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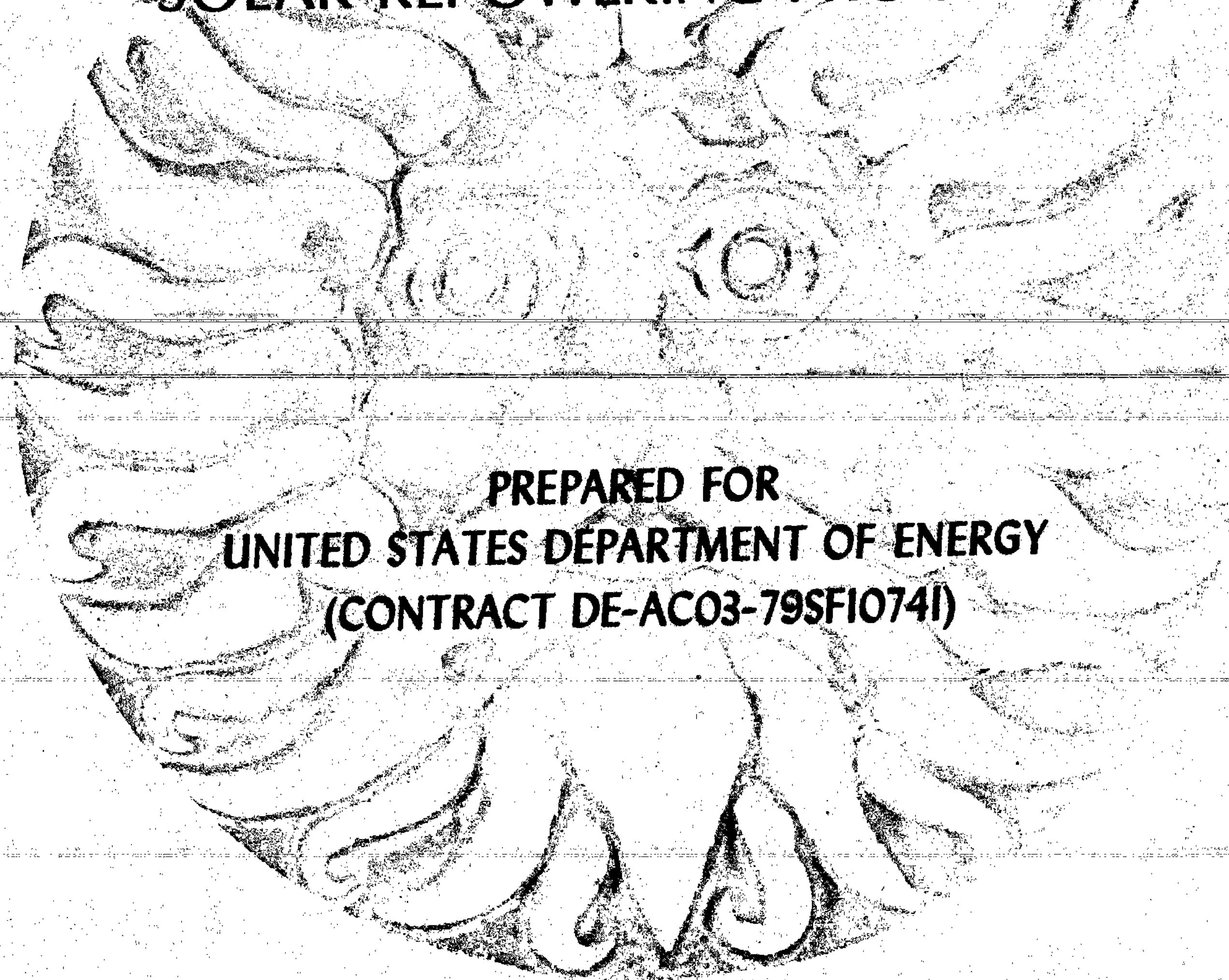
DOE/SF/10741-1

FINAL TECHNICAL REPORT
VOLUME I
CONCEPTUAL DESIGN & EVALUATION
JULY 1980

SOUTHWESTERN PUBLIC SERVICE COMPANY SOLAR REPOWERING PROGRAM



PREPARED FOR
UNITED STATES DEPARTMENT OF ENERGY
(CONTRACT DE-AC03-79SF10741)

GENERAL ELECTRIC COMPANY
ENERGY SYSTEMS PROGRAMS DEPARTMENT
SCHENECTADY, NEW YORK

GENERAL ELECTRIC

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ABSTRACT

Solar technology needs a successful demonstration project to meet national energy independence goals. General Electric and Southwestern Public Service Company consider the use of solar energy a viable alternative to conventional sources of energy. After an extensive nine-month study, the companies consider the application of the sodium central receiver technically feasible for repowering of fossil fuel installations. Additional engineering required to integrate the solar power source with the existing Plant X Unit 3 represents no major technical problem.

Southwestern Public Service Company participated in the development of a cost estimate for the demonstration project. They believe the cost estimate proposed in the repowering study is valid. In the development plan portion of the study, a management program is presented that will result in a project that can be successfully completed with the lowest practical expenditure. Southwestern would emphasize that maintaining an aggressive schedule for completion and start-up by mid-1985 is important for cost control and a successful project.

We recognize that demonstration project economics are specific to the installation, and a first-of-a-kind facility usually costs more than subsequent ones. The best use of development funds would be to demonstrate solar repowering technology for future commercial applications of solar electric power. The economic advantage of the Plant X repowering project predicted in the report is a fuel savings of over one billion cubic feet of natural gas per year.

Southwestern, an owner/operator of a number of power plant facilities, does not foresee extraordinary safety hazards associated with the sodium central receiver concept. Southwestern has selected sodium for its heat transfer medium because of proven industrial technology which offers superior characteristics in providing for repowering of existing reheat machines.

A General Electric/Southwestern survey for additional solar repowering sites of gas-fired generating system equipment operated by SPS indicated a favorable potential for the solar repowering concept. However, strong economic incentives, component cost reductions, and resolution of regulatory uncertainties will be needed before future solar repowering can become an attractive option to Southwestern and other utilities.

General Electric and Southwestern Public Service Company conclude that the Plant X repowering conceptual design study lays the foundation for construction and operation of a solar demonstration facility. It is our opinion that a repowering demonstration facility is needed to develop acceptable experience for the commercial use of solar technology in the nation's utility industry.

ACKNOWLEDGMENTS

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J.A. Elsner was Program Manager and G. Oganowski was Technical Manager for this study.

Other General Electric components participating in this program were the Advanced Reactor Systems Department, the Electric Utility Systems Engineering Department and the Projects Engineering Operation. Kaiser Engineers and Southwestern Public Service Company were subcontractors.

This report is based upon work performed by the authors and the following technical contributors.

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SECTION 1
EXECUTIVE SUMMARY

CONTENTS

In recent years the United States has been relying increasingly on imported fuels, principally oil, for satisfaction of its domestic energy needs. Legislation such as the National Energy Act of 1978 has attempted to decrease the usage of premium fuels (oil and natural gas) for electric power generation.

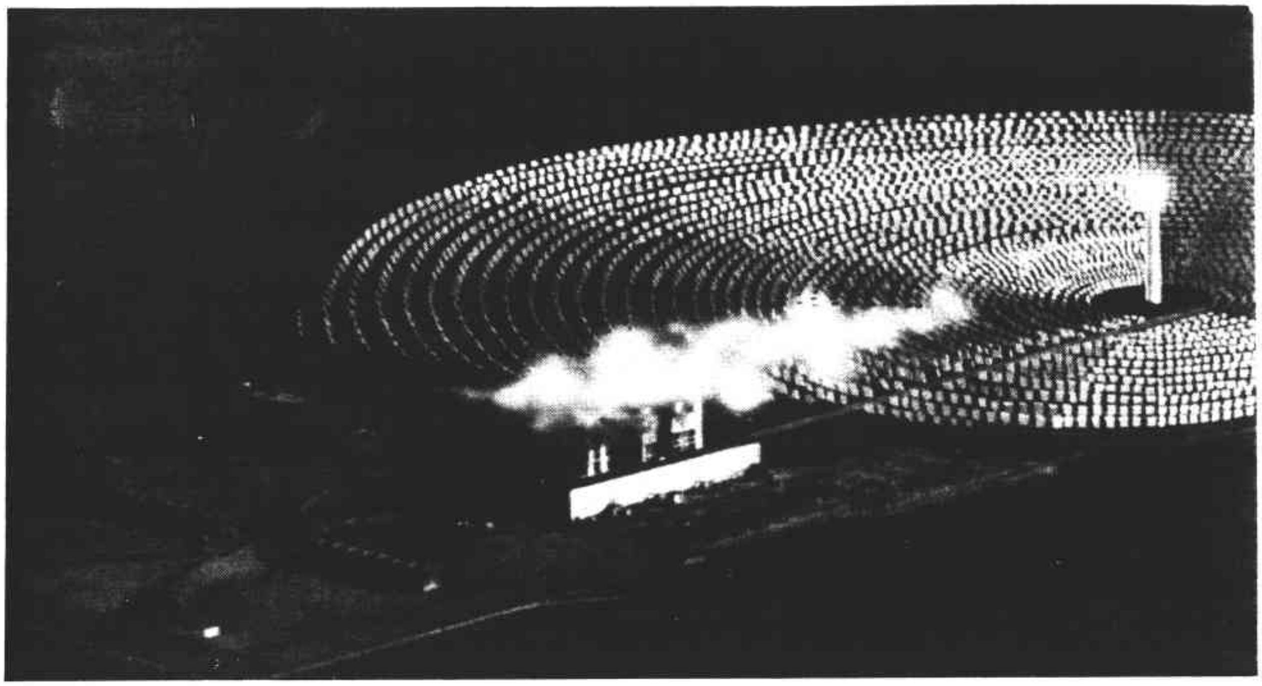
Solar energy is recognized as an inexhaustible source of energy for electric power generation, if cost and performance competitiveness can be achieved. Central Receiver technology has been identified as a promising alternative for electric utility applications, and the use of a solar central receiver at an existing oil or gas fired power station offers several potential advantages for the development of solar technology. First, it allows the use of existing equipment and reduces overall solar plant capital investment. Second, it allows utilities to gain first hand operating experience with a solar plant. And third, repowering displaces natural gas or oil, thereby reducing utility consumption of these premium fuels.

In the Spring of 1979, the Department of Energy awarded a contract to the General Electric Company and the Southwestern Public Service Company for the conceptual design and evaluation of an energy supply to one of Southwestern's existing power plants. The Energy Systems Programs Department (ESPD) of the General Electric Company managed the project, performed the system integration and determined system performance. The Advanced Reactor Systems Department (ARSD) of General Electric provided the expertise in the areas of sodium components and engineering. General Electric's Electric Utility Systems Engineering Department used their extensive background in utility system analysis and economics to assess the value of the solar retrofit. Southwestern provided system requirements and specifications and assisted in the integration analysis. Kaiser Engineers, Inc. of Oakland, California, provided the balance-of-plant design, receiver tower design and cost analysis for construction of the solar power plant. This team provided the Department of Energy with a sound conceptual design which meets utility operational and design requirements, as well as a realistic economic evaluation consistent with this site specific application.

The Department of Energy's concern that the utility user's perspective be reflected in the conceptual design was evident in the request for proposal. At the onset of the study, Southwestern was also concerned that the report should reflect the utility's viewpoint, and agreed to participate in the study only if allowed to review all work conducted in connection with the study and to comment on the applicability and adequacy of the design selected. Southwestern, therefore, assumed a very active part in the program.

This final report reflects Southwestern's utility perspective. Southwestern's design preferences have been incorporated into the study.

INTRODUCTION



ENERGY SYSTEMS PROGRAMS DEPARTMENT
GENERAL ELECTRIC COMPANY

- PROGRAM MANAGEMENT
- SYSTEMS ENGINEERING
- PLANT INTEGRATION

SOUTHWESTERN PUBLIC SERVICE COMPANY

- PLANT X DESIGN
- UTILITY INTEGRATION
- DEVELOPMENT PLANNING
- ECONOMIC ASSUMPTIONS
- PROJECT EVALUATION

ELECTRIC UTILITY SYSTEMS ENGINEERING DEPARTMENT
GENERAL ELECTRIC CO.

- ECONOMIC ANALYSIS

ADVANCED REACTOR SYSTEMS DEPARTMENT
GENERAL ELECTRIC CO.

- LIQUID METAL ENGINEERING
- SODIUM COMPONENTS

KAISER ENGINEERING INC.

