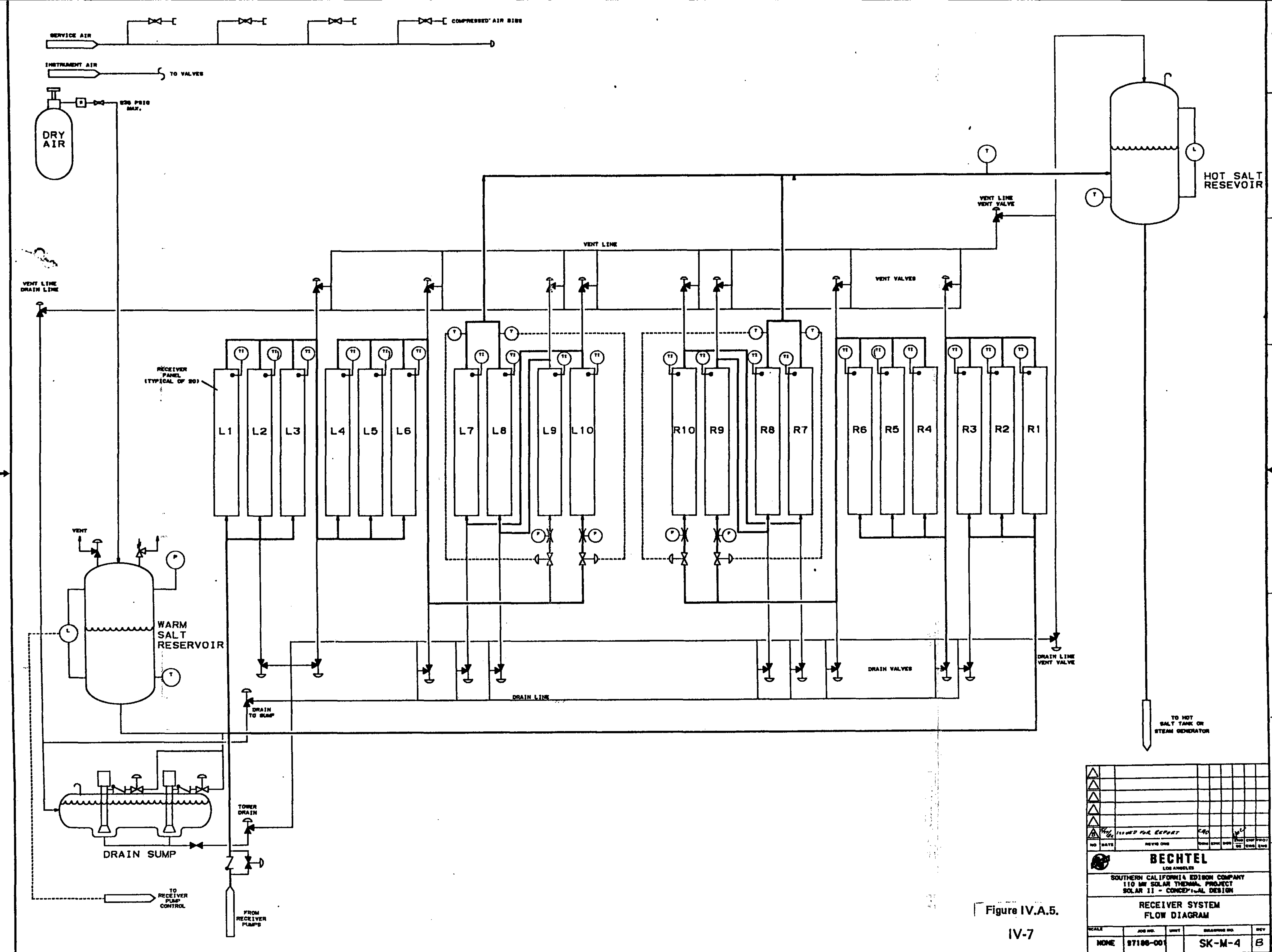

SERVICE AIR
COMPRESSED AIR BIBS
INSTRUMENT AIR
TO VALVES
DRY AIR
HOT SALT RESEVOIR
VENT LINE VENT VALVE
VENT LINE
VENT VALVES
VENT LINE DRAIN LINE
RECEIVER PANEL (TYPICAL OF 20)
L1
L2
L3
L4
L5
L6
L7
L8
L9
L10
R10
R9
R8
R7
R6
R5
R4
R3
R2
R1
VENT
WARM SALT RESERVOIR
DRAIN VALVES
DRAIN LINE VENT VALVE
DRAIN LINE
DRAIN TO SUMP
TO HOT SALT TANK OR STEAM GENERATOR
TOWER DRAIN
DRAIN SUMP
TO RECEIVER PUMP CONTROL
FROM RECEIVER PUMPS
ISSUED FOR REPORT
NO
DATE
BECHTEL
LOS ANGELES
SOUTHERN CALIFORNIA EDISON COMPANY
110 MW SOLAR THERMAL PROJECT
SOLAR II - CONCEPTUAL DESIGN
RECEIVER SYSTEM
FLOW DIAGRAM
SCALE
NONE
97186-001
SK-M-4
B

Figure IV.A.5.

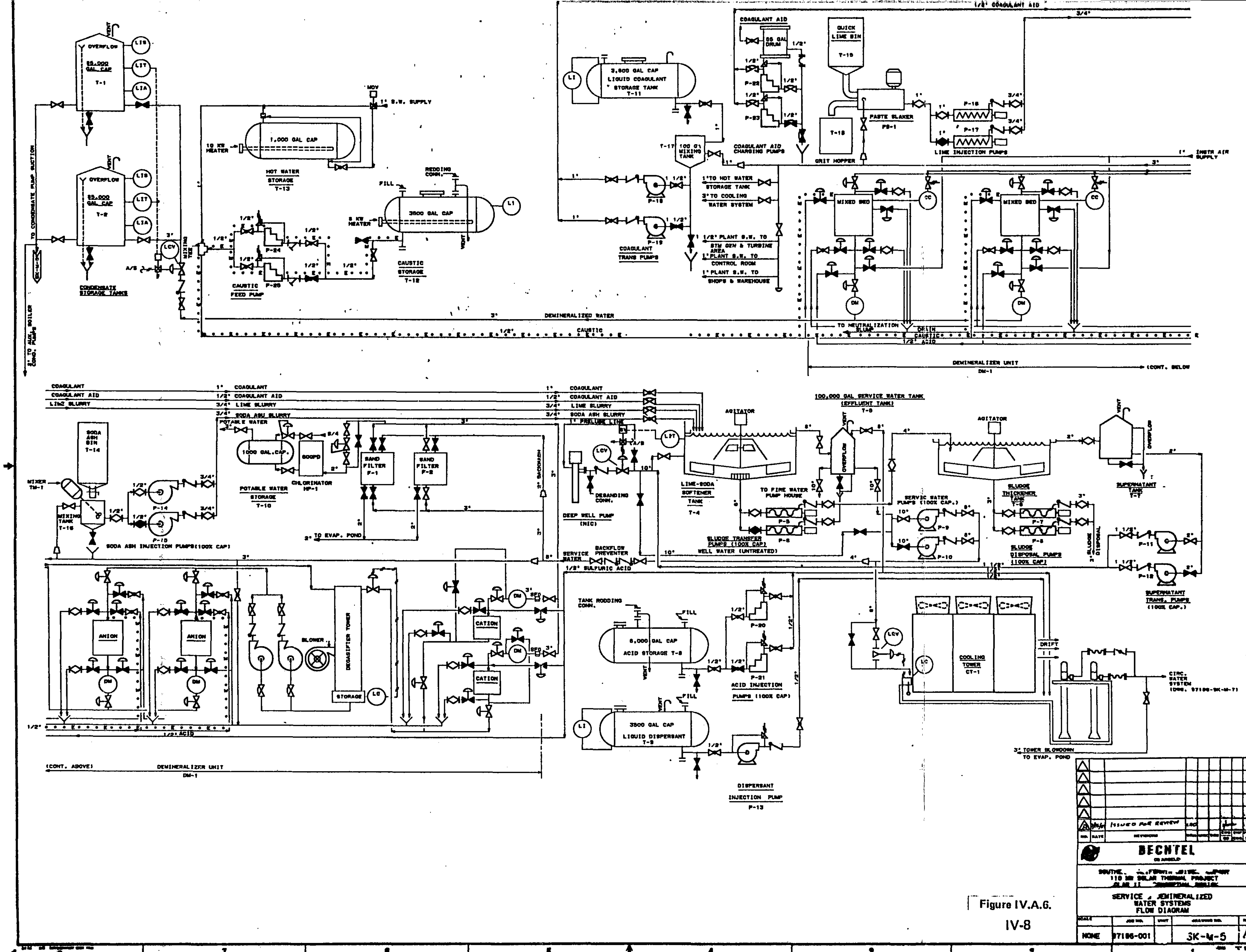

CONDENSATE STORAGE TANKS
HOT WATER STORAGE T-13
CAUSTIC STORAGE T-12
CAUSTIC FEED PUMP
DEMINERALIZED WATER
CAUSTIC
3,800 GAL CAP LIQUID COAGULANT STORAGE TANK T-11
COAGULANT AID
QUICK LIME BIN T-15
PASTE SLAKER PS-1
GRIT HOPPER
LIME INJECTION PUMPS
COAGULANT AID CHARGING PUMPS
COAGULANT TRANS PUMPS
MIXED BED
TO NEUTRALIZATION SUMP
DEMINERALIZER UNIT DM-1
COAGULANT
COAGULANT AID
LIME SLURRY
SODA ASH SLURRY
SODA ASH BIN T-14
SODA ASH INJECTION PUMPS (100% CAP)
POTABLE WATER STORAGE T-10
CHLORINATOR HP-1
SAND FILTER F-1
SAND FILTER F-2
TO EVAP. POND
DEEP WELL PUMP
LIME-SODA SOFTENER TANK T-4
TO FIRE WATER PUMP HOUSE
SLUDGE TRANSFER PUMPS (100% CAP)
WELL WATER (UNTREATED)
100,000 GAL SERVICE WATER TANK (EFFLUENT TANK) T-5
SERVIC WATER PUMPS (100% CAP.)
SLUDGE THICKENER TANK T-6
SLUDGE DISPOSAL PUMPS (100% CAP)
SUPERNATANT TANK T-7
SUPERNATANT TRANS. PUMPS (100% CAP.)
SERVICE WATER
BACKFLOW PREVENTER
1/2" SULFURIC ACID
ANION
CATION
BLOWER
DEGASIFIER TOWER
STORAGE
8,000 GAL CAP ACID STORAGE T-8
ACID INJECTION PUMPS (100% CAP)
3500 GAL CAP LIQUID DISPERSANT T-9
DISPERSANT INJECTION PUMP P-13
COOLING TOWER CT-1
CIRC. WATER SYSTEM
3" TOWER BLOWDOWN TO EVAP. POND
(CONT. ABOVE)
DEMINERALIZER UNIT DM-1
BECHTEL
SERVICE & DEMINERALIZED WATER SYSTEMS FLOW DIAGRAM
NONE
3K-M-5
A

Figure IV.A.6.

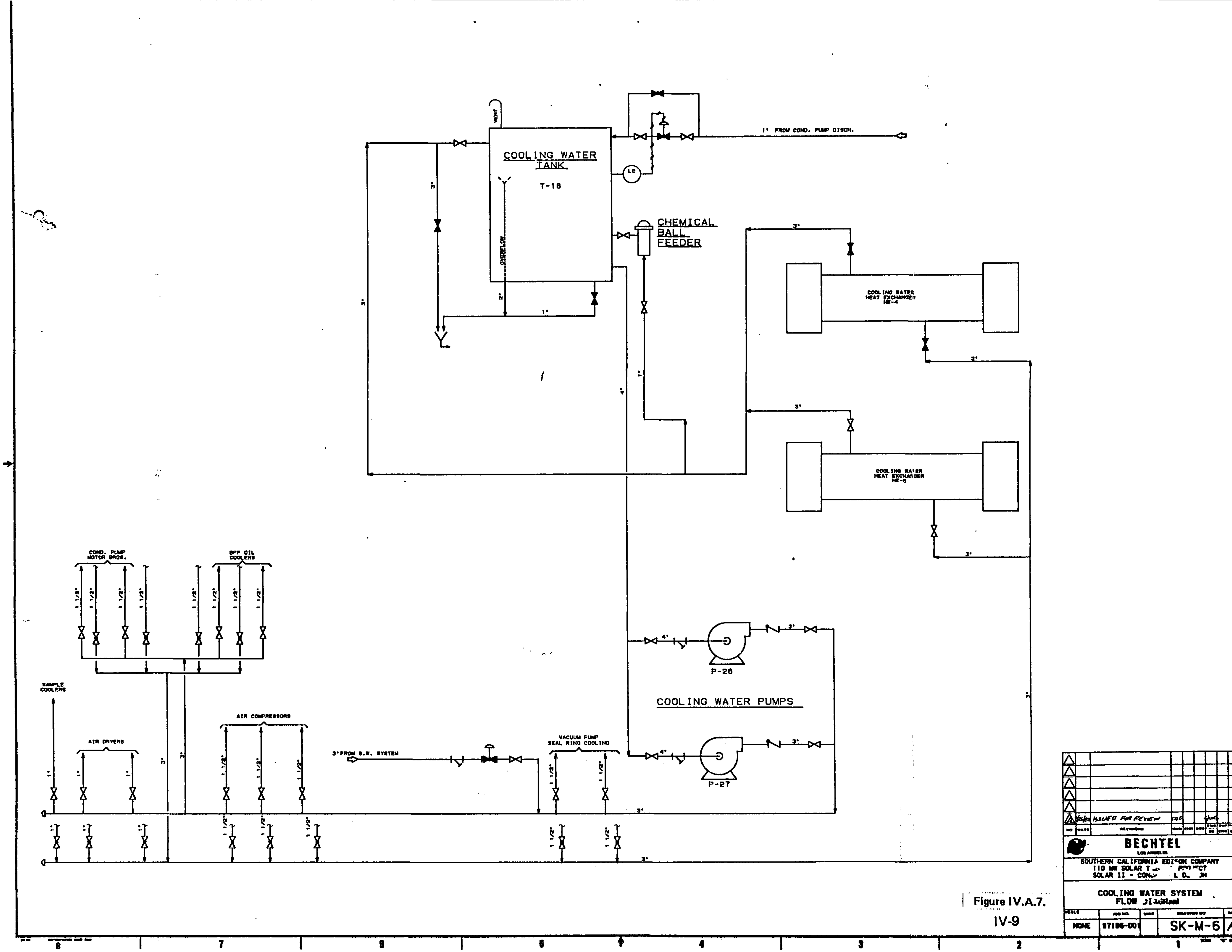
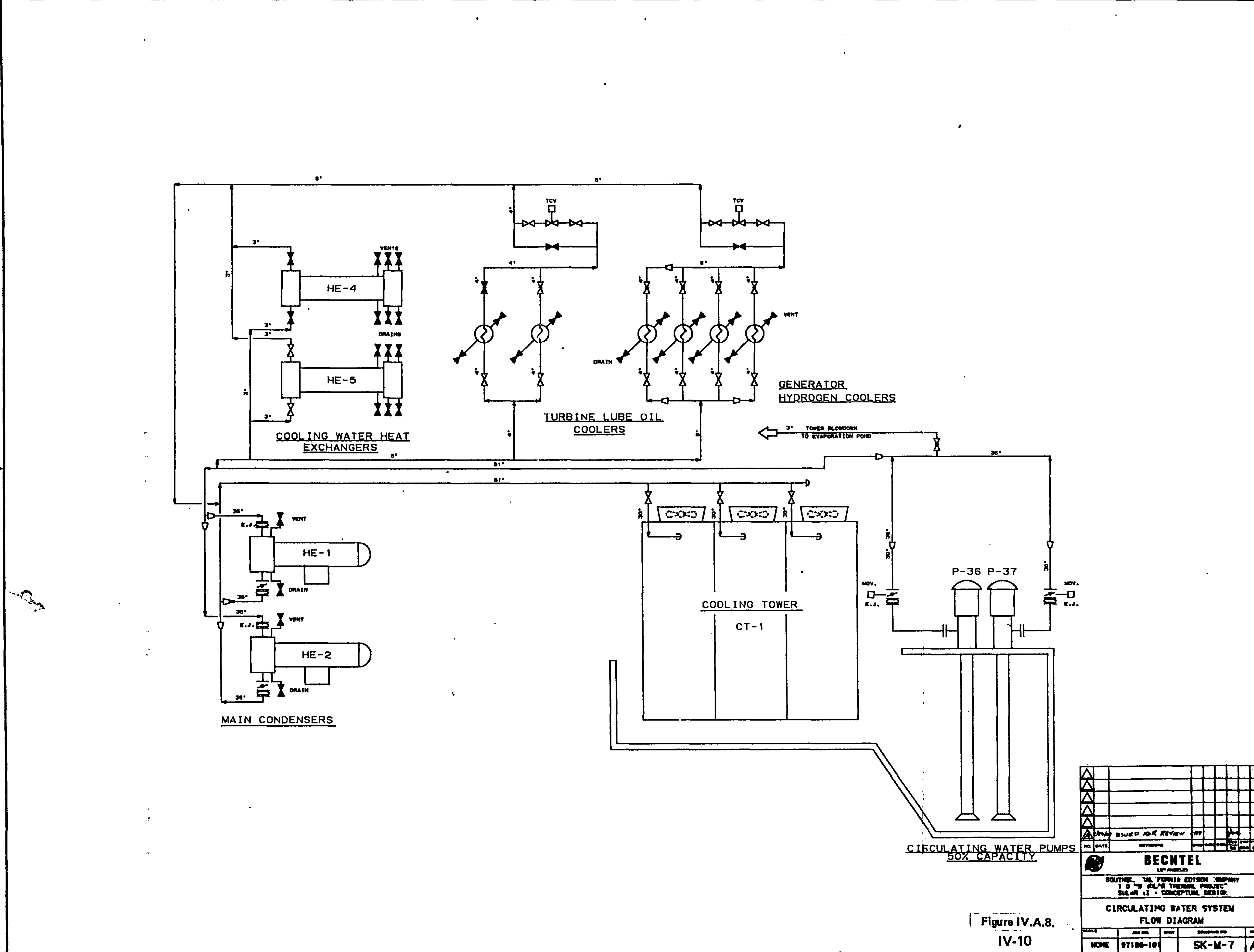

COOLING WATER TANK
T-18
VENT
OVERFLOW
1" FROM COND. PUMP DISCH.
CHEMICAL BALL FEEDER
COOLING WATER HEAT EXCHANGER HE-4
COOLING WATER HEAT EXCHANGER HE-5
COOLING WATER PUMPS
P-26
P-27
COND. PUMP MOTOR BRGS.
BFP OIL COOLERS
SAMPLE COOLERS
AIR DRYERS
AIR COMPRESSORS
3" FROM S.W. SYSTEM
VACUUM PUMP SEAL RING COOLING
ISSUED FOR REVIEW
BECHTEL
LOS ANGELES
SOUTHERN CALIFORNIA EDISON COMPANY
COOLING WATER SYSTEM
NONE
SK-M-6
A

Figure IV.A.7.



COOLING WATER HEAT EXCHANGERS
HE-4
HE-5
VENTS
DRAINS
TCV
TURBINE LUBE OIL COOLERS
GENERATOR HYDROGEN COOLERS
VENT
DRAIN
TOWER BLOWDOWN TO EVAPORATION POND
HE-1
HE-2
MAIN CONDENSERS
E.J.
COOLING TOWER
CT-1
P-36 P-37
MOV.
CIRCULATING WATER PUMPS 50% CAPACITY
BECHTEL
CIRCULATING WATER SYSTEM
FLOW DIAGRAM
NONE
SK-M-7
A

Figure IV.A.8.

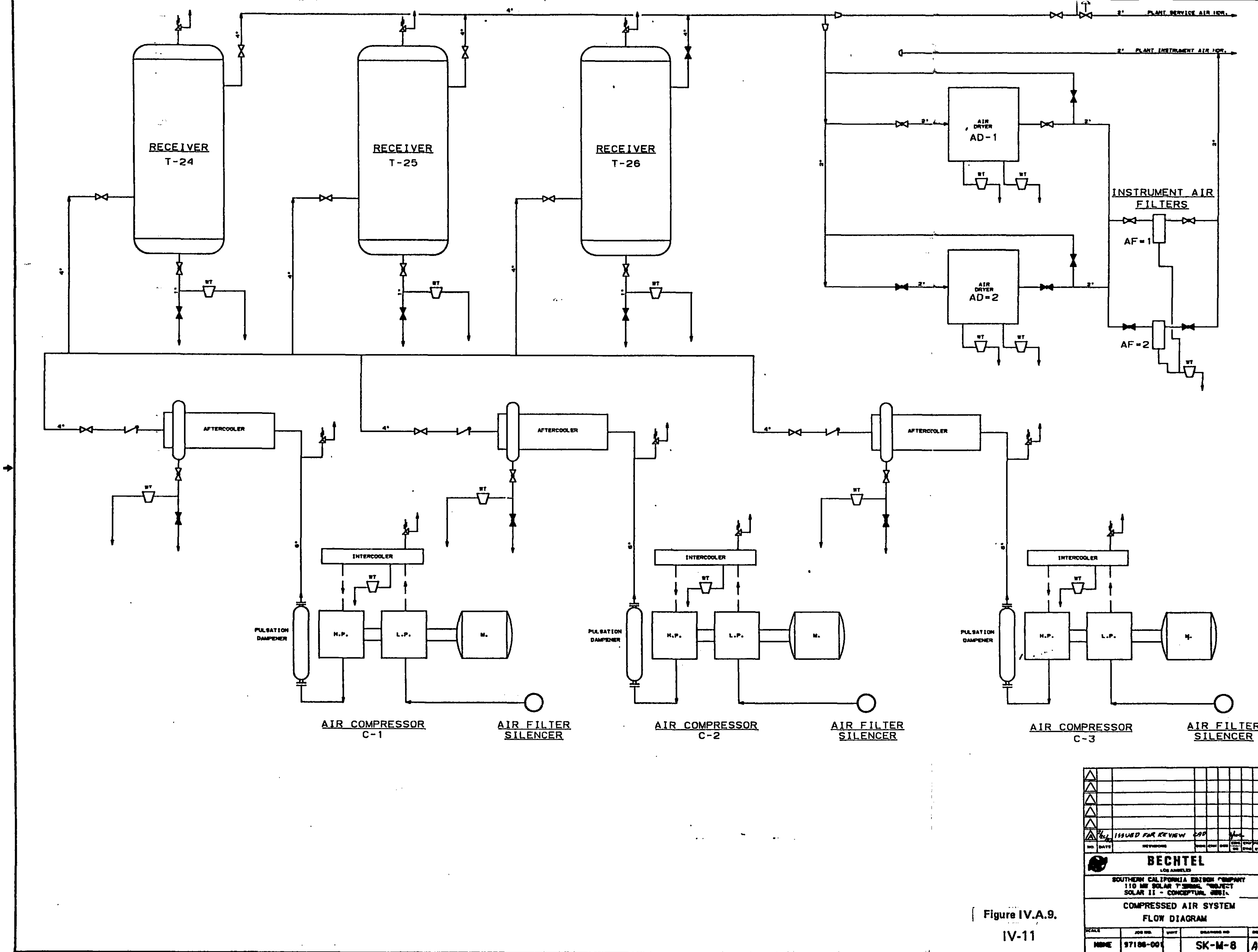

PLANT SERVICE AIR HDR.
PLANT INSTRUMENT AIR HDR.
RECEIVER
T-24
RECEIVER
T-25
RECEIVER
T-26
AIR DRYER
AD-1
AIR DRYER
AD-2
INSTRUMENT AIR
FILTERS
AF-1
AF-2
AFTERCOOLER
AFTERCOOLER
AFTERCOOLER
INTERCOOLER
INTERCOOLER
INTERCOOLER
PULSATION DAMPENER
PULSATION DAMPENER
PULSATION DAMPENER
H.P.
L.P.
M.
AIR COMPRESSOR
C-1
AIR FILTER
SILENCER
AIR COMPRESSOR
C-2
AIR FILTER
SILENCER
AIR COMPRESSOR
C-3
AIR FILTER
SILENCER
ISSUED FOR REVIEW
BECHTEL
LOS ANGELES
SOUTHERN CALIFORNIA EDISON COMPANY
110 MW SOLAR THERMAL PROJECT
SOLAR II - CONCEPTUAL DESIGN
COMPRESSED AIR SYSTEM
FLOW DIAGRAM
NONE
97186-001
SK-M-8
A

Figure IV.A.9.

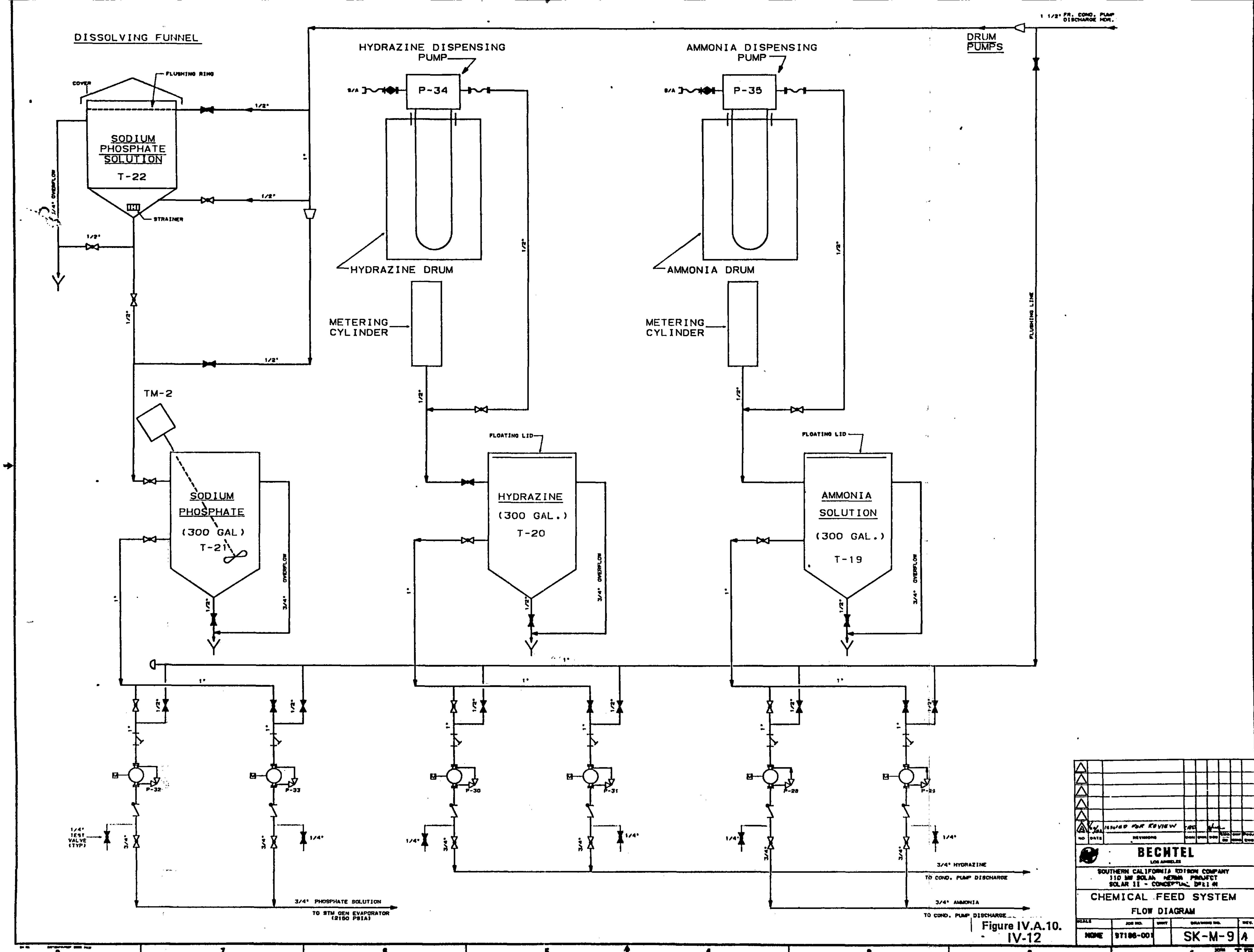
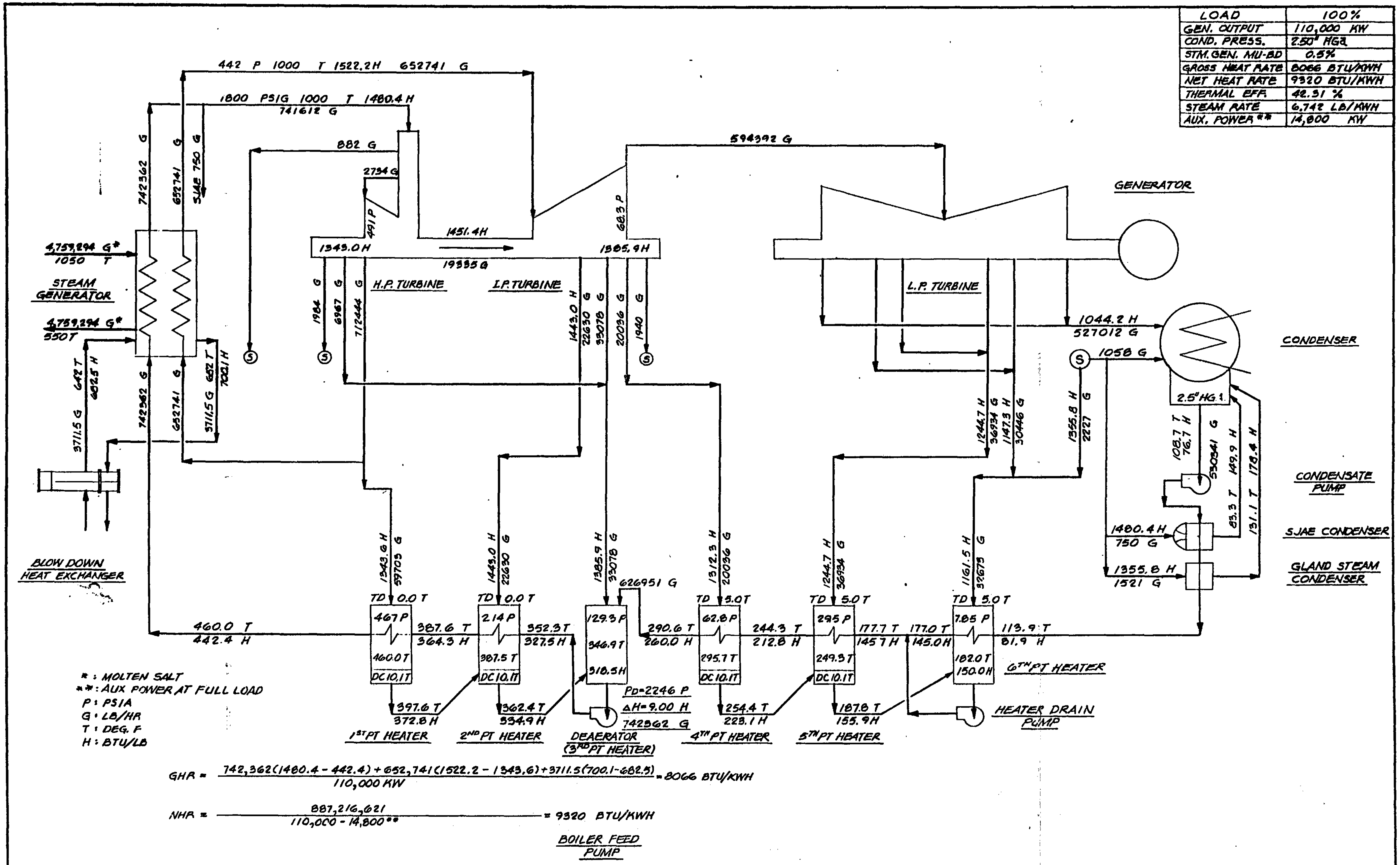


Figure IV.A.10.



LOAD	100%
GEN. OUTPUT	110,000 KW
COND. PRESS.	2.50" HGA
STM. GEN. MU-BD	0.5%
GROSS HEAT RATE	8066 BTU/KWH
NET HEAT RATE	9320 BTU/KWH
THERMAL EFF.	42.31 %
STEAM RATE	6.742 LB/KWH
AUX. POWER **	14,800 KW

$$GHR = \frac{742{,}362(1480.4 - 442.4) + 652{,}741(1522.2 - 1343.6) + 3711.5(700.1 - 682.5)}{110{,}000\ KW} = 8066\ BTU/KWH$$

$$NHR = \frac{887{,}216{,}621}{110{,}000 - 14{,}800^{**}} = 9320\ BTU/KWH$$

Location SOLAR TWO GENERATING STATION

STEAM TURBINE HEAT BALANCE
100% LOAD, 110MW GROSS OUTPUT

JZ 6552

Reference Drawings | No. | Revisions | Date | Approved | O.K. | O.K. | Ck'd. | Made | J.O. No. | Scale

Southern California Edison Company SCE

Figure IV.A.11.

SK-6552-M1-A

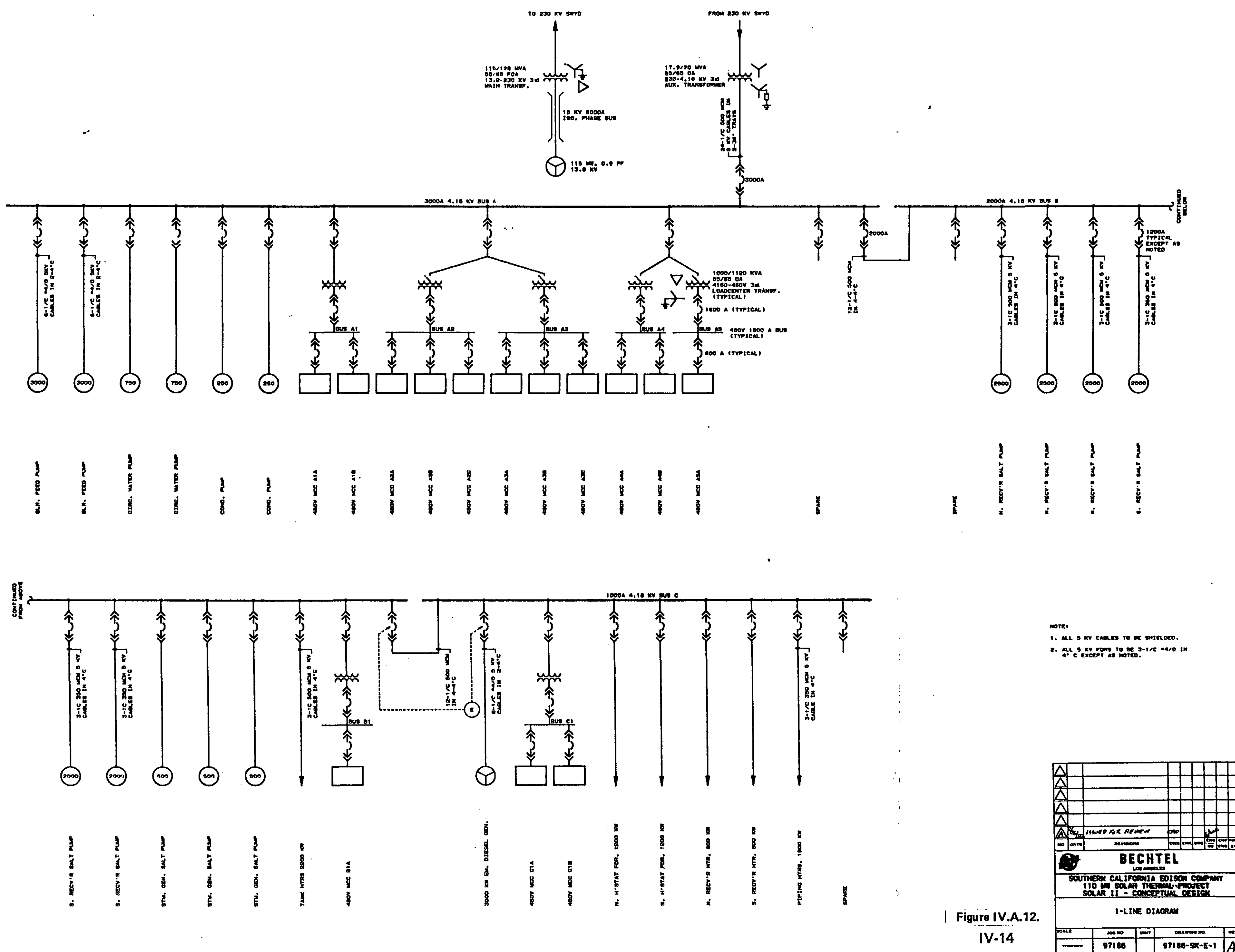


Figure IV.A.12.

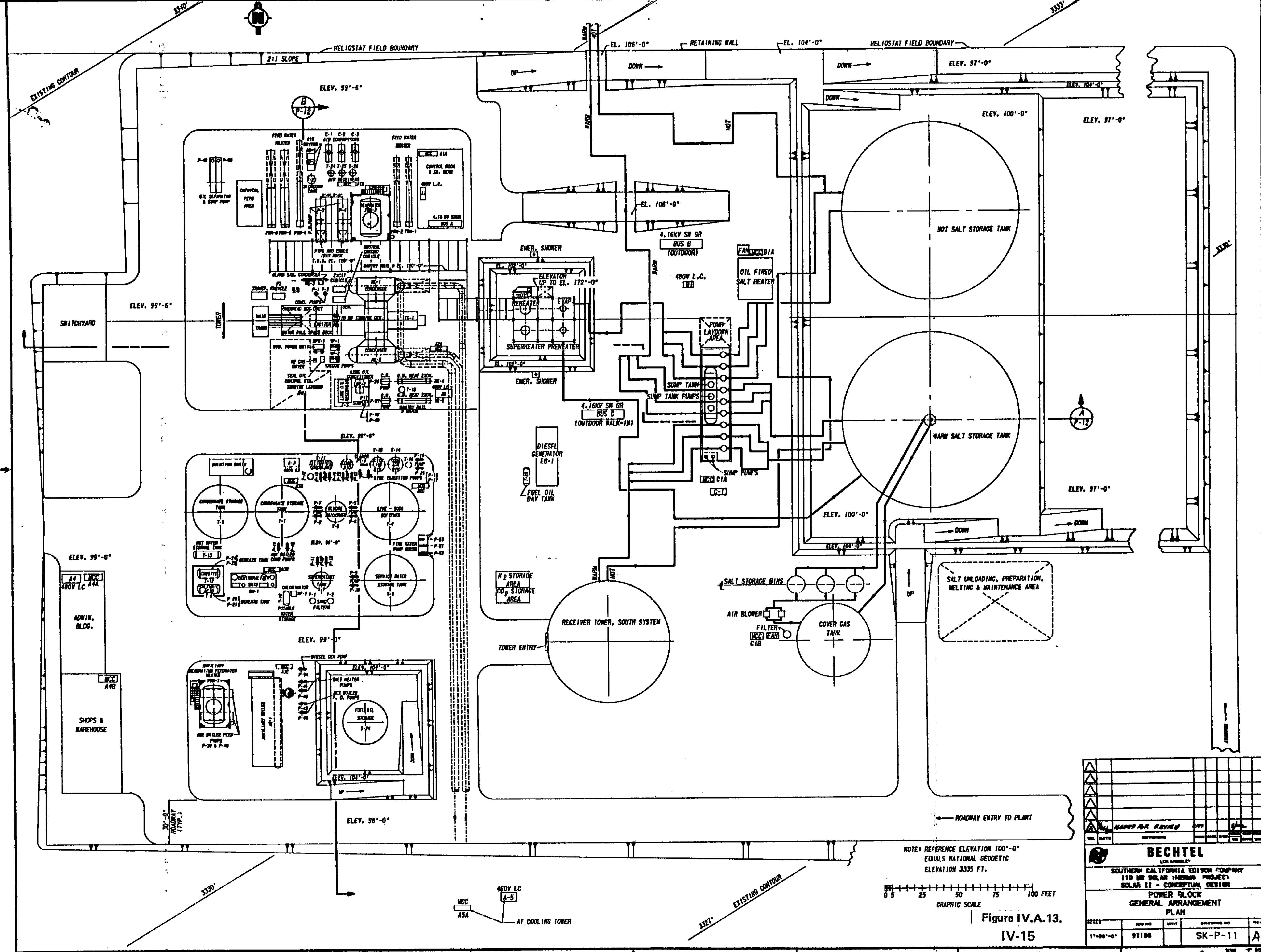


Figure IV.A.13.

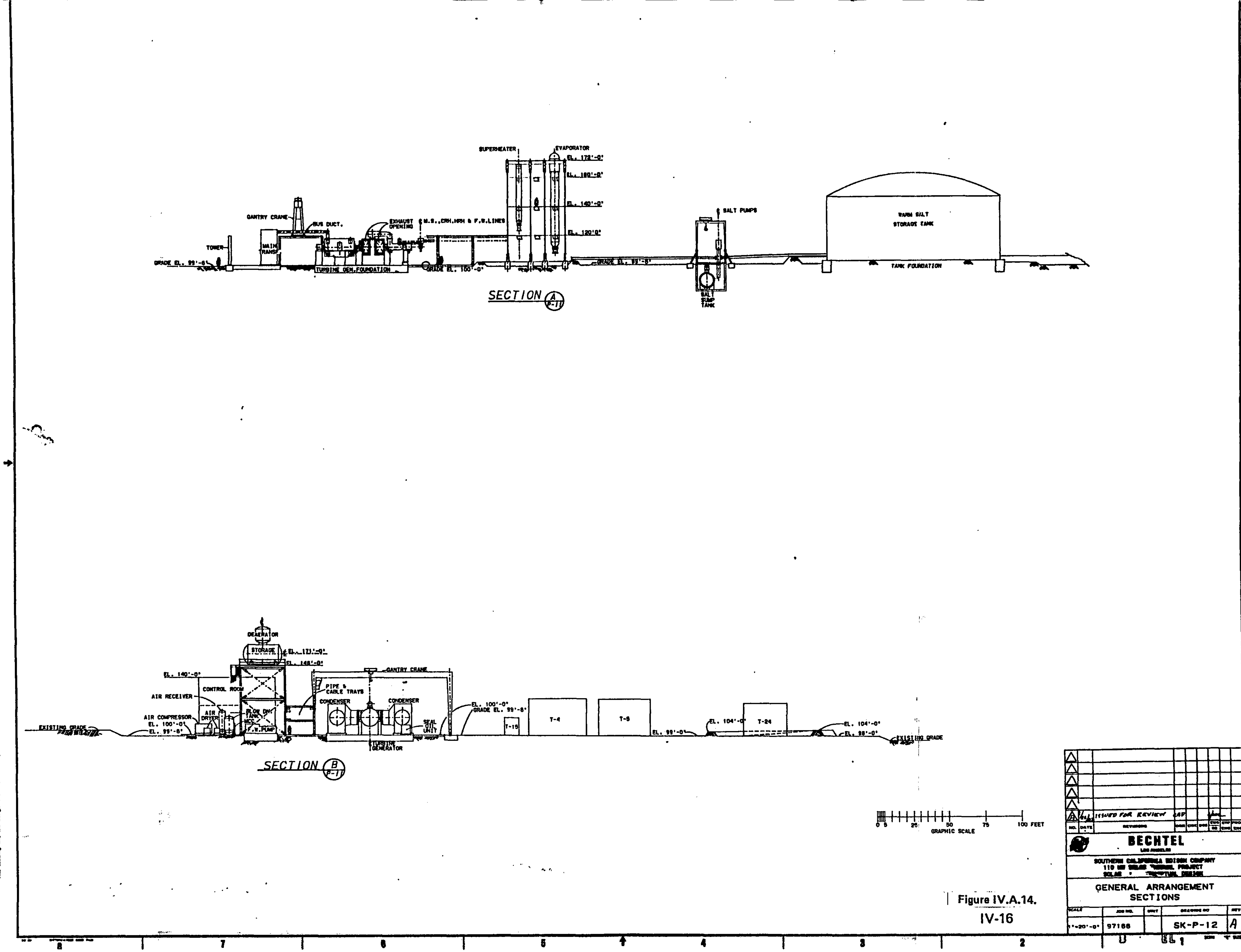
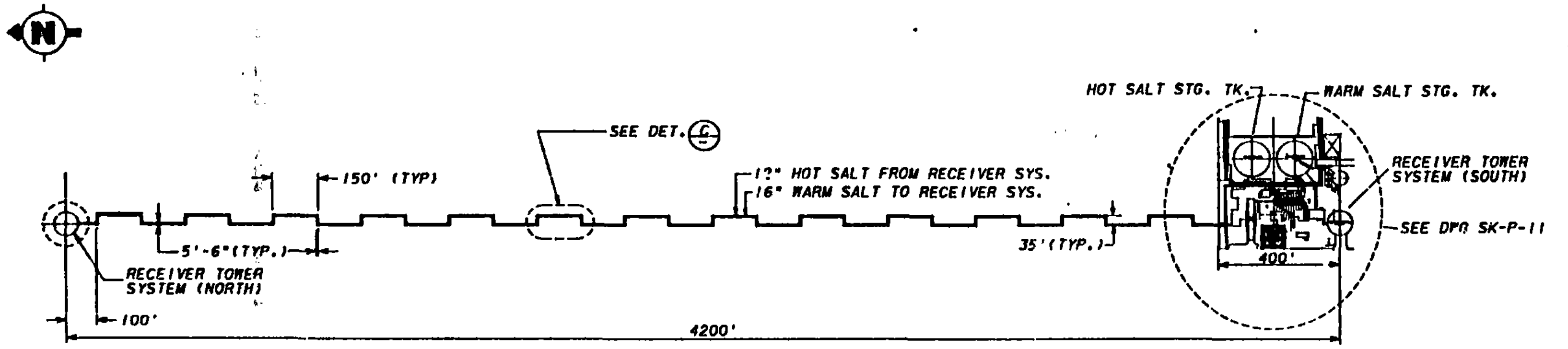


Figure IV.A.14.

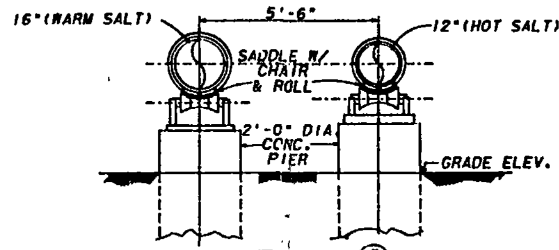


ENLARGED DET. OF PIPEWAY

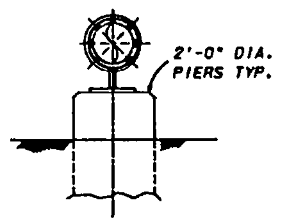
SCALE 1"=200'

0 100 200 400 FEET

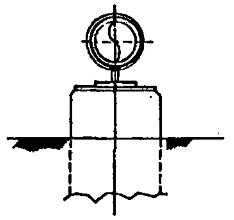
GRAPHIC SCALE



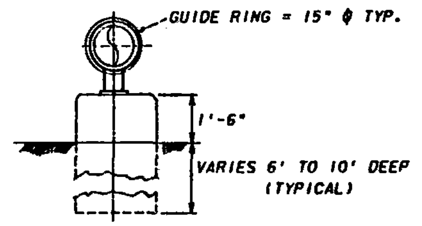
DETAIL D
(TYP)
NO SCALE



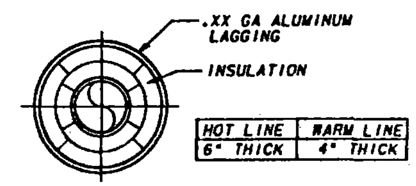
DETAIL E
THREE WAY RESTRAINT



DETAIL F
VERTICAL RESTRAINT



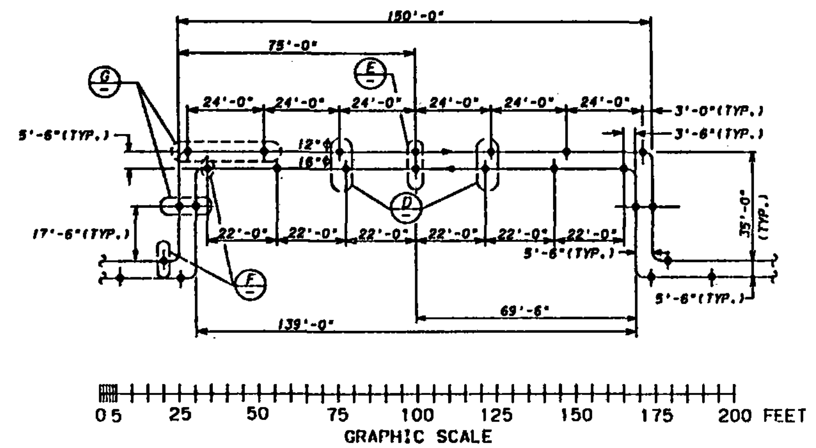
DETAIL G
VERTICAL AND LATERAL RESTRAIINT



INSULATION DETAIL H
NO SCALE

PIPING SPECIFICATION

	WARM SALT			HOT SALT		
	SOUTH RECEIVER SUPPLY	NORTH RECEIVER SUPPLY	STEAM GENERATOR RETURN	SOUTH RECEIVER RETURN	NORTH RECEIVER RETURN	STEAM GENERATOR SUPPLY
DESIGN PRESSURE, PSIG	860	1,045	70	545	610	220
DESIGN TEMPERATURE, °F	575	575	575	1,100	1,100	1,100
PIPE MATERIAL	A106, GR. C	A106, GR. C	A106, GR. C	A312 (316SS)	A312 (316SS)	A312 (316SS)
CODE	ANSI B31.1	ANSI B31.1	ANSI B31.1	ANSI B31.1	ANSI B31.1	ANSI B31.1
PIPE SIZE	16 INCH, SCH. 60	16 INCH, SCH. 80	14 INCH, SCH. 20	12 INCH, SCH. 60	12 INCH, SCH. 60	12 INCH, SCH. 30
WEIGHT PER FOOT, LB.						
PIPE	108	137	46	73	89	44
SALT	140	133	116	88	84	95
INSULATION	27	27	20	35	35	35
TOTAL	275	297	182	196	208	174
INSULATION						
TYPE	CALCIUM SILICATE	CALCIUM SILICATE	CALCIUM SILICATE	CALCIUM SILICATE	CALCIUM SILICATE	CALCIUM SILICATE
THICKNESS, INCH	4	4	4	6	6	6
HEAT LOSS, W/FT.	77	77	70	119	119	119
BTU / HR. FT.	264	264	237	407	407	407
SALT TEMPERATURE, °F	550	550	550	1,050	1,050	1,050



DETAIL C
PIPE EXPANSION LOOPS (TYP.)
SCALE 1"=20'-0"

Figure IV.A.15.

ISSUED FOR REVIEW

BECHTEL
LOS ANGELES

SOUTHERN CALIFORNIA EDISON COMPANY
110 MW SOLAR THERMAL PROJECT
SOLAR II - CONCEPTUAL DESIGN

MOLTEN SALT PIPING

SCALE	JOB NO.	UNIT	DRAWING NO.	REV.
NOTED	97186-001		SK-P-13	A

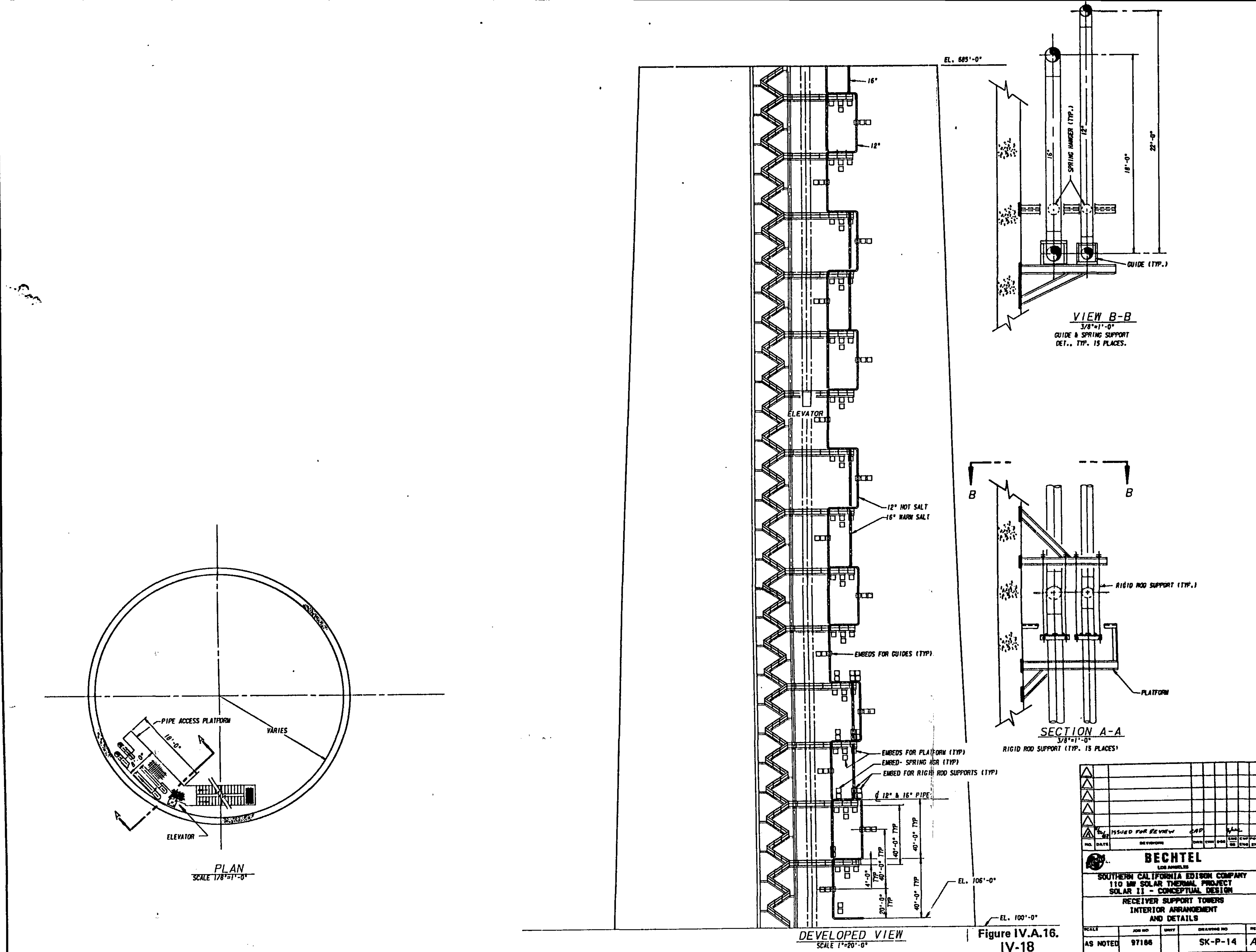


Figure IV.A.16.

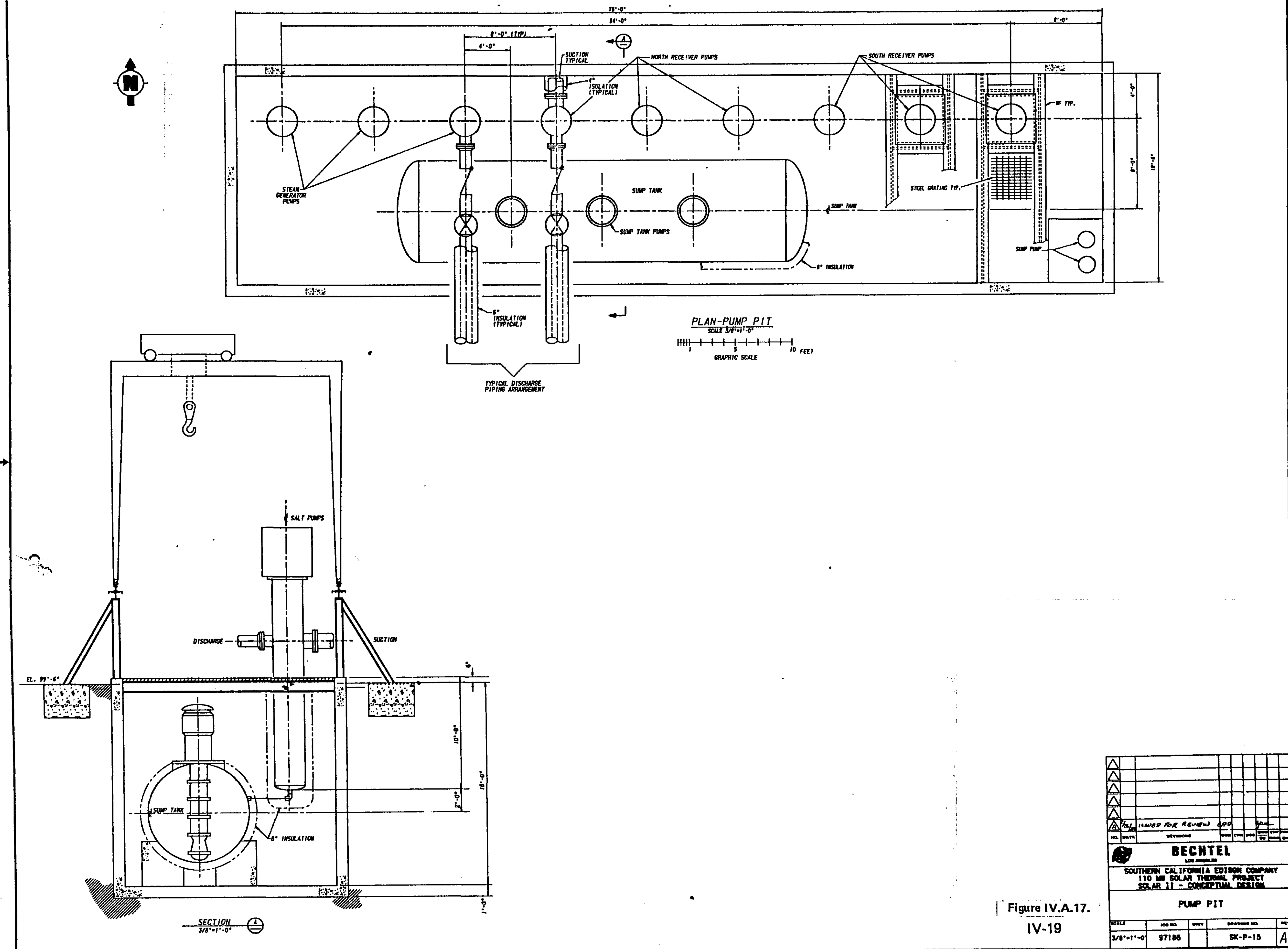
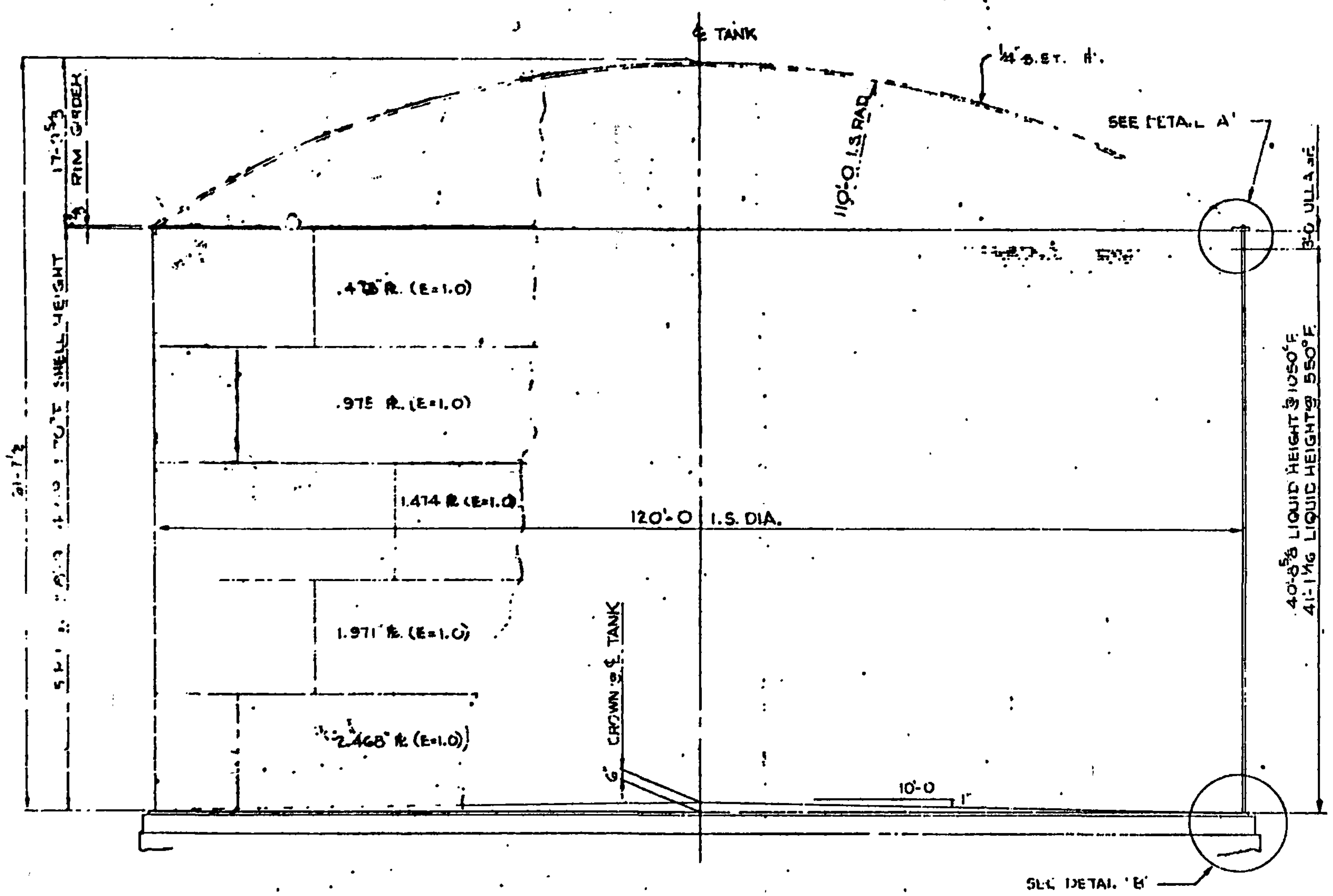
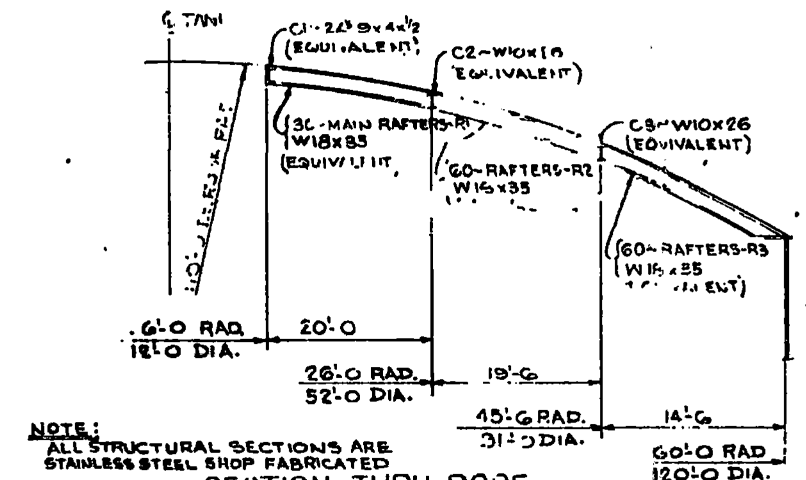


Figure IV.A.17.

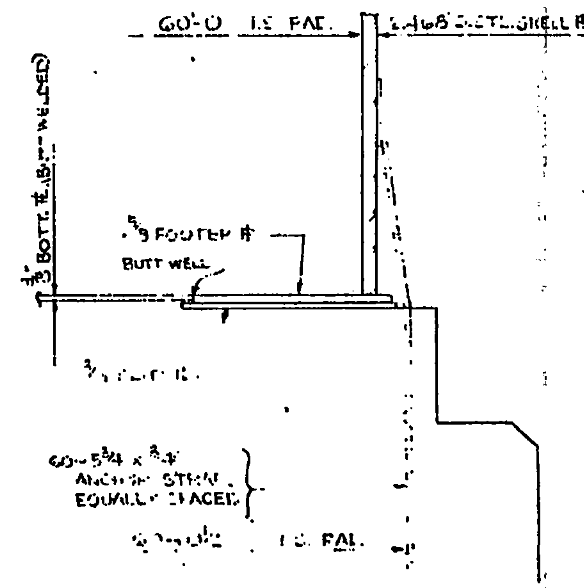


TANK ELEVATION

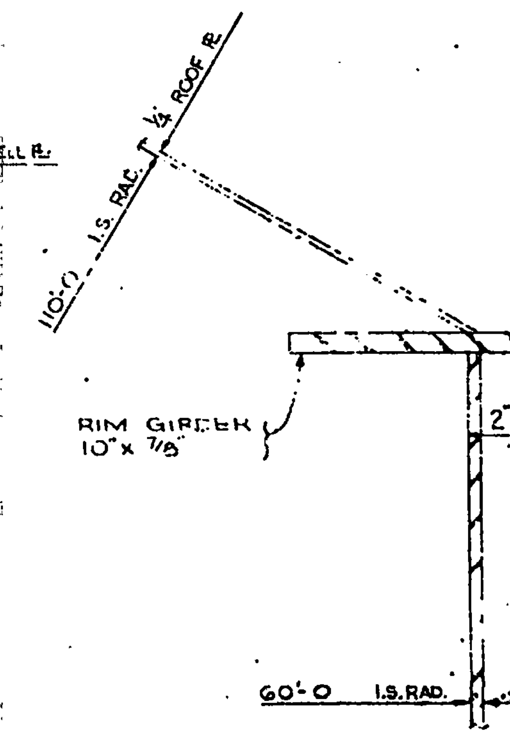


NOTE:
ALL STRUCTURAL SECTIONS ARE STAINLESS STEEL SHOP FABRICATED

SECTION THRU ROOF



DETAIL 'B'



DETAIL "A"

NOTES:

I DESIGN DATA

CONTENTS: 467850 CF (INCLUDES 3'-0 HEEL) MOLTEN SALT @ 119 #/CF @ 550°F

DESIGN PRESSURE: 0.1 PSIG + LIQ HEAD

DESIGN TEMPERATURE: 1050° F

WIND LOAD: 96 MPH @ 30 FT. HT. (EQUIVALENT TO UBC 25 PSF @ 30'-0)

EARTHQUAKE: API 650 APPK E ' ZONE 4

ROOF LOAD: APPROX. 20 PSF (WIND, VACUUM & INSULATION)

5000 PSI SOIL

SPECIFICATIONS: ASME SECT. VIII DIV. 1, API CODES, & CUSTOMER SPECS

MATERIALS OF CONSTRUCTION

TANK SHELL & BOTTOM ℞ SA 240 - 316

ROOF SA 240 - 316

RIM GIRDER SA 240 - 316

ROOF STRUCTURAL SA 240 - 316 OR EQUIVALENT SHOP FABRICATED

TANK STIFFENERS NONE

ANCHORS SA 240 - 316

BOTTOM INSULATION SUPPLIED BY PDM

SHELL & ROOF INSULATION SUPPLIED BY CUSTOMER

Figure IV.A.18.

