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CONCEPTUAL DESIGN OF ADVANCED CENTRAL RECEIVER POWER SYSTEM, PHASE I

Executive Summary and Final Report

September 1978

Work Performed Under Contract No. EG-77-C-03-1724

Martin Marietta Corporation
Denver, Colorado

U.S. Department of Energy

Solar Energy

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Executive
Summary

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Approved

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FOREWORD

These documents, submitted to the Department of Energy, San Francisco, California, in response to Contract EG-77-C-03-1724, presents the Martin Marietta Corporation's plan for developing Conceptual Design of Advanced Central Receiver Power System.

Our report is submitted in two volumes:

Final Report

Executive Summary

CONTENTS

FIGURES

TABLES

I. INTRODUCTION

The primary objective of the program is to develop a solar power plant to reduce the cost of electricity significantly below that of the first-generation plants. Other desirable benefits are higher capacity displacement, greater national market penetration, increased potential for subsequent performance improvement, and reduced environmental impact. We believe our recommended system achieves the objectives and does so with low technical risk.

Table I-1 gives the cost of electricity for the recommended system. We believe the proposed alternative molten salt system has potential to reduce the cost of electricity well over a factor of two relative to the first generation. Because solar energy is available only on an intermittent basis, the cost of storage is important to the future success of solar power. The attractive cost of the molten salt storage system is quite competitive with existing pumped storage systems in use today. The low storage cost will undoubtedly result in a significant improvement in capacity displacement. In fact, we believe that the proposed system will meet utility requirements for an intermediate plant. The requirements are as follows:

1) Must be operated at least 4000 hours per year;
2) Must be available most of the time during the utility's peak period.

The primary factor affecting market penetration is cost; therefore, the recommended system will be able to provide larger market penetration than the first-generation plants. Also, the attractive cost of storage will undoubtedly add to wider acceptance of solar power. The primary factor in environmental impact is land use. The recommended system is approximately 20 percent more efficient than the first-generation plants when operating from the receiver and is 70 percent more efficient when operating from storage; therefore, the percentage of improvement in performance

Table I-1 Cost of Electricity (BBEC) and Storage

	Recommend Alternative Molten Salt System
Cost of Electricity (mills/kWhe) - with Economic Ground Rules Used in First Generation (Cost of Money 7.5%)	28.0
- Present Economic Ground Rules (Cost of Money 11%)	38.4
Cost of Storage - Thermal ($/kWht) - Electrical ($/kWhe)	 3.40 8.20

depends on the amount of storage used. For the recommended plant, the overall average performance is at least 30 percent better than the first generation. As a result it will require about 30 percent fewer heliostats and less land per unit output.

Another important advantage of a molten salt system is safety. The salt does not react with water or air. It is commonly used in open baths in industry and has an excellent safety record. On the other hand, sodium reacts spontaneously with air and violently with water.

Major program tasks will be summarized; they are titled as follows:

1) Recommended Commercial Plant Conceptual Design and Performance
2) Rationale for System Selection
3) Assessment of Commercial System
4) Development Status
5) Recommended Development Plan
6) Alternative 100 MWe System

II. RECOMMENDED COMMERCIAL PLANT CONCEPTUAL DESIGN AND PERFORMANCE

A. SYSTEM DESCRIPTION

The system has a net electrical output of 300 MWe and has sufficient heliostats and storage capacity to provide full load operation 24 hours per day at summer solstice. The system consists of nine heliostat fields with 7711 heliostats in each (Fig. II-1). The heliostats track the sun and direct the solar energy incident on them to one of four cavity apertures located at the top of a 155-meter (510 ft) tower. The system is shown schematically in Figure II-2. Inside the cavity the flux is absorbed on panels. The panels are cooled by molten salt that enters the receiver at 561 K (550°F) and leaves the receiver at 838 K (1050°F). Salt flowrate is controlled to maintain a

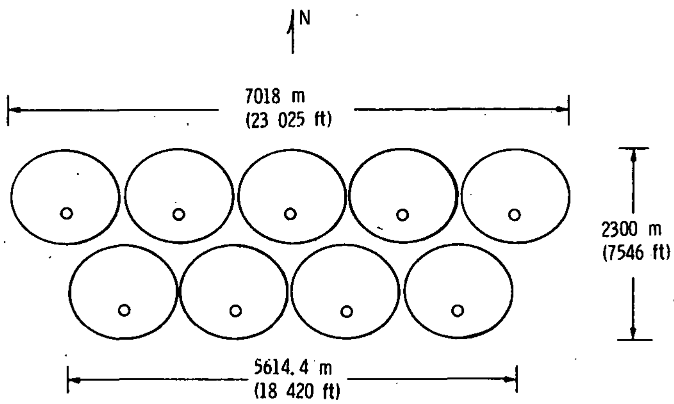

Figure II-1 300 MWe Module Layout

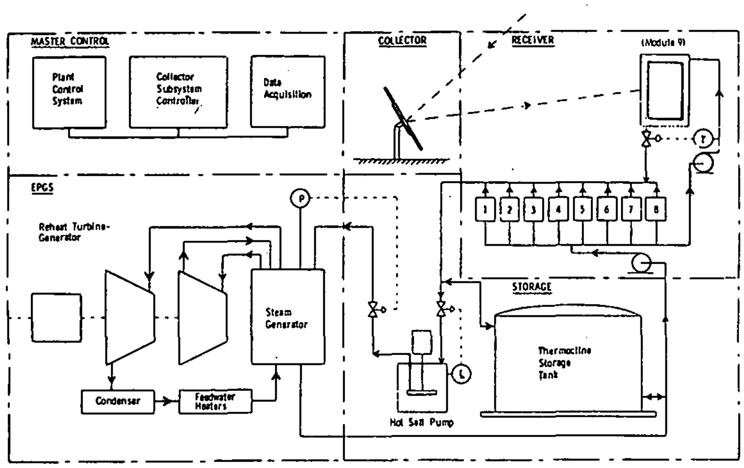

Figure II-2 System Schematic

constant salt exit temperature at the receiver outlet. The hot salt is pumped to the steam generator and/or the storage system. Hot salt pumped to the storage system is stored for later use by the steam generator. The hot salt pumped to the steam generating system is used by the steam generator to heat boiler feedwater and make 783 K (950°F), 16.5 MPa (2400 psig) superheated steam for the steam turbine/generator. During the process the hot salt is cooled to 561 K (550°F). The cold salt is pumped to the bottom of the thermal storage tank and/or back to the receivers. During periods when solar insolation is insufficient for rated operation, energy is extracted from the storage system and used to supply heat to the steam generator. The master control system is computerized and provides operator over-rides that serve as overall plant control. It also provides data display and storage.

The electrical power generating plant and the storage facility are located between the middle three module fields (Fig. II-1). The location was selected to minimize salt piping runs to the field. The plant layout consists of four areas (Fig. II-3). The electric power generation subsystem (EPGS) building houses EPGS equipment with the turbine on the upper, or operating floor, and the condenser and condensate/feedwater pumps on the lower floor. The building also houses the master control system and the collector control system on a mezzanine floor. The steam generator (heat exchanger) area is located as near as possible to the turbine to minimize piping runs. The thermal storage tanks are across the road. The area is diked to contain the molten salt in case of a tank rupture. The EPGS water treatment area is similar to conventional plants. An artist's concept of the system is shown in Figure II-3a.