- TOWER DESIGN
- BALANCE OF PLANT DESIGN

KEY SYSTEM DESIGN FEATURES

The Solar Repowering Plant has been sized to deliver 60 MWe of electrical power. This size was selected because it meets Southwestern's system criteria and is the best size to meet the dual criteria of lowest cost and adequate size to satisfactorily demonstrate feasibility to the utility industry. The plant will operate in parallel with a fossil boiler maintaining the reliability of the power generating facility.

The plant selected for repowering is a highly efficient reheat plant. There is a potential market of over 1000 MWe of solar reheat repowering in Southwestern's utility system, and over 15,000 MWe in the Southwest, making the reheat market the largest near term opportunity for central receivers in the utility sector.

The nonreheat market is not as attractive for solar because most plants are old and operate at efficiencies less than reheat plants and would require relatively larger, most costly solar plants for repowering. However, there will likely be a few selected opportunities for nonreheat solar repowering and the design presented in this report can be easily adapted to meet the requirements of these installations.

Sodium is a particularly attractive working fluid for the reheat repowering market. Its high temperature performance capability exceeds the requirements of the reheat plants, and additional development and properties characterization are not needed. The steam generators can be located at ground level, permitting a low system cost and providing ease of maintenance. There are over 30 years of experience with this technology in the utility and industrial sections, and all of the sodium components in the power plant (with the exception of the receiver) are state-of-the-art. No further development is required for these components.

Design and Performance Characteristics

Only sufficient storage (10 minutes, at full power) is provided to protect the system from solar transients since analysis shows there is no significant benefit in additional amounts of storage (for this application, in Southwestern's system). This small quantity of storage is sufficient to demonstrate the concept and minimizes the cost of the first plant.

The plant will produce 114,475 MWe-hrs of energy per year. This is equivalent to displacement of 200,000 bbls of oil per year. Over the 30-year life of the plant, it is expected the solar plant will displace 15.7 billion cubic feet of gas, and 769,000 tons of coal of Southwestern's system projected fuel consumption.

The plant can be on-line by the end of 1985, assuming a start of detailed design by May 1981. This short time span is made possible through the use of state-of-the-art component technology.

SOLAR PLANT KEY DESIGN FEATURES

Optimum Power Level

- Meets Southwestern's System Criteria
- Adequate Size to Demonstrate Feasibility to Utilities
- Lowest Cost to Meet Above Criteria

Designed for Repowering of Reheat Power Plants

- Major Solar Repowering Market
- Over 15,000 MWe Available for Repowering in Southwest USA

Wide Range of Application

- Can Easily be Adapted to Nonreheat Plants

Attractive Working Fluid (Sodium)

- Exceeds High Temperature Needs of Modern Reheat Plants
- Steam Generators Located at Ground Level
- 30 Years Experience
- State-of-the-Art Components

MAJOR SYSTEM DESIGN AND PERFORMANCE CHARACTERISTICS

• Plant Size	- 60 MWe
• Number of Heliostats	- 4809
• Storage Capability	- 10 Minutes at Full Power
• Modes of Operation	- Solar Alone - Parallel with Fossil Boiler - Fossil Boiler Alone
• Annual Energy Output	- 114,476 MWe-hr/yr - 200,000 bbl/yr (Equivalent)
• Actual Life Time Fuel Displacement	- 15.7 Billion Cubic Feet of Gas - 769,000 Tons of Coal

The comprehensive conceptual design and evaluation of the Solar Repowering Plant at Southwestern has led to several important conclusions with respect to the specific application as well as to solar repowering in general.

1. General

No great barriers have been identified for the design and construction of a solar repowering demonstration plant that would be operational within a time frame useful to the utilities.

The successful completion of the demonstration project is considered an essential next step toward the development of cost effective solar power. The Southwest is an excellent location for such a demonstration since the plant will be operating in the actual environment where large scale implementation is likely. Although the first plant will not be cost-effective there are a number of ways to reduce costs for succeeding installations. One of the most fruitful areas for cost reduction is the heliostat.

2. Technical Feasibility

Solar repowering of existing fossil-fired electric power plants using a Sodium Central Receiver is technically feasible. Early plant demonstration of the concept is possible since no further system or component development is required beyond that planned in the current government program. All plant components - with the exception of the receiver - have been previously demonstrated in operation. A receiver development program is currently in progress under a General Electric contract to DOE, and the receiver concept is scheduled for testing in early 1981.

3. Value of the Demonstration Project to Utility Industry

The real value of the repowering project will be to demonstrate to the utility industry that solar technology can be applied on a commercial scale. However, the growth of a commercial repowering market will depend principally upon three important considerations:

1. The demonstration project must be successfully completed, and it must demonstrate to the utility the technical feasibility of solar power.
2. The cost of succeeding solar power plants must be significantly reduced.
3. Strong governmental economic incentives will be required in the near term to spur initial acceptance and market penetration.

4. Near-Term Market

The largest near-term market for solar power plants in the electric utility sector is for the repowering of modern reheat electric power plants. Emphasis should be placed in the Government Program on the continuation of the development of solar technology for this very important application.

Commercial cost goals for solar equipment and power plant should be established to aid the development of this market. These goals should be established on the basis of likely value to the utilities in order to compete with other power generation equipment. Additional work, expanding the site specific economic analysis performed in this study, should be performed to establish these goals.

5. Economics

Operation of the solar repowering plant results in a significant fuel savings which partially offsets the costs of the demonstration plant. However, strong economic incentives, component cost reductions, and resolution of regulatory uncertainties will be needed before solar repowering can become an attractive option to the utility industry.

Specific economic results presented in this report are extremely site dependent and apply only to the demonstration plant itself. The results cannot, and should not, be generalized to other applications where such factors as insolation level, degree of penetration, system fuel mix, and plans for future plant additions can vary significantly.

6. Working Fluid Technology

With the exception of the sodium receiver, no further technology development is required for the use of sodium as a working fluid. There is a considerable industry experience base with sodium, and existing practices and procedures for the use of sodium are deemed adequate to apply to the design of Central Receiver Systems. Sodium has been used at temperature levels in excess of those required for repowering, and its properties are well known and characterized. Confirmatory work is currently underway to verify acceptability of the receiver material (Incoloy 800) in a sodium environment. Major loop components, including steam generators, pumps, and valves are state-of-the art, and have been built and tested for other applications with design conditions similar to repowering.

7. Storage

Only a small amount of thermal storage is required for the demonstration project, which greatly minimizes cost. The small (10 minute) storage system included in the plant design for transient protection is prototypical of the larger systems and is therefore adequate for technology demonstration.

The Southwestern Public Service Company is an investor-owned utility serving 286,000 customers in a four-state, 45,000 square mile service area. The 3100 MWe generating system consists of coal and gas fuel units distributed through the service area.

Plant X, the existing electric power generation station selected for the solar repowering study, is located south of Amarillo, Texas, in a predominantly agricultural region with low population density. The site has high insolation levels and a flat terrain suitable for installing a large array of heliostats. The area available for the solar power plant is immediately adjacent to Plant X, thereby minimizing the pipe run from the receiver to the fossil plant and minimizing thermal losses.

Plant X is situated on 1700-acre site and contains four gas-fired generating units. Units 1 and 2 are nonreheat plants characteristic of pre-1955 vintage machines. Units 3 and 4 are more efficient, modern, reheat cycle facilities, with steam conditions ($538^{o}C/1000^{o}F$) characteristic of the majority of installed power plants in the Southwest suitable for repowering.

Unit No. 3 within Plant X was selected for repowering. It has had a recent major turbine overhaul and inspection in 1979 which showed the turbine to be in excellent condition. To repower with solar, only minor modifications to the plant will be necessary to accommodate variable power operation. The required turbine modifications are similar to those made elsewhere in the system to adapt baseload units to cycling duty and will present no difficulty. The turbine is currently scheduled for retirement in the year 1995, but this can and will be extended if it is repowered with solar.

Southwestern conducted a survey of its own system to identify additional solar repowering sites. Although limited in scope because of time and budget constraints, this survey identified existing generating facilities on Southwestern's system which have potential for being repowered. The potential is significant. Eight of the 32 gas-fired units now in operation on the electrical system represent a solar repowering potential of approximately 1,000 MW.

CHARACTERISTICS OF PLANT X POWER GENERATING UNITS

	UNIT #1	UNIT #2	UNIT #3	UNIT #4
Net Capability	49.5 MWe	106 MWe	106 MWe	200 MWe
In-Service Date	1952	1953	1955	1964
Main Steam Conditions	850 psig 900°F	1450 psig 950°F	1450 psig 1000°F	1800 psig 1000°F
Reheat Steam Temperature	Non-Reheat	Non-Reheat	1000°F	1000°F
Expected Retirement Date	1992	1993	2014*	2004
Fuel	Gas	Gas	Gas	Gas

*If repowered with solar

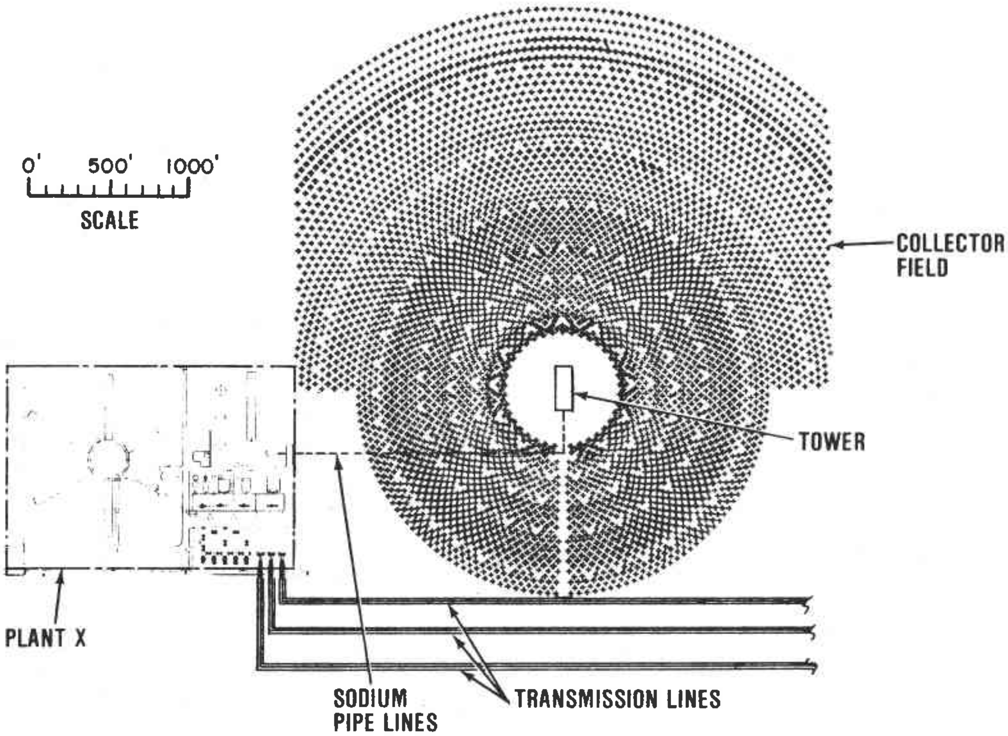
A 212-acre collector field will contain 4809 glass heliostats in a surround configuration. At noon equinox, the design point, the heliostats will deliver 158 MWth to the receiver which is mounted on top of a 140-meter tower. The cylindrical receiver consists of 24 absorber panel subassemblies. Sodium is pumped to the top of the tower by a constant speed centrifugal pump and enters the lower portion of the absorber panels at 293°C (560°F). It exits from the single pass receiver at 593°C (1100°F). The heated sodium flows down the tower to a hot storage tank located at ground level. From there a variable speed centrifugal pump delivers the sodium to a three-module steam generator facility (evaporator, superheater and reheater). The cooled sodium returns to the cold tank and is then pumped to the top of the tower.

The solar plant supplies steam to the Plant X, Unit 3, 100 MWe reheat turbine-generator. The plant is designed to operate in parallel with the Unit No. 3 fossil boiler and, in the hybrid mode, the steam produced by the solar plant is combined with the steam from the boiler prior to entering the turbine. Although the hybrid mode is the usual operating mode, the solar and fossil plants are capable of operating separately when appropriate.