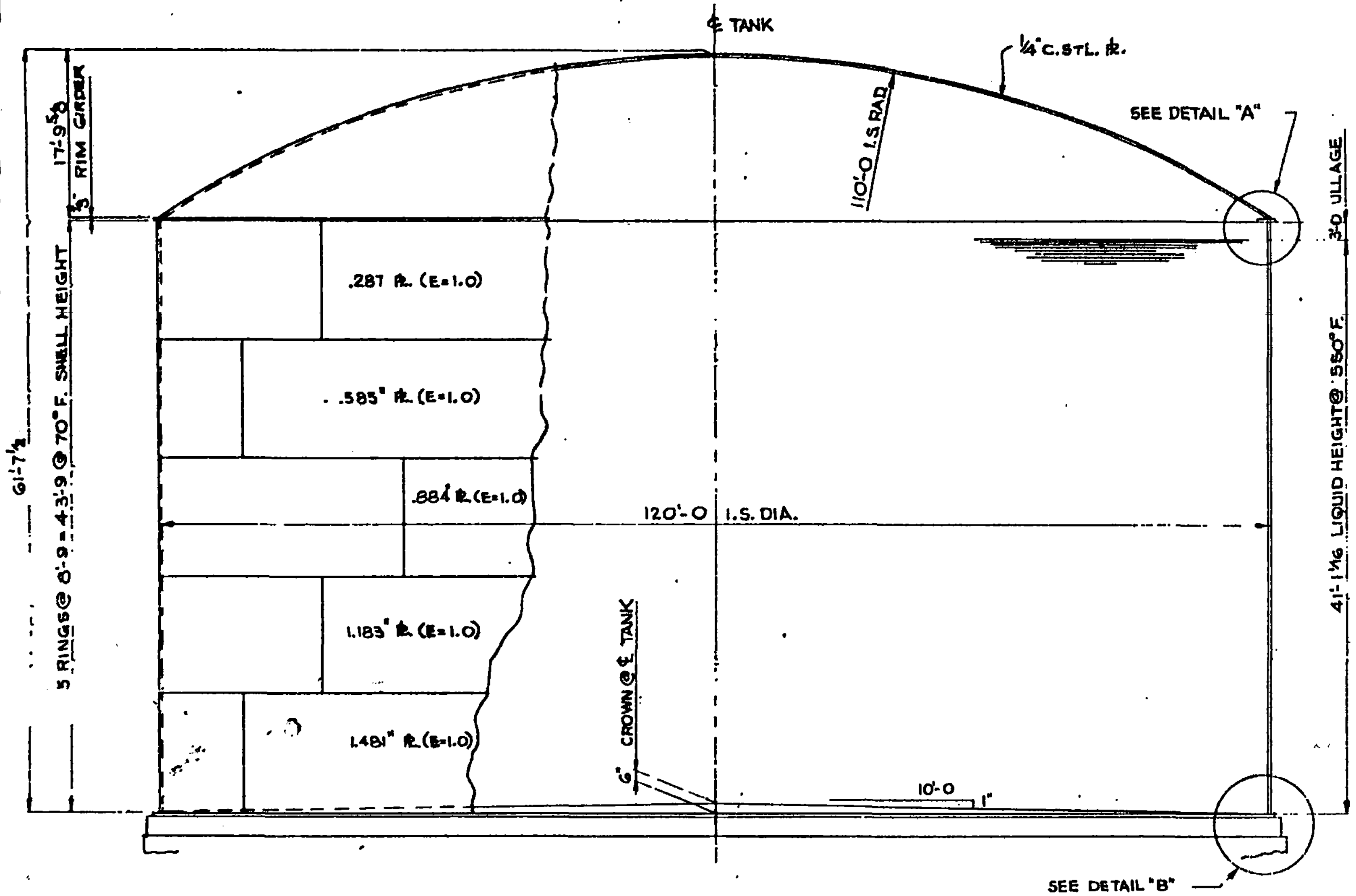
PITTSBURGH-DES MOINES CORP.
ENGINEERS - FABRICATORS - CONTRACTORS
PITTSBURGH PA

DRAWN RS 11-19-81

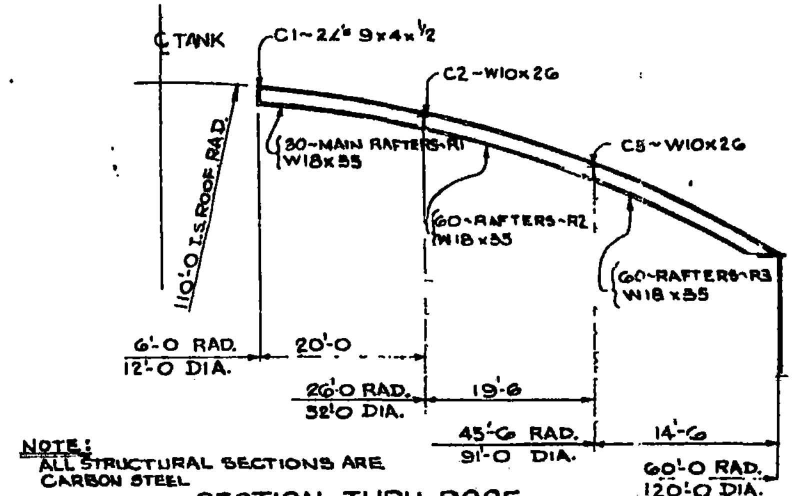
CONTRACT NO. 81181

DESIGN DRAWING NO.

DAB

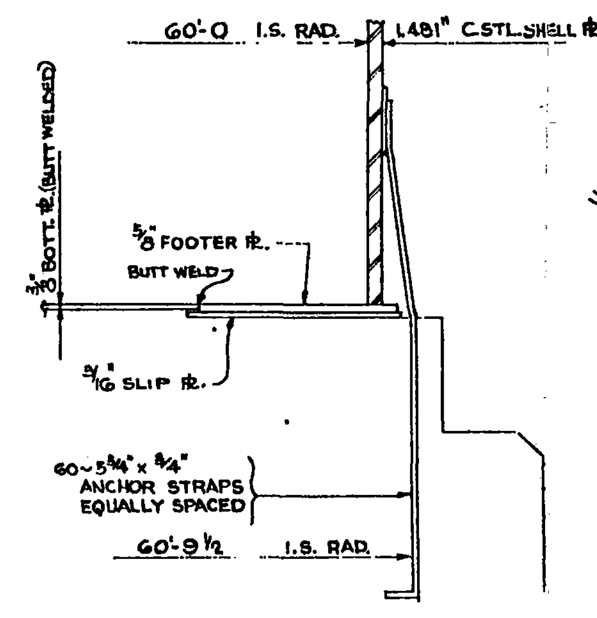


TANK ELEVATION

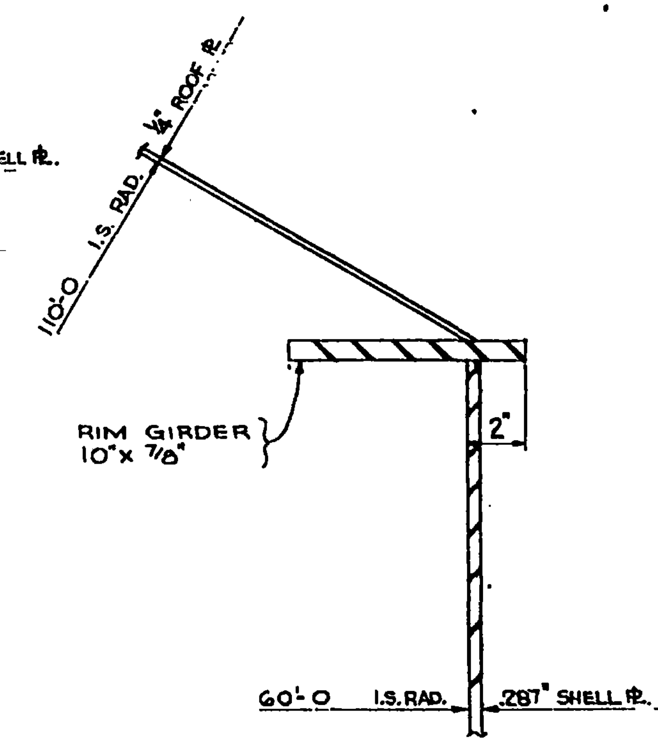


NOTE: ALL STRUCTURAL SECTIONS ARE CARBON STEEL

SECTION THRU ROOF



DETAIL "B"



DETAIL "A"

NOTES:

I DESIGN DATA

1.) CONTENTS: 467850 CF (INCLUDES 3'-0 HEEL) MOLTEN SALT @ 119#/CF @ 550°F
2.) DESIGN PRESSURE: 0.1 PSIG + LIQ. HEAD
3.) DESIGN TEMPERATURE: 550° F.
4.) WIND LOAD: 90 MPH @ 30 FT. HT. (EQUIVALENT TO UBC 25 PSF @ 30'-0)
5.) EARTHQUAKE: API 650 APPX. E ZONE 4
6.) LIVE ROOF LOAD: APPROX. 20 PSF (WIND, VACUUM & INSULATION)
7.) SOIL PRESSURE: 3000 PSI SOIL
8.) SPECIFICATIONS: ASME SECT. VIII DIV. 1, API CODES, & CUSTOMER SPECS.

II MATERIALS OF CONSTRUCTION

1.) TANK: SHELL & BOTTOM PL. SA 516-GR.70
ROOF SA 516-GR.70
RIM GIRDER SA 516-GR.70
ROOF STRUCTURAL SA 36 OR EQUIVALENT
TANK STIFFENERS NONE
ANCHORS SA 36
2.) BOTTOM INSULATION SUPPLIED BY PDM
3.) SHELL & ROOF INSULATION SUPPLIED BY CUSTOMER

Figure IV.A.19.

IV-21

NO	DATE	DESCRIPTION OF REVISION	BY	CKD.	PROJ ENGR.
0	11-11-81	INITIAL ISSUE	RS		

PITTSBURGH-DES MOINES CORP.
ENGINEERS – FABRICATORS – CONTRACTORS
PITTSBURGH, PA.

550° F. MOLTEN SALT TANK
DAGETT, CALIFORNIA

	BY	DATE
DESIGNED		
DRAWN	RS	11-10-81
CHECKED		
SCALE		

CONTRACT NO. 81181
DESIGN DRAWING NO. D-2

MODIFICATION MAY BE MADE BY THE PITTSBURGH - DES MOINES CORP. IN THE DESIGN OF THIS STRUCTURE BUT THE REVISED DESIGN MUST COMPLY WITH THE SPECIFICATIONS.

1. Operating Modes

Plant operating modes are most easily described by separating the plant into a heat collection and a power generation function. The heat collection function involves the receiver, collector, and receiver salt loop equipment. The function is to circulate salt from the warm tank through the receiver to heat the salt, and return it to the hot tank. The power generation function involves the steam generator, the turbine and feedwater system, the circulation water system, and the steam generator salt loop. The function is to circulate salt from the hot tank through the steam generator, produce steam, and return the salt to the warm tank, expand the steam through the turbine to generate electricity, and return preheated feedwater to the steam generator.

a. Heat Collection Operating Modes

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

Normal Operation - In this mode, salt is supplied to the receivers at about 550°F with adequate pressure to maintain receiver flow and control. The salt flow is regulated by a throttle valve downsteam of the receiver feed pumps. The throttle valve adjusts the salt flow to maintain the salt level in the warm surge tank.

There are three half-capacity receiver feed pumps for each receiver. The system runs on one pump at up to 50% rated flow and two pumps from 50 to 100%. One pump is kept in reserve. Pump startup time is sufficiently rapid to maintain minimum receiver flow rate in the event of transition to the reserve pump.

A receiver warm surge tank serves as a buffer to protect the warm salt line from hydraulic ram. The tank also provides a reservoir of salt to maintain receiver flow in the event of a receiver feed pump shutdown.

The salt flow through the receiver is regulated by control valves for each of four parallel circuits. Under normal operation, the salt flow is regulated to 1050°F outlet temperature. Under conditions of low receiver flow (less than 20% of maximum flow) or rapid insolation variation (due to partial cloud cover), the system automatically transitions to bypass flow operation, as discussed in the following.

The receiver control utilizes outlet temperature feedback as the outer control loop. An inner control loop senses heat flux to provide rapid response feed-forward control under variable insolation conditions.

A second surge tank is provided on the receiver outlet to protect the hot salt line from hydraulic ram. Level in this tank is controlled by a throttle valve near the hot tank inlet. The outlet surge tank is kept at ambient pressure.

In early morning and late afternoon, energy is available from the collector field in quantities worth collecting. However, the receiver may not be able to operate at rated conditions for one or more of these reasons:

- The flow in one of the receiver circuits may be slow enough to transition to laminar flow with a resulting heat transfer co-efficient too low for receiver tube temperature to stay within operating conditions.

- The flux distribution on a circuit may peak too high for tube temperature to stay within operating conditions.

- The control valve for a circuit may be driven out of its desired range of operation.

A minimum of 20% rated flow is maintained in each circuit under low receiver power conditions. This condition results in a receiver outlet temperature less than 1050°F. A bypass loop allows the salt flow from the receiver to be diverted to the warm storage tank. Salt below 1045°F is diverted to the warm tank when the hot storage tank temperature is approaching 1045°F.

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, the 20% rated flow minimum condition may be reached. The reasons are the same as those for early morning and late afternoon. The minimum flow constraint of 20% is applied under all insolation conditions.

Warm or Overnight Hold - During periods of no insolation, such as nighttime, the heat collection system 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.

b. 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.

Normal Operation - In this mode, salt is supplied to the steam generator at 1050°F. The steam generator produces primary steam at 1005°F and 1850 psi and reheat steam at 1005°F. The salt is returned to the warm tank at 550°F. Feedwater is supplied at 460°F.

The salt flows through the superheater and reheater in counterflow. The salt flow rate is regulated to produce the desired steam outlet temperature without attemporation. A salt bypass around the super-heater and reheater is provided to balance the salt flow. The salt streams merge and flow through the evaporator. Water flows through the evaporator by natural circulation. An integral drum separator provides dry, saturated steam to the superheater. From the evaporator the salt flows through the preheater in counterflow. Total salt flow is regulated by a control valve on the preheater outlet. This valve also provides positive back pressure on the salt at all times.

Two half-capacity pumps circulate the salt. A redundant pump is provided to ensure availability.

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. Turbine pressure control is achieved by varying evaporator drum pressure. The drum pressure is, in turn, controlled by the salt flow rate.

During startup, the feedwater preheaters operate at a reduced temperature. Drum steam is fed to the final preheater to peg its temperature at 460°F. The pressure ramp rate is controlled to keep the superheater inlet temperature ramp rate below 150°F per hour.

Startup is initiated with one steam generator salt pump. The second pump will be started when the salt flow rate approaches 50% of rated flow. Below 35% load, steam flow is controlled by the turbine throttle valve. Salt flow is adjusted to maintain drum pressure.

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 do not require the use of trace heating.

The evaporator and preheater are similarly isolated. The preheater requires almost immediate trace heating. The evaporator requires no trace heating for two or more days. Evaporator drum pressure is monitored because heat contained in the salt at shutdown continues to make steam until equilibrium is established. When the steam generator undergoes rapid shutdown (no sliding pressure), steam is vented from the drum or steam is blown to the condenser.

Trace heating is required in the salt line from the preheater to the warm tank for overnight hold. Other salt lines require trace heating only during extended shutdown.

c. Typical Daily Operation Timeline

Operation on a typical equinox day is shown on Figure IV.B.1. Insolation is depicted in the first chart. Usable energy levels are reached at about a 10° sun elevation angle. The insolation appears to be significant below 10°, but the field cosine angle is too low to provide much useful energy on the receiver. However, some of this energy below 10° can be used in receiver startup.

The afternoon is depicted with insolation dropouts typical of a desert site. Approximately 17% of the time cloud transients are experienced. Hence, cloud transients are sufficiently typical that they are included in a "typical" day. The insolation level is typical of a clear day. However, bright days can have insolation 10% higher.

The receiver response to the insolation is shown in the second chart. For simplicity, the receiver is shown as starting at the 10° sun elevation angle. Note that at startup, the receiver is above the 20% power level threshold. However, a short period of bypass salt flow is still required for a controlled startup.

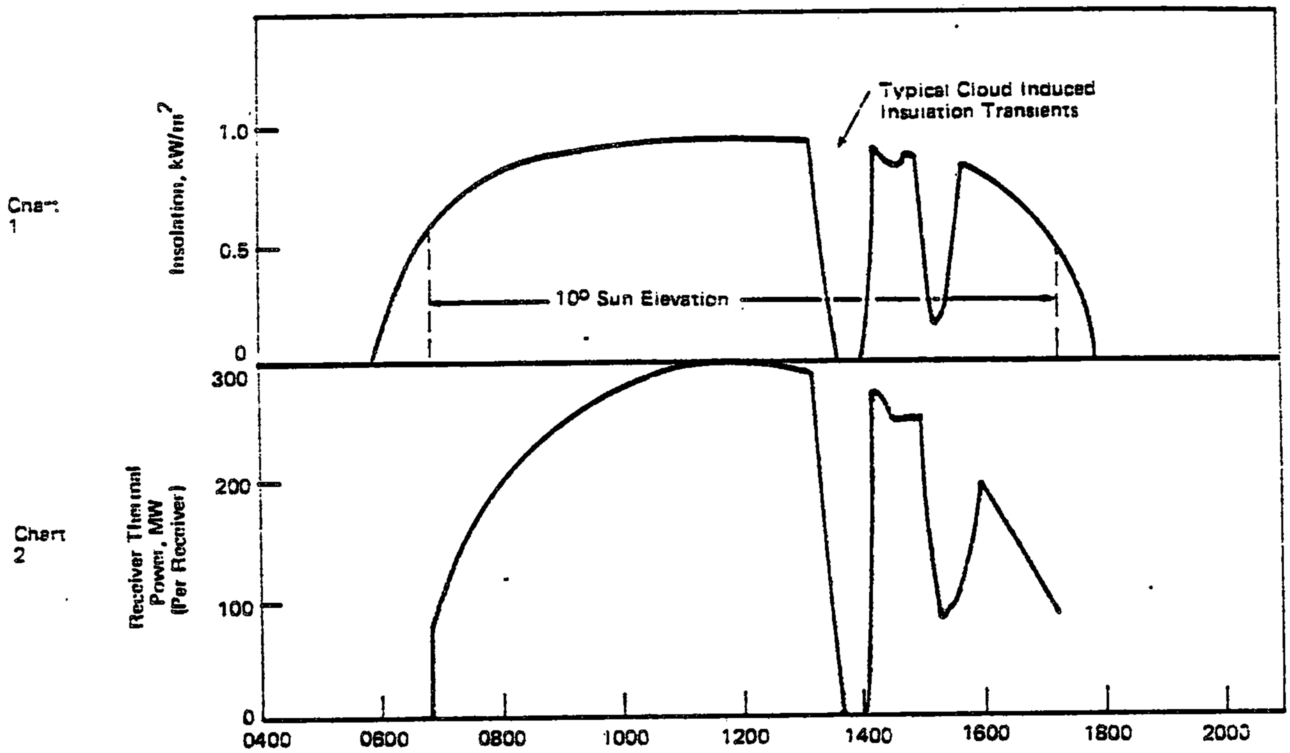


Figure IV.B.1(a). Typical Daily Operation Timeline

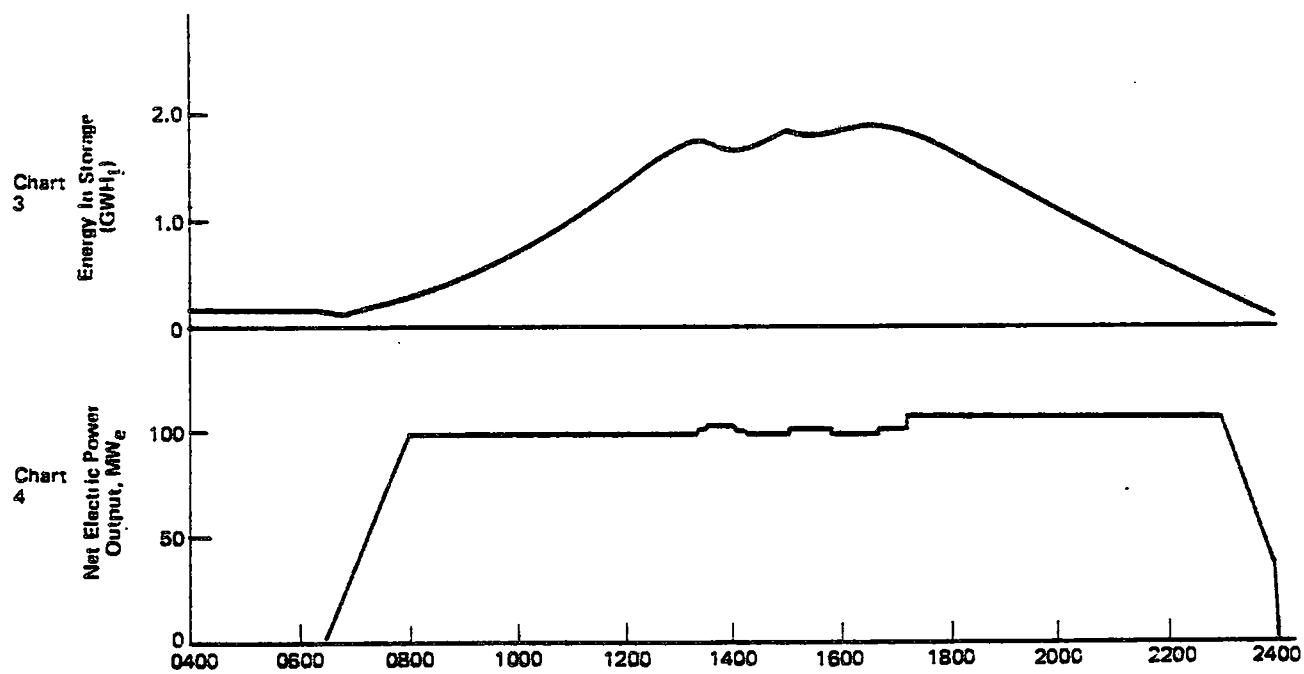


Figure IV.B.1(b). Typical Daily Operation Timeline

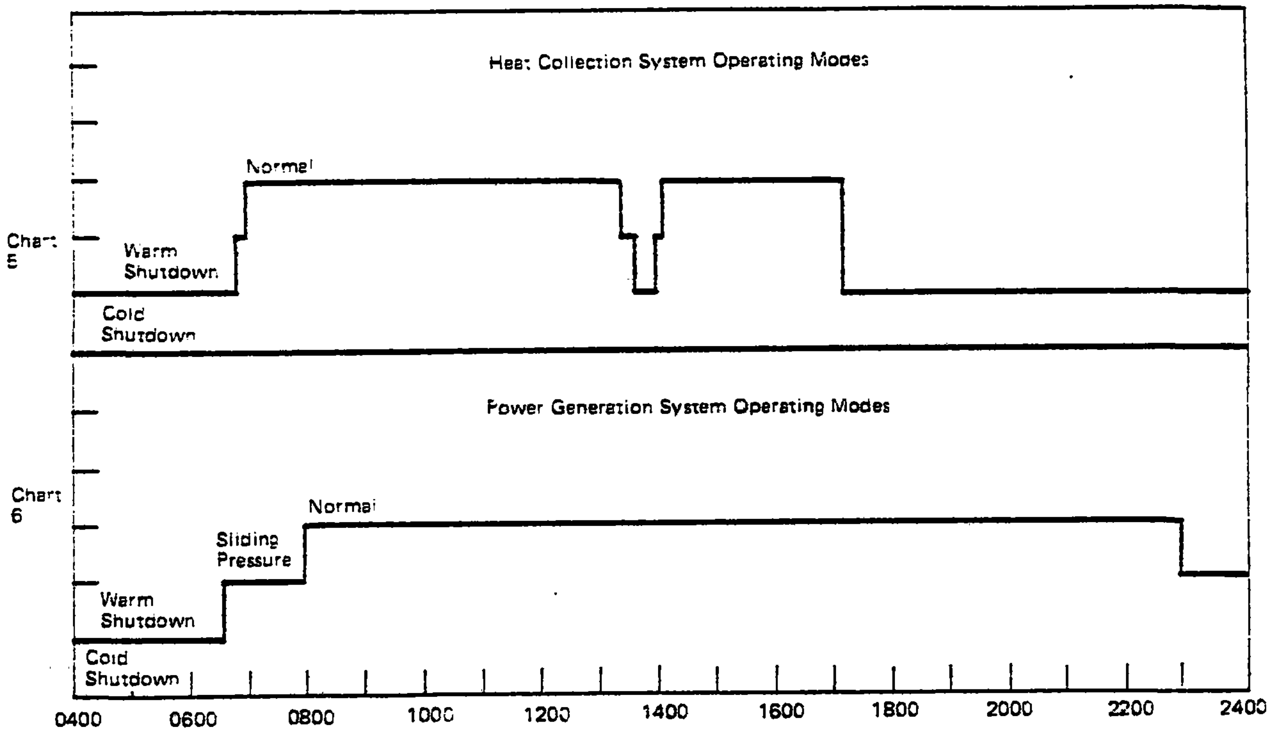


Figure IV.B.1(c). Typical Daily Operation Timeline

The first afternoon clouds cause a complete receiver shutdown, and necessitate a restart. The second cloud is not totally opaque. The receiver continues to operate through this transient, although a period of bypass salt flow may be required.

The energy collected by the receiver is stored in the molten salt hot tank. As shown in the third chart, there is about one-half hour reserve in the tank for morning startup. The startup cycle begins at about sun up. The steam generator and turbine are operated at reduced pressure when the receiver is started. Energy collected in excess of turbine demand is accumulated in the hot tank. The relatively small impact of the cloud transients on energy stored indicates the degree of buffering provided by storage.

Storage is exhausted about midnight. The turbine goes into sliding pressure operation at about 11:00 p.m. to keep the superheater inlet temperature ramp rate within the allowable range.

During the day, the turbine generator output varies only in the startup and shutdown operations. Chart 4 depicts this, as well as small variations in net station output resulting from changes in auxiliary power load.

The heat collection system operating modes are shown in Chart 5. Cold shutdown is atypical, and rarely used. The transition to warm shutdown caused by the afternoon clouds is also indicated. Similarly, Chart 6 shows the power generation system operating modes. The full extended period of normal operation is unaffected by cloud transients.

2. Safety Provisions

The safety procedures and features for the plant are, in general, covered by existing standards, codes, and procedures (see Reference VIII.B.1). Some of the highlights are described in the following paragraphs.

Collector - Safety precautions for the collector system are conventional and covered by OSHA-type requirements. The only unique hazard concerns the energy in reflected beams for heliostats. Extensive analysis for Solar I at Barstow (Reference III.B.1) shows that the reflected beams from one heliostat are safe for personnel at any point in the beam, but a point which is in the beams from two or more heliostats may be unsafe. The dominant damage mechanism is a burn on the retina of the eye, but cornea (eye) or skin burns must also be considered.

Operation of the collector field requires that many beams from heliostats converge at specified points. An example is the standby aimpoint for the collector used in collector/receiver startup. Areas in the airspace above the site which have unsafe beam conditions will be designated as exclusion zones. A preliminary estimate indicates that safe conditions always exist at an elevation 1000 feet above the tower. Even 500 feet above the tower is likely to be safe, but further validation is required.

All beam conditions on the ground within the collector field are safe. South of the collector field, unsafe conditions potentially exist. Personnel and equipment exclusion zones are established to protect the operations and maintenance crews. Workers in the field are required to wear lightweight protective clothing and glasses.

Receiver - The receiver system design is governed by Section VIII of the ASME Boiler and Pressure Vessel Code. The piping is designed to ANSI B31.1. Insulation is provided to prevent excessive temperature on the external surfaces of the receiver and salt loop piping.

The receiver unit is drained into the warm storage tank to prevent freezing in the event of extended shutdown and to allow personnel access to the interior of the receiver for maintenance or replacement.

Tower - The receiver tower requires aircraft warning lights and listing on air navigation maps.

The tower requires ventilation to prevent the buildup of heat leakage through the insulation. Natural convection is expected to provide adequate ventilation.

Storage and Transport - A berm and salt containment area is provided around the thermal storage tanks to contain salt leakage.

Steam Generator - The steam generator heat exchangers are designed to Section VIII of the ASME Boiler and Pressure Vessel Code.

Steam piping and interfaces with the existing plant will be designed to the ANSI B31.1 power piping code.

Plant Control - Plant control is provided with appropriate interlock logic to assure safe operation. Mode changes and trip conditions are coordinated to provide safe transitions and shutdown.

Storage of heliostats and transition between stowage and standby is under the control of the HAC and is programmed to assure safe beam intensity.

Turbine Generator and Balance of Plant - Safety precautions for these systems will be conventional.

3. Trips and Emergency Operations

System trips and emergency procedures will be designed to assure safe operation and to prevent damage to equipment. Analysis of trips will be determined in preliminary engineering.

IV-C. COLLECTOR SYSTEM

1. Functional Description

The collector system consists of two fields of heliostats, the required power elements and control elements for directing individual heliostats and groups of heliostats. The purpose of the collector system is to redirect solar radiation and to focus it onto the receiver absorbing surface. The field supplies 326 MW_t incident energy to the 5598 ft^2 receiver aperture at winter solstice noon.

Each heliostat automatically tracks the sun and continually directs reflected sunlight onto the receiver. The heliostat control and drives position the heliostat reflecting surface such that the pointing accuracy meets specified requirements for receiver flux distribution. In addition, the control and drives reposition the reflecting surface from any operational orientation to a position for night stow, periodic maintenance, high wind stow, and emergency or planned defocusing of the heliostats (standby).

An aim strategy is used to achieve a power distribution on the receiver absorbing surface and to preclude exceeding the design flux limit of 0.6 MW/m^2. A number of heliostats are assigned to each aimpoint. During the day, the peak flux will vary along with the receiver intercept factor. The resulting flux distribution is described in the receiver system, Section IV-E. Command and monitor of the collector system originates in the plant control system described in Section IV-J. Plant electrical power is provided to operate the heliostats.

2. General Arrangement

Each of the two collector system fields occupies 509.3 acres within the plant site. They are adjacent to each other in north-south positions, as shown on the site plot plan, Figure IV.A.1. Each field contains 7712 heliostats in a radially staggered orientation, as shown on Figure IV.C.1, where the individual heliostat positions are shown with respect to the receiver tower.

$7712 \times 56.85 \approx 438427 m^2$

3. Major Equipment Descriptions

The major equipment items associated with the collector field are the heliostats, the field control (including a beam characterization system (BCS)) and field electrical power and wiring, as shown on Figure IV.C.2.

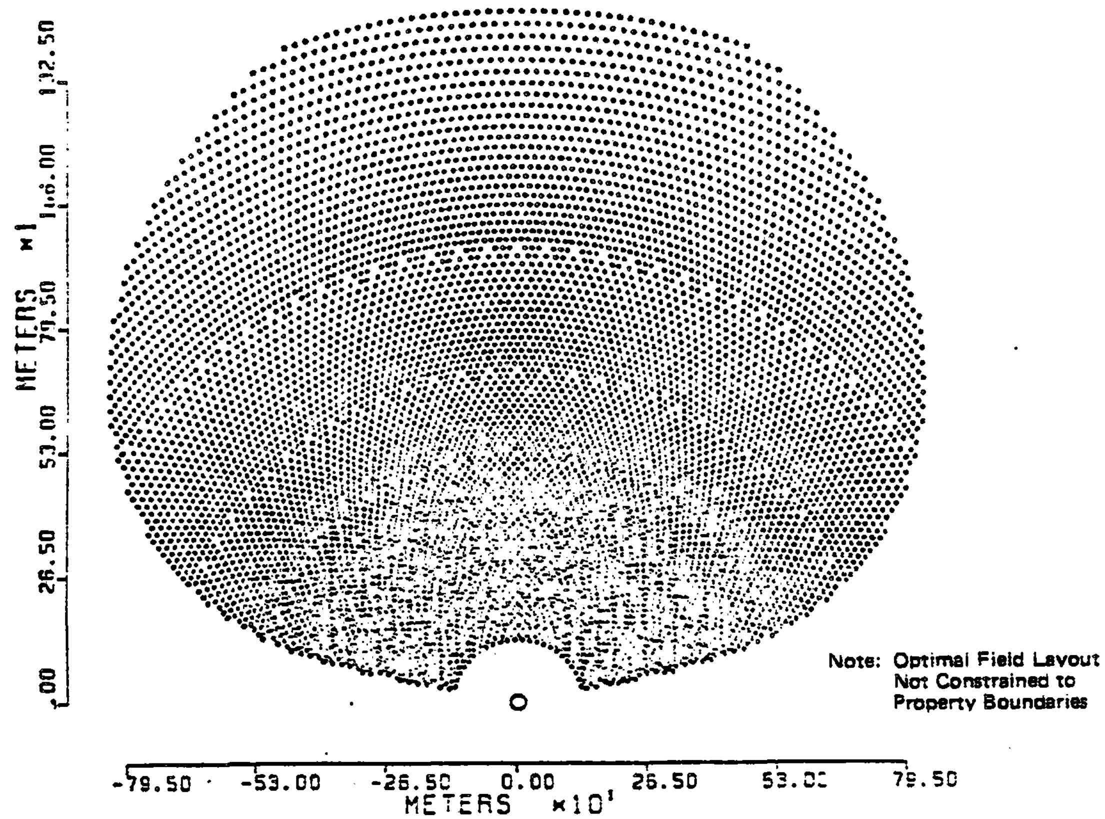


Figure IV.C.1. Heliostat Layout

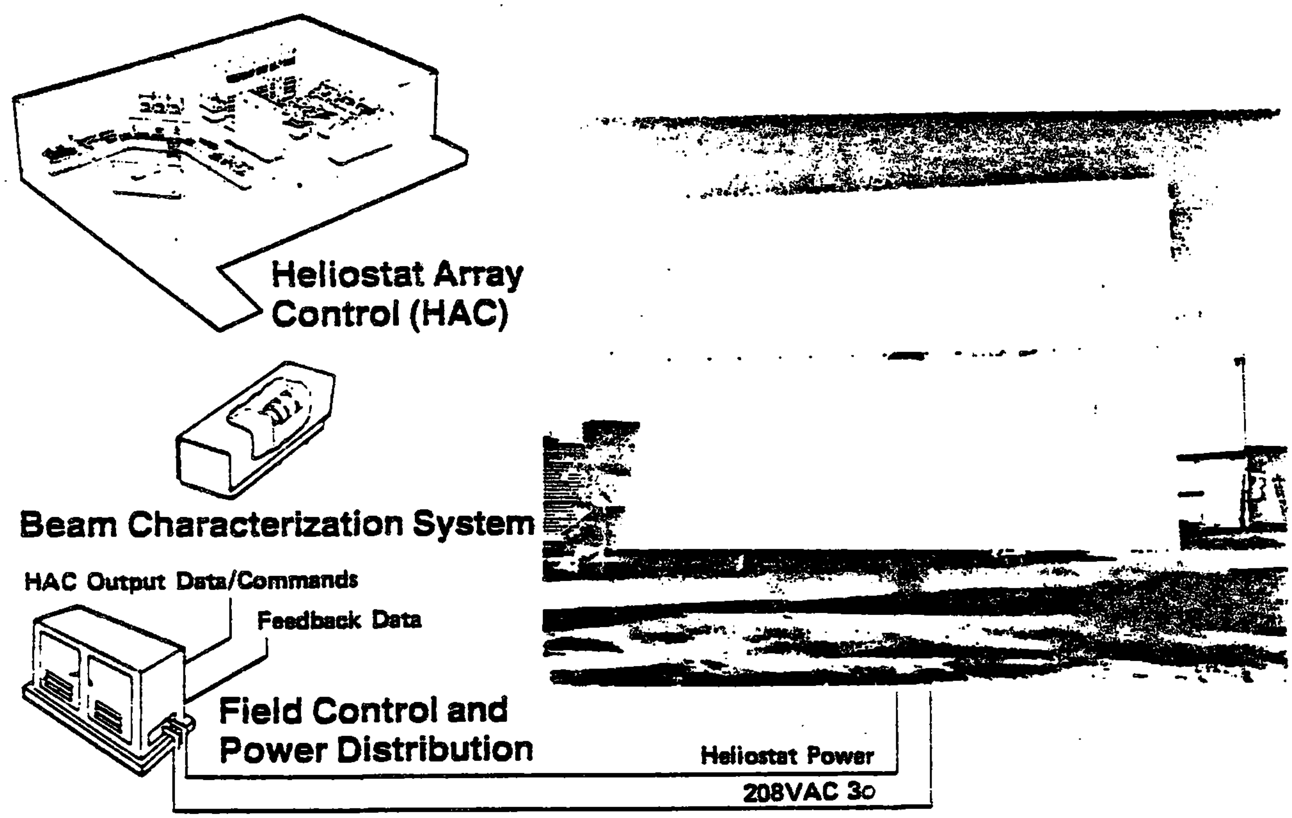


Figure IV.C.2. MDC Collector System

c. Heliostats

The heliostat design is the MDC Model 50 configuration illustrated on Figure IV.C.3. The Model 50 is the MDC second generation heliostat which has been qualified to the Sandia National Laboratory Specification (Ref. IV.C.1) for performance, environmental and life testing. It is the only heliostat subjected to these tests which has met the specification in all respects (Ref. IV.C.2).

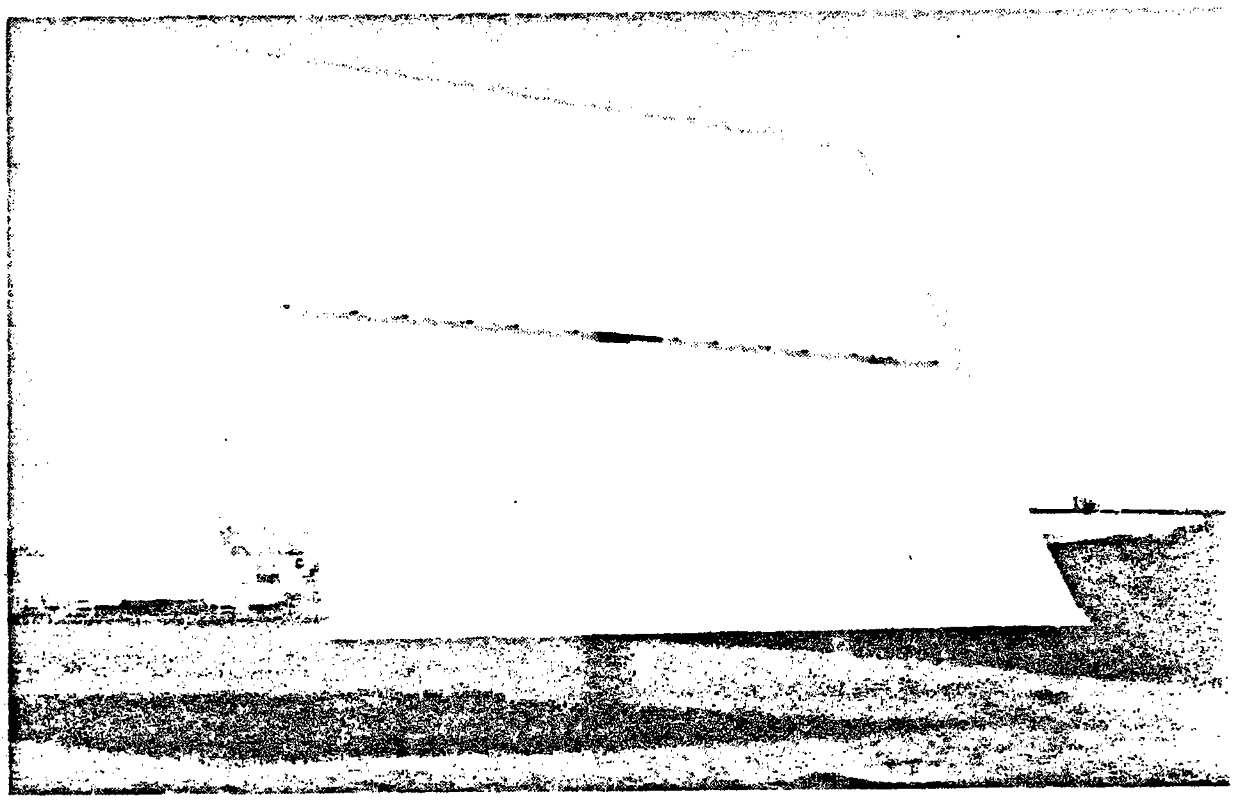


Figure IV.C.3. MDC Second Generation Heliostat

The Model 50, which evolved from four previous hardware prototypes, has been designed with the following considerations in mind:

- A factory design to aid in volume protection.
- Simple functional configuration with low parts count.
- Minimum site assembly labor.
- 30-year lifetime
- Economic goals for central receiver plant readiness in the 1980s.
- Technical specifications from DOE/Sandia

Specific design features are presented in Table IV.C.1.

TABLE IV.C.1
DESIGN FEATURES OF HELIOSTAT COMPONENTS

The MDC Model 50 Heliostat design uses proven processes and materials with flexibility to apply future cost reducing processes and materials.

Subsystem	Design Feature
Reflector	• Conventional Auto Safety Glass Laminate • Bonded Stiffeners - Double Curvature
Support Structure	• High Volume Roll Formed Parts • Automated Spot Welded Assembly
Drive	• Proven Azimuth Harmonic Drive • Conventional Ball Screw Elevation • Only Two Reduction Stages, Both Drives
Controls	• High Reliability Extended Temperature • High Pointing Accuracy Software
Foundation	• Poured in Place Reinforced Concrete • Taper Fit Pedestal Joint • Compatible With Any Soil
Site Assembly	• Three Self-Jigging Field Components • Factory Alignment of Mirrors • Software Field Alignment

The heliostat is manufactured in three subassemblies. These subassemblies, which are shipped to the field for heliostat assembly, are the two reflector panels (one-half of the reflective unit) and the drive unit, which includes the heliostat controller electronics and sensors and the pedestal. Basic design characteristics are shown on Table IV.C.2. Complete characteristics are provided in the final report on the second generation heliostat program (Ref. IV.C.3). Each reflector panel is composed of seven laminated mirrors on a support frame. Each mirror is 48 by 132 inches. A thin second surface silver/glass mirror is bonded to a glass back panel. The mirrors are bonded to stringers which are, in turn, bolted to support beams. This assembly is adjusted for focal length in the factory.

TABLE IV.C.2
DESIGN CHARACTERISTICS OF THE
MDC SECOND-GENERATION HELIOSTAT

Reflector Area	56.85 m^2 (612 ft^2)
Reflector Shape Rectangular	8.56 m wide, 6.87 m high (28.4 ft x 22.5 ft)
Normal Stowage Position	Reflector -2° from vertical
Severe Wind Stowage Position	Reflector face up
Number of Panels	14
Panel Dimensions	1.22 x 3.36 m (4 x 11 ft)
Minimum Azimuthal Spacing	13.3 m (43.6 ft) minimum
Minimum Radial Spacing	10.6 m (35.5 ft)
Control	Open Loop
Power	335 W per motor

The drive unit is composed of a rotary azimuth drive, a jack elevation drive, control sensors, a main beam, a controller, and a tapered pedestal. All drive motors are three-phase, 208 VAC. This unit is also assembled and aligned in the factory. A partially prewired circuit breaker junction box with the heliostat-side cable installed is also provided to the field to be installed during field wiring operations.

Heliostat Installation

The foundation is a conventionally drilled and poured column with a tapered cone extending 4 feet above grade. The configuration and dimensions are shown on Figure IV.C.4. The foundation also provides for electrical grounding of the heliostat. Integral conduits are provided to allow for (1) electrical wires at ground level to be routed through the cone, and (2) water drainage from the top of the cone to ground level. The cone is made during the foundation pour with a reusable form which provides the integral conduits, as well as pulldown cavities on the periphery of the cone. Foundation reinforcement is a rebar cage of twelve #6 rebars spirally wrapped at a 16 inch diameter. Rebar is allowed to extend above the pour to allow grounding of the drive unit pedestal to the rebar and attachment of the junction box.

Because of the existence of rock outcroppings in some of the heliostat locations, some of the foundations will require drilling into rock. Specific designs for these conditions will be determined in the plant design phase.

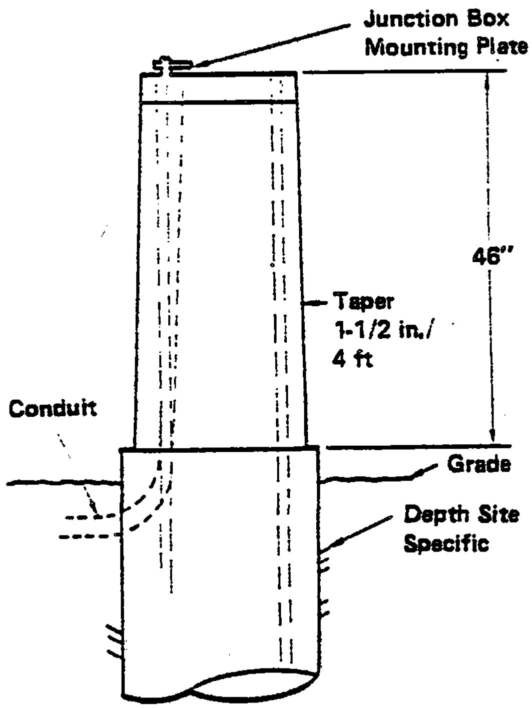


Figure IV.C.4. Foundation Configuration

At heliostat installation, the drive unit pedestal is placed over the cone and drawn down into place by tooling which connects to the pulldown cavities on the base of the foundation cone. The engagement overlap of the drive unit pedestal with the foundation is greater than 2 feet before an interference fit requiring a pulldown force is required. Consequently, no vertical control is required in this operation. Rotational control is provided by alignment of scribe marks on the foundation cone and the pedestal. Pulldown requires less than 1 minute. The operation is illustrated on Figure IV.C.5.

The electrical interface connection requires connecting the junction box cable assembly into the heliostat controller. Each heliostat in the field also has a unique address for communication which must be set. This requires opening the heliostat controller box and adjusting the DIP switch mounted on the processor board. The switch is set in accordance with the master field layout plan so that each heliostat address code corresponds with the surveyed coordinates of the heliostat.

The reflector assemblies are canted at the factory for focal length. Each of the two complete shipped assemblies is installed in one operation. Installation involves placement on the drive unit main beam and fastening by bolts, as shown on Figure IV.C.6.

b. Control

Heliostat beam pointing is achieved using open-loop command algorithms. A set of ephemeris equations is used to calculate the azimuth and elevation of

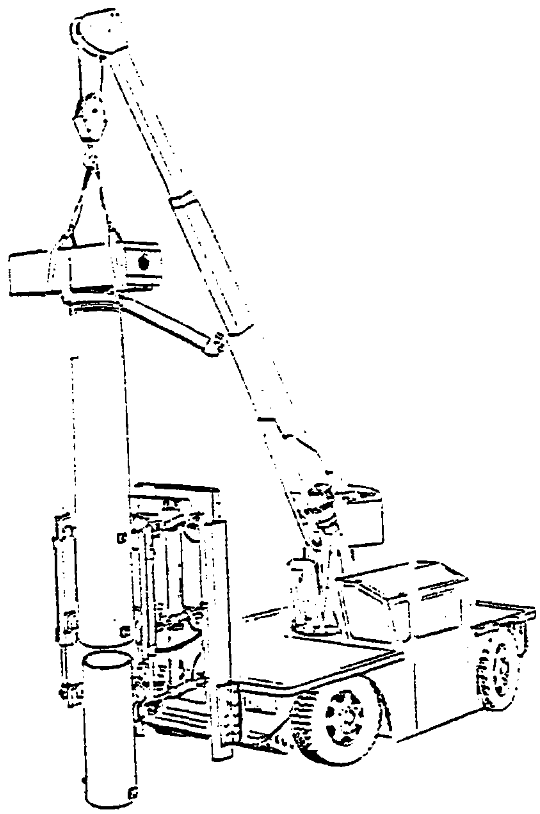


Figure IV.C.5. Pedestal Installation

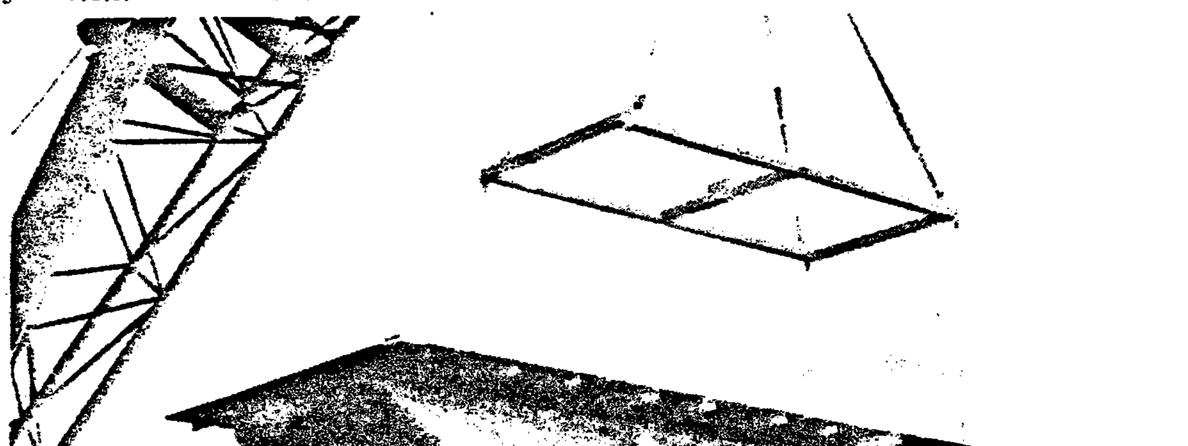


Figure IV.C.6. Reflector Installation

the sun for a given time of the day. Knowing the relative position of the receiver and heliostat, the required heliostat gimbal angles to reflect the beam to the receiver aimpoint are calculated. The calculation accounts for atmospheric refraction, gravitational structured bending, drive pivot point error, foundation tilt error, and location error. The transfer function of the azimuth and elevation drive system are used to transform the modified gimbal angles into drive motor turns. The motors are energized until the desired number of motor turns, as indicated by an incremental encoder mounted on the motor shaft, have been achieved.

There are four basic electronic components used in controlling the heliostats in the collector field. These components are a Heliostat Array Controller (HAC), a Heliostat Field Controller (HFC), a Heliostat Controller (HC), and a Motor/Sensor. The functions of these components and the information flow between them is summarized on Figure IV.C.2. The specific equipment making up these components and the communication paths between them are illustrated on Figure IV.C.7. There is also a Beam Characterization System (BCS) which is a video-based system for updating beam pointing accuracy.

One HAC for each of the two collector fields is located in the plant control room. Each of the two HACs consists of two minicomputer systems, each capable of independently controlling the heliostats. One minicomputer-based system will be designated as the primary HAC and the other as the backup HAC. Each HAC computer will have a dedicated associated set of peripherals and will be capable of independent two-way communication with the plant control system, including the data acquisition system (DAS), and with the beam characterization system (BCS). The two HAC minicomputers will also receive, and make available to the HFC, data from a time-of-day generator located at the control room. The two HAC computers will function concurrently, with each redundantly processing all commands and data. Switchover from primary to backup HAC will be controlled by the Plant Control System computer/operator upon sensing a fault in the HAC.

The HAC control panel will incorporate provisions for the operator to call from software subroutines to startup and operate in normal, high wind and defocus modes. These subroutines provide automatic control of heliostats to increase or decrease flux to the receiver and move to selected positions. However, individual heliostats are addressable through HAC keyboard. Positioning heliostats for maintenance will thus be accomplished through keying in motion commands at the HAC keyboard. Positioning heliostats for BCS operations will be accomplished automatically on a computer-to-computer basis.

The HAC communicates with the HFCs via a redundant data highway. Each HFC contains a microprocessor with capability to control up to 32 HCs. An HFC receives all commands and data from either the main or backup HAC. A message error check is made of the received message and, if there are no errors, the HFC will echo back the received message or the received message with the requested data. The HFCs will check the echo message against the transmitted message before declaring the transmission good. The HRCs are co-located with the power/control distribution centers described in the next section (IV.C.3.c).

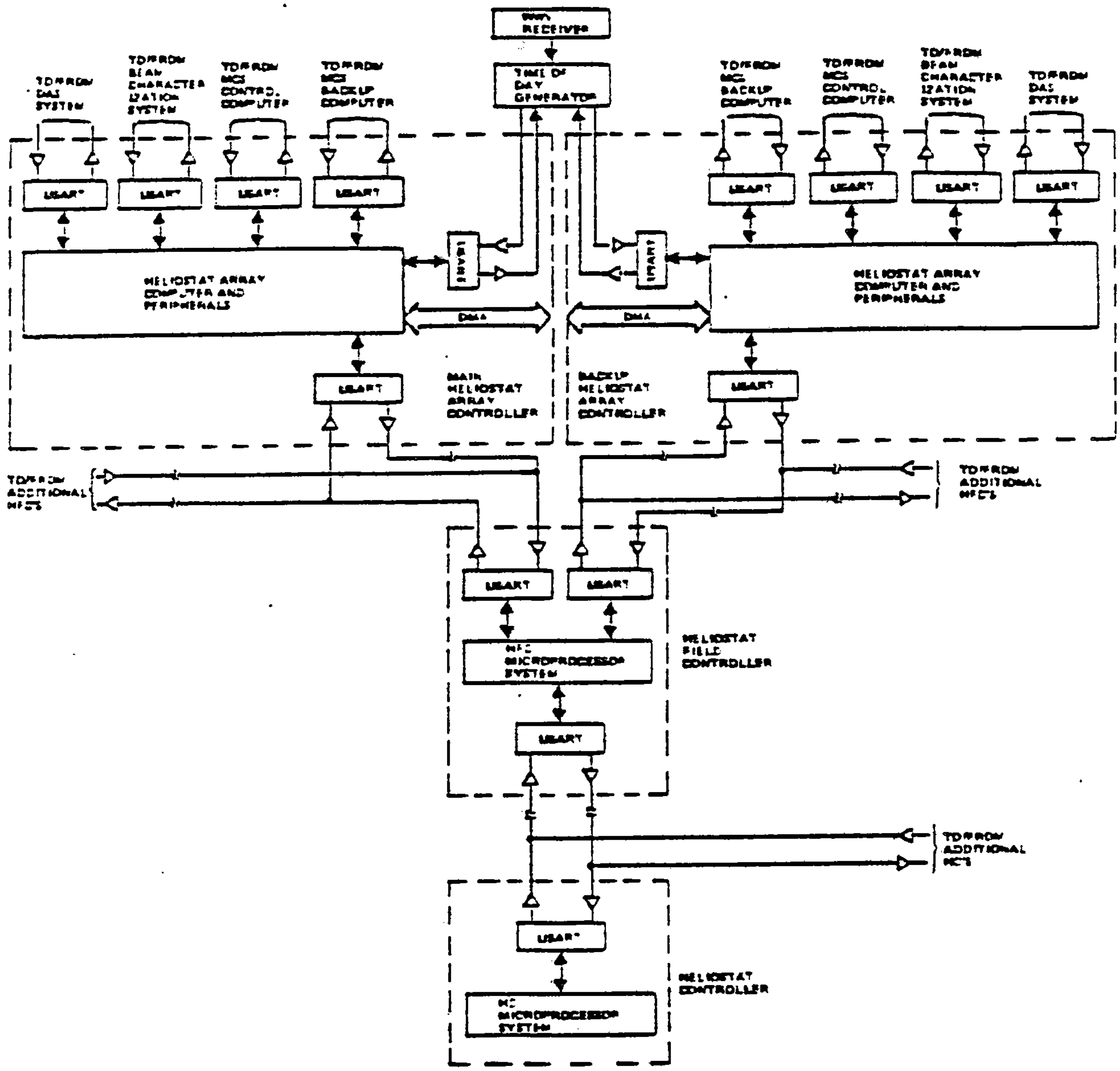


Figure IV.C.7. Collector Field Controller Hardware

The HC also contains a microprocessor; it executes position commands, determines its associated heliostat's position, performs diagnostic tests and monitors transmission signals. As shown on Figure IV.C.2, it is located in a housing on the drive unit pedestal.

A manual controller can be plugged into the heliostat circuit breaker junction box for local control of the heliostat. Local manual control isolates a heliostat without affecting control of any other heliostat.

The elevation jack motor and azimuth drive motor each have an incremental encoder. These encoders, in conjunction with position reference switches are used to update incremental counts and reference position during recoevery from c power failure. Both drive motors are three-phase, 208 VAC.

Heliostat Alignment

The alignment technique uses a Digital Image Radiometer (DIR) Beam Characterization System (BCS), consisting of a white target beneath the receiver, a TV camera located in the field to view the target, and a video digitizer interface to a control computer. Two targets are provided to allow a shorter time period for initial field alignment. The heliostat's reflected beam is projected onto the target and the DIR/BCS used to scan the beam and determine centroid and power distribution. For alignment, only the centroid data are required.

A coarse track alignment is done in order to acquire the BCS target. First, the heliostats are commanded to move to the gimbal reference sensors where a zero estimate is used as the elevation and azimuth reference position. A standby aimpoint is then commanded that is a distance from the BCS target aimpoint. A search mode is used to find the target and acquire the target center. A second estimate is then made of the azimuth and elevation reference position. This estimate is accurate enough for the control system to keep the beam on the target or find the target the next time it is unstowed. In the final step, the beam is put on the target and the BCS is used to take measurements and calculate the beam centroid. This is done at one-half to one-hour intervals from early morning to late afternoon. Using these measurements, the errors in the heliostat orientation are determined. These error terms are then used by the HFC to determine the gimbal position which should be commanded in order to move the beam to the desired aimpoint. Structural alignment and location errors are accommodated.

c. Electrical Power Wiring

Collector field power is distributed from 4160 VAC plant power source through Power/Control Distribution Centers (PCDC).

A field distribution center for each field feeds parallel redundant primary power to PCDCs on each side of the field. A fiber optics link from the HAC in the control room also runs to the field distribution center where data are converted for transmission by wire to the HFCs. The PCDCs are environmental enclosures dispersed throughout the field which contain power equipment (primary power auto-transfer switches, switch gear, transformer and secondary distribution breakers) as well as the HFCs and an uninterruptible power supply (UPS). Figure IV.C.2 illustrates the PCDC.

The arrangement for power distribution in the field is shown on Figure IV.C.8. Control lines parallel power lines as shown on the figure. The T blocks represent PCDCs containing the secondary transformer and six HFCs. Distribution from this point is made typically with 32 heliostats interconnected to each field controller and power circuit breaker, as shown schematically on Figure IV.C.9. The sector letters refer to the field layout sectors.

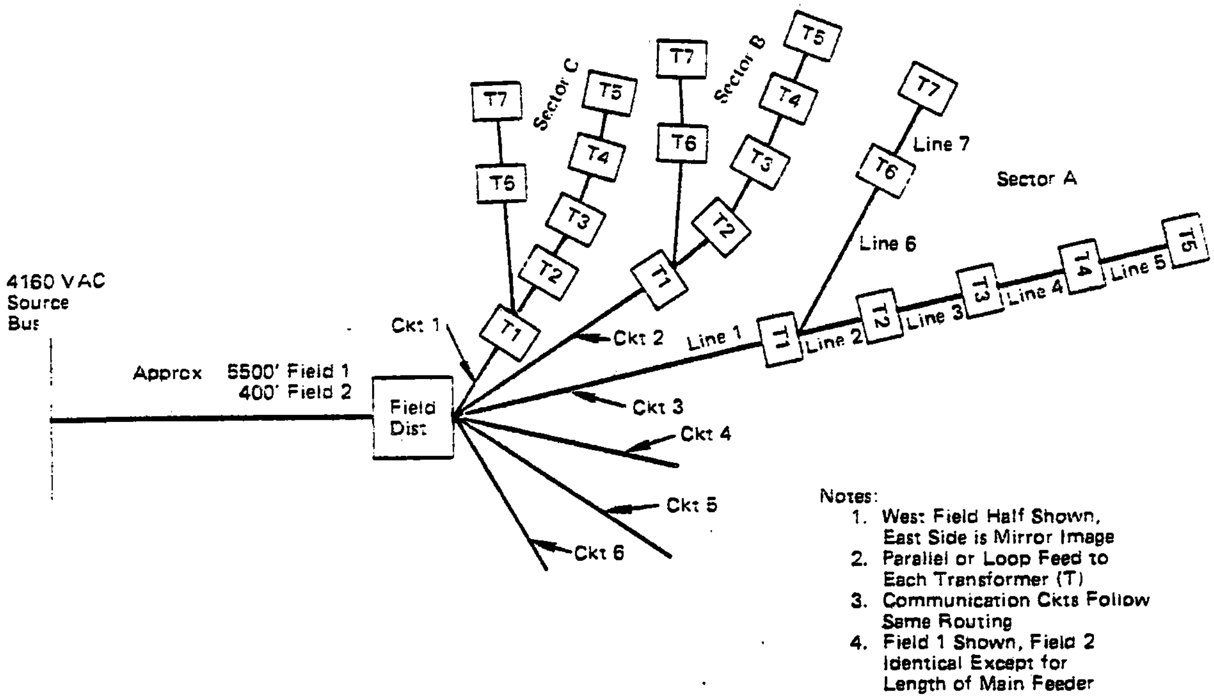


Figure IV.C.8. Electric Power Distribution Schematic

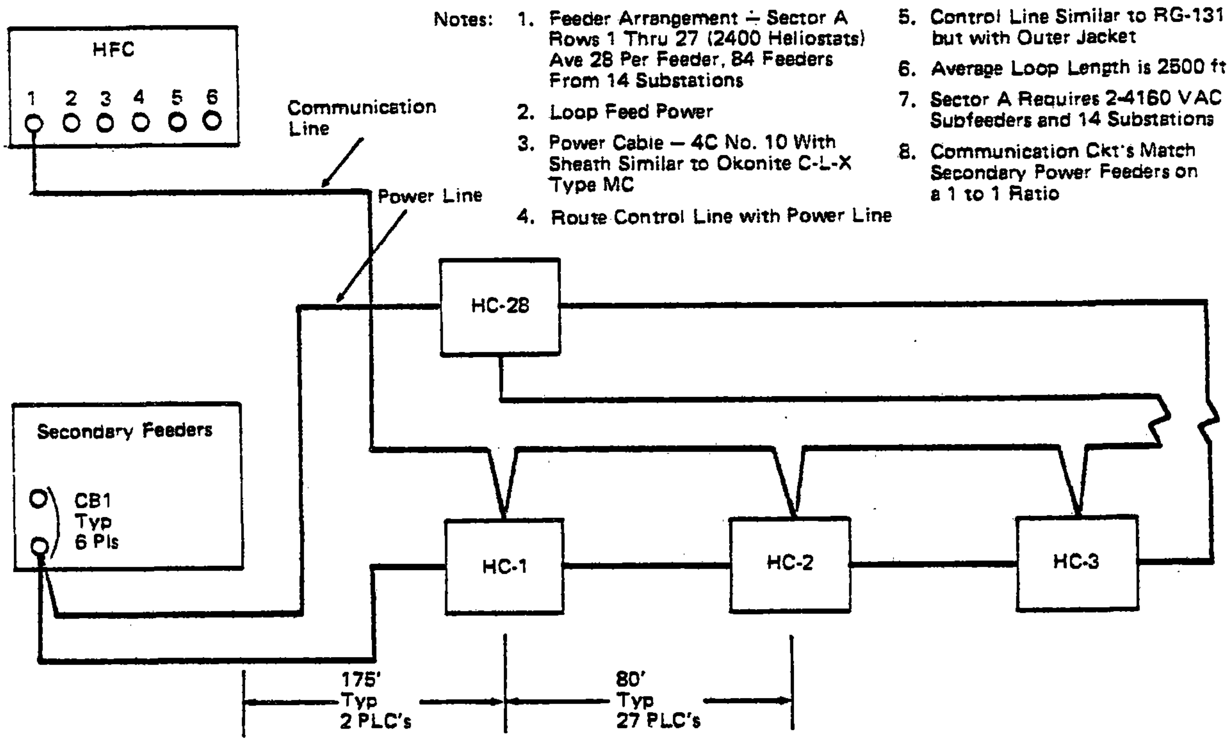


Figure IV.C.9. Electric Power Distribution Sector Layout

4. System Support Requirements

The support requirements for the heliostat field are electrical power and the availability of deionized water for heliostat washing. The water source for the steam loop makeup will be sized for heliostat washing requirements also. The washing capability requirement is 3000 gal/day. This is based on total field washing 12 times per year.

Power provisions are required for all operating modes. Power system sizing requirements are as follows per field:

	Peak Power Requirement	Total Energy (Annual
	KW	MW
Normal operation	1125	3727
High wind stow	2400	

5. Operational Features

In addition to normal operation, maintenance and night stow, repositioning of the whole field, or individual heliostats is accomplished in high winds and in the event of emergencies such as failure of the receiver fluid control sytem. Beam safety is a major consideration during this period with individual heliostat motion controlled in a manner to preclude concentrated beams on the ground, on the unprotected tower structure or above the clearout air space over the plant. These operations may be accomplished with the MDC heliostats by sequenced travel in elevation only. For both high wind and emergency defocus, a face-up position is desired. As a result, beams at ground level are never produced. In the defocus case, azimuth travel may also be employed, but is probably not required. In both cases, heliostats are controlled by positioning to a known location and path. Heliostat washing will be acomplished at night. For this operation, the heliostats are in the normal night stow position (vertical). Cleaning is accomplished by a truck which continuously travels through the field. A boom-mounted spray cleaning unit is used with deionized water, as shown on Figure IV.C.10.

IV-D. RECEIVER SYSTEM

1. Functional Description

The receiver is a tower-mounted heat exchanger that converts the radiant energy reflected from the collector field into thermal energy in the receiver coolant, a molten heat transfer salt. The net thermal power output from the receiver at the design point (winter solstice noon with 1000 W/m^2 insolation) is 312 MW_t. At the design point, 5.52 x 10^6 lbs/hr of molten salt (60% wt. fraction of $NaNO_3$ and 40% wt. fraction of KNO_3) are heated from an inlet temperature of 550°F to an outlet temperature of 1050°F. Salt is received from the warm salt storage tank and returned to the hot salt storage tank for subsequent use in the steam generator. For Solar 100, each of the two collector fields has a receiver which operates in parallel flow with the other. The receiver interfaces with the plant control system as well as the collector, tower and thermal transport and storage systems. Electrical power and other support is provided by the balance of plant system.

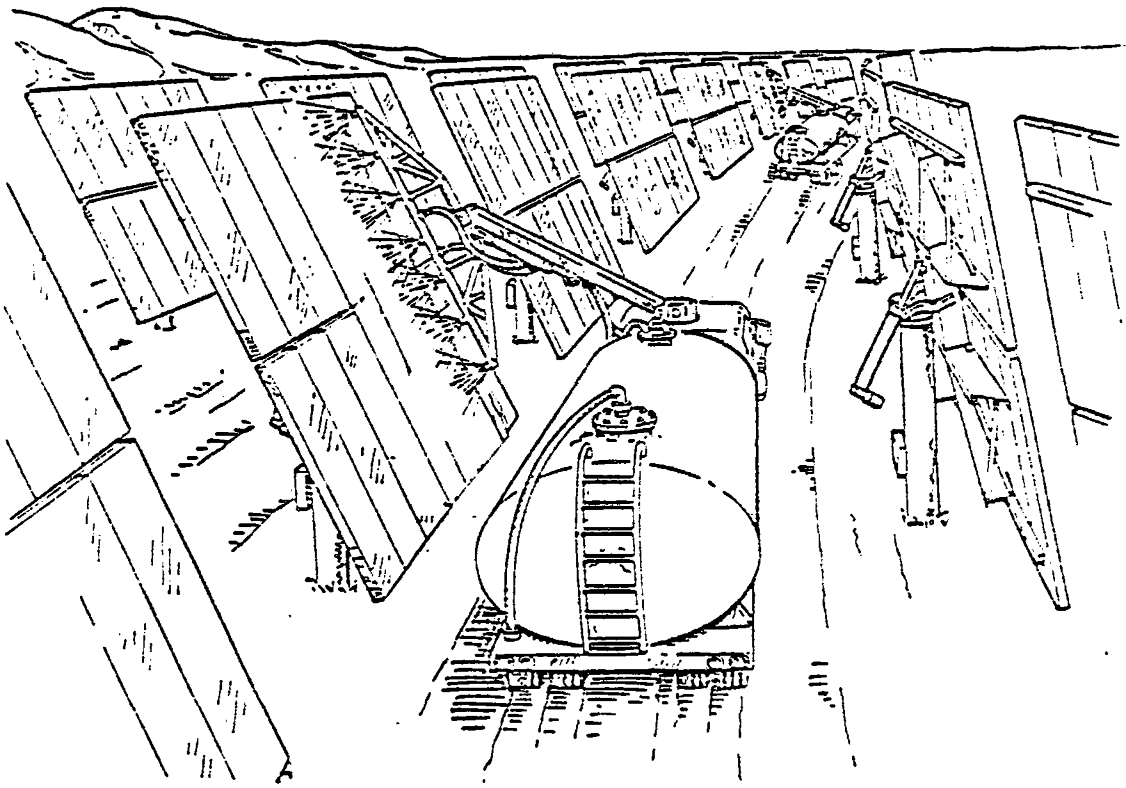


Figure IV.C.10. Large Field Cleaning

The receiver includes absorber panels, support structure, insulated doors, and flow distribution and control elements (interconnecting piping, surge tanks, valves and controls). A crane is included for installation and removal of equipment at the tower top.