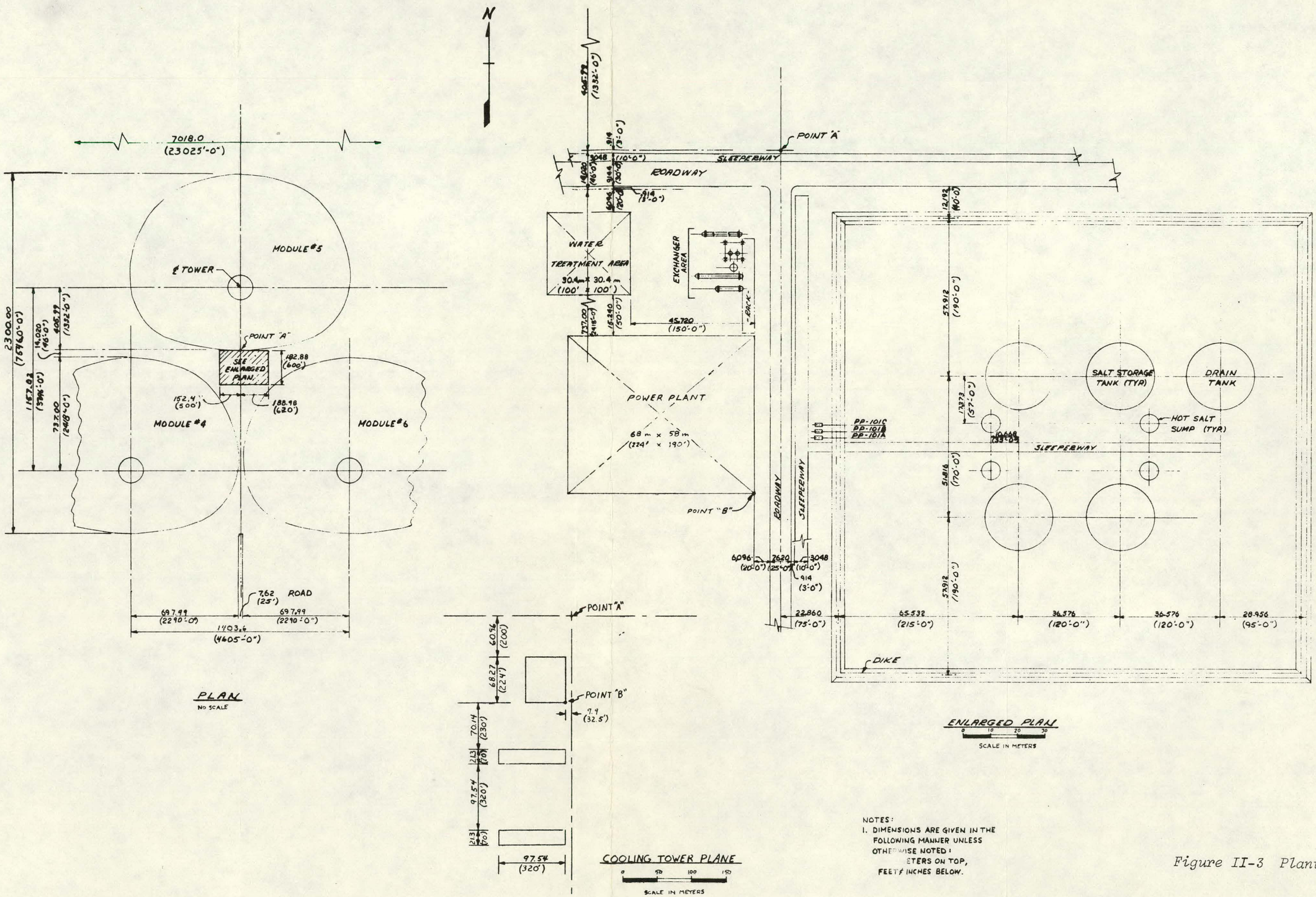

Figure II-3 Plant Layout

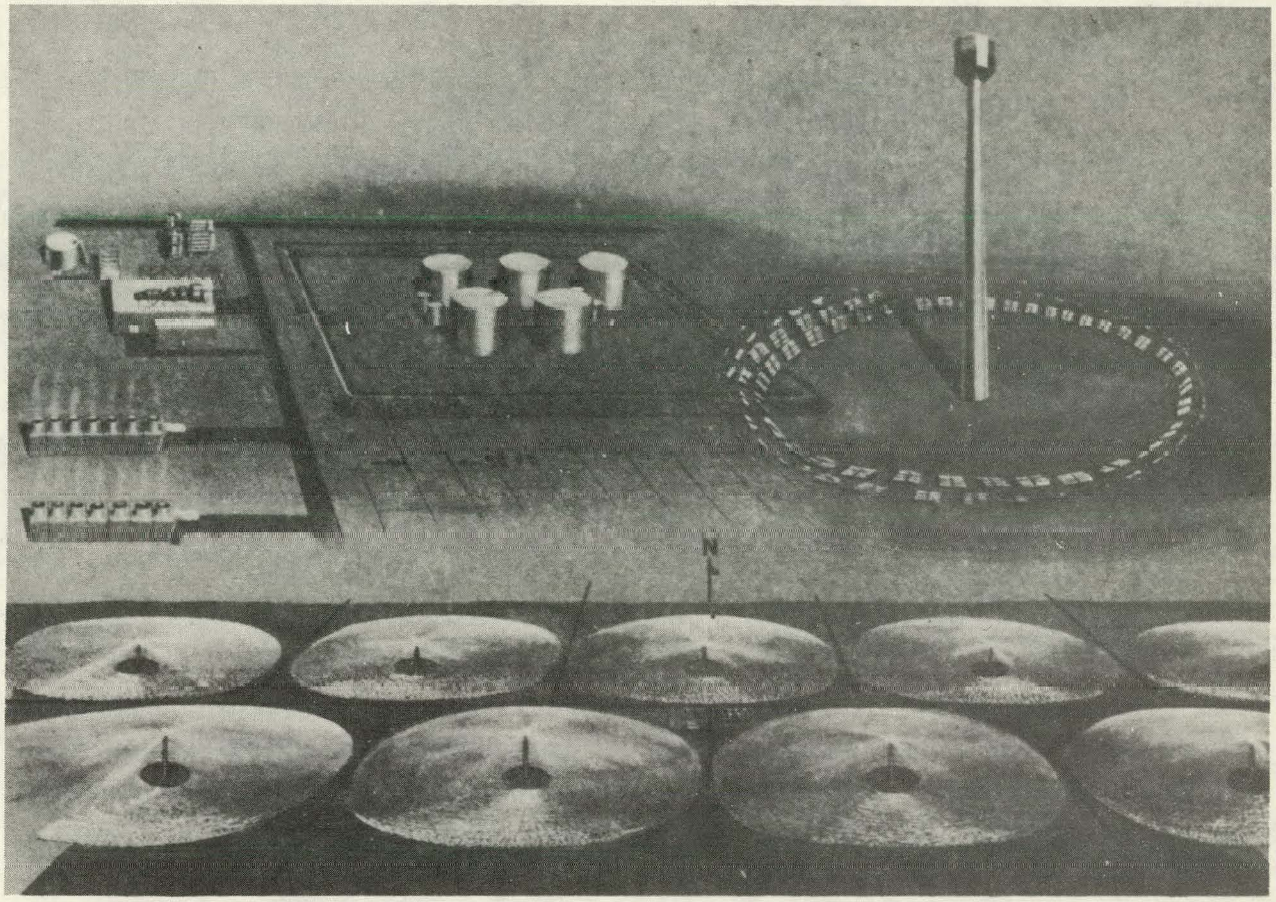

Figure II-3a Artist's Concept of Advanced Central Receiver Power System

B. SUBSYSTEM DESCRIPTION

The system is comprised of a collector, a tower, an electric power generation subsystem (EPGS), molten-salt components that include receivers, tanks, heat exchangers, pumps, associated piping, thermal storage, and master control.

1. Collector

The module configuration shown in Figure II-1 consists of nine modules, five in an east-west row with another four modules in a row just to the south of the first row; both rows are symmetrically aligned on the same north-south line. This layout was selected to minimize salt piping runs and expansion joints in the piping.

The heliostats in the field are positioned along radial lines with the receiver tower at the center. The rows of heliostats are spaced to minimize shadowing or blocking along the north-south line at the design point (21 June). An aiming strategy was developed to minimize spillage and produce an acceptable receiver heat flux. This strategy will be discussed later under receiver performance. The coordinates and aim points for each heliostat were determined and are described in Appendix D.

The heliostat requirements for the conceptual design are given in Table II-1. It is emphasized that the system could use various heliostat designs and is not limited to the ones that meet the requirements of Table II-1. In fact, as discussed in

Table II-1 Heliostat Requirements

Size	39.95 m^2 (430 ft^2)
Reflectivity (clear)	0.91
Focal Length*	712.3 m (2338 ft)
Tolerances (Mirror Normal 1σ)	
- Aiming (Elevation and Azimuth)	0.75 m rad.
- Image Quality	0.70 m rad.
* Facets focused and canted	

Task 5, there is potential for reducing system cost by reducing heliostat requirements.

2. <u>Tower</u>

The selected tower design is shown in Figure II-3b. It is a reinforced concrete tower of 12.9 m (40 ft) diameter at the base and 7.63 m (25 ft) diameter at an elevation of 155.45 m (510 ft).

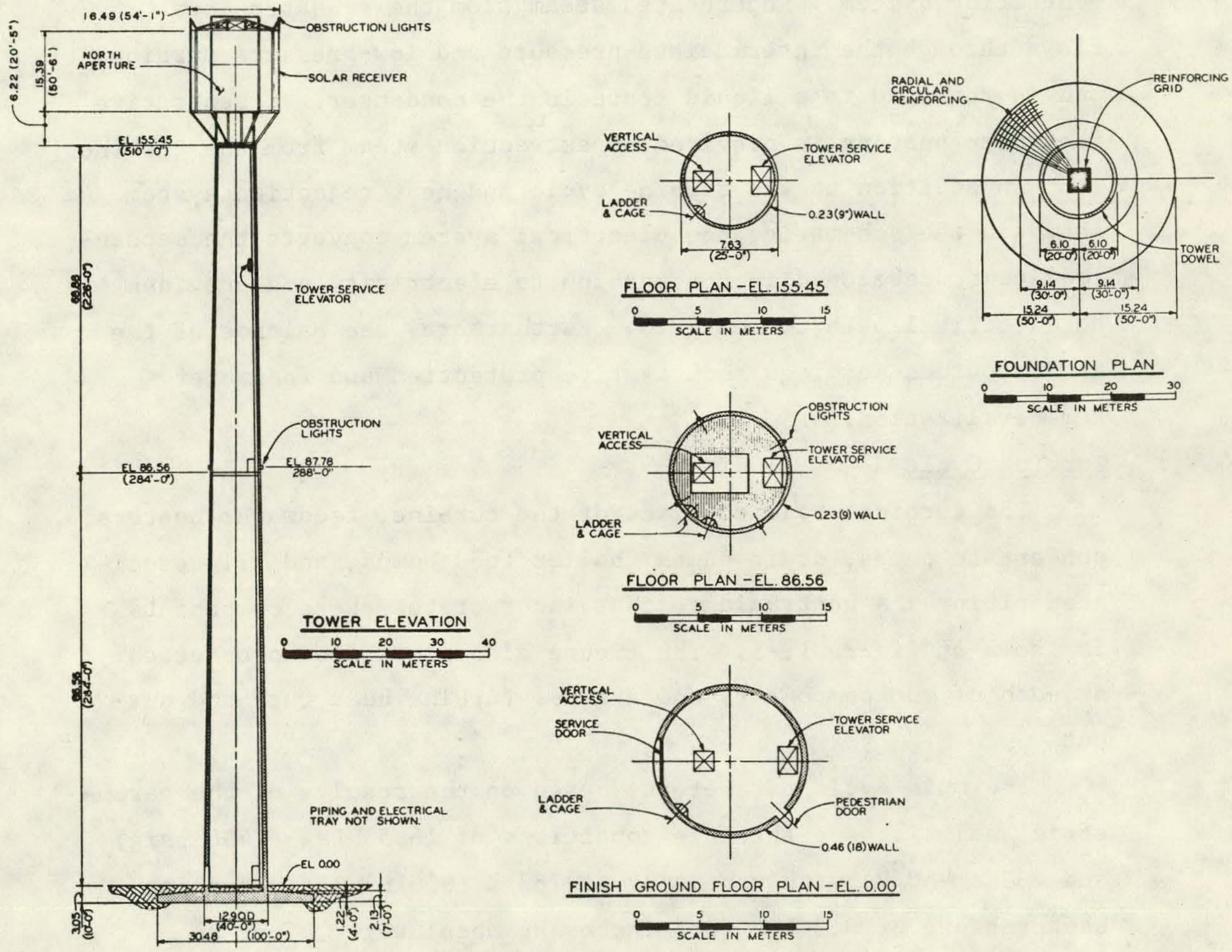

Figure II-3b Receiver Tower and Foundation

3. Electric Power Generation System (EPGS)

In overall design, the EPGS is similar to the EPGS of a conventional fossil-fired 300 MWe plant. The interface between the EPGS and the other subsystems of the plant are the main steam line, the cold and hot reheat steam lines, the feedwater line, auxiliary electrical power, the control system, and the net electrical output of the plant. The functional relationships of major EPGS components are shown on Figure II-4. Superheated steam from the steam generator flows through the high-pressure turbine and then to the single reheater, contained in the steam generating system. Superheated steam from the reheater then flows through the intermediate-pressure and low-pressure turbines and is returned to a liquid state in the condenser. Regenerative feedwater heating is provided by extraction steam from the turbine.

In addition to the turbine cycle and heat rejection system shown in the schematic, the electrical system converts the mechanical power developed in the turbine to electricity and provides an electrical path to the grid. Furthermore, the balance of the EPGS provides services such as fire protection and feedwater demineralization.

4. Turbine Cycle

The turbine cycle consists of the turbine, feedwater heaters, condensate pumps, drain pumps, boiler feed pumps, and all associated piping. A heat balance that incorporates these components is shown on Figure II-5. The figure also shows flow properties at each of the components and a gross turbine heat rate and output.

The main cycle parameters, based on the results of the parametric analysis, are throttle conditions of 16.5 MPag (2400 psig) and 783K (950°F) with reheating to 783 K (950°F) and a turbine backpressure of 8.5 kPa (2.5 inches Hg absolute). After an allowance for auxiliary loads of approximately 35 MWe, the unit