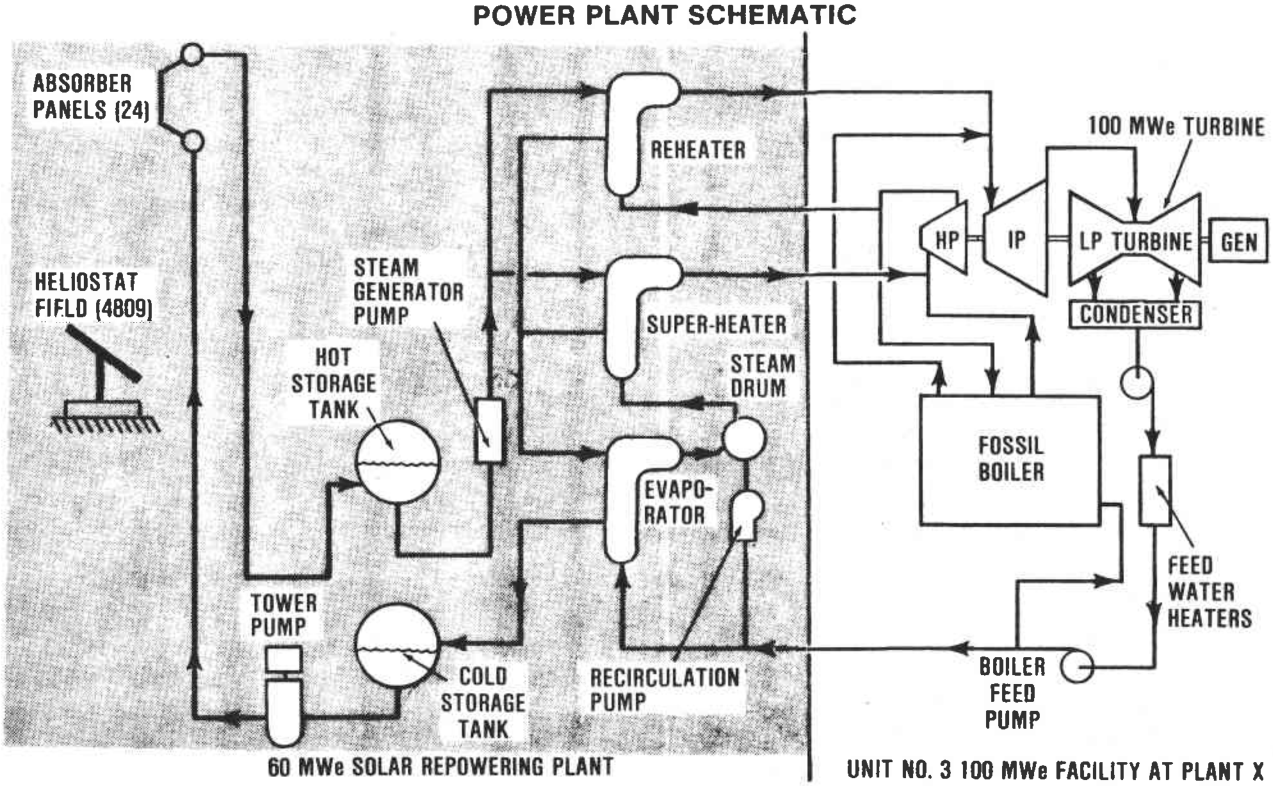
A 10 MWe-hr storage subsystem is provided to buffer the Unit No. 3 plant output from solar transients. In the event of a loss of solar power due to a cloud transient, the storage subsystem enables control of the solar plant shutdown rate to a sufficient degree to allow the fossil plant to assume the load, thus maintaining constant power output.

The overall plant will be controlled by a master control computer. This device monitors and integrates the activities of the distributed control loops and enables the plant to operate in the solar alone, fossil alone, or hybrid modes.

The sodium central receiver design developed in the program will demonstrate the repowering technology for the full range of utility applications. The 538°C (1000°F) steam temperature and the reheat application are the critical design features to be demonstrated. All repowerable facilities operate at these temperatures or below and have reheat cycles or less complicated nonreheat cycles.



POWER PLANT SCHEMATIC



PLANT DATA

• Prime Contractor:	General Electric Company, Energy Systems Programs Department
• Subcontractors:	Southwestern Public Service Company Kaiser Engineers, Inc.
• Existing Plant Description:	Name: Plant X, Unit 3 Initial Operation - 1955 Turbine - 10MPa/538°C/538°C (1450 psig/1000°F/1000°F) General Electric Reheat Steam Turbine Boiler - Gas-fired; Natural Circulation; Combustion Engineering, Inc. Boiler
• Site Location:	Earth, Texas
• Solar Insolation:	Average Annual - 6.5 kW-hr/m^2-day Source - Combination of Albuquerque SOLMET Data and Site Measured Data Local Insolation Monitoring - Southwestern-owned direct and total insolation monitoring station 8 miles from Plant X in operation since August, 1979
• Solar Plant Description:	Sodium-cooled Central Receiver
• Design Point:	Noon, Équinox
• Design Point Insolation:	940 W/m^2 (site-measured)
• Solar Fraction:	60%
• Design Point Solar Plant Efficiency:	25.7% (Hybrid Mode) 25.4% (Solar Alone Mode)
• Capacity Factor:	23% (Gross) 20% (Net - including maintenance time and part load turbine operation effects)
• Annual Energy Output:	114,745 MWe-hr 290,527 MWth-hr
• Annual Energy Savings:	200,000 bbl oil (equivalent)
• $\frac{\text{Annual Energy Output}}{\text{Collector Field Area}}$:	$\frac{0.338 \text{ MWth-hr}}{m^2}$
• Type of Fuel Displaced:	54% gas; 46% coal (lifetime average)
• Project Capital Cost:	$116 million
• $\frac{\text{Capital Cost}}{\text{Annual Energy Output}}$:	$399/MWth-hr

SUBSYSTEM DATA

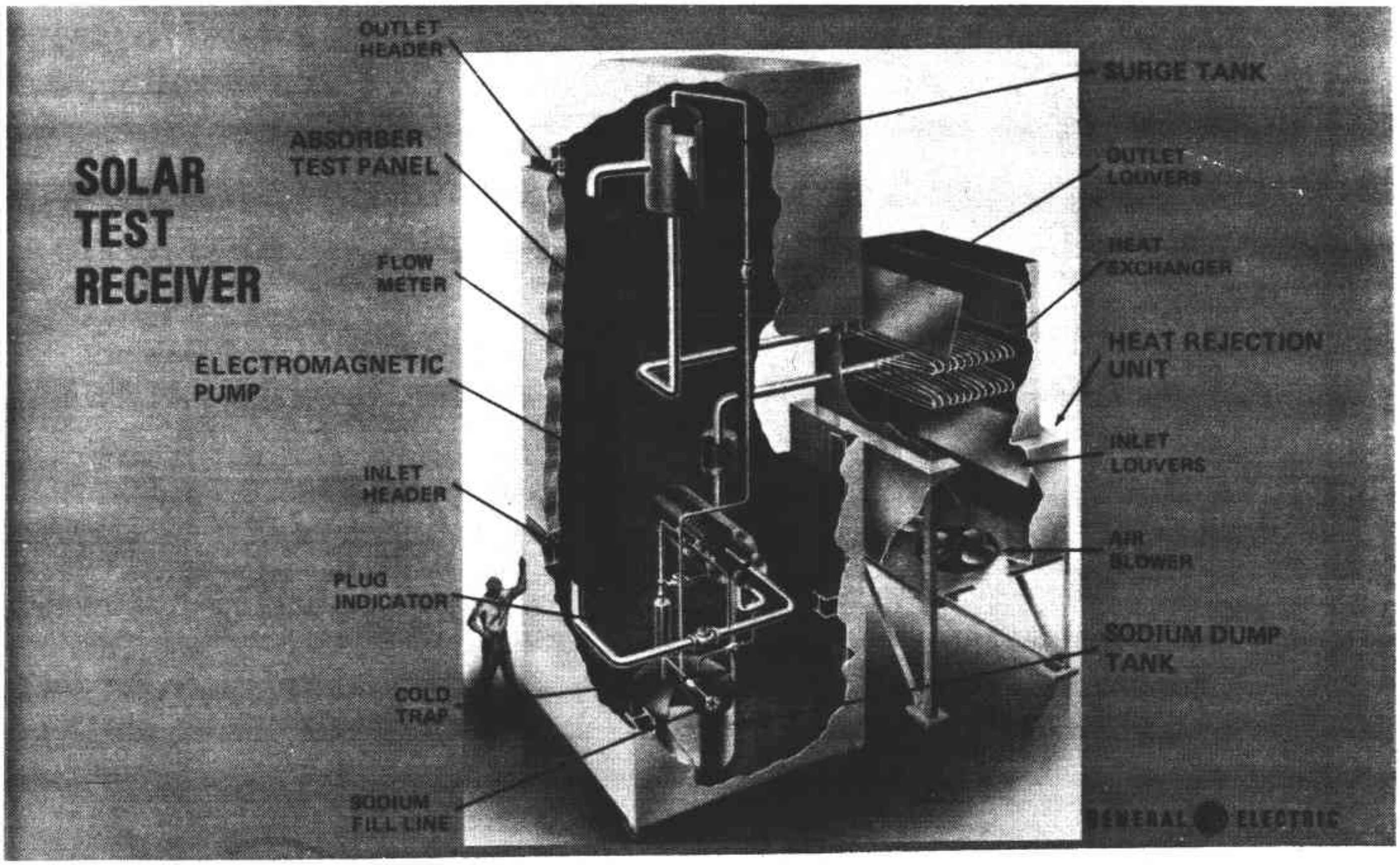
COLLECTOR SUBSYSTEM	RECEIVER SUBSYSTEM
• Field Config: Surround • Heliostats: 4809, $49 m^2$, 2nd Generation Glass • Area: 212 Acres • Cost: $\$230/m^2$	• Receiver: 12m x 12m External Cylindrical • Flow Control: 12 Electromagnetic Pumps • Tower: 140M Slip-Formed Concrete • Working Fluid: Sodium • Operating Temp: 293°C (560°F) inlet, 593°C (1100°F) outlet • Sodium Flow: 1.34×10^6 kg/hr (2.95×10^6 lbs/hr)
STORAGE SUBSYSTEM	**STEAM GENERATOR SUBSYSTEM**
• Design: Hot and Cold Tank Buffer • Capacity: 10 MWe-hrs • Storage Medium: Sodium • Tank Design: Field Fabricated Double-Wall	• Modules: Evaporator, Superheater, Reheater • Steam Conditions: 10 MPa/538°C/538°C (1450 psig/1000°F/1000°F) • Steam Flow: 1.9×10^5 kg/hr (4.1×10^5 lbs/hr) • Sodium Flow: 1.34×10^6 kg/hr (2.95×10^6 lbs/hr)
FOSSIL ENERGY SUBSYSTEM	**ELECTRIC POWER GENERATING SUBSYSTEM**
• Boiler Manufacturer: Combustion Engineering • Design: Natural Circulation, Gas-Fired, Reheat Boiler • Efficiency: 84-85%	• Turbine Manufacturer: GE • Design: 10 MPa/538°C/538°C (1450 psig/1000°F/1000°F) Reheat, Condensing Turbine • Efficiency: 42% (Full Load)
MASTER CONTROL SUBSYSTEM	
• Design: Distributed Control Loops with Supervision By Redundant CPU Master Control System	

RECEIVER DEVELOPMENT

The sodium cooled receiver is the only plant element not yet demonstrated either in actual operation or in test. However, at the current time, the General Electric Company under the Alternate Central Receiver Power System Program, Sandia Contract No. 83-7550, is preparing a sodium cooled test receiver to be tested at CRTF in early 1981. The receiver concept presented in this report is an evolution from the test receiver and has been updated to incorporate the lessons learned from component fabrication.

The 2.5 MWth test receiver contains a single receiver panel and the necessary sodium components to complete a closed loop. An electromagnetic pump provides flow control and several sodium valves are included in the test loop. The test panel will be subjected to heat fluxes similar to those expected on the repowering receiver and will be operated at the maximum expected sodium temperature of 593°C (1100°F). Test loop control methodology will be prototypical of the repowering receiver.

The receiver test will be an adequate demonstration of the repowering receiver design. The close interaction of the receiver test program and the repowering design project has resulted in a timely, effective receiver development program. The test receiver is sufficiently prototypical of the repowering design that additional large scale testing will not be necessary prior to full-scale use on the solar repowering demonstration power plant.