2. General Arrangement

Figure IV.D.1 shows the general arrangement of the receiver in its support structure at the tower top. The receiver tilts forward 25 degrees toward the collector field to improve the view factors for heliostats at the eastern and western edges of the field. A service crane will be mounted on top of the support structure. Figure IV.D.2 shows the general arrangement of the receiver panels and interconnecting piping. There are 10 internal side panels, 8 internal rear panels and 2 external wing panels in an omega shape. The midpoint of the receiver aperture is 675 feet above grade.

3. Major Component Descriptions

1" OD

a. Absorber Panels

Figure IV.D.3 shows a typical panel. The panels are identical in length, but the two wing panels have 118 tubes each, while side and rear panels have 94 tubes. All panel material is Incoloy 800. The panel and jumper tubes are 1 in. O.D. with 0.065 in. minimum wall. The inlet and outlet headers are 10 in.

wings $3m \times 26m \times 2 = 156\ m^2$

$2.39m \times 26m \times 18 = 1117.7\ m^2$

1273.7

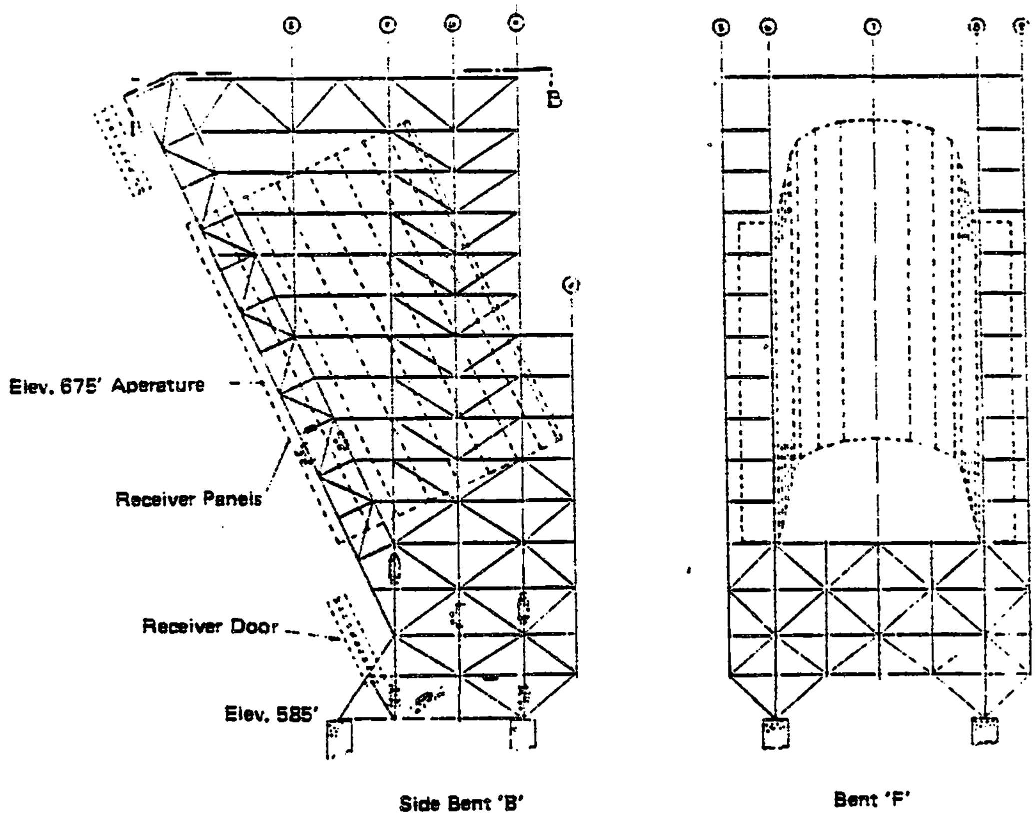


Figure IV.D.1. Receiver Support Structure

Schedule 40 pipe with two 6 in. nozzle connections for feeders and risers. Foster Wheeler has successfully welded small test sections of these tubes and is developing the required weld procedures during Phase I of the DOE Molten Salt Receiver SRE program.

The figure also illustrates the panel support. Support lugs are welded between every fifth panel tube and vertically spaced 4.2 ft. apart. The central lug at each elevation is fixed to a buckstay which traverses the panel width. Lateral expansion of the panel is permitted by movement of the remaining lugs relative to the buckstay. The buckstay is attached to the support structure by support links which permit longitudinal panel expansion. The central support links position the center of each panel.

The panel is hung from the support structure by hangers attached to the support lugs. The jumper tubes connecting the panel to the header are designed with sufficient flexibility to permit expansion between the fixed panel top and the upper header, which is fixed to the support structure. The lower header is permitted to move with the longitudinal expansion of the panel. A support link is provided to position the lower header, which is supported by the panel tubes.

The receiver floor and ceiling are uncooled surfaces consisting of ceramic materials anchored to a carbon steel plate. Ceramic materials were selected for the uncooled receiver ceiling and floor because of their ability to withstand the incident solar flux levels with minimum expansion and interference with the receiver panels.

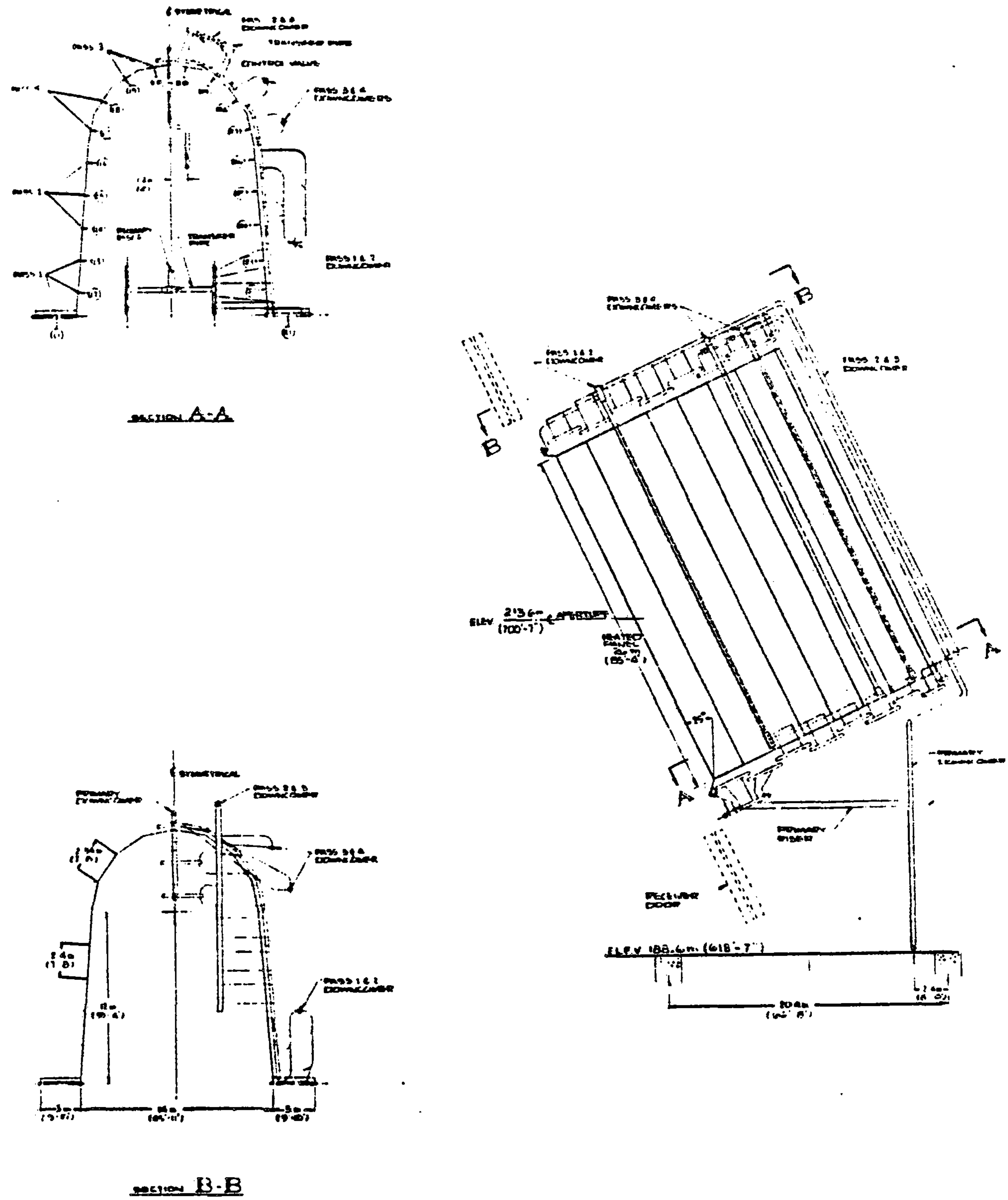


Figure IV.D.2. Receiver General Arrangement

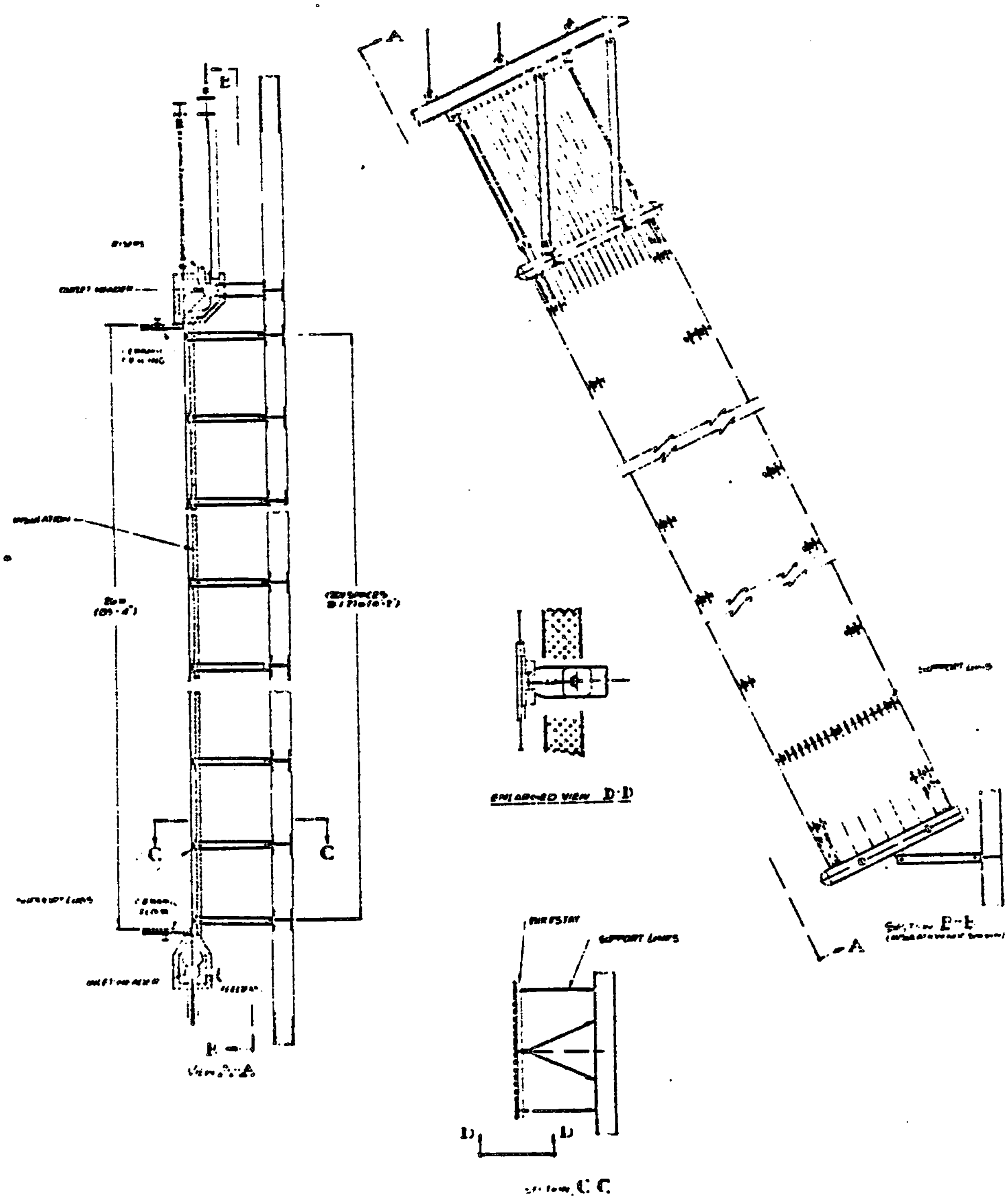


Figure IV.D.3. Typical Absorber Panel

The ceiling is formed by two staggered layers of ceramic fiberboard, 0.5 in. and 1 in. thick. The ceramic fiberboard (alumini silicate fiber) is anchored with Set-Lok ceramic anchors stud welded to a 25 in. thick, reinforced carbon steel plate rigidly supported from the receiver support structure. No allowance for vertical expansion is required because the top of the receiver panels is fixed.

The floor is formed by a layer of castable concrete atop two staggered layers of ceramic fiberboard, both of which are anchored with KSM Wav-Lok anchors welded to a carbon steel plate. The castable concrete consists of a mixture of Al_2O_3 aggregate bonded with high-purity, low-iron calcium aluminate hydraulic setting cement and reinforced with stainless steel fiber (4 percent by weight). A flexible seal is provided between the floor and panels (see Figure IV.D.3) to minimize thermal losses from the receiver.

Figure IV.D.4 shows typical receiver panel absorbed heat flux profiles determined from two-dimensional heat flux maps from the MDAC computer program CONCEN. Tube-to-tube flowrate variations within a panel were determined to be very insensitive to heat flux variations. Figure IV.D.5 shows salt inlet temperature and lateral outlet temperature distribution for each panel. Based on Foster Wheeler past experience, the high temperature distribution on the R1 wing panel may result in panel stresses which are not tolerable. Detail analysis is required to determine the acceptable limits, but solutions are available if this condition is not acceptable. These include dividing the panel, orificing tubes and orificing feeders.

The tube panels are arranged in flow circuits, as shown on Figure IV.D.6, to minimize overall pressure drop through the receiver and to account for the differences in heat flux and tube wall temperature from panel to panel.

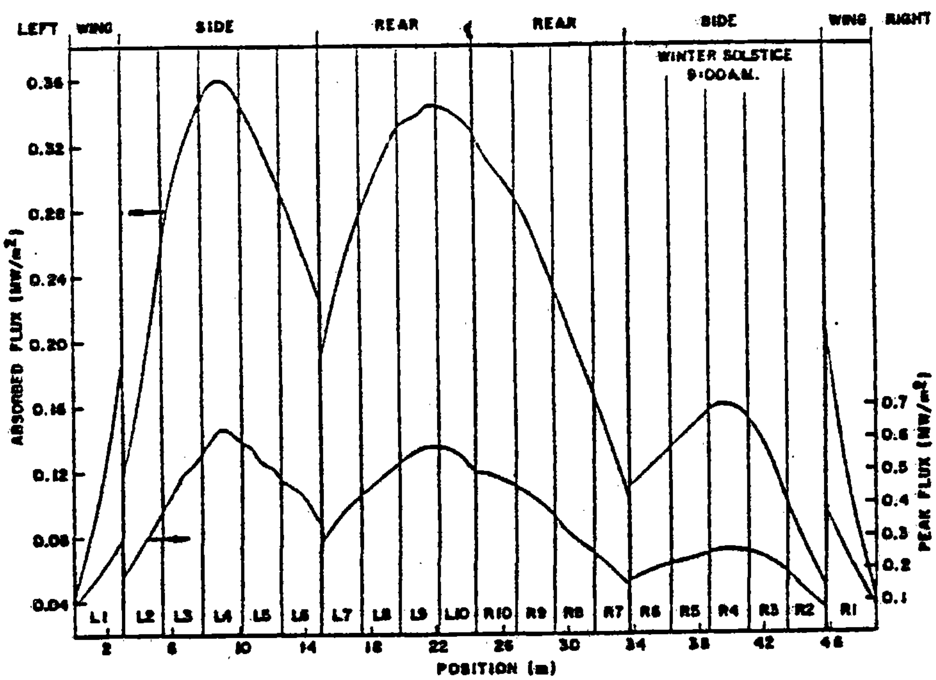


Figure IV.D.4. Winter Solstice Absorbed Flux Profile

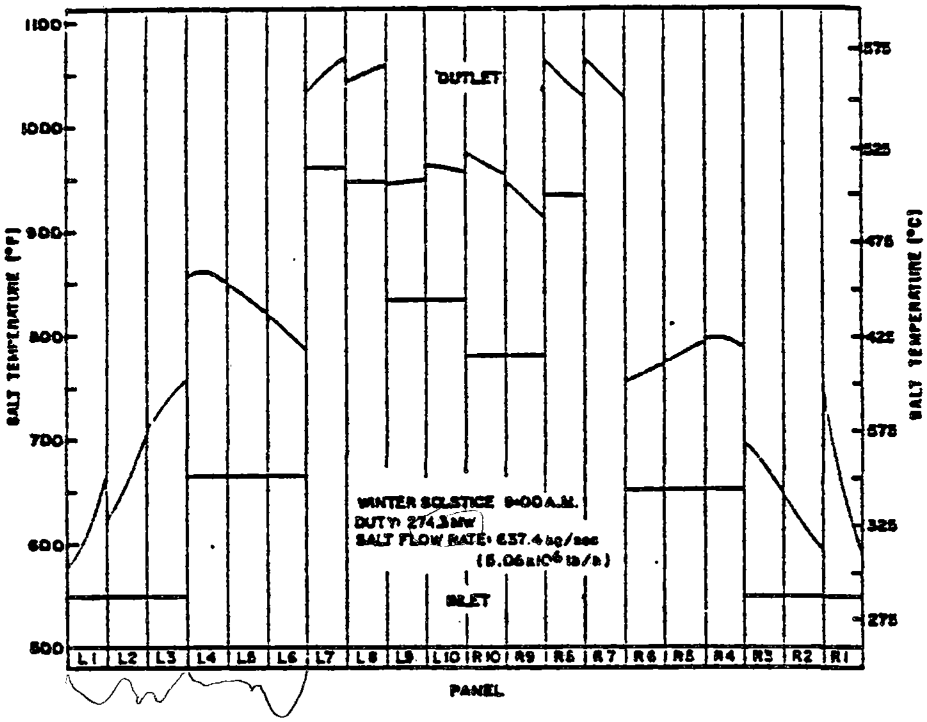


Figure IV.D.5. Winter Solstice Salt Temperature Profile

Thus, tube temperature gradients and resultant tube stress levels are controlled. Design point frictional pressure drop through the complete receiver circuit is 124 lb/in^2.

Individual receiver tubes were analyzed using a Foster Wheeler computer program to determine tube and salt temperature. The Dittus-Boelter correlation is used to determine salt film coefficients. Significant results for the hottest tube at equinox noon conditions are plotted on Figure IV.D.7. The tube I.D. temperature shows that local salt film temperature in a small region can reach approximately 1120°F.

Although only a small quantity of salt will reach this temperature for a short time, it is preferred to reduce this temperature to minimize salt compositional degradation and corrosion problems. This can be accomplished in detail design by optimizing salt side flow characteristics and heat flux distribution.

b. Support Structure

Table IV.D.1 lists the estimated weights of the structure required to support the receiver. The structure was sized for an 0.57-g seismic load and a 50 lb/ft^2 wind load.

Referring to Figure IV.D.1, the front is open to allow an uninterrupted path for solar radiation. A latticed column on both sides of this opening transfers the shear load resulting from the side-to-side seismic and wind loadings to the roof and to the base of the structure. The shear load, which is transferred to the roof truss, is transmitted to rear bent H and then down to the base. This causes torsion in the structure which is resisted by a couple

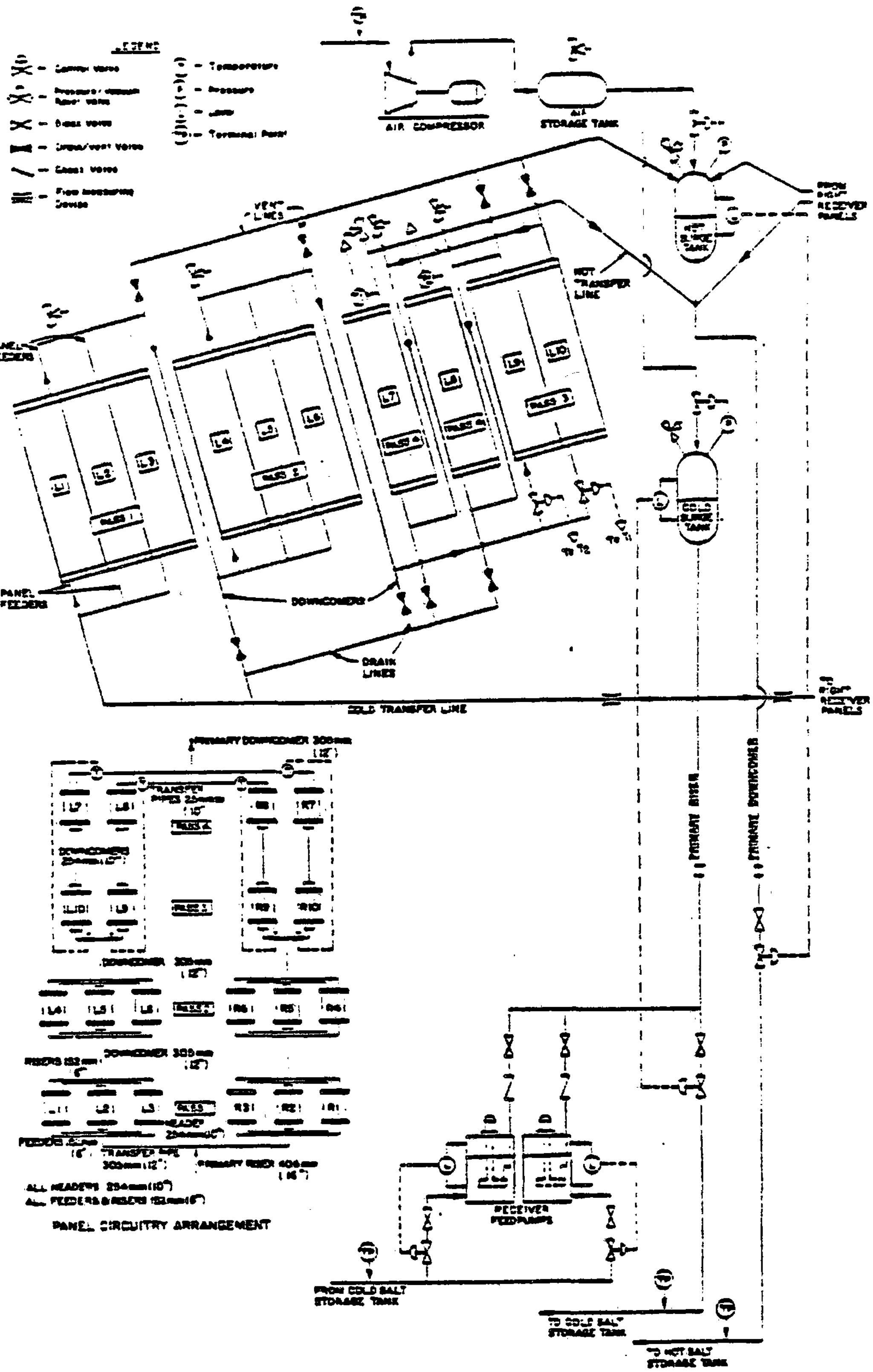


Figure IV.D.6. Receiver Flow Circuitry

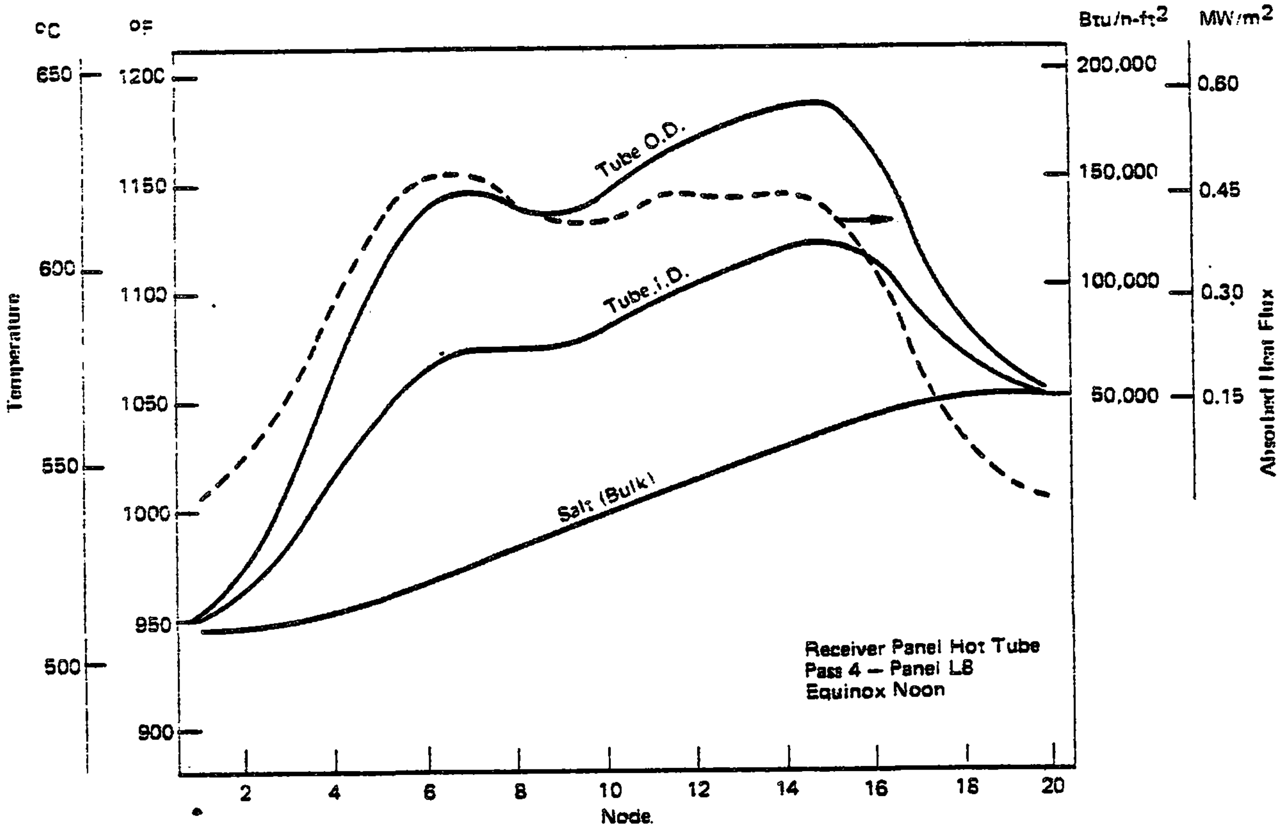


Figure IV.D.7. Receiver Tube Temperature Profile

TABLE IV.D.1
RECEIVER SUPPORT STRUCTURE WEIGHT BREAKDOWN

Structural Item	Weight (10^3 lbs)
Columns	258
Roof steel	60
Horizontal steel	635
Platforms and ladders	110
Vertical bearing	323
Connections	139
	1,525

whose forces are transmitted to the base of the structure via side bents 6 and 8. Seismic and wind loads in the front-to-rear direction are continuously transmitted to the base through shear via side bents 6 and 8.

The receiver gravity loads are taken to the roof via hangers and then transmitted to the base of the structure via bents 6, 8, and H. Lateral lodas originating at the receiver and external wind loads are taken by horizontal ties to the structural steel. Horizontal trusses on both sides of the receiver at each level transmit the loads to the appropriate bents.

The structure was arranged to provide space for panel doors in the open position, thereby minimizing gravity uplift on the H column. With a tower diameter of 66.7 ft., the seismic uplift on the rear bent columns is approximately 2.05 x 10^6 kg (4.5 x 10^6 lb). This load will require special design consideration in transmitting the load to the concrete tower.

All components of the support structure that may be exposed to concentrated solar flux (such as the front bent) are insulated and covered with a stainless steel radiation shield. The remainder of the support structure is covered with aluminum sheet.

c. Insulated Doors

The receiver includes a door to minimize thermal losses when the receiver is not in operation and to protect the receiver from interruption of coolant flow. The door consists of four sections, each of which spans the receiver aperature horizontally. When opening and closing, the door sections move up and down parallel to the face of the receiver. Two sections move upward and two downward, nesting in pairs in the open position so that a minimum area is exposed to the wind. The lower sections are counterbalanced by the upper sections, minimizing the power required for opening and closing. The upper sections are heavier so that the doors can close by gravity in the event of power failure. Each door section has large cam-follower bearings which run in fixed guiderails mounted in the outboard sides of the receiver wing panels. The door is covered on the outside with an ablative material that protects the door assembly and receiver until the motion of the sun moves the reflected beam away from the receiver aperture. The aperture side of the door is faced with insulation.

d. Flow Distribution and Control Elements

The receiver flow schematic is shown on Figure IV.D.6. All interconnecting salt piping is completely drainable. Headers, feeders, and risers are 10 in., 6 in., and 6 in. Schedule 40 pipe, respectively. Sizes were selected to minimize header flow imbalance, pressure drop, and length required for flexibility. Drain and vent lines are 4 in. Schedule 40 pipe.

Molten salt flows upward through all absorber panels in the combination of series and parallel paths illustrated in the figure. The upward flow in the panels minimizes the possibility of thermal hydraulic instability. Four control valves are used to maintain the desired outlet temperature by controlling both the amount and distribution of salt flow. This flow arrangement accommodates both diurnal and seasonal flux distributions and, combined with the collector field aim strategy, minimizes control problems caused by panel-to-panel input power variations during cloud transients.

The control valves and the drain and vent valves shown in the figure are self-draining globe-type valves with internal bellows seals. All valves are capable of both manual and pneumatic actuation.

Figure IV.D.6 also depicts the surge tanks. The warm surge tank in the riser at the inlet to the receiver isolates the receiver and control valves from the dynamics of the pump and water hammer in the warm salt piping. A level sensor on this tank controls the feed pump throttle valve. The hot surge tank in the downcomer at the receiver outlet isolates the downcomer and drag valve from the receiver dynamics and water hammer. A level sensor on this tank, with appropriate modulation to prevent rapid valve motions, controls the drag valve at the bottom of the downcomer. Set points for both tank levels are set at one-half to provide a control margin and a ready supply of salt. The warm tank also provides an emergency 60 seconds of salt flow to protect the receiver in case of a feed pump or power failure and is pressurized to provide the driving pressure for salt circulation. The hot surge tank connected to the 12 in. primary downcomer is located at an elevation above the highest absorber panel. Surge tank specifications have been selected, as shown on Table IV.D.2.

TABLE IV.D.2
HOT AND COLD RECEIVER TANKS SPECIFICATIONS

	Cold Tank	Hot Tank
Tank diameter, m (ft)	3.2 (10.5)	3.2 (10.5)
Tank height, m (ft)	7.0 (23)	7.0 (23)
Salt capacity, kg (lb)	48,100 (106,000)	48,100 (106,000)
Operating pressure, kPa gage (lb/in^2g)	945 (137)	35 (5)
Material	SA-515 - GR.B	SA-240 (304-SS)

Compressed air for the surge tanks is supplied from an air storage tank located at the top of the tower. The air storage tank also drives salt from the warm surge tank through the receiver during an emergency. It is sized to provide salt flow for one minute.

Figure IV.D.8 illustrates the receiver unit instrumentation and control valves. Air-cooled flux sensors and rear wall thermocouples will provide data to the valve controllers. Header salt thermocouples at intermediate locations and at the receiver unit exit are also provided. Thermocouples are distributed throughout the pipework, headers, and valves to indicate cold spots so that appropriate actions (e.g., trace heating adjustment, draining) can be taken to prevent salt freeze-up. Salt flow rates are measured by a

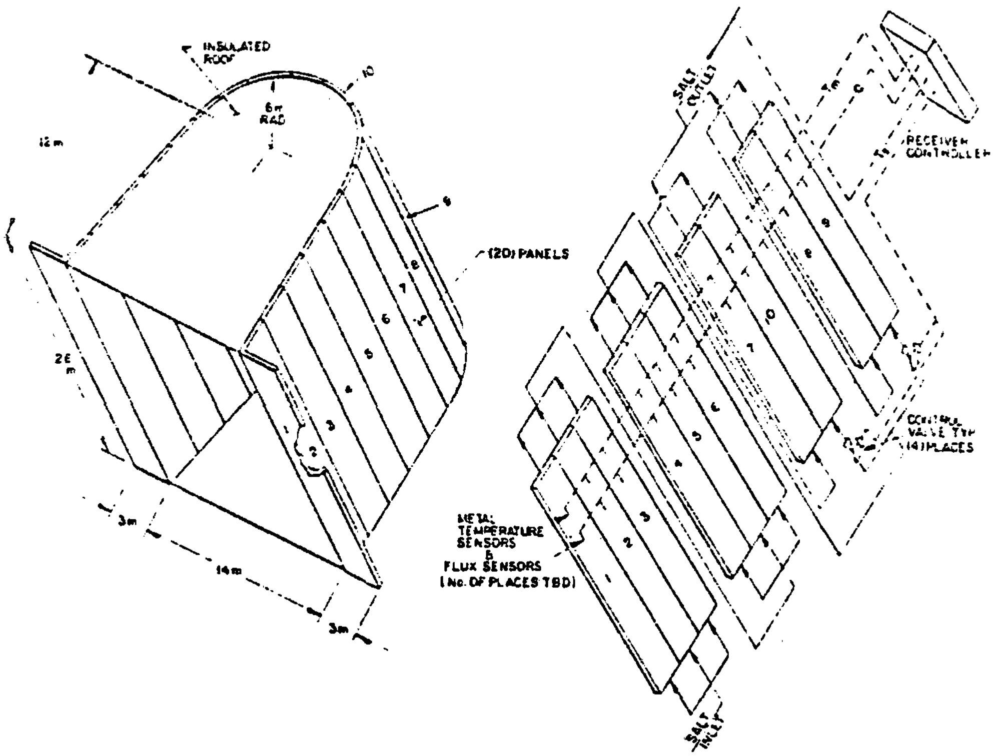


Figure IV.D.8. Receiver Panel Sensor Arrangement

wedge-type flowmeter which can be completely drained. Pressure measurements are made using silicone-oil-filled lines with diaphragms to isolate the sensing units from the high-temperature salt.

Three sequential flow-control loops, buffered from each other by the two surge tanks, control the receiver. Feed pump flow control is accomplished by throttle valve control responding to the level in the warm surge tank. Receiver salt flow is controlled by four valves, as shown on Figure IV.D.6. These valves modulate flow to control outlet temperature from four parallel flow paths. The hot surge tank level then controls the drag valve and output to the hot storage tank.

Control of the individual receiver flow paths will include both flux and temperature data to anticipate requirements for flow control. The design of these algorithms will reflect considerations of both low noise steady-state control and rapid response transient control during cloud passage.

e. <u>Auxiliary Support Equipment</u>

Thermal conditioning is required to maintain all molten salt equipment above 430°F to prevent salt from freezing during overnight and extended cloudy period shutdowns. Conventional electric heat tracing (thermostatically controlled, single conductor MI cable) will be used on all pipework and valves, and on the surge tanks and drain sump.

The absorber panel will be heated from three separate systems: 1) back flow of hot salt from the hot salt surge tank, 2) electric trace heaters installed behind the wing wall panels at the factory, and 3) radiant heaters installed in the cavity floor.

Preliminary calculations have indicated that the 100,000 lbs. of hot salt stored in the hot salt surge tank at 1050°F can provide enough heat to maintain the cavity panels above 550°F for up to nine hours. Once the thermal energy stored in the hot salt has been expended, then the radiant heaters will be activiated to compensate for the ongoing thermal losses due to conduction through the insulation and structure and convective losses through gaps in the door seals.

The radiant heaters will be located in the cavity floor, as shown on Figure IV.D.9. These heaters are flat resistance Chromalox heaters with woven refractory cloth (black ceramic coating). At 1600°F, they emit 25 watt/in^2 at a peak emission wave length of 2.5 microns, a wavelength within the high absorptivity part of the spectrum for the receiver coating. These heaters will be recessed in the cavity floor to protect them from incident radiation during normal receiver operations.

The wing panels will be fitted with factory-installed trace heaters because they can't benefit from the radiation and natural convection within the cavity during shutdowns. Backwall temperature of less than 700°F will permit weld or braze, as shown on Figure IV.D.10. Ten parallel heaters, running the length of the panel, will operate at 0.7 /ft resistance and 49W/ft power. The total available power per panel will be 37.5 kW.

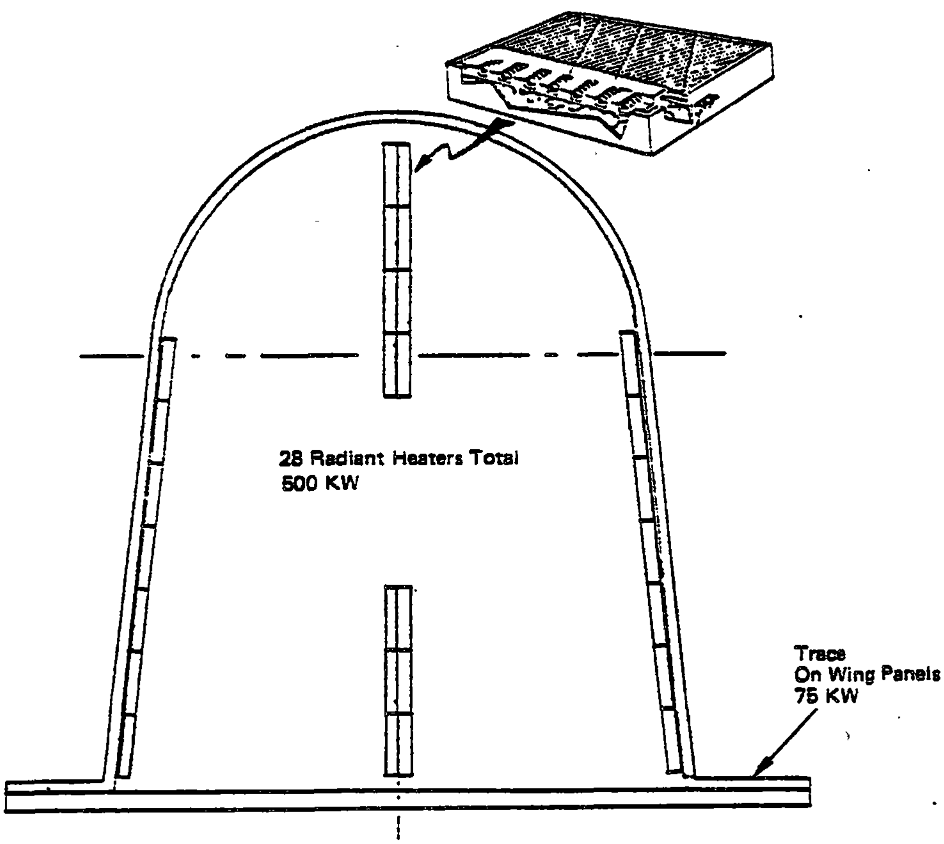


Figure IV.D.9. Heater Panel Layout — Plan View

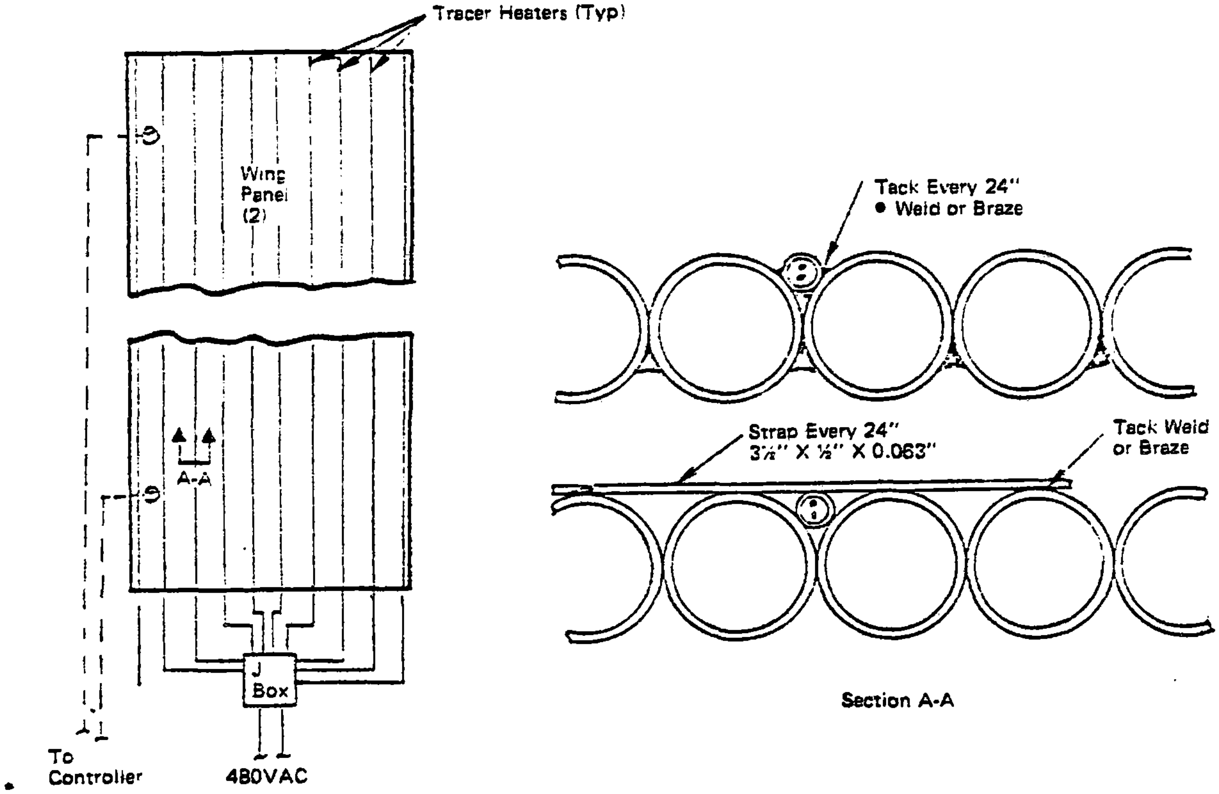


Figure IV.D.10. Panel Heater Configuration — Wing Panels Only

All equipment containing molten salt will be insulated. Table IV.D.3 lists materials and thicknesses for all insulation. Standard aluminum lagging will be used for all pipework and the surge tanks. The cavity roof and floor, and back sides of the absorber panels will be encased in aluminum sheet to provide weather protection. During an extended shudown period with the electric trace heaters maintaining the salt in the receiver circuitry at 550°F, the heat loss through the panel, piping, header enclosure, floor, roof, and door insulation is approximately 0.42 MW_t based on a calm day with 60°F ambient temperature.

f. Receiver Crane

The receiver crane is a 10-ton bridge crane with a 50-foot span and 730 ft. of hoist lift. The hoist will have a variable speed drive with a range of speeds from 10 ft/min minimum to 100 ft/min maximum. Remote radio control will enable personnel to operate the lift from anywhere in the receiver structure.

g. Receiver Construction

After erection of the receiver support structure on the tower top and installation of the receiver crane, the following steps will be taken to complete construction of the receiver;

- o Preparatory work - setting scaffolds, hoists, and worker safety protection equipment in place.

TABLE IV.D.3
RECEIVER INSULATION SUMMARY

Item	Thickness	Material
Interconnecting piping	6" for all 12" transfer pipes and downcomers 4" for the remaining piping	Calcium Silicate
Tube panels	4" for Pass 1 panels 5" for Pass 2 panels 6" for Pass 3 panels 7" for Pass 4 panels	Mineral Wool
Roof, floor and header enclosures	4"	Mineral Wool
Surge tanks	4" for inlet tank 6" for outlet tank	Calcium Silicate

- Erect receiver panels - erection of panels beginning with pass #3 (rear panels) and progressing through passes #4, #2, and #1, respectively, to the front wind panels. Includes setting panels in place by using the tower to crane and connecting the panel assemblies to the support structure.
- Erect receiver floor and roof.
- Erect receiver door - Rigging and placing the door frame/track and controller assembly is first. This is followed by installing the four sections of the door into the frame.
- Install door operating mechanism, air compressor, and storage tank.
- Erect all piping and valves.
- Install all instrumentation and controls.
- Install heat tracing, insulation and lagging.
- Erection phase-out - checkup, demobilization and cleanup.

4. System Support Requirements and Interfaces

Primary system support for the receiver will be electrical. Electrical power at 480 V will be required for trace heaters, radiant cavity heaters, door and pump motors, and welding equipment for maintenance. The trace heaters will use approximately 75 kW. The cavity radiant heaters will use approximately 500 kW.

None of these units will ordinarily be active during normal daytime operations. Additional power is used on an as-needed basis for trace heating of tanks, pumps, valves, and interconnecting piping. The door motors will use power during startup and shutdown operations and the sump pump motors will use power on a periodic basis.

Compressed air will be required to charge and maintain instrument air and cover gas for warm and hot surge tanks.

5. Operational Features

Receiver operations include: cold startup, morning or warm startup, normal operation (including load changes), cloud transient operations, overnight or warm shutdown and conditioning, emergency shutdown, and cold shutdown.

Cold startup begins with salt in the warm storage tank and the receiver system empty. The panel trace heaters and cavity radiant heaters will be activated to preheat the panels. Trace heating will be turned on to condition all pipework, sumps, valves and tanks. All vent and drain valves are opened. The riser and downcomer, surge tanks, and panels are then filled from the bottom upward.

During filling, pressure in the warm surge tank increases to control its fluid level as the panels and hot surge tank fill. Completion of fill is verified by level in the hot salt surge tank which is at the high point in the system. When filling is complete, vent and drain valves are closed and salt in lines which are not in the operating panel flow paths is drained into the drain sump.

Morning or warm startup begins with panels full and receiver doors closed. Salt circulation is initiated. The doors are then opened and a few heliostats are rapidly focused onto the receiver. Then the remaining heliostats are focused on the receiver.

During normal operation, the design salt outlet temperature is controlled by varying flowrates in response to input power, as discussed in Section IV.D.3. During cloud transients, the receiver is operated normally until a predetermined minimum outlet flow rate is reached. Then temperature control ceases and the receiver continues to operate at the minimum flow rate. When the outlet temperature falls below design specification, salt is circulated either to the warm surge tank (for a short duration) or to the warm storage tank for longer periods. When salt outlet temperature returns to the required value, flow rate modulation resumes and the salt is supplied to the hot storage tank. When dictated by weather or storage tank conditions, extended periods of low flowrate operations are terminated and warm shutdown is initiated.

Overnight or warm shutdown begins with the field defocusing and the receiver doors closing. Salt stays in the receiver panels and is kept hot by the thermal conditioning equipment. Emergency shutdown occurs when receiver flow or flow control is lost because of pump, control system, or power failures or after collector field failures caused by power or control system failures. When a flow-related failure is detected, the field is defocused while the warm surge tank empties under pressure. The receiver doors close (under gravity load if power has failed). Based on salt receiver operating experience at the DOE/Sandia CRTF, a limited amount of time (several minutes) is available after the doors are closed before salt must be drained. During this time, assessment of the problem is made and appropriate action taken. If it is not possible to maintain molten salt in the panels, the panels are drained to the warm surge tank. Once the panels are drained, an additional hour or more is available to determine whether it is necessary to drain all salt back into the storage tanks and go to a cold shutdown condition.

In the event of collector field failure, maximum salt flow rate is initiated in the panels to prevent overheating while all operable heliostats are removed from the receiver. During this time, panel and flow temperatures are monitored and receiver doors are closed if unsafe temperatures are detected.

IV-E. RECEIVER TOWERS

Two reinforced concrete towers are provided to support the two solar receivers. Each tower is a hollow, slightly tapered cylinder, similar to a concrete chimney and will be designed and constructed with conventional technology. Tentative dimensions are:

o	Height		585 feet
o	Outside diameter:	top	71 feet
		bottom	86 feet

o Wall thickness varies, 13 1/2 to 15 inches

o	Foundation	105 foot octagon, 6 feet thick

A 16 inch diameter carbon steel riser pipe inside each tower carries the warm salt to the receiver while 12 inch stainless steel downcomer carries the hot salt down. A staircase, access platforms, elevator and lighting are provided inside the tower for maintenance of the pipelines and access to the top. (See Figure IV.A.16) A work platform is also provided on top of the tower.

An open steel framework, 160 feet high, supports the receiver and associated equipment above the tower. A staircase, access platforms, aircraft obstruction lights, electric power and bridge crane are provided. The bridge crane is supported near the top of the steel framework. It has a capacity of 10 tons and is used to erect the receiver and for subsequent maintenance. The crane hoist is provided with 730 feet of lift so that items can be raised from or lowered to grade level, inside the tower.

IV-F. THERMAL STORAGE AND TRANSPORT

1. Functional Description

a. General

The thermal storage and transport system provides storage for a portion of the collected energy and transports the energy between the receivers, storage tanks and the steam generator. The system consists of the molten salt receiver coolant, two storage tanks (one for hot salt at 1050°F and one for warm salt at 550°F), a receiver pipe loop and a steam generator loop. The receiver loop consists of a set of pumps and piping which carry 550°F salt from the warm tank up the towers to the two receivers and additional piping which takes 1050°F salt from the receivers to the hot tank. The steam generator loop has a set of pumps and piping which carry 1050°F salt from the hot tank to the steam generator and additional piping which takes 550°F salt from the steam generator to the warm tank.

The static head of the hot salt in the receiver downcomers is dissipated in throttle valves prior to discharge into the atmospheric pressure hot salt tank. An option is available for by-passing receiver downcomer flow around the hot tank directly to the steam generator. This avoids the necessity of operating the steam generator pumps and permits a corresponding savings in auxiliary power. This operating option is exercised only during clear weather when it is not possible for receiver transients, due to cloud passage, to be transmitted to the turbine.

The thermal transport and storage system has a number of features which are discussed below. They include:

- Drainability
- Heat tracing of all lines and components.
- Enclosed cover gas system.
- Mini-flow loops for pump protection.
- Auxiliary fossil heater for freeze protection and use in initial salt charging operation.
- Blending tee for controlled mixing of warm and hot salt during steam generator start up.
- Make up salt charging system.

All of these features are shown in the flow diagram on Figure IV.A.3.

b. Coolant

Fifty six million pounds of molten nitrate salt, 60% potassium nitrate, and 40% sodium nitrate, are used as the receiver coolant.

c. Drainage

All lines are sloped to provide complete drainage from the receiver and steam generator to the storage tanks. A drain sump tank is located at the bottom of the pump pit. During normal operation the drain sump pumps return receiver and steam generator pump seal leakage to the warm salt storage tank. The drain pumps also provide the capability for pumping the entire system salt inventory into either of the two storage tanks.

d. Heat Tracing

All lines and components are electrically heat traced. The heat tracing is used to preheat equipment prior to the introduction of molten salt and to reduce salt cooldown during overnight standby, as required. It will also be used to melt frozen salt in pipes and components, if required.

e. Mini-Flow Loops and Auxiliary Heater

In order to avoid pump damage from prolonged operation at very small flow rates, mini-flow loops are provided around the pumps. They return flow to the supply tank as necessary to sustain the minimum flow required through the pumps. The receiver and steam generator pump mini-flow loops shown in Figure IV.A.3 have valving arrangements which permit inclusion of an auxiliary fossil heater. This heater is available for heating the salt in either tank. The mini-flow loops are potential locations for salt contaminant removal equipment, should they ever be needed.

f. Tanks

The hot salt tank stores sufficient salt from the reciever, at 1050°F, to operate the turbine generator plant at maximum capacity for nine hours. The warm tank stores the salt, at 550°F, after it has gone through the steam generator prior to being pumped back through the receivers.

g. Cover Gas System

A cover gas is used above the salt in both storage tanks to avoid contamination of the salt. The cover gas is air from which moisture and carbon dioxide have been removed by dessicant type air dryers and activated carbon filters. The upper portions of the tanks, above the highest salt levels, are connected to each other and to an ullage tank, which maintains the cover gas pressure slightly above atmospheric, and allows the cover gas to move freely between the tanks, as the salt levels go up and down. All salt-air interface cavities in the system are vented to this enclosed atmospheric pressure air supply, including the pump seal cavities and the drain sump. The ullage tank has a moveable diaphragm which separates the cover gas from atmospheric air.

h. Salt Temperature Blending

A blending tee is provided to permit a controlled mixing of warm and hot salt delivered to the steam generator during startups which follow an extended shutdown period. The mixing permits programing of salt temperature at a rate within the 150°F per hour limitation of the steam generator. For normal overnight shutdown hot salt is kept in the steam generator supply line maintaining the steam generator at or near operating temperature.

i. Salt Makeup

Makeup salt requirements are provided by means of a pneumatic system which blows salt prill to a hopper on top of the warm salt tank. The pneumatic system uses air from the warm salt tank and discharges salt into the tank where it is melted.

j. Charging Procedure

The initial charging of the salt inventory is done by the salt supplier. The cost of this service is included in the cost of the salt. Prior to charging, however, the warm salt tank is heated to a temperature of 550°F with heat tracing on the tank ceiling, on the walls and in the soil beneath the tank. The heat tracing is designed to preheat the tank at 5°F per hour. This gradual rate of heating brings the tank to 550°F in about four days and avoids the occurrence of large temperature differences and thermal stresses.

The heating beneath the tank prevents the thermal mass of the soil from causing thermal gradients between the tank bottom and the tank walls and top.

Once the warm tank is at 550°F, the salt melter is provided its initial charge of salt and the filling process begins; it will take approximately 90 days to fill the tank. When the warm tank is near twenty percent full, the hot tank is preheated to 550°F over a period of four days just as the warm tank was previously. The receiver pumps are then primed with 550°F salt from the warm tank and approximately ten percent of the design inventory is transferred to the hot tank. The steam generator pumps are primed with 550°F salt from the hot tank and pump mini-flow through the auxiliary fossil heater is established. The fossil heater is fired at the rate required to bring the hot tank from 550°F to 1050°F in approximately four days. Natural convection and radiation cause the unwetted tank walls and roof temperatures to closely track (within 10°F) the temperature of the salt. The fossil heater can thereafter be used to heat salt from the warm tank or the hot tank as needed to keep either supply from falling below rated temperature. This capability is used for temperature maintenance during prolonged periods of cloudy weather.

k. Freeze Protection

Calculations based on the conservative assumption of no lateral migration of cooled fluid indicate the following: When the salt lines to the receiver and steam generator are filled and the system is shutdown at night, normal heat loss causes cooling of a almost 8°F per hour for the insulated hot piping and about 3°F per hour for insulated warm piping. If allowed to continue cooling, salt in the 12 inch hot pipe would begin to freeze in about three days and would be completely frozen in eight days. Salt in the 16 inch warm salt lines would commence freezing in one and half days and would be completely frozen in eight days. These cooling rates indicate that overnight operation of the heat tracing may not be necessary except possibly at the base of vertical runs of the warm salt piping.

Upon lengthy shutdown due to cloudy weather, the salt can be maintained at temperature by means of the electric heat tracing. If the cloudy weather persists, the salt may be drained to the tanks. In the tanks, if permitted, the warm salt would cool to the freezing temperature (430°F) in approximately three months. It would take well over six months for the salt in the hot tank to begin to freeze. Maintenance of salt temperature in the tanks is possible by means of heat tracing, mini-flow pump recirculation with heat from pumping losses, and mini-flow pump recirculation with heat from the auxiliary fossil heater. The many redundant defenses against freezing make the likelihood of such an occurrence essentially nil. Nevertheless, should freezing ever occur, the tank heat tracing system is capable of thawing out a frozen system. The major function of the pipe and tank heat tracing systems is the required preheating prior to charging with salt.

2. General Arrangement

The plant general arrangement is shown in the Figure IV.A.1 Plot Plan and in the Figure IV.A.13 and 14 General Arrangement drawings.

The major salt loop equipment is shown east of the turbine-generator. The steam generator is closest to the turbine generator. The warm and hot salt tanks are east of the steam generator. The pumping pit, containing the receiver pumps, steam generator pumps and the salt drain sump system, is located between the tanks and the steam generator. One set of warm and hot salt lines supply a receiver located over 600 ft. above grade on the tower at the southern edge of the power block. Another set of salt lines supply the second receiver located on another tower, 4200 ft. to the north. The salt tanks are located within berms that are designed to contain the entire salt inventory in event of a major spill. The cover gas tank, makeup salt storage bins and the salt charging area are located next to the warm salt tank just outside of the berm. The auxiliary oil fired salt heater is adjacent to the pump pit.

3. Component Description

a. Salt Storage Tanks

The storage tanks are shown on Figures IV.A.18 and 19. The major features of the storage tanks are:

	Warm Tank	Hot Tank
Salt temperature, °F	550	1050
Maximum operating volume, ft^3	414,440	454,330
Maximum salt storage at 550°F (nonoperational), ft^3	467,850	467,850
Material	Carbon steel, SA516-Gr. 70	Stainless steel, type 316
Diameter, ft	120	120
Height to spring line, ft	44	44
Plate thickness, inches	1/4 to 1 1/2	1/4 to 2 1/2

Each tank is supported on a sand foundation, enclosed by a concrete ring wall. Refractory concrete is used as required. Provisions are made for thermal expansion of the tanks.

b. Cover Gas Tank

The cover gas tank is 64 feet in diameter by 48 feet high to the spring line. It is supported on a ringwall foundation. The tank is manufactured from carbon steel plate. Gas containment volume is varied by means of a counterweighted piston which maintains the air pressure at 0.1 ± 0.1 psig.

c. Molten Salt Pumps

The receiver and steam generator feed pumps are vertical, multi-stage pumps, similar to those used in condenser hotwell service. Shaft sealing is by throttle bushings; throttle bushing leakage is routed to the sump tank and pumped from there to the warm storage tank. Three-half capacity pumps, two operating and one on standby, supply hot salt to the steam generator. Similarly, two banks of three-half capacity pumps supply warm salt to each of the receivers. Pumps requirements are given below.

	Warm Salt Pumps		Hot Salt Pumps
	North Receiver	South Receiver	
Number Required	3 half capacity	3 half capacity	3 half capacity
Head, ft.	1265	1042	294
Capacity, gpm	3212	3212	2690
Fluid Temperature, °F	550	550	1050
Fluid Density, lb/ft^3	107.6	107.6	118.9
Viscosity, cp	3.50	3.50	1.13
Stages	9	7	3
Materials	316SS impeller C.S. bowls		316SS

d. Pipelines

The main warm and hot salt transport lines are 16 inch and 12 inch diameter, respectively. The warm pipelines are manufactured from carbon steel; the hot pipe from type 316 stainless steel. The lines are looped to facilitate thermal expansion. Piping support details are shown in Figure IV.A.15. Piping specifications are given below.

Warm Salt Piping Specification

	South Receiver Supply	North Receiver Supply	Steam Generator Return
Design Pressure PSIG	860	1,045	70
Design Temperature, °F	575	575	575
Pipe Material	A106, GR. C	A106, GR. C	A106, GR. C
Code	ANSI B31.1	ANSI B31.1	ANSI B31.1
Pipe Size	16 inch Schedule 60	16 inch Schedule 80	14 inch Schedule 20
Weight Per Foot Lb.			
Pipe	108	137	46
Salt	140	133	116

Insulation	27	27	20
Total	275	297	182

Insulation

Type	Calcium Silicate	Calcium Silicate	Calcium Silicate
Thickness, Inch	4	4	4
Heat Loss, W/Ft.	77	77	70
Btu/hr-ft	264	264	237

Salt Temperature °F	550	550	550

Hot Salt Piping Specification

	South Receiver Return	North Receiver Return	Steam Generator Supply
Design Pressure, PSIG	545	610	220
Design Temperature, °F	1,100	1,100	1,100
Pipe Material	A312 (316SS)	A312 (316SS)	A312 (316SS)
Code	ANSI B31.1	ANSI B31.1	ANSI B31.1
Pipe Size	12 inch Schedule 60	12 inch Schedule 60	12 inch Schedule 30
Weight Per Foot, Lb.			
Pipe	73	89	44
Salt	88	84	95
Insulation	35	35	35
Total	196	208	174
Insulation			
Type	Calcium Silicate	Calcium Silicate	Calcium Silicate
Thichness, Inch	6	6	6

Heat Loss, W/Ft.	119	149	119
Btu/hr-ft	407	407	407
Salt Temperature °F	1,050	1,050	1,050

e. Insulation

The molten salt pipe lines are insulated as follows:

Warm pipe	4 inches calcium silicate
Hot pipe	6 inches calcium silicate

The storage tanks are insulated as follows:

Warm tank	4 inches fiberglass
Hot tank	3 inches calcium silicate, inner layers, plus 5 inches fiberglass, outer layers

Insulation on pipe and tank walls is protected by aluminum cladding, .016 and 0.24 inches thick, respectively. The wall cladding will consists of corrugated sheets. The tank roofs will be protected by 3/16 inch carbon steel plate, with welded seams.

IV-G. STEAM GENERATOR SYSTEM

1. Functional Description

The steam generator system receives hot molten salt from the receiver or hot storage tank to produce superheated steam for use in the steam and condensate system. The warm salt exiting from the steam generator is sent to the warm storage tank for cycling to the receiver system.

The steam generator system consists of four separate heat exchangers (preheater, evaporator with integral steam drum, superheater and reheater) and the flow distribution and control elements (interconnecting piping, pumps, valves and controls). All four heat exchangers are of the straight-tube type with salt on the shell side and steam/water on the tube side. The preheater, superheater, and reheater are counterflow heat exchangers; the evaporator is a parallel-flow heat exchanger. A steam drum is located atop the evaporator to separate evaporated steam from the water. The steam generator system interfaces with the plant control system as well as the thermal transport and storage and the steam and condensate systems. Electrical power and other support is provided by the balance of plant system.

2. General Arrangement

The steam generator system heat exchangers are located between the molten salt storage tanks and the turbine generator in the arrangement shown on the power block plan, Figure IV.A.13.

The heat exchangers are located close to the turbine to minimize the run lengths of high pressure steam piping. The superheater and reheater are located on the side closest to the turbine.

The heat exchangers are hung from a steel beam superstructure. A catch basin (berm) surrounds the heat exchangers to contain a salt leak.

3. Major Component Descriptions

a. Heat Exchangers

The heat exchangers are the straight-tube, single-pass, shell-and-tube type, each with a floating lower steam/water inlet head and double segmental baffles. An expansion bellows welded to the lower shell head and the steam/water inlet nozzle permits differential expansion between the tube bundle and the shell. Figures IV.G.1 through IV.G4 illustrate the preheater, evaporator, superheater, and reheater designs. The superheater and reheater are built of Type 304 stainless steel. The preheater is made of carbon steel and the evaporator of 1-1/4% CR-1/2%Mo (T-11) material.

The designs of the preheater, superheater, and reheater are similar in that hot salt enters an upper nozzle located in a flared-out section of the exchanger shell that forms an annular space with a shroud surrounding the tube bundle in the flared area. The shroud acts as an impingement plate and is circumferentially slotted to distribute salt uniformly to the tube bundle. Sufficient space is provided between the nozzle and distributor slots to create a uniform flow pattern. After passing through the distributor slots the salt flows downward through the tube bundle and out of the exchanger through a nozzle located in the shell head. Tie-rods attached to the upper tubesheet support the double segmental baffles, which function as tube support plates to suppress vibration and buckling. Heat-transfer tubes are welded to the face of the tube-sheet using the fillet welds. The superheater and reheater are vertically hung from a support skirt welded to the shell near the upper tubesheet. The preheater is vertically hung from lugs welded to the exchanger shell.

The evaporator design is similar to the preheater, superheater, and reheater designs except for the following:

- Steam/water discharges into a vertical drum mounted on top of the evaporator.
- Hot salt enters through a nozzle in the flared-out secton of the shell at the bottom of the unit and leaves through the upper nozzle located in the shell.

The vertical steam drum, which is designed as an integral part of the evaporator, is equipped with spiral arm separators and box type chevron dryers to provide dry, saturated steam. Feedwater enters the steam drum through a toroidal distribution pipe positioned below the drum-water level. Blowdown and chemical feed lines control the concentration levels of impurities in the evaporator water. A steam line feeding the first stage feedwater heater is attached directly to the steam drum. A manway is provided to gain access to the upper tubesheet for maintenance.