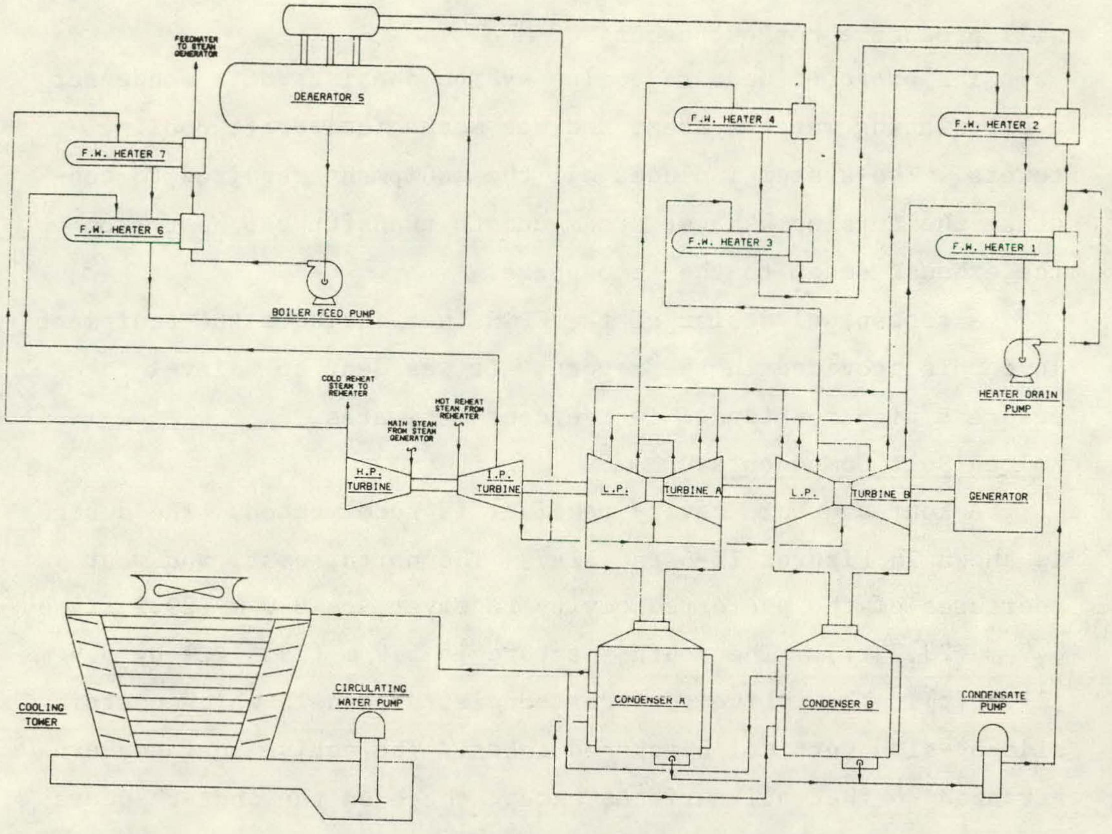

Figure II-4 Electric Power Generation Subsystem System Schematic

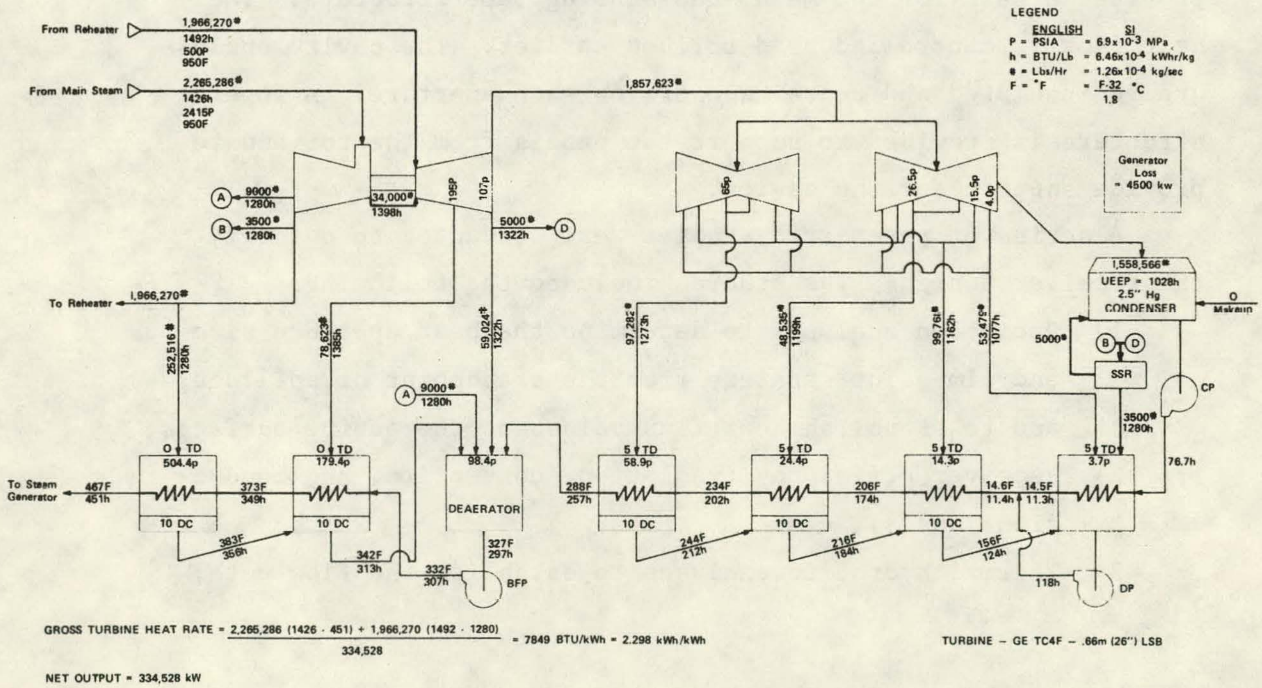

Figure II-5 Heat Balance for 300-MWe EPGS will produce a net output of 300 MWe.

The proposed heat rejection system consists of a condenser, a circulating water system, and wet mechanical draft cooling towers. The system includes all the equipment required to condense the turbine exhaust steam and to transfer the heat from the exhaust steam to the atmosphere.

A conceptual design of the EPGS that includes the equipment layout is provided in the report. It was done to a level to ensure a high confidence in the cost estimates.

5. Molten Salt Components

A four-aperture cavity receiver is recommended. The design is shown in Figures II-6 and II-7. The north, east, and west apertures of the preferred cavity receiver are 8.9 m (29.2 ft) by 8.9 m (29.2 ft). The south aperture is 5.9 m (19.5 ft) by 5.9 m (19.5 ft). The active surfaces consist of panels which contain side-by-side vertical blackened tubes. The active surfaces are arranged so that all surfaces except those on the center square are irradiated from both sides. The center square section also provides a path for the main load-bearing superstructure. The salt flow is controlled as described earlier. The cavity enclosure is insulated and contains doors on each aperture. A superstructure is provided to support the panels from the top and to provide support for the cavity.

A series of parametric studies were conducted to quantify the receiver design. The studies included the following:

1) Radiation analysis to determine the best aperture size and aim-point strategy from the standpoint of spillage, and to establish heat flux values on the active surfaces;
2) Receiver efficiency (radiation, convection, and conduction losses);
3) Thermal hydraulic analyses to establish the flow path,

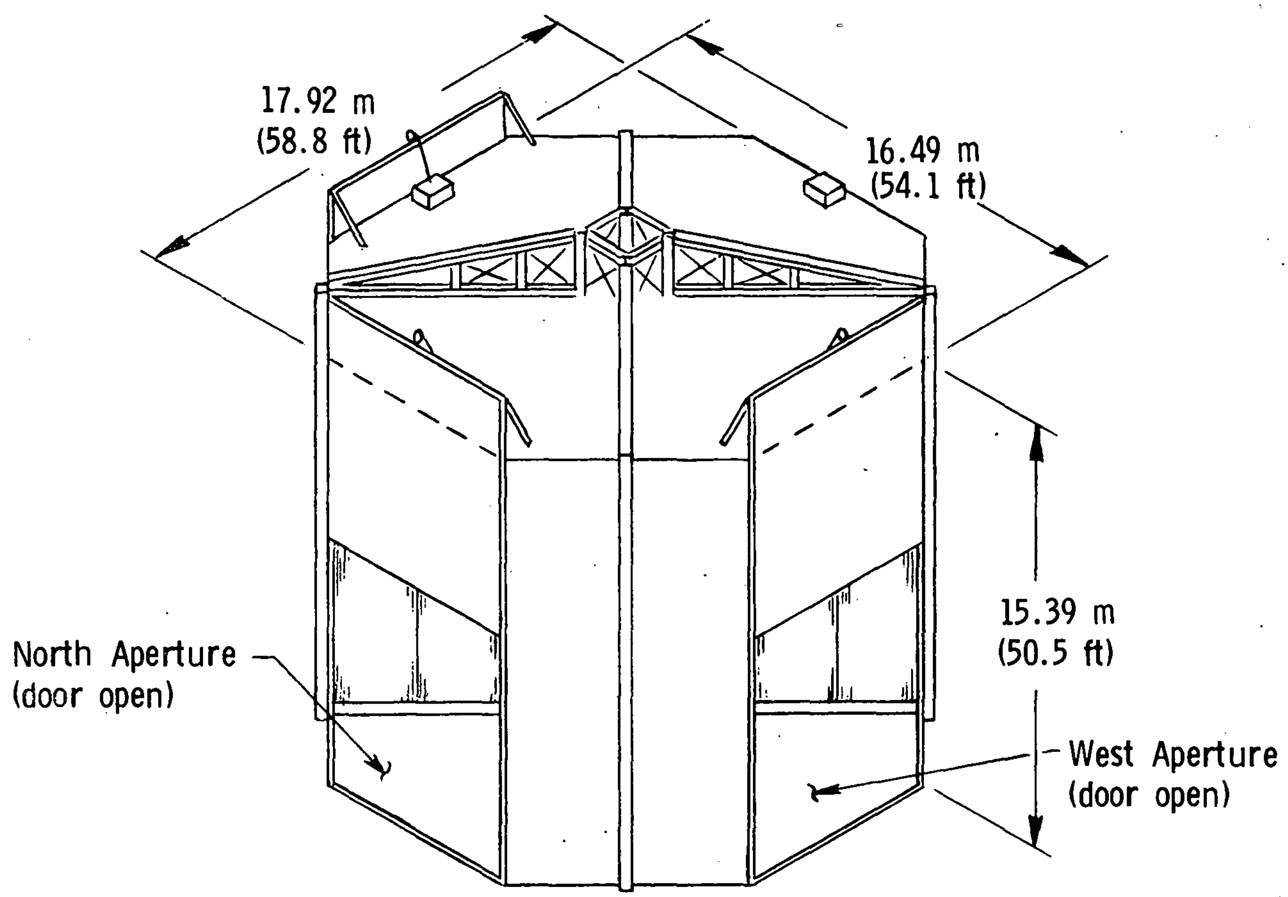

Figure II-6 Cavity Receiver

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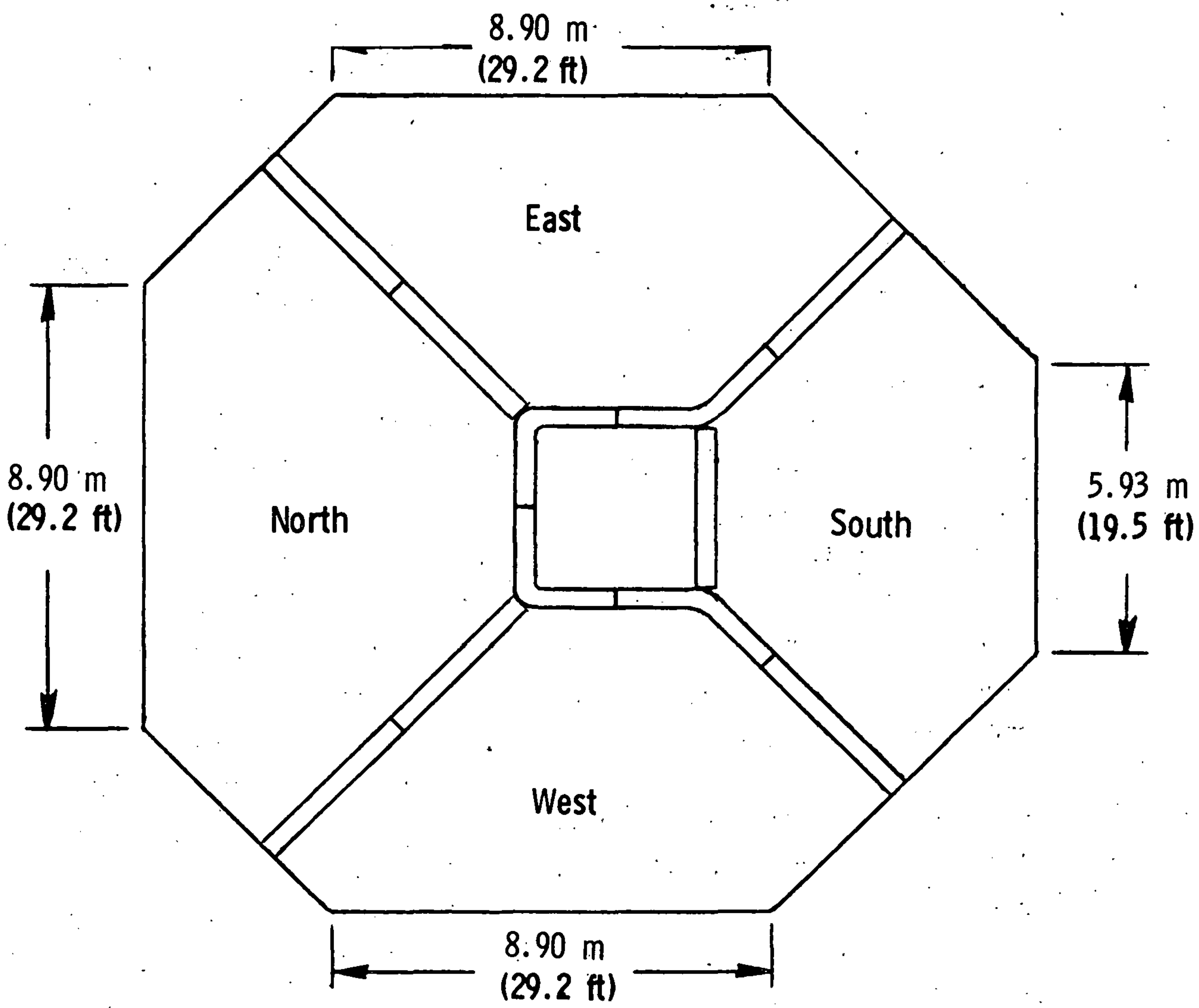


Figure II-7 Cavity Receiver Plan View

pressure drop, heat transfer coefficients, and tube metal temperatures;

4) Receiver tube thermal stress analyses to determine tube life;

5) Mechanical design studies to establish the active surface configuration and method of support, enclosure configuration, and structure configuration.