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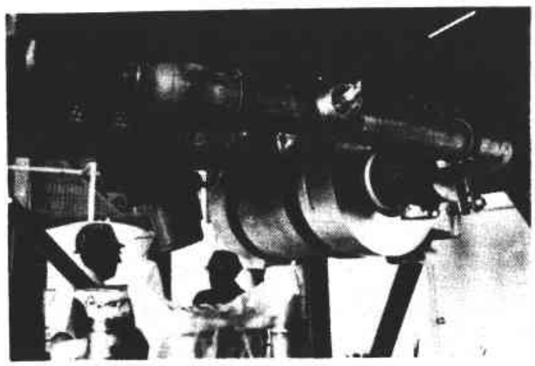

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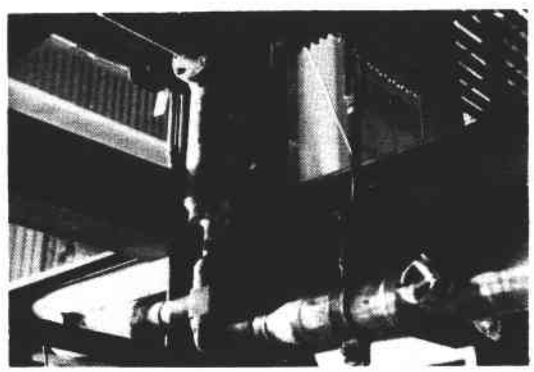

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1 TEST RECEIVER STRUCTURE SHOWING FRONT FACE

2 TEST RECEIVER SODIUM VALVES

3 EM PUMP MOUNTED IN TEST RECEIVER

4 MOTOR OPERATED 2" SODIUM VALVE IN TEST RECEIVER PUMP OUTLET LEG

During the course of the year, the solar plant will operate either in the hybrid mode or the solar-alone mode, depending upon utility dispatch requirements. Design calculations, to size solar equipment, were based on hybrid operation which results in slightly higher operational power levels.

At the noon equinox design point, the solar portion of the plant will contribute 57 MWe to the total plant output of 100 MWe. This output, representing a solar plant design point efficiency of 25.7%, was calculated using a clear day insolation level of 940 W/M^2, the value measured at a monitoring station eight miles from the plant site. The system losses were established through detailed calculations of the performance of individual subsystems and components.

Assuming constant operation in the hybrid mode for a full year, the average annual solar plant efficiency would be 20.2%, based on an hour by hour assessment of plant performance, including weathering effects. The performance of all individual subsystems and major components was determined as a function of appropriate time dependent variables such as sun position, wind speed, temperature, and plant power level. Hourly insolation and weather data based on local measurements were used in the Sandia-developed performance analysis code STEAEC, together with the subsystem and component performance data. The code determined hourly solar output for a reference year.

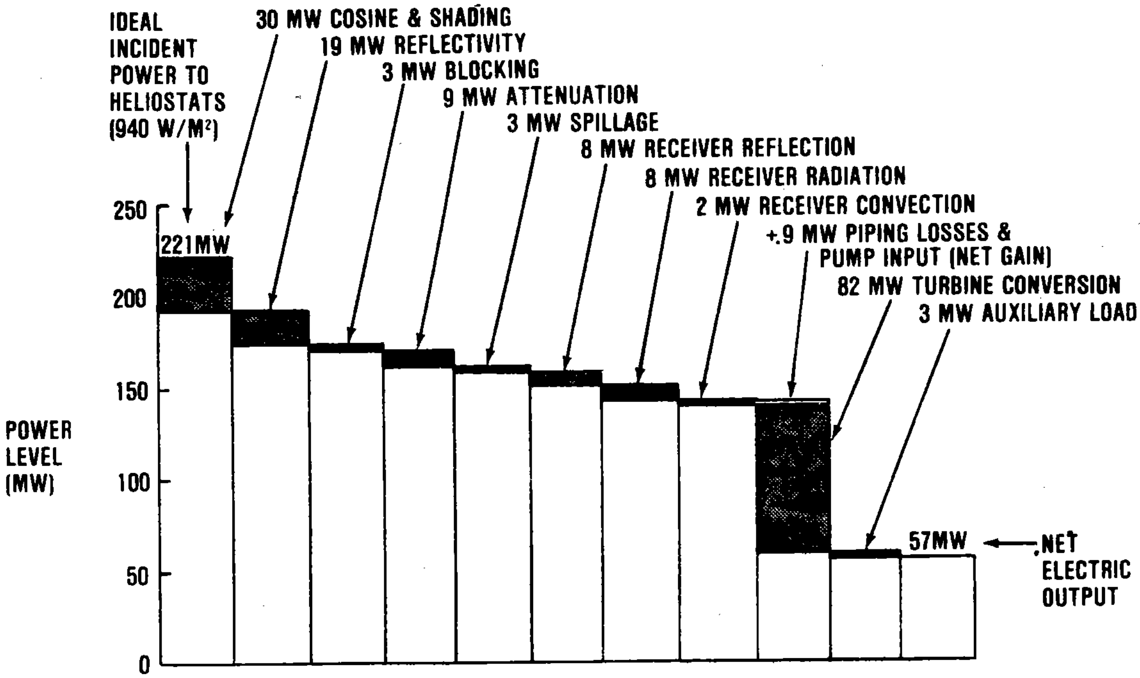
If the plant is operating in the solar-alone mode at noon equinox, the maximum power output will decrease about 1% to 56.5 MWe. This results from lower turbine efficiencies at partial load operating conditions. Assuming the plant operates for a full year in the solar-alone mode, the annual plant efficiency drops to 18%.

In actual use, annual plant efficiency will be between 18 and 20.2% depending upon the dispatch requirements for the facility.

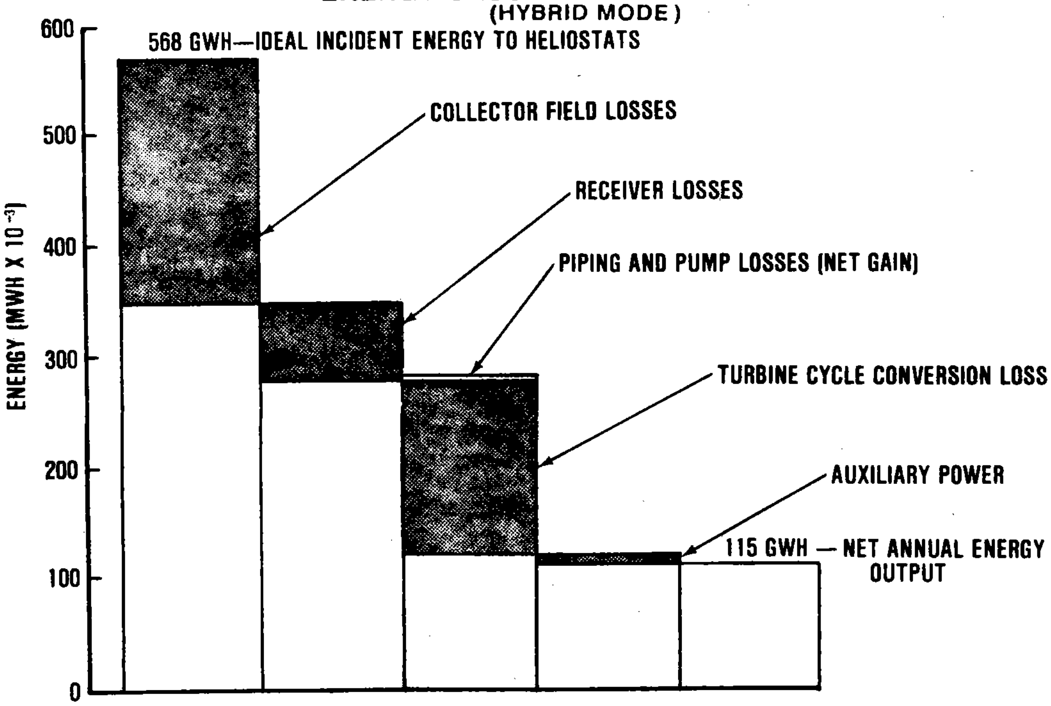
PLANT POWER OUTPUT AND EFFICIENCY

	Net Power Output (MWe)			Solar Plant Efficiency (%)	
Mode of Operation	Fossil Boiler	Solar Plant	Combined Output	Peak	Annual Average
Hybrid	43	57	100	25.7	20.2
Stand Alone	0	56.5	56.5	25.5	18.0

POWER CASCADE
(HYBRID MODE, DESIGN POINT)



ENERGY CASCADE — ANNUAL SUMMARY
(HYBRID MODE)



Plant Costs

The total estimated capital cost of the Solar Repowering Plant is $116 million, in 1980 dollars. This includes all costs associated with design, construction, test, and integration into Unit #3 at Plant X. The major uncertainty in the cost of the power plant is the collector subsystem, which is estimated to be $56.7M. It was assumed in the cost analysis that heliostats would be available at $230/m^2$, installed (in 1980 dollars).

The owner's cost of $989,000 includes the site owner's expenses related to the plant construction. These include, for example, costs for items such as environmental assessment studies, licensing and permits, taxes, and insurance.

Southwestern plans to lead the design and construction of the Solar Repowering Plant, eliminating the need for the services of the architect-engineer normally required for such projects. This is the normal procedure followed by Southwestern for the design and construction of power plant additions to its service area. The cost savings to the repowering project using this approach are estimated to be between 10 and 20 million dollars.

A significant portion of the existing plant modification costs and all the indirect project costs were estimated by Southwestern. The design and engineering, home office, and construction management costs were taken from actual Southwestern construction experience but were substantially increased due to the engineering uncertainty inherent in this type project. The contingency figure was arrived at by the same method. Southwestern supplied actual union craft rates effective at Company construction sites.

To cover the uncertainties in the cost estimate, and to be conservative, a 15% contingency ($7.6M) was added to all elements of the project (with the exception of the collector subsystem, since the $230/m^2$ estimate contains its own contingency).

Southwestern has reviewed the plant cost estimate in detail. It is Southwestern's opinion that the cost estimates are realistic for this type of study.

PLANT CAPITAL COSTS

(1980 DOLLARS)

Cost Element	Cost (Thousands)
Site Improvements	$ 3,627
Site Facilities	3,130
Collector Subsystem	56,697
Receiver Subsystem (Includes Steam Generators)	34,083
Control Subsystem	3,893
Fossil Energy Subsystem	1,392
Energy Storage Subsystem	1,721
Electrical Power Generating Subsystem	2,066
Miscellaneous Items	752
Owner's Cost	989
Contingency	7,600
Total Cost	$115,950

In general, the value of a solar repowering plant will depend upon many factors including the quantity and cost of fossil fuel displaced by operation of the solar plant, the operation and maintenance costs, which tend to offset the fuel savings, the capacity credit which can be attributed to the solar plant, and major economic assumptions. All of these factors are site specific. The value of the solar repowering demonstration plant to Southwestern was determined from a detailed solar plant performance model to determine fuel displacement and from economic assumptions provided by Southwestern.

FUEL DISPLACEMENT

The net annual electric energy produced by the solar plant is 114,745 MWh, which is equivalent to 200,000 barrels of oil. Initially, this output displaces mostly gas or synfuel. However, as Southwestern begins to retire gas plants and to expand generating capacity with coal plant additions, the solar plant will increasingly displace coal. In the first year of operation, 78% of the solar plant output displaces gas or synfuel; by 1996, 56% of the output will be displacing coal. Based on realistic dispatch scenarios over the life of the plant, solar energy will displace over 15 billion cubic feet of gas and 769,000 tons of coal.

SOLAR PLANT TOTAL FOSSIL FUEL DISPLACEMENT

- Gas - 15 Billion Cubic Feet
- Coal - 769,000 Tons
- Savings - $41M (levelized)

The determination of the actual fuel displacement was based on a detailed hour-by-hour analysis of the Southwestern system. General Electric's Electric Utility Systems Engineering Department utilized complex computer simulation codes to model the utility system using Southwestern projections of capacity, demand, and generation mix. The technique is identical to those used by utilities in general for assessing the implications of installing other generation types. The resulting projections of life-time fuel savings are thus quite realistic.

By utilizing several of their own existing computer codes, Southwestern has independently confirmed that the fuel savings calculated by General Electric can be achieved under the given assumptions.

SOLAR PLANT OPERATION AND MAINTENANCE COSTS

Operating and maintenance costs include such items as the costs for operating personnel, spare equipment, and maintenance labor. During the first year of operation, an operating and staff crew of 13 personnel will be required. In subsequent years, however, a much smaller crew (8 personnel) will be needed to operate the plant.