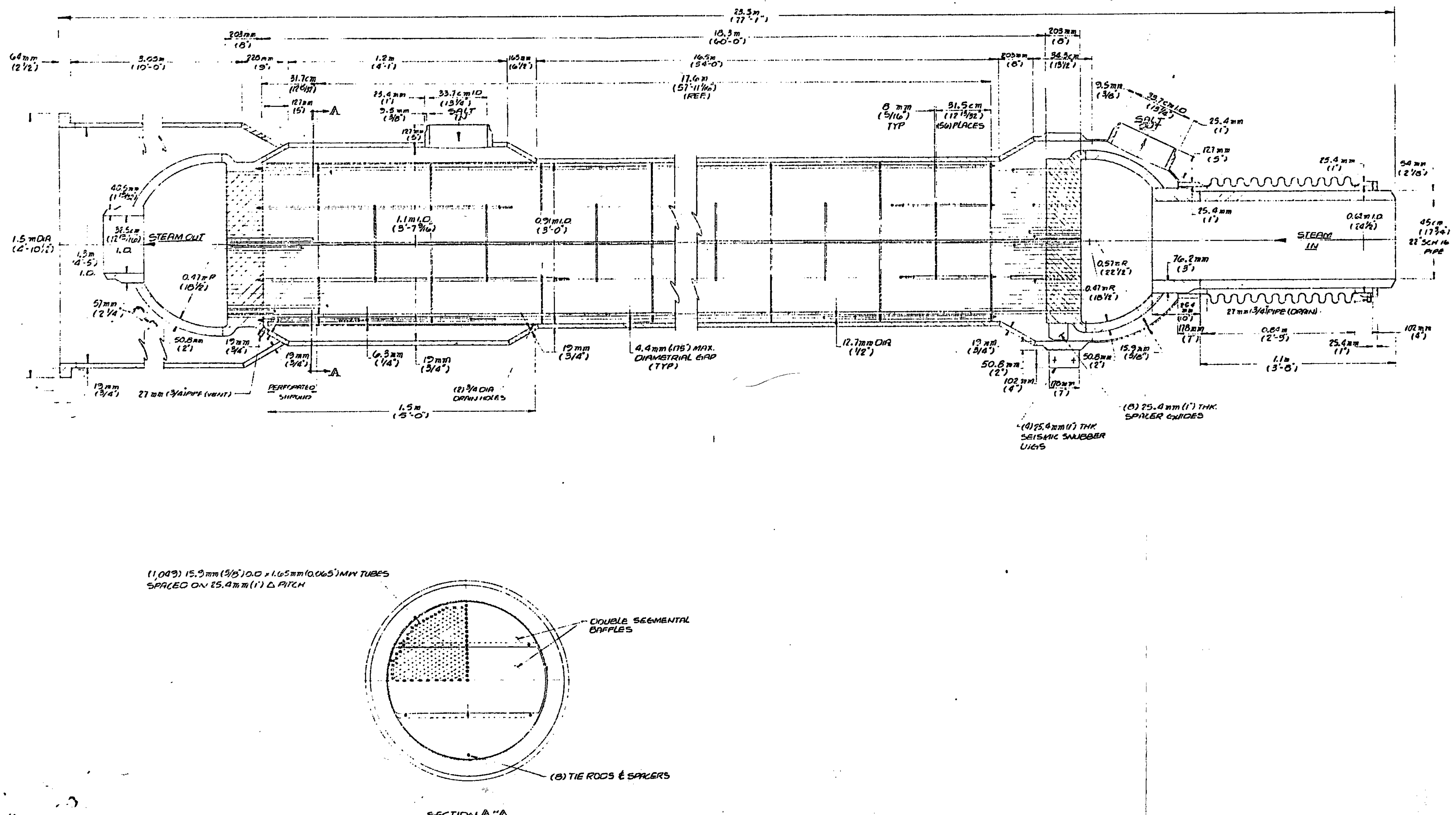


Figure IV. G. 1. Salt Preheater Heat Exchanger

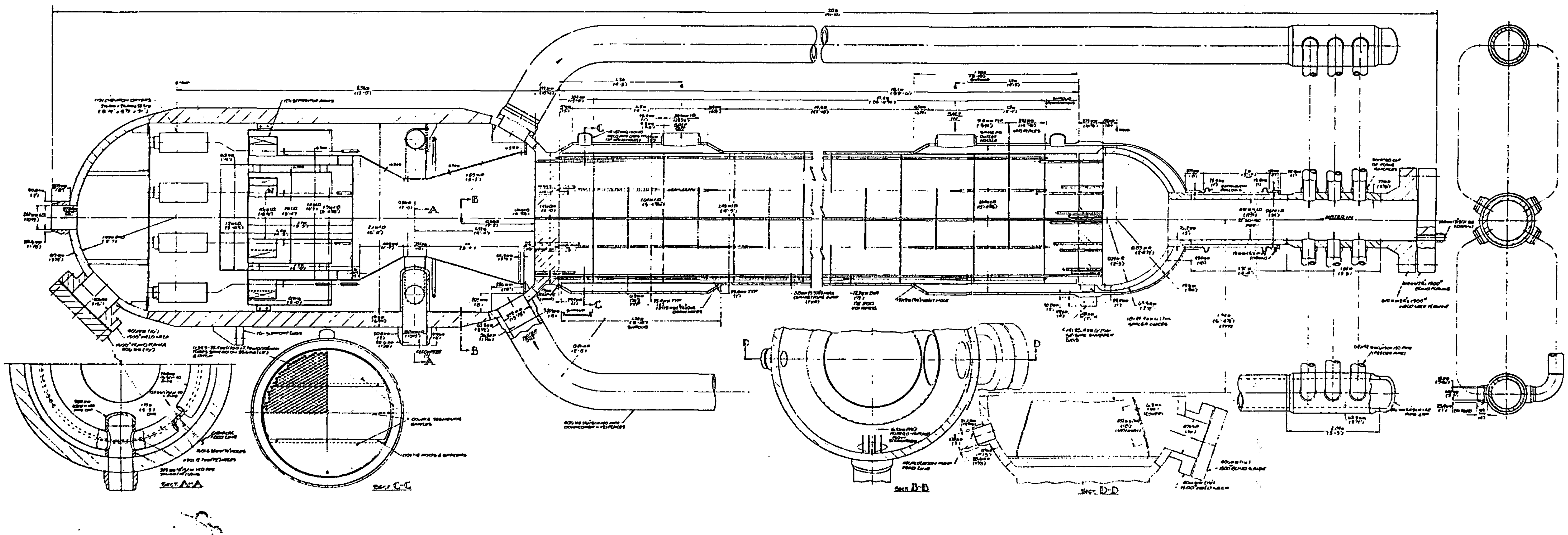


Figure IV. G. 2. Salt Evaporator Heat Exchanger

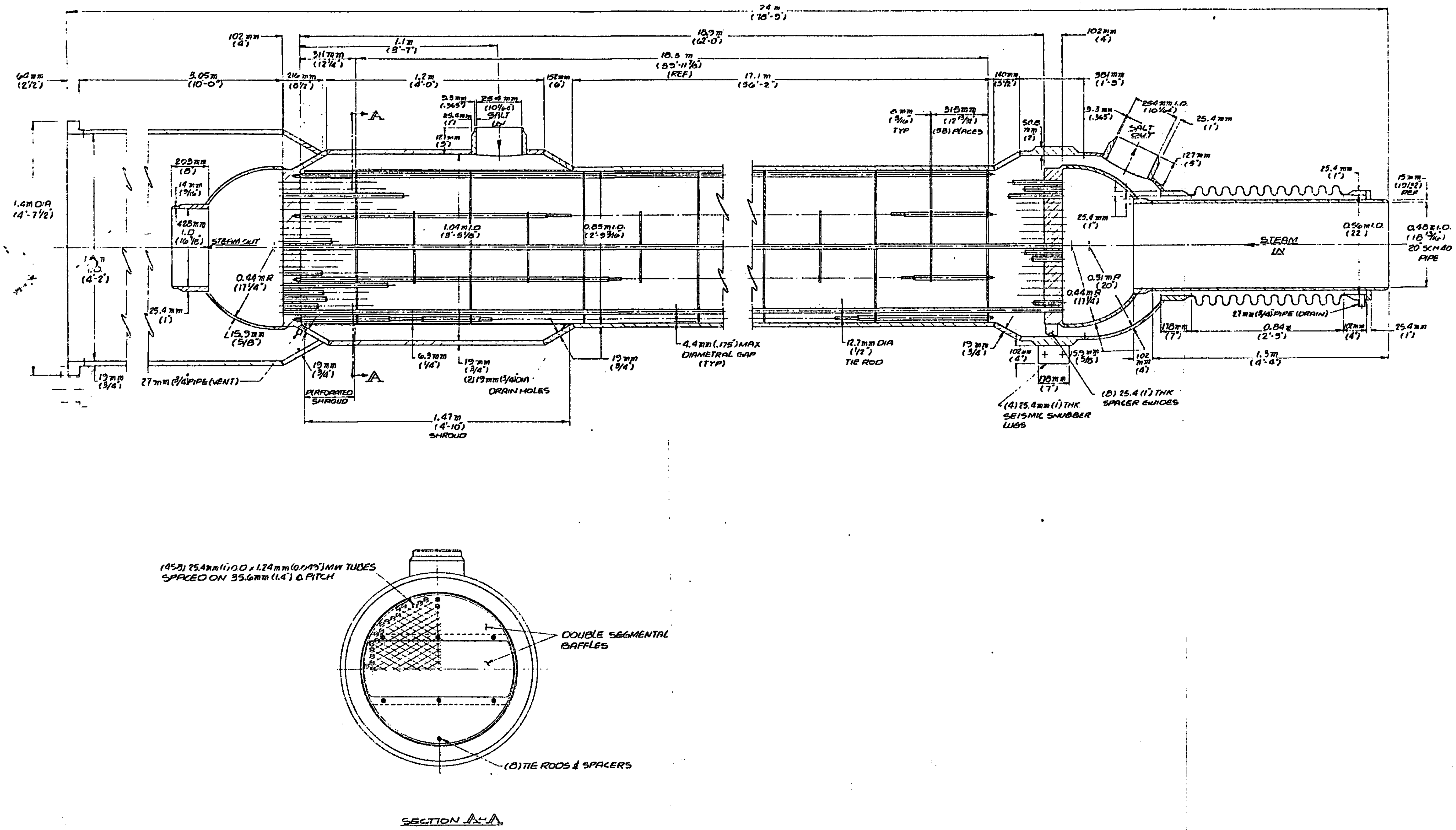


Figure IV. G. 3. Salt Superheater Heat Exchanger

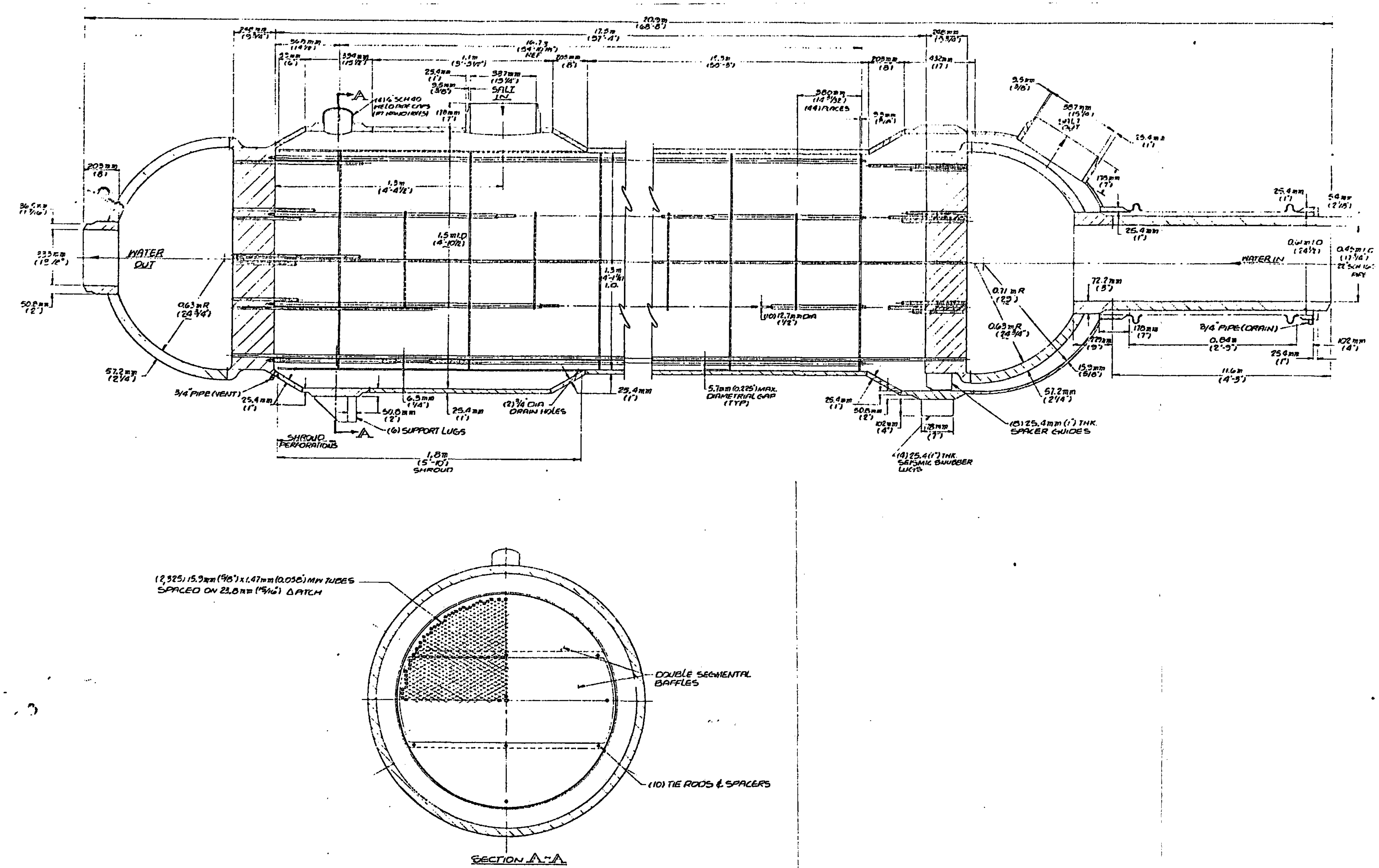


Figure IV. G. 4. Salt Reheater Heat Exchanger.

b. Flow Distribution and Control

A schematic of the steam generator system is shown on Figure IV.G.5. The control valves and their functions are shown on Table IV.G.1. Salt from the hot storage tank enters the system at 1050°F and flows in parallel through the superheater and reheater. After transferring heat to the reheat and main steam, the salt streams exiting from the reheater and superheater combine with a bypass hot-salt steam and enter the evaporator, where the hot salt gives up heat to evaporate water. The salt is then routed to the preheater where the feedwater is heated. Warm salt leaves the preheater at approximately 550°F.

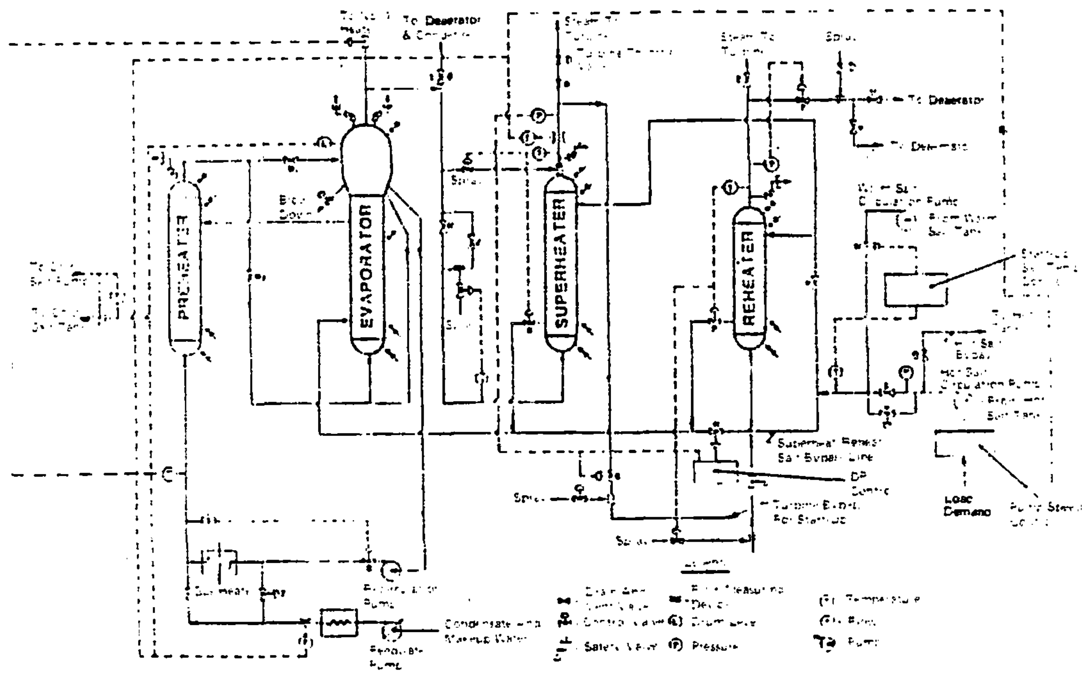


Figure IV.G.5. Steam Generator System Schematic

A feedwater pump supplies treated water preheated to 460°F to the preheater, where it is heated to nearly saturation before entering the evaporator. Saturated steam is generated in the natural-circulation evaporator and routed to the superheater, where it is superheated before passing to the high-pressure turbine for power generation. Intermediate pressure steam from the turbine is brought to the reheater for superheating and sent to the intermediate-pressure turbine. The exiting steam goes to a condenser, and the condensed water is then recycled through the feedwater pump and feedwater heater train.

Feedwater is maintained at a temperature above the salt freezing point, 430°F, during startup and part-load operation by regulating drum steam to the first stage feedwater heater. A fossil-fired heater is provided for cold startup feedwater heating. A drum water recirculaton pump circulates water through the fossil-heater during cold startup. A warm-salt

TABLE IV.G.1
SOLAR STAND-ALONE STEAM GENERATOR
SYSTEM CONTROL VALVES

Valve	Function
A	Feedwater Shutoff
B	Water Recirculation Control
C	Cold Reheat Steam Shutoff
D	Superheater Steam Shutoff
E	Reheater Steam Shutoff
F	Reheater Turbine Bypass
G	Superheater Turbine Bypass
H	Drum Steam Shutoff
I	Drum Steam Condenser Bypass
J	Drum Steam Letdown
K	Salt Shutoff to Reheater and Superheater
L	#1 Feedwater Preheater Peg Steam Control
M	Warm Salt Flow Control
N	Salt Bypass Control
P	Reheater Salt Flow Control
R	Superheater Salt Flow Control
S	Hot Salt Shutoff
T	Total Salt Flow Control
U	Condenser Bypass
V	Deaerator Bypass
W_1, W_2	Start-Up Evaporator Water Flow
Y	Hot Salt Start-Up Bypass
Z	Feedwater Start-Up Bypass

recirculation pump controls the temperature of salt entering the system by blending with hot salt during unit startup and shutdown.

c. Control System

The control system for the steam generator system uses interlocking controls to ensure safe and stable performance of the system over its operating range. ~~The final main steam temperature is controlled by regulating the salt flow through the superheater by adjusting its salt outlet~~

valve. A saturated steam spray from the steam drum to the superheater outlet is used for emergency temperature control. Reheat steam temperature is controlled by a valve at the reheat salt outlet that controls salt flow through the reheater. A spray attemperature is located at the reheater steam inlet for secondary control. Superheater outlet pressure is controlled by the total salt flow (firing rate). A bypass valve that bypasses hot salt around the superheater and reheater to the evaporator provides the ability to regulate total salt flow independent of superheater and reheater salt flow. The flow of feedwater to the steam generator system is controlled by signals from the feedwater flow, superheater steam flow and drum-water level.

The steam generator and turbine will operate in a sliding pressure mode above apoproximately 35% output. Above 35% load, the turbine throttle valves are wide open and turbine output is controlled by steam generator outlet pressure. Main steam pressure is controlled by varying the steam drum pressure. The drum pressure is controlled by the salt flow rate, which is equivalent to drum pressure control by firing rate in a fossil system. Steam temperature to the turbine is held constant by the action of the superheater and the reheater, as previously described. Figure IV.G.6 indicates the basic control relationships. A variation of the standard integrated boiler-turbine-generator control system is used. The drum maintains a constant pressure of about 700 psi when the turbine load is below 35%. Drum pressure is ramped-up with load to 100%. The ramp rate is controlled to keep the superheater inlet temperature ramp rate below 150°F/hour. Figure IV.G.7 shows the standard three-element control diagram for the feedwater. Figures IV.G.8, 9 and 10 show the detail control diagram for the boiler, superheater, reheater, and bypass salt flow controls.

d. Auxiliary Support Equipment

Electric trace heating is provided on all steam generator components containing molten salt. The trace heaters are sized to preheat the unit

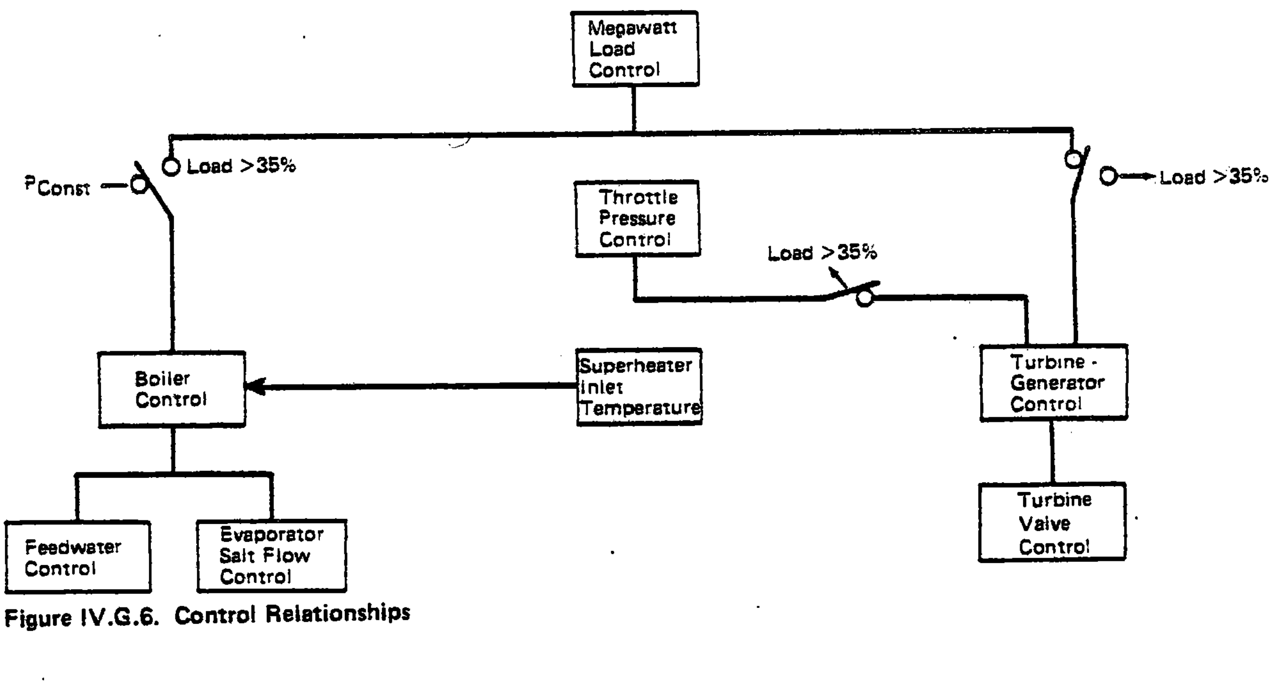


Figure IV.G.6. Control Relationships

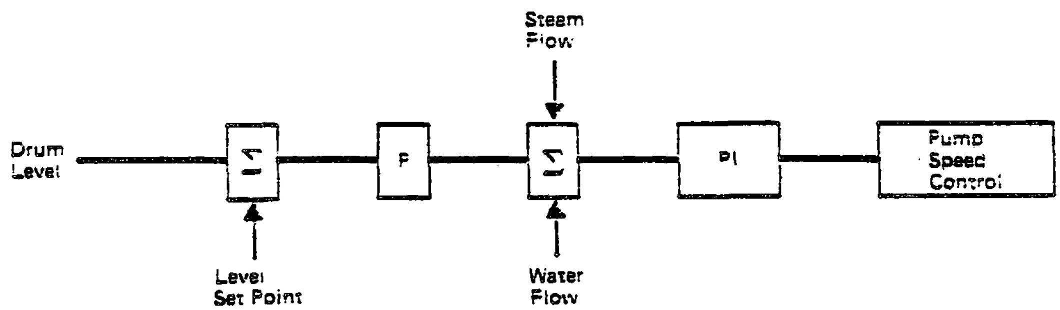


Figure IV.G.7. Feedwater Control

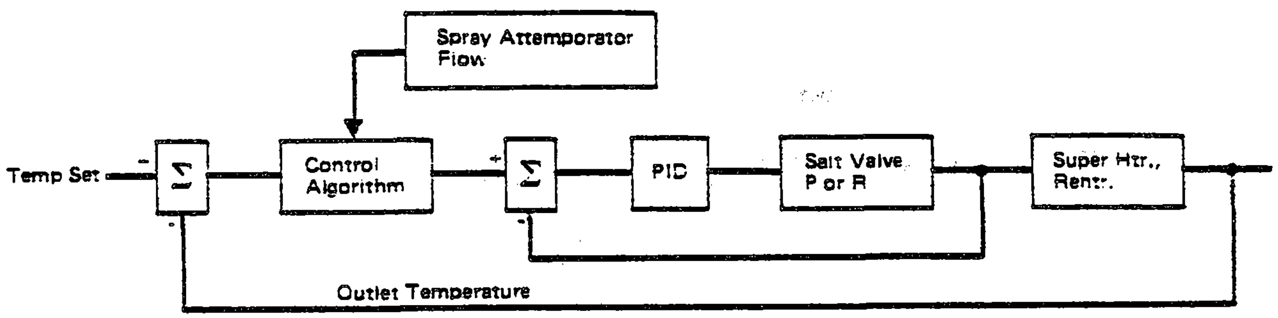


Figure IV.G.8. Superheater, Reheater Temperature Control

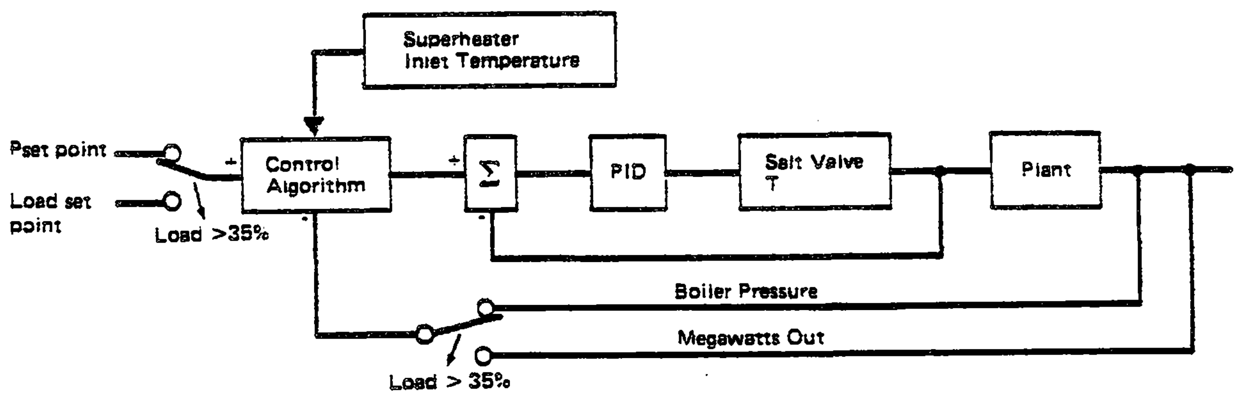


Figure IV.G.9. Boiler Control

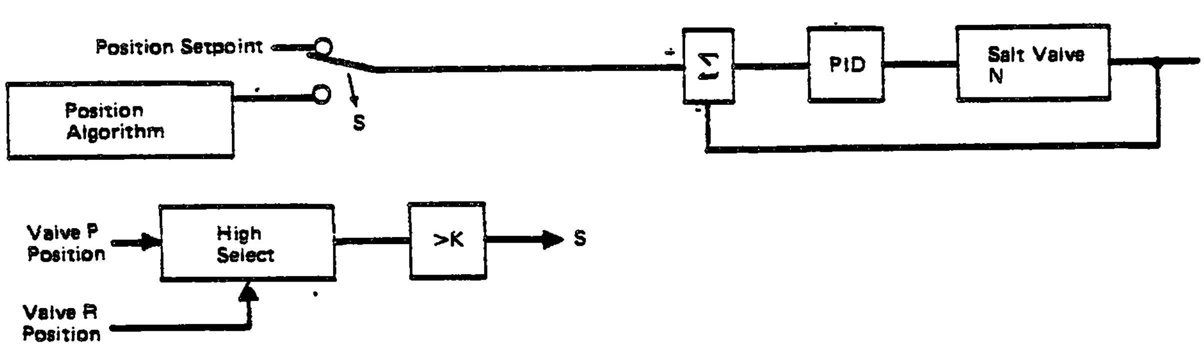


Figure IV.G.10. Salt Bypass Valve Control

initially and to compensate for ambient heat losses during warm standby. Insulation and lagging are provided on all components that might be a danger to personnel and on all components that are potential sources for significant heat loss. Safety vales are provided on the preheater outlet, steam drum, superheater outlet, and reheater inlet and outlet as required by the ASME code. Rupture discs in the salt inlet and outlet of each heat exchanger prevent overpressuring of the exchanger shell in the event of a tube leak. The lines from the rupture discs dump to the sump. Spray control devices are used to prevent showering the area with hot salt. All steam/water and salt components can be fully drained. Salt drains from the steam generator system to a sump, from which it is pumped back to the warm storage tank.

4. System Support Requirements

The water treatment facility in the steam and condensate system will maintain the desired quality of feedwater entering the steam generator system. Considering the steam drum operating pressure in this application, the maximum limits on critical impurities in the feedwater are:

o	Total hardness, $CaCO^3$	= 0 ppm
o	Organics	= 0 ppm
o	pH	= 8.5 to 9.2 nonferrous tubes in heaters
		= 9.2 to 9.6 steel tubes in heaters
o	Oxygen	= 0.077 ppm
o	Silica	= 0.02 ppm
o	Iron	= 0.01 ppm
o	Copper	= 0.005 ppm
o	Hydrazine, as N_2H_4	= 0.02 ppm

The concentration of impurities in the evaporator water are limited by continuous blowdown from the drum. A blowdown rate of 0.5% is used in the design.

Clean dry air at 100 psig is required for instrumentation and pneumatic control. Fossil fuel is required for the feedwater heater during cold startup. A salt sump tank is required to store the salt contents of all heat exchanger components and interconnecting salt piping. A salt sump pump is provided to circulate salt back to the warm storage tank.

Electric power is required to operate the recirculation pumps, heat tracing, and instrumentation and controls. Two identical pumps, each sized for 100% capacity, are used in the recirculation loop for redundancy. Motor rating of each pump is 20 HP. The trace heating load is estimated to be approximately 200 kW.

5. Operational Features

Steam generator operations include cold startup, warm (or morning) startup, sliding pressure operation, normal operation, low power operation, warm standby, and cold shutdown. The cold startup procedure is illustrated on Figure IV.G.11. This procedure is manually controlled.

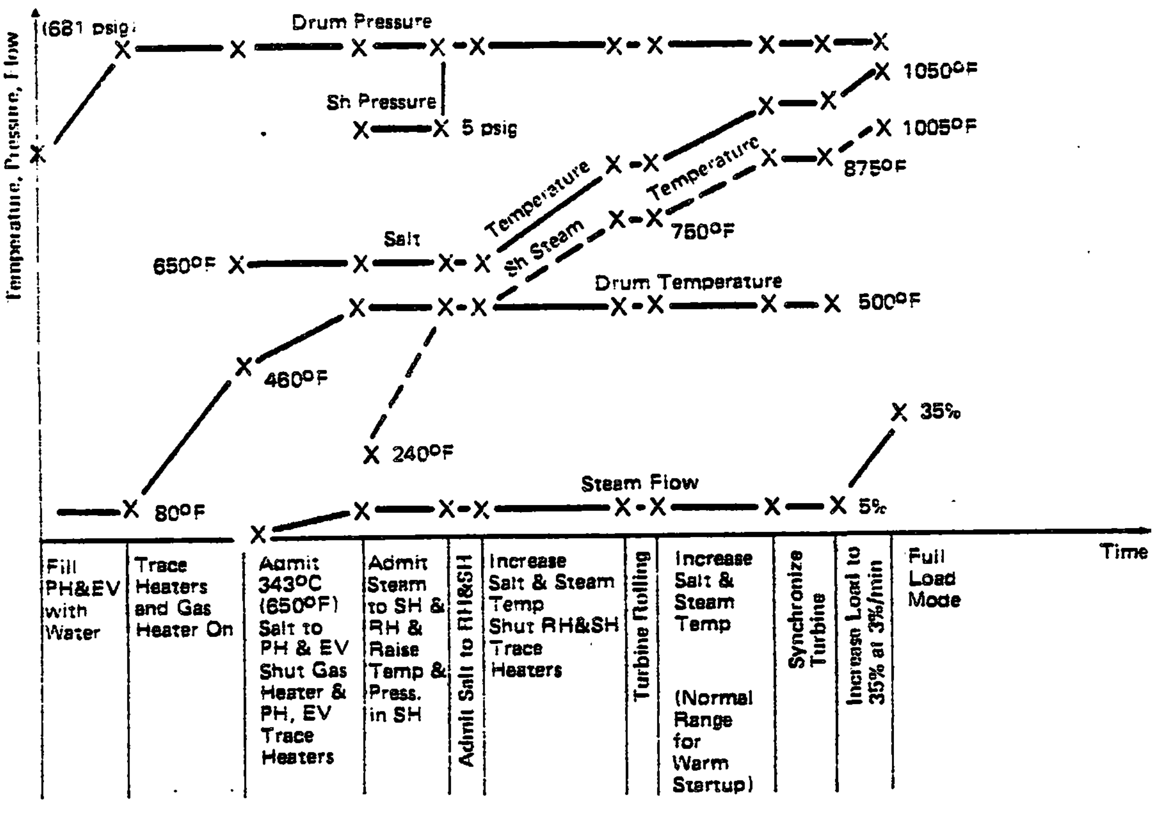


Figure IV.G.11. Cold Start-Up — 100-MWe Solar Stand-Alone SGS

The preheater and evaporator are filled with water until the desired drum-water level is achieved. The recirculation pump is started to circulate water through the preheater and evaporator at approximately 12" flow. A gas heater at the discharge of the water recirculation pump is used to heat the water. The heated water passes through the preheater and the evaporator. Water from the drum is routed back to the recirculation pump.

Trace heaters are started; when required temperature conditions are established, salt blended to approximately 650°F is admitted to the evaporator and preheater.

Salt flow is adjusted to obtain 55% steam flow at approximately 500°F. Feedwater pump speed is regulated to maintain drum-water level. Steam from the drum is used for heating feedwater and for initial turbine warmup. (Initial turbine warmup takes approximately six hours.) Reduced-pressure steam is admitted to the superheater and reheater.

When temperature conditions are stabilized, pressure in the superheater is allowed to rise to approximatley 681 psia. Salt at 650°F is admitted to the reheater and superheater (at 5% rated flow) to generate 500°F saturated steam at 5% flow. Blended salt temperature is increased at the rate of 150°F/hour.

Steam temperature increases as a result of the increased salt temperature. Water sprays maintain steam temperature entering the reheater. When the main steam temperature reaches 750-°F, turbine roll is initiated. High-pressure turbine exit steam enters the reheater and reheater steam enters the intermediate-pressure turbine. Rolling is established in approximately 15 minutes. The turbine is synchronized when the main steam temperature is stabilized at 875°F.

The load and steam temperature and pressure are increased linearly to 35% (1005°F and about 700 psia) by increasing the salt temperature to 1050°F and salt flow to its 35% value. Turbine valves are full open at 35% load. The load is increased at the rate of 3%/minute while maintaining steam to turbine temperature differences within specified limits.

Following stabilization at 35% load, control is transferred from the turbine throttle valves to drum pressure and automatic control. This transfer is performed by the operator.

The sliding pressure operating load range is from 35 to 100%. For sliding pressure load operation, the feedwater flow to the preheater is controlled from the superheated steam flow and drum-water level. Feedwater flow is adjusted to maintain these parameters. To preclude salt freeze-up in the preheater, the temperature of the feedwater entering the preheater is kept at 460°F minimum, using drum steam feed to the No. 1 feedwater heater preheater. The preheated water enters the steam drum in the evaporator and is circulated, using natural circulation, through the downcomer. Saturated steam from the steam drum at 495°F to 636°F enters the superheater, where it is superheated to 1005°F. The superheated steam enters the high-pressure turbine to do work. A saturated steam spray from the steam drum exit to the superheater steam exit is used for emergency temperature control. The superheated steam temperature is controlled primarily by regulating the salt flow through the superheater. Superheater outlet pressure is maintained at the set point by controlling the superheater reheater salt bypass.

Steam from the high-pressure turbine exit enters the reheater. The reheated steam exit temperature is controlled by salt flow through the reheater. Spray control at the reheater inlet is also available to moderate the reheat steam exit tempteature. All controls are on automatic during full- and part-load operation.

The steam generator system is designed to operate continuously at any load between full and 35%. However, this mode is normally used only to transition to and from full load operation at startup and shutdown. Load change between these operating points is achieved by adjusting the feedwater and salt flows using the automatic control logic.

To increase load, salt flow is increased. The increased firing rate causes the drum pressure to rise and increases steam flow to the turbine. This increase signals increased feedwater flow. The higher steam flow also causes a reduction in drum-water level. The reduced drum-water level combines with the increased steam flow to demand higher feedwater flow. The increased load signal also adjusts salt bypass in anticipation of the increased load. Superheater and reheater salt flow is balanced for higher salt flow.

Similar logic in reverse order is used for reduction in load. All load changes are limited by the superheater steam inlet temperature ramp rate limit of 150°F/hour.

When full load is reached, primary system control continues to rely on the drum pressure. Hence, the transition from sliding pressure control to normal operation is automatic, once the drum pressure set point is reached.

Warm startup is similar to cold startup, except for the initial conditions. At the beginning, all lines and heat exchangers are full of salt and/or water/steam. Temperatures are stabilized at some point consistent with an intermediate stage in the ramping of the salt and steam temperatures to operating conditions. Usually, the drum pressure is above the 700 psia desired for startup.

The superheater and reheater steam set points are matched to the warm turbine temperature.

Following turbine roll and synchronization, the salt and steam temperatures are ramped as with cold shutdown.

The steam generator and turbine are normally operated at rated load at all times other than startup and shutdown. At rated load, the turbine-generator produces 110 MWe (gross). The steam generator provides main steam at 1805 psia and 1005°F. The turbine returns reheat steam at 491 psia and 675°F. The reheater provides reheat steam at 442 psia and 1005°F to the turbine. Feedwater is supplied to the preheater at 460°F and about 2000 psia. The system operates at steady state. Attemporator flow to both the superheater and reheater is shut off. Figure IV.G.12 shows the status of key operating parameters over the complete load profile.

When the hot-salt storage tank level reaches the one-hour mark, a procedure is initiated for daily (warm) shutdown. The steam generator system is brought down at a rate governed by the 150°F/hour superheater inlet temperature ramp rate to 35% load and at 2%/minute beyond that. The steam generator is tripped at 15% load. The superheater salt inlet and steam outlet temperatures are 1050°F and 1005°F. The steam generator is isolated.

During the overnight shutdown period, the salt and steam reach a common temperature at every point in the sytem. The temperatures at the top and bottom on the superheater are 1011°F and 770°F, respectively. The temperatures at the other levels vary linearly between these values. The reheater salt and steam temperature reaches 1003°F at the top and 761°F at the bottom. The turbine first-stage temperature cools down to 925°F during this period. The temperature of salt and water in the preheater is 510°F at the bottom and 640°F at the top as a result of cooldown.

Residual thermal energy in the salt causes evaporator temperature to rise. The evaporator is isolated to prevent excessive loss of drum water. With the evaporator isolated, the temperature and pressure will rise to 572°F and 1244 psia, respectively.

~~Trace heating is initiated on the preheater inlet to maintain at least 510°F.~~

~~The evaporator does not require trace heating for overnight hold, but does require it if not started for two consecutive days. The reheater will require trace heating~~

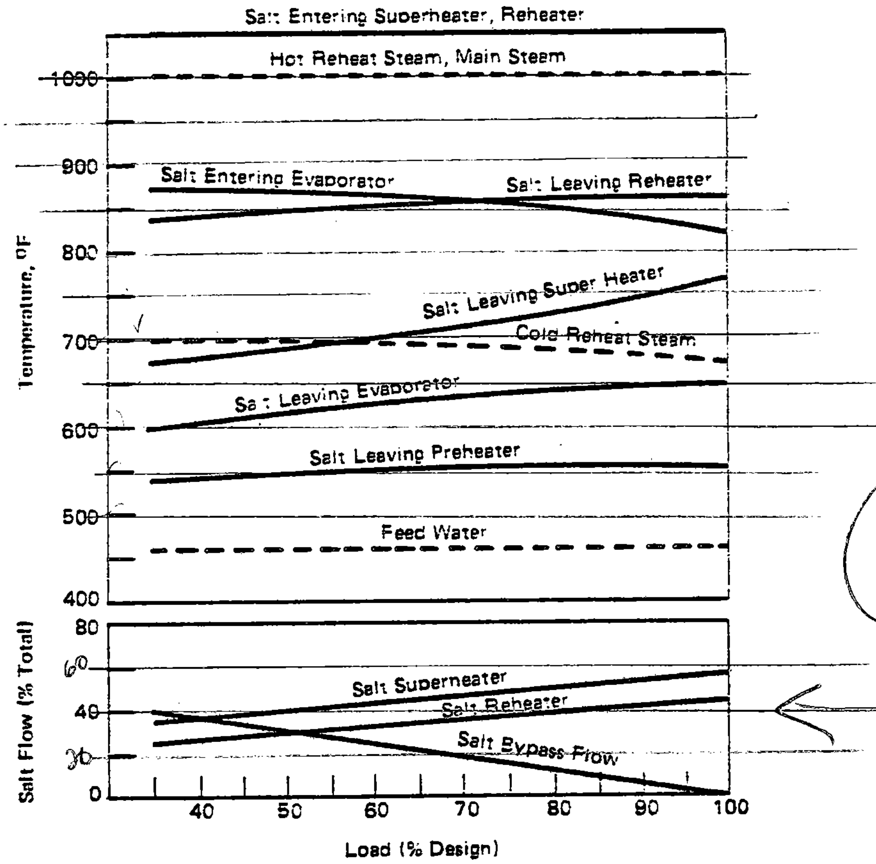


Figure IV.G.12. State Point Variation with Load at Sliding Pressure

~~if not started within six days. The superheater will require trace heating only after an eight-day shutdown.~~

In the event of a turbine trip, the steam generator executes a rapid shutdown. Salt flow is terminated at a controlled rate. Steam is shut off to the superheater and reheater. Excess pressure in the superheater and reheater is bled off by automatic control and the preheater and evaporator are isolated.

The evaporator pressure tends to rise above the design point of 1955 psia. Automatic control prevents evaporator overpressure. Feedwater flow is resumed to prevent low water level as drum steam is vented.

As in the case of warm shutdown, the preheater requires trace heating. The remaining heat exchangers will not require trace heating unless there are several consecutive days of shutdowns.

Shutdown to cold conditions begins at warm standby and terminates in long-term cold shutdown of the steam generator system in a cold, dry, ambient state.

Trace heaters are shut off and salt is drained from the steam generator system. All salt-side drain and vent valves in the heat exchangers and the piping are opened. The salt is collected and routed to the warm-salt tank. The salt side of the steam generator system is then purged with nitrogen and drain and vent valves are closed, leaving a nitrogen blanket on the salt side of the steam generator system.

Water is drained from the steam generator after the salt-side draining has been completed. Steam is blown to the condenser. After atmospheric pressure is achieved, the system is purged with nitrogen and all drain and vent valves are closed, leaving nitrogen on the steam/water-side of the heat exchangers and piping. The system is allowed to cool down to ambient conditions. More nitrogen is supplied to keep pressure slightly above atmospheric.

IV-H. STEAM AND CONDENSATE SYSTEM

1. Functional Description

The steam and condensate system is a traditional rankine power cycle that is typically found in fossil and nuclear stations. Steam is generated in the steam generator at a rate of approximately 742,000 lbs/hr at 1800 psig and 1000^{o}F. The steam is then expanded through the turbine to produce shaft works which in turn drive the generator to produce 100 MWe (gross). The heat source for the steam generator is the hot receiver fluid which is recirculated to the tower (or storage tanks).

The steam is condensed in a conventional shell and tube condenser and the resulting condensate is then pumped through a string of five feedwater heaters including a deaerator. The condensate is then fed back to the steam generator at a temperature of 460^{o}F to complete the steam and condensate process. A heat and mass balance is shown in Figure IV.A.11. As noted, the net turbine heat rate is 9,320 Btu/kW. This heat rate is defined as the amount of heat contained in steam divided by the equivalent net power generated. It is therefore exclusive of any solar losses such as collector field losses or receiver/salt piping losses.

2. General Arrangement

The layout of the steam and condensate system is depicted in Figure IV.A.13. The site of the power block was selected to minimize piping and transmission lines. As noted, both collector fields will be located north of their respective power blocks.

3. Major Component Description

The major equipment of the steam and condensate system can be categorized into three major topics:

- o Turbine
- o Feedwater/Condensate System
- o Condenser

a. Turbine

It is assumed that the turbine will be started up and shutdown every day during 30 years plant life. Accordingly, it is very important to select a properly designed turbine to meet this requirement. The thermal stress caused by two-shift operation and the low-cycle fatigue must be minimized by design measures. The turbine selected is a sliding pressure, tandem compound, double-flow, reheat condensing unit rated at 110 MW at 2.5 in

HgA back pressure when operating with inlet steam conditions of 1805 psia and 1005°F and hot reheat steam conditions of 442 psia and 1005°F. The turbine is designed for variable pressure full arc admission operation. The initial stages are the reaction type. The absence of a control stage enhances the machine operating reliability by avoiding the localized thermal and mechanical stresses that occur as a result of unsymmetrical steam admission particularly at low loads.

The concept of variable-pressure operaton is that the steam pressure is ramped with load while the main and reheat steam temperatures are maintained constant. The advantages of variable pressure operation with full arc admission are as follows:

- o The steam temperature at each stage of HP turbine remains almost constant in a wide load range. The turbine low-cycle fatigue caused by steam temperature variation during turbine startup and shutdown, therefore, can be avoided.

- o Low steam pressure results in a small heat transfer coefficient and thus in lower thermal stress levels at the same temperature differential between the steam and the metal components during startup.

- o Low pressure at low turbine output unloads all cycle components between the feedpump and the HP turbine, thus prolonging the life span of the system components, and it reduces auxiliary power requirements.

- o Because of the absence of the HP control stage, the net turbine-generator heat rate is improved over the full partial load range (refer to Figure IV.H.1).

The thermodynamic implication of variable pressure operation in conjunction with full arc admission and the constant pressure operation with nozzle control are shown on the Mollier diagram, Figure IV.H.2. In the case of constant pressure operation and nozzle control of the turbine, the temperature of the steam behind the control stage drops by 82°F when the load is decreased from 100 percent with four valves open to 32 percent with one valve open. In the case of variable pressure operation with the turbine valve wide open, however, the temperature at corresponding point remains virtually constant over the same load change. The HP exhaust steam temperature rises very slightly as load is reduced from 100 percent to 36 percent under variable pressure operating condition, whereas the corresponding temperature of a same size turbine operated under constant pressure condition sinks about 130°F over the same load range. The almost constant cold reheat steam temperature would help the reheater to maintain a constant hot reheat steam temperature.

The turbine is of triple-tandem construction with an HP casing, an IP casing and a double-flow LP casing. Each casing rests, completely separate from the adjacent casings, on a bearing pedestal. Each rotor is supported by two bearings of its own. As a result, differing temperatures of the HP and IP steam flows do not develop large temperature differentials in any single casing. The rotors are machined from solid one-piece vacuum - degassed

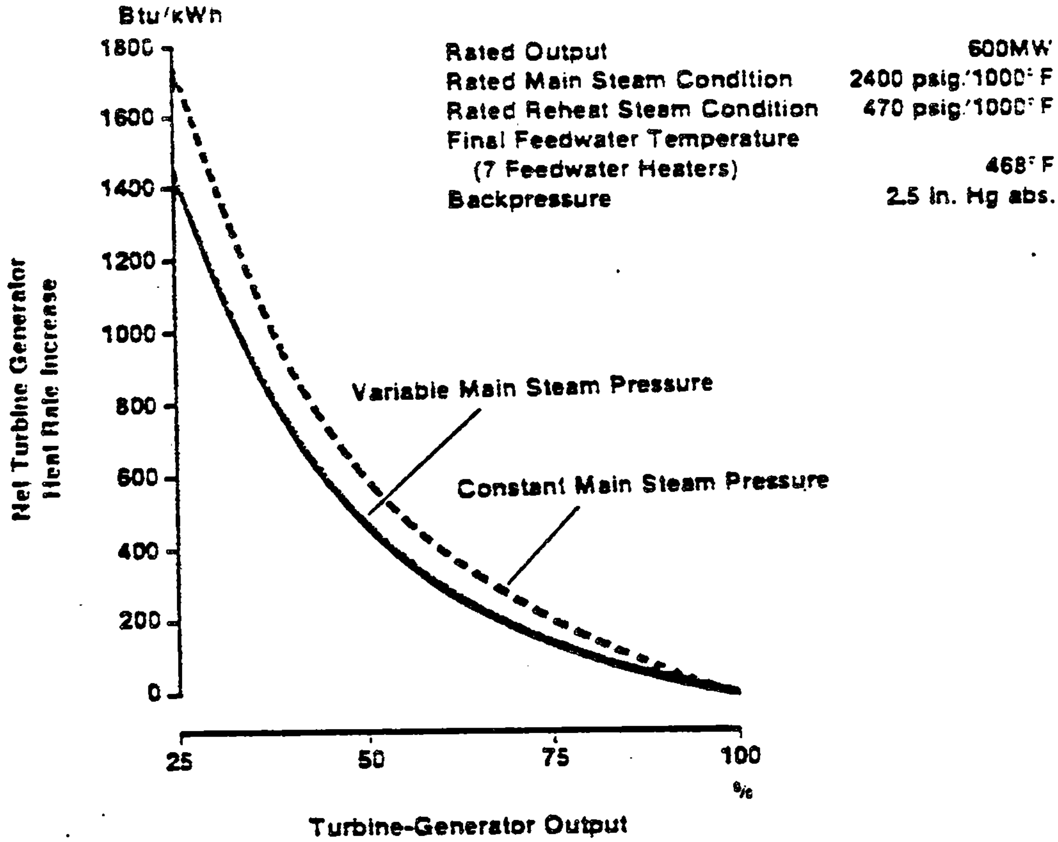


Figure IV.H.1. Net Heat Rate Differentials for Full-Arc Admission Turbines

forgings for avoiding the high operating stress caused by providing axial through-bores. The first critical speeds of HP and LP rotors lie well above 3600 RPM because of the short bearing span and the stiff rotor. Dynamic stability is assured when the rotors are brought up to or down from synchronous speed. The HP outer casing is a barrel-type design. Because of the symmetry of its cylindrical shape, large localized accumulations of metal masses are avoided and thermal stresses due to temperature variations are very low. The steam can be admitted into the annular spaces between the outer and inner casings. The positive pressure acting on the outside walls of the inner casing permits it to be designed with just a slender axial joint that requires only relatively light bolting.

The HP, IP and part of LP turbine blades are integrally shrouded reaction type. The last several stages of LP turbine are free-standing blades. Being completely devoid of the attachments of any kind, neither types of blades are subjected to the stress risers associated with riveted-shroud bands and lashing wiring.

The steam-strainers are installed into the main and hot reheat steam pipes upstream of the control stop valves. The valve bodies are compact and symmetrical, thereby minimizing stress levels. The valve cones and stems are protected by guide sleeves to safeguard them against temperature shocks due to possible steam generator upsets. The IP turbine control valves also exercise a throttling control function at low steam flows, the precision and stability of speed and low-load operation is greatly enhanced.

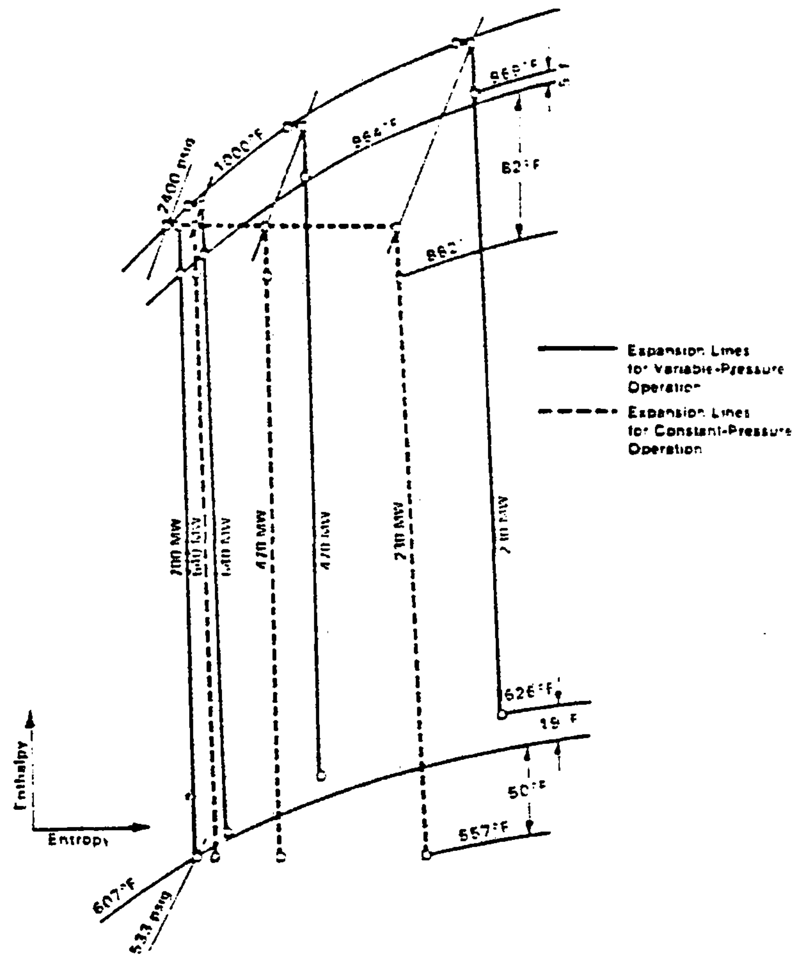


Figure IV.H.2. Comparison of Effect of Variable and Constant-Pressure Operation on the Steam Temperature Variations

b. Feedwater/Condensate System

The condensate and feedwater systems consist of the pumps, piping, heaters and controls in the fluid systems supplying the steam generator with heated, deaerated, and chemically treated water. The condensate system is the low pressure portion of the system from the condenser to the boiler feed pump suction flanges. The feedwater system is the high pressure portion of the system from the boiler feed pump suction flanges to the preheater inlet. The condenser air removal system is the air and vacuum system from the condenser air off-take connection through the air ejectors to the atmospheric exhaust flanges. The condensate and feedwater system is illustrated in Figure IV.A.11 "Heat and Mass Balance."

1) Condensate System

Condensate from the condensed turbine exhaust together with cascaded heater drains and miscellaneous equipment drains and vents is pumped from the condenser hotwell by the condensate pump. A separate suction line is installed from each half of the divided hotwell with a crossover connecting the two lines so that either pump can take suction from one or both halves of the hotwell.

The discharge piping from the two condensate pumps is joined into a common header. A valved connection is provided in each condensate pump discharge pipe through which the condensate can be discharged to waste in the event of circulating water contamination or other unsuitable condensate conditions. In the control room pressure in the condensate pump discharge header is indicated, low pressure is annunciated, and temperature is recorded. Hydrazine and ammonia or amine are injected into the condensate header from separate lines from the Chemical Feed System.

A connection is provided on the discharge header from which condensate is automatically drawn off to the distilled water tanks when the condenser hotwell level is high.

A service connection with branches is provided to supply high pressure condensate for turbine exhaust hood spray, chemical feed, cooling water makeup and fill; and, through a pressure reducing valve, to the condensate pump seals, vacuum breaker, and to miscellaneous valve seals.

The condensate header branches to permit parallel flow through the air ejectors and gland steam condenser and joins into a common header downstream of these units. The condensate flow is measured by a flow element which operates the recirculation control valve through a flow transmitter and flow controller to maintain a minimum flow through this portion of the system. Condensate flow at this point is recorded in the control room and flows below the set minimum flow annunciated. The condensate then enters the No. 6 heater, flows from the No. 6 to the No. 5 heater and from there to the No. 4 heater and there to the No. 4 heater and then to the deaerator where it is heated and deaerated by direct contact with extraction steam.

2) Feedwater System

The condensate leaves the deaerating (heater No. 3) storage tank in a common suction header and flows to the feedwater pumps where the header suction temperature is indicated locally. A minimum flow recirculation connection and a pump warm-up connection are provided in the discharge of each feedwater pump.

Feedwater discharge header pressure is indicated in the control room. Feedwater flow is measured by a flow element and the flow is recorded in the control room and transmitted to the three element feedwater control.

After flowing through the feedwater control valves and the No. 2 and No. 1 heaters, the feedwater passes to the preheater inlet where temperature and pressure are indicated locally and recorded in the control room.

3) High and Low Pressure Heaters

The No. 5 and No. 6 low pressure hecters comprise the first two stages of the regenerative cycle. The No. 1 and No. 2 nigh pressure heaters comprise the last two stages of the six stage regenerative feedwater heating cycle.

The heaters are of the closed U-tube type, with provision for removing the shell for maintenance and inspection of the tube bundle. The high pressure heater has a shrouded desuperheating section and an internal drain cooling section. The condensate or feedwater flows through the channels and tubes, and the extraction steam and drains flow through the shell around the tubes. Each heater is supplied with inlet and outlet block valves and a bypass to permit operation of the condensate and feedwater system with one or two heaters out of service for maintenance. The extraction steam lines to each of the heaters are provided with bleeder trip valves to stop flow in the line in the event of a turbine trip sudden load reduction or high condensate level in the heaters. The correct liquid level in each heater is maintained by a control valve. Drains from the No. 1 heater are cascaded to the No. 2 heater and drains from the No. 2 heater are routed to the deaerator. Drains from the No. 4 and No. 5 heaters are cascaded to the No. 6 heater and drains from the No. 6 heater are pumped into the feedwater stream or returned to the condensers. An alarm is sounded in the control room to signal high or low level in any heater. Relief valves are provided to protect the channels and shells of heaters from damage by overpressure. The channel relief valves are of the low capacity type, which safeguard against liquid expansion and relieve to atmosphere. The shell relief valves are manifolded and directed to the boiler blowdown tank. Both heaters can be blanketed with either nitrogen or steam when they are out of service.

Condensate or feedwater temperature entering each heater is indicated locally. Extraction steam pressure and temperature at the entrance to each heater are indicated locally. Heater shell pressure, temperature, condensate level, and drain temperature are also indicated at the heaters.

c. Condensers

The turbine has two side exhausts discharging into twin condensers. These condensers serve primarily to condense the turbine exhaust steam and retain the condensate for a period of time before it is permitted to enter the condensate system. The cascaded drains and vents from heaters No. 5 and 6, the air ejector inter and after condenser drains, and makeup from the distilled water tanks are all collected in the condenser. In addition, the deaerator overflow, the condensate pump vents, all emergency feedwater heater shell side dumps, and miscellaneous high and low pressure drains are all routed to the condenser. The cascaded drains from heaters No. 2. and 1 are also discharged into the condenser in the event of a high level condition in the deaerating heater.

The condenser hotwells have a condensate retention capacity equal to 4 minutes of maximum load flow. Condensate level in each hotwell is indicated locally by level gauges and transmitted to remote indicators on the recorder board in the control room. In addition, level in one of the two hotwells, as chosen by operation of a selector valve, is recorded in the control room. High and low level in each hotwell are annunciated in the control room. The level in the hotwell is maintained by the addition of makeup from the distilled water tanks on low level or by diverting excess condensate from the condensate pump discharge to the distilled water tanks on high level. Condensate conductivity in each hotwell is recorded in the control room and high conductivity is also alarmed in the control room. When the condensate conductivity exceeds the acceptable limit the contaminated condensate is discharged to waste. Condenser vacuum and temperature are indicated locally and are also transmitted to and indicated in the control room. The temperature of the condensate leaving each hotwell is indicated locally.

Each condenser is of the horizontal two pass divided hotwell design, with vertically divided waterboxes. Tubes are rolled into the tubesheets. Exhaust steam from the turbine flows sideward to each condenser. Steam which reaches the lower portion of the tube bundles mixes intimately with the condensate formed on the tubes above, resulting in deaeration and the release of entrained gases. An air cooler section with its own air off-take connection is provided in each condenser half.

All connections except the low level makeup connection from the distilled water tanks are brought into the condenser shell above the tube banks, or as high as possible in the tube banks, in order to achieve maximum deaeration. High velocity drains have baffle or impingement plates to prevent erosion of tubes.

The cooling water side or the condenser is described under the Circulating Water System Description.

d. Miscellaneous Equipment

There are, of course, more equipment and ancillary systems which augment the steam and condensate system. However, all of this equipment is conventional in design and is of no consequence to this conceptual study.

IV-I. BALANCE OF PLANT SUBSYSTEMS

1. Cooling Water Description (Ref. Figure IV.A.7)

The cooling water system provides a closed loop arrangement in which treated condensate is circulated by pumps through the shell side of a water to water heat exchanger (where the heat is rejected to circulating water) then through the auxiliary equipment requiring cooling and then back to the pumps. An atmospheric, vented elevated surge tank, connected to the suction header of the pumps, provides a reservoir to absorb thermal expansion of the fluid and pressurizes the entire system.

A chemical feed is provided to prevent the formation of scale within the system. Makeup for system losses is automatically provided from the condensate system through a control valve which maintains the water level in the surge tank.

Two, 100 percent capacity pumps will be installed to provide circulation throughout the system. One pump is normally in service and the other is on standby. Each pump is of the horizontal single stage centrifugal type with double suction impellers and directly connected to an induction type motor. Pump control is actuated from the plant control room with pump start effected by manually turning the control switch to "start". The standby pump will start automatically on low cooling water pressure when its' control switch is on "Auto". Pumps are normally stopped manually.

Two, single unit capacity cooling water heat exchangers will be installed, with one exchanger normally in service, the other serving as standby. Each exchanger is of the horizontal straight tube, counter flow type, with removable tubes and floating tube sheet. Cooling water passes through the shell side, circulating water through the tubes.

One cooling water surge tank with a capacity of 1500 gallons is mounted upon an elevated platform between the two heat exchangers to serve the following functions:

a. Provide a volume of water to accomodate surges in the closed cooling water system.

b. Provide a column of water to maintain a constant suction head on the pumps and insuring that all parts of the system are under a positive pressure at all times.

2. Circulating Water System (Ref. Figure IV.A.8)

The circulating water system provides circulating water to condense the turbine exhaust, cool the turbine lube oil, the generator cooling gas and the cooling water heat exchangers. The system consists of a mechanical draft, cooling tower, tower basin and intake structure, two circulating water pumps, and the distribution piping. The heat exchanger flow path is in parallel with the condenser shell flow path. Makeup water to replace tower evaporation, drift and blowdown losses is provided from the plant's service water system.

The cooling tower will be a three cell minimum draft mechanical draft tower of either cross-flow or counter flow design. The tower will be erected on a reinforced concrete basin located 560 feet south of the turbine generator center-line.

The intake structure is an extension of the cooling tower basin, projecting approximately 40 feet beyond the north end of the cooling tower and will be constructed integrally with the cooling tower basin. Removable screens and trash racks will be installed within the intake structure to remove any solid matter that might otherwise clog the pumps and condenser tubes. Stop logs will be provided for insertion to stop flow when necessary.

Two, 50 percent capacity circulating water pumps will be provided and installed within the cooling tower intake structure. Each pump will be of the vertical, single stage, mixed flow type, designed for wet pit installation. Pump drivers will be vertical, solid shaft motors with weatherproof enclosures.

A single buried pipeline, approximately 51 inches in internal diameter will transport the water from the pump discharge manifold to the condensers and return the water to the cooling tower. Valving and expansion joints will be provided as needed for flow and pipe isolation. The pipe will be constructed of one of the following pipe designs:

1. Carbon steel, cement mortar lined, coal tar coated or wrapped for exterior protection

2. Reinforced concrete, cylinder type or prestressed

3. Fiberglass reinforced plastic

Circulating water chemical control will be provided by the injection of sulfuric acid, liquid dispersant and blowdown. Calcium carbonate scale formation will be controlled by automatic feed of sulfuric acid. Silica and calcium sulfate scale formation will be controlled by automatic adjustment of the system blowdown; liquid dispersant further inhibits scale formation and enhances the coagulation of suspended materials for removal by the blowdown system. A timer controlled chlorination system will also be installed to automatically adjust chlorine feed for system control of biological growth.

3. Compressed Air System (Ref. Figure IV.A.9)

A compressed air system will be provided to supply plant instrument air as well as plant service air. The system will consist of three nonlubricated air compressors, two of which will be available for operation at all times as demand dictates; the remaining unit will be on ready standby.

The discharge of each compressor will be manifolded into a common supply header serving each of three air receivers. The outlet side of each receiver is manifolded and serves two branch lines, one to the service air system, the other to the instrument air supply system. The instrument air passes through one of the two instrument air dryers where moisture is removed and then through one of two instrument air filters where any remaining solid particles larger than 5 microns are separated from the air. The instrument air header then divides into branches which lead to various items of station equipment which are operated by instrument air.

Air supply to the stations service outlets passes through a back pressure control valve which closes when air pressure falls to 80 psig thus protecting the instrument air supply by sacrificing the service air demands. Branches from the service air header lead throughout the plant to provide service air connections where needed. Each of the three compressors will be heavy duty, two stage double acting, reciprocating type with water cooled, oil free cylinders and teflon piston rings. The compressors will be driven by direct connected induction motors. Each compressor will be equipped with intake filter-silencer, intercooler, discharge pulsation dampener and an after cooler equipped with moisture separator. Condensed moisture is removed from the intercoolers and aftercoolers by drain traps. Each compressor will be cooled by treated condensate from the cooling water system, which will flow through jackets in the cylinders and cylinder heads as well as through the inter and after coolers.

The compressors will be started and stopped from the control room. Selection of the "lead" and "lag" unit will also be made from the control room. Each compressor will be equipped with automatic unloading and starting devices to permit compressor start unloaded.

The three air receivers will be of vertical axis cylindrical design. Connections will be provided for air inlet and outlet, pressure gauge, relief valve, pressure controller and drain. A drain trap will be provided for moisture removal.

Two refrigerant type instrument dryers will be provided to remove moisture from the instrument air. One dryer is normally in service with the other in standby. One dryer will include an electric motor driven compressor, a refrigerant-to-air exchanger, evaporator thermostat, air-to-air heat exchanger and moisture traps. Dryer units will be started and stopped locally.

Two instrument air filters will be installed, arranged for parallel operation. Normally one filter will be operational and the other on standby. Each filter will be equipped with removable, reusable filter elements.

4. Chemical Feed Systems (Ref. Figure IV.A.10)

The chemical feed systems will be installed to deliver and inject chemical solutions of the proper concentration and quantity where same are required to inhibit scaling and/or corrosion of the internal surfaces of the equipment and piping.

The systems to be included are:

a. A high pressure system for intermittent direct injection into the feedwater piping, immediately downstream of the steam generator, of chemicals used to prevent acidic corrosion, possible scaling and caustic metal embrittlement.

b. A low pressure system for the continuous injection of neutralizing and scavenging chemicals into the condensate system.

The sodium phosphate (high pressure) system consists of a dissolving funnel for the blending of dibasic sodium phosphate powder with demineralized water (condensate); a mixing tank; two 100 percent capacity phosphate feed pumps connecting piping from the tank through the pump to a chemical feed discharge header, a flushing system and a mixing water system.

The hydrazine or oxygen scavenging (low pressure) system consists of a tank for dilution and mixing of a hydrazine solution with demineralized water (condensate), two 100 percent capacity feed pumps, one dispensing pump and interconnecting piping.

The ammonia system is identical to the hydrazine system, utilizing a 26 degree Baume Ammonia Reagent. The hydrazine and ammonia systems will both be equipped with a compressed air motor driven dispensing pump for the transfer of reagents from their shipping drums to the mixing tanks.

All three chemical tanks will be vertical axis, cylindrical in shape with hopper bottoms and flat tops. Each tank will have an effective volume of 300 gallons, supported by four angle iron legs. The sodium phosphate tank will be equipped with hinged cover, electric motor driven stainless steel propeller type mixer, gauge glass and liquid level switch. The hydrazine and ammonia tanks will each be equipped with floating lids, gauge glass and liquid level switch. Both tanks will be equipped with a plastic metering cylinder, calibrated in millimeters, which will be mounted on the tank and connected so that the measured amount of reagent can flow by gravity into the tank.

All six of the metering pumps, two for each system, will be of the positive displacement piston type with adjustable stroke control. Pump control will be by selector switch; with the selector switch on "start", and level switch closed, the pump will start. Pump stop will occur when low level is reached in the tank or when the selector switch is placed on "stop".

5. Service and Demineralizer Water System (Ref. Figure IV.A.6)

Raw water from the plant water supply enters the station and is piped directly into the lime-soda softener tank. The water enters the softener tank through a level control valve which maintains a full tank level at all times. The softener tank will be constructed of a size sufficient to assure adequate water residence time for the degree of water purification desired. The water effluent from the softener will be continuously monitored to assure proper water quality. An agitator system within the softener tank provides a continual movement of the water, thus stimulating proper mixing of chemicals and water.