6. Heat Exchangers

Heat exchangers required to transfer the heat from the molten salt to the water stream are shown schematically in Figure II-8. The exchangers consist of a superheater, reheater, two boilers, and two preheaters. The relatively low-pressure molten salt is on the shell side of the exchangers and the high-pressure water/steam is on the tube side. The hot molten salt at 836 K (1045^{o}F) flows through the superheater and reheater in parallel and then through the two boilers in parallel followed by the two preheaters in series. Steam is produced out of the superheater at 16.5 MPag (2400 psig), 783 K (950^{o}F), and at 3.45 MPag (500 psig), 783 K (950^{o}F) from the reheater.

7. Pumps

The pumps that pump molten salt from the storage area to the base of the towers (circulating pumps) and the pumps that pump the salt up the towers (booster pumps) are conventional single-stage centrifugal pumps with mechanical seals. The pumps operate at 561 K (550^{o}F). The hot molten salt pumps that operate at 838 K (1050^{o}F) are conventional single-stage vertical cantilevered centrifugal pumps. No bearings or seals are exposed to the hot salt.

8. Piping

The recommended piping system uses a basic plant layout that allows thermal expansion of the piping within allowable stresses.

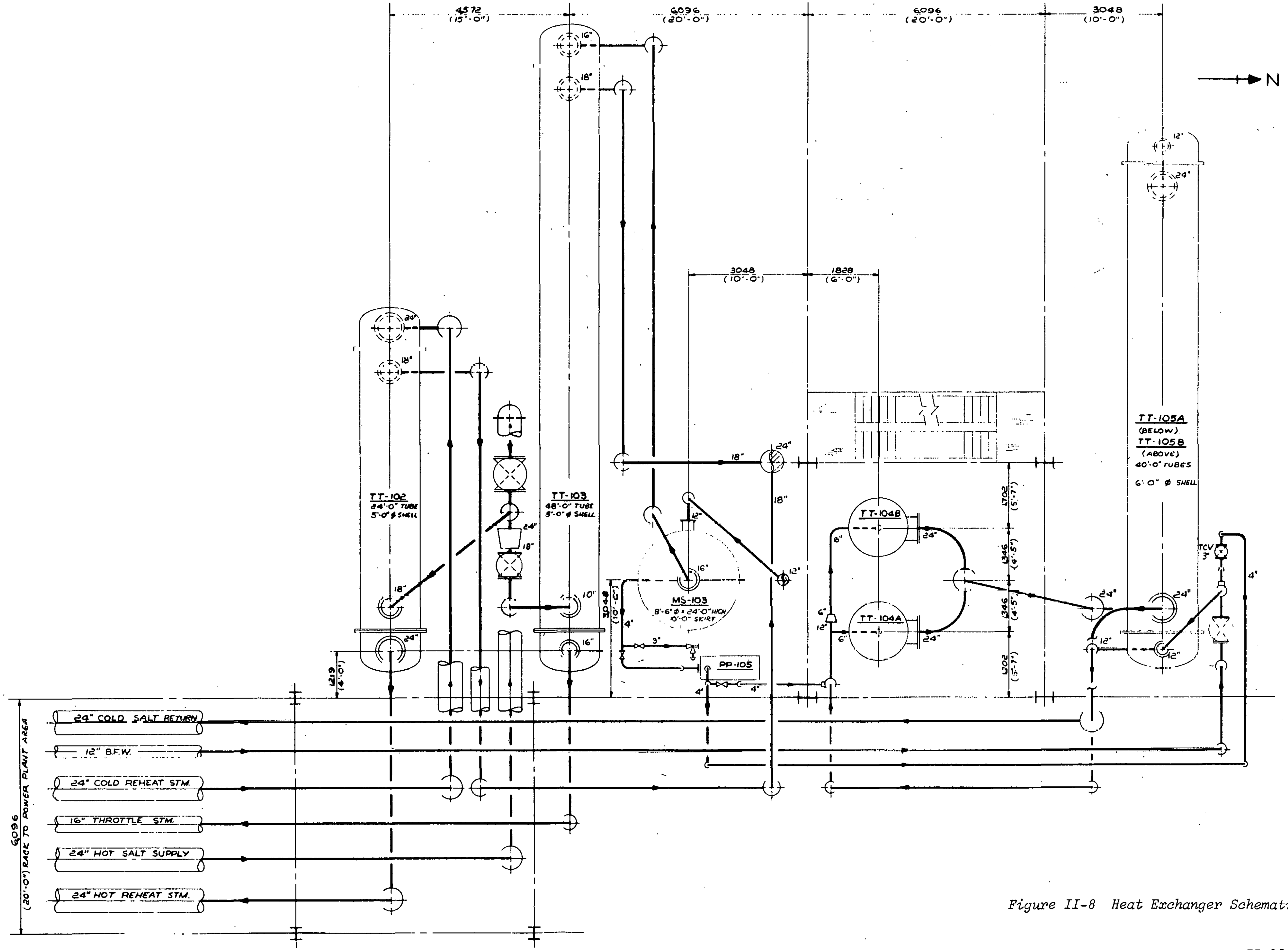


Figure II-8 Heat Exchanger Schematic

and a minimum number of expansion joints to minimize cost. Pipe sizes vary from 12- to 30-inch diameter. Incoloy 800 is used on the hot lines and carbon steel is used on the cold side. A detailed flow and stress analysis of the piping was done to prove feasibility of the concept.

9. Thermal Storage

Thermal energy is stored as sensible heat in four cylindrical flat-bottomed tanks, each of which is designed to operate as a thermocline. The tanks are 23.8 m (78 ft) in diameter and 26.8 m (88 ft) high. The API tanks are specially insulated on the inside to allow use of carbon steel and to minimize heat loss. Each storage tank is complete with its own cantilever type hot salt pump and sump. The storage tanks area is completely enclosed by a dike, designed to contain the total volume of working media in the event of an emergency.

Except for the concept of the internal insulation in the tanks, all the components of the storage subsystem use concepts and/or hardware consistent with existing and proven technology.

10. Master Control Subsystem

The Master Control Subsystem (MCS) is comprised of those system-level elements that accomplish the control, communications, and data acquisition and analysis functions for the system. The various elements of the MCS integrate the functioning of the autonomous controls of the five subsystems (receiver, collectors, thermal storage, steam generation, and electric power generation) to achieve a coordinated central control capability. Efficient operation of the plant is centralized by the operator, and therefore the MCS design has provided a manual intervention and override capability that will allow full use of operator judgement during all phases of plant operation. During routine operation, the mode of operation of the design can be generally described as one of process management in which the operator's objective is to provide a maximum of electrical power at minimum cost. Also, our design has eliminated potential single-point failure modes in the control of the plant.

11. Master Control Subsystem (MCS) Definition

Figure II-9 is a simplified block diagram of the control philosophy selected for the commercial plant configuration of the Advanced Central Receiver Solar Power System. The design emphasizes the use of computers, but with manual intervention capability, in order to:

1) Monitor more data simultaneously;
2) Provide more efficient control of interactive variables;
3) Present more information for operator interpretation "by exception," rather than all information continuously;
4) Data acquisition and reduction;
5) Emergency operations.

C. SYSTEM PERFORMANCE

Yearly system performance was evaluated using the Solar Thermal Electric Annual Energy Calculator (STEAEC) program with the 1976 Barstow weather data type. (System parameters input to STEAEC are discussed in detail in Appendix A.) Major yearly performance results are listed in Table II-2.

The STEAEC output indicates that the system has a CF_A of 0.649; that is, it could have produced 64.9% of the power of a plant operating at full load for 24 hours per day, 366 days per year, at Barstow, California in 1976. This assumes that plant downtime is negligible and that maintenance is performed at night after plant shutdown.

Figure II-10 shows an average yearly energy stairstep derived using the STEAEC output.

Figure II-11 shows the stairstep for the Design Point, 1200 hours, 21 June.

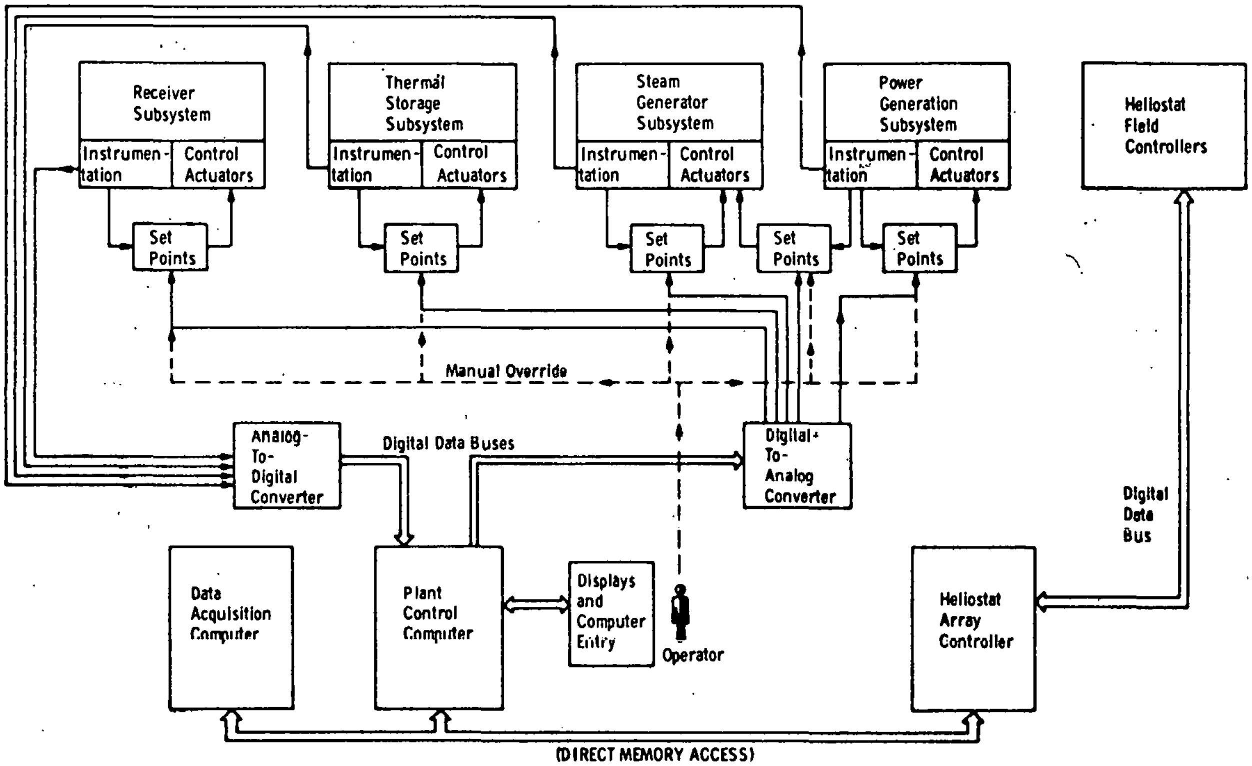


Figure II-9 MCS Control Philosophy

Table II-2 STEAEC outputs

Yearly Energy to Collector Field	7 439 000	MWht
Yearly Energy Incident on Receiver	4 663 000	MWht
Yearly Available Energy in Molten Salt	4 239 000	MWht
- To turbine	2 730 000	MWht
- To storage	1 509 000	MWht
Yearly Energy to Turbine from Storage	1 484 000	MWht
Yearly Gross Electricity from Turbine	1 849 000	MWhe
Yearly Net Electricity from Turbine	1 726 000	MWhe
Yearly Auxiliary Energy Purchases from Grid	16 000	MWhe