OPERATION AND MAINTENANCE COSTS

(1980 DOLLARS)

	Crew Size	Annual Cost (Thousands)
First Year	13	$892
Subsequent Years	8	$650

BASE CASE VALUE ANALYSIS

A value analysis of the Solar Repowering Demonstration Plant was performed using realistic economic assumptions provided by Southwestern. Coal and natural gas costs were assumed to escalate at 2% above general inflation (which was taken as 8%) over the life of the plant. The discount and fixed charge rates consistent with this general inflation level are 13.2% and 14.9% respectively. Since the Plant X, Unit 3 fossil boiler will probably remain operational throughout the life of the solar plant, the solar portion will not receive a capacity credit. The levelized cost savings for the displaced 15 billion cubic feet of gas and 769,000 tons of coal is $41 M, or $730/kW (in 1980 dollars). Offsetting this substantial savings are the plant operation and maintenance costs, estimated to be $160/kW. The total value of the demonstration project is $570/kW.

ASSUMPTIONS FOR THE VALUE ANALYSIS
(BASE CASE)

Solar Plant Life	- 30 years
Investment Tax Credit	- 10%
Discount Rate	- 13.2%
Fixed Charge Rate	- 14.9%
Fuel Costs (1980$):	
Coal	- $1.90/MBTU
Gas	- $1.95-2.82/MBTU
Fuel Price Escalation Above Inflation	- 2%
Fossil Boiler Availability	- Life of the Solar Plant

Given the assumptions on fuel escalation, load growth, construction, and expansion plans along with the economic parameters utilized, Southwestern agrees that the performance modeling and economic analysis of the base case is accurate and attainable.

ALTERNATIVE CASE

An alternative case was evaluated to examine the impact of changing fuel price escalation relative to inflation (which was constant in base case). Gas prices were assumed to reach oil prices by 1990, and fuel prices were assumed to escalate at 2% above inflation until year 2000, and then increase at a rate equal to inflation. This scenario was selected because it is anticipated that (1) prior to year 2000, the high desirability of gas, coupled with deregulation, will cause the price of gas to escalate faster than other, less attractive, fossil fuels such as coal, and (2) by the year 2000 alternative energy sources will greatly reduce or eliminate excessive fossil fuel cost increases. Under these assumptions, the plant value increases to $750/kW.

IMPACT OF BOILER RETIREMENT

Some utilities may assign a capacity credit to the solar repowering plant after the fossil boiler is retired, since it would contribute some amount toward peak load reliability. An analysis was performed on the Southwestern solar repowering plant to assess the magnitude of this credit, using the same performance and economic assumptions as the base case. If the boiler is retired in 1995, the solar plant capacity credit would be $100/kW (in 1980 dollars) and could be significantly higher with earlier retirement. The total value of the solar plant would then be $850/kW.

SOLAR PLANT VALUE
$/kW, 1980 dollars

Item	Base Case	Alternate Case	Retired Boiler
Capacity Credit	0	0	100
Fuel Savings	730	910	910
O&M	-160	-160	-160
TOTAL	570	750	850

Value Discussion

A number of factors have been identified which have affected the value of the Solar Repowering Plant. The more important factors are summarized below.

1. Displaced Fuel

The Plant X, Unit 3 solar facility displaces a high percentage of coal over the plant life. If Southwestern's program for replacing gas capacity with coal is delayed, the solar plant will displace more gas and less coal resulting in higher value. The same value increase would occur on a utility system with a less ambitious coal capacity addition program.

Only two areas affecting possible fuel displacement accuracy have not been addressed in the analysis. First, no contractual factors regarding natural gas have been included in the model. Under current contracts, Southwestern is required to pay for a certain amount of gas whether or not it is used. This "take or pay" system can adversely affect a strict economic dispatch approach to analysis. The potential effect of this factor is not considered significant since several gas contracts will be renewed before the solar plant goes on line, thus making contract adjustments possible.

A second factor not included in the analysis was the impact of the Fuel Use Act which requires curtailment of natural gas use. Omission of this factor was justified under the assumption that synfuel will be available as a replacement fuel for the gas-fired units.

2. Fuel Escalation

The plant value is sensitive to the difference in fuel inflation rate and general inflation rate. The faster fuel costs escalate relative to general inflation the higher the solar plant value will be.

The plant value is not significantly affected by the general inflation level since the levelizing factors used to predict both the lifetime fuel savings and the fixed charge rate used to capitalize the fuel savings are similarly affected by the general inflation rate.

3. Insolation Level

The solar plant output is proportional to the hours and intensity of solar insolation. Areas with higher insolation will have higher plant values assuming the same economic and utility system parameters.

4. Investment Tax Credit

Investor-owned utilities are limited to a 10% investment tax credit for solar installations. An increase in investment tax credit to the level available to industry (25%) would significantly reduce the fixed charge rate, thus increasing plant value.

5. Scheduled Maintenance

The value analysis conducted for this program assumed a one-month scheduled maintenance period. Although the maintenance was scheduled for the poorest insolation month (January), it still had the effect of reducing plant capacity factor (and value) by 6%. The assumed month-long shutdown was based primarily on boiler and turbine considerations. If maintenance operations show the solar plant will not require a four-week shutdown, future plants could realize increased value by providing tie-ins to other existing turbines to recover part or all of this lost value.

6. Part Load Turbine Efficiency

The amount of energy displaced by the solar plant is directly related to the turbine efficiency. During hybrid operation the turbine will be operating at, or near, full load. During solar-alone operation, the turbine will be operating at greatly reduced load and efficiency. Since the cost of natural gas is high, and Unit No. 3 plant efficiency is relatively low compared to other power plants in the Southwestern System, economic dispatch of the plant output will result in infrequent fossil boiler operation and frequent solar-alone operation. This situation has the effect of lowering the value of the solar plant.

In future applications, consideration should be given to the solar repowering of power plants which have a high ranking in the utility system dispatch scheme. This will result in more frequent operation in the hybrid mode and an increase in solar plant value. As an upper limit, if the fossil portion of the output was dispatched whenever the solar plant is in operation the turbine would always be operating at peak efficiency, and a 10% increase in capacity factor and plant value could be expected over the values reported in this report.

Approximately four and one-half years will be required to complete the construction of the solar repowering plant. No further component development work is required to support the remainder of the program, which greatly reduces schedule risk. Assuming a go-ahead by June 1981, the plant will be on line by the end of 1985. Procurement of the steam generators will pace construction, and orders must be placed by early 1982. Because of the emphasis placed on the evaluation and analysis of these components during conceptual design, detailed specifications will be available to support the procurement when required.

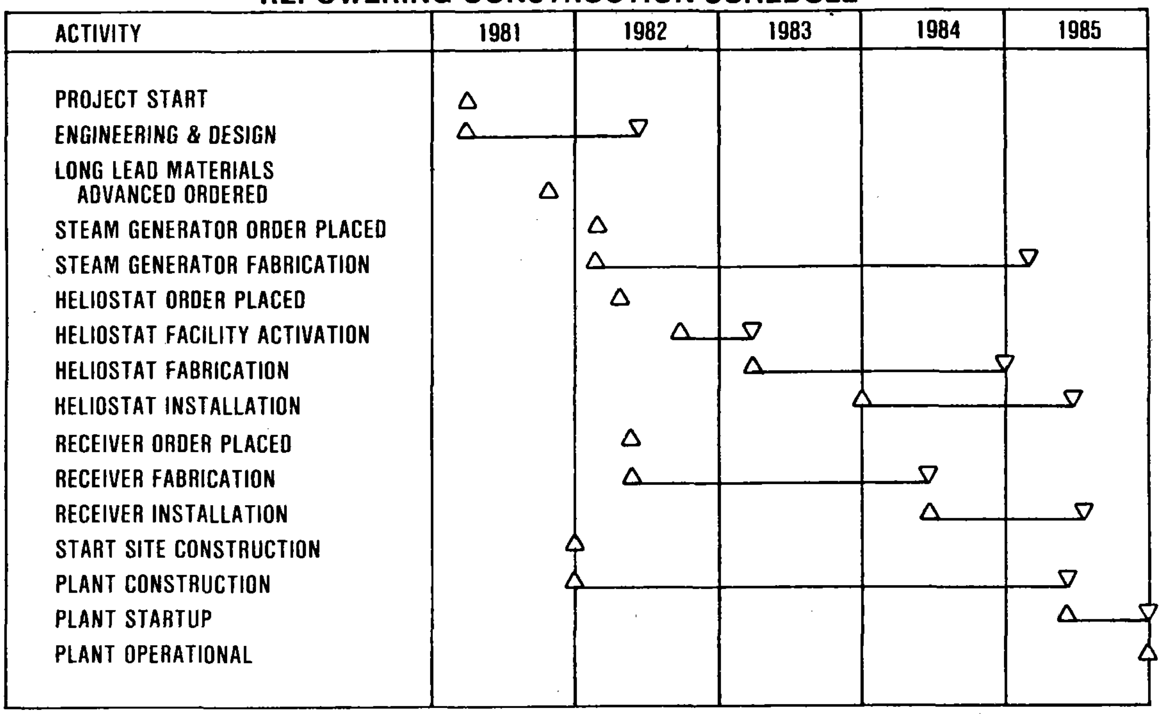
The final selection of heliostats for the project must be made and the order placed, by early 1982. Southwestern has already initiated discussions with possible heliostat vendors and evaluations are in progress. The selection of heliostats by early 1982 presents no problems.

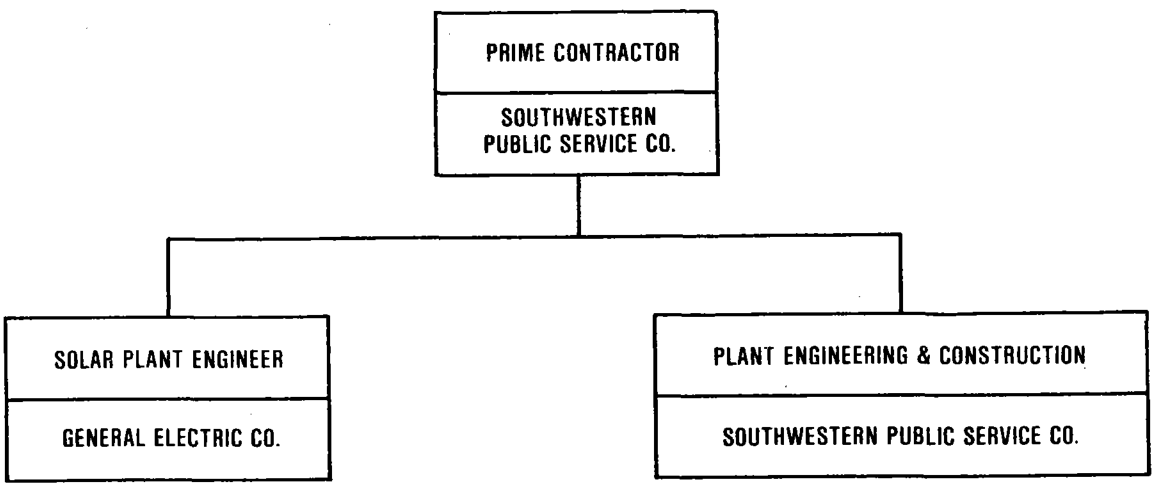
Southwestern will lead the final design and construction efforts of the program, with support from the General Electric Company in the area of solar plant engineering. Southwestern plans to perform the program with the same design and construction techniques they use for building coal-fired electric generating plants, plants which they install at costs less than the current national average. The principal cost-effective techniques Southwestern employs in the design and construction of plants include:

- Design, procurement, and construction in parallel when appropriate to support the schedule
- Use of their own standardized and proven procurement procedures
- Construction management by Southwestern rather than by an architect-engineer

This approach will provide DOE with a solar repowering plant at the lowest possible cost for a plant of this size.

REPOWERING CONSTRUCTION SCHEDULE





- RECEIVER DESIGN AND FABRICATION
- SOLAR PLANT DESIGN & SPECIFICATION
- SODIUM ENGINEERING

- PLANT CONTROLS
- COMPONENT PROCUREMENT
- PLANT ENGINEERING
- CONSTRUCTION MANAGEMENT
- OPERATIONS

Southwestern is perhaps in a better position than most utilities to review and critique the proposed design. The company is among the few electric utilities in the nation that design and supervise construction of their own generating facilities; in effect, Southwestern is its own architect and engineer consultant. Southwestern, therefore, assumed a much more active part in the actual design than most utilities would.