A chemical storage and injection system sufficient to intermittently recharge the softener will be provided in the area adjacent thereto. This system consists of an elevated soda ash bin with mixing tank and two 100 percent capacity injection pumps; a 3,000 gallon liquid coagulant storage tank, with mixing tank and two 100 percent capacity transfer pumps, two 100 percent capacity coagulant aid charging pumps; and an elevated quick lime storage bin with lime paste slaker, grit hopper and two 100 percent lime slurry injection pumps. Service water (softened) will be used for dilution of both lime and soda ash prior to their transport and injection into the softener.

The softened effluent from the softener tank is transported by gravity to a 100,000 gallon service water storage tank. Sludge, drawn off the bottom of the softener, is transferred by two, 100 percent capacity, sludge transfer pumps to the sludge thickener tank. The sludge thickener tank separates the supernatant fluid from the sludge; the supernatant gravitates to a 4250 gallon storage tank from where it is pumped by one of two 100 percent capacity supernatant transfer pumps to the inlet of the softener; the sludge is transported by one of two 100 percent capacity sludge disposal pumps to a nearby evaporation pond. The sludge thickener tank is equipped with a slow moving agitator which promotes separation of supernatant from the thickened sludge.

One of two 100 percent capacity service water pumps takes suction from the service water tank and distributes the softened service water to the cooling tower basin for circulating water system makeup and, via a backflow preventer, to the sand filters and demineralizer system. In addition, branch lines downstream of the backflow preventer provide soft water supply to the caustic soda hot water storage tank, the plant cooling water system (makeup), the steam generator and turbine area, the plant control room and switchgear building, the administration building, and the shop and warehouse building. A bypass line from the well water supply entering the plant site to the suction side of the service water pumps will be provided for emergency purposes.

A branch from the softwater header, downstream of the service water pumps, supplies water through one of two sand filters which removes the remaining particulate carried over the lime-soda softener. Once through the filter the water enters one bank of a dual train makeup demineralizer unit which discharges into the two 85,000 gallon demineralized water (condensate) storage tanks. A secondary branch off of the discharge side of the sand filters supplies water to the domestic water system which consists of a hypochlorinator unit and a hydropneumatic tank for treatment and delivery of the station's potable water supply.

The service water pumps provide system pressurization for the station domestic water, service water and demineralized water. Two full capacity pumps fill be furnished with one pump normally running and the other in standby. Each pump will be of the single stage, horizontal centrifugal type with direct connected induction motor. Pump control will be from the control room with each pump started manually by control switch. The standby pump will start automatically on low service water discharge pressure. The pumps are stopped manually by control switch or automatically on motor overload. Minimum flow protection will be provided by orificed lines returning to the service water tank.

The service water and supernatant storage tanks will be of vertical cylindrical design with capacities of 100,000 gallons and 4,250 gallons respectively. Each tank will be constructed of carbon steel plate and will be supplied with a plastic lining to prevent corrosion. The service water tank will also provide a reservoir source of water for fire fighting purposes.

The demineralized water (condensate) storage facility consist of two, 85,000 gallon capacity storage tanks of vertical cylindrical design constructed as described above. This water is used as makeup to the steam generator.

The potable water supply system consists of a hypochlorinator and a hydropneumatic tank. The hypochlorinator unit is composed of a water meter with external device for controlling the rate of operation of a water driven pump which will pump a hypochlorite solution from a storage container at a rate proportional to the flow through the meter and injects it into the domestic water line downstream of the meter. The unit will treat water at flow rates of 10 to 50 gpm and has a capacity of feeding 60 gallons of hypochlorite solution per day. The hydropneumatic tank provides a means of treated water storage and sufficient pressure for the required delivery at the fixtures. The tank will be of the 1,000 gallon capacity horizontal cylindrical design and charged with compressed air from the station's service air system.

Two parallel flow, 100 percent capacity vertical self-backwashing pressure filters will provide removal of suspended material from the softened water. Each filter will contain two types of sand each with a different gradation for proper filtering media. Each filter will have a total flow rate of 100 gpm and will be equipped with flow elements and local flow indicators. In addition, instrumentation for filter pressure drop and turbidity will be provided to indicate when a filter requires backwashing. Backwashing water will be piped to the evaporation pond. While one filter is being backwashed, the second will remain in service.

The makeup demineralizer system will provide high purity deionized water to the demineralized water storage tanks. Two 100 percent capacity demineralizer trains consisting of cation, anion and mixed bed demineralizer tanks will be provided. Each train has a capacity of 100 gpm with the ability to produce 200 gpm when both trains are in service. The demineralizer resins will be regenerated in the operating tanks with the provided chemical regeneration system consisting of sulfuric acid supply equipment, sodium hydroxide supply equipment, water heating equipment and the necessary piping, valves and controls.

The demineralizer system is as follows:

a. Cation Demineralizers

Two cation demineralizers will be provided. The acid storage and pumping equipment which is common to the mixed bed units, circulating water treatment and the demineralizer neutralization system will include a 6,000 gallon storage tank and two 100 percent capacity metering pumps which will supply concentrated sulfuric acid to the dilution system for the cation and mixed bed units and to the cooling tower basin, for circulting water treatment. The controls, valves and piping necessary to backwash, dilute and inject the acid, rinse and place the demineralizers into service will be part of the cation demineralizer equipment.

b. Anion Demineralizers

Two anion units will be provided, each consisting of a vertical axis cylindrical vessel approximately 3 feet in diameter by 7 foot high. The caustic storage and mixing equipment will be common to the mixed bed units and the neutralization system. An electrically heated 3,500 gallon caustic storage tank will supply caustic to the anion demineralizers, mixed-bed demineralizers and the neutralization system. Two, 100 percent capacity metering pumps will supply caustic to the heating and dilution system which will be common to the mixed bed units. A 1,000 gallon hot water storage tank will be common to the demineralizer regeneration and dilution system. The controls, valves and piping necessary to backwash, dilute, heat and inject the caustic, rinse and place the beds in service will be part of the anion demineralizer equipment.

c. Mixed Bed Demineralizers

Two mixed bed demineralizers will be provided, each consisting of a 3 foot diameter by 6 foot high vessel. The acid and caustic storage, pumping, dilution and heating systems will be used in common with the cation and anion vessels. The mixed bed demineralizers are the final step in each train. The effluent from each mixed bed unit will be monitored for conductivity and silica concentrations.

d. Vacuum Degasifier

A vacuum degasifier will be installed in series with the makeup demineralizer for oxygen and carbon dioxide removal.

e. Demineralizer Waste Treatment

The regenerant waste from the demineralizers will be collected in a neutralization sump. The sump will be equipped with a mixer for mixing of the sump contents and a centrifugal pump for discharging the neutralized fluid to the plant evaporation pond.

Level controllers and pH measuring devices will be provided to control the neutralization process. The controllers will annunciate abnormal operating conditions and stop the discharge pump and mixer when the treated waste is not meeting specified requirements or when the sump level is low. After initial sump content mixing, caustic or acid is added in response to the pH controller. These chemicals are pumped from the demineralizer regeneration caustic and acid metering pumps.

f. Cooling Tower Basin Water Treatment

In addition to the foregoing, a liquid dispersent system will be installed which will consist of a 3,500 gallon horizontal storage tank and a centrifugal pump for the storage and injection of a chemically premixed solution into the cooling tower basin. This system will be located adjacent to the cooling tower basin.

6. Fuel Oil System

The station fuel oil system will be installed to supply Number 2 fuel oil to the auxiliary boiler burner system, the diesel generator day tank and to the burner system of the salt recirculation heater. The system consists of a 100,000 gallon capacity above grade, atmospheric storage tank of vertical axis cylindrical design and the transfer pumps for the systems described herein before. All pumps will be of the positive displacement type with integral relief valve installed between discharge and suction connections of the pump. Both the auxiliary boiler fuel oil pumps and the salt recirculation heater fuel oil pumps include a 100 percent capacity standby pump to assure system reliability. No backup is planned for the diesel generator fuel oil supply pump.

7. Diesel Generator System

The diesel generator system consists of the engine-generator set, and its attendant equipment. The engine-generator will be located where indicated upon the General Arrangement drawing to provide all station essential electrical services in the event of total system power failure. The unit will be self contained, complete with jacket water cooling, engine starting and fuel oil supply from a 5,000 gallon fuel oil day tank. The unit will be installed within a weatherproof enclosure equipped with adequate ventilation and cooling for summer operation and maintenance as well as winter inhabitation. The unit capacity will be 3,000 kW, which will provide emergency electrical energy for the station compressed air system, turbine-generator turning gear, essential bearing cooling, control systems battery charging, essential air conditioning, emergency lighting, communication systems, and heliostat defocusing.

8. Fire Protection System

The primary means of fighting fires in the station is with water supplied from hydrants in the yard area or from hose reel stations mounted at strategic locations within the operating areas of the plant and within the structures. The fire main serving the hydrants and hose stations will normally be pressurized and supplied with water from the service water storage tank by the fire water pumps located within a pump house adjacent to the service water storage tank. Water pressure in the fire main will be constantly indicated and low pressure annunciated in the control room.

Yard area fire containment will be provided by hydrants located adjacent to the service roads within the power station limits. These hydrants will be fed by an underground fire water loop which is supplied water by one of two horizontal shaft, single stage, centrifugal pumps manufactured to UL design standards. In addition, one fire water jockey pump will be installed to maintain a constant, at rest, system pressure. Each fire pump will be sized for the stations largest single fire risk, normally taking suction from the service water storage tank but manually valved to utilize demineralized water as an emergency measure.

Dry chemical extinguishing material and foam will be available from portable extinguishers stored in the two fire fighting equipment storage areas, one located in the motor control center building and the other in the shops and warehouse building. Hoses will be conveyed to the hydrants by means of hose carts located in the fire equipment storage areas.

Fixed water spray systems of the deluge type will be provided over the turbine lube oil reservoir and conditioner area, hydrogen gas control and seal oil area, each transformer and within each cell of the cooling tower. A fire detection system for spray system actuation and alarm will be provided. Fixed pipe water spray systems hose reels and hose cabinets will be fed from the underground fire loop.

Fire hose cabinets and portable fire extinguishers will be placed at strategic points throughout the administration building, shops and warehouse building and the control room and switchgear building. Low hazard areas within these structures will be equipped with smoke detection devices tied to a central annunciation board. A Halon 1301 fire suppression and detection system will be installed in the equipment room section of the control room building for protection of the electronic equipment housed therein.

9. Heating, Ventilating and Air Conditioning (HVAC)

Heating, ventilating and air conditioning will be provided for personal comfort and for equipment protection within the administration building and the control room and switchgear building. Ventilation and heating only will be provided in the shops and warehouse building.

The criteria for conditioned areas of the administration building and the control room and switchgear building is:

1.	Temperature:	$70^{\circ}F \pm 4^{\circ}F$
2.	Relative Humidity:	$50\% \pm 5\%$
3.	Filtration of outside air supply	85%

The basis of design for the shops and warehouse building will be to maintain adequate ventilation throughout the structure with a 15 minute air change and a minimum temperature of 65°F ± 5°F.

The administration building will be supplied with a roof mounted direct expansion refrigeration unit of approximately 20 tons capacity. Air supply will be furnished by fan coil units equipped with inlet filters for control of dust and wind born elements. Electric heating coils and refrigeration coils will be installed in the direct path of the fan discharge and air distribution will be provided by an overhead duct system designed for variable volume, constant flow control. A return air duct system will also be provided with adjustable damper control for blending of the air supply. The building will be equipped with spring loaded exhaust air vents to assure the structure is maintained in a pressurized condition of approximately 1/4 inch water gauge above atmospheric pressure at all times. Temperature level will be controlled by a manually adjustable wall mounted thermostat.

The control room and switchgear building will be treated in general as described above, with the added provision that the 60 ton direct expansion unit will be of the split system design whereby the compressor and condensing unit will be roof mounted and the evaporator coil and fan section installed at grade. Further, in order to assure protection of the electronic equipment housed within the structure, a totally redundant refrigeration unit will be supplied; no redundancy in heating of this building is considered. The building's control, equipment and termination rooms will be constructed utilizing an underfloor pressurized plenum distribution system with floor resisters. The underfloor system will be served by a separate cabinet mounted cooling unit utilizing room air for its supply medium. Fans and automatic dampers will be interlocked with smoke and fire detection systems to secure operation upon annunciation.

The shops and warehouse building will be equipped with roof mounted exhaust fans supplied with manual start/stop control for selective air flow conditions throughout the building. A horizontal air intake louvre section will be provided along the lower segment of the building siding equipped with recleanable filters and self closing dampers for outside air inlet. Heating of the structure will be by electric unit heaters of the horizontal air flow type, complete with air distribution fan and thermostatic control.

10. <u>Electrical Systems and Equipment (Figure IV.A.12)</u>

The main generator terminals are connected, through a length of isolated phase bus, to a 230 kV switchyard. The plant electrical auxiliary systems are powered from an auxiliary transformer, energized from the same 230 kV switchyard. This auxiliary transformer also serves as the source of the plant startup power.

The distribution of power within the plant boundaries is radial. Three serially-fed assemblies of medium voltage metal-clad switchgear are provided: their busses are identified as Bus A, Bus B and Bus C respectively. Bus A supplies the auxiliary loads of the turbine-generator plant, Bus B, those of molten salt transport and tank heater systems; and Bus C energizes the salt piping and receiver heaters, and the heliostat feeders. An emergency diesel generator is connected, through an interlocked circuit breaker, to Bus C. The interlock prevents parelleling the diesel generator with the normal plant power system.

The 480 volt plant loads are energized from load-center substations and motor control conters, located at centers of load throughout the plant.

Equipment ratings are as follows:

Main Transformer:	115/128 mva, 55C/65C FOA, 13.2-230 kV, 3 phase, delta-wye connected with standard impedance.
Iso-phase Bus:	15 kV, 6000 A, 3 wire
Auxiliary Transformer:	17.9/20 mva, 55C/65C, OA, 4.16-230 kV, 3 phase, 8% impedance, wye-wye connected with resistance-grounded 4.16 kV neutral. A tertiary delta winding may be included if recommended by the manufacturer.
Medium-Voltage Switchgear:	5 kV nominal, 350 mva class drawout air circuit breakers. Main circuit breaker, 3000A; Bus A, 3000A; Bus B, 2000A; Bus C, 1000A. Switchgear assemblies located outdoors are weatherproof non-walk-in type.
480 Volt Load-Centers:	Each primary section will consist of an air-filled terminal chamber (or loadbreak air switch if two or more loadcenters are supplied from the same 4.16 kV feeder). Transforming section will be 1000/1120 kVA, 3 phase, 55C/65C, OA, 4160-480 V, delta-wye connected, with standard impedance and solidly-grounded 480 volt neutral. Secondary Sections will be low-voltage drawout air circuit breakers.
480 Volt Motor Centers:	Will be NEMA Class I Type B, in 3R enclosures when located outdoors.
Emergency Generator:	3000 kW, 0.9 pf, 4.16 kV, 3 phase.

11. Miscellaneous Plant Elements

a. Gas Storage

The power station will use three industrial gases during periods of standby and normal operation. Nitrogen gas will be used to exclude air from steam spaces in the steam generator, and feedwater heaters during extended shutdowns. Hydrogen is used as an atmosphere within the main generator.

Carbon dioxide is used to displace the air from the generator housing prior to initial and subsequent filling with hydrogen and to displace the hydrogen gas from the housing when changing the atmosphere.

The gas storage area is designated upon the General Arrangement Plan (Figure IV.A.13) and will be constructed upon a raised deck, enclosed with chain link fencing, and roofed. An extension of the deck will serve as an unloading dock for the gas cylinders.

The gas storage will consist of cylinder gas bottles arranged in active and reserve racks, gas manifolds and pressure control cabinets where bottle pressure is reduced to a delivery pressure of 70 psig. In addition, a vaporizer will be installed to transform the liquified carbon dioxide into a gas for delivery to the generator.

b. Sampling System

A sampling system will be provided which will consist of sample collecting nozzles, sample coolers, analyzers, recorders and controls necessary to determine the characteristics of the plant's process fluids, to indicate and record the values and to annunciate undesirable values of importance.

Provisions will be made for manual collection of samples within the station limits. In addition, samples of condensate, feedwater and steam will be piped to a central location, where automatic analysis will be performed and the results recorded. Provision will also be made for parallel withdrawal, in the laboratory, of samples which are collected for analysis by the centralized system.

Remotely analyzed and recorded samples of the condenser hotwell condensate conductivity will be accomplished on a continuous basis. Other continuously monitored samples will be the condensate pump discharge, second feedwater heater drains, the deaerator outlet and the boiler blowdown.

Sample nozzles will be provided to withdraw samples from other locations. These locations include the circulating water discharge from each condenser, demineralized water (condensate storage tanks) and the discharge from the cooling water heat exchangers.

c. Plant Waste Systems

Drainage is directed off of the plant operating area by surface grading and paving to achieve a water run off pattern which will direct flow to the site boundaries. Concrete sumps such as the lube oil reservoir and the molten salt pump pit will be equipped with duplex sump pump assemblies complete with float control and "Lead-Lag" selector switches. Pump discharge will be directed to the evaporation pond.

An oily waste separater pit will be provided and located where indicated upon the General Arrangement Plant drawing. Equipment drains will be directed to this sump in which the contaminates will be separated from the water. The contaminates (oil, grease, etc.) will periodically be removed and disposed of off site. The water will be pumped by a duplex pump set to the evaporation pond.

Backwash and regeneration waste from the demineralizer units will be directed to a neutralization sump, the operation of which has hereinbefore been described.

IV-J. PLANT CONTROL SYSTEM

1. Functional Description

The plant control system consists of hardware (supervisory and heliostat array control computers, displays, and other distribution and processing equipment) and software.

The purpose of the control system is to provide safe and effective plant operation by sensing and controlling necessary system parameters in a timely and integrated manner.

The control system interfaces with the collector fields, receivers, storage, steam generators, turbine generator and balance of plant. Its operations include:

- Control - interacting with the instruments, valves, motors, and pumps to regulate the plant process temperatures, pressures, flows, and other parameters to meet plant operating requirements.
- Interlock - coordinating plant actions so that the state of the system is properly set up for impending control actions, also referred to as interlock or interposing logic system (ILS).
- Monitor/alarms - measuring and reporting of plant process temperatures, pressures, flows, and other parameters; determining and reporting when measurements violate predetermined threshold values.
- Trip - stand-alone monitoring for major functional system to take the system offline when certain key system parameter threshold levels have been crossed.
- Display/Command - Man-machine interfacing to report plant data and respond to operator commands.

2. General Arrangement

The major control equipment is divided among four areas: remote Stations No. 1 and No. 2 (on collector Field Towers No. 1 and No. 2, respectively), and an equipment room and control room in the control building shown on the power block plan, (refer to power block general arrangement), Figures IV.J.1 and IV.J.2 show, in a schematic arrangement, the location of the major pieces of control equipment in these four areas. Figure IV.J.3 shows the layout of remote Stations No. 1 and No. 2, which are at the uppermost level of the towers below the receiver. Figure IV.J.4 shows the layout of the equipment room.

Consideration of operability requirements has resulted in the control console design shown on Figure IV.J.5. The console is divided into two separate sections with a "U"-shaped main control console and a separate straight segment used for auxiliary plant operating functions. The table top on the left side of the main control console is used to mount individual printers needed to log plant level, and various system and operator functions, and to list online diagnostic summaries.

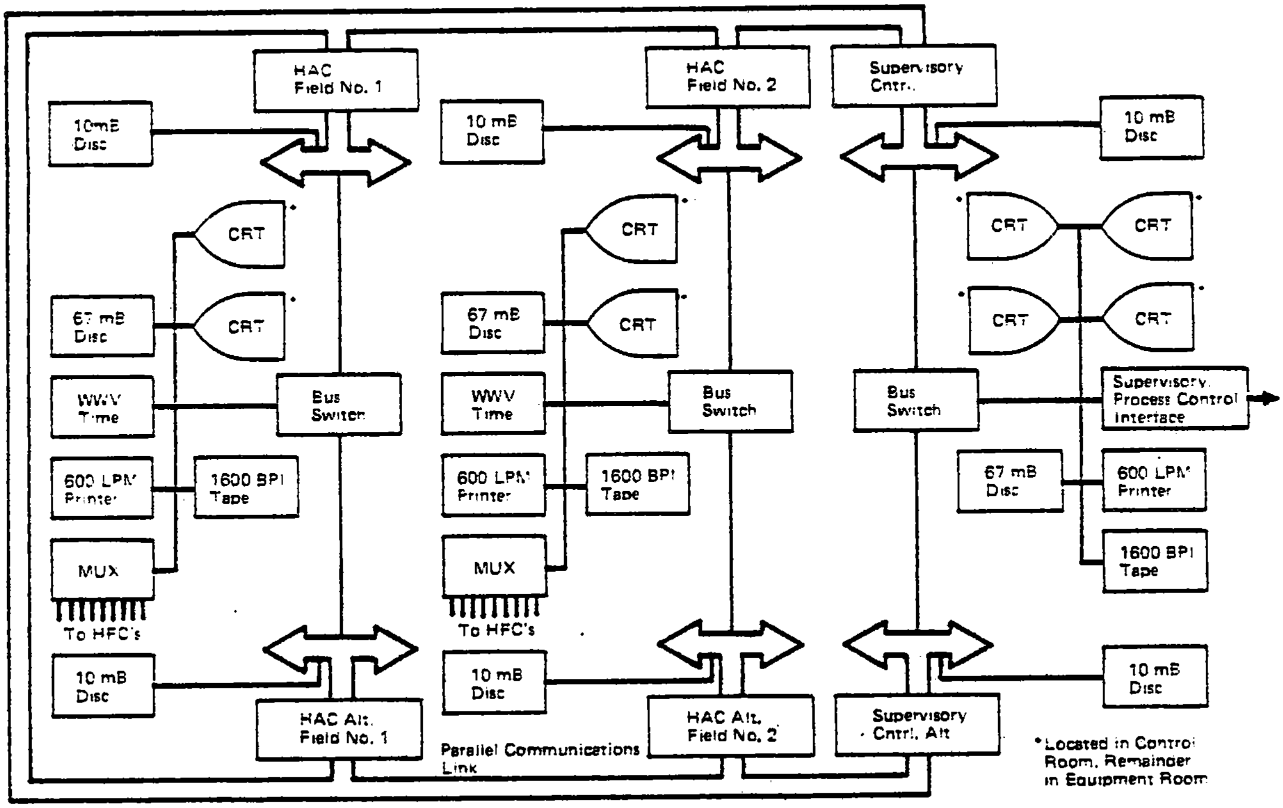


Figure IV.J.1. Computer Configuration

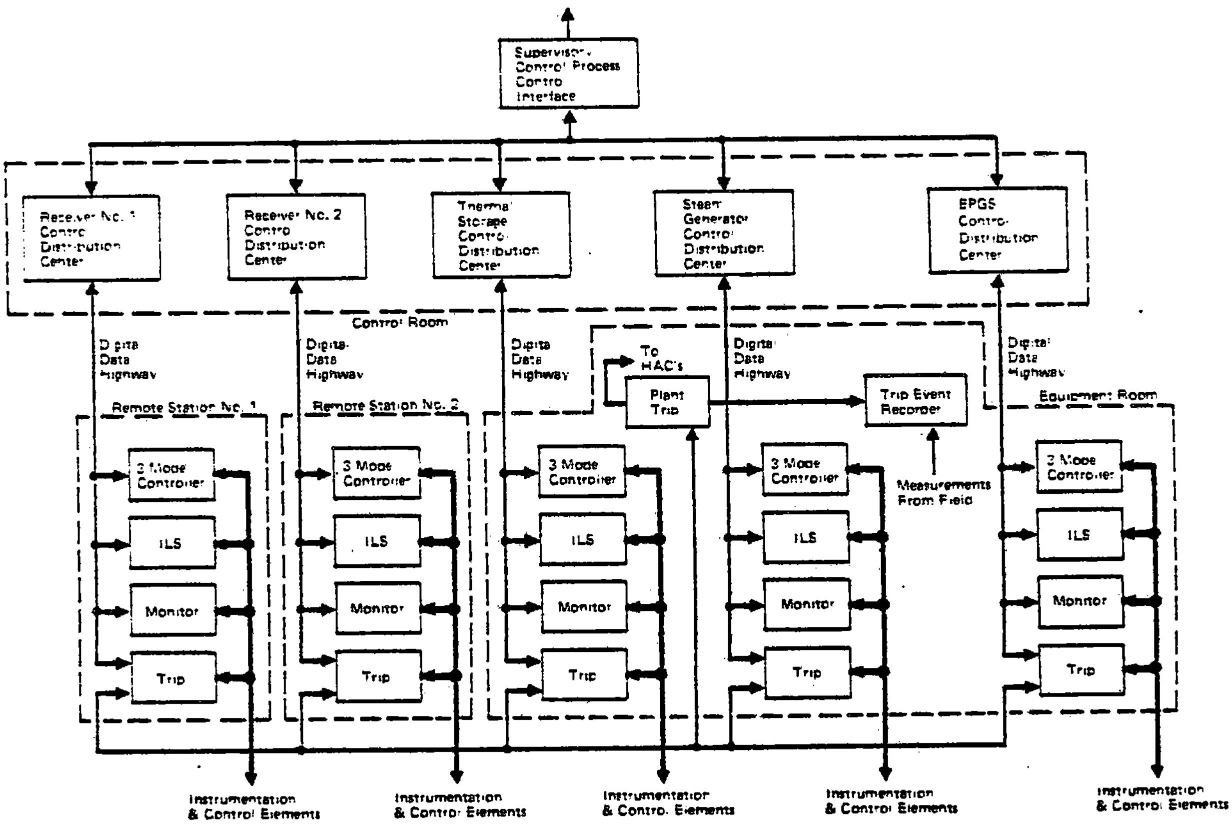


Figure IV.J.2. Control Configuration

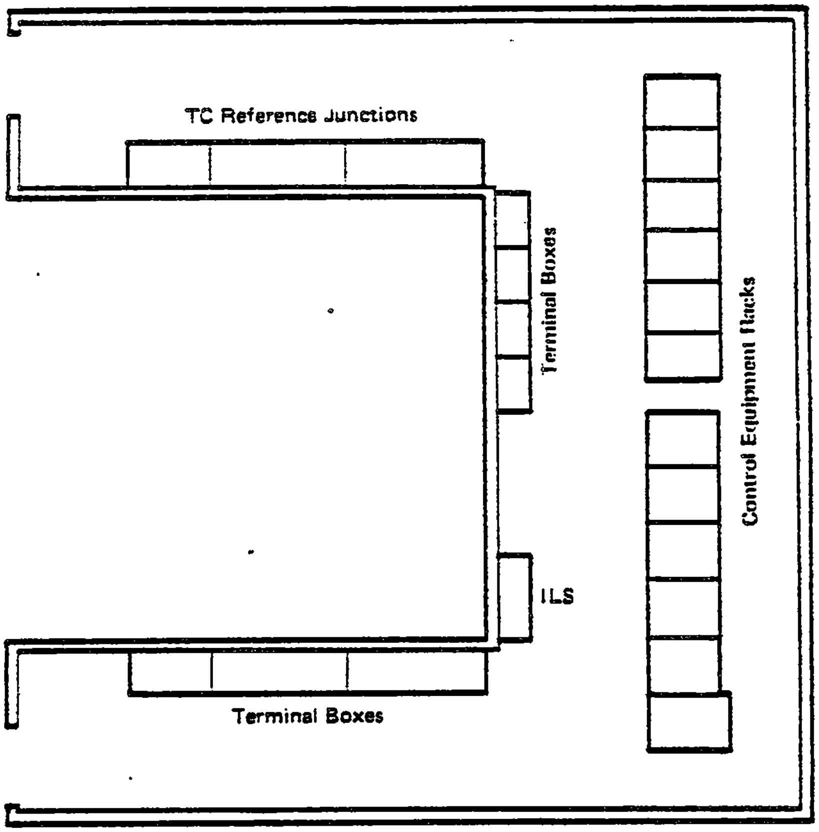


Figure IV.J.3. Remote Station Layout

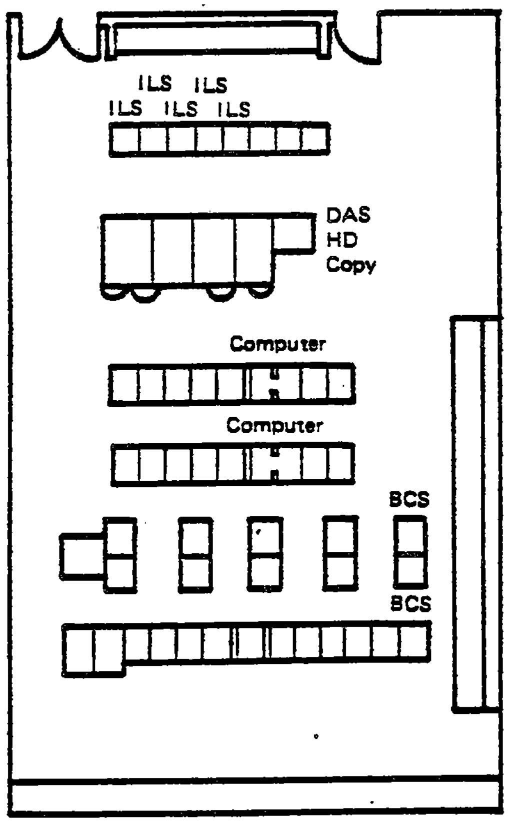


Figure IV.J.4. Equipment Room Layout

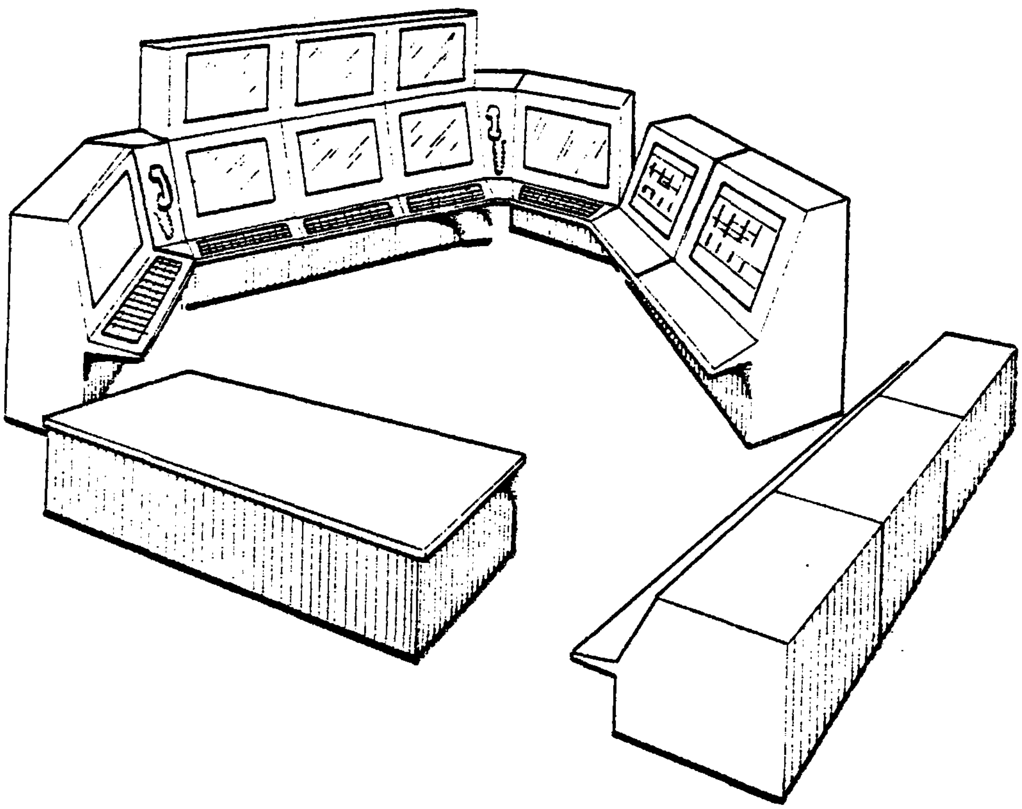


Figure IV.J.5. Integrated Control Console Layout

Immediately left of center is a section with a CRT dedicated to alarms, with a color coded listing of alarms, to give the operator a quick overview of alarm and status conditions. An indicator panel below the CRT gives the alarm status of large sections of the plant or of specific critical components to provide backup in the event of a loss of video.

The center section of the main console houses six CRTs for plant operation. The four on the right hand side are normally used for plant level graphics, including collector field displays, while the two on the left side are normally used for various system level functions. The two system level CRTs will allow the operator to page down through the display hierarchy to reach any available display. In this way, the operator maintains the visual contact at the plant level while observing a specific system level operation. Also, the operator can change a specific parameter while viewing the interacting plant interfaces and resulting changes. The four plant level CRTs can also be used to display system level functions, to facilitate startup and shutdown activities.

The console on the immediate right side of the center section houses an additional CRT dedicated to alarms, similar to that on the left. The far right side of the main console houses the turbine controls and indicators supplied with the turbine/generator. These controls can be coordinated with the center section CRTs for graphic displays.

The auxiliary controls to the rear of the main console are divided into three sections. One section is for safety functions to monitor and check out fire protection. The other two sections are for auxiliary functions such as beam characterization, meteorology, air and water. These sections have a wide, clear writing surface shelf to carry out activities such as reviewing large documents.

3. Major Component Descriptions

The major equipment items associated with the control system are: (1) the computers and associated peripherals and software for display/command, and (2) process control hardware and wiring.

a. Computers, Peripherals and Software

The computers chosen for the HACs and the supervisory control are moderate capability catalogue-listed minicomputers of the DEC PDP-11/40 genre. Key characteristics considered for the computer supplier/equipment for this project are:

- o Demonstrated reliability and serviceability in an industrial or utility environment.
- o Redundancy to offset the great dependence on computers required for plant operation.
- o Capable supplier hardware design and software applications personnel.
- o Availability of a knowledgeable, competent, quick responding supplier service organization.

The three pairs of redundant computers, as shown on Figure IV.J.1, are connected in a network configuration so that each can easily communicate with any of the others through use of furnished networking software. The computers communicate with associated periphera s through a bus switch. During detail design, it will be determined if dependence on disks and tapes for normal system operations can be eliminated by storing plant operating data in core. This would increase reliability and decrease operating complexity somewhat.

An off-the-shelf industry-proven scanning, data acquisition display and control software package will be purchased and adapted for this project. This software will provide the data base, data manipulation and conversion, data display and the man/machine interface for the HACs and the supervisory computers. Application software, to adapt the purchased hardware and software to the Solar 100 plant for the HACs and supervisory computers, will be generated at MDAC.

b. Process Control

Process control, as diagrammed on Figure IV.J.2, is accomplished by a distributed, digital control system of the type represented by Beckman MV-8000, Honeywell TDC-2000 and similar systems manufactured by Bailey, Foxboro, Forney and others. These are systems in which the conventional proportional, integral and derivative algorithms are computed by a small digital computer which can be located close to the instruments. The particular algorithms, gains, compensations, and rolloffs desired are easily implemented by programming the system much as with a programmable calculator, thus providing ease and flexibility for changes. The small computers, which calculate the control algorithms, service eight to sixteen control elements and are redundant, so that a single failure will not disrupt plant operations. The small computer communicates with the centralized control console over a multiplexed data highway.

Distributed, digital systems are basically multiplexing systems. That is, information (commands or data) passing between the remotely located control hardware and the centrally located command and display hardware is electronically condensed so that many signals are transmitted over a pair of wires. The signal transmission path is usually referred to as a "data highway" and consists of a pair (for redundancy) of twisted, shielded 16 gauge wires. A single data highway can replace hundreds of analog signal wires. In an extensive plant layout, such as this project, there is a great advantage, for simplicity and cost, in replacing hundreds to thousands of wires, with runs of a mile or more, by a few data highways. For this reason, a data highway is incorporated in the control system to a high degree in the collector and receiver controls and to some degree in other system controls in the power block area. Further extension of this approach in the power block area will be considered for potential economic advantage in the plant preliminary design.

The ILS functions are implemented similarly to the control functions and integrated into the control system functions. A key requirement for the ILS is that no single failure can affect more than one ILS loop.

The stand-alone protective trip functions are implemented similarly to the control and ILS, but with completely separate hardware, so that equipment failure effects are not exchanged between the control and protection functions.

Plant monitoring and alarming is accomplished by the distributed digital system with parameter monitoring specifications and alarming levels implemented by programming.

4. System Support Requirements

The principal control system support required is electrical power, HVAC, and fire protection. There are also specific lighting, architectural features, and cabling provisions required.

Facility power (120 VAC) is required for electronic equipment, as follows:

Control Room	5 KVA
Equipment Room	13 KVA
Tower Remote Station (each)	5 KVA

An uninterruptible power supply (UPS) is required for electronic equipment, as follows:

Control Room	14 KVA
Equipment Room	80 KVA

The UPS will provide 120/208 VAC, 3 phase, 60 Hz for 30 minutes minimum.

The Control and Equipment rooms will require the following HVAC:

- o $70^{\circ} \pm 4^{\circ}$F at the electronic equipment intakes
- o 68° to 80°F room interior
- o $50^{\circ} \pm 5\%$ relative humidity
- o 85% filtration with high-pressure alarm lights

In addition, a Halon 1301 fire suppression and detection system will be provided for the computers in the Equipment Room.

5. Operational Features

There are several control system issues that are unique to the solar plant or this plant and require specific consideration for this project.

a. Cloud Transient Effects

During an insolation transient caused by passing clouds, receiver flowrate must respond to maintain the receiver tube wall temperature and coolant fluid at a reasonably constant temperature (within allowable limits). In the water/steam receiver system (Solar I), the insolation transient ripples through the whole system, eventually affecting turbine operation. The receiver controls, thermal storage controls, and computer-implemented operator aids are quite complex to minimize the transient impact on the receiver and turbine. In this project, the molten salt receiver is decoupled from the rest of the plant by the large storage tank. The insolation transient is effectively limited to the receiver only; the plant control is less complex. In addition, the single-phase, receiver-coolant flow is less critical to control than the single-pass-to-superheat water/steam flow of the Solar I receiver. However, certain control features must be incorporated in this design to assure safe, long-life efficient operation of the molten salt receiver. These include:

- o Incident flux and receiver back-wall temperature measurement to anticipate changes in coolant temperatures and position receiver control valves so that coolant flowrate and distribution respond quickly to keep excursions within reasonable bounds.
- o Redundant salt feed pumps with bypass control responding to a warm salt surge tank liquid level to decouple pump and receiver dynamics and avoid waterhammer.

- o A downcomer pressure reducing valves (drag valve) to modulate supply pressure to the hot salt storage tank in response to changes in the receiver flowrate controlled by liquid level in a hot salt surge tank to decouple receiver and downcomer dynamics and avoid waterhammer.

  System operation is described in Section IV.E.

b. <u>Sliding Pressure Steam Generator/Turbine</u>

See Section IV.G.5 for discussion on sliding pressure turbine.

c. <u>Operability of a Large Complex Plant</u>

The following features are included in the control system design to provide relatively simple, reliable operation for the many components on the new process of this plant:

- o Automated operational aids to assist the operator in plant mode changes.
- o Color CRT graphics for operational visibility from the plant level down to individual control loop.
- o Simplified manipulation of control hardware and software, such as keyboard operations and changing tapes and discs.
- o Redundant supervisory and heliostat array computers.
- o Programmable digital hardware with digital data highway communication between the control room and remote equipment.
- o Failover backup provisions in critical portions of the control distribution centers with complete isolation of trip circuits.

  This control system will be built on Solar I experience in every way possible to improve the plant reliability and operability.

V. PERFORMANCE

V-A. INSOLATION MODEL

A major factor in the size of the collector field for a central receiver plant is the amount and distribution of direct normal insolation available. For this study, extensive data available from the U. S. Meteorological Service for Barstow were used because of the proximity to and similarity of weather conditions for the plant site in the Lucerne Valley. This resulted in a value of 2576.4 kWhr/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 sun elevations greater than 10° above the horizon.

Three different computer programs are used in the study to analyze plant performance and value. These are Sandia Laboratories code - DELSOL, a University of Houston code - R-CELL, and the SCE value analysis code. Computational methods of these computer programs require different but comparable models of the insolation data base.

In this section, the insolation data base and the insolation models that have been used will be presented.

1. Insolation Data Base and Modelling Approach

Estimates for the insolation 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 meteorological data. The DELSOL and R-CELL computer programs can generate clear day insolation by the latter method.

For Barstow, four years of direct normal insolation measurements are available through SCE and West Associates (Ref. V.A.1), and approximately 30 years of data are available using the Jet Propulsion Laboratory SOLINS (Ref. V.A.2) computer program with SOLMET (Ref. V.A.3) global insolation and meteorological data. Figure V.A.1 compares the four-year average West Associates data with the SOLINS 30-year data for each computed month-long average day and the year long average day. Also shown on the figure is an Aerospace (Ref. V.A.4) model which is based on two years of West Associates data with some small changes due to screening of some data for suspected errors. As noted on the figure, these data are for all sun elevations above the horizon (i.e., 0°) rather than just for those with usable insolation (i.e., greater than 10° above the horizon).

Because the JPL SOLINS model using SOLMET data can be used more easily and consistently for comparison at different locatons and because the correlations were so close, it was decided to base the insolation model on the SOLINS data.

The approach for modelling these data was to run the DELSOL and R-CELL computer codes from 0° - 0° sun elevation to get an annual clear day insolation. The ratio of the SOLINS annual insolation to this clear day insolation was then used to define a weather factor, thus normalizing the computer derived model to the extensive meteorological data base. The final insolation model for each code used this weather factor, a 10° sun elevation cutoff, and the code-interval daily variations of insolation and sun position to calculate collector field performance.

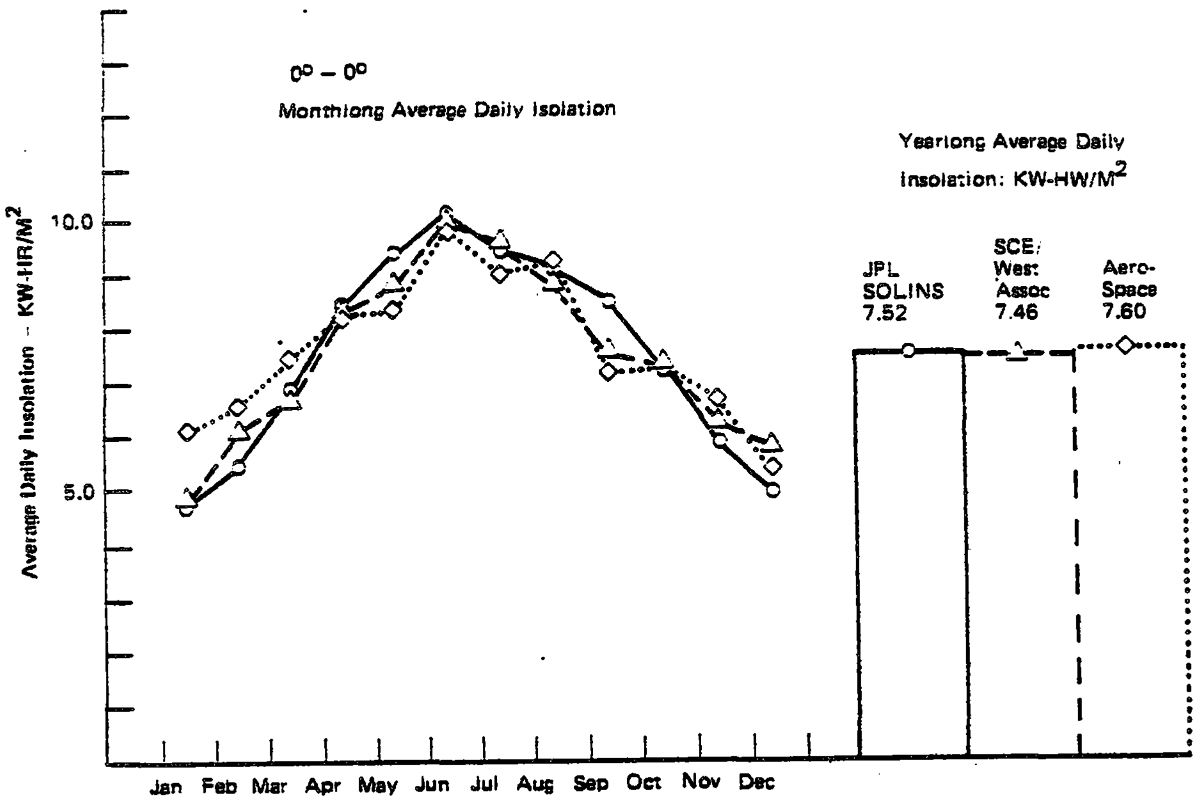


Figure V.A.1. Insolation Data Base — Barstow, California

Figure V.A.2 shows the comparison of the normalized month-long average day insolation for SOLINS (0° - 0°), DELSOL (10° - 10°) and University of Houston (10° - 10°) models. The plot shows that the codes over-predict first quarter insolation and under-predict third quarter insolation with second and fourth quarters more closely predicted. Figure V.A.3 shows the hourly insolation for an average clear day near summer solstice as modelled in DELSOL.

Annual performance calculations were derived by calculating the collector field performance on one day per month using these average clear day values, ratioing down these clear day values using the weather factor and summing these values using an average of 30.4 days per month.

2. <u>Insolation Model for System Trade Studies</u>

The system trade studies were performed with DELSOL because it is easier and faster to use. The clear day insolation map shown on Figure V.A.4 and the computer weather factor of 0.84 were used.

Typical conversion efficiencies from insolation to thermal energy are shown on Figure V.A.5. These data are for the selected molten salt, partial cavity north field configuration. To define the average clear day performance at any point, the insolation value is multiplied by the number of heliostats times the area of each heliostat times the energy collection efficiency at the appropriate date and time. To account for the effects of weather, this value must be multiplied by the weather factor.

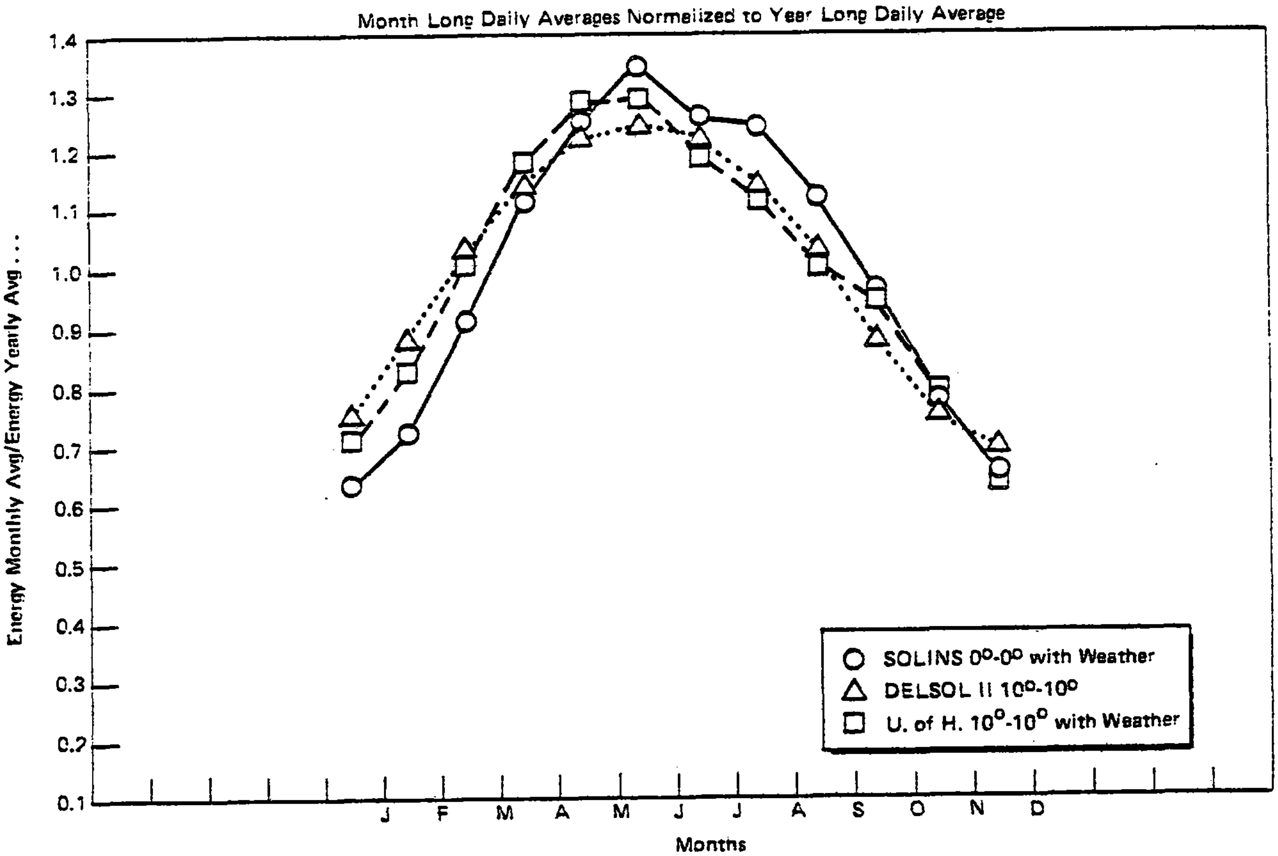


Figure V.A.2. Comparison of Monthly Distributions of Insolation

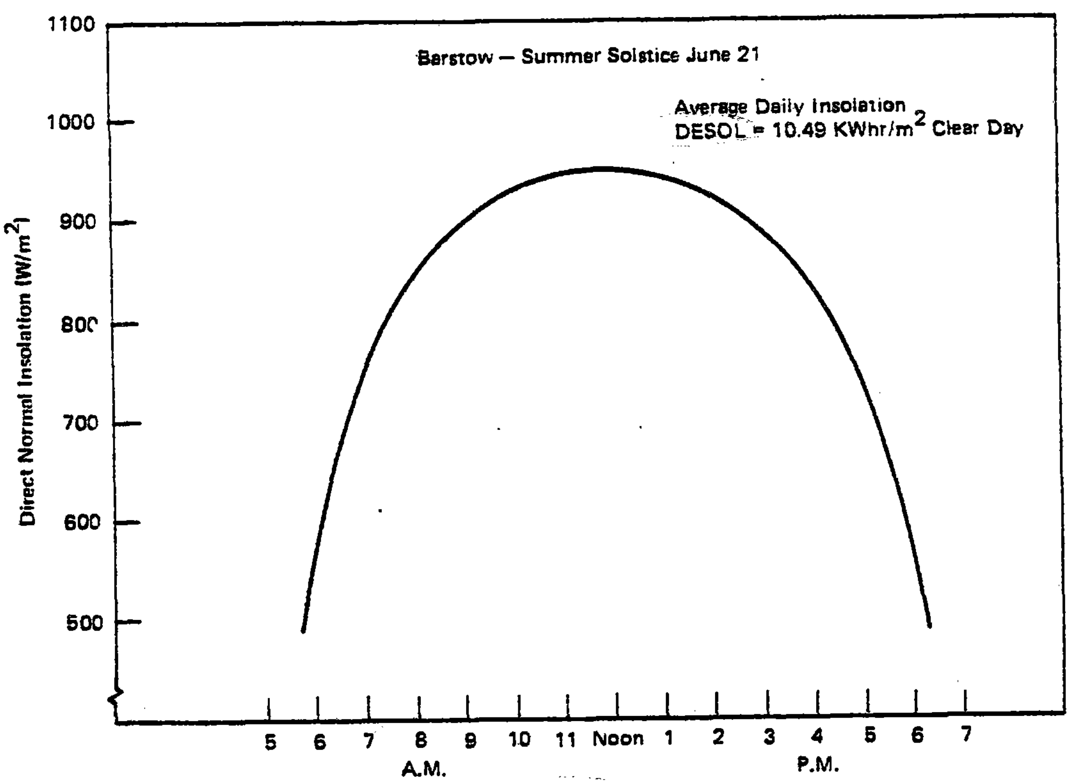


Figure V.A.3. Typical Variation of Average Clear Day Insulation

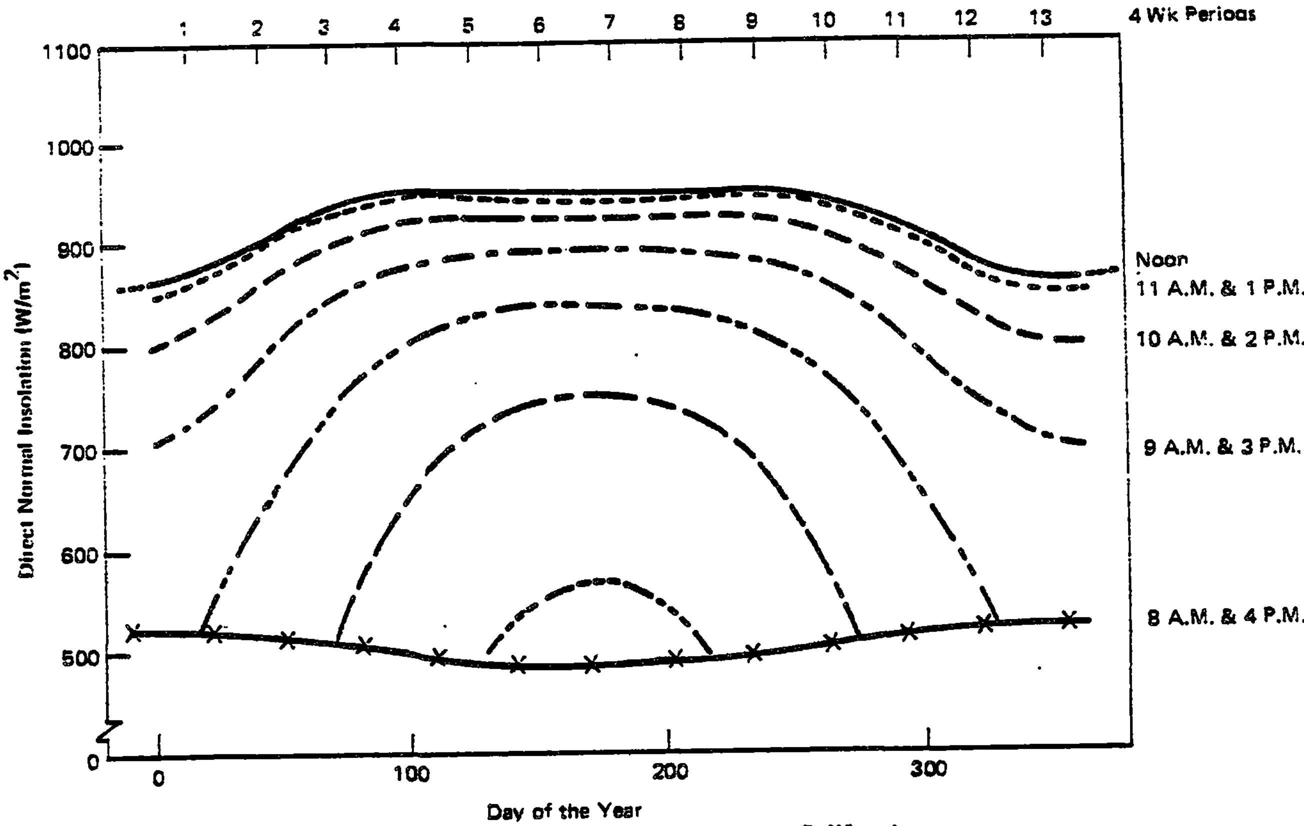


Figure V.A.4. DELSOL Average Clear Day Insolation Model Barstow, California

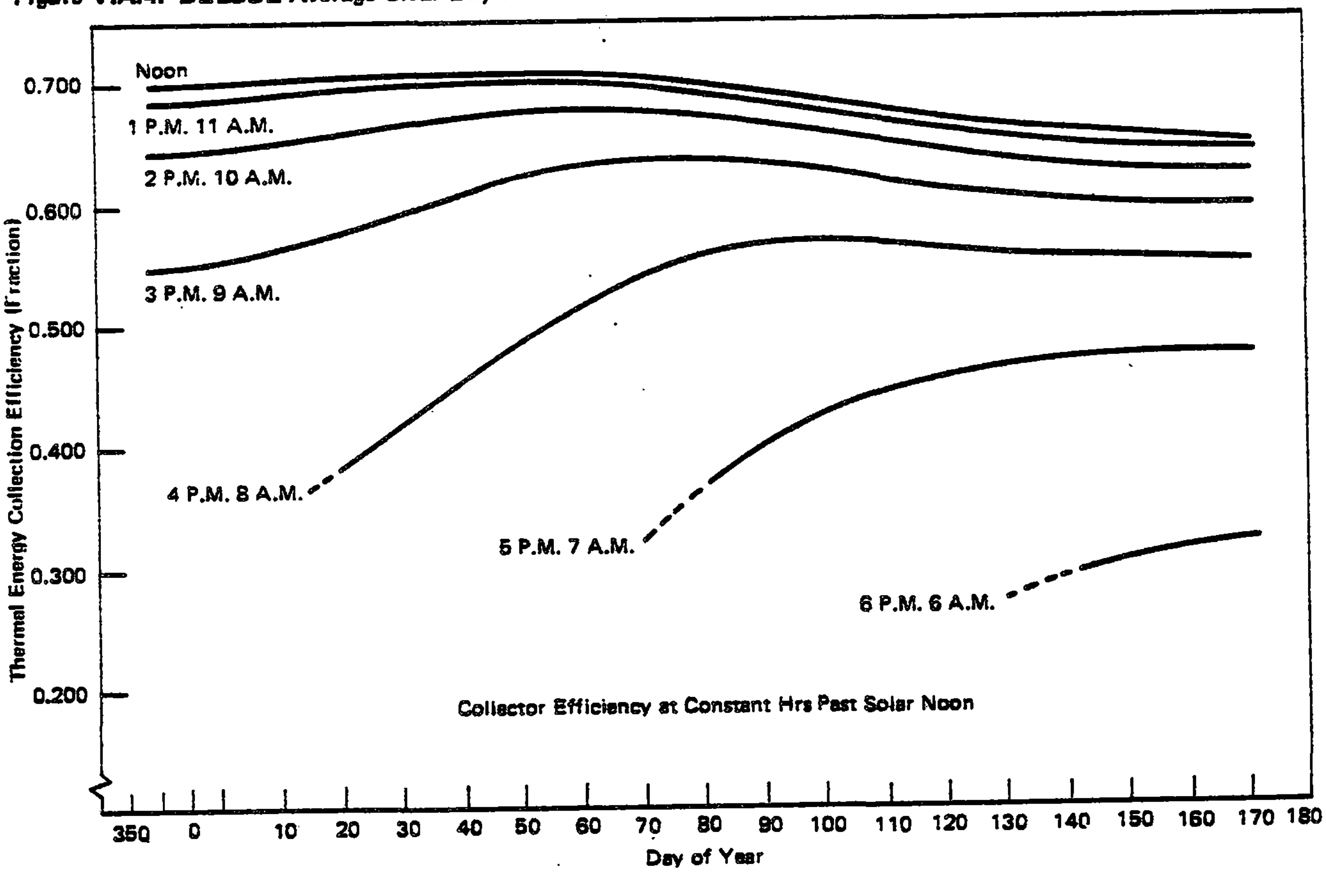


Figure V.A.5. Conversion Efficiency from Insolation to Thermal Energy

3. Insolation Model for Final Sizing and System Performance

Because the Lucerne Valley site has a 1 1/2° to 2 1/2° slope, it was necessary to use the University of Houston codes to model the sloping field. (This capability is not available in DELSOL.) The clear day month-long average insolation data are shown on Figure V.A.6. Also shown on the figure are these data ratioed with the appropriate weather factor.

4. Insolation Model for SCE Value Analysis

SCE's grid model operates on the basis of 13 four-week periods with average days for each period modelled with 12 two-hour periods. For this model, the insolation and efficiency data from the DELSOL trade study results were converted to two-hour averages and input to the program. Figure V.A.7 illustrates the data format and representative data.

Because it was necessary to apply the weather factor to these data to make the annual results for total energy correct, the data did not properly model good summer clear day peformance well enough for the case when storage is fully charged and late night operation ocurs. Therefore, another model, which statistically modelled insolation day-to-day variations, based on West Associates data, and correctly maintained annual total energy was used for the final analyses. Figure V.A.8 illustrates these results.

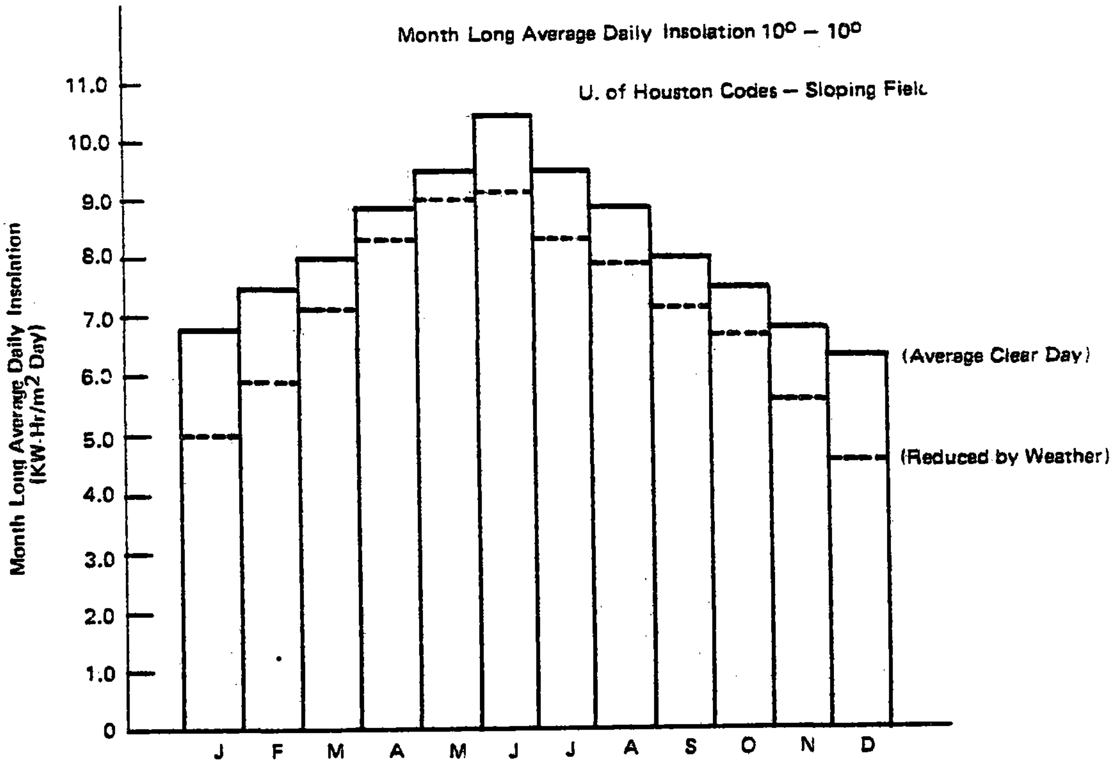


Figure V.A.6. Insolation Model for Final Performance Analysis

Hours from Solar Noon

4-Week Period	0-2		2-4	4-6	6-8	8-10	10-12	12-14	14-16	16-18	18-20	20-24
I mean insol (w/m^2)	0		0	0	0	501	590	590	501	0	0	0
eff day	0		0	0	0	.568	.694	.694	.568	0	0	0
from Jan I	14	1/14										
2	0		0	0	0	549	618	618	549	0	0	0
	0		0	0	0	.612	.700	.700	.612	0	0	0
	42	2/11										
3	0		0	0	427	646	703	703	646	427	0	0
	0		0	0	.324	.638	.698	.698	.638	.324	0	0
	70	3/11										
4	0		0	0	567	733	783	783	733	567	0	0
	0		0	0	.420	.631	.680	.680	.631	.420	0	0
	98	4/8										
5	0		0	0	639	766	822	822	766	639	0	0
	0		0	0	.463	.610	.659	.659	.610	.463	0	0
	126	5/6										
6	0		0	0	688	823	868	868	823	688	0	0
	0		0	0	.476	.602	.648	.648	.602	.476	0	0
	154	6/3										
7	0		0	0	641	780	825	825	780	641	0	0
	0		0	0	.476	.598	.645	.645	.598	.476	0	0
	182	7/1										
8	0		0	0	641	780	825	825	780	641	0	0
	0		0	0	.468	.607	.655	.655	.607	.468	0	0
	210	7/29										
9	0		0	0	614	794	848	848	794	614	0	0
	0		0	0	.435	.570	.674	.674	.570	.435	0	0
	238	8/26										
10	0		0	0	524	793	863	863	793	524	0	0
	0		0	0	.357	.638	.693	.693	.638	.357	0	0
	266	9/23										
11	0		0	0	0	731	823	823	731	0	0	0
	0		0	0	0	.624	.704	.704	.624	0	0	0
	294	10/21										
12	0		0	0	0	621	732	732	621	0	0	0
	0		0	0	0	.579	.698	.698	.579	0	0	0
	322	11/18										
13	0		0	0	0	527	638	638	527	0	0	0
	0		0	0	0	.549	.687	.687	.549	0	0	0
	350	12/16										

Σ insol = 47466 x 2 x 28 = 2658.1 $kWhr/m^2yr$

$10^\circ - 10^\circ$ = 2576.4 2658.1/2576.4 = 1.0317

Figure V.A.7. Typical Inputs for Insolation and Efficiency for SCE Value Analysis Program

CONTROL CODE 50, SOLMAC ,BASE DOS, ECONOMY ENRGY (8PM-4AM), NO 100SOLAR 1/1/88, AUG31 RUN DATE 09/02/81 AT 18:59:06 PAGE 25

----------------DAILY SOLAR INTENSITY PROFILE FOR THIRTEEN 4-WEEK PERIODS OF YEAR----------------

SOLAR INTENSITY (WATTS/SQM) RECORDED AT SITE NO. 1 PHOTO-VOLTAIC TYPE

	00-02 HOURS	02-04 HOURS	04-06 HOURS	06-08 HOURS	08-10 HOURS	10-12 HOURS	12-14 HOURS	14-16 HOURS	16-18 HOURS	18-20 HOURS	20-22 HOURS	22-24 HOURS	PRD NO.
AVG INT	0.0	0.0	0.0	26.000	221.000	390.000	398.000	226.000	49.000	0.0	0.0	0.0	1
STD DEV	0.0	0.0	0.0	17.000	118.000	181.000	177.000	134.000	27.000	0.0	0.0	0.0	1
MAX INT	0.0	0.0	0.0	67.000	409.000	604.000	595.000	389.000	55.000	0.0	0.0	0.0	1
MIN INT	0.0	0.0	0.0	4.000	31.000	62.000	46.000	24.000	3.000	0.0	0.0	0.0	1
AVG INT	0.0	0.0	0.0	67.000	390.000	629.000	612.000	320.000	69.000	0.0	0.0	0.0	2
STD DEV	0.0	0.0	0.0	27.000	85.000	100.000	140.000	115.000	27.000	0.0	0.0	0.0	2
MAX INT	0.0	0.0	0.0	129.000	503.000	745.000	761.000	521.000	114.000	0.0	0.0	0.0	2
MIN INT	0.0	0.0	0.0	18.000	138.000	318.000	183.000	96.000	4.000	0.0	0.0	0.0	2
AVG INT	0.0	0.0	0.0	114.000	454.000	645.000	641.000	441.000	127.000	0.0	0.0	0.0	3
STD DEV	0.0	0.0	0.0	70.000	165.000	245.000	235.000	156.000	44.000	0.0	0.0	0.0	3
MAX INT	0.0	0.0	0.0	256.000	646.000	874.000	859.000	602.000	195.000	0.0	0.0	0.0	3
MIN INT	0.0	0.0	0.0	15.000	66.000	105.000	142.000	74.000	35.000	0.0	0.0	0.0	3
AVG INT	0.0	0.0	16.000	307.000	681.000	900.000	875.000	610.000	207.000	3.000	0.0	0.0	4
STD DEV	0.0	0.0	9.000	48.000	54.000	42.000	46.000	50.000	40.000	2.000	0.0	0.0	4
MAX INT	0.0	0.0	36.000	373.000	741.000	950.000	947.000	692.000	263.000	6.000	0.0	0.0	4
MIN INT	0.0	0.0	0.0	167.000	494.000	766.000	706.000	433.000	77.000	0.0	0.0	0.0	4
AVG INT	0.0	0.0	51.000	381.000	746.000	937.000	893.000	640.000	272.000	15.000	0.0	0.0	5
STD DEV	0.0	0.0	13.000	64.000	62.000	76.000	119.000	105.000	48.000	5.000	0.0	0.0	5
MAX INT	0.0	0.0	72.000	434.000	833.000	1030.000	995.000	763.000	340.000	24.000	0.0	0.0	5
MIN INT	0.0	0.0	18.000	145.000	493.000	616.000	422.000	299.000	117.000	0.0	0.0	0.0	5
AVG INT	0.0	0.0	67.000	423.000	773.000	971.000	930.000	696.000	332.000	30.000	0.0	0.0	6
STD DEV	0.0	0.0	12.000	30.000	37.000	34.000	97.000	82.000	42.000	5.000	0.0	0.0	6
MAX INT	0.0	0.0	82.000	458.000	815.000	1019.000	983.000	782.000	408.000	38.000	0.0	0.0	6
MIN INT	0.0	0.0	30.000	314.000	618.000	828.000	493.000	382.000	177.000	0.0	0.0	0.0	6
AVG INT	0.0	0.0	48.000	369.000	726.000	935.000	911.000	688.000	317.000	26.000	0.0	0.0	7
STD DEV	0.0	0.0	14.000	65.000	71.000	73.000	125.000	92.000	63.000	7.000	0.0	0.0	7
MAX INT	0.0	0.0	69.000	427.000	782.000	989.000	979.000	769.000	378.000	40.000	0.0	0.0	7
MIN INT	0.0	0.0	8.000	103.000	428.000	574.000	324.000	297.000	82.000	7.000	0.0	0.0	7
AVG INT	0.0	0.0	23.000	300.000	648.000	836.000	786.000	540.000	212.000	7.000	0.0	0.0	8
STD DEV	0.0	0.0	9.000	75.000	134.000	186.000	226.000	193.000	85.000	6.000	0.0	0.0	8
MAX INT	0.0	0.0	39.000	364.000	737.000	957.000	951.000	701.000	324.000	20.000	0.0	0.0	8
MIN INT	0.0	0.0	3.000	33.000	178.000	182.000	107.000	10.000	10.000	0.0	0.0	0.0	8
AVG INT	0.0	0.0	9.000	245.000	612.000	814.000	736.000	492.000	133.000	0.0	0.0	0.0	9
STD DEV	0.0	0.0	5.000	53.000	73.000	93.000	164.000	118.000	47.000	0.0	0.0	0.0	9
MAX INT	0.0	0.0	18.000	310.000	694.000	912.000	876.000	000	214.000	0.0	0.0	0.0	9
MIN INT	0.0	0.0	[illegible]	74.000	[illegible]	[illegible]	220.000	[illegible]	29.000	0.0			

Figure V.A.8. Typical Input Data for Statistical Insolation Model for SCE Value Analysis Program

V-B. PLANT OUTPUT

1. Gross Plant Output

The steam generator and turbine generator are sized for a gross output of 110 MWe. Because the hot salt used to generate steam in the steam generator may be drawn directly from the hot salt storage tank, the gross electric output is independent of receiver operations and dependent only on the availability of hot salt in the storage tank. 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 (based on the available insolation per the model of Section V-A).