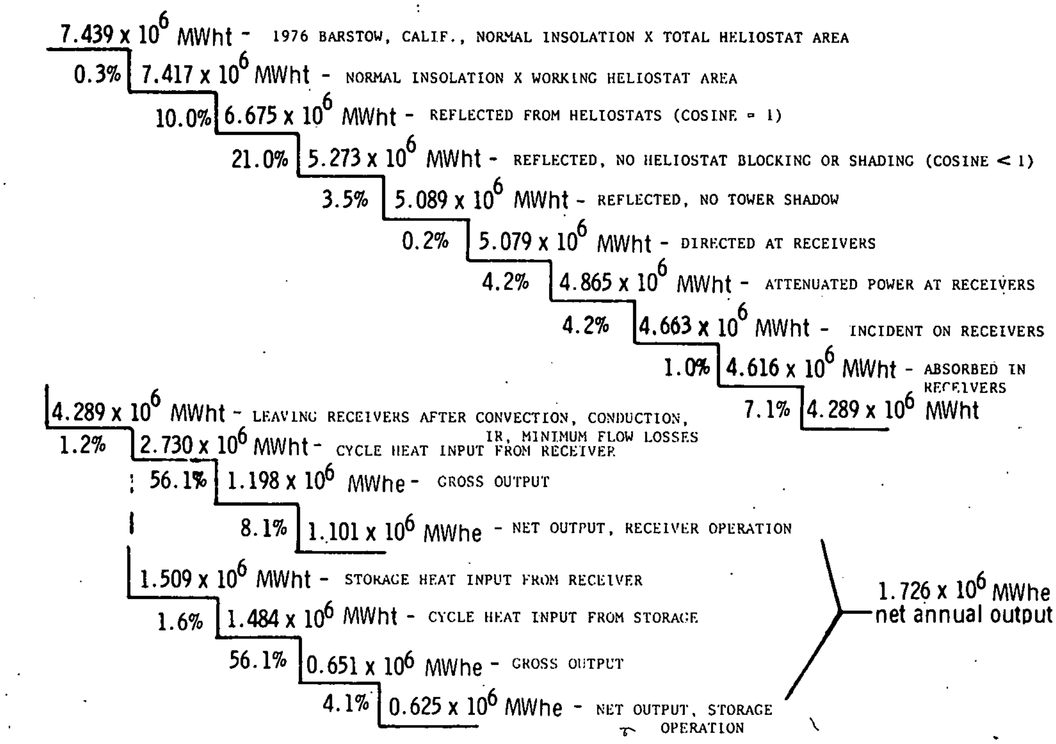


Figure II-10 Average Energy Per Year (Barstow, CA, 1976)

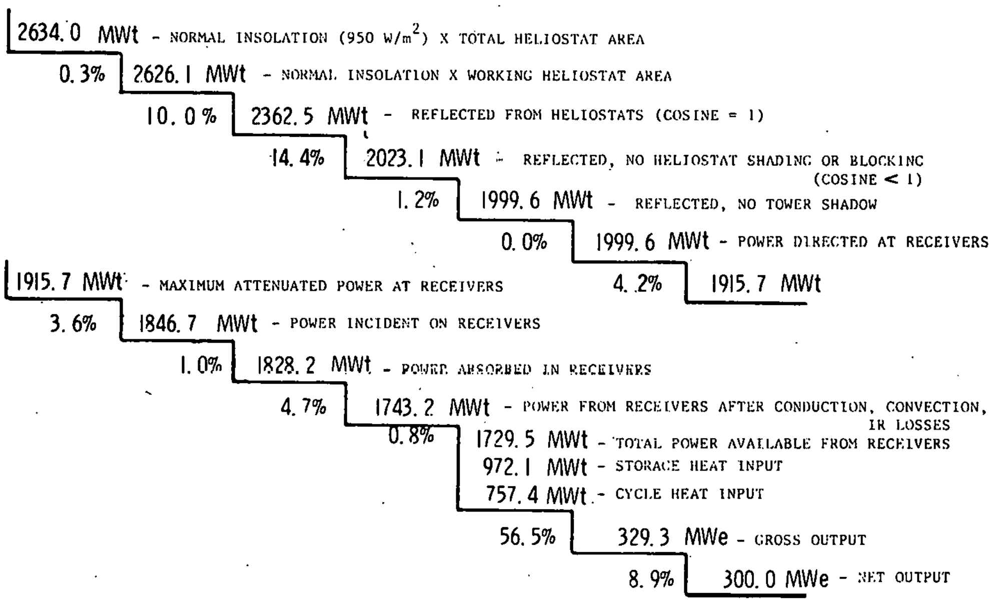


Figure II-11 Design Point Stairstep (1200 hr, 21 June)

III. RATIONALE FOR SYSTEM SELECTION

Parametric analyses of the subsystems were performed. The primary criterion for selection of a given design alternative was its potential to reduce the cost of electricity generated by the solar plant. A number of design alternatives for each design were studied considering development risk and interfacing with other subsystems. Specifically, studies were made for (1) the collector subsystem, (2) the receiver subsystem, (3) the energy storage subsystem, (4) the electric power generation subsystem, (5) the master control subsystem, and (6) critical factors common to more than one subsystem, such as plant size and molten salt components.

The general purpose of the studies was to examine parametric sensitivities at the subsystem level. These data were then used to arrive at a system-level optimum configuration. An iterative approach was used that compared system cost and performance to an assumed baseline plant and then changed that baseline as the optimization studies dictated.

1. North versus Surrounding Field

Figure III-1 shows the percentage of difference in plant capital cost of north versus surrounding field plants as a function of number of modules. The baseline is the preferred design configuration (300 MWe, 9-module plant with surrounding field and 24-hour operation at full load at the design point) with either $75.35/m^2 ($7/ft^2) or $107.64/m^2 ($10/ft^2) heliostats. The costs are differentials from the cost of the baseline design for both heliostat costs. The surrounding field has a small, though distinct, advantage over a north field concept.

2. Modularity

Figure III-1 also shows the difference in total plant cost as a function of the number of modules. The baseline for the study is the 300 MWe, 9-module plant with 24 hours continuous operation at the design point with full load. The curves are flat between 6 and 10 modules. We selected nine modules because smaller modules have less scaling problems from the pilot plant to the commercial plant and provide more flexibility in plant layout

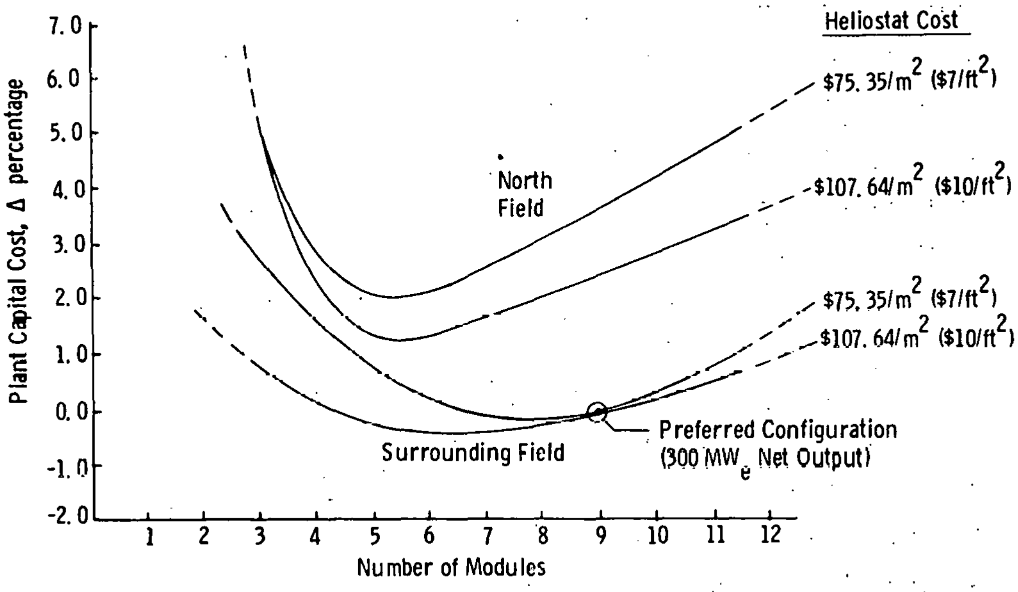


Figure III-1 Delta Percentage of Plant Capital Cost vs Modules for North and Surrounding Field

3. Exposed Versus Cavity Receiver

Table III-1 summarizes the result of the receiver trade-off study. The relatively small increase in cost of the cavity-type receiver is far lower than the reduced cost of heliostats as a result of the superior cavity efficiency.

Table III-1 Exposed Versus Cavity Receiver

	Yearly Average Thermal Efficiency-%*	Spillage-%	Number of Heliostats	Cost of Heliostats** ($107.64/m²) ($10/ft²)	Cost of Receivers	Cost of Heliostats Plus Receivers
Exposed	84.7	1.0	72,936	$313.6M	$9.3M	$322.9M
Cavity	92.0	4.2	69,399	$298.4M	$11.9M	$310.3M
Potential Savings	$					$12.6M
	%					3.9%

*Yearly energy leaving receiver/yearly energy incident on receiver, as calculated by STEAEC using 1976 Barstow insolation.

**Each heliostat 39.95 m² (430 ft²)

4. Plant Size

The system cost difference versus plant size is shown in Figure III-2. Data are based on plants that operate at full load 24 hours a day on June 21. Based on this study we selected a plant size of 300 MWe that is close to the minimum cost per unit output.

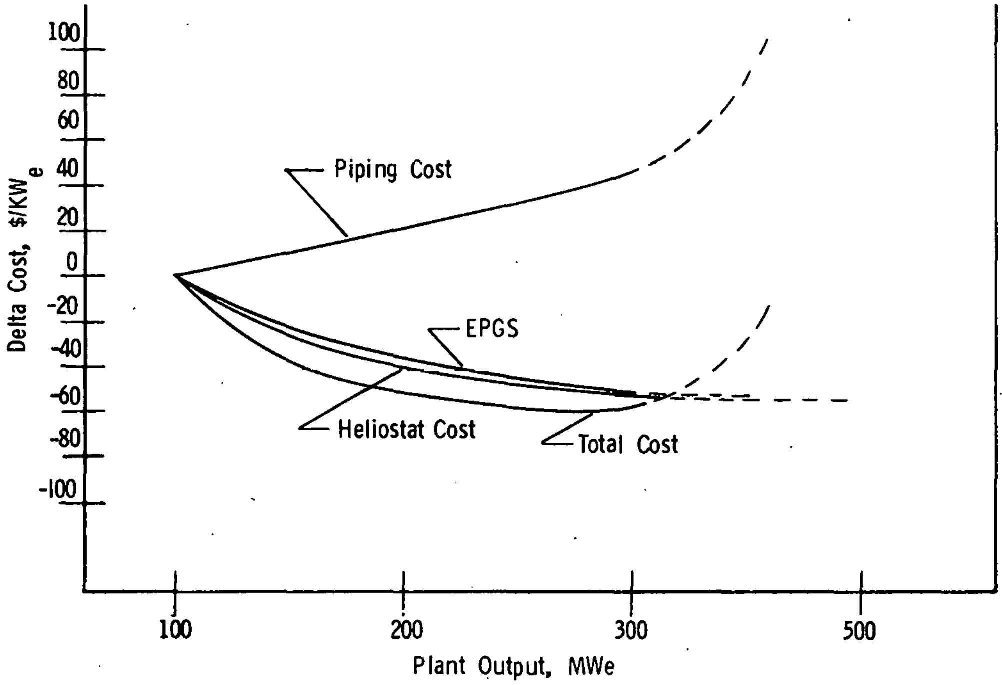


Figure III-2 Plant Output Optimization

5. Storage Capacity

The $\overline{BBEC}$ versus the amount of storage is shown in Figure III-3. At 12 hours of storage the BBEC is still decreasing. Therefore, we selected a storage capacity that will allow the plant to operate at full load 24 hours per day on June 21.