1. Endorsement of the Conceptual Design

Southwestern endorses the Plant X repowering study as a comprehensive conceptual design influenced by the company's engineering standards and design practices. The company considers the proposed design technically achievable requiring only engineering effort to produce a functional solar-electric generation facility.

2. Plant Cost Estimate

Southwestern participated in the development of the conceptual design cost estimate. The company believes the cost estimate presented in the repowering study is valid. Southwestern's productivity on numerous construction projects is significantly greater than the standard architect engineer productivity figures used in the cost estimate. Use of the lower productivity figure indicates the conservative approach General Electric and Southwestern applied in estimating construction cost.

3. System Performance and Economics

Southwestern used its existing computer codes and estimation methods to verify GE's system performance and economic analysis. Uncertainties such as government regulations and economic variables may affect a definitive cost estimate.

4. Value of Project to Industry

The real value of the proposed project is to demonstrate to the utility industry that solar repowering technology can be applied successfully on a commercial scale.

5. Solar Repowering Potential at Southwestern

Southwestern conducted a survey of other existing generating units in its service territory and determined it has a maximum solar repowering potential of approximately 50 percent of existing natural gas-fired capacity.

6. Safety

Southwestern does not foresee any extraordinary safety hazards associated with sodium central receiver technology. It is Southwestern's opinion that adequate safety practices and procedures exist or can be developed that would reduce hazards inherent to solar thermal facilities. The conceptual design has selected and located proper equipment to augment these safety procedures.

7. Environmental Impact

The positive benefits of new jobs and the resultant boost to the local economy outweigh the minimal adverse environmental impact of the solar installation.

8. Project Implementation

Southwestern would design and construct the solar facility in the same manner as it does any of its power plants. The company's objective is to conduct a turnkey project and meet the proposed 1985 start-up date.

9. Advantage of Repowering

The principal advantage of repowering is replacement of fossil fuel, while maintaining the capacity credit of the existing unit to overcome rising fuel costs, government regulations, and the conversion to coal-fired generation.

10. Role of Solar Repowering in Corporate Planning

Southwestern cannot at this time consider repowering as being an economically viable option because of economic and regulatory uncertainties. Southwestern's present strategy is to build coal-fired plants and utilize existing gas-fired facilities. However, if in the future solar repowering becomes economically attractive, it would be considered in Southwestern's corporate planning activities.

11. Permits

There is no significant environmental or regulatory permit requirement for repowering an existing facility. There is no local or state agency permitting or approval problem.

12. Acceptability of Central Receiver Technology for Repowering

Southwestern believes the central receiver design is particularly acceptable to repowering. The major constraint is the high cost of heliostats, which must be decreased before commercial implementation is practical.

SECTION 2
INTRODUCTION

Section 2
INTRODUCTION

The Southwestern Public Service Company (SPS) Solar Repowering Program was performed over a nine-month period ending in June 1980. The program was one of twelve competitively selected (under DOE RFP DE-RP03-795F10506) to study the solar retrofit of existing fossil fired facilities. It resulted in the preparation of a sound conceptual design for a solar retrofit of a reheat electric generating plant in Texas. Subsequent sections of this report document the technical work. This introduction provides an overview of the project and describes the gas-fired power plant selected for repowering.

2.1 STUDY OBJECTIVE

The objective of the SPS Solar Repowering Program was to perform a conceptual design and economic assessment of central receiver technology at a specific utility site in close coordination with the user utility. General Electric Company used its years of power generation experience to work with Southwestern Public Service Company in a pragmatic evaluation of repowering Plant X, Unit 3, located near Earth, Texas. This report documents the results.

In recent years the United States has been relying increasingly on imported fuels, principally oil, for satisfaction of its domestic energy needs. Legislation such as the National Energy Act of 1978 has attempted to decrease the usage of premium fuels (oil and natural gas) for electric power generation.

Solar energy is recognized to be an inexhaustible source of energy for electric power generation, if cost and performance competitiveness can be achieved. Central receiver technology has been identified as offering a promising, approach for electric utility applications.

The use of a solar central receiver at an existing oil or gas fixed power station offers several potential advantages for the development of solar technology. First, such a retrofit allows the use of existing equipment and, therefore, reduces overall solar plant capital investment. Second, it allows utilities to attain first hand operating experience with a solar plant, while retaining existing generation capability in case of difficulties. Three, repowering displaces natural gas or oil, thereby reducing utility consumption of these premium fuels.

2.2 TECHNICAL APPROACH AND UNIT SELECTION

General Electric performed the conceptual design and economic analysis of a solar central receiver retrofit of an existing reheat gas-fired power plant. The selected facility, Plant X, Unit No. 3 on the Southwestern Public Service Company (SPS) system is shown in Figure 2.2-1. Plant X consists of four units (two reheat and two nonreheat) that are located in the Texas Panhandle near Lubbock. The site is well suited for a solar retrofit. It is remote but relatively accessible and very flat with good insolation characteristics. SPS already owns 1700 acres of land appropriately situated around the plant.

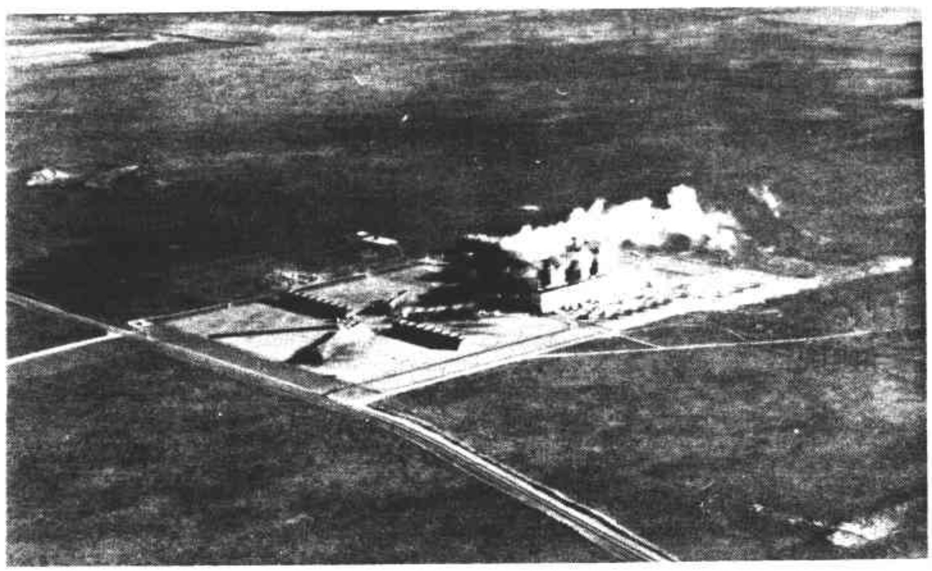


Figure 2.2-1. Southwestern Public Service Plant X, near Earth, Texas.

2.2.1 TECHNICAL APPROACH

The work flow for the SPS Solar Repowering Program is shown on Figure 2.2-2. Following preparation of a detailed system specification, trade-off studies were performed to select the preferred plant configuration. The repowering plant was then conceptually designed and a "bottom-up" cost estimate prepared. Based upon detailed cost and performance information, an economic analysis was performed to assess the cost/ value characteristic of the concept. Finally, a development plan was prepared that describes all activities required to take the plant from conceptual design through construction to start up and operation.

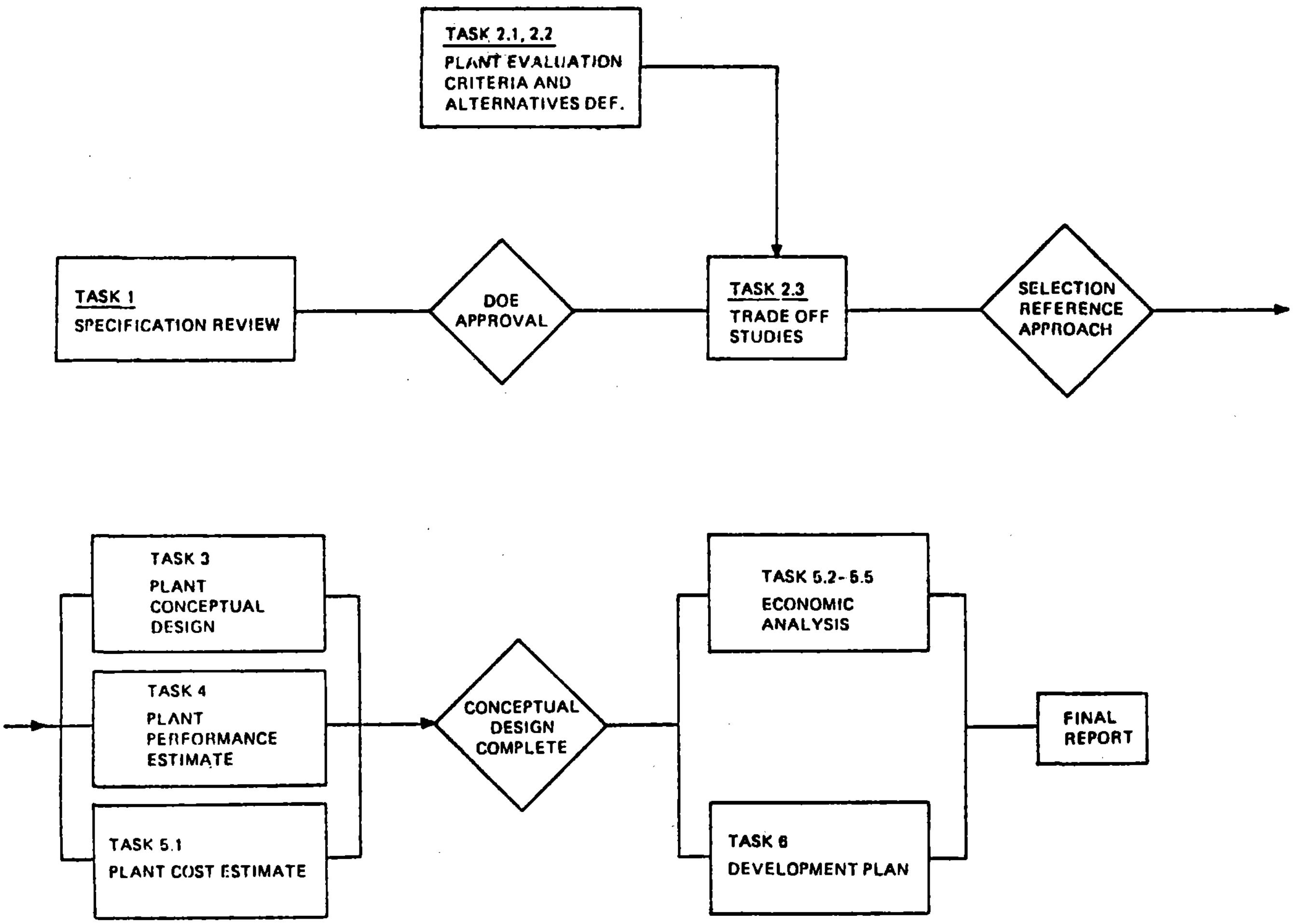


Figure 2.2-2. SPS Solar Repowering Program Work Flow Diagram

2.2.1.1 System Concept

The system concept, shown in Figure 2.2-3, utilizes a liquid metal-cooled central receiver to repower the 100 MWe gas-fired reheat Plant X, Unit No. 3. The solar system is designed to generate 60 MWe gross electric output at equinox noon.