2. Plant Auxiliary Loads

The plant auxiliary loads are shown on Table V.B.1. The table also shows annual operating hours. A breakdown of loads and operating hours for major collector field operations is included.

Loads associated with collector field operations are based on the following considerations:

- o 3,313 operating hours per year from usable insolation with sun elevations greater than 10° above the horizon.

TABLE V.B.1(a)
SOLAR 100 AUXILIARY POWER REQUIREMENTS

Electric Loads	Design Point Power (kW)	Shutdown Power (kw)	Annual Utilization (hrs) Normal	Annual Utilization (hrs) Shutdown	Annual MW_ehr Normal	Annual MW_ehr Shutdown
I. Heliostats						
a. Slew (Normal)	0	Incl. in Ic.	----	----	----	----
b. Slew (Emergency)	0	2400	0	0	----	----
c. Track	1125	0	3313	0	3727.1	----
d. Overnight	0	24	----	5447	----	130.7
e. UPS	24	0	5447	0	130.7	----
II. Pumps - Salt						
a. Receiver Feed Pumps (Tower #1 North)						
2 Pump Operation	3636	0	2648	0	9628.0	----
1 Pump Operation	1653	0	662	0	1094.3	----
b. Receiver Feed Pumps (Tower #2 South)						
2 Pump Operation	2893	0	2648	0	7660.7	----
1 Pump Operation	1322	0	662	0	875.1	----
c. Steam Generator Feed Pumps	793	0	5256	0	4168.0	----
d. Receiver Drain Sump Pumps						
Tower 1 (North)	Used During Cold Fill		0	0	----	----
Tower 2 (South)	Used During Cold Fill		0	0	----	----
e. Thermal Storage Drain Sump Pumps	70	0	730	0	51.1	----
III. Pumps - Feedwater						
a. Compensate Pumps	207	0	5256	0	1088.0	----
b. Feedwater Pumps	2202	0	5256	0	11537.7	----
c. Heater Drain Pump	21	0	5256	0	110.4	----
IV. Pumps - Circ. Water						
a. 2 Pumps	909	0	5256	0	4777.7	----
b. 1 Pump	0	454.5	0	3504	----	1592.6
V. Pumps - Miscellaneous						
a. Condenser Vacuum Pumps	33.6	0	5256	0	176.6	----
b. Turbine Control, Seal and Lube Oil	100	0	5256	0	525.6	----
c. Turbine Turning Gear	0	16.5	0	3504	----	57.8
d. Bearing Cooling Water	41.3	41.3	5256	3504	217.0	144.7
e. Gland Seal Condenser Fan	16.5	16.5	5256	3504	86.7	57.8
f. Water Treatment System	54.5	54.5	2628	1752	143.2	95.5
g. Service Water Pumps	124	124	2628	1752	325.9	217.2

TABLE V.B.1(b)
SOLAR 100 AUXILIARY POWER REQUIREMENTS

Electric Loads	Design Point Power (kW)	Shutdown Power (kw)	Annual Utilization (hrs) Normal	Annual Utilization (hrs) Shutdown	Annual MW_eh Normal	Annual MW_eh Shutdown
VI. Trace Heating						
a. Receiver Towers	0	Stored Energy Utilized	0	----	----	----
b. Steam Generator	0	61	0	927	----	56.6
c. Salt Piping (Hot)	0	360	0	730	----	262.8
d. Salt Piping (Cold)	0	480	0	730	----	350.4
e. Storage Tanks	0	Stored Energy Utilized	0	----	----	----
VII. Fans - Cooling Tower						
a. 3 Cells Operating	496	0	5256	0	260.7	---
b. 1 Cell Operating	0	165.30	0	3504	----	579.2
VIII. HVAC						
a. Control Equip. & Term. Rooms	80.5	80.5	5256	3504	423.1	282.1
b. Admin. Bldg. & Warehouse	20	0	2600	0	52.0	----
IX. Plant Control						
a. Control Room Equipment	110	20	5256	3504	578.2	70.1
b. Remote Equipment	10	10	5256	3504	52.6	35.0
X. Miscellaneous						
a. Lighting	274	180	5256	3504	1440.1	630.7
b. Compressed Air System	51.7	10	5256	3504	271.7	35.0
c. Cover Gas System	Negligible		-----	----	----	
d. Auxiliary Boiler System	0	74	0	3504	----	259.3
Subtotal					51,748.5	4,857.3
Total Annual Auxiliary Power Required					56,605.8	

w/o outages PG V-26 = 58,994
w/ " PG V-25 = 62,777

- Equivalent collector field operating days of 312 (equivalent annual clear days derived from the weather factor per Section V.A.1).

- 24 minutes per operating day are required to unstow and stow collector field (i.e., 12 minutes each).

- One receiver feed pump per field is operating whenever there is usable insolation. The second receiver feed pump per field is required 80% of the time the first pump is required. Reduction in usage of the second receiver feed pump results from the lower insolation and reduced receiver thermal power and flowrates during early morning and evening hours.

Loads associated with the turbine generator, steam generator, and related equipment are based on operating during equivalent collector field operating days as follows:

- Begin loading at start of receiver operations.
- Ramp from zero to full load in one-half hour.

- Operate continuously at full load until salt inventory in hot salt storage tank from current day's receiver operation will just be exhausted at end of one-half hour ramp from full load to zero load.

- Ramp from full load to zero load in one-half hour.

Loads associated with trace heating for the receivers and steam generator are based on the hours for equivalent collector field operating days shown on Table V.B.2 and continuous operation for non-operating days.

Loads associated with trace heating for major pipework are based on operating these heaters continuously during the non-operating days and not operating days and not operating them during the equivalent collector field operating days. Stored energy in these large lines generally precludes trace heater operation during normal operating days.

On nonoperating days, all baseload equipment operates continuously. Other equipment is not operated on these days.

3. Net Plant Output

The net plant output during operations at full gross power rating of 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 (based on the 5,325 hours/year from Section B.1).

TABLE V.B.2
RECEIVER AND STEAM GENERATOR TRACE HEATING REQUIREMENTS

			Hours/Equivalent Operating Day						
			Dec	Jan/Nov	Feb/Oct	Mar/Sep	Apr/Aug	May/Jul	June
Receiver Units									
1712 Trace heaters	Wing Panel Trace Heaters	2477hrs 75 kW_e	14.8	14.4	13.3	12.2	11.1	10.3	10.1
28	Cavity Radiant Heaters	730hrs 500 kW_e	4.6	4.2	3.1	2.0	0.9	0	0
	Pipework, Sumps	500 kW_e	4.6	4.2	3.1	2.0	0.9	0	0
Steam Generator									
92	Heat Exchangers & Pipework	927hrs 61 kW_e	3.8	2.0	2.0	2.0	2.0	1.0	0

206.99days

operating = 22.51 22.75/24.68 21.94/27.6 27.62/26.7 28.1/27.6 29.39/27 26.13

= 556 hrs over 312.02 operating days —
371
927

V-C. AVAILABILITY ANALYSIS

1. Introduction

Availability is defined as the percent of time a system, or the complete plant, is capable of performing its specified function or provide its specified output during the system, or plant, annual operating periods. A unit is available when it is capable of service, whether or not it is actually in service. It is unavailable when it is rendered inoperable because of the failure of a component, work being performed or other adverse condition.

The availability calculation for a solar power plant considers several factors different than for a conventional fossil plant. One is the fact that the output of the plant (and specific systems) is time limited by the sun cycle. The other is the fact that the plant can produce electric power (plant output) from two separate sources, but one (thermal storage) is somewhat dependent on the other (receiver output). The output of the thermal storage is capacity limited and the output of the receiver(s) is time dependent (both time of day and day of year).

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 in a bottom-up manner in which the predicted failure rate and recovery time for each component was considered and then cumulated into a predicted forced outage rate. The remainder of the plant was analyzed by utilizing industry-wide availability data for similar units. The failure rates and recovery times were obtained from References V.C.1 through V.C.7. The industry data were obtained from Reference V.C.8.

2. Availability Results

The results of the availability analysis are shown on Tables V.C.1, 2, 3 and 4. Table V.C.1 gives the results of the analysis of the heliostat field. The heliostat field will not affect plant availability if the industry standard of power plant availability is used. This standard states that the output power must be reduced by at least 2% before a reduction in availability is considered. Table V.C.1 shows that only about seven heliostats will fail in any one day, and if we assume that they will be repaired before the next day's operation, this means that the reduction of power would be only about 0.05%.

Tables V.C.2 and V.C.3 gives the results of the component-by-component analysis of the receiver and steam generator systems. Table V.C.2 results add up to about three failures per year in each receiver, of which about 2.5 will shut the system down. The individual receiver downtime (unplanned outage) per year will be about 52 hours for an unplanned outage rate of 1.57% . Table V.C.3 gives similar results for the steam generator system. This system will experience about 3.6 failures per year, of which 2.8 will be critical. The total downtime will be about 63 hours/year for an unplanned outage rate of 1.20%.

Table V.C.4 gives the overall results by system. The heliostat field (collector system) shows a zero downtime and unplanned outage rate, as discussed previously. There are two receivers which will each reduce the output power by 50% when down. Therefore, the total downtime for both receivers is twice the 52 hours discussed previously, but only a partial (50%) unplanned outage is charged

TABLE V.C.I
COLLECTOR SYSTEM - SOLAR 100
ON-EQUIPMENT CORRECTIVE MAINTENANCE SUMMARY

Component	Failure Rate (10^{-6})	Operating Time	Population	Annual Failures	MTTR	Crew	Hours
Heliostat Controller	23.68	3313	15,424	1,210	1.3	2	3,146
Hel. Power/Data Cables	0.11	3313	77,120	28	1.8	2	101
Secondary Field Power/Data Cables	0.22	3313	504	--	3.5	2	--
Primary Power/Data Cables	0.22	3313	84	--	3.5	2	--
Power Distribution Panel	7.0	3313	84	2	1.6	2	7
Mirror Module	0.1 Hel.	8760	15,424	14	2.0	2.5	70
Elevation Actuator	2.73	3313	15,424	140	2.2	2	616
Azimuth Drive	2.94	3313	15,424	150	4.0	5	3,000
Elevation Drive Motor	*3.35	3313	15,424	171	1.9	2	650
Azimuth Drive Motor	*3.35	3313	15,424	171	1.7	2	582
Heliostat Field Controller	17.03	3313	504	29	2.1	2	122
Field J-Box	1.0	3313	15,424	51	1.6	2	164
Pedestal	0.11	8760	15,424	15	1.0	2	30
Reflector Support Structure	0.12	8760	15,424	16	1.5	2	48
Power Transformer	2.0	3313	84	--	2.4	3.5	--
Position Sensors	1.133	3313	77,120	290	2.1	2	1,218
TOTAL							9,754

*Includes Motor Failure Rate 2.0 and Incremental Encoder Failure Rate 1.35.

TABLE V.C.2
RECEIVER - SOLAR 100

Component	Population	Operational Hours/Year	MTBF (Hours)	Total Failures Per Year (10^{-3})	MTTR (Hrs)	Forced Outage Hrs/Yr	Critical	System Down Hrs/Yr	Comments
Receiver Panels	20	3133	62,500	1060.2	22.5	23.85	Yes	23.85	
Receiver Doors and Motors	2	122	250,000	0.98	11.3	0.01	No	0	Assume 10 min. to open and close, once each day hrs/yr = (1/3)(365) = 122
Trace Heaters	712	730	2,500,000	207.9	17.5	3.64	No	0	
Radiant Heaters	28	2477	2,500,000	27.7	17.5	0.48	No	0	Heaters required for time beyond (operation hours plus 9 hours) 8760 - 3313 ~~3133~~ - 9 (330) = 2477
Remote Valves	31	3313 3133	160,000	641.7	19.8	12.71	Yes	12.71	
Check Valves	3	3133	250,000	39.8	19.1	0.76	Yes	0.76	
Relief Valves	2	3133	100,000	66.3	19.4	1.29	Yes	1.29	
Hand Valves - *FTR Open	74	3133	1,000,000	245.2	19.1	4.68	Yes	4.68	
Hand Valves - *FTR Closed	10	3133	250,000	132.5	19.1	2.53	Yes	2.53	
Level Sensors	2	3133	1,000,000	6.63	2.2	0.01	No	0	
Temp Sensors	30	3133	1,000,000	99.4	2.2	0.22	No	0	
Press. Sensors	1	3133	1,000,000	3.31	19.7	1.96	No	0	
Tanks	3	8760	1,000,000	26.28	32.	0.84	Yes	0.84	
Orifices	4	3133	80,000	165.7	22.	3.65	Yes	3.65	
Pumps	2	10	16,000	1.25	26.5	0.03	Yes	.03	
Control Valves	4	3133	160,000	82.8	19.8	1.64	Yes	1.64	
Flow Sensor	1	3133	32,500	101.9	19.4	1.98	No	0	

*FTR - failure to remain

TABLE V.C.3
STEAM GENERATOR SYSTEM - SOLAR 100

Component	Population	Operational Hours/Year	MTBF (Hours)	Total Failures Per Year (10^{-3})	MTTR (Hrs)	Forced Outage Hrs/Yr	Critical	System Down Hrs/Yr
Heat Exchangers	4	5256	31,000	678.2	28.5	19.33	Yes	19.33
Remote Valves	9	5256	160,000	295.7	19.8	5.85	Yes	5.85
Control Valves	20	5256	160,000	657.0	19.8	13.01	Yes	13.01
Relief Valves	5	5256	100,000	262.8	19.4	5.10	Yes	5.10
Tanks	1	8760	1,000,000	8.76	32.	0.28	Yes	0.28
Hand Valves - *FTR Open	58	5256	1,000,000	304.9	19.1	5.82	Yes	5.82
Hand Valves - *FTR Closed	12	5256	250,000	252.3	19.1	4.82	Yes	4.82
Fossil Heater	1	662	91,000	7.27	13.5	0.1	Yes	0.1
Pumps	1	5256	16,000	328.5	26.5	8.71	Yes	8.71
Temp. Sensors	20	5256	1,000,000	105.1	2.2	0.23	No	0
Press. Sensors	5	5256	1,000,000	26.3	19.7	0.52	No	0
Flow Sensors	4	5256	32,500	646.9	19.4	12.55	No	0
Level Sensors	1	5256	1,000,000	5.26	2.2	0.01	No	0
Trace Heaters	92	927	2,500,000	34.1	17.5	0.6	No	0

*FTR - failure to remain

TABLE V.C.4
TOTAL PLANT AVAILABILITY ANALYSIS

System		Expected** Operating Hours/Year	System Downtime (Forced Outage) Hours/Year	Outage %: Charge Against Operations Time	Outage %: Allocated to Operations vs Non-Operations Time
Heliostat Field		3,313	0	0	0
Receivers (2)		3,313	103.96	1.57*	0.59
Steam Generator		5,256	63.62	1.20	0.72
Turbine		5,256	220	4.19	2.51
Molten salt loop	Receiver	3,313	20	.30*	.11
	Stm. Gen.	5,256	10	.19	.11
Control System		8,760	0	0	0
Total		Unplanned outaged		7.45	4.04
		Plant availability (excl. planned outage)			95.96%

* Two receivers each reduce power by 50% when down.
** Based on initial operating time estimates only; availability analysis not revised to reflect final estimate of operating time.

against plant availability for each downtime hour. Thus, the unplanned outage rate is 1.57%. The value for the turbine system was obtained using historical data for similar power plants. The zero values for the control system were obtained because all automatic control systems are backed-up by a manual system and thus are not critical. Also, the supervisory and heliostat computers are redundant. The results shown in the first plant outage column on Table V.C.4 are conservative; the actual availability will be higher. These results assume that all of the recovery period for a failed component occurs during operating hours when, in fact, some of the recovery time falls during nonoperating (nighttime, cloudy days). A calculation to take this into account (on a rigorous statistical basis) is beyond the scope of this study, however, a top level estimate has been prepared. The downtime was assumed to distribute evenly over all times whether operating or nonoperating times. The receiver unavailability is the number of downtime hours (52 hours/year) divided by the number of hours in a year (8760). Similarly, the steam generator, turbine, and molten salt loop downtime is apportioned to the total annual hours, with the salt loop downtime split between the receiver and steam generator loop a shown on the table. The result is an unplanned outage rate of 4.04%, (≈96% availability excluding planned outage) as shown on Table V.C.4.

An analysis was performed on the planned outage of 6 weeks every 4 years. This maintenance was assumed to be performed during December and the first two weeks of January. The plant output in these months was adjusted downward to reflect this quadrennial outage on an annual basis.

V-D. ANNUAL PLANT OUTPUT

The annual plant output is summarized in the "waterfall" chart of Figure V-D.1. The figure shows annual performance assuming 100% plant availability (based on available insolation per the model of Section V-A). The effects of outages are discussed in Section V.C.2.

Figures V.D.2 to V.D.5 show similar waterfall data for winter solstice, spring and fall equinox, and summer solstice.

Collector field performance was calculated using the University of Houston R-CELL code and annual insolation of 2576.4 kWhr/m^2, as described in Section V.A.1. Latitude and elevation were based on Barstow to be consistent with the insolation model. A survey of West Associates data (Reference V.A.1) in the California desert did not indicate any systematic variation of insolation with elevation. A collector field down-

$\frac{2,258,000}{2576.4} = 876417\,m^2$

2 adjusted in VG handouts to 2432

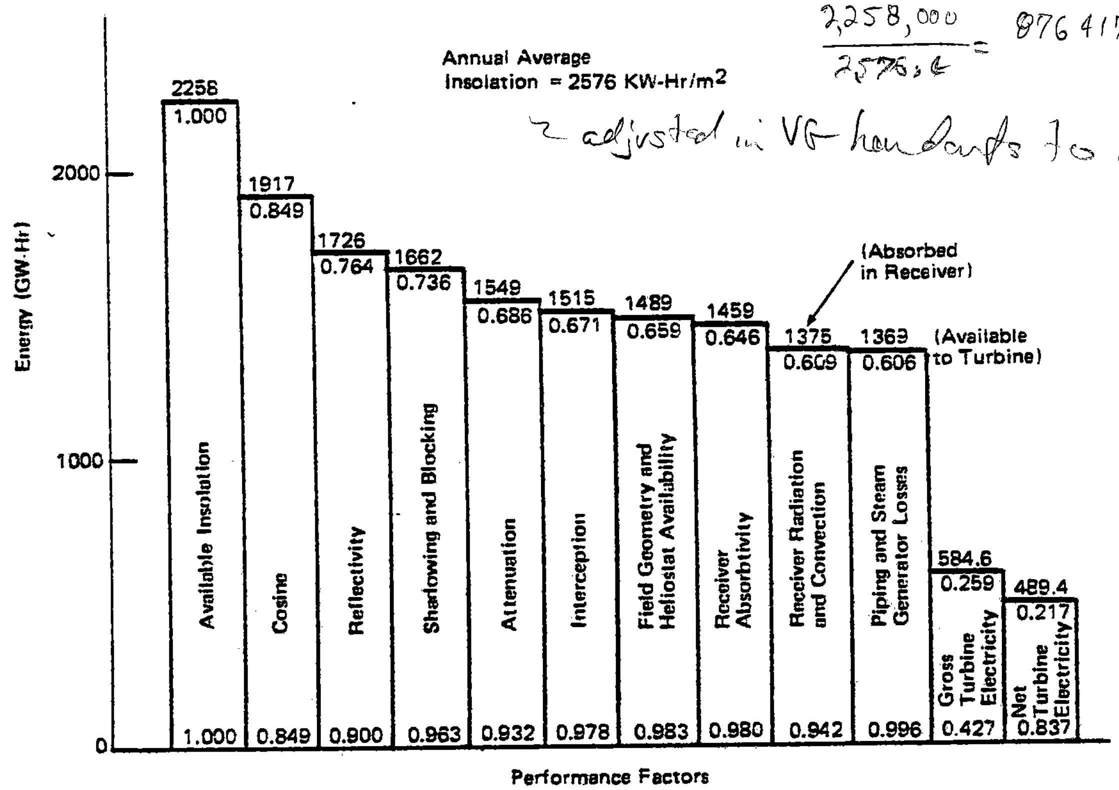


Figure V.D.1. Annual Average Performance

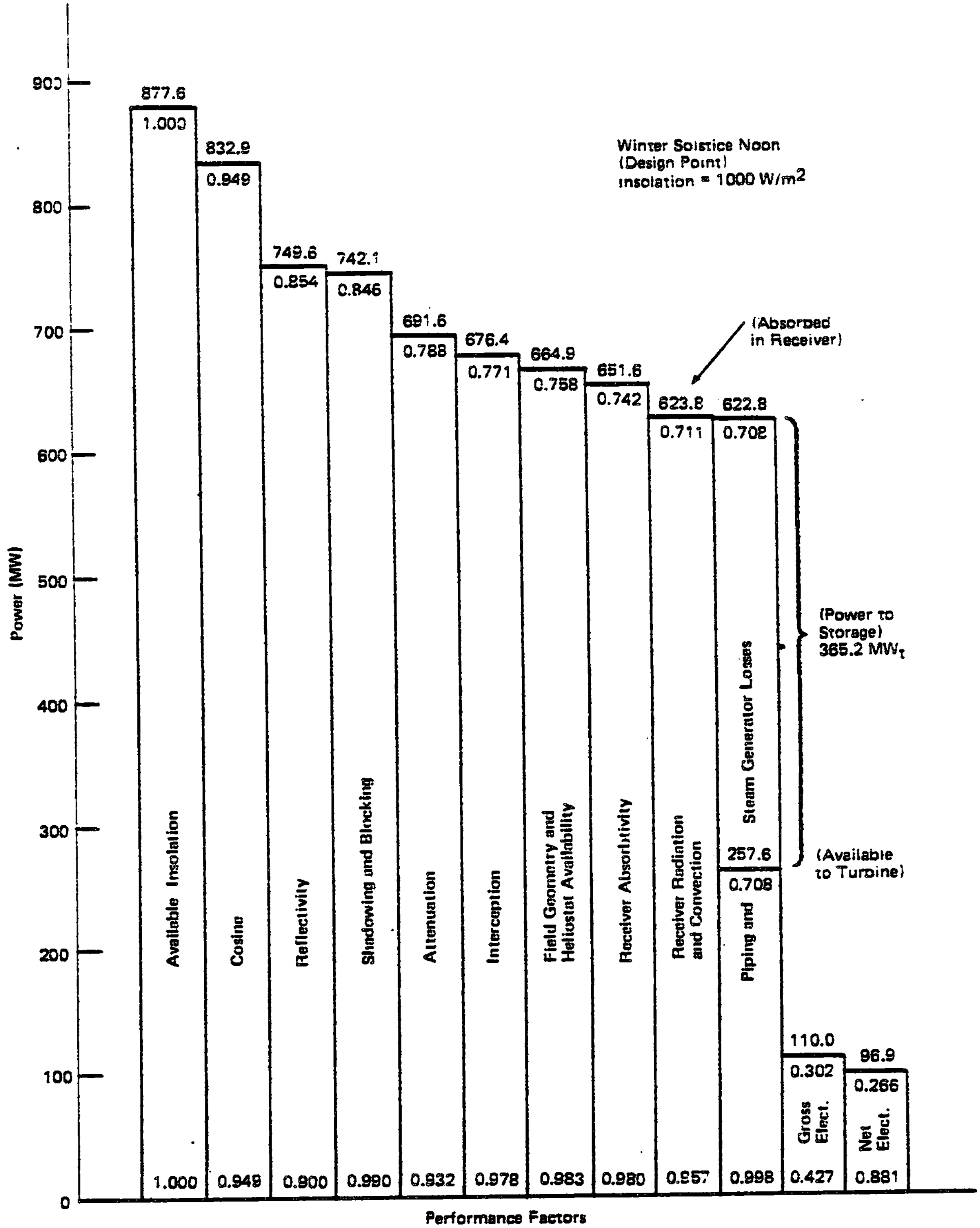


Figure V.D.2. Winter Solstice Noon Performance (Design Point)

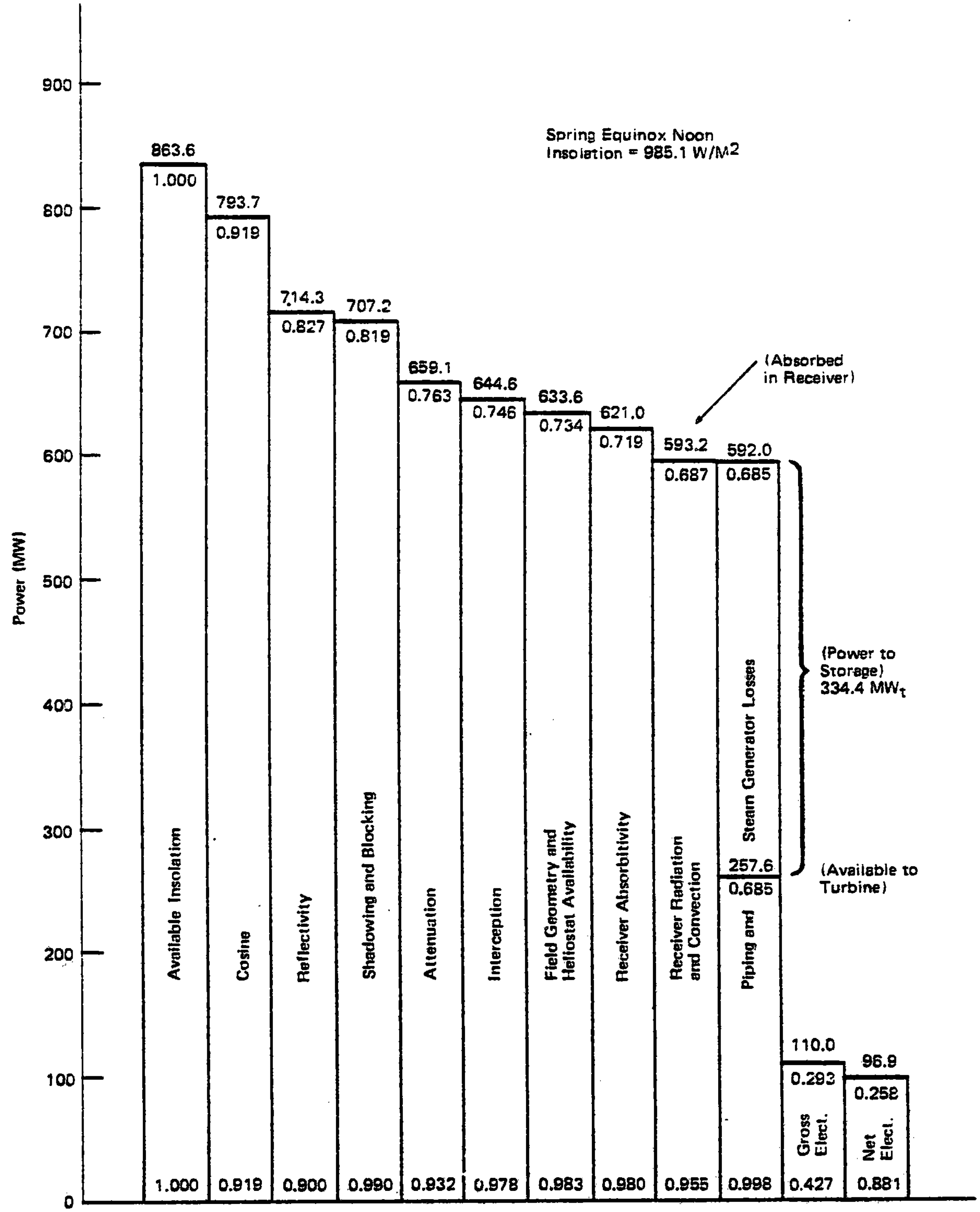


Figure V.D.3. Spring Equinox Noon Performance

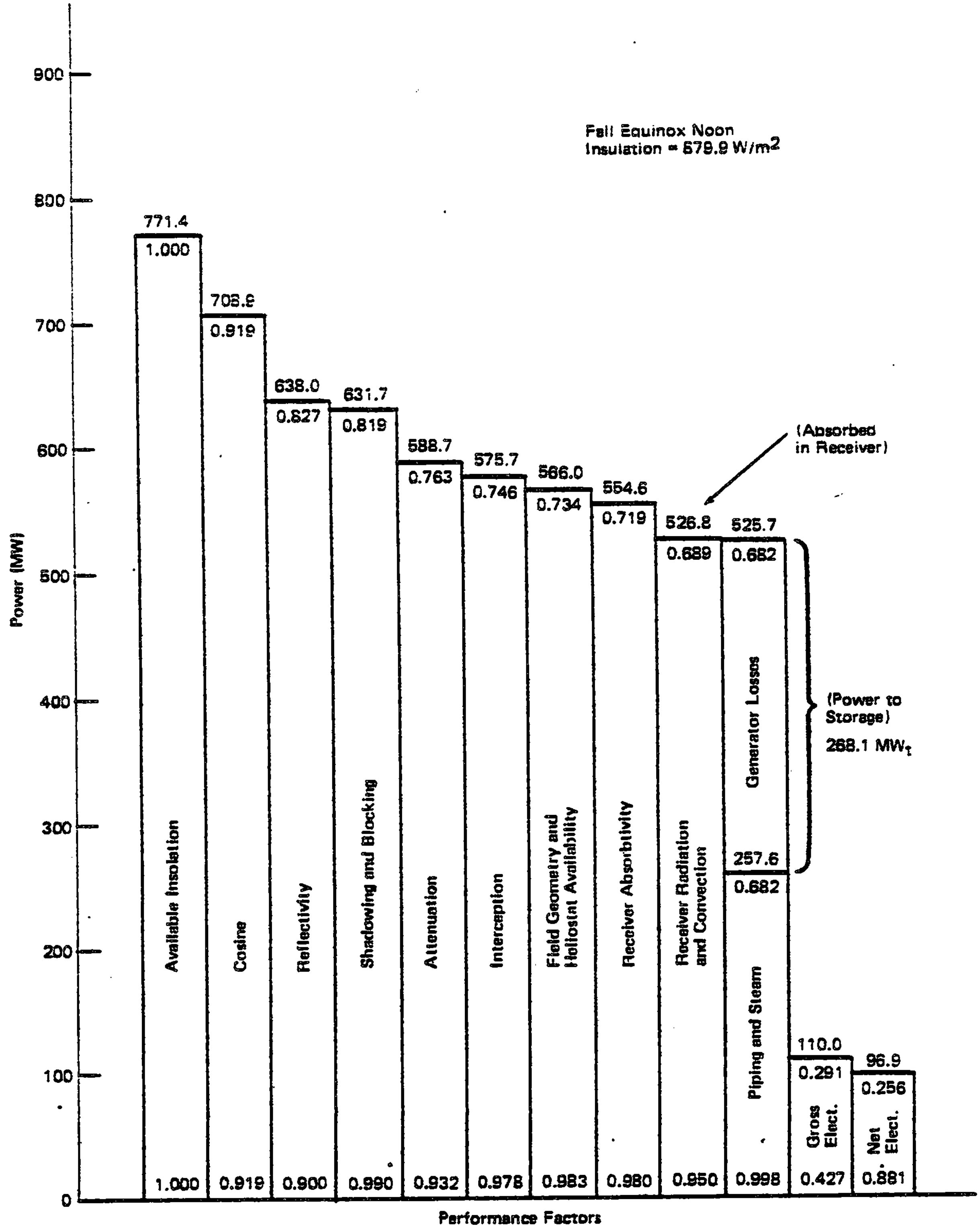


Figure V.D.4. Fall Equinox Noon Performance

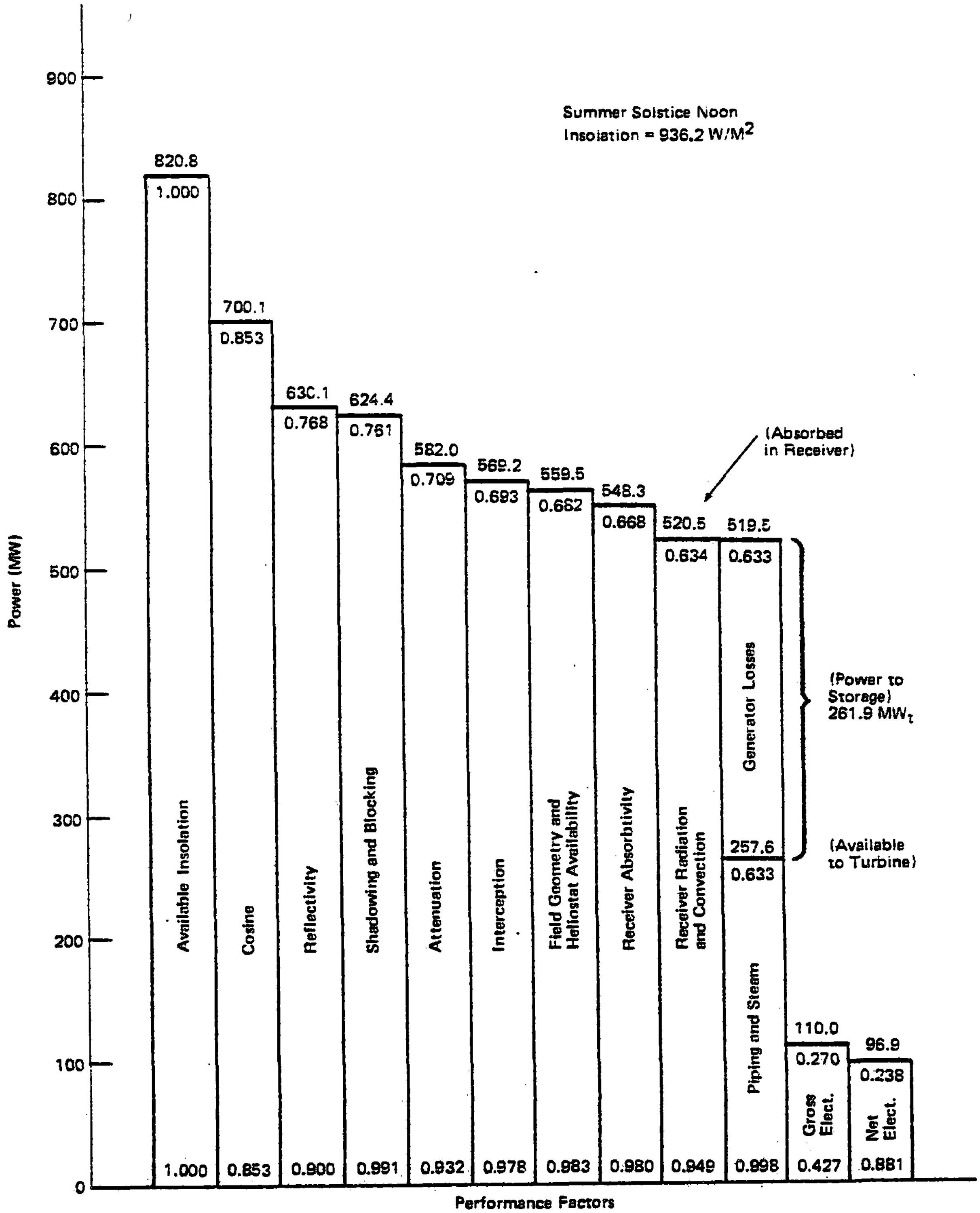


Figure V.D.5. Summer Solstice Noon Performance slope, from north-to-south, of 1.5° was used for both fields. This value was selected as a representative average for the field based on several collector field performance runs from zero to 2.5° slope.

Heliostat size and performance data are based on MDAC Model 50 heliostat characteristics.

Table V.D.1 summarizes the design point and annual average efficiency for the receiver.

TABLE V.D.1
BASELINE RECEIVER EFFICIENCY DATA

Loss Mechanism	Design Point Efficiency	Annual Average Efficiency
Reflection	0.980	0.980
Radiation	0.983	0.976
Convection	0.974	0.965
Conduction	0.998	0.986
Total Thermal	0.936	0.910
Spillage	0.978	0.978
Total Receiver Efficiency	0.916	0.890

Reflection and radiation losses were estimated using a NASA radiation heat transfer computer code, TRASYS. Convection losses were modelled as a root-sum-square of natural and forced convection. Natural convection was modelled with the simplified Abrams model which predicted an enhancement of free convection for the cavity over that for an exposed flat plate. Forced convection was modelled based on receiver frontal area, the Achenbach correlation, and the Lucerne Valley "wind rose."

Gross turbine generator cycle efficiency of 0.427 was used for all turbine generator operations. This corresponds to a gross turbine heat rate of 7988 Btu/kWe/hr.

Plant auxiliary loads and availability were calculated as discussed in Sections V.B.2 and V.C. A tabular summary of the plant net output is shown on Table V.D.2. Daily gross output values shown are for monthly average clear days. Net monthly values are derived from the daily gross output values by accounting for weather, and auxiliary loads. The resulting annual energy output is 524 million kWh. Table V.D.3 shows the adjustments to monthly gross output and auxiliaries for planned and unplanned outage. Monthly values from Table V.D.2 were adjusted by the 0.96 plant availability due to unplanned outages. January and December values were adjusted for the quadrennial planned outage. The final annual energy output is 489 million kWh.

TABLE V.D.2(a)
PLANT NET OUTPUT

Month	(AM) 12-2	2-4	4-5	5-6	6-7	7-8	8-10	10-12	Hours 12-2	(PM) 2-4	4-6	6-8	8-10	10-12	Totals	Net Load/ Gross Load
Jan (22.75 Op Days per Month)																
Gross/Day	0	0	0	0	0	0.55	199.76	220	220	220	220	220	220	121.4	1641.75	
Gross/Month	0	0	0	0	0	12.5	4544.5	5005.0	5005.0	5005.0	5005.0	5005.0	5005.0	2762.8	37349.8	
Aux/Month	130.0	139.1	110.7	110.7	112.4	131.8	606.5	666.6	666.6	606.5	331.9	315.3	326.1	262.1	4526.3	
Net/Month	-130	-139.1	-110.7	-110.7	-112.4	-119.3	3938.0	4338.4	4338.4	4398.5	4673.1	4679.7	4678.9	2500.7	32823.5	.879
Feb (21.94 Op Days per Month)																
Gross/Day	8.32	0	0	0	0	37.95	220	220	220	220	220	220	220	214.43	1800.70	
Gross/Month	182.5	0	0	0	0	832.6	4826.8	4826.8	4826.8	4826.8	4826.8	4826.8	4826.8	4704.6	39507.3	
Aux/Month	135.5	109.7	81.2	99.5	100.4	190.8	601.4	626.7	626.7	601.4	402.6	297.1	298.4	297.4	4468.8	
Net/Month	47.0	-109.7	-81.2	-99.5	-100.4	641.8	4225.4	4200.1	4200.1	4225.4	4424.2	4529.7	4528.4	4407.2	35038.5	.887
Mar (27.62 Op Days per Month)																
Gross/Day	15.55	0	0	0	3.25	98.12	220	220	220	220	220	220	220	218.31	1875.23	
Gross/Month	429.5	0	0	0	89.8	2710.1	6076.4	6076.4	6076.4	6076.4	6076.4	6076.4	6076.4	6079.7	51793.9	
Aux/Month	146.6	102.2	56.8	108.0	148.0	292.2	752.8	752.8	752.8	752.8	482.9	335.8	339.5	338.4	5361.6	
Net/Month	282.9	-102.2	-56.8	-108.0	-58.2	2417.9	5323.6	5323.6	5323.6	5323.6	5593.5	5740.6	5736.9	5691.3	46432.3	.896
Apr (28.10 Op Days per Month)																
Gross/Day	40.37	0	0	0	50.38	110	220	220	220	220	220	220	220	220	1960.75	
Gross/Month	1134.4	0	0	0	1415.7	3091.0	6182.0	6182.0	6182.0	6182.0	6182.0	6182.0	6182.0	6182.0	55097.1	
Aux/Month	167.7	92.3	47.1	76.4	242.9	339.3	766.0	766.0	766.0	766.0	592.8	331.6	338.0	336.9	5629.0	
Net/Month	966.7	-92.3	-47.1	-76.4	1172.8	2751.7	5416.0	5416.0	5416.0	5416.0	5589.2	5850.4	5844.0	5845.1	49468.1	.898
May (29.39 Op Days per Month)																
Gross/Day	76.34	0	0	1.36	93.35	110	220	220	220	220	220	220	220	220	2041.5	
Gross/Month	2243.6	0	0	40.0	2743.6	3232.9	6465.8	6465.8	6465.8	6465.8	6465.8	6465.8	6465.8	6465.8	59986.5	
Aux/Month	210.5	91.9	45.9	81.5	287.3	381.0	784.2	784.2	784.2	784.2	668.1	355.9	344.4	343.3	5946.6	
Net/Month	2033.1	-91.9	-45.9	-41.5	2456.3	2851.9	5681.6	5681.6	5681.6	5681.6	5797.7	6109.9	6121.4	6122.5	54039.9	.901

TABLE V.D.2(b)
PLANT NET OUTPUT

Month	(AM) 12-2	2-4	4-5	5-6	6-7	7-8	Hours 8-10	10-12	(PM) 12-2	2-4	4-6	6-8	8-10	10-12	Totals	Net Load/ Gross Load
Jun (26.13 Op Days per Month)																
Gross/Day	215.15	9.25	0	8.44	104.53	110	220	220	220	220	220	220	220	220	2207.37	
Gross/Month	5621.9	241.7	0	220.5	2731.4	2874.3	5748.6	5748.6	5748.6	5748.6	5748.6	5748.6	5748.6	5748.6	57678.6	
Aux/Month	325.9	134.8	51.2	116.6	267.8	359.4	717.9	717.9	717.9	717.9	627.1	354.8	326.9	325.7	5762.0	
Net/Month	5296.0	106.9	-51.2	103.9	2463.6	2514.9	5030.7	5030.7	5030.7	5030.7	5121.5	5393.8	5421.7	5422.7	51916.6	.900
Jul (27.00 Op Days per Month)																
Gross/Day	76.01	0	0	1.36	93.35	110	220	220	220	220	220	220	220	220	2040.72	
Gross/Month	2052.3	0	0	36.7	2520.5	2970.0	5940.	5940.	5940.	5940.	5940.	5940.	5940.	5940.	55099.5	
Aux/Month	214.8	105.8	52.9	85.5	274.7	360.8	741.8	741.8	741.8	741.8	635.2	348.3	337.8	336.8	5719.8	
Net/Month	1837.5	-105.8	-52.9	-48.8	2245.8	2609.2	5198.2	5198.2	5198.2	5198.2	5304.8	5591.7	5602.2	5603.2	49379.7	.896
Aug (27.60 Op Days per Month)																
Gross/Day	68.20	0	0	0	50.38	110	220	220	220	220	220	220	220	220	1988.58	
Gross/Month	1882.3	0	0	0	1390.5	3036.0	6072.0	6072.0	6072.0	6072.0	6072.0	6072.0	6072.0	6072.0	54884.8	
Aux/Month	175.1	102.3	52.2	80.4	241.0	334.1	752.5	752.5	752.5	752.5	585.1	333.3	339.5	338.4	5591.4	
Net/Month	1707.2	-102.3	-52.2	-80.4	1149.5	2701.9	5319.5	5319.5	5319.5	5319.5	5486.9	5738.7	5732.5	5733.6	49293.4	.898
Sep (26.70 Op Days per Month)																
Gross/Day	15.88	0	0	0	3.25	98.17	220	220	220	220	220	220	220	218.42	1875.72	
Gross/Month	424.0	0	0	0	86.8	2621.1	5874.0	5874.0	5874.0	5874.0	5874.0	5874.0	5874.0	5831.8	50081.7	
Aux/Month	142.0	99.0	55.1	104.6	143.2	282.6	728.1	728.1	728.1	728.1	467.2	325.0	328.5	327.4	5187.0	
Net/Month	282.0	-99.0	-55.1	-104.6	-56.4	2338.5	5145.9	5145.9	5145.9	5145.9	5406.8	5549.0	5545.5	5504.4	44894.7	.896
Oct (27.60 Op Days per Month)																
Gross/Day	8.56	0	0	0	0	37.95	220	220	220	220	220	220	220	214.63	1801.14	
Gross/Month	236.3	0	0	0	0	1047.4	6072.0	6072.0	6072.0	6072.0	6072.0	6072.0	6072.0	5923.8	49711.5	
Aux/Month	134.8	102.3	84.3	107.2	108.3	222.0	720.7	752.5	752.5	720.7	470.5	337.9	339.5	338.4	5191.6	
Net/Month	101.5	-102.3	-84.3	-107.2	-108.3	825.4	5351.3	5319.5	5319.5	5351.3	5601.5	5739.1	5732.5	5585.4	44519.9	.896

TABLE V.D.2(c)
PLANT NET OUTPUT

(AM) Hours (PM)

Month	12-2	2-4	4-5	5-6	6-7	7-8	8-10	10-12	12-2	2-4	4-6	6-8	8-10	10-12	Totals	Net Load/ Gross Load
Nov (24.68 Op Days per Month)																
Gross/Day	0	0	0	0	0	0.56	199.75	220	220	220	220	220	220	121.22	1641.53	
Gross/Month	0	0	0	0	0	13.8	4929.8	5429.6	5429.6	5429.6	5429.6	5429.6	5429.6	2991.7	40512.9	
Aux/Month	110.3	120.2	104.7	104.7	106.6	126.8	627.0	692.2	692.2	627.0	329.0	322.2	322.9	253.7	4539.5	
Net/Month	-103.3	-120.2	-104.7	-104.7	-106.6	-113.	4302.8	4737.4	4737.4	4802.6	5100.6	5107.4	5106.7	2738.0	35973.4	.888
Dec (22.51 Op Days per Month)																
Gross/Day	0	0	0	0	0	0	175.45	220	220	220	220	220	219.26	19.22	1513.93	
Gross/Month	0	0	0	0	0	0	3949.4	4952.2	4952.2	4952.2	4952.2	4952.2	4935.5	432.6	34078.5	
Aux/Month	131.9	149.9	112.0	112.3	112.6	114.5	572.8	662.3	662.3	578.0	322.0	324.7	325.5	172.1	4352.9	
Net/Month	-131.9	-149.9	-112.0	-112.3	-112.6	-114.5	3376.6	4289.9	4289.9	4374.2	4630.2	4627.5	4610.0	260.5	29725.6	.872
Yearly Totals (312.02 Op Days per Year)																
Gross/Year															585782.1	
Aux/Year															62276.5	
Net/Year	12181.7	-1107.8	-854.1	-890.2	8833.1	19306.4	58309.6	60000.8	60000.8	60267.5	67730.0	64652.5	64660.7	55414.6	523505.6	.894
	2.33%	-0.21%	-0.16%	-0.17%	1.69%	3.69%	11.14%	11.46%	11.46%	11.51%	11.98%	12.35%	12.35%	10.59%		
Hours	12-2	2-4	4-5	5-6	6-7	7-8	8-10	10-12	12-2	2-4	4-6	6-8	8-10	10-12		

ie $\frac{312.02}{365}$ = .855 WF

does not include planned/forced outages

Summary by Periods

12PM - 6AM	9329.6	1.78%
12PM - 8AM	37469.1	7.16%
10PM - 6 AM	64749.2	12.37%
10PM - 8AM	92883.7	17.74%

TABLE V.D.3
PLANT OUTPUT WITH PLANNED AND UNPLANNED OUTAGES

Unplanned (4%) & planned (2%)

Month	~~.96~~ x Gross .94 -	Aux. Adj. for Outage =	Net
Jan	30072.4	Aux. 3968.9	26103.5
Feb	37927.0	4340.5	33586.5
Mar	49722.1	5175.2	44546.9
Apr	52893.2	5419.7	47473.5
May	57587.0	5722.1	51864.9
Jun	55371.5	5563.7	49807.8
Jul	52895.5	5524.3	47371.2
Aug	52689.4	5396.0	47293.4
Sep	48078.4	5007.0	43071.4
Oct	47723.0	5012.2	42710.8
Nov	38892.4	4402.2	34490.2
Dec	24536.8	3462.6	21074.2
	548,388.7	58,994.4	489,394.3

V-E. PLANT OPERATION AND MAINTENANCE

1. Introduction

This section describes elements of the plant maintenance plan including the maintenance concept and support resources required to operate the plant. This plan forms the basis for operations and maintenance (O&M) cost estimates presented in Section VIII.B.

2. Plant Maintenance Concept

All maintenance functions performed on plant hardware, including support equipment, are categorized in one of three maintenance levels defined as:

Online - Maintenance performed on plant equipment while installed in its operating location. This includes scheduled and unscheduled (corrective) actions required to inspect, service, calibrate, fault isolate, replace components, repair in-place, and verify system operation.

Offline - onsite level - Maintenance performed on plant equipment subsequent to removal from its operating location or installed condition and accomplished in the plant maintenance and repair building. This includes disassembly, inspection, repair, service, calibration, reverification operation, and proof testing or load reverification.

Offsite - Maintenance performed on plant equipment at designated offsite locations; for example, at supplier's manufacturing facilities. It consists of maintenance that requires equipment, facilities, or skills which are not economical to establish at the plant maintenance facility. This includes repair, overhaul and rebuilding. Maintenance analyses were performed to include both scheduled and unscheduled maintenance. Reliability analyses were conducted on the solar design to determine mean time between failure, as discussed in Section V.

The basic field maintenance concept is to remove and replace failed functional assemblies. For each item, actions required to remove and replace the crew size, the time required to remove and replace spares and spare parts, and any support facilities and equipment are defined. This is based on MDAS product support experience including specific experience during the Collector SRE for the Solar I program.

a. Online Maintenance

Corrective - System repair is accomplished in the most economical manner consistent with meeting availability requirements without degrading performance, reliability or safety. Repair methods for each of the plant major equipment group is selected to satisfy this criterion.

Functional assembly replacement - Removal and replacement of a complete functional assembly which implies a spare item is available onsite to replace the failed item. The failed item is repaired, functionally tested, and returned to spares stock. Procedures provide sufficient date to identify the failed item, system maintenance preparation (operational mode or status requirements), safety precautions, special replacement requirements, support equipment, and any servicing or functional test subsequent to replacement

Detail part replacement - Applicable for specific failure modes when functional assembly design and installation permits access for replacement of detail parts. Examples include panel switches and indicators, electrical connectors, and valve packing, seats, poppets, or other internal parts. Spare parts are stocked on site. Procedures provide coverage similar to that described for functional assembly replacement.

Standard repair process - Apply to static mechanical, structural and other nonoperating components such as piping, support structures, electrical cables and wiring. Actions include welding or splicing in new sections, corrosion control, cleaning, refinishing and painting. Bulk materials, raw stock and spare parts are stocked onsite.

Remove, repair and reinstall - Applicable to functional assemblies and other major items when in-place repair is not feasible and repair by replacement is not warranted due to high cost of replacement items.

Scheduled - Scheduled maintenance is categorized as routine or planned outage. Routine scheduled maintenance includes inspection, servicing, cleaning, painting, calibrating, testing, and component replacement or change-out which can be accomplished during normal system operation or during daily non-operating periods (i.e., overnight).

Planned outage consists of the refurbishment or major overhaul of system equipment. System planned outages are scheduled concurrently when possible and planned well in advance to reduce down time and assure availability of maintenance support equipment, replacement parts, bulk materials, and personnel.

Certain tasks are planned to be performed by outside maintenance organizations, working under negotiated service contracts. The use of service contracts for these tasks is preferable to establishing new skill classifications and incurring training and capital equipment expenses.

b. Offline, Onsite Maintenance

Maintenance performed in the plant maintenance and repair shop is essentially limited to bench type repairs which can be accomplished with standard (off-the-shelf) multi-purpose tools and test equipment. Meintenance beyond this capability is accomplished offsite unless increased capability in the form of additional tools and test equipment is justified by cost considerations or technical reasons. Repair parts and bulk materials to support maintenance of components designed as onsite shop repairable are stocked in the maintenance facility.

c. Offline, Offsite Maintenance

Plant equipment designated for offsite maintenance is repaired at existing utility maintenance facilities or a supplier manufacturing facility. Repaired or overhauled items are subjected to the original product acceptance test or equivalent prior to returning to spares stock.

3. Support Resources

A preliminary assessment of the support resources needed for the Solar 100 plant has been completed. These resources are categorized as:

- Spares and repair parts
- Documentation
- Training
- Special tools and test equipment
- Facilities
- Staff

a. Spares and Repair Parts

A preliminary spares analysis was conducted based on the hardware configuration and the mean time to repair. Repairable functional assemblies, upon failure, are removed from the system, placed in the repair cycle, and subsequently returned to spare stock inventory. Initial spares quantity for these items is the sum of the pipeline quantity and a contingency supply. The quantity is based on the maximum number of items in the repair pipeline at any given time, which is calculated using the failure rate and the repair cycle time. A repair cycle time of five days is projected. The initial spares quantity for nonrepairable items (i.e., those discarded at failure) is set at the predicted number of failures per year plus a contingency quantity. The initial spares quantity will be procured and stocked at the repair location when the first year of operation begins.

The discard factor represents the number of failures which result in an item being discarded instead of repaired. The product of the total number of failures per year and the discard factor equals the number of replacement items to be procured during subsequent years.

Spares, repair parts, and bulk materials are procured and stocked to directly support the maintenance functions at each maintenance level (online, offline onsite, and offsite). Specific requirmeents are derived by allocation of the maintenance analysis to each of the major systems.

b. Documentation

Characteristics and Performance

Design requirements including physical configuration, performance, operating characteristics and limitations, test data and requirements are provided to completely describe the system.

Instructions

Station manuals consisting of the following three volumes or books for each system will be provided:

- o System Description Book
- o Equipment Data Book
- o Drawings and Diagrams

In addition to the station manuals, user's manuals will be provided which contain operating instructions and maintenance data.

Operational functions will be described in sufficient detail to permit development of overall system operating manuals. The minimum data required by a skilled and knowledgeable technician to accomplish maintenance functions will be provided.

c. <u>Training</u>

The training will concentrate on the tasks, skills, and knowledge the SCE operational and maintenance personnel will need to effectively and safely operate and maintain the solar systems in the plant. It is anticipated that most of the training will be conducted at the Solar 100 site; however, it many be necessary to have some portions of the instruction conducted at offsite locations, e.g., equipment supplier facilities. Any supplier units of instruciton which are conducted either onsite or offsite will be integrated with MDAC instruciton.

The courses planned for Solar 100 personnel include the following:

- o Solar Equipment Orientation
- o Control Room Operations
- o Plant Equipment Operations
- o Electrical/Electronic (E/E) Equipment Maintenance
- o Mechanical Equipment Maintenance

d. <u>Special Tools and Test Equipment</u>

In addition to the traditional power plant support equipment, e.g., welding, flushing, water conditioning and mobile lifting and hoisting equipment, the Solar 100 plant will require equipment and tools unique to the collector. A tentative list of these litems is provided in Table V.E.1.

e. <u>Facilities Requirements</u>

The maintenance concept as applied to the collector field requires onsite facilities for storage of maintenance support spares and material, and for repair of discrepant items.

<u>Storage Facilities</u> - Based on the quantity of spares recommended for maintenance support, an area of approximately 2000 ft^2 is required for storage. In addition to usual utilities, this area will be furnished with parts, racks, and bins and a loading dock.

The storage area will be colocated with the maintenance area.

<u>Maintenance Facilities</u> - The facilities needed to house and support the repair activities are determined by both the nature and the frequency of repairs. About 1,000 ft^2 is required. Only one special fixture is required, a support fixture needed to hold the heliostat azimuth drive during preparation of the unit for shipment and installation. Other items can be disassembled, inspected, reassembled and test on standard work benches.

The azimuth drive weight, approximately 330 pounds, precludes manual lifting of the unit. A mobile, hand-operated joist or jib crane is considered adequate for this purpose. This area will also be furnished with tool cribs and storage to test equipment.

TABLE V.E.1.
SUPPORT EQUIPMENT SUMMARY

Item	Use
Commercial items	
1. Mobile crane 10-tons, with standard rigging	Remove and hold heliostat reflector during removal and replace of azimuth drive.
2. Forklift with hoisting adapater	Remove and replace azimuth drive.
3. Hydra-Set, 2-1/2 tons	Precise positioning of reflector during reinstallation on the azimuth drive.
4. Pickup truck	General.
5. Wyler minilevel	Measurement of mirror module cant angle.
6. Oil injector	Fill drive housing with oil.
Special items	
1. *Portable control unit	Fault isolation and control of an individual heliostat.
2. Service link kit	Stabilize heliostat reflector during removal and replacement of elevation jack.
3. Jack adjustment tool	Set elevation jack extension to a design point for initial track calibration.
4. Clinometer mount	Provide interface between clinometer or minilevel and main beam reference point.
5. Hoisting tool, azimuth	Remove and replace azimuth drive.
6. Hoisting tool, reflector/drive/support assembly	Remove and replace reflector/drive/support assembly during azimuth drive change out.
7. Tool, panel leveling	Measure mirror module cant angle. Used in conjunction with Wyler mini-level.
8. Sling, mirror module lifting	Remove and replace mirror module.

The maintenance requirements of the remaining plant require additional facilities similar to standard utility plant support.

f. Staffing

Supervisory, operations, maintenance, clearical and security requirements were considered in developing a staffing estimate for Solar 100. The manning recommendations presented on Table VIII.D.1 resulted from analyses which explored the accepted provision of personnel to operate and maintain established SCE plants (such as San Bernardino and Coolwater) and extrapolated these data to determine requirements for the turbine generator and balance of plant at Solar 100. Solar unique personnel requirements were added. The solar manpower requirements were developed by detailed analysis of equipment characteristics. Predicted failure rates, equipment quantities, annual operating hours, crew sizes, and estimated repair times were combined to develop annual manhour estimates.

These resultant manhour numbers were then converted into equivalent numbers of personnel needed. The total quantity of personnel was segregated into the necessary crafts and skills, and combined with the turbine generator and balance of plant personnel to form the plant total staffing requirements.

Potential support by the external maintenance division of Southern California Edison was not considered in the development of the staffing plan at this time.

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.

VI-A. CRITERIA FOR SITE SELECTION

The intent of the siting study was to provide a systematic evaluation of candidate sites, within and outside the Edison service territory, that can be utilized for solar thermal development. A broad spectrum of real estate properties were considered. These included Edison owned properties, privately owned real estate and federal land. Consideration was given to sites that have at least two sections (1,280 acres) of unobstructed land with a gentle south facing slope, close proximity to highway and transmission lines, and low environmental impacts. Sites with low elevations (below 500 ft.) and high ambient wind conditions (over 30 mph wind for more than 5% of the time) were excluded because of low solar insolation and fugitive dust problems both of which greatly impair solar thermal heliostat performance. Basic assumptions were established to aid in the preliminary screening of candidate sites. They are listed as follows:

Design Criteria

Insolation (Direct)	- 7.5 kWh/m^2/day (300 Btu/ft.^{2}/day)
Wind	- < 20 mph 95% of time
Seismic	- low
Soil loading	- 3,000 lbs/ft.^{2}
Slope	- less than 10^o south slope
Area required	- 1,200 acres (minimum)
Altitude	- 3,000 - 4,000 ft. elev.
Water availability	- 2,600 afy

Collector and Receiver

Point focusing heliostats
North field arrangement
2 fields. east-west or north-south arrangement
(each field requires 600 acres)

No. of heliostats required	-	15,000 to 16,000
Tower Height	-	670 feet (2 towers)

Based on the above criteria, the candidate sites were evaluated and rated on compatibility with public acceptance, environmental impact, seismicity, economics and other potential physical constraints.

VI-B. CANDIDATE SOLAR THERMAL SITES

The basic assumptions presented in Section A were used for the preliminary screening of candidate sites. A total of twenty potentially developable sites were proposed for evaluation. These sites were further reduced to ten for an in depth siting evaluation. These sites are listed in Table VI.B.I.

Table VI.B.I
Candidate Solar Sites

1. Lucerne Valley - San Bernardino County (T6N, R3E, Sections 25, 36 and T5N, R3E, Section 1).

2. Cool Water - San Bernardino County (T9N, R1E, Sections 13, 14, 15, 23 and 24).

3. Alvord Well - San Bernardino County (T11N, R3E, Sections 13, 14, 23 and 24).

4. Vidal Valley - San Bernardino County (T1N, R223, Sections 25 and 26, T1N, R23E and Section 30).

5. Tenmile Well - Nevada, on Searc;hlight quad (T30S, R63E, Sections 13, 14 and 15).

6. North Lucerne Valley - San Bernardino County T7N, R1W, Sections 31, 32 and 33).

7. Ord Mountain, South - San Bernardino County (T5N, R1E, Sections 1 and 2).

8. Lockhart Ranch, Harper Lake Area - San Bernardino County (T11N, R5W, Section 25 and T11N, R4W, Section 30).

9. Camino - San Bernardino County (T8N, R20E, Sections 19, 20 and 21).

10. Midland or Big Marias - Riverside County (T4S, R21E, Sections 34, 35 and 36).

These sites were selected because of their advantageous physical settings, minimal environmental impacts and favorable political climates.

VI-C. LOCATION AND ENVIRONMENTAL DESCRIPTION OF CANDIDATE SITES

The following is a brief summary of the locations and general descriptions of each candidate site. An overall presentation of the locations of the sites is depicted in Figure VI.C.1.

Figure VI.C.1. Candidate Site Locations

Site No. 1 <u>Lucerne Valley</u>

This site is located in the Upper Johnson Valley, San Bernardino County, 32 miles southeast of Barstow, in T6N, R3E, Sections 25, 36 and T5N, R3E, Section 1. Elevation of the site is between 3,200 and 3,600 feet with a slope facing south to south-southeast. All three sections of the land are owned by Edison.

Slopes are in the 2 to 5% class range and simple except for part of Section 36 which is undulating. The predominant vegetation at the site consists of a widespread desert creosote scrub, 5 to 14% density with herb understory of less than 4% density (A. dumosa - L. tridentata community type).

The NE corner of Section 25 is a part of the Emerson fault. Primary access to the site will be by way of Bessemer Road (a typical desert dirt road) extending from State Highway 247 about 16 miles northeast to Bessemer Mine. The Atchinson, Topeka, and Santa Fe Railroad Company's Cushenbury Line terminates about 30 miles southwest of the plant site.

Site No. 2 <u>Cool Water</u>

The site is located in the SCE's Cool Water Generating Station, which is 12 miles east of Barstow, in the Mohave Desert of San Bernardino County (in T9N, R1E, Sections 13, 14, 15, 23 and 24). Elevation of the site is between 1,935 and 1,970 feet with a slope facing east. The site is completely owned by SCE. Slopes are in the 0 to 2% class with a simple surface configuration of undissected to slightly dissected alluvium.

Presently, nearly all land within the Edison property is occupied by permanent structures, parking lots, storage yards, roads, evaporation pond and agricultural crops. Cresote Brush Scrub was at one time the predominant vegetation at the site. Because of the type and extent of human activities occurring on and around the site, desert tortoises and Mohave ground squirrels, which are considered rare and protected animal species, are no longer observed at the site.

Site No. 3 <u>Alvord Well</u>

The site is located south of the Alvord Mountain in T11N, R3E, Sections 13, 15, 23 and 24, of San Bernardino County. The elevation of the site is between 1,780 and 2,120 feet. Slope faces southwest. Alvord Mountain is to the north at 3,456 feet. Fort Irwin Military Reservation is 6 miles to the north over the Alvord Mountain.

Slopes are generally greater than 2% to 5%, primarily undulating, no complex surfaces, small inclusions of sand dunes and wash area. Land forms are primarily moderate dissected alluvial fans which are of Quaternary age, except for the wash which is Recent in origin and is composed mostly of sand.

The predominant vegetation from visual field inspection is a shrub overstory of less than 4% density and herb with understory, also less than 4% density. This vegetation is primarily of A. dumosa - L. tridentata, dune L. Tridentata - Lycium Sp., and wash H. salsola - L. tridentata community types.

Site No. 4

Vidal Valley

This site is located in Vida Valley southwest of Vidal Junction in T1IN, R22E, Sections 25 and 26 and T1N, R23E, Section 30 in San Bernardino County. Elevation at the site is between 830 and 940 feet with southeast facing slope. The site is wedged between the Colorado River Aqueduct and Route 62 and the Santa Fe Railroad.

Slope at the site is gentle between 0 to 2% across the area. Majority of the area has a simple surface; remaining area is undulating, moderately dissected alluvial fan or fan terrace. The site is vacant and undeveloped.

The prevalent vegetation consists of a shrub overstory with less than 4% density and a herb with understory also less than 4%. Larrea tridentata - Lycium sp. community type with much A. dumosa is the prevailing vegetation.

Site No. 5

Tenmile Well

This site is located at the western border of Nevada in the Piute Valley in T30S, R63E, Sections 13, 14 and 15. Elevation is between 2,672 and 2,890 feet, with a slope facing southeast. The site is approximately 9 miles south of the town Searchlight, Nevada; 8 miles to the east are mountains at about 1,000 feet higher. There are also mountains to the west (Hart Peak at 5,543 feet, approximately 8 miles to the SW).