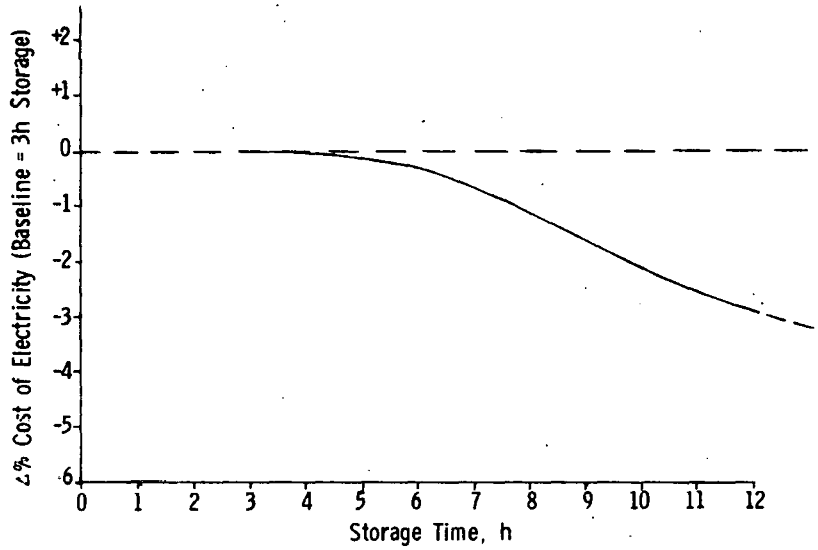


Figure III-3 Cost of Electricity vs Storage Capacity

6. EPGS Parameters

Tradeoff studies were conducted on the throttle pressure, turbine inlet temperature, reheat temperature, turbine exhaust pressure, and double versus single reheat. The results of these studies are as follows:

Parameter	Selected Value	Rationale
Throttle Pressure	16.5 MP_{ag} (2400 psig)	- Most Cost Effective - Availability
Temperature	794 K (950° F)	- Cost Effective - Upper End of Materials Data
Exhaust Pressure	8.44 Pa (2.5in. Hg)	- Cost Effective
Double vs Single Reheat	Single Reheat	- Cost Effective - Availability

7. Molten Salt

A salt nominally consisting of 60 percent $NaNO_3$ and 40 percent KNO_3 was selected because (1) it is thermally stable at the system operating temperature, (2) it is compatible with the selected materials at the system operating conditions, (3) it is inexpensive (raw material cost 18.7¢/Kg - 8.5¢/lb) and (4) the raw materials are plentiful.

8. Molten-Salt Components

Detailed tradeoff studies were conducted to select the most cost-effective molten salt components taking full advantage of the many years of industrial salt system experience. Studies were conducted to select the following:

1) Flow scheme
2) Heat exchangers
3) Pumps
4) Piping system and valves
5) Thermal storage

In all cases conventional components were selected with the exception of thermal storage tanks. Internally insulated thermocline tanks were selected because we are convinced that this approach is the most cost effective. The use of a thermocline reduces the number of tanks required. Detailed thermocline analysis was done to show that molten salt is a good thermocline fluid. With use of internal insulation, relatively thin-walled carbon steel tanks can be used. Also, the tanks will have relatively small thermal gradients resulting in low thermal stresses. Externally insulated tanks would require thick-walled alloy steel tanks that would be expensive and would have severe thermal stresses.

IV. ASSESSMENT OF COMMERCIAL SYSTEM

An assessment of the recommended system was performed, which included the following:

1) Detailed cost analysis;
2) An economic analysis to compute the bus bar electricity cost, $\overline{\text{BBEC}}$, using the cost analysis and performance analysis results;
3) Potential for future improvements;
4) Definition of possible limitations to the application of the system;
5) The value of thermal storage.

Results of the cost analysis are given in Figure IV-1. The values shown are for a 300 MWe (net) plant with sufficient heliostats and thermal storage to operate at full load for 24 hours on June 21. The largest single cost item is the heliostat cost. Two cases are given; one using $\$75/m^2$ ($\$7/ft^2$) and the other using $\$108/m^2$ ($\$10/ft^2$) heliostats. The EPGS costs are based on a conventional system estimated by Black and Veatch after thorough study. The largest part of the storage cost is the salt, which was based on 24.5¢/kg (11.5¢/lb). The raw materials are available at 18.7¢/kg (8.5¢/lb) FOB in the southeast. The transportation and processing will not add more than 6.6¢/kg (3¢/lb). All other hardware costs are based on estimates of the design developed during the study using methods developed by the process industry over the years. Most of the component estimates are backed up by quotes from reputable suppliers.

The BUCKS computer program was run using the results of the cost analysis given above and the results of the STEAEC performance program presented earlier. The results are given in Table IV-1.

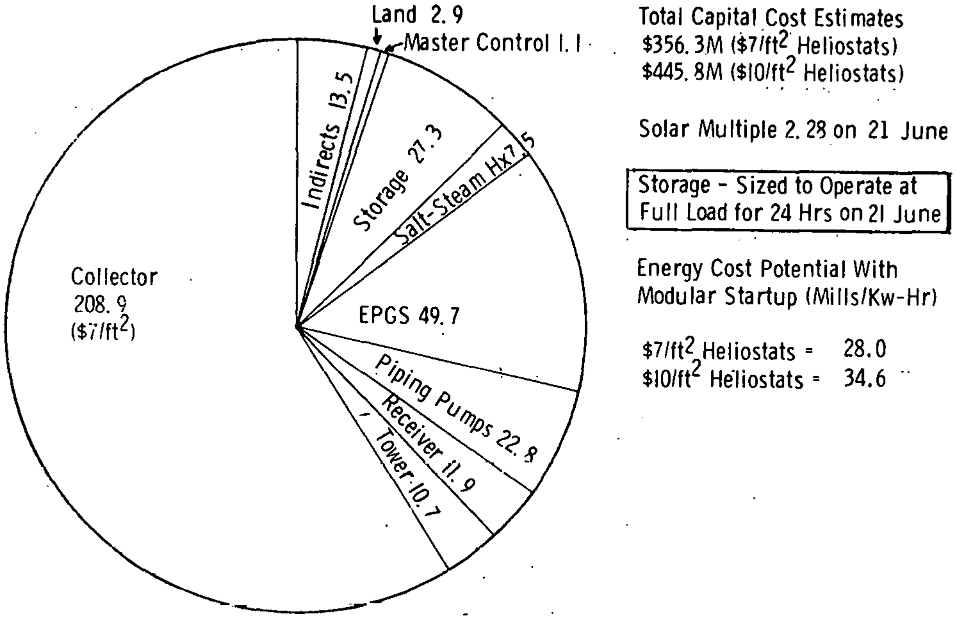


Figure IV-1 300 MWe Capital Cost in Millions of Dollars

Table IV-1 Results of Cost Analysis

	Recommend Alternative Molten Salt System
Cost of Electricity (mills/kWhe) - with Economic Ground Rules Used in First Generation (Cost of Money 7.5%)	28.0
- Present Economic Ground Rules (Cost of Money 11%)	38.4
Cost of Storage - Thermal (\$/kWht) - Electrical (\$/kWhe)	 3.40 8.20

The large improvement over the first generation is due to several factors. The cost per unit output is significantly reduced primarily because the receivers, towers, storage, and EPGS are less expensive. The receiver is a relatively simple lightweight single phase heat exchanger. The reinforced concrete towers were estimated by experts in the field and are considerably less expensive than estimates used during the first generation. The larger size EPGS is more cost effective. Thermal storage is much less expensive because the low cost molten salt operating over large temperature differences is much more cost effective. The storage tanks are large and economical carbon steel thermocline tanks. Performance of the system is over 10 percent better than the first generation when operating from the receiver and over 35 percent better when operating from storage. For the recommended system, the average performance improvement is over 20 percent. We have modified the BUCKS computer program to use incremental start-up; that is, the plant is built so the modules are activated as they are completed, which significantly reduces the interest during construction.

Potential improvements to the system were identified including the following:

1) Conduct a tradeoff between the receiver aperture size and heliostat requirements. As the aperture size is increased the receiver efficiency decreases but the requirements on the heliostats decrease, which will decrease heliostat cost.
2) The configuration of the modular collector fields should be optimized. It should be possible to improve the heliostat field efficiency and reduce the size of the plant, which would reduce piping cost and land use.

3) The present utility standard is 812 K (1000°F) steam and a study to increase the steam temperature to at least this temperature should be done. The higher the temperature the better the efficiency of the cycle and the fewer heliostats required. The study should include both increasing the molten salt temperature from the receiver and increasing the heat exchanger area. Another important factor is to obtain more material compatibility data at higher temperature. Besides potentially improving the cost of electricity, higher temperatures would reduce the cost of thermal storage and reduce the land required.

4) Possible use of a hydraulic turbine at the base of each tower to recover some of the pump work should be studied. The primary concern is for the development of high temperature molten salt seals.

5) Tests should be conducted on other lower cost stainless steels to reduce plant cost.

Possible Limitations - The most important potential limitation to the use of the recommended system is the cost of electricity, which is a function of the following:

1) The insolation available;
2) The performance of the plant;
3) The capital cost of the plant.

As the performance and cost of a system is improved it will be more economical in areas of the country with poorer insolation. We believe the recommended system represents a significant improvement in performance and cost over the first generation.

The primary environmental impact of a solar power plant is the land use; therefore, the best way to minimize the environmental impact is to improve the efficiency. The recommended plant is at least 20 percent better then first generation plants.

Cooling water required for a Rankine cycle is a possible limitation and must be an important consideration in the site selections. Wet-dry and dry cooling should be studied to minimize this potential problem.

We have conducted a study of all materials used in the system and are confident that the application of the system will not be limited by the use of scarce or imported materials. The large potential use of nitrates is not limited by raw materials; however, it may be necessary to build more processing plants. The relatively large amounts of Incoloy 800 used is available in the quantities required.

We believe that the status of the technology is such that it could be used in the early 1980s.

Value of Storage - A preliminary analysis was done to estimate the value of thermal storage to a utility. The value of storage to a utility has two components; fuel displacement value and capacity displacement value. Based on an analysis of the APS system the fuel displacement alone can justify the storage system.

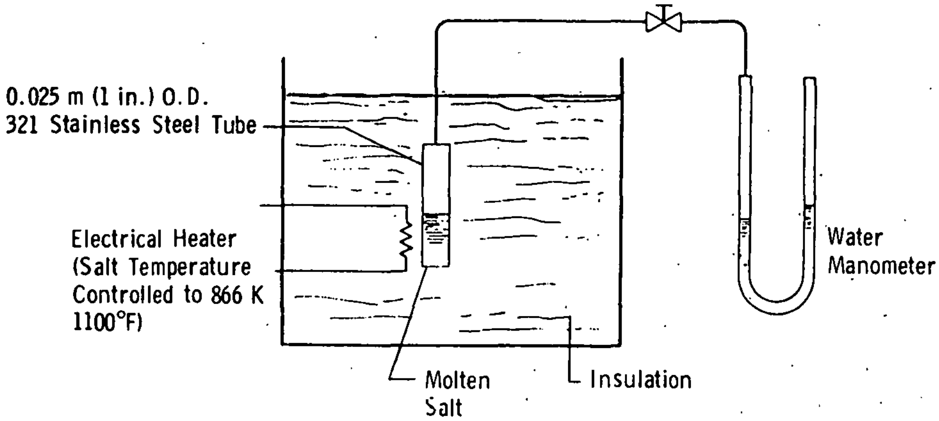
V. DEVELOPMENT STATUS

The primary technical risks associated with the recommended system are long-term high-temperature thermal stability of the molten salt and material compatibility with the salt at the system operating conditions. These issues were addressed in a comprehensive test program, which included the following:

1) Long-term high-temperature stability;
2) Basic molten salt chemistry;
3) Materials compatibility;
4) Fluid-loop testing.

Each of the tests and the results are summarized in Figures V-1 through V-4. After over 6000 hours at 866 K (1100°F) the molten salt shows negligible decomposition. Molten salt chemical analyses and tests resulted in a good understanding of the chemistry. Equilibrium constants as a function of salt composition, cover gas composition, and temperature were determined. Formation of oxides and carbonates is negligible. Materials tests show that Incoloy 800 can be used for the high-temperature components and carbon steel can be used for the low-temperature components. A section of a receiver tube was subjected to 10 000 cycles of single-sided heating at the operating temperature with no adverse effects on the material. Heat transfer coefficients were verified under realistic conditions. No evidence of erosion was observed at design fluid velocities.

Based on these test results we believe the system is feasible and Phase II should be undertaken as soon as possible.