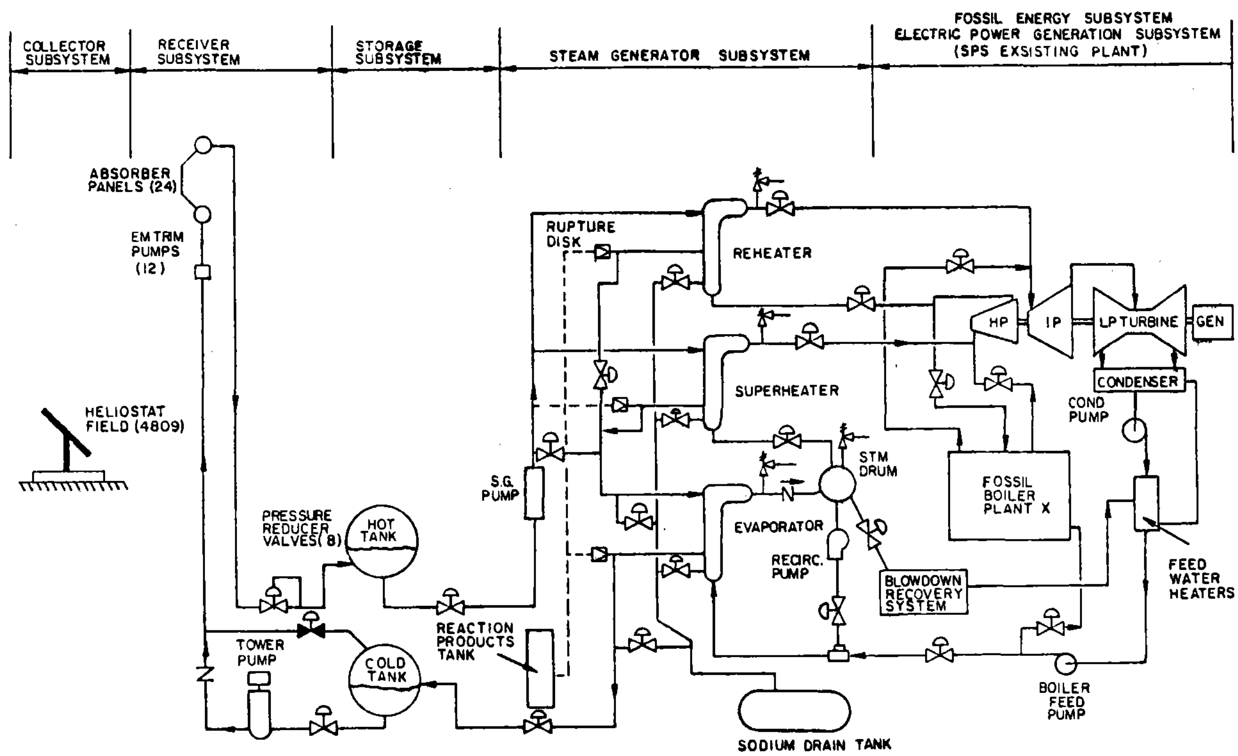


Figure 2.2-3. SPS Plant X Reheat Solar Repowering Concept

The solar portion of the system consists of a surround field of steel-framed, glass-mirrored, unenclosed heliostats reflecting the solar insolation to a tower-mounted cylindrical receiver. The receiver is cooled by liquid sodium with the flow rate through each receiver panel controlled by electromagnetic (EM) pumps, so that a constant outlet temperature can be maintained. The hot sodium flows to an in-line hot buffer storage tank and then to the steam generators. Cold discharge sodium returns to the receiver through an in-line cold buffer storage tank. The solar superheater, reheater, and evaporator parallel their respective fossil fired components. The superheat and reheat steam temperatures and pressures produced by the solar steam generators are the same as those of the fossil plant. The steam flows from the fossil and solar plants are combined and routed to the steam turbines to produce the desired plant output.

The impact on the existing plant is limited to piping tie-ins and controls modifications. Minimum intrusion into existing plant operating requirements and capabilities has been a major design objective of GE and SPS.

The buffer storage system is relatively small (10 full-power minutes). It is sized to maintain a solar output ramp rate during transients consistent with the capability of the parallel fossil boiler to pick up the load. This liquid metal solar plant design and the small amount of storage results in a plant that can maintain a steady total plant output during solar transients.

The overall concept represents a highly flexible system capable of meeting utility needs while operating in the hybrid (i.e., combined solar and fossil), fossil-alone, or solar-alone modes.

2.2.1.2 Description of Work Tasks

Activities to be performed in each task were carefully planned and executed by General Electric and Southwestern Public Service to develop the proposed concept into a firm conceptual design.

2.2.1.2.1 Systems Requirements Specifications - The emphasis here was in having Southwestern Public Service define design requirements to be used in the conceptual design effort, such as operating modes, performance requirements, environmental considerations, and economic parameters.

After initial review and approval by DOE, the specifications were updated and maintained to reflect current information generated throughout the program. The final version is provided as Appendix A.

2.2.1.2.2 Selection of Site-Specific System Configuration - This task reviewed and refined the extensive pre-proposal concept selection process used to identify the proposed Plant X repowering configuration. Southwestern Public Service input to the selection process was emphasized.

2.2.1.2.3 Plant Conceptual Design - This task developed a conceptual design for the overall repowered plant. Each subsystem was designed to provide the most cost-effective overall design in light of other subsystem requirements. These designs resulted from cost/performance trade-off studies performed during the task. Frequent interactions between user and designer were emphasized to assure Southwestern Public Service acceptance of and input to the design approaches.

The design emphasis was placed on interface and controls aspects. These areas required significant attention, particularly with respect to reheat steam conditions and flow control approaches. In addition to steam supply interfaces and controls, significant effort was directed at integration of the fossil and solar plant controls to provide an overall system responsive to demand changes and capable of controlled operation in the various operating modes and during transitions between those modes. General Electric and SPS experience in the design and analysis of complex power generation systems allowed this effort to be performed effectively.

2.2.1.2.4 Plant Performance Estimates - During this task the plant, as conceptually designed, was evaluated against operating requirements, and the overall plant capabilities and characteristics were determined. The results of this task were incorporated into the final systems requirements specification (Appendix A). Southwestern Public Service defined required operating modes and worked closely with General Electric to determine the acceptability of the plant response in these modes.

2.2.1.2.5 Plant Cost Estimates and Economic Analysis - Plant capital costs for a completed, operational repowered plant were estimated based on component and system designs prepared by personnel experienced in construction and component cost estimating. Southwestern Public Service provided local labor rate and productivity information to the construction cost estimators (Kaiser Engineers) to ensure correct consideration of site-specific factors. With respect to indirect costs and distributables, SPS defined its expected role in the detailed design and construction phases to allow these costs to be accurately assessed. Operating and maintenance (O&M) costs were determined for the integrated plant and were factored into the economic assessment.

The plant costs reflect the SPS approach to engineering and construction which utilizes internal resources for engineering and construction management rather than an architect-engineer. This efficient approach has resulted in SPS being able to build coal plants at costs far below the national average.

The plant capital and O&M costs, together with costs associated with plant shutdown for solar plant tie-in and any identified fossil plant modifications, provided one input to the overall economic analysis. The second input was a calculation of the value of the plant in terms of fuel savings resulting from displacement of fossil energy by solar energy. To provide an accurate assessment of this value, a General Electric utility hourly production cost model using projected demands and plant capacities was utilized.

2.2.1.2.6 Development Plan - A development plan was prepared outlining the activities and timetable required to have the Plant X repowered plant operational in 1985.

2.2.2 UNIT SELECTION

The selection of the site and plant for the conceptual design study was made by establishing selection criteria, then evaluating the alternatives against the criteria. The site selected for the study is the four-unit Plant X on the Southwestern Public Service Company system located near Earth, Texas, as illustrated in Figure 2.2-4. Table 2.2-1 indicates Plant X conformance with the site selection criteria.

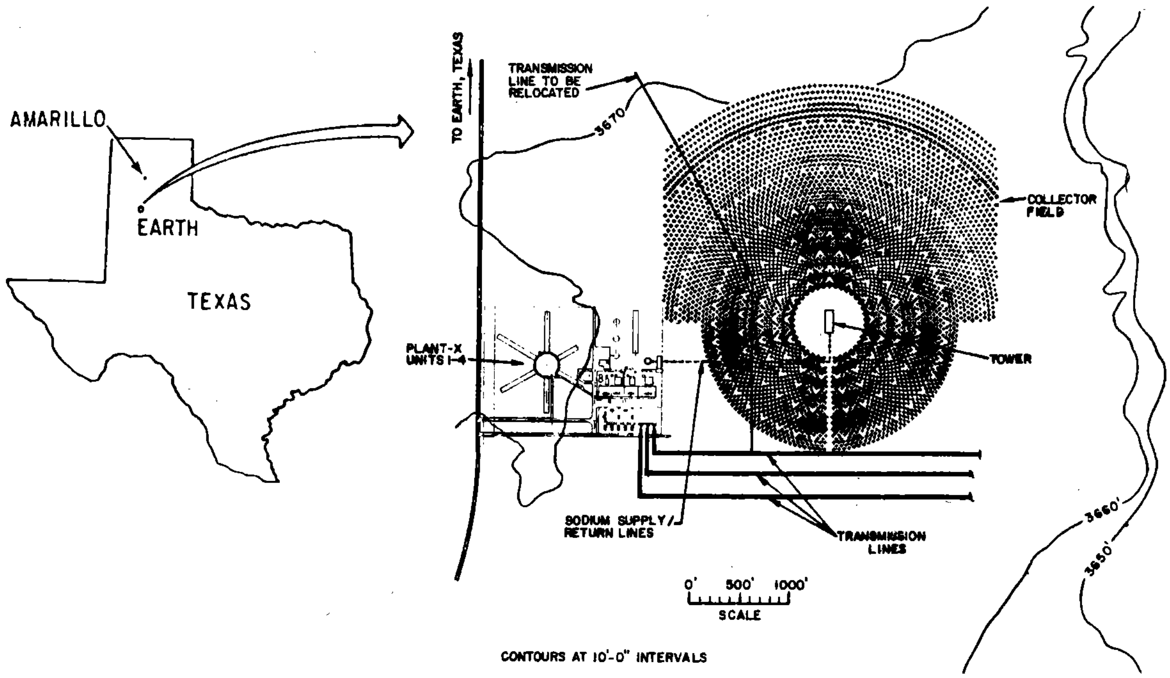


Figure 2.2-4. Selected Repowered Plant Location

Table 2.2-1

PLANT X SITE CHARACTERISTICS

Criteria	Plant X Characteristics
Solar Insolation	The annual average insolation levels in the Southwestern United States vary from 4.5 to 7.5 kWh/m^2-day. The Plant X site has an insolation level of 6.5 kWh/m^2-day and therefore is representative of the area considered prime for repowering.
Land Availability	SPS owns approximately 1700 acres of land surrounding Plant X. It is generally flat and semiarid with no planned use by the utility. This land area represents approximately 300 MWe repowering potential which is more than adequate for the concept under consideration.
Fuel Usage	The SPS generation capacity mix is currently comprised of 34% coal and 66% gas. By 1985, the mix will be ∿43% coal and ∿57% gas. This mix will ensure that at least early in plant life the solar energy will be displacing almost exclusively gas or oil (nearly all the SPS gas units have the ability to run on #2 oil if gas is not available).
Environmental Impact	Plant X is located 5 miles from the nearest residential center (Earth, Texas) in an area used almost exclusively for irrigated farming and cattle raising. No significant environmental concerns have been identified.

Unit 3 was selected over the other three units at Plant X for the conceptual design study for the following reasons:

- Unit 3 is a reheat unit while Units 1 and 2 are nonreheat and of lower efficiency.
- Unit 3 has steam conditions of 10 MPa/538°C/538°C (1450 psig/1000°F/1000°F). The 538°C (1000°F) temperature is representative of the vast majority of reheat steam cycles run at pressures of 10 MPa (1450 psig), 12.4 MPa (1800 psig), 16.6 MPa (2400 psig). The pressure is not considered a key factor in selection since all three pressures are common and the impact on plant design is significant only in sizing steam generator tubes. Thus, Unit 3 has a representative steam cycle for demonstration.
- Unit 3 has a nameplate rating of 100 MWe while Unit 4, 12.4 MPa/538°C/538°C (1800 psig/1000°F/1000°F), has a 200 MWe nameplate rating. Although economic analysis indicates that the economics of repowering Unit 4 may be better, Unit 3 was chosen based on the SPS desire to repower the smaller, somewhat older unit first.

2.3 SITE LOCATION

Plant X is located in Earth, Texas, which is approximately 100 miles south of the city of Amarillo, Texas, in an area of predominantly agricultural activities. An area map locating the plant was shown in Figure 2.2-4.

2.4 SITE GEOGRAPHY

The Plant X site is located at Latitude 34° - 10' North and Longitude 102° - 24' West. This puts the plant in the Texas high plains area with the actual site elevation being 1160 m (3660 feet) above sea level.

This area of Texas is predominantly level, but contains numerous minor irregularities such as small playas (or clay-lined depressions) and small stream valleys. During the rainy months the playas collect runoff water and form small alkes or ponds. The stream valleys drain into the major rivers of west Texas, but throughout most of the year these streams carry only very light flows. The actual plant site is consistent with the general area terrain--basically flat with local perturbations. The proposed collector field area is flat over about half the area with several small local hills (∿3 m high) covering the other half.

The soil is a combination of sand and clay layers with the top surface loose sand. A profile of the soil composition is provided in Figure 5.4-8.