Prevailing vegetation is a short tree overstory with less than 4% absolute density witha shrub understory at 5 to 14% density. A. dumosa - L. tridentata with Y. breviofolia - Y. schidigera is the major community type.

The area is fairly homogeneous with a 0-2% slope undulating terrain across a moderately dissected alluvial fan of Quaternary-aged material

The site is currently vacant and undeveloped. There are no active faults in the surrounding area.

Site No. 6

North Lucerne Valley

This site is located in North Lucerne Valley, bordered on the north by the Stoddard Ridge and south by Sidewinder Mountain, in T7N, R1W, Sections 31, 32 and 33 of San Bernardino County. The site is basically ringed by mountains open to the SE. There is agriculture and residences to the SE. Elevation is between 3,200 and 3,560 feet with slopes facing SSE in Section 31, S in 32, and SSW in 33.

The majority of the area is in the 0-2% and 2%-5% slopes, with only a very small aea up to 10% slope. Almost all of the area has a simple surface on undissected to slightly dissected alluvial fan or undissected to slightly dissected pediment. The principal vegetation is a shrub overstory of 5 to 14% density and a herb understory of less than 4% density. In the east or west portions of this area are short trees. A. dumosa - L. tridentata and L. tridentata - Lycium Sp. are the main shrubs with Yucca schidigera.

Site No.7 Ord Mountain, South

This site is located in Lucerne Valley, with East Ord Mountain to the NE, approximately 5 miles away, and West Ord Mountain to the NW at about the same distance. T5N, R1E, in Sections 1 and 2 of San Bernardino County, is the legal locational description of the site. Elevation is between 3,075 and 3,400 feet with slope facing mostly south in Section 1 and southwest in Section 2. The surrounding peaks and ridges are at 4,636 feet two miles to the north, 3,916 feet three miles ESE, and 4,419 feet 7 miles WSW.

Slopes are generally between 2-5%, undulating and range from simple to complex; the complex area is moderately dissected fan terrace, while the rest is moderately dissected alluvial terrace. Major vegetation consists of a sparse shrub overlay with 5 to 14% density, with a herb understory of less than 4% density. Ambrosia dumosa - L. tridentata is the main community type.

Site No. 8 Lockhart Ranch

This site is located directly southwest of the Harper Dry Lake area in T11N, R5W, Section 25 and T11, R4W, Section 30 of San Bernardino County. The elevation is between 2,045 and 2,133 feet with slope facing northeast. The Bureau of Land Management (BLM) has designated two Areas of Critical Environmental Concern around Harper Lake.

Slopes are all less than 2% with a simple or smooth surface configuration. Section 25 is primarily undissected alluvial fan of Quaternary age, as is Section 30, although Section 30 has been disturbed for the most part. Section 25 also has a Holocene (active) wash running SW to NE across its NW quarter.

Land use varies from vacant undeveloped to rural residential (2 1/2 acre lots or separation) to irrigated field crops. Vegetation on the undisturbed alluvial fan is a shrub overstory in the 5 to 14% density class with a herb understory of less than 4% density. There is a prominent fault half a mile southwest of Section 25.

Site No. 9 Camino

This site is located in the Ward Valley, southwest of the Sacramento Mountains, in T8N, R20E, Sections 19, 20, and 21 of San Bernardino County. Elevation is between 1,850 and 1,950 feet. Sections 19 and

20 are around the confluence of two washes and vary in slope aspect from SE to SW; Section 21 faces SW. The peak of Sacramento Mountain (3,314 feet) is approximately 5 miles in a NNE direction from the site.

Except for the wash in Sections 19 and 20, the area is strongly or moderately dissected alluvial fan in the 0-2% slope on an undulating surface of Quaternary alluvium. Primary vegetation is short tree overstory of less than 4% density, with a shrub understory of 5 to 14% density. A. dumosa - L. tridentata with Y. schidigera and Ephedra Sp. - H. Salsola is the main species present.

Site No. 10 Midland

This site is located SW of the Big Maria Mountains and at the SE top of the Little Maria Mountains in T4S, R21E of Sections 34, 35 and 36. Elevation is between 660 and 740 feet with a south facing slope.

Slopes are all less than 2% - the rise is about 100 feet per 2 miles except for Section 36 which is only slightly more steep and faces gently SW. The surface form is undulating for all three sections with much of the area classed as strongly dissected alluvial fan. There are also three washes, although the washes in Sections 34 and 35 are quite broad and fairly smooth surfaced. The alluvial fans are composed of Quaternary coarse-grained continental deposits that are moderately to well consolidated with moderate to high strength and stability.

VI-D. RANKING OF CANDIDATE SITES

The ten viable sites were ranked and weighted according to Table VI.D.1.

Table VI.D.1
Candidate Site Ranking Weights

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

A brief summation and rating of each criteria is presented as follows (ten rating is best):

1. Public Acceptance Rating

Public acceptance is, of course, highly subjective. Ratings were listed in Table VI.D.2 determined by consultations with city/county elected officials and rating the public acceptance of other industrial developments:

2. Environmental Impact

The study was based solely on available information which varied in level of detail from essentially complete to very limited, depending on the site and the discipline

Table VI.D.2
Public Acceptance Ratings

Site	Rating
Lucerne Valley	9
Cool Water	9
Alvord Well	6
Vidal Valley	4
N. Lucerne Valley	4
Ord Mountain	5
Lockhart Ranch	8
Camino	3
Midland	7
Tenmile Well	4

(biological resources, cultural resources, land use/visual and socioeconomics) in question. In general, good documentation is available for the Lucerne and Cool Water sites; good, but somewhat dated, general overview information is available for the Tenmile Well, Alvord Well, North Lucerne Valley, Vidal Valley, and Harper Lake sites; with little information available for the Midland-Big Marias site.

To determine the overall rank of each site, the sums of the rankings for each discipline were totaled. Where two or more sites had the same sum, they were ranked the same. These ratings summarized in Table VI.D.3.

Table VI.D.3
Environmental Impact Ratings

	Site	Biology	Ranking Cultural	Land Use/ Visual	Sum of Ranks	Overall Rank
1.	Lockhart Ranch	5	3	4	12	1
2.	Ord Mountain	7	2	3	12	1
3.	North Lucerne Valley	7	1	4	12	1
4.	Cool Water	1	7	5	13	2
5.	Alvord Well	3	5	6	14	3
6.	Lucerne Valley	9	4	1	14	3
7.	Vidal Valley	1	8	8	17	4
8.	Tenmile Well	10	6	2	18	5
9.	Camino	4	9	7	20	6
10.	Midland-Big Marias	6	10	6	22	7

3. Economics

Based on information developed in Reference VI.F.1, a differential capital cost was prepared for each site. From the total capital differential costs, the values were fist escalated to 1988 costs, then were levelized for 30 years, and finally were computed to 1988 present worth values. The present worth (P.W.) costs for the year 1981 were computed by deescalating the 1988 P.W. values, and are shown in the last column to the right of the table. The following Table VI.D.4 is a summary of the economic evaluation for all the candidate sites. The differential costs for each site were computed based on the assumption that Lucerne Valley was the 'Base Case' site. They are presented in the last column to the right in the table.

Table VI.D.4
Economics Ratings

($ MILLIONS)

SITE	CAPITAL	O & M	TOTAL	DIFFERENTIAL
Lucerne Valley	3,960	54,164	58,124	BASE
Cool Water	5,931	61,000	66,931	8,807
Alvord Well	11,397	65,900	77,297	19,173
Vidal Valley	9,417	0	9,417	(48,707)
Tenmile Well	21,040	1,414	22,454	(35,579)
North Lucerne Valley	8,332	31,127	39,459	(18,665)
Ord Mountain	3,793	45,764	49,557	(8,567)
Lockhart Ranch	5,415	45,764	51,179	(6,945)
Camino	19,439	1,414	20,853	(37,271)
Midland or Big Marias	20,145	708	20,853	(37,271)

4. Meteorological Factors

Meterological factors that were considered for qualitative evaluaton of the candidate sites include wind speed, weather severity, dust conditions, air quality and topographic obstructions. Wind speed defines the average velocities of the prevailing wind through the proximity of the site. Weather severity identifies the frequency of storms in the site vicinity. Dust conditions assess the significance of fugitive dust problems. Air quality evaluates the general ambient air conditions at each candidate site relevant to the presence of various airborne pollutants such as oxidants, NO_2, SO_2, CO_2, etc. Topographic obstruction identifies the proximity of the site to high mountains. In general, results of this ranking process reflect that all sites are meteorologically acceptable for solar thermal development.

TABLE VI.D.5
METEORLOGICAL FACTORS USED IN
RANKING CANDIDATE 100 MW SOLAR THERMAL SITES

Site	Wind Speed	Weather Severity	Dust Cond.	Air Quality	Prox. to Mtn.	Overall Ranking
Camino	3	1	3	3	3	2.6
Lockhart Ranch	3	3	1	2	2	2.2
Tenmile Well	2	1	2	3	3	2.1
Ord Mountain	2	3	1	2	2	2.0
North Lucerne	2	1	3	2	2	2.0
Lucerne Valley	2	1	3	2	2	2.0
Midland	3	2	1	3	1	1.9
Alvord Mountain	2	1	2	2	3	1.9
Cool Water	2	1	2	2	2	1.8

5. Seismicity

The following Table VI.D.6 is a brief description of the potential seismic risks of each candidate site. In general, the location of fault zones for each site, as well as the maximum credible acceleration, is identified or defined. Faults are classified as either active or potentially active. Active faults are those along which historic (last 200 years) displacement has occurred and are associated with either surface rupture from recorded earthquake, fault creep slippage or displaced survey lines. Potentially active faults are those along which there is quaternary fault displacement (during the past two million years), without historic (approximately 200 years) record.

6. Road Access

All the sites, with the exception of Cool Water Generating Station and Lockhart Ranch sites, require the construction of paved roads to the sites. None of the sites, however, require grading other than compaction. The following Table VI.D.7 is a summary of the length of access road required to be constructed to each of the candidate sites.

7. Land Acquisition/Cost

Land ownership and real estate costs are presented as follows. Four of the sites that are privately owned include: Lucerne Valley, Cool Water, Harper Lake and Ord Mountains. Of these, only Lucerne Valley and Cool Water sites are SCE owned properties. North Lucerne Valley site is primarily owned by the State of California. The remaining five sites, Alvord Well, Camino, Midland, Tenmile Well and Vidal Valley sites, are on federal land, administered primarily by the Bureau of Land Management.

Land values at each candidate site are estimated by the Edison Department of Right of Way and Land. Land costs are tabulated in Table VI.D.8 were made without benefit of detailed information that an appraiser is normally required to make. For this reason, the land values have an assumed accuracy of ±50%.

8. Summary of Site Ranking

To rank the overall desirabilitgy of each candidate site, a Site Evaluation Matrix was developed. Although numerous parameters were considered for this parametric evaluation, only six were selected for ranking purposes. They are public acceptance, economics, environmental impact, seismicity, road accessibility and meteorology. In this matrix development, the ratings for each parameter were provided by an assigned Siting Evaluation Task Work Force member.

Since each parameter was ranked by an individual Task Force, the rating system had to be normalized to reflect the desired weighting of each parameter. To do this, it was decided that 10 be considered the most favorable situation and 1 the least desirable. For economics, the actual differential costs were adjusted to a rating scale of 1 to 10 where 10 was assigned to the least cost site (in this case the highest negative differential cost from the "base cost" site of Lucerne Valley) and 1 to the highest positive differential cost site. A rating scale was then developed for each parameter of each candidate site with values between 1 and 10.

TABLE VI.D.6
SOLAR SITE DATA AND SEISMIC RATING

SITE	DISTANCE FROM SITE-FAULT/S	EARTHQUAKE MAGNITUDE AND PROBABLE ACCELERATION	RANKING
Tenmile Well	120 miles NE of San Andreas Fault, 70 miles NE of Ludlow Fault	M8+, 0.01g M5.0	1
Vidal Valley	77 miles NE of San Andreas Fault	M8+, 0.04g	2
Camino	59 miles NE of San Andreas Fault, 77 miles NE of Imperial Fault	M8+, .05g M6.5, 0.3g	3
Midland or Big Marias	59 miles NE of San Andreas Fault, 69 miles NE of Imperial Fault	M8+, .05 M6.5, .04g	4
Cool Water	14.3 miles SW of Manix Fault	M6.2, .12g	5
Harper Lake	.55 miles SW of Lockhart Fault, 44 miles NE of San Andreas Fault	M5.0, .2g M8+, .09g	6
Lucerne Valley	NE corner of site underlain by Camp Rock-Emerson Fault, 33 miles NE of San Andreas Fault	M5.0, .21g M8+, .12g	7
Ord Mountain	6.6 miles NE of Helendale Fault 30 miles NE of San Andreas Fault	M6.0, .21g .14g	8
North Lucerne Valley	5 miles NE Helendale Fault	M6.0, .26g	9
Alvord Well	2.75 miles north of Manix Fault	M6.2, .44g	10

Table VI.D.7
Ease of Access

Candidate Site	Road Required	Ranking of Site
Lucerne Valley	2 miles	3
Cool Water	none	10
Alvord Well	1 mile	6
Vidal Valley	0.5 mile	8
Tenmile Well	1,000 feet	9
North Lucerne Valley	0.5 mile	8
Ord Mountain, South	1 mile	6
Lockhart Ranch	none	10
Camino	1,000 feet	9
Midland	1,000 feet	9

Table VI.D.8
LAND VALUES OF CANDIDATE SITES
(1981 dollars)

Site	Vicinity ($/acre)	Total Site Value (minimum of 2 sections)	Site Ranking
Lucerne Valley	200	$256,000	10
Cool Water	200	256,000	10
Alvord Well	175	224,000	7
Vidal Valley	100	128,000	9
Tenmile Well	400	512,000	2
North Lucerne Valley	225	288,000	6
Ord Mountain, South	350	448,000	3
Lockhart Ranch	175	224,000	7
Camino	100	128,000	9
Midland	100	128,000	9

V-E. RECOMMENDED SITE

The siting study was performed independently of the Solar 100 Feasibility Study and yielded the following overall results.

TABLE VI.E.1
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

The Edison Company is presently in the process of licensing a 1290 MW peaker park at Lucerne Valley (see Chapter VII) and decided to file an application with the California Energy Commission to include the Solar 100 project.

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.

VII-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 5500 et. seq.). Jurisdiction of the CEC is limited to licensing only those thermal power plants rated at 50 or more megawatts (MW). New transmission lines from the generating station up to the first point of interconnection with the existing system also fall under CEC authority.

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. Through a series of public hearings and CEC staff analysis, one or more sites and technologies may be given approval for further study. The AFC is the vehicle for further study.

There are, however, several exceptions to this general licensing process. Specifically, Section 25541 of the Warren-Alquist Act 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 CEC is required to issue its final decision within 12 months of the filing date. As a 100 MW (net) solar thermal power plant, Solar II can qualify for this exemption.

Another possible approach for an NOI exemption is found in Section 25540.6(e). This section pertains to thermal power plants designed to develop or demonstrate technologies that have not previously been built or operated on a commercial scale. A 300 MW limit is placed upon projects seeking this exemption unless the Commission, by regulation, authorizes a greater capacity. Again only an AFC is required and the Commission shall issue a final decision within 12 months of the filing date.

A typical 12-month hearing schedule is presented below:

Event	Days from Filing
File Application	0
Commence Staff Meetings	30
Commence Pre-hearing Conference	60
Commence Hearings	90
Conclude Hearings	150
Publish Committee Report	210
End Comment Period	270
Publish Proposed Decision	300
Hold Final Hearings	330-345
Issue Decision	360

Under the normal process, alternative sites and technologies are discussed in the NOI. In order to remain in compliance with the California Environmental Quality Act (CEQA), (Cal. Pub. Res. Code Sections 21000 et. seq.) the applicant must discuss the "availability and feasibility of alternative sites and related facilities which could satisfy the purposes of the applicant's proposal and which may substantially lessen any significant environmental impact anticipated for the proposal." While the statutes and the regulations are silent with regard to the number of sites that are required to be analyzed, generally three sites are discussed in the AFC. The data submitted for the alternate sites can be in less detail than that submitted for the proposed site.

Pursuit to California law, Edison filed for a Solar 100 site at the Lucerne Valley site (see Section VI) in November, 1981. Final approval is expected in 12 months (November, 1982).

VII-B. CALIFORNIA PUBLIC UTILITIES COMMISSION

In addition to certification by the CEC, Edison is required to obtain a Certificate of Public Convenience and Necessity from the California Public Utilities Commission. The CPUC application has to be filed shortly after filing with the CEC. It will not be necessary to file a Proponent's Environmental Assessment and the AFC can be referenced in the CPUC application. CPUC authority is limited to rate and system reliability issues. If the Solar plant is owned by a nonutility entity, CPUC filing is not required.

VII-C. FEDERAL AUTHORITY

Generation and transmission facilities that are to be sited on federal lands will require a permit from the appropriate landholding agency.

VII-D. LOCAL AGENCY CERTIFICATION

Section 25541 of the Warren-Alquist Act provides for exemption from the Commission NOI-AFC process. This section allows the Commission to exempt power plants with a capacity of up to 100 MW from the NOI-AFC process. In order to receive an exemption, the Company must file an Application for Exemption. There are no fees associated with this filing. The Commission is required to convene public hearings and issue a final decision no later than 135 days after the application is filed. For a project to be granted an exemption, the Commission must make the following two findings:

1) No substantial adverse impact on the environment or energy resources will result from the construction or operation of the proposed project and;

2) The proposed project will not add generating capacity that is substantially in excess of the CEC forecast adopted in the Biennial Report.

   If Edison were to seek and was granted an exemption from the Commission proceedings, necessary permits would have to be acquired from various federal, state and local governmental agencies.

VIII. COST/ECONOMICS/FINANCIAL

VIII-A. CAPITAL COST ESTIMATE

The Capital Cost Estimate is shown on Table VIII.A.1. Major construction quantities are shown on Table VIII.A.2. The estimate is based on a joint effort by the three participating companies: Southern California Edison Company (SCE), McDonnel Douglas Corporation (MDC) and Bechtel Power Corporation (BPC). Each company contributed estimated costs as follows:

Description	Responsibility
Solar Plant	
Collector Fields	MDC
Towers and Foundations	BPC
Receivers	MDC
Plant Control	MDC
Thermal Storage and Transport	BPC
Steam Generator	MDC
Turbine Generator Plant	BPC
Switchyard and Transmission Line	SCE

The estimate includes all additives (i.e.: 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.

1. Bases

The estimate is based on the following:

- The conceptual design conforms to that described in Section IV, Description of Selected Plant, and other sections of this report.
- All costs are in December 1981 dollars.
- The .engineering, procurement, construction and startup schedule will conform to the milestones shown in Section X, Schedule.
- SCE owns 100% of the plant.
- Seismic Design is 0.20 g factor.
- The heliostat hardware cost (\$120 x 10^6 for approximately 15,000 heliostats) is based on the production of 75,000 heliostats over a period of ten years.

TABLE VIII.A.1
CONCEPTUAL COST ESTIMATE SUMMARY BY SYSTEM
SOLAR 100 MW THERMAL PLANT

(Molten Salt)

System Description		Cost in Dec. 1981 \$ ($\$ \times 10^6$)	
Collector Field		163.6*	
Tower and Foundation		13.1	
Receiver		29.8*	
Thermal Storage		52.5	
Steam Generator		9.2**	
Plant Master Control		12.1**	
Turbine - Generator		14.2	
Balance of Plant		35.7	
	Subtotal		330.2
Switchyard		2.5	
Transmission Line		1.1	
Land		-	
Fuel Inventory		-	
	Subtotal		3.6
	Total Field Cost		333.8
Special Maintenance Equipment		.2	
Spare Parts		.6	
Sales Tax		12.7	
	Subtotal		13.5
Engineerng and Home Office:			
MDC		12.2	
BPC		13.0	
SCE		3.8	
	Subtotal		29.0
Additional Contingency			54.5
Escalation			-
	Total - Word 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 of the cost shown is MDC scope which includes their Assessment of Continency.
** All of the cost shown in MDC scope which includes their Assessment of Contingency.

TABLE VIII.A.2
MAJOR QUANTITY DATA
(EXCLUDING COLLECTOR FIELD ELECTRICAL BULKS)

Description	Quantity	Unit	
Concrete	40,000	CY	
Metallic Conduit	74,000	LF	
Non Metallic Conduit	60,000	LF	
Cable Trays	14,500	LF	
Wire & Cable	1,820,000	LF	
Grounding System	80,000	LF	
Process Pipe			
2-1/2" & Less	12,930	LF	
2" & More	12,250	LF	
Salt Syst. Pipe			
2-1/2" & Less	19,050	LF	
2" & More	650	LF	
Piping Total	44,880	LF	
Instrument Pipe & Tubing	34,100	LF	
Salt System			
Initial Charge	56×10^6	LBS	
Site Improvement (Imported Fill)	200,000	CY	
Fence	6	MILES	
Roads			
Minor	5	MILES	
Major	2	MILES	
Evap. Pond w/Clay Lining	216,700	SY	
Heliostat Assemblies	15,240 ?	EA	2 fields
Concrete Towers (585')	2 ?	EA	

- The heliostat hardware cost (\$120 x 10^6 for approximately 15,000 heliostats) is based on the production of 75,000 heliostats over a period of ten years.

2. Exclusions

Costs for the following items are not included in the estimate:

- Offsite facilities such as telephone, water, temporary power and access roads

- Drainage Facilities

- Guard Service

- Shiftwork or Scheduled Overtime

- Scope Changes

- Changes in Existing Regulatory Requirements

- Special Provisions for Accident Protection

- Operator Training

- Land Costs

- Escalation (December 1981 $)

3. Industry Participation

Technical, scheduling and pricing information, furnished by cooperating manufacturers and contractors, was used extensively in the estimate, resulting in an industry wide effort. The participating companies were:

Turbine Generator, Condensate and Feedwater Trains

Toshiba
Mitsubishi Heavy Industries, Ltd.
Sumitomo Corporation of America
Marley Cooling Tower Company
Research-Cottrell, Inc.

Thermal Transport & Storage Systems

- Storage Tanks
  Pittsburgh-Des Moines Corporation
  GATX Tank Erection Corporation

- Piping
  Pipe Fabricating & Supply Company
  Associated Piping & Engineering Company

- Valves
  Kieley Mueller
  Valtec
  Hammeldahl

- Pumps
  Bingham—Willamette Company
  Bryon Jackson
  Lawrence Pumps Inc.

- Heat Tracing
  - Montgomery Brothers
  - Foley Electrical Contractors
  - Nelson Electric
  - George Yardley Company (Thermon)

- Insulation
  - Owens Corning Fiberglass
  - Thorpe Insulation

- Salt Inventory
  - Olin Corporation

<u>Heliostats</u>

- Heliostat Design and Component Pricing

  - McDonnell Douglas Corp.

- Heliostat Assembly
  - Modern Alloys Inc.

- Heliostat Foundations
  - Modern Alloys Inc.
  - Longyear Company
  - Case International
  - D. H. Mahaffy Inc.

- Heliostat Wiring
  - Taft Electric

<u>Receiver Systems</u>

- Receivers
  - McDonnell Douglas Corp./Foster Wheeler

- Receiver Support Structure and Bridge Crane, Erection Only
  - Marks Crane and Rigging Company
  - National Steel Erectors Corporation

- Receiver Towers
  - Rust Chimney Incorporated
  - Pullman Power Products
  - Custodis Construction Company

- Receiver Tower Elevators
  - Linden-Alimak, Inc.

<u>Steam Generator System</u>

McDonnell Douglas Corp./Foster Wheeler

<u>Water Treatment Demineralizer System</u>

F&F Industries (Belco Pollution Control Corp.)

Turbine Gantry Crane

Harnishfeger Inc.
Ederer Inc.

Miscellaneous Tanks

Richmond Engineering Corp.

Component Cooling Water Heat Exchanger

South Western Engineering

4. Conceptual Cost Estimate Summary

Table VIII.A.1 itemizes the conceptual cost estimate by system within an accuracy of ± 40%; cost analysis also indicates that the probability of exceeding the total cost estimate is 50%. This 50% confidence factor was derived by Edison's "Contingency and Range Analysis" computer code. Specific sensitivities to component/system costs is presented in Section VIII-C.

This estimate includes all costs to be incurred in the engineering, design, procurement, construction, testing and initial operation of the generation facilities and solar field. The estimate was prepared by a combined effort of McDonnell Douglas (MDC), Bechtel Power Corporation (BPC), and Southern California Edison (SCE).

BPC prepared a conceptual design and cost estimate of the towers, molten salt transport, storage and support systems, turbine plant and associated equipment, and balance of plant facilities. BPC prepared their estimate assuming they would be awarded an Engineering, Procurement and Construction (EPC) type of contract. MDC prepared a conceptual design and cost estimate of the collector field, plant master control, steam generator and receiver. Foster-Wheeler assisted MDC in the latter two items. These costs were supplied to BPC to arrive at an overall field cost. SCE prepared a conceptual design and cost estimate of the switchyard and transmission line.

The SCE Generation Estimating Group consolidated all the inputs and added SCE Home Office Cost, Construction Overhead Cost, Contingency and Cost of Capital.

5. Cash Flow

A cash flow was prepared utilizing the construction schedule mentioned above. Both BPC and MDC prepared their own cash flow for their respective area of responsibilities. SCE consolidated these cash flows into an overall project cash flow as shown in Table VIII.A.3. and shown graphically in Figure VIII.A.1.

VIII-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 determined and discussed in three categories: material, labor, and water. The estimates are given on Table VIII.B.1

TABLE VIII.A.3
CASH FLOW

Year		%	Capital Cost* ($ x 10^6) W/O AFUDC or COC	W/ AFUDC		W/ COC		
1982	4.20	0.5	2.3	2.7	~~2.9~~	2.9	× 1.07	3.10
1983	3.62	2.6	11.7	14.0	15.73	15.1	× 1.03	16.64
1984	5.0	18.4	82.8	99.4	115.21	106.7	× 1.06	124.65
1985	7.0	46.6	209.7	251.6	306.44	270.3	× 1.1	347.35
1986	10.0	28.9	130.0	156.1	203.21	167.6	× 1.1	236.91
1987		3.0	13.5	16.2	23.22	17.4	× 1.1	27.06
Total		100.0	$450.0	$540.0	666.81 Δ = 86.81	$580.0		755.71 Δ = 175.71 escalation

*All Capital Costs are in December 1981 $.

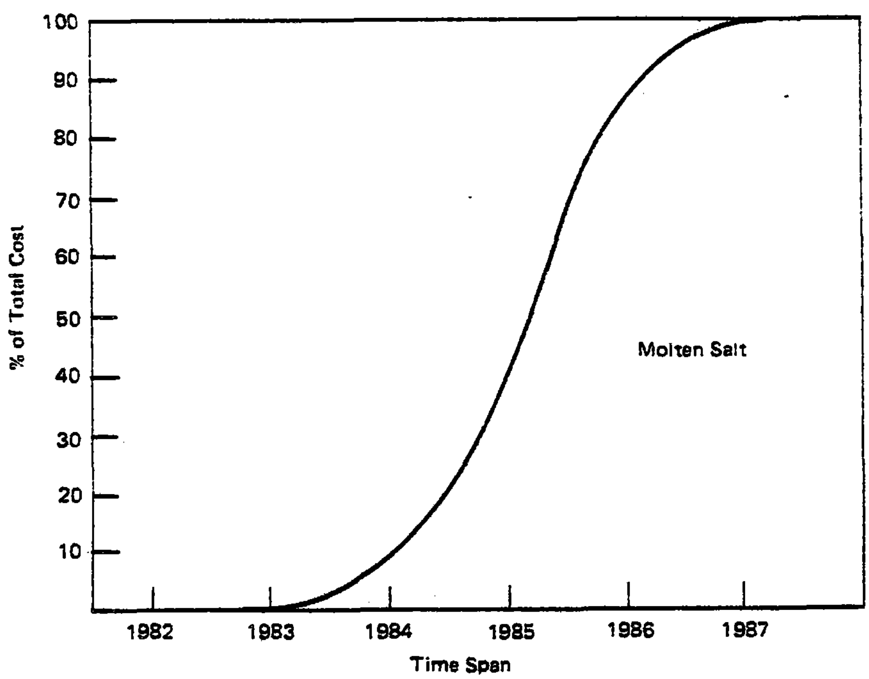


Figure VIII.A.1. Cash Flow Molten Salt

TABLE VIII.B.1
O&M SUMMARY
AVERAGE YEAR ($ IN 1000'S)

Materials	Spares	Repair Parts	Service Contracts	Consumables	Total
Collector Field	87.	296.	370	-	$ 753
Tower	1.	-	-	-	1
Receiver	11.1	-	-	-	11
Ther Strg & Transpt	26.	-	-	-	26
Steam Generator	1.	-	-	-	1
Turbine & Bal of Plant	360.	-	-	188.	548
Plant Control	-	-	202	-	202
					$1542
Labor	**Manning**				
Supervisors	4				160
Operators	27				1138
Maintenance	26				1035
Security	10				277
					$2610
Water (Solar) for other water expenses, see text				1393	1393
					$5545

First Year $ (1000's):		
	Materials:	$3309
	Labor:	$3047
		$6355

1. Material

Material includes spares, repair parts, consumables, and service contracts (which include their own labor material and consumables).

Total quantity of spares and repair parts for hardware in the collector, receiver, and steam generator systems is based on reliability/availability estimates reported in Section V-C. Spares and repair parts costs are derived from annual failures, discard factors, and repair parts factors, (as discussed in Section V-C), and unit costs.

Spares costs for the other systems are estimated as a percentage of the investment costs for those particular systems.

Consumables costs are estimated from related experience.

Service contracts are assumed for the plant control system and the collector field washing task.

Plant process control O&M is covered by a contract of $2,000 per month based on comparability to Solar I equipment. Additional contracts cover service of the computers and related equipment at an industry standard rate of 1% per month of the computer equipment investment cost.

Collector field washing costs are based on MDC experience and studies assuming washing frequency of 12 times per year. Consumables and wash truck amortization and expense are included in the estimate.

2. Labor

Labor includes scheduled and corrective maintenance and is based on crew sizes estimated by SCE and MDC.

Failure rates and repair times have also been determined (See Section V.C). These are adjusted for efficiency and rework factors to build up a crew size. Supervisory personnel are also identified. Labor rates and burdens are applied to determine O&M cost.

3. Water

The water expenses itemized below are incurred if the 100 MW_e facility is constructed in the Lucerne Valley, approximately 30 miles southeast of Barstow, California. The January 1982 costs are as follows:

		Potential Total Cost	Prorated Share
1.	Metropolitan Water Agency One-time surcharge	$12.0M	$1.114M
2.	Municipal Bond to cover the cost of the water line	$ 8.0M	$ .743M/yr
3.	O&M to service the line	$ 1.0M	$ .093M/yr
4.	Annual water expense	-	$1.3M/yr

The 42-inch diameter line is 40 miles long and will take three years to build. An entitlement has been negotiated with the Metropolitan Water Agency for 50,800 acre feet of water. The one-time surcharge is based upon a contract for 28,000 acre feet per year, however. Solar 100's prorated share is based upon SCE's projected water usage of 2,600 acre feet ratioed against the 28,000 acre feet (2,600 ÷ 28,000 = .0929, or 9.29%).

The Municipal Bond is for a total capital cost of approximately $35M at 15% interest for 30 years. Solar 100's prorated share is calculated at 9.29% of the yearly total payment and remains constant after having been escalated to the midpoint of the three-year water-line construction period.

The Operations and Maintenance costs to service Solar 100's share of the line is 9.29% and escalates each year.

Annual water expense is based upon a rate of \$1.0M per 2,000 acre feet. This value also escalates each year, just as the annual O&M cost to service the line. These two items are the only ones which escalate, as the municipal bond payment remains constant after the midpoint of the construction period.

The O&M costs provided do not include ad valorem tax, A, G, and I (Administrative, General, and Insurance) costs, or the cost of the electrical power required to run the plant. The plant electrical power is provided by the difference between net power supplied to the grid and gross turbine output, except during certain winter off-peak hours when such requirements must be met by the grid. These costs appear as a decrease in the revenue stream provided for the financial analysis of the plant by an amount equivalent to the avoided cost for the required power.

Ad valorem tax is 1% of capital investment and escalates at 2% per year. A, G, and I is estimated at 1.1% of capital investment (1% other, .1% insurance from the levelized Fixed Charge Rate) and escalates at 9% per year. These allocations must be added to the total O&M costs shown in Table VIII.B.1 in order to arrive at a total annual cost.

VIII-C. COST SENSITIVITY ANALYSIS (CAPITAL, PERFORMANCE AND O&M)

The sensitivity of solar generated electric energy cost to changes in selected design, performance and investment variables has been assessed in relation to capital cost uncertainty, plant location (insolation), equipment performance expectations, unit size, capacity factor, O&M cost fluctuation, and fixed charge rate projection. Upper and lower bounds were chosen for each variable for graphic illustration. Where possible, expected limits were defined to identify reasonable cost risk range associated with each variable. Table VIII.C.1 illustrates the cost sensitivity (shown as a multiplier on levelized busbar energy cost) chosen for each variable. Overall evaluation of the range of extremes considered for the total group of variables shows the change in electric energy cost to fall within a range of minus 28% to plus 20%. The following paragraphs provide a discussion and explanation for each specific sensitivity variable shown on the figure.

1. Capital Cost Uncertainty

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.

a. Collector Field - The collector field includes all delivered collector hardware, site preparation, foundations, installation, field wiring, and collector alignment and checkout. The overall bounds shown for the collector field represent an arbitrarily chosen ±25% variation from the baseline estimate of \$170 million. This extreme variation in collector field cost results in a ±11% change in energy cost per kWh. Within the range shown to illustrate sensitivity, the cost risk associated with the collector field is expected to fall within the range of minus 7% to plus 12%. Possible future variations in the delivered collector hardware pricing policy account for 50% of the 7% downside uncertainty and 60% of the 12% upside

TABLE VIII.C.1
SYSTEM SENSITIVITIES SUMMARY

Parameter	Intrinsic Risk Level	Estimated Risk Range	System Cost Sensitivity
Capital Cost			
Collector Field	Moderate	- 7% to + 12%	- 3% to + 5%
Balance of Solar Plant	High	-15% to + 20%	- 5% to +6 1/2%
Conventional Thermal Plant	Low	- 5% to + 5%	- 1% to + 1 %
Insolation (Plant Location)	Moderate	8.0 to 7.0	- 3% to + 4%
Performance			
Collection Efficiency	Moderate	.746 to .686	- 2% to 2 1/2%
Generation Efficiency	Low	None	None
Unit Size Variation	N/A	None	None
Capacity Factor	N/A	None	None
O&M Cost	Moderate	2% to 2 1/2%	- 0% to + 4.6%
Fixed Charge Rate	High	.20 to .25	- 20% to + 0%

uncertainty. The extent of bedrock outcroppings at the proposed plant location, which could affect site preparation and foundations cost, accounts for 50% of the downside uncertainty and 40% of the upside uncertainty. The indicated risk range limits of 93% and 112% of baseline cost equate to changes of approximately minus 3% and plus 5% in cost per kWh.

b. Balance of Solar Plant - The balance of solar plant includes tower, receiver, thermal storage and transport, steam generator, and plant control. The overall bounds shown for balance of solar plant again represent an arbitrary ± 25% variation from the baseline estimate of $127 million. This variation in balance of solar plant cost results in a ± 8% change in energy cost per kWh. Within the range shown to illustrate sensitivity, the cost risk associated with the balance of solar plant is expected to fall within the range of minus 15% to plus 20%. Relatively less maturity of design associated with the receiver, tower, and thermal storage and transport causes these items to be the major contributors to cost uncertainty within the balance of solar plant. The estimated thermal storage and transport cost risk variations account for 57% of the 15% downside uncertainty and 59% of the 20% upside uncertainty. The estimated receiver and tower cost risk variations together account for 34% of the downside uncertainty and 33% of the upside uncertainty. The indicated risk range limits of 85% and 120% of baseline cost equate to changes of approximately minus 5% and plus 6-1/2% in cost per kWh.

c. 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 bounds shown for conventional thermal plant represent an arbitrary ± 25% variation from the baseline estimate of $62 million. This variation in conventional thermal plant cost results in a ± 4% change in energy cost per kWh. Since these systems are conventional and well understood, the cost risk is expected to fall within the range of minus 5% to plus 5%. These values equate to changes of approximately minus 1% and plus 1% in cost per kWh.

2. Plant Location (Insolation)

The sensitivity of electric energy cost to variation in insolation associated with possible plant location changes has been assessed over a range of 6.5 to 8.0 $kWh/m^2/day$ (baseline = 7.5) with annual energy output held constant. This represents an extreme range of insolation values for any solar sites. This scenario requires resizing of the collector field and tower (inversely to insolation change), with the design of the remaining portion of the total plant unchanged from the baseline design. Baseline collector field and tower costs were scaled in relation to the range of insolation variation with all remaining total plant costs held constant at baseline values. This results in changes in energy cost per kWh ranging from an 8% increase at 6.5 $kWh/m^2/day$ to a 3% reduction at 8.0 $kWh/m^2/day$. Within the range shown to illustrate sensitivity, the cost risk associated with insolation variation is expected to fall within the range of 7.0 to 8.0 $kWh/m^2/day$ for possible alternate sites. These values equate to changes of approximately plus 4% and minus 3% in cost per kWh.

3. Equipment Performance

The impact of equipment performance uncertainty has been assessed for two primary functions in terms of efficiency.

a. Collection Efficiency - The sensitivity of electric energy cost to potential variations in collection efficiency has been assessed over an efficiency range of .65 to .75 at the design point (baseline approximately .72), with annual energy output held constant. This performance variation requires resizing of the collector field and tower (inversely to collection efficiency change) with the design of the remaining portions of the total plant unchanged from the baseline design. Baseline collector field and tower costs were scaled in relation to the range of collection efficiency variation with all remaining elements of total plant cost held constant at baseline values. This results in changes in energy cost per kWh ranging from a 5-1/2% increase at .65 efficiency to a 2-1/2% reduction at .75 efficiency. The individual, constituent efficiencies are accurately known. However, the cumulative effect of minor variations in the seven efficiencies making up the collection efficiency leads to a an estimated risk range of ± 3%. This range in collection efficiency equates to changes in cost per kWh ranging from a 2-1/2% increase at .686 efficiency to a 2% reduction at .746 efficiency.

b. Generation Efficiency - The sensitivity of electric energy cost to expected turbine generator efficiency has been assessed in relation to variations in equivalent heat rate over a range of 7584 to 8533 Btu/kWh (baseline - 7974), corresponding to an efficiency range from 0.45 to 0.40, with annual energy output held constant. This performance variation requires resizing of the collector field, tower, receiver, thermal storage, and steam generator (inversely with turbine generator efficiency or directly with equivalent heat rate change), with the design of the turbine generator, plant control, and balance of plant remaining unchanged from the baseline design. Baseline costs for the collector field, tower, receiver, thermal storage, and steam generator were scaled in relation to the range of heat rate variation with the remaining elements of total plant cost held constant at baseline values. This results in changes in energy cost per kWh ranging from a 5% increase at 8533 Btu/kWh to a 3-1/2% decrease at 7584 Btu/kWh. Since turbine generator efficiency is accurately known, no risk range was considered.

4. Unit Size Variation

The sensitivity of electric energy cost to potential variations in unit size has been assessed over a range of 95 to 170 MW_e gross power rating (baseline = 110), with annual energy output held constant. This scenario requires resizing of the steam generator, turbine generator and balance of plant (scaled in proportion to power rating changes), and portions of thermal storage (downsized), with the design of the remaining portions of the total plant unchanged from the baseline design. Baseline steam generator, turbine generator and balance of plant, and applicable thermal storage costs were scaled in relation to the range of power rating variation with all remaining elements of total plant cost held constant at baseline values. This results in changes in energy cost per kWh ranging from a 2-1/2% increase at 170 MWe to a decrease at 95 MWe of less than 1%.

5. Capacity Factor

The sensitivity of electric energy cost to variations in specified plant capacity factor has been assessed over a capacity factor range of 0.4 to 0.7 (baseline = 0.6), with annual energy output varying in proportion to changes in capacity factor. This scenario requires resizing of the collector field, tower, receiver, and thermal storage (scaled in proportion to capacity factor changes), with the design of the remaining portions of the total plant remaining unchanged from the baseline design. Baseline costs for the collector field, tower, receiver, and thermal storage were scaled in relation to the range of capacity factor variation with the remaining elements of total plant cost held constant at baseline values. The resulting capital costs for each selected capacity factor were ratioed inversely by the capacity factor to establish the relationship of busbar energy cost to capacity factor. This relationship, when normalized to the baseline capacity factor of 0.6, shows variation in energy cost per kWh ranging from a 15% increase at 0.4 capacity factor to 4% reduction at 0.7 capacity factor.

6. O&M Cost as a Percent of Captial

The sensitivity of electric energy cost to variations in operations and maintenance (O&M) cost has been assessed in terms of percent of capital cost over a range of 1.5% to 3% (baseline = 2%), with the fixed charge rate, capital cost and annual energy output held constant. This variation in O&M cost results in changes in energy cost per kWh ranging from a 9-1/2% increase at 3% O&M to a 5% reduction at 1.5% O&M. Within the range shown to illustrate sensitivity, the cost risk associated with O&M cost variation is expected to be all on the high side of the baseline due to lack of detailed thermal transport equipment maintenance plans, and should fall within the range of 2% to 2.5% of capital cost. This risk variation over the baseline equates to an increase of 4.6% in cost per kWh.

7. Fixed Charge Rate

The sensitivity of electric energy cost to variations in the projected fixed charge rate has been assessed over a range of 18% to 30% (baseline = 25%), with capital cost, operations and maintenance cost, and annual energy output held constant. This variation in fixed charge rate results in potential changes in energy cost per kWh that are much more significant than all the other sensitivity variables considered, ranging from a 20% increase at .30 fixed charge rate to a 28% reduction at .18 fixed charge rate. Within the range shown to illustrate sensitivity, the cost risk is expected to fall within the range of 20% to 25%. This assumes no worsening of present economic conditions affecting fixed charge rate with all of the risk being for potential improvement on the downside. This assumption results in a possible reduction in cost per kWh of up to 20%.

A summary of the system sensitivities is presented on Table VIII.C.1. For each of the sensitivities, there is an indication of a subjective assessment of intrinsic risk level. Systems which are state-of-the-art and well known have a lower intrinsic risk on cost and performance than new technology systems. In addition, the relative state of design, verification testing, and production planning affects intrinsic risk.

The collector cost intrinsic risk level is moderate because of the extensive design, testing and production planning completed. The balance of solar plant is assessed as high, because of the relatively less mature state of the design. These assessments are relative, and should be interpreted as allowing for the possibility of both upside and downside risk being equally probable.

The conventional thermal plant has a low intrinsic risk because of its maturity.

The moderate risk on insolation reflects both uncertainty at the Lucerne Valley site and the possible selection of an alternate site. The moderate risk for collection efficiency arises primarily from atmospheric transmission and receiver convective loss uncertainties. Generation efficiency is accurately known. Unit size and capacity factor have no applicable intrinsic risk, as these are preselected. However, performance variations will reflect themselves in capacity factor, and possibly in net capacity.

The O&M cost risk is moderate, because detailed maintenance plans for the salt equipment have not been developed.

The fixed charge rate is a function of economic parameters beyond the control of the utility. The probability of change is high.

An overview of the cost sensitivity/cost risk analysis shows the fixed charge rate to outweigh all other variables in terms of degree of sensitivity and potential cost risk. As mentioned in the discussion of the system sensitivities summary table, most of the fixed charge rate components are determined by general economic conditions beyond the control of the utility. However, if a more definite economic trend becomes apparent during the project review cycle, any resulting change in fixed charge rate should be assessed to determine the impact on energy cost. Other variables with relatively significant cost sensitivities include collector field capital cost, balance of solar plant capital cost, and capacity factor. Safeguards involving system specifications and hardware design should be introduced early in the project planning activity to control the growth in these variables and incorporate changes resulting in lower energy cost wherever possible.

VIII-D. FINANCIAL ANALYSIS

The purpose of the economic and financial analyses which follow was to develop a preliminary assessment of the economic and financial feasibility of the Solar 100 project as described and defined in earlier sections of this report.

A 100 MW solar facility could reasonably be owned by a utility, a municipality, or with modification of existing federal regulations, an entrepreneur. To insure that the alternate scenario results would be based on comparable data, the common input values and assumptions, as detailed in Table VIII.D.1 were held constant between scenarios.

The mode of ownership would impact the means of financing and the availability of tax credits. Currently, if owned by a third party, a solar facility would be eligible for a 10% investment tax credit (ITC) and a 15% energy tax credit (ETC). A utility would only qualify for the ITC while a municipally owned facilty would not qualify for either credit, nor would it pay taxes in general. Financing would be more readily available to a utility or municipality than to an entreprenuer. The cost of financing would be least for a municipality and most costly to the entrepreneur.

Given the unique set of advantages and disadvantages, the overall assessment of the results based on the financial analyses of the three scenarios that a solar 100 plant owned by private investors which sells the output to SCE shows the most promise. However, it is important to note that under the present provisions of PURPA, a 100 MW solar plant owned by private investors would be subject to State and federal rate regulation.

1. Utility Ownership

A utility's objective function is to minimize the cost to the ratepayer subject to the constraints of reliability, capital availability, regulatory law and demand. The focus of a financial analysis from the utility perspective must therefore be on the total cost of a project to the ratepayer. The objective of the financial analysis of the 100 MW Solar facility was to access the reasonableness of the various potential modes of ownership, the total cost to the ratepayer under utility and third party ownership were compared. Additional utility specific assumptions are shown on Table VIII.D.2.

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. Because the project is relatively small and to the extent that the Commission allows full cost recovery, there would be no incremental financial risk per se.

TABLE VIII.D.1(a)
~~FINANCIAL ANALYSIS~~
COMMON ASSUMPTIONS

1. <u>General</u>

- Plant rated capacity - 100 MWe (100% electricity, no cogeneration)
- 30 year operational life
- Power availability: ~~must be tax-free~~ [365x24x100MWe x .56 = 489,990 MWe hr]
  - 489,990 MWh/Year net of scheduled and forced outage and auxiliary power requirements
  - Scheduled availability:

1986	12.5%
1987	62.5%
1988 on	100%

2. <u>Annual Escalation Rates</u>

• Capital Equipment	10%
• O&M and A&G	9%
• Energy Payments	

1982-1985	11.0%	
1986	10.0%	30yr avg = 9.34
1987-1990	9.6%	
1991 on	9.3%	
Property tax	2.0%	

3. <u>Revenues</u>

- Schedule - Avoided Cost Basis (11/81 basis)
- Energy Payments
  - Rates (November 1981 - January 1982 Dollars)

\$0.080/KWh	On-Peak
\$0.073/KWh	Mid-Peak
\$0.071/KWh	Off-Peak

TABLE VIII.D.1(b)
FINANCIAL ANALYSIS
COMMON ASSUMPTIONS

4. Costs

- Investment

	Dec. 81$
Base Investment (incl engr)	$363.6M
Sales Tax	12.7
Additional Contingencies	54.5
SCE Construction Overhead	17.5
Total Investment	$448.3M

≃ 1 field [illegible]

- O&M

Annual O&M (incl waterline)	
Average	$5.55M*
1st year add (one time)	.81M**
Municipal Bond Debt service	$.74M***
One time water surcharge	$1.11M
Insurance	2.5% of Principal
A&G	1.1% of Investment* esc. 9%/yr
Property tax	1.0% of Investment esc. 2%/yr

expensed

* Allocate relative to power availability.
** 1986 cost - $1.25M.
*** $.985 M/Year, starting in 1986.

5. Capitalization

- Assumptions

Element	Debt	Capitalized for TC	Deprec.	P.Tax	Expense	Levelized O&M
Capital	X	X	X	X		
Sales Tax	X	X	X	X		
IDC/Commit Fees	·	X	X			
Property Tax		X	X			
Construct/Liab. Ins.	X	X	X	X		
Engineer (1st 2 Yrs)	X	A	A		X	
SCE AG&I	X	X	X	X		
Water Main						X
O&M - Basic					X	
- AG&I					X	
Property Tax					X	

X = Prime Treatment
A = Alternative

- Funding

Type Cost	N/R Engineering		Capital Investment				
Year	82	83	84	85	86	87	Total
Percent	.5	2.6	18.4	46.6	28.9	3.0	100.0

TABLE VIII.D.2
~~FINANCIAL ANALYSIS~~
UTILITY ASSUMPTIONS

1. Cost of Capital

Component	Capital Ratio	Cost	Weight Cost
Long-Term Debt	45%	12%	5.4%
Preferred Stock	11	11	1.2
Common Stock	44	19	8.4
Total	100%	—	15.0%

2. AFUDC Rates

1982	9.20%
1983	9.75
1984	10.25
1985	10.50
1986	11.30
1987	11.60

avg 10.43%

3. SCE Corp. Capital Escalation Rates

1983	13.0%
1984	14.0
1985-1986	11.0
1987 on	10.0

avg = 11.8%

4. Capacity Payment

- $180/kW/Year
- 60% nominal capacity factor

5. Tax Considerations

- Federal
  - 15 Year ACRS depreciation
  - 10% ITC
- State
  - 30 year straight line depreciation

6. Regulation

- Normalization of ACRS depreciation & ITC

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, as shown in Figure VIII.D.1, 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. The revenue requirement has increased by about 17% over the initial levels. Avoided cost payments, under the study assumptions, would increase over the entire 30-year period. Figure VIII.D.2 shows that 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 VIII.D.3 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. Note that that is true whether a 10% capital escalation rate or Edison's corporate capital escalation rates are assumed. The decision variables are as follows:

	Capital Escalation Assumptions	
	10%	SCE CORP.
	(Millions)	
Total PW Revenue Requirements	$601.1	$640.5
Total PW Avoided Cost Payment	536.1	536.1

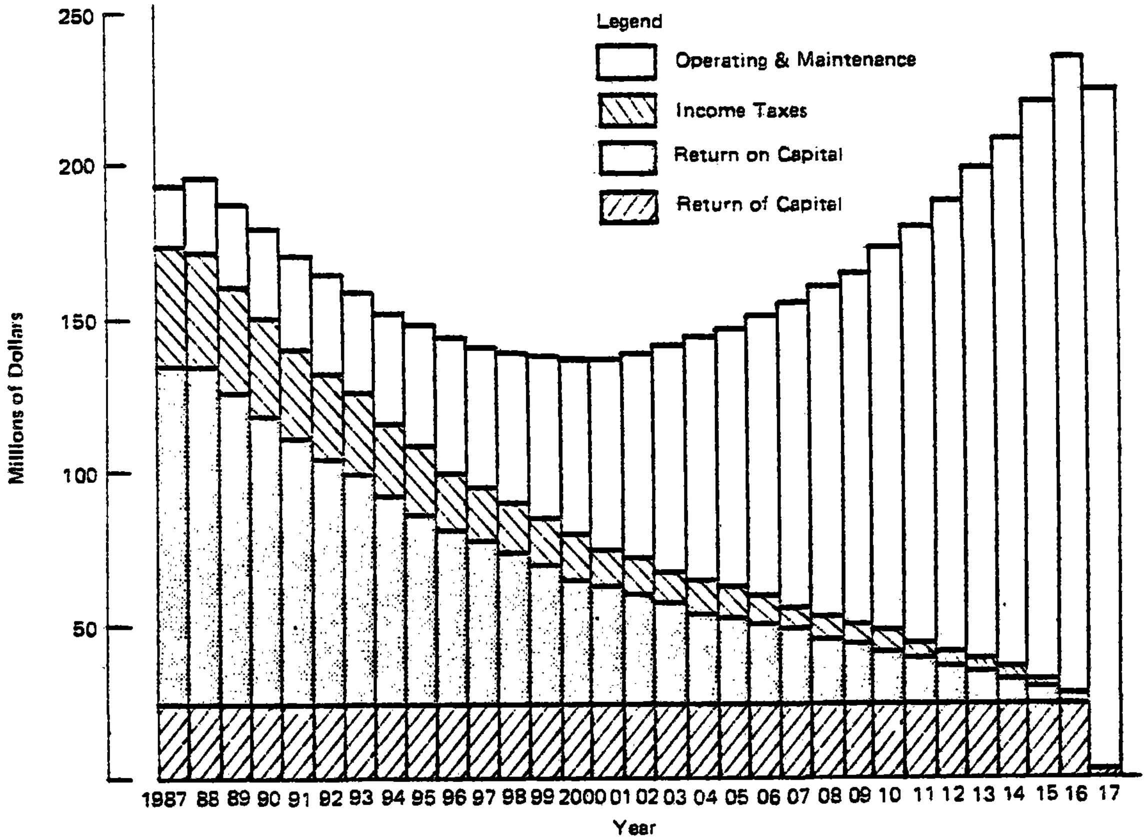


Figure VIII.D.1. Annual Revenue Requirement — Utility Ownership

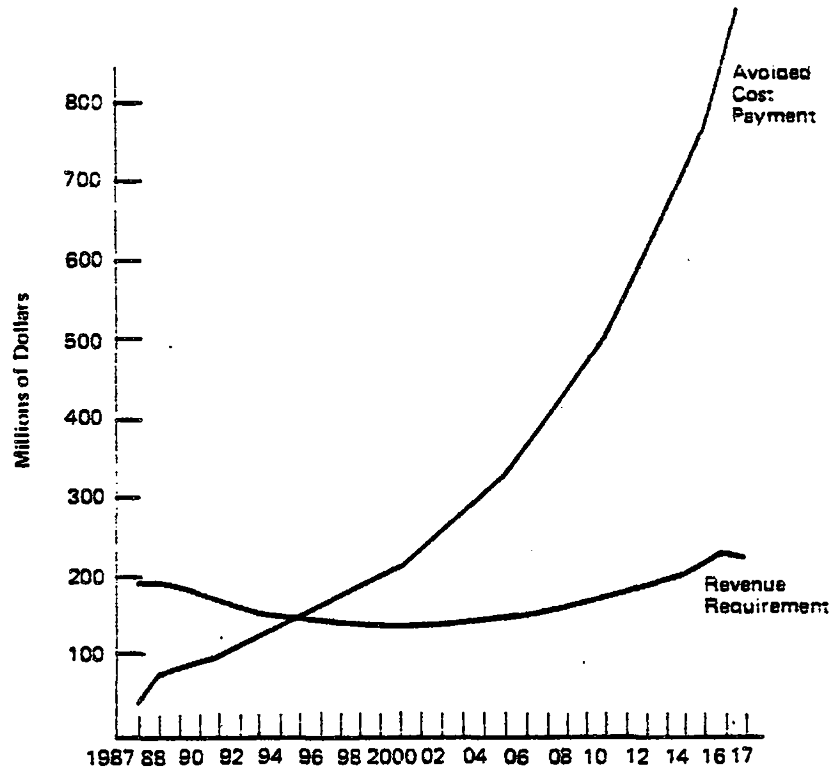


Figure VIII.D.2. Comparison of Annual Cost to Ratepayer — Utility Ownership

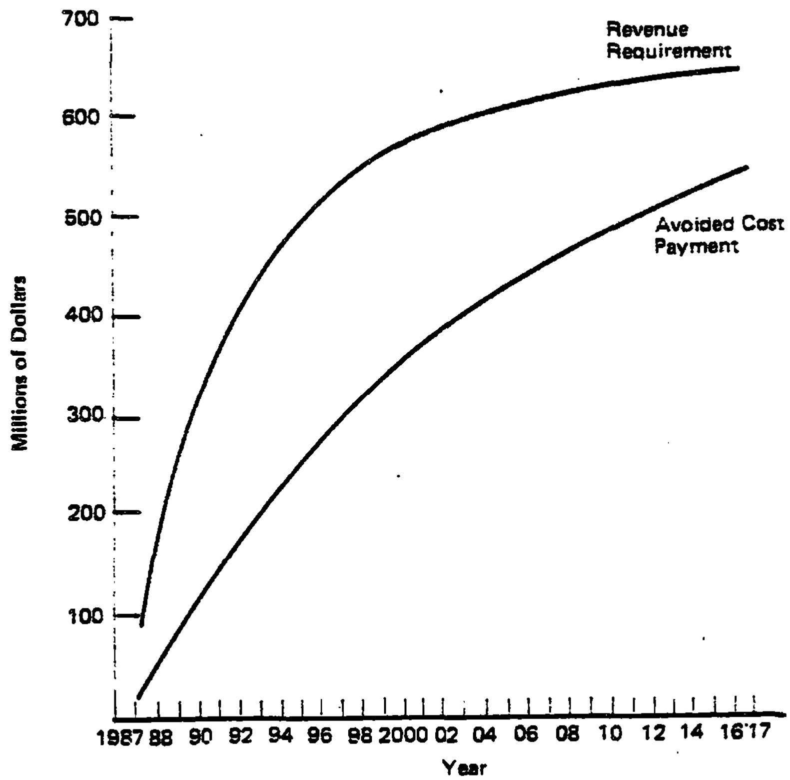


Figure VIII.D.3. Utility Ownership — Cumulative Present Worth

These results indicate that the cost to Edison's ratepayer of obtaining electricity from a 100 MW solar facility would be minimized by purchasing the power from a third party at full avoided cost.

The results of any financial analysis will be sensitive to the input assumptions. Figures VIII.D.4 and VIII.D.5 depict the results of changing the capital costs or the rate at which the avoided cost payment escalates. Depending on the capital escalation rate, capital costs would have to decline 10-15% before the decision would change. As the heliostats represent nearly 40% of the total costs the required reduction in capital costs could be achieved by a 25-40% reduction in the heliostat costs.

On a levelized basis, the base case annual escalation rate for the avoided cost payment is approximately 9.6%. For the decision to change, the escalation rate would have to increase to 10.5% - 11.0% annually depending on the capital escalation rate.

In conclusion, without a reduction in the capital costs or an increase in rate of escalation of avoided cost, from the financial perspective the utility ratepayer is better off if the power is puchased at full avoided cost from a third party. This conclusion is Edison specific because the input is based on Edison's cost of capital, capital structure, and avoided cost schedule.

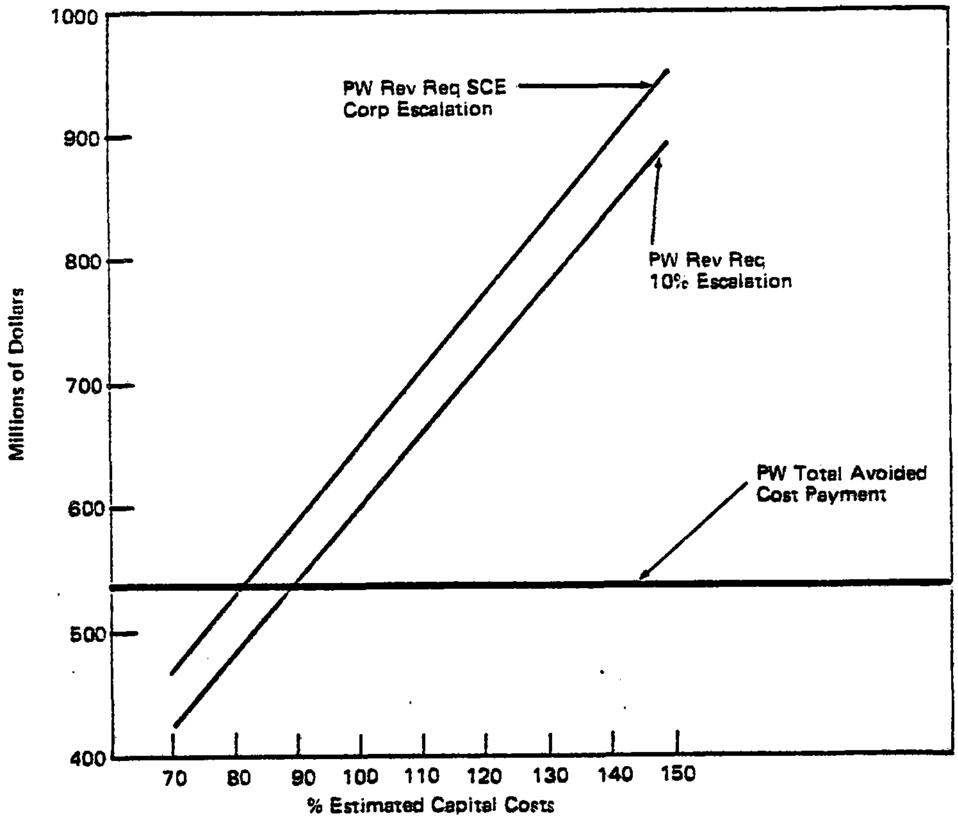


Figure VIII.D.4. Sensitivity to Capital Cost — Utility Ownership

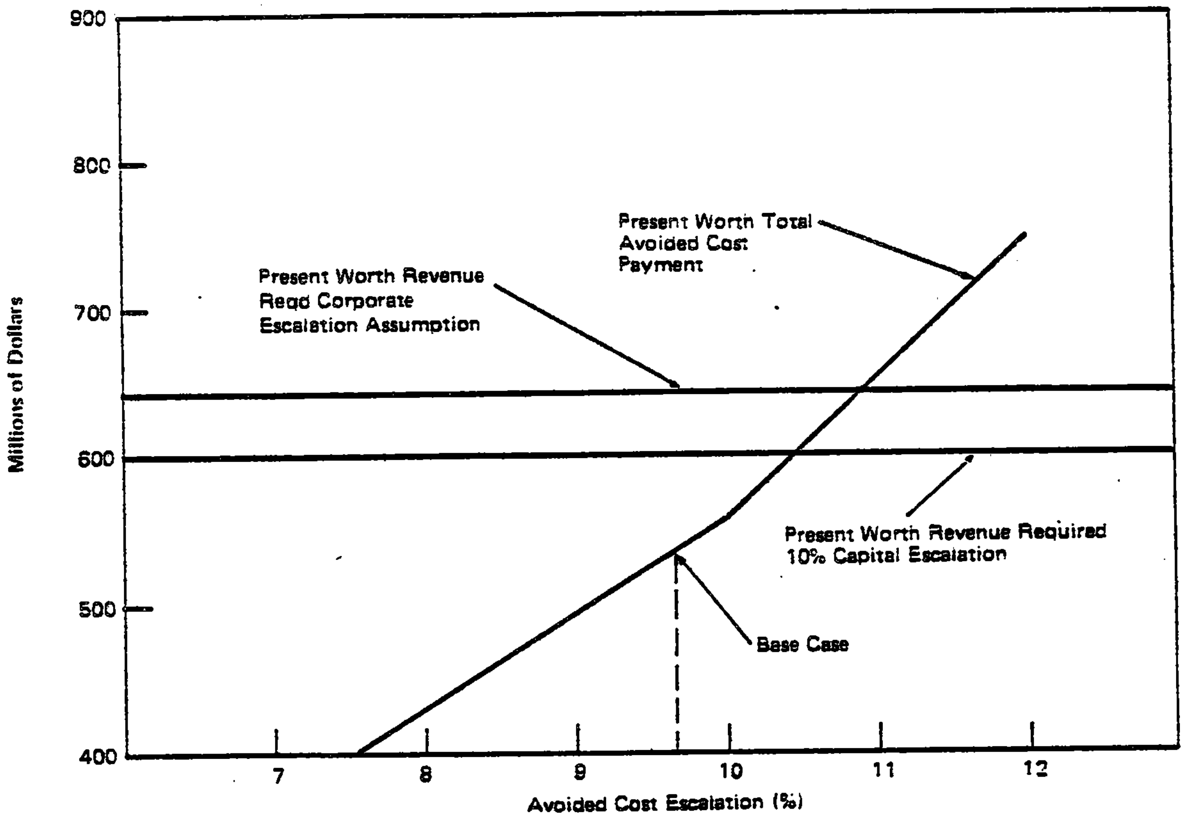


Figure VIII.D.5. Sensitivity to Avoided Cost — Utility Ownership

2. Entrepreneur Owner

a. Financial Analysis

The entrepreneur owner supports the utility's objective of minimizing ratepayor 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 stream. 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.

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:

	Dollars in Millions			Year 2000 Return on	
	NPV @ 20%	Maximum Exposure*	IRR	Sales	Capital
Baseline	$35	$67	35%	35%	16%
80% Cost Multiplier	$50	$54	43%	37%	21%
120% Cost Multiplier	$20	$112	28%	34%	12%
100% Avoided Cost	$48	$67	39%	36%	18%
80% Avoided Cost	$23	$67	30%	34%	13%

* Occurs in 1985

The baseline case calculates the avoided cost energy payments at 90 percent of allowable avoided costs, and considers capital and engineering costs of 427 million in December 1981 dollars. This value is based on the total work order level costs of 431 million less 4 million for the switchyard and transmission line, which the utility provides (Table VIII.A.1). The cost also excludes the utilities' construction overhead and cost of capital which are considered in other cash flows. Heliostat hardware costs, which account for almost 30 percent of total costs, are based on assumed overall production of 75,000 heliostats over 10 years. Table VIII.D.1 details the common assumptions while Table VIII.D.3 delineates specific assumptions used for the entrepreneur perspective. Detail reports providing cash flow, pro forma tax calculations, and other financial statements and ground rules are included in the reference document. Figure VIII.D.6 indicates the nature of cash flow.

The detail report shows that, by the year 2000, the internal rate of return and the return on sales are within a few points of their final values, but the return on net capital employed ultimately grows to 80%. Figures VIII.D.7 and VIII.D.8 add further perspective about the influence of profitability and capital cost variation while Figure VIII.D.9 deals with the value of the federal energy tax credit. Other sensitivities are examined in the reference document.

Figure VIII.D.7 indicates quick profitability once operations start, but then several years of negative net cash flow cause declining returns as the tax impact of depreciation and interest expense lessens. The downward spike reflects one year (1997) when the cumulative net cash flow goes negative, again. The final loan payment is made in that year ending any further negative net cash flows. Capital overruns may still allow an acceptable internal rate of return (IRR), but as implied, may extend the period of negative cumulative net cash flow by several years. Underruns will maintain a positive cumulative net cash flow as-well-as substantially improve the IRR.

Figure VIII.D.8 shows the combined impact of escalation rates and the percent of avoided cost realized in revenue. Profitability appears especially sensitive to the escalation rate of revenues although the level of avoided cost revenue realized is also quite significant. The figure suggests that energy cost escalation below general inflation need not discourage investors provided the power purchase contract provide revenues at close to full avoided cost.

TABLE VIII.D.3(a)
FINANCIAL ANALYSIS
ENTREPENEUR ASSUMPTIONS

1. Financial

- Construction loan

    Short term loans until turnover

    First loan 1982

    Payment of interest only during construction period based on loan to date + 1/2 of current year loan

    65% debt, 35% equity

    18% interest rate

    Commitment fee at .005 per year of remaining loan

    Commitment based on total loan commitment less loan to date + 1/2 of current year

- Project financing

    65% debt, 35% equity

    16% interest rate

    10% year loan

    Constant payment loan

    Loan cost issuance fee at .006

- Discount rate

    20% after tax

2. Avoided Cost Payment

- Energy Payment

    - Negotiated at 90% of full payment (consideration for SCE providing land, interconnection facilities, and switchyard hardware).

- Capacity Payment (levelized, 1988 dollars)

    - $240/KW/Year (based on the 1985 figure, escalated — not an SCE published payment)

TABLE VIII.D.3(b)
~~FINANCIAL ANALYSIS~~
ENTREPRENEUR ASSUMPTIONS

- 0.60 nominal capacity factor (0.56 calculated, after forced outage)

On-Peak		Mid-Peak		Off-Peak	
Summer	Winter	Summer	Winter	Summer	Winter
.87	.78	.88	.72	.48	.30

- Capacity and availability penalties applicable in off-peak period, only.

- Negotiated at full payment, due.