Results

Testing for Over 6000 Hours Shows Negligible Decomposition

Figure V-1 Long-Term High-Temperature Molten Salt Stability

Description

- Flask tests were similar to long-term tests except with gas pressure and composition varied.
- Oven tests were made in oxygen and air with varying salt composition.

Results

- A consistent equilibrium constant was determined for the salt that is close to the value for potassium nitrate.
- The salt contains 3% nitrite at 840 K (1050°F) with air at one atmosphere.
- Formation of oxides and carbonates is negligible.

Figure V-2 Basic Molten-Salt Chemistry Tests

Description

One-Inch Diameter Metal Specimens Placed In Molten Salt

Carbon Steel 590K, 672K, 756K (600°F, 750°F, 900°F)
Low Alloy Carbon Steel 756K, 812K (900°F, 1000°F)
Incoloy 800
316
321 } 812K, 867K, 895K (1000°F, 1100°F, 1150°F)
A286
Measured Weight Change Versus Time
Microstructure Examination
Stress Corrosion Samples at Highest Temperature for Specimen

Results

Incoloy 800 and A286 look very good up to 867K (1100°F). After 3000 hours
316 exhibits intergranular corrosion due to high temperature.
Carbon steel was badly attacked at 756K (900°F).
Carbon steel looks good at 672K (750°F) after 1000 hours.

Figure V-3 Materials Compatibility Tests

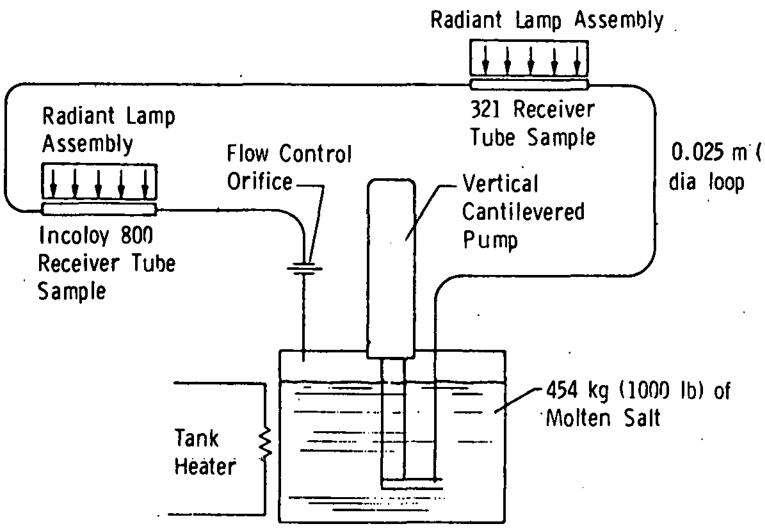


Figure V-4 Molten-Salt Loop Test Schematic

VI. RECOMMENDED DEVELOPMENT PLAN

The key issue in deriving a development plan is the configuration of the Critical Module (pilot plant) to be designed in Phase III.

The objective of the Critical Module is basically to develop the technology to a degree that will encourage the utilities to proceed with commercial-sized plants. From a purely technical standpoint, the program must be designed to provide the answers to specific technical concerns. However, from the utility user's standpoint the module must also be of sufficient size to prove system operation on a utility grid.

Options considered included:

1) Retrofit Barstow;
2) Build a new Barstow-type plant;
3) Build a scale model of one of the solar modules with storage and steam generator included but without an EPGS;
4) Build a full-scale module with storage and a steam generator without an EPGS;
5) Demonstrate the technology at the STTF.

The obvious advantage to the retrofit of Barstow is the potential cost saving. The disadvantages are (1) potential schedule confict with the first generation, (2) mismatch of the steam cycle and steam conditions, and (3) the likelihood of new, lower-cost heliostats being available at the time that should be used with the new system.

A new Barstow-type plant would cost more than the first option but would eliminate many of the disadvantages discussed earlier. However, a disadvantage to this approach is that reheat-steam turbines with the desired steam conditions are not practical in the 10-MWe size.

A scale model of one of the recommended modules eliminates the problem of the steam turbine mentioned previously and reduces cost. The disadvantage of this approach is that no electricity is produced to operate on a utility grid. A good way to solve this problem is to provide the steam generated to an existing power plant.

A full-scale module, which incudes a full-scale storage tank that would provide steam to an existing power plant, has the advantage of demonstrating all solar-unique subsystems without any scaling risk. Because utilities would be required to invest large sums of money in commercial plants they will want to take a minimum risk. Therefore we recommend that the Critical Module be a full-scale module of the preferred plant.

The problems of trying to demonstrate the technology at STTF are as follows:

1) The extremely bad distortion of the heat flux from a surrounding field at only 5 MWt (there would only be a couple of heliostat rows on the south side);
2) Turbomachinery with the required steam conditions are impractical at the size required;
3) It is impractical to provide the steam to an existing plant;
4) The STTF heliostats would not be representative of the ones used in the proposed system.

A. CONCEPTUAL DESIGN OF THE CRITICAL MODULE

The Critical Module consists of a single module of the preferred system with a single full-scale storage tank, scaled-down heat exchangers and associated piping, instrumentation, and control. The key module parameters are as follows:

Peak Thermal Output (into Fluid)	208.3 MWt
Number of Heliostats (40 m^2)	7711
Tower Height	155.4 m (510 ft)
Receiver	Four-Aperture Cavity (Full Scale)
Storage Tank	23.8 m (78 ft) dia. 26.8 m (88 ft) high (Full Scale) 1995.6 MWHt max. Thermal Capacity
Heat Exchangers	Same as Preferred Design Scaled 9 to 1
Piping	Hot Line-Incoloy 800, 0.305 m (12 in.) dia. Cold-Line Carbon Steel, 0.305 m (12 in.) dia.

The steam produced would be used in an existing power plant. We studied this type of application in some depth for application to the Saguaro power plant with Arizona Public Service Company. The study was based on a solar system similar to the Critical Module defined above. The land required is available near the plant, and all interfaces were resolved without any major problems.

B. COST ESTIMATE OF THE CRITICAL MODULE

The cost estimate for the critical module is given in Figure VI-1. The cost of heliostats is assumed to be $\$161.50/m^2$ ($\$15/ft^2$) installed. The thermal storage system consists of a single full-scale tank from the preferred 300 MWe system. The costs were based on the detail cost estimates given in Task 5, scaled to the proper size, with appropriate factors for the first build with the exception of the engineering costs, indirect costs, and distributable costs. The latter items were estimated separately based on the experimental nature of the application. It is assumed that the land would be provided by the participating utility.

We calculated the value of the output of the critical module to a utility by calculating the fuel saving over a thirty-year life, assuming a net thermal-to-electric conversion efficiency of 31.5 percent, and using the yearly thermal output from the STEAEC program using 1976 Barstow insolation data. The present value of the 30-year fuel saving is approximately $30 million in 1978 assuming fuel cost escalation equal to general inflation.

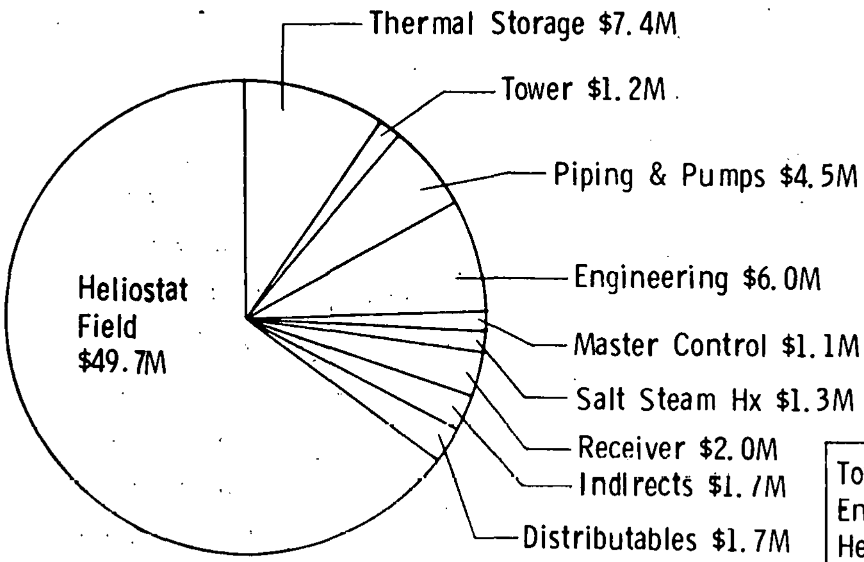
C. RESEARCH EXPERIMENTS

After planning the Phase III program, we defined the following small research experiments (SRE) to be conducted during Phase II. The purpose of the SREs is to provide development data to design the Phase III critical module and to provide other data needed in addition to the critical module test. The SREs are as follows:

1) A 5 MWt molten-salt receiver test at STTF;
2) A long-term fluid loop test simulating the system temperature extremes, materials of construction, and fluid velocities;
3) Additional materials and molten salt stability testing to explore possible effects of trace contaminants and to improve confidence in material durability;
4) A small-scale internally insulated thermocline tank development program to develop economical internal insulation schemes and to check out thermocline analytical models.

D. DEVELOPMENT SCHEDULE AND COST ESTIMATE

The development schedule and fiscal year funding required is given on Figure VI-2. The Preliminary Design and SRE phase consists of the four SREs listed, a preliminary design of the critical module, and updating of the commercial plant. The phase is approximately 15-months long. It is assumed that the thermocline tank testing program will start at the beginning of FY 1979 because the tank's development data is needed to complete the preliminary design of the storage tanks. The long-term loop extends beyond the preliminary design phase. Because the data from this test is primarily long-life verification, it is not necessary to complete the testing before completion of the preliminary design. The Critical Module program would start in midfiscal 1980 and continue for a three-year period that includes a six-month engineering test period. The build of the Barstow heliostats is shown for reference. The fiscal-year funding is shown on the bottom line and includes the cost of all the activities shown. As pointed out earlier, the potential value of the output of the Critical Module is about $30 million. The costs shown do not take any credit for the value of the power produced.



Total Capital Cost	\$70.6M
Engineering Cost	\$ 6.0M
Heliostat Cost	\$161.50/m^2 (\$ 15/ft^2)
Storage	Single Full-Scale Tank

Figure VI-1 Critical Module Cost

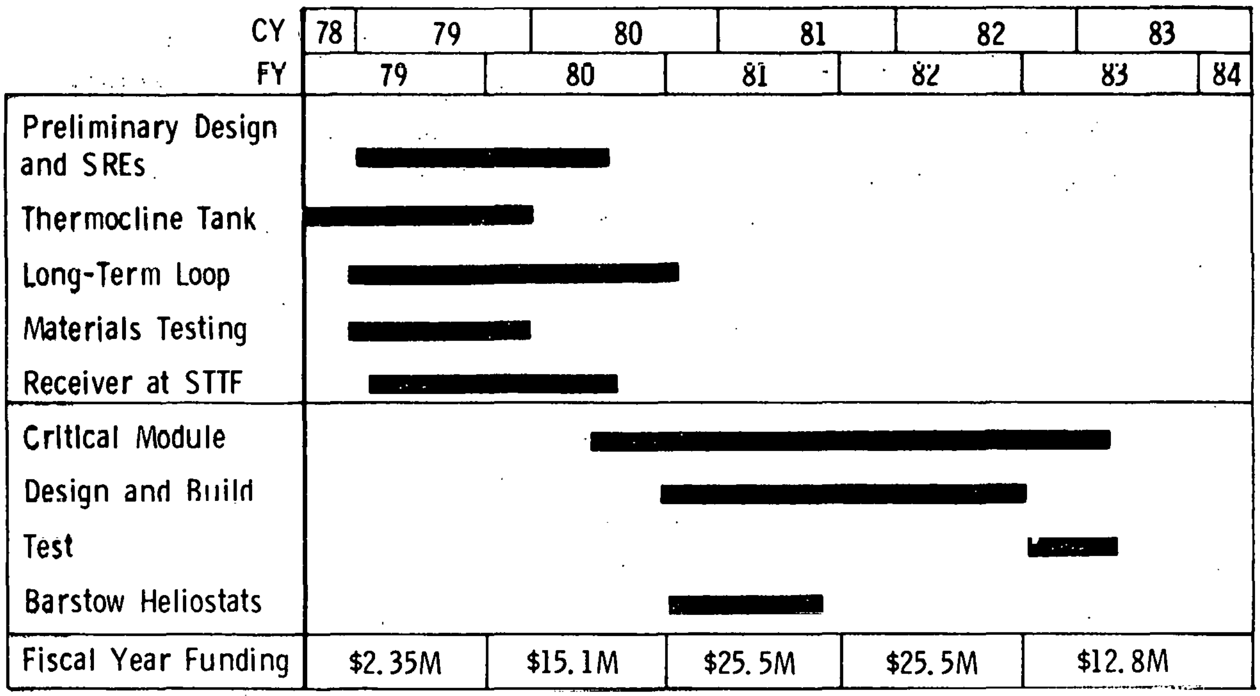


Figure VI-2 Critical Module Development Schedule

VII. ALTERNATIVE 100-MW ELECTRICAL PLANT

For purposes of comparison with other contractor designs, a 100-MWe plant having three hours of storage is described. This smaller design consists of three modules of 5059 heliostats each as shown in Figure VII-1. The heliostats are arranged symmetrically about the north-south line with the EPGS located in the center and adjacent to all three modules. This layout was chosen to minimize piping length from the towers to the EPGS. Table VII-1 presents the parameters associated with the 100-MWe plant configuration.