Southwestern Public Service owns approximately 1700 acres of land surrounding the existing Plant X site as shown in Figure 2.2-4. The collector field will be located on ~220 acres due east of the existing plant on the Southwestern Public Service land.

2.5 CLIMATE

Plant X's location in the high plains area of the Texas panhandle results in a good climatological environment for solar applications. Details of the climate are discussed in the following sections.

2.5.1 WEATHER MONITORING STATIONS

Muleshoe, Texas, 12 miles due west of the site, is the closest weather reporting station, recording only temperature and precipitation. The nearest National Weather Service Station (NWS) is Lubbock, Texas, 50 miles southeast of the site. Meteorological data from both of these sites and the Amarillo National Weather Service Station (80 miles northeast) are presented in this section of the final report. Southwestern Public Service Company installed Eppley solar radiation monitoring equipment (both total and direct) 8 miles west of the site. This equipment has been operating since August 1979.

2.5.2 PRECIPITATION

The area is semi-arid, transitional between the desert condition on the west and the humid climates to the east and southeast. Precipitation data for the Muleshoe reporting station and the Lubbock National Weather Service is shown in Table 2.5-1.

Table 2.5-1

PRECIPITATION DATA

PARAMETER	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
NWS Lubbock, TX													
Normal Precipitation (in.)	0.55	0.50	0.89	1.08	3.17	2.78	2.23	1.87	2.19	2.05	0.49	0.61	18.41
Maximum Precipitation (in.)	4.05	2.51	3.23	3.48	7.80	7.95	7.20	8.85	6.62	7.76	2.67	1.47	40.55
Minimum Precipitation (in.)	0.00	T	T	0.10	0.10	0.32	T	0.05	T	0.00	0.00	T	8.73
Maximum in 24 hours (in.)	0.93	2.15	1.80	1.92	5.14	5.70	2.75	3.78	2.80	3.90	1.57	1.12	5.70
Mean number of days 0.01 inches or more of Precipitation	3	4	4	4	7	7	7	6	6	5	3	3	60
Average Snowfall (in.)	9.4	16.8	14.3	0.3	0.0	0.0	0.0	0.0	0.0	7.5	9.1	9.9	16.80
Maximum Snowfall in 24 hours (in.)	7.8	12.1	10.0	0.3	0.0	0.0	0.0	0.0	0.0	4.7	5.4	6.3	12.10
Mean number of days 1.0 inch or more of snowfall	1	1	1	0	0	0	0	0	0	<.5	<.5	<.5	3
MULESHOE, TX													
Normal Precipitation (in.)	0.55	0.47	0.53	0.93	2.42	2.65	2.91	2.10	1.99	1.67	0.52	0.55	17.29

Notes:

1. Normals Based on 1941 to 1970 period
2. "T" Trace
3. Muleshoe Precipitation Data 57 years of record

For Lubbock, normal annual precipitation is 46.8 cm (18.41 in.). The greatest monthly rainfall totals may be carried into the area from the Gulf of Mexico. This air mass often brings moderate to heavy afternoon and evening thunderstorms, which may be accompanied by hail. Precipitation across the area is characterized by its variability. Annual totals at Lubbock during the period of record range from as much as 103 cm (40.55 in.) to a low value of only 22.2 cm (8.73 in.).

The normal annual precipitation closer to the site, as the Muleshoe data indicate, is on the order of an inch less than the Lubbock data. The annual rainfall pattern, however, and its wide variability are the same.

Snow may occur from late October until April. Each snowfall is generally light and seldom remains on the ground more than two or three days at any one period.

2.5.3 TEMPERATURE

The Lubbock NWS reports the normal annual temperature is 15.4°C (59.7°F). The warmest months are June, July, and August with a normal daily maximum in July of 33.6°C (92.4°F). The coldest months are December and January with a normal daily minimum temperature in January of -4°C (24.8°F). For the nearby area, the record maximum temperature is 42.7°C (109°F), and the all-time minimum temperature is -27.2°C (-17°F).

The normal annual temperature for the Muleshoe reporting station is 13.9°C (57.1°F), slightly lower than Lubbock.

Table 2.5-2 shows the available monthly temperature data for both the Lubbock NWS and Muleshoe reporting stations.

Table 2.5-2

TEMPERATURE DATA (°F)

PARAMETER	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
NWS Lubbock, TX													
Normal Daily Maximum	53.4	57.0	63.8	74.8	82.5	90.6	92.4	91.3	83.8	74.7	63.1	55.2	73.6
Normal Daily Minimum	24.8	28.3	34.0	45.1	54.5	63.6	66.9	65.5	58.2	47.3	34.4	27.4	45.8
Monthly Average	39.1	42.7	48.9	60.0	68.5	77.1	79.7	78.4	71.0	61.0	48.8	41.3	59.7
Extreme Maximum	83.0	86.0	94.0	96.0	104.0	107.0	107.0	106.0	103.0	93.0	86.0	81.0	107.0
Extreme Minimum	-16.0	- 8.0	2.0	22.0	30.0	44.0	51.0	52.0	38.0	25.0	- 1.0	1.0	-16.0
MULESHOE, TX													
Monthly Average	36.2	40.0	46.0	57.0	65.9	75.1	77.9	76.4	68.9	58.0	45.5	38.5	57.1

Notes:

1. Normals Based on 1941 to 1970 period
2. Muleshoe Temperature Data 51 years on record
3. To convert to metric, °C = (°F - 32) x 5/9

2.5.4 WIND

The Muleshoe reporting station does not record wind data. The closest wind recording stations are Lubbock and Amarillo. Table 2.5-3 shows the Amarillo winds tend to be higher than those in Lubbock. The winds at the site should be between those in Amarillo and those in Lubbock.

Table 2.5-3
WIND DATA & THUNDERSTORM DATA

PARAMETER	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
NWS Lubbock, TX													
Mean Wind Speed MPH	12.4	13.8	15.3	15.4	14.5	14.0	11.4	10.1	10.7	11.3	11.8	12.8	12.8
Prevailing Direction	SW	SW	SW	SW	S	S	S	S	S	WSW	WSW	S	S
Fastest Mile Speed MPH	59.0	58.0	69.0	58.0	70.0	63.0	64.0	46.0	45.0	65.0	59.0	58.0	70.0
Direction (deg)	280	250	340	250	360	50	250	160	360	250	250	25	360
Mean number of days Thunderstorms Occur	< .5	< .5	2	3	9	9	8	7	4	3	1	< .5	45
NWS Amarillo, TX													
Mean Wind Speed MPH	13.1	14.2	15.6	15.5	14.8	14.4	12.5	12.1	13.0	13.0	13.2	13.0	13.7
Prevailing Direction	SW	SW	SW	SW	S	S	S	S	S	SW	SW	SW	SW
Fastest Mile Speed MPH	62.0	70.0	72.0	74.0	84.0	75.0	66.0	65.0	68.0	68.0	59.0	62.0	84.0
Direction	NE	NW	W	SW	SW	NW	SW	E	NE	S	NW	NE	SW
Mean number of days Thunderstorms Occur	< .5	1	1	3	9	9	10	9	4	2	1	< .5	49

Notes:

1. Normals Based on 1941 to 1970 period
2. Prevailing wind direction recorded through 1963
3. Wind direction - indicated from true north
4. Fastest mile wind - speed is the fastest 1-minute value observed when direction within ten degrees
5. To convert to metric - m/sec = mph x 0.447

Maximum winds are associated primarily with intense thunderstorms, and even though they are of short duration at times, they may cause significant damage to structures. Winds in excess of 11.1 m/s (25 mph) occasionally occur for periods of 12 hours or longer. These prolonged winds are generally associated with late winter and springtime low-pressure centers. The stronger winds usually blow from a westerly direction.

These strong winds may bring widespread dust and can cause discomfort to residents for periods of several hours. The precipitation patterns of the previous few days and the agricultural practices of the area significantly affect the pattern and amount of the dust.

2.5.5 SEVERE STORMS

Severe local storms are infrequent, though a few thunderstorms with damaging hail, lightning, and wind in a very localized area occur most years, usually in spring and summer. These storms are often accompanied by very heavy rain, which produces local flooding, particularly of roads and streets. Tornadoes are rare; one of record moved through the City of Amarillo late Sunday afternoon, May 15, 1949, causing 6 deaths and 87 injuries, with damage estimated at $4.8 million. Lubbock suffered major damage from a May 1971 tornado which caused several million dollars worth of damage and several deaths.

Table 2.5-3 shows the mean number of days that thunderstorms occur for both Amarillo and Lubbock, according to National Weather Service data.

2.5.6 CLOUD COVER

National Weather Service data for Lubbock (Table 2.5-4) shows that the area receives 76% of the annual available sunshine; Amarillo receives 73%.

Table 2.5-4

CLOUD COVER DATA

PARAMETER	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	YEAR
Lubbock, TX NWS													
Percent of Possible Sunshine	70	73	78	73	78	82	74	79	72	76	76	75	76
Mean Sky Cover, tenths (sunrise to sunset)	5.0	4.9	5.0	4.8	4.9	4.1	4.5	4.1	4.2	3.7	4.2	4.6	4.5
Mean Number of Days (sunrise to sunset)													
Clear	13	11	12	12	11	14	14	15	15	17	15	14	163
Partly Cloudy	7	7	9	9	12	11	11	10	8	6	7	7	104
Cloudy	11	10	10	9	8	5	6	6	7	8	8	10	98
Amarillo, TX NWS													
Percent of Possible Sunshine	69	69	72	72	72	77	77	77	74	74	73	68	73
Mean Sky Cover, Tenths (sunrise to sunset)	5.0	5.1	5.2	5.0	5.0	4.3	4.6	4.2	4.0	3.8	4.3	4.7	4.6
Mean Number of Days (sunrise to sunset)													
Clear	13	11	12	12	11	13	13	15	16	17	15	13	161
Partly Cloudy	7	7	8	8	11	12	12	10	7	6	7	8	103
Cloudy	11	10	11	10	9	5	6	6	7	8	8	10	101

The summer months show less cloud cover than the winter, with the most cloud cover occurring in December and January.

The mean number of clear days/year is 163 and 161 for Lubbock and Amarillo, respectively.

2.5.7 SOLAR RADIATION

No complete direct insolation data for the Plant X area exist. Southwestern

Public Service has installed direct and total insolation monitoring equipment 8 miles west of the site. However, the station has been in operation only since August 1979, and thus complete data are not available.

To estimate the direct insolation for the area Albuquerque insolation data (~same latitude) was used with adjustments based on direct insolation results from the Southwestern Public Service monitoring station. This approach was justified on the basis that the latitudes are comparable and the average percentage of available sunshine experienced in the two areas is the same (~76%).

The insolation data from the Albuquerque SOLMET tape was adjusted by a ratio of the peak SPS-measured insolation around the fall 1979 and spring 1980 equinoxes to the peak Albuquerque insolation for the same periods (965 W/m^2/1020 W/m^2=0.95). This adjustment was applied across the board to all the Albuquerque data.

The resulting average daily predicted insolation for Plant X is 6.5 kWh/m^2-day. This number is based on an average of the 1973-1975 Albuquerque data.

2.6 EXISTING PLANT DESCRIPTION

The plant selected for solar repowering on the Southwestern Public Service Company's system is Plant X, located near Earth, (Lamb County) Texas. Plant X has four units, all designed by Southwestern Public Service. Unit #1, a 49.5/MWe nonreheat unit, began operation in 1952. Unit #2, rated at 106 MWe, began operation in 1953. The third unit at Plant X, the first reheat unit in the Company's system, is also rated 106 MWe and began operation in 1955. The newest unit at Plant X, #4, is 200 MWe and began operation in 1964. Table 2.6-1 presents the major operating characteristics of each unit.

Table 2.6-1

PLANT X FULL LOAD DATA

	UNIT #1	UNIT #2	UNIT #3	UNIT #4
Net Capability	49.5 MWe	106 MWe	106 MWe	200 MWe
In-Service Date	1952	1953	1955	1964
Main Steam Conditions	5.9 MPa (850 psig)	10 MPa (1450 psig)	10 MPa (1450 psig)	12.4 MPa (1800 psig)
	482°C (900°F)	510°C (950°F)	538°C (1000°F)	538°C (1000°F)
Reheat Steam Temperature	Non-reheat	Non-reheat	538°C (1000°F)	538°C (1000°F)
Expected Retirement Date	1992	1993	1995	2004
Primary Fuel	Natural Gas			