3. Tax Considerations

- Tax Credit
  - Federal 25% (in year cost incurred)
  - State 0%
- Tax Rates
  - Federal 46%
  - State 9.6%
- Depreciation (partial start in 1986, balance in 1987)
  - Federal 5 year ACRS on federal
  - State 8 year SYD

Figure VIII.D.9 indicates the importance of the federal energy credit, as-well-as the impact if the credit is cut-off before project completion. The curve reflects that the energy tax credits are taken as capital outlays are made. Thus, an advantage is gained as the cut-off date is extended. As a result, a December 1985 cut-off, when the credit is scheduled to expire, may still allow an acceptable return to many investors even if the credit is not "grandfathered" out.

b. Financial Risks

Lenders generally are concerned with the adequacy of a project's debt service capability. That is, lenders require a high degree of assurance that regardless of events the entity will be able to fulfill its contractual obligations. Therefore, to successfully obtain project financing for this

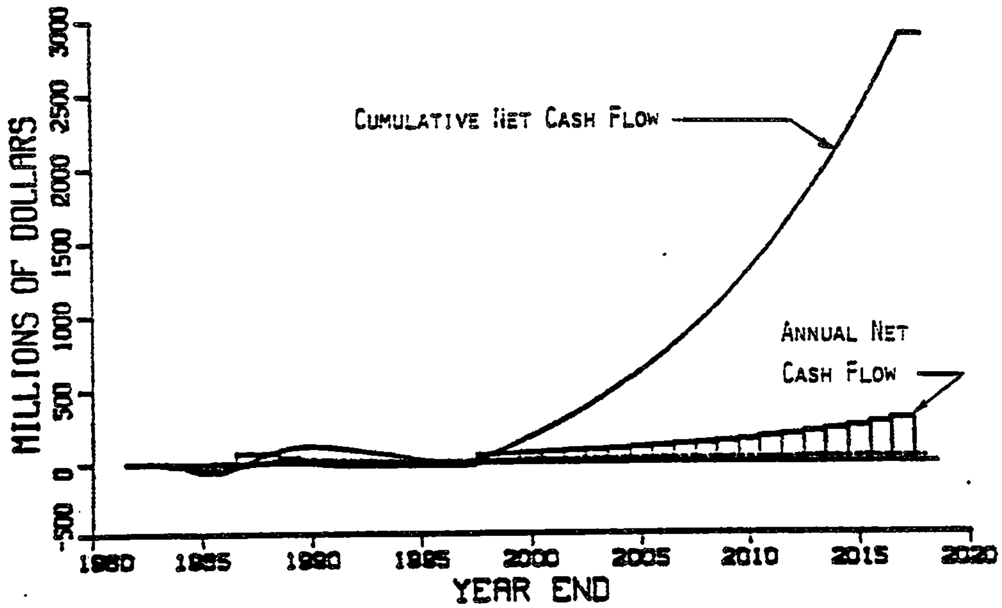


Figure VIII.D.6. Entrepreneur Ownership — Baseline Cash Flow

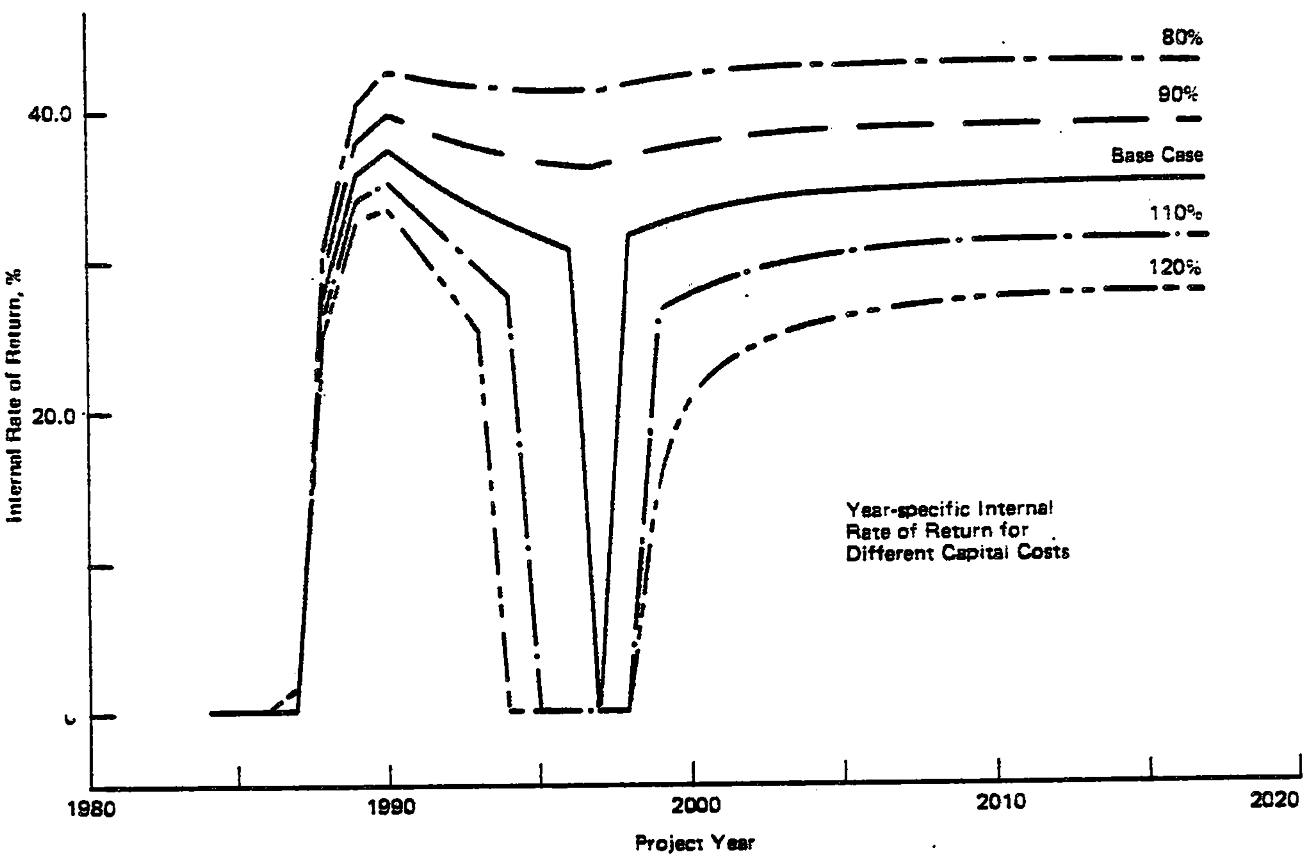


Figure VIII.D.7. Sensitivity to Capital Cost

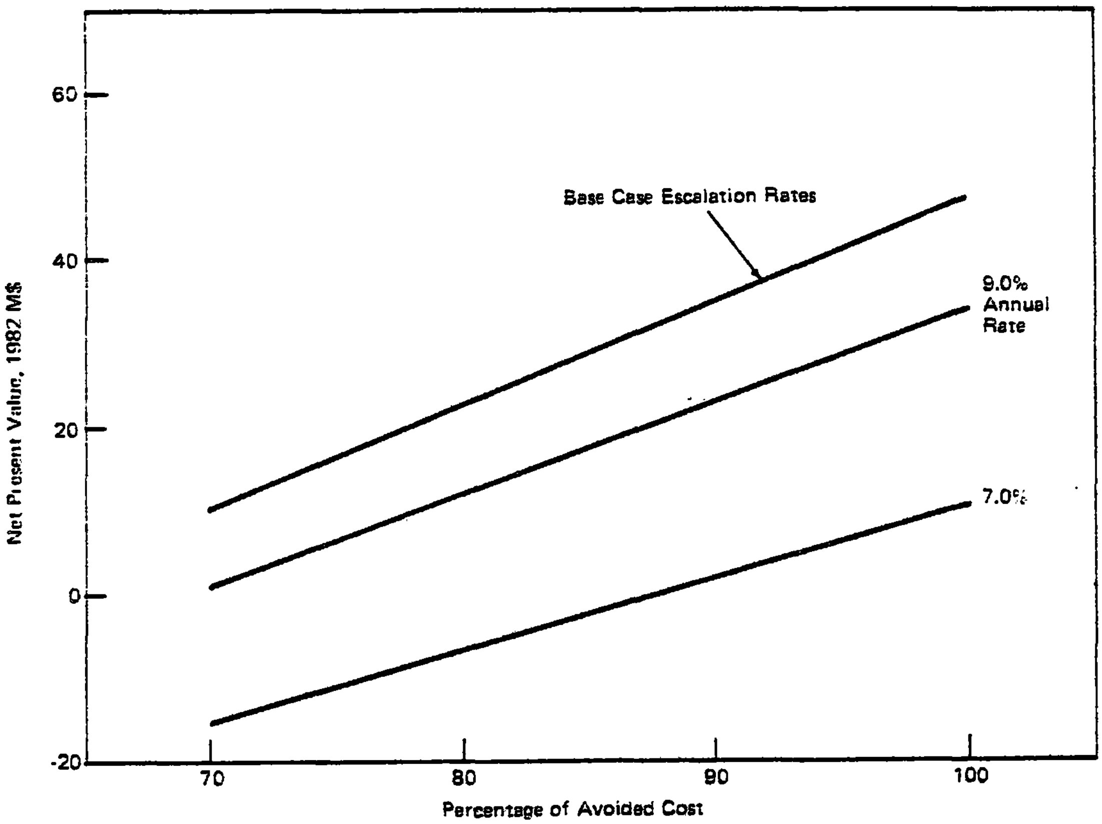


Figure VIII.D.8. Sensitivity to Electricity Revenues

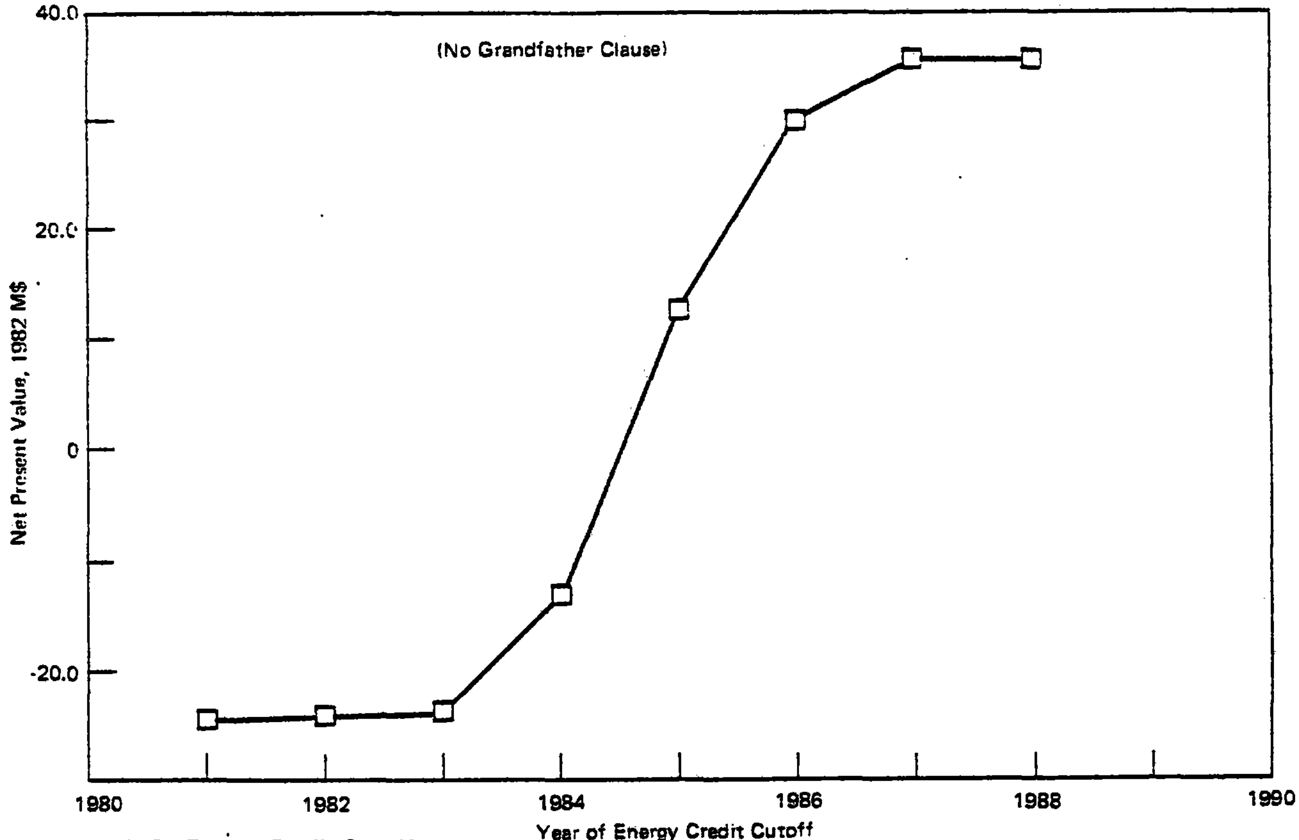


Figure VIII.D.9. Energy Credit Cutoff

project, the risks will have to be adequately addressed and appropriate guarantees provided to assure the lenders that debt service can be maintained. Technical risks are addressed in Section IX of this report; the purpose of this section is to adequately describe financial risks associated with raising of capital by the entrepreneur for construction.

Effective risk management is key to the projects attractiveness to both the investor and lender. Risks associated with a project such as this are generally divided into two categories:

o Risks presented during the construction phase, and
o Risks presented during the operational phase.

There are two primary components to risks presented during construction; cost overruns and cosntuction delays.

For a fee, an A&E firm may be willing to guarantee the date of completion and accept a firm price contract with appropriate escalation clauses. In turn, the A&E firm may require similar guarantees and contracts from its suppliers. However, in a new technology program of considerable cost, the A&E and suppliers may require a substantial fee for schedule and cost guarantees. Fee requirements may be offset somewhat by other considerations such as market entry or an equity position if the return is attractive. Even so, preventative measures which include adequate time for design and test, proper system selection, selection of competent contractors and suppliers, advance permitting, and schedule incentives may be the most effective risk management devices. Such measures are usually combined with insurance to provide an adequate risk management portfolio.

Risks presented during operation include, but are not limited to, underperformance due to design, underperformance due to negligent operation, underperformance due to inadequate solar insolation, and decreases in the price of electricity. As with the construction risk, the A&E firm and the individual suppliers may be required through negotiation to guarantee some degree of performance at a specified level of solar insolation. Again, for a new technology program, the price would be very substantial. Also, the scope of A&E liability typically falls short in two ways: (1) vendor liability is usually limited to repair or replace equipment, and (2) the length of guarantee is usually too short to satisfy lenders. If vendor reputation is strong, insurance may be obtained to extend coverge to satisfactory levels.

Another risk associated with the operation phase is underperformance caused by operator negligence. The facility operator would be required to assume this risk. The investment bankers indicated that both lenders and investors would prefer to have the utility who purchases the power to be the operator. With a utility as the facility operator, there would be no apparent problem in providing assurance that the facility will be operated in an effective manner.

Solar insolation risk is the risk that the quality and quantity of energy (i.e., sunshine) will be within the design limits. Competent system design analysis is critical in assessing this risk. The entity responsible for site selection may be in the best position to assume this risk. Insurance might be available.

Once the factors that could cause power output shortfalls are properly assured against, another risk lenders and investors are concerned with is the assurance that the power produced will be purchased and the energy payment will be enough to cover the debt service. A long term power purchase contract between a utility and the project owner would be required. This contract would specify that the utility would be obligated to purchase all the power produced. The power purchase price typically is established as a percent of the utility's published avoided cost.

If the economics of the project are heavily dependent upon.the levels of the future avoided cost, the energy payment could be too low to cover the debt service. This risk can best be managed by in depth analysis and a carefully negotiated power purchase contract.

Regulatory risk may be presented during both construction and operation. Regulatory risk concerns changes in state and federal regualtions. This risk may be assumed by the owner or the purchaser of power as negotiated. Two examples of regulatory risks are the availability of the federal energy tax credit, as previously discussed, and the size limitation under PURPA, which currently does not cover a 100 MWe noncogeneration plant. The latter if not changed, forces a more creative legal structure. Although difficult to control, continued awareness allows effective anticipation of potential changes, and a strong lobby can make legislators aware of industry concerns.

Lenders and investors are also concerned with project delay in the event of a mishap while the parties argue over liability. Instead of waiting for liability to be determined, the project owner would be the lender's choice as the overall responsible party for debt repayment. The project owner will then deal with the other parties to determine the cause of underperformance and the debt repayment responsibility.

In sum, preventative measures associated with competent management and realistic schedules are the most effective risk management devices. Guarantees for costs, schedule and performance would require substantial fees unless market entry or an equity position is a consideration, and at best, they have limited application in a new technology program. As indicated, many of the above-mentioned risks or other as yet unidentified risks could possibly be managed through an insurance policy that would be adequate to satisfy lender and/or investor requirements. However, a commercial enterprise based on a new technology is likely to be subject to high rates by insurers due to lack of claims experience.

The sensitivity analysis indicates that there are circumstances, particularly in consort, that may so unfavorably influence the solar project's profitability that it would be difficult to attract investors. However, provided the projected returns, and with effective allocation and management of cost, schedule, revenue, performance and regulatory risks, there appears adequate leeway to assure investor and utility interest in an entrepreneur ownership arrangement.

3. Municipal Ownership

One of the scenarios considered in the Solar 100 Project study is the possible financing and ownership of a 100 megawatt solar generating facility by a municipality or other public agency.

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 on purchased power.

From the standpoint of the Southern California Edison Company, this scenario has the advantage of making approximately 100 MW of generating capacity in the Edison system presently used to serve public agencies in its service area available for alternative uses thus delaying the need for adding new capacity.

From the standpoint of the local public agency, this scenario would reduce the agency's reliance on purchased power and the uncertainties associated with future price and availability which such dependence entails. While it does not offer total energy independence, it may offer a substantial measure of energy self-sufficiency.

In exchange for a substantial present investment the community would be gaining the potential for significant long-term savings.

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

On the other hand, the potential tax benefits associated with private financing and ownership would be lost under this scenario.

To assess the possible interest in ownership of a 100 MW solar plant by a local public entity, a financial analysis of such an investment has been prepared.

The assumptions used in the base case analysis are found in Table VIII.D.I and VIII.D.4; the results of the analysis are shown in Table VIII.D.5. Table VIIII.D.6 shows the impact of certain changed input values on the price of electricity in the first year of operation.

Table VIII.D.7 which follows is based on an estimated average cost of purchased power of 6.0345 cents per kilowatt hour in the fourth quarter of 1981 and shows how the estimated cost of purchased power compares with the estimated cost of power generated at the solar plant based on the assumptions used. No transmission costs have been included in the anloysis. Figure VIII.D.10 shows the same information as that contained in Table VIII.D.7 in graphic form.

Risks

The financing, construction and operation of a 100 MW solar plant by a municipality is subject to the usual project risks of cost overruns and completions delays in the construction period and failure to perform adequately and costly maintenance during the operating period. Risks are compounded in a project utilizing new technology or one which will operate on a scale not previously attempted.

TABLE VIII.D.4
FINANCIAL ANALYSIS
MUNICIPAL ASSUMPTIONS

1. Construction Costs

• Total Investment	$448.3M
Less	
• Sales Tax	12.7
• SCE Const. Overhead	17.5
Municipal Investment	418.1

2. Financing

- Interest on bonds 12%
- Bond reserve fund - 1 yr. level debt service
- Bond issuance cost - 3% of bond amount
- Interest earned on unexpended bond proceeds 14%
- Interest earned on debt service/reserve fund 12%
- 30 year maturity
- Level debt service
- Bond issuance 3Q82

The principal project risks are discussed in an earlier part of this section and many of these apply to the Municipal Ownership Case. In addition, the municipal scenario is subject to a few risks that are unique to that case. These include the possibility that the bond issued will not be sufficient to complete the project or that a taxpayer's suit may delay or block the project.

Insufficiency of bond proceeds can be addressed by seeking authorization for bonds in excess of anticipated needs. The best protection against a taxpayer's suit is a comprehensive feasibility study which demonstrates the project to be in the community's best interest.

Volatile interest rates present another uncertainty. It may be possible to issue short term debt to finance engineering design work and thus await more favorable market conditions for the issuance of long term debt.

TABLE VIII.D.5(a)
JOINT SOLAR GENERATION STUDY
SOURCES AND USES OF FUNDS STATEMENT
MUNICIPAL OWNERSHIP CASE

(MILLIONS OF DOLLARS)

YEAR:

Sources of Funds	1982	1983	1984	1985	1986	1987	Total
Tax Exempt Bond Proceeds	852.11	-	-	-	-	-	852.11
Interest Earnings on Bond Funds @ 14%	101.60	102.30	95.92	69.06	31.54	7.25	407.67
Interest Earnings on DSRF @ 12% (.12 * 105.78)	12.69	12.69	12.69	12.69	12.69	12.69	76.12
Unexpended Funds	-	730.61	730.81	639.54	347.06	103.50	2551.52
Total Sources of Funds	966.40	845.60	839.43	721.30	391.30	123.44	3887.47
Uses of Funds							
Eng./Constr. Costs	2.19	12.54	97.63	271.98	185.54	21.19	591.08
Interest on Bonds @ 12% (852.11 * .12)	102.25	102.25	102.25	102.25	102.25	102.25	613.52
Debt Service Reserve Fund	105.78	-	-	-	-	-	105.79
Bond Issuance Costs @ 3%	25.56	-	-	-	-	-	25.56
Unexpended Funds	730.61	730.81	639.54	347.06	103.50	-	2551.52
Total Uses of Funds	966.40	845.60	839.43	721.30	391.30	123.44	3887.47

TABLE VIII.D.5(b)
JOINT SOLAR GENERATION STUDY
MUNICIPAL OWNERSHIP CASE
ANALYSIS OF REVENUE REQUIREMENTS

$852.11, 30 yr, 12%

(MILLIONS OF DOLLARS)

	YEAR:							
Annual Costs	1988	1989	1990	1991	1992	1993	1994	1995
Debt Service	105.78	105.78	105.78	105.78	105.78	105.78	105.78	105.78
Debt Service Coverage @ 30% .3 x 105.78	31.74	31.74	31.74	31.74	31.74	31.74	31.74	31.74
O&M	9.63	10.50	11.44	12.47	13.59	14.82	16.15	17.60
G&A	7.09	7.73	8.43	9.18	10.01	10.91	11.89	12.96
Total Annual Costs	154.24	155.75	157.39	159.17	161.12	163.25	165.56	168.09
Less: Interest Earnings on DSRF	12.69	12.69	12.69	12.69	12.69	12.69	12.69	12.69
Net Annual Costs	141.55	143.05	144.69	146.48	148.43	150.55	152.87	155.39
Price Per kWhr to Break Even	.29	.29	.30	.30	.30	.31	.31	.32

TABLE VIII.D.5(c)
JOINT SOLAR GENERATION STUDY
MUNICIPAL OWNERSHIP CASE
ANALYSIS OF REVENUE REQUIREMENTS

(MILLIONS OF DOLLARS) (Continued)

Annual Costs	1996	1997	1998	1999	2000	2001	2002	2003
Debt Service	105.78	105.78	105.78	105.78	105.78	105.78	105.78	105.78
Debt Service Coverage @ 30%	31.74	31.74	31.74	31.74	31.74	31.74	31.74	31.74
O&M	19.19	20.92	22.80	24.85	27.09	29.52	32.18	35.08
G&A	14.13	15.40	16.79	18.30	19.95	21.74	23.70	25.83
Total Annual Costs	170.84	173.84	177.11	180.67	184.55	188.78	193.40	198.43
Less: Interest Earnings on DSRF	12.69	12.69	12.69	12.69	12.69	12.69	12.69	12.69
Net Annual Costs	158.14	161.14	164.41	167.97	171.86	176.09	180.70	185.73
Price Per kWhr to Break Even	.32	.33	.34	.34	.35	.36	.37	.38

TABLE VIII.D.5(d)
JOINT SOLAR GENERATION STUDY
MUNICIPAL OWNERSHIP CASE
ANALYSIS OF REVENUE REQUIREMENTS'

(MILLIONS OF DOLLARS) (continued)

Annual Costs	2004	2005	2006	2007	2008	2009	2010	2011
	YEAR:							
Debt Service	105.78	105.78	105.78	105.78	105.78	105.78	105.78	105.78
Debt Service Coverage @ 30%	31.74	31.74	31.74	31.74	31.74	31.74	31.74	31.74
O&M	38.23	41.68	45.43	49.52	53.97	58.83	64.12	69.89
G&A	28.15	30.69	33.45	36.46	39.74	43.32	47.22	51.47
Total Annual Costs	203.91	209.88	216.40	223.50	231.23	239.67	248.86	258.88
Less: Interest Earnings on DSRF	12.69	12.69	12.69	12.69	12.69	12.69	12.69	12.69
Net Annual Costs	191.21	197.19	203.70	210.80	218.54	226.97	236.17	246.19
Price Per kWhr to Break Even	.39	.40	.42	.43	.45	.46	.48	.50

TABLE VIII.D.5(e)
JOINT SOLAR GENERATION STUDY
MUNICIPAL OWNERSHIP CASE
ANALYSIS OF REVENUE REQUIREMENTS

(MILLIONS OF DOLLARS) continued,

YEAR:

Annual Costs	2012	2013	2014	2015	2016	2017	Total
Debt Service	105.78	105.78	105.78	105.78	105.78	-	3170.00
Debt Service Coverage @ 30%	31.74	31.74	31.74	31.74	31.74	-	951.00
O&M	76.19	83.04	90.52	98.66	107.54	117.22	1319.20
G&A	56.10	61.15	66.65	72.65	79.19	86.32	971.41
Total Annual Costs	269.80	281.71	294.69	308.83	324.25	203.54	6411.61
Less: Interest Earnings on DSRF	12.69	12.69	12.69	12.69	12.69	12.69	380.82
Net Annual Costs	257.11	269.02	281.99	296.14	311.56	190.84	6030.79
Price Per kWhr to Break Even	.52	.55	.58	.60	.64	.39	12.48

TABLE VIII.D.6
IMPACT OF CHANGES IN COSTS ON THE FIRST
YEAR PRICE OF ELECTRICITY
(CENTS PER kWhr)

Capital Costs	
+25%	35
Base Case	29
-25%	23
O&M Costs	
+25%	29
Base Case	29
-25%	28

Certain protections for bondholders have been incorporated in the Cash Flow Analysis for the Municipal Ownership Case. These include a debt service reserve fund equal to a year's debt service which provides assurance that bondholders will be paid if there is a delay in project construction or insufficient revenues during operation, and the assumption that debt service coverage of 1.30 will be required by the bond indenture.

Conclusion

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 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.

TABLE VIII.D.7
ESTIMATED COST OF SOLAR GENERATED POWER
COMPARED TO ESTIMATED PURCHASED POWER COSTS AT
SELECTED ESCALATION RATES
(CENTS PER KILOWATT HOUR)

Year	Solar Generated Power Cost	Purchase Power Cost Escalated at: 8%	10%	12%
1982		7	7	7
...	...	...	...	...
1988	29	11	12	14
89	29	11	13	15
90	30	12	15	17
91	30	13	16	19
92	30	14	18	21
93	31	16	19	24
94	31	17	21	27
95	32	18	23	30
96	32	20	26	34
97	33	21	28	38
98	34	23	31	42
99	34	25	34	47
2000	35	27	38	53
01	36	29	41	59
02	37	31	46	66
03	38	34	50	74
04	39	36	55	83
05	40	39	61	93
06	42	42	66	104
07	43	46	74	117
08	45	49	81	131
09	46	53	89	147
10	48	58	98	164
11	50	62	108	184
12	52	67	118	206
13	55	73	130	231
14	58	78	143	259
15	60	85	158	290
16	64	92	173	324
17	69	99	191	363
TOTAL	$12.02	$12.01	$19.76	$32.76

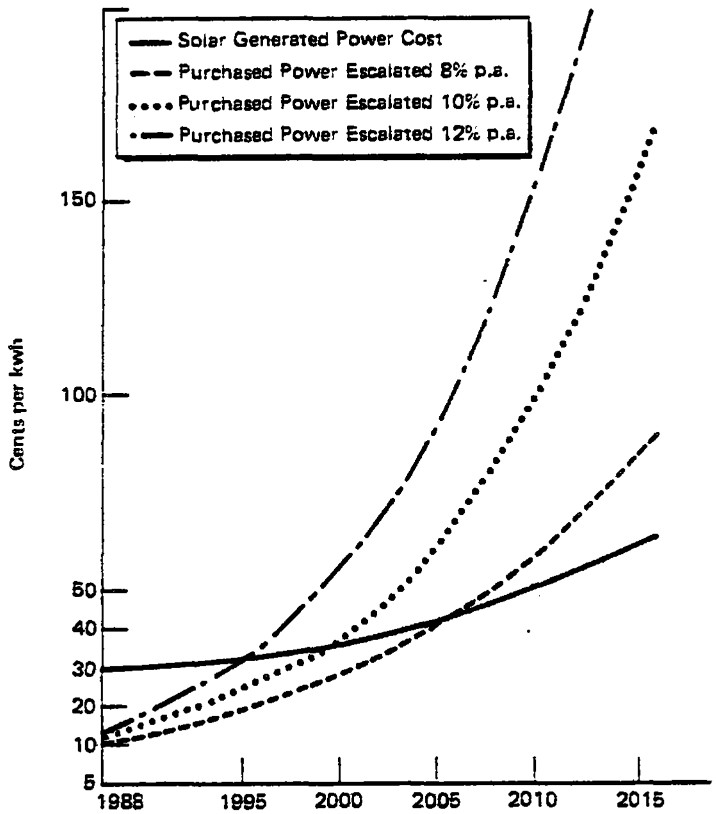


Figure VIII.D.10. Estimated Cost of Solar Generated Power Compared to Estimated Purchased Power Costs at Selected Escalation Rates

IX. RISKS AND CONSTRAINTS

A. Technical Risks and Management Plan

This subject was introduced in Section III where technology readiness is discussed for alternative central receiver systems. The design and operation of Solar I and additional studies and developments specifically related to molten salts provide the basis for the Solar 100 design. The general conclusion is that the technology is ready, but residual issues relating to extrapolations of results to a larger scale and extended operating times do exist. It is believed that these issues can be satisfactorily resolved within state-of-the-art design and manufacturing capabilities.

Nitrate-based molten salts have been used as heat transport media in the petroleum and chemical process industries and in metallurgical heat treatment operations for more than 40 years. Their application in processes where water and organic fluids were inadequate (temperatures above 700°F) required the development of equipment to handle and contain the material.

Physical and chemical properties, heat transfer data, and corrosion rates were reported for molten salt as early as 1940. More recently, the potential benefits from use of molten salt in solar applications (see discussions in Section III.C) motivated the Department of Energy to sponsor an extensive program to provide additional technical information for the design of solar central receiver systems using this medium. These activities provide a substantial additional base in combination with the past industrial experience for this medium.

As with any new technology which uses designs and experience from related fields and experimentation, there are equipment designs which require modification and data which must be extrapolated. This carries a certain degree of risk in the form of potential cost incurred for equipment design changes and potential penalties resulting from degraded performance or reduced life. However, the specific programs, experiments and analyses of the DOE and others directed toward use of molten nitrate salts in solar central receivers work to both identify areas of risk and reduce them to acceptable levels. This is the essential objective of a risk management plan. For this conceptual engineering study, an assessment of these risk areas has been made and a preliminary apporach to risk reduction has been identified.

1. Development Status

The Solar 100 central receiver power plant consists of two fields of heliostats, two towers and receiver systems, a molten salt transport and storage system with associated pumps, tanks and valves, a salt driven steam generator and a conventional turbine generator plant. The development of all of these, except the turbine generator plant (which makes use of proven equipment and procedures) is discussed below.

Heliostats

Several generations of heliostat development have occurred as a consequence of DOE-funded programs. The predecessor of current heliostat designs were installed at the solar furnace facility at O'Deillo in France in 1969 and are still in operation. The first American central receiver heliostats, installed at the Central

Receiver Test Facility (CRTF) in Albuquerque in 1977, are also still in operation. CRTF utilizes 222 heliostats, each with 37 m^2 of reflective area. The Solar I Pilot Plant in Barstow, which began shakedown testing in 1981, utilizes 1818 heliostats of an improved design. These 40 m^2 Solar I heliostats are the product of several competitive DOE-funded heliostat development efforts which took place in 1977 and 1978. These first generation central receiver system heliostats were designed to a Sandia Laboratories heliostat specification and were extensively tested by Sandia at CRTF.

A second generation of five competitive heliostat development contracts was funded by DOE in 1979 and 1980. The resulting heliostat design corrected deficiencies of the first generation heliostats. Heliostats from four of the five second generation heliostat suppliers were tested extensively by Sandia early in 1981. The results of the evaluation showed that with minor design changes, the four tested second generation heliostats are viable designs (Reference IX.A.1). The inherent weaknesses of the first generation designs were all eliminated by one or more of the second generation heliostats. Several of the second generation heliostats met substantially all functional requirements and need only minor modifications for complete functional compliance with the Sandia National Laboratories at Livermore (SNLL) A10772 heliostat specification. Accelerated life testing identified several second generation mirror module designs with long life potential. One second generation mirror module design, with a specific adhesive modification, was judged by SNLL (Reference IX.A.2) to have an anticipated life of 20 to 30 years.

More long-term testing is needed to confirm attainment of the specified 30-year life capability.

Receiver Towers

Based on existing power plant stack practice, the technology required to design and construct the two required receiver towers, using slip-formed concrete, is judged to be fully developed and proven.

Receivers

A summary of receiver developments of the last five years is shown in Table IX.A.1. The list is based on information contained in References IX.A.3 to 10. It includes twelve receivers ranging from 0.3 to 42 MW_t in capacity, most of which have operated at temperatures near 1,000°F. Five of the receivers are associated with central receiver pilot plants which have just recently come into service. One of these pilot plant receivers, part of the THEMIS plant at Targassone, France, utilizes a (HITEC) salt receiver that operates at an outlet temperature of 850°F.

Steam Generators

Many sodium heated steam generators of various sizes, up to several hundred MW_t, have been built and thoroughly tested. This technology is to a large extent applicable to molten salt steam generators, superheaters and preheaters. Several hundred small (11 MW_t max.) and low pressure (1,000 psig max.) molten salt steam generators are in use in industry. All users contacted are satisfied with the performance obtained with molten salt. Tube leaks in the industrial molten salt

TABLE IX.A.1
RECEIVER DEVELOPMENT SUMMARY

Contractor	Identification	Media	Size	Max. Media Temperature	Maximum Heat Flux	Test Facility	Year	Heat Source	Test Hours
			MW_t	°F	MW/m^2				
(Italy)	Francia	W/S	0.3	----	----	ACTF	1978	Solar	150
MMC	--------	W/S	1	1,010	----	CRNS, France	1976	Solar	161
MMC/FW	DOE Dev. Rcvr.	W/S	5	960	0.7	SNLA-RHF	1977	Quartz Lamp	231
Rocketdyne	Barstow 70 Tube	W/S	2	1,010	0.31	CRTF	1979-80	Solar	400
Boeing	EPRI-DOE	Air	1	1,500	0.10	CRTF	1979	Solar	114
MMC	DOE Dev. Rcvr.	Draw Salt	5	1,050	0.63	CRTF	1980-81	Solar	400+
ESG/Rockwell		Sodium	3	1,100	1.5	CRTF	1981-1982	Solar	---
Rocketdyne	Barstow Solar I	W/S	47	960	0.3	Barstow, CA	1982-	Solar	---
B&W (Great Britain)	IEA Almeria (Spain)	Sodium	2.9	985	0.62	Almeria, Spain	1981	Solar	---
---	Themis (France)	HITEC Salt	11.2	840	0.70	Targassone, France	1982-	Solar	---
Ansaldo	Eurelios (Italy)	W/S	4.8	950	0.8	Adrano, Sicily	1981-	Solar	---
(Japan)	Sunshine Project	W/S	6	480	---	Nio-Machi, Kagawa	1981	Solar	---
(Spain)	CESA-I	W/S	4.8	980	0.6	Almeria, Spain	1982	Solar	---
Solar 100 Requirements		Draw Salt	320	1,050	0.6	Commercial Plant	1987	Solar	

steam generators are common and are attributed by the users to inadequate feedwater chemical control. All of these industrial molten salt steam generators operate with HITEC (see next paragraph) salt/at temperatures of 850°F and below. They produce saturated steam with no superheating.

Molten Salt Transport and Storage System

The thermal transport and storage system utilizes draw salt (60% sodium nitrate, 40% potassium nitrate) as the thermal transport medium. Draw salt melts at 430°F and its primary industrial use is as a bath for heat treatment of aluminum alloys. A very similar and related salt, HITEC (7% sodium nitrate; 40% sodium nitrite; 53% potassium nitrate) is widely used in the industrial heat transfer loops discussed in Section IX.A.2. It melts at 290°F but is twice as expensive as draw salt and is also significantly more corrosive at high temperatures. A considerable body of materials design data for draw salt systems has been gathered by DOE-funded laboratory and test loop programs. Most component experience is with the related HITEC salt.

a. Salt Stability - Laboratory tests (Reference IX.A.19) and extended running of a material test loop (Reference IX.A.14) have demonstrated that draw salt exposed to air cover gas operating between the limits of 550°F and 1,050°F equilibrates with an approximately 2% concentration of sodium nitrite and remains stable at this state. This small chemical change in chemistry leaves salt properties essentially unaltered and is acceptable.

b. Impurities and Contaminants - Trace impurities of calcium, magnesium and silicon form compounds which can precipitate and stick to metal surfaces. Contamination by water and carbon dioxide forms hydroxides and carbonates which can also separate out as precipitates. All of these precipitates are filterable. NO_2 bubblers were shown to be very effective in removing hydroxides and carbonates during opertion of a draw salt test loop (Reference IX.A.14).

c. Materials Compatability - The Solar 100 draw salt thermal transport and storage loop requires materials which will permit 30 years of operation between the temperature limits of 550°F and 1,050°F. Carbon steel has a well demonstrated capability of reliable service in chemical process industry HITEC salt loops at temperatures well above 550°F (actually as high as 850°F) for periods in excess of 20 years. The same installations commonly operate type 304 stainless steel (SS) tanks and reactor shells in HITEC at 850°F. Laboratory tests at SNLL (Reference IX.A.11, 12 and 13) and two years operation of a dynamic draw salt test loop at Martin Marietta Corporation (Reference IX.A.14) have identified Inconel 800, 316SS and 304SS as acceptable containment materials for draw salt at 1,100°F. Thirty-year corrosion allowances based upon two-year corrosion tests and the most conservative of three extrapolation techniques (Reference IX.A.14) are shown in Table IX.A.2.

These corrosion allowances do not account for the possible effects of creep and thermal cycling on corrosion rates. Very severe repeated thermal shocking (1100F/70F quench) of corroded coupons (Reference IX.A.14) showed the corrosion film to be very hardy. Microscopic examination after 50 quench cycles showed no evidence of spalling. Subsequent measurements of the effect of creep (Reference IX.A.15 and 16) in 1,000 hour tests of

Table IX A-2

30-YEAR CORROSION ALLOWANCES IN MOLTEN DRAW SALT (Mils)

	550°F	750°F	1075°F
Inconel 800	-	-	6.
316 SS	-	-	12.
304 SS	-	-	19.5*
Carbon Steel	9.5	54.8	-

*Linear extrapolation of one years corrosion (Reference IX A-13).

Inconel 800 in draw salt has revealed that corrosion layers on creep-deformed specimens are thicker than on undeformed specimens, but the rate of growth of the corrosion layers are essentially the same. The effects of corrosion film cracking due to creep had no measurable effect on material strength properties and microstructural observation revealed no propensity for environmental cracking to occur. Intrusions of the oxide into the base metal were judged to be the result of deformation-induced grain boundary cracking and not the result of exposure to the molten salt. In other words, draw salt does not promote a stress corrosion mode of material removal when the corrosion film is cracked.

d. Pumps - Vertical multi-stage pumps with submerged bearings, similar in configuration to vertical condensate pumps, have been used in industrial HITEC heat transfer loops for over 40 years. These pumps cover a range of capacities exceeding the requirements of the Solar 100 receiver and steam generator salt pumps but operate at considerably lower head (a maximum of 250 feet of head compared to over 1,000 feet required for the receiver pumps). Fluid temperatures are usually below 850°F although satisfactory service at temperatures up to 950°F has been documented. Industrial experience with salt pumps has been favorable.

e. Valves and Instrumentation - Valves have been operating satisfactorily in several hundred of the industrial HITEC molten salt systems that have been built during the last 40 years. Most are globe valves that operate at 850°F and below, are self-drainable and commonly have internal bellows stem seals to prevent leakage. Some butterfly and plug valves have also been used. The HITEC loop valves range from 3 to 8 inches, involve throttling of less than 100 psi and operate continuously at one operating condition for months at a time. All users are satisfied with the valves overall performance.

Industrial HITEC loops do not use check valves or high pressure reducing valves and do not experience daily thermal cycling characteristic of solar central receiver service.

The commonly used valve trim material, Stellite #6, did not show any visual corrosion after a 6,000-hour immersion test conducted by Martin Marietta (Reference IX.A.12). Erosion-corrosion characteristics of Stellite in high throttling service have not been determined.

f. Tanks - Hundreds of horizontal cylindrical HITEC salt tanks are presently in service in industrial plants. Typical tank sizes are up to 12 feet diameter and 30 feet long. They are constructed of 304 SS and usually operate at 850°F and below. Operation at temperatures as high as 950°F has been reported.

Two vertical axis cylindrical tanks each 120 feet diameter and 45 feet high are required (one for storage of 550°F salt; the other for storage of 1,050°F salt) for the Solar 100 molten salt system. Each tank holds up to 3.5 million gallons of salt. Similar flat bottom tanks approximately 280 feet in diameter and 65 feet high (28 million gallons) are used for storage of 450°F oil in the Syncrude Inc. Project in Alberta, Canada. Three vertical cylindrical dump tanks each 28 feet diameter x 28 feet high (125,000 gallons) have been fabricated for 700°F sodium service and are currently stored at Memphis preparatory to installation at the Clinch River Breeder Reactor (CRBR). A 60 feet diameter 45 feet high thermal storage tank for containment of oil and rock at 575°F has been installed at the Solar I Central Receiver Pilot Plant at Barstow, California. And finally, a number of vertical flat bottom cylindrical tanks over 200 feet in diameter and 100 feet tall, which have been constructed for LNG storage, require allowances for large thermal contraction similar in nature to the allowances for large thermal expansion required for the large molten salt tanks of Solar 100.

g. Heat Tracing - All Solar 100 molten salt piping, the salt storage tanks and portions of the receiver and steam generator require 550°F heat tracing. Heat tracing is required to:

- preheat piping and components prior to charging with molten salt
- prevent freezing of salt during extended shutdown
- thaw frozen salt should it ever become necessary.

Much of the heat tracing must withstand 1,050°F temperature in a passive state for 30 years.

While similar heat tracing requirements are rare, they do exist and hve been addressed with uniform success at three separate liquid sodium installations; the Energy Technology Engineering Center (ETEC) at Santa Susanna, California; the Fast Flux Test Facility (FFTF) in Hanford, Washington; and the Experimental Breeder Reactor Facility (EBR2) near Idaho Falls, Idaho.

Thousands of trace heaters are installed in sodium loops at ETEC. They operate at temperatures from 300°F to 1,200°F. Some heaters have operted continuously for nearly 10 years. Most heaters are periodically shut down as repairs and modifications are made to the sodium loops. Tubular electric heater replacements are routinely made on 300°F to 400°F sodium lines without shutting the loop down. ETEC has experienced reliable service from their heat tracing and do not consider heat tracing to be a significant cause of facility shutdown.

FFTF heat tracing operates between 300°F and 1,200°F and is also based on the use of tubular electric heaters. Redundant heaters are used and each element is operated at only one-third of its rated capacity. After experiencing a number of problems during shakedown testing, reliable operation of the heat tracing has been obtained.

EBR2 has been operating for 18 years with induction type heat tracing. The induction field set up by lagging No. 8 wire at a one-inch pitch outside of the insulation, causes heating of the carbon steel pipe by wrapping it with a sheet metal carbon steel sleeve. Axial breaks in the sleeve are permitted. Circumferential breaks are bridged with tack welds. Normal operation of these heaters is at 580°F. The system has been operating for 18 years very reliably. With less than 10 hours of repair a year, mostly on controls, the heat tracing has no impact on availability of the facility.

In each of these systems, reliable operation was attained following an initial shakedown period during which operating deficiencies were identified and corrected.

h. Salt Properties - Salt's viscosity, surface tension, density and phase diagram have been determined and reported by DOE (References IX.A.16 and 17). Heat capacity measurements of draw salt made by Sandia Laboratories are reported in Reference IX.A.18. Data on the thermal conductivity of the salt are being generted by the Norwegion Institute of Technology under a DOE contract.

i. Salt Handling - Methods of handling and charging systems with large quantities of molten salt have been studied by Olin Chemical Group for DOE. The charging procedure for Solar 100 is straight-forward from past experience. However, Olin has addressed methods to improve the handling efficiency and time to charge the system, which will be considered for this plant.

2. Industrial Experience

During the last 40 years, well over 500 industrial HITEC heat transfer loops have been placed in operation around the world. Most of these loops have salt inventories about 1% the size required for the Solar 100 central receiver power plant. Their pump capacities equal and surpass Solar 100 salt pumping requirements, although pumping heads are considerably less than the Solar 100 receiver pump requirements.

Operating temperatures are usually 850°F and below. But some operation at 950°F (in Houdry process loops prior to World War II) and at 1,000°F (at the Intenco plant in Houston, Texas) has been reported. The experience is significant since the HITEC salt is known to be more corrosive than the Solar 100 draw salt at high temperatures. These loops also provide field experience with 3- to 8-inch valves. Solar 100 uses mostly 12-inch valves. The loops do not thermally cycle or duplicate the high pressure throttling requirements of Solar 100 valves.

These loops provide a significant body of relevant experience regarding component designs, materials and operating procedures.

3. Solar 100 Technical Risk Areas

Technical risks associated with the Solar 100 central receiver power plant are discussed below in descending order.

Receiver

The greatest technical risk is in the molten salt receiver. Some of the risk is inherent in the increase in size over previous receivers (over 7 times as large as the Barstow Pilot Plant water/system receiver; over 27 times as large as the THEMIS HITEC salt receiver; over 60 times as large as the Martin Marietta draw salt receiver). Part of the risk must be associated with the fact that the hottest metal temperatures in contact with the salt are at the receiver tubes.

Given the large scale up from previous designs, the high temperature of the receiver tubes and the temperature cycling characteristics of receiver operation, a risk of premature tube failures in early generation receivers does exist.

Steam Generator

The risk of steam generator tube sheet leaks is judged to be moderate. Tube sheet leaks are common in industrial HITEC salt heat transfer loops. The use of welded tube sheet joints fabricated to utility industry standards should significantly improve the prospects for obtaining a leak-free steam generator. Until this result is demonstrated, however, some risk of water/steam leakage into the salt through tube sheet cracks must be acknowledged. Such leakage is a contaminant which would form hydroxides in the salt.

Molten Salt Corrosion Allowance

Corrosion allowances discussed in Section IX.A.1 and cited in Table IX.A.2 are based on materials testing tht did not simulate the daily thermal cycling that is characteristic of Solar 100 salt loop operation. It should be expected that corrosion tests conducted with thermal cycling will yield corrosion allowances greater than those listed in Table IX.A.2. Severe thermal shock (1,100 F/70 F quench) tests of corroded specimens and corrosion tests measured under creep stress conditions have revealed that the salt induced corrosion films are very hardy and that corrosion film cracking does not induce stress corrosion modes of material removal. From Table IX.A.2, it is clear that a considerable increase in the previously projected corrosion allowances can be accommodated without serious impact on component designs. Without a change in corrosion mode (e.g., stress corrosion) the corrosion rate cannot exceed the initial rate of oxide buildup on uncorroded parent metal which, for the alloy steels, extrapolates to an upper bound of about 0.1 inch for 30 years, based on information reported in Reference IX.A.14. A minor fraction of this upper bound is the most that might be expected to result from thermal cycling corrosion, so the prospects of discovering that one of the alloy steels selected for Solar 100 (i.e., carbon steel, 304SS, 316SS and Incoloy 800) is unacceptable is certainly small.

It is clear that the possible effect of thermal cycling on required corrosion allowance constitutes a risk that must be addressed.

Precipitation of Salt Impurities

The potentially adverse effects of precipitation of salt impurities constitutes a moderate to small risk considering the fact that they are all known to be filterable. Nevertheless, measures for the disposition and control of precipitates must be defined and demonstrated to eliminate the risks of heat transfer degradation, sludge formation and component fouling.

Tanks

The 1,050°F draw salt tank will be the largest tank ever constructed for operation at that temperature. While the required technology for fabrication of large stainless steel tanks with large dimensional changes is known and demonstrated, some level of technical risk is inherent for a tank which exceeds previously demonstrated combinations of size and temperature. This risk is judged to be moderate, but will require special attention to provision of access should repairs be required.

Heat Tracing

While experience at sodium facilities indicates that, after an initial shakedown period, reliable heat tracing operation is attainable, some risk of piping or component rupture during a thawing operation exists due to expansion of the salt. The salt should be thawed progressively away from an available free liquid surface to avoid damage.

Valves

Although many years of experience with valves in industrial, HITEC salt loops exists, the lack of thermal cycling, large throttling and 1,050°F operation in these loops introduces the risk of earlier-than-expected curtailment of valve life.

Pumps

Technical risks associated with the salt pumps are considered small.

4. Technical Risk Management Plan

General

The following is a plan for reduction of technical risk by:

- o adoption conservative design measures and criteria
- o reenforcement of the design bases with data from a molten salt test loop currently being designed by Olin Corporation, McDonnell Douglas Astronautics Company and Foster Wheeler Development Corporation

Receiver

In order to reduce the likelihood of early failure of receiver tubes the following measures will be adopted:

- o reduction of peak receiver design heat flux from the 0.7 MW/m^2 of the French THEMIS pilot plant receiver, and the 0.63 MW/m^2 of the Martin Marietta salt receiver to a value of 0.60 MW/m^2
- o provision of a real time infrared optical scanner for location and measurement of peak receiver tube temperatures during operation (to permit remedial action in the event of unexpectedly high flux concentration and temperature)
- o design to facilitate replacement of receiver tubes

Steam Generator

- o Minimize risk of tube sheet leaks by
  - use of highest quality tube sheet welds
  - intensive quality control
- o Provide for measurements of hydroxides in steam generator salt flow outlet for detection of steam genertor water/steam leaks.
- o Provide an NO_2 bubbler in the molten salt pump minimum-flow recirculation loops for removal of hydroxides whenever steam generator leaks occur.

Corrosion Allowances

- o Measure corrosion under thermal cycling conditions in the OLIN/MDAC/FW salt loop and alter the corrosion allowance of Table IX.A.2 accordingly.

Precipitants

- o Add filter stations to the molten salt pump minimum-flow recirculation loops for removal of precipitants.
- o Test filtration and other precipitant control methods in the OLIN/MDAC/FW salt loop.

Heat Tracing

- o Conduct thaw tests in the OLIN/MDAC/FW salt loop for identification of satisfactory procedures.

Valves

- o Test a variety of valves (including conventional designs without bellows stem seals) under thermally cycling conditions in the OLIN/MDAC/FW salt loop

Tanks

- o Size the hot and warm salt tanks to permit either tank to hold the entire system inventory (to enable access for repair of the other tank).
- o Make provisions for flushing tanks with water to dissolve and remove salt residues prior to repair.

5. Complementary Activities Affecting Technical Risk

Pilot Plant Operation

In addition to the Barstow 10 MW Pilot Plant there are 5 foreign pilot plants (3 currently operating, 2 scheduled for operation in 1982) that will be valuable sources of operational experience and will provide extended field testing of many important components. Each pilot plant is scheduled to operate for several years. The complete list is

- o Barstow (USA, W/S 47 MWt)
- o THEMIS (France, HITEC salt, 11 MWt)
- o ALMERIA (IEA, sodium, 3 MWt)
- o CESA-I (Spain, W/S, 5 MWt)
- o EURELIOS (Italy, W/S, 6 MWt)
- o SUNSHINE (Japan, W/S, 6 MWt)

Maintenance of technical liaison with these projects and timely information of their progress can help to significantly reduce the technical risks of the Solar 100 project. Some of the expected products of the pilot plant test programs include:

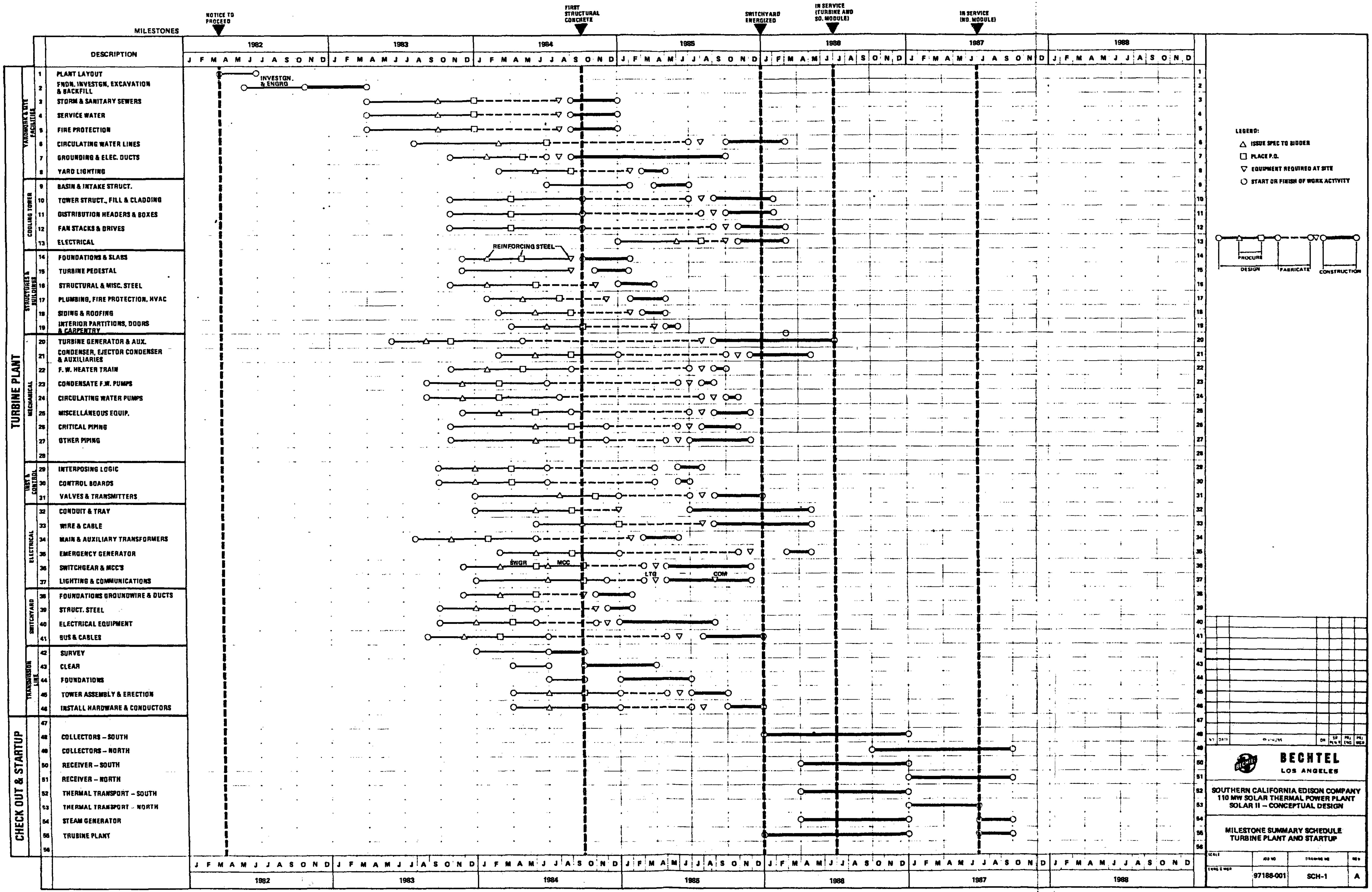
- o verification of receiver design margins
- o field performance, life and availability records for major components
- o record of component failures and their remedies
- o establishment of preferred plant operating procedures

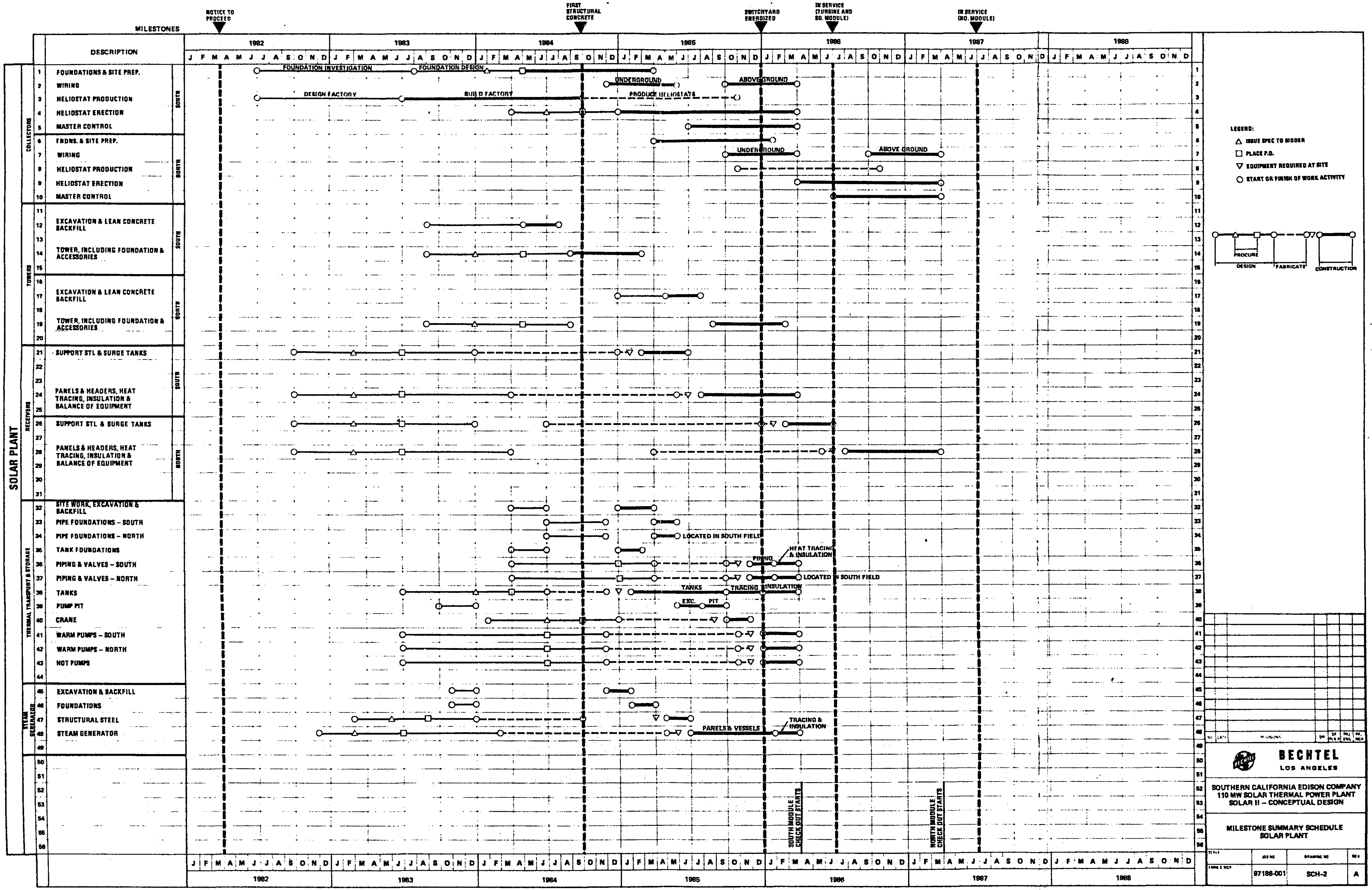
The pump, valve, tank, receiver and steam generator experience with the THEMIS HITEC salt system at Targassone, France will yield much information of particular value to the Solar 100 project.

<u>Combined System Experiment</u>

With the planned termination of DOE funded solar programs late in 1983, efforts are underway to arrange for operation of a combined system experiment at CRTF before the facility is shutdown. This experiment would involve operation of a 5 MWt molten salt loop combining the Martin Marietta 1,050°F draw salt receiver and salt tanks (already at CRTF) with a 5 MWt salt steam generator made of off-the-shelf heat exchanger elements adapted for salt service. Extended operation of this loop could be of immense value to the Solar 100 project. It would duplicate Solar 100 thermal cycling, high P valve throttling, system corrosion, precipitant control, heat tracing and system operating procedure constraints with full temperature draw salt to a degree unmatched by any other available facility.

The minimization of Solar 100 technical risks would be well served by support of efforts to run the combined system experiment and by lobbying efforts to keep CRTF open for extended operation of the experiment through 1984.


MILESTONES
NOTICE TO PROCEED
FIRST STRUCTURAL CONCRETE
SWITCHYARD ENERGIZED
IN SERVICE (TURBINE AND SO. MODULE)
IN SERVICE (NO. MODULE)
DESCRIPTION
1982
1983
1984
1985
1986
1987
1988
J F M A M J J A S O N D
TURBINE PLANT
YARDWORK & SITE FACILITIES
1 PLANT LAYOUT
2 FNDN. INVESTGN, EXCAVATION & BACKFILL
INVESTGN. & ENGRG
3 STORM & SANITARY SEWERS
4 SERVICE WATER
5 FIRE PROTECTION
6 CIRCULATING WATER LINES
7 GROUNDING & ELEC. DUCTS
8 YARD LIGHTING
COOLING TOWER
9 BASIN & INTAKE STRUCT.
10 TOWER STRUCT., FILL & CLADDING
11 DISTRIBUTION HEADERS & BOXES
12 FAN STACKS & DRIVES
13 ELECTRICAL
STRUCTURES & BUILDINGS
14 FOUNDATIONS & SLABS
REINFORCING STEEL
15 TURBINE PEDESTAL
16 STRUCTURAL & MISC. STEEL
17 PLUMBING, FIRE PROTECTION, HVAC
18 SIDING & ROOFING
19 INTERIOR PARTITIONS, DOORS & CARPENTRY
MECHANICAL
20 TURBINE GENERATOR & AUX.
21 CONDENSER, EJECTOR CONDENSER & AUXILIARIES
22 F.W. HEATER TRAIN
23 CONDENSATE F.W. PUMPS
24 CIRCULATING WATER PUMPS
25 MISCELLANEOUS EQUIP.
26 CRITICAL PIPING
27 OTHER PIPING
28
INST & CONTROL
29 INTERPOSING LOGIC
30 CONTROL BOARDS
31 VALVES & TRANSMITTERS
ELECTRICAL
32 CONDUIT & TRAY
33 WIRE & CABLE
34 MAIN & AUXILIARY TRANSFORMERS
35 EMERGENCY GENERATOR
36 SWITCHGEAR & MCC'S
SWGR
MCC
37 LIGHTING & COMMUNICATIONS
LTG
COM
SWITCHYARD
38 FOUNDATIONS GROUNDWIRE & DUCTS
39 STRUCT. STEEL
40 ELECTRICAL EQUIPMENT
41 BUS & CABLES
TRANSMISSION LINE
42 SURVEY
43 CLEAR
44 FOUNDATIONS
45 TOWER ASSEMBLY & ERECTION
46 INSTALL HARDWARE & CONDUCTORS
CHECK OUT & STARTUP
47
48 COLLECTORS – SOUTH
49 COLLECTORS – NORTH
50 RECEIVER – SOUTH
51 RECEIVER – NORTH
52 THERMAL TRANSPORT – SOUTH
53 THERMAL TRANSPORT – NORTH
54 STEAM GENERATOR
55 TURBINE PLANT
56
LEGEND:
ISSUE SPEC TO BIDDER
PLACE P.O.
EQUIPMENT REQUIRED AT SITE
START OR FINISH OF WORK ACTIVITY
PROCURE
DESIGN
FABRICATE
CONSTRUCTION
BECHTEL
LOS ANGELES
SOUTHERN CALIFORNIA EDISON COMPANY
110 MW SOLAR THERMAL POWER PLANT
SOLAR II – CONCEPTUAL DESIGN
MILESTONE SUMMARY SCHEDULE
TURBINE PLANT AND STARTUP
97188-001
SCH-1
A



BECHTEL
LOS ANGELES

SOUTHERN CALIFORNIA EDISON COMPANY
110 MW SOLAR THERMAL POWER PLANT
SOLAR II – CONCEPTUAL DESIGN

MILESTONE SUMMARY SCHEDULE
SOLAR PLANT

JOB NO.	DRAWING NO.	REV.
97188-001	SCH-2	A

XI. 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 commerical 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.

Participation in the UAB was by representatives of the following utilities and organizations:

Electric Power Research Institute
Arizona Public Service Company
Sierra Pacific Power Company
Pacific Gas and Electric Company
Public Service Company of Colorado
U.S. Department of Interior - Bureau of Reclamation
Public Service Company of New Mexico
Bonneville Power Administration
El Paso Electric Company
Los Angeles Department of Water and Power
San Diego Gas and Electric
Utah Power and Light
California Department of Water Resources

Two meetings of the UAB were held, and a final meeting to review the final report will be held when it is completed. The first meeting of the UAB was held on June 8, 1981. The purpose of this meeting was to present the intended scope of the study and to solicit comments from the utilities. Presented were the basic ground rules and assumptions necessary to conduct the study, the methodology for comparing the various candidate systems, the scope of the conceptual design and costing, and finally the scope of the business/financial study.

On August 27, 1981, the second UAB meeting was held. The trade studies had been completed and a molten salt system had been selected to be carried into conceptual engineering, costing and innovative financing. During the meeting, detailed discussions of the trade study were held including comparative system efficiencies, costs and risks. Financial discussions consisted of potential structures, participants and modeling techniques. Additionally, potential areas of government impact were delineated. These areas included continuation of energy tax credits and various PURPA considerations.

The Utility Advisory Board provided a useful forum where ideas from other utilities could be expressed and incorporated as appropriate.

XII. CONCLUSIONS AND RECOMMENDATIONS

The three participating companys, Southern California Edison, McDonnell Douglas and Bechtel reached the following conclusions:

1. It is technically feasible to build a 100 MWe solar thermal power plant by 1988. Such a plant is envisioned to use 2-50 MW heliostat fields each with a separate receiver/tower in a surround field(s) configuration; both fields will supply a common power block.

2. The technical risks of building a 100 MWe solar plant appear to be manageable. The technology is ready although residual issues relating to extrapolation of results from prior prototypes and tests to larger scale and extended operating times do exist. It is believed that these issues can be resolved within state-of-the art design and manufacturing capabilities.

3. The financial analyses showed that utility ownership was not a viable option since the resulting energy costs would exceed Edison's avoided cost. Municipal ownership is a possible viable option although highly contingent upon methods of financing. Third party or entrepreneurial ownership offers the potential of electricity priced below avoided or marginal costs and a sufficiently high rate of return to attract investors. Third party financing is viable due to different tax laws associated with nonutility ownership.

4. Although this report investigated a conceptual design that was site specific to Edison, it was also concluded that the solar thermal central receiver concept is potentially viable anywhere in the southwestern U.S. and Hawaii.

   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.

   There are different methods of solar generation (e.g., photovoltaic, trough, parabolic disk), however, none of the methods in their present state-of-the art offers the immediate potential of producing electricity at below fossil (oil/gas) generated costs. These costs could be appreciably lower if heliostat production costs could be lowered. Given the alternatives facing today's utilities, a central receiver solar thermal power plant must be an alternative carefully compared to other forms of generation. Contrary to other forms of nonrenewable sources of power which has, and will continue to have, a constantly spiralling increase in both capital and fuel costs, solar thermal offers lower unit costs with production increases and no fuel cost.

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