Collector Field

The collector field is geometrically similar to the 300-MWe field except the number of heliostats in the 100-MWe field has been reduced to reflect the proper plant size (including storage). The performance of the 100-MWe field was assumed to be similar to the 300-MWe field adjusted for the improvement in atmospheric attenuation due to the shorter slant ranges.

Tower

The 100-MWe plant tower height was scaled from the 300-MWe plant tower height, keeping the rim angle (angle from the horizontal to the top of the tower at the furtherest heliostat) constant. This scaling results in a 128-m (420-ft) high tower.

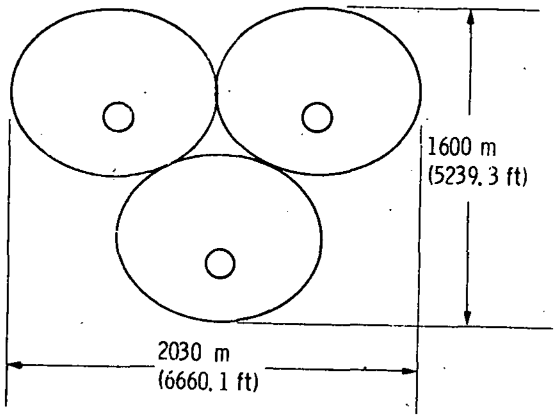


Figure VII-1 Plant Module Layout

Plant Size	-	100 MWe
Storage Size	-	3 Hours
Field Configuration	-	Surrounding Field 5059 Heliostats per Field (40m^2 per heliostat)
Plant Configuration	-	3 Modules
Receiver Type	-	Four Aperture Cavity
Conversion Cycle	-	Water/Steam Rankine 783 K (950^{0}F); 16.5 MPag (2400 psig) 783 K (950^{0}F) Reheat
Storage	-	Internally insulated thermocline cylindrical configuration
	-	17.4m (57 ft) Dia.; 19.2m (63 ft) high
	-	Salt temperature 560.8 K (550^{0}F) to 838.6 K (1050^{0}F)
Tower Height	-	128m (420 ft)

Table VII-1 100-MWe System Parameters

Receiver

The 100-MWe plant receiver aperture size was scaled by keeping the ratio of the maximum slant range to aperture area constant. This scaling results in a 100-MWe receiver having a square aperture in the north, east and west cavities approximately 7.6 m (25 ft) on a side and the south cavity approximately 5.3 m (17.4 ft) on a side.

Storage

The storage system will consist of one internally insulated thermocline tank that is 17.4 m (57 ft) in diameter and 19.2 m (63 ft) in height. The construction of this tank will be similar to the construction of the 300-MWe system storage tanks.

Master Control

The master control concept will be the same as described for the 300-MWe plant.

System Performance

Appendix C presents the input data calculated for the 100-MWe plant, which was used in the STEAEC program to calculate the annual performance.

Cost Estimate

Figure VII-2 contains the cost data for the 100-MWe plant. In most cases the costs were extrapolated from data generated in the costing of the 300-MWe plant.

Economic Analysis

The performance as generated by STEAEC and the cost estimates were input into the BUCKS program to evaluate the bus bar energy cost.

The results as shown in Table VII-2 indicate that the 100-MWe plant is capable of producing electricity at a cost approximately 35 percent higher than the preferred 300-MWe system.

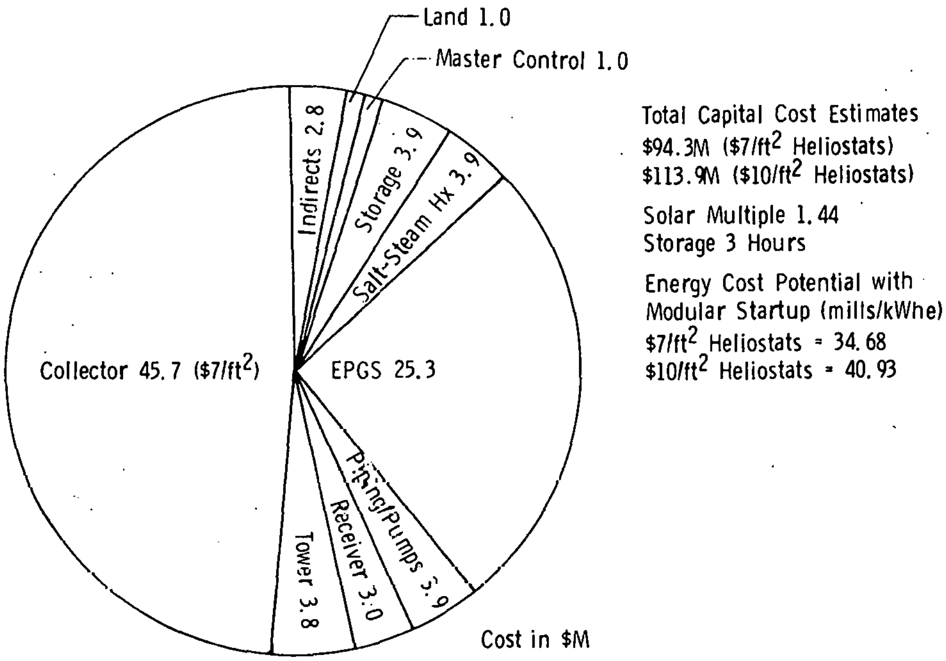


Figure VII-2 100 MWe Plant Cost

	300 MWe ACR System (Nth Plant)	100-MWe ACR System (Nth Plant)
First-Generation Economics		
$7/ft^2 Heliostats	28.0	37.7
$10/ft^2 Heliostats	34.6	44.6
Present Economics		
$7/ft^2 Heliostats	38.4	53.8
$10/ft^2 Heliostats	47.2	61.9
Capacity Factor	0.65	0.42

Table VII-2 MWe Cost of Electricity (mills/kWhe)

VIII. ALTERNATE SYSTEM USING AN EXPOSED RECEIVER

In selecting the cavity type receiver some important assumptions had to be made on the potential effect on heliostat cost and convective losses. The receiver configuration and size will effect the heliostat requirements and cost. We were unable to conduct this tradeoff study because we did not have heliostat cost as a function of heliostat requirements. It is possible that this type of tradeoff may favor an exposed type receiver. Also, it is difficult to determine the convective losses, particularly from a cavity type receiver. Therefore, we have included an alternate system design which uses an exposed type receiver.

The recommended alternative exposed receiver is shown in Figure VIII-1. The receiver approximates a cylinder 10.4 m (34 ft) in diameter and 15.8 m (52 ft) high. The irradiated surfaces consist of panels which contain side-by-side vertical, blackened tubes. Two parallel flow circuits are used. The inlet for both circuits is at the panels on the north side which have the highest flux. The outlet (highest fluid temperature) is on the south side which has the lowest flux.

A series of parametric studies was conducted to quantify the design. The studies included the following:

1) Radiation analysis to determine the heat flux values and the best heliostat aiming strategy from the standpoint of spillage and heat flux levels;
2) Receiver efficiency (radiation, convection, and conduction losses);
3) Thermal hydraulic analyses to establish the flow path, pressure drop, heat transfer coefficients, and tube metal temperatures;
4) Receiver tube thermal stress analysis to determine tube life;

5) Mechanical design studies to determine methods of support and structural configuration.

Our best estimate of the impact of the exposed receiver is that it will increase the system cost and the cost of electricity about 4 percent over a cavity receiver system.

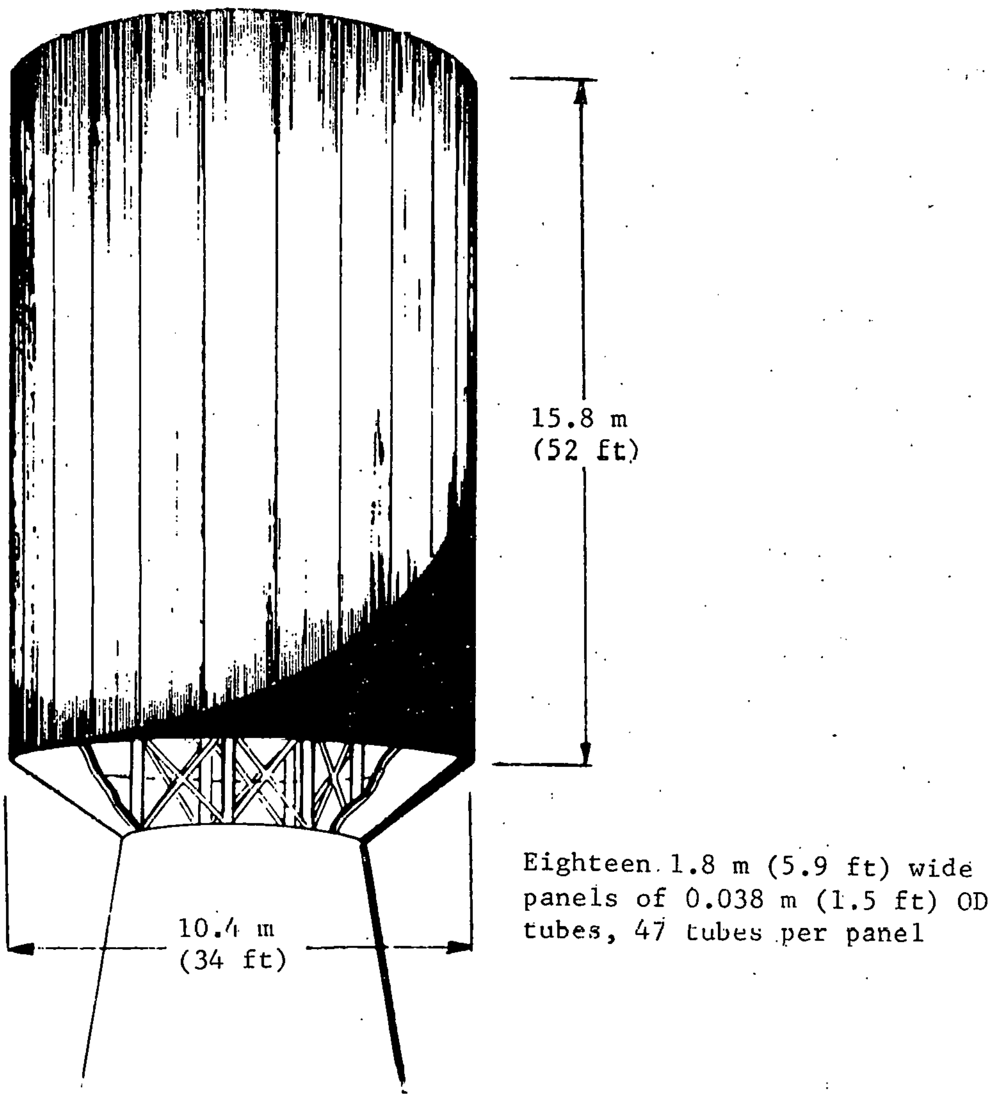


Figure VIII-1 Exposed Receiver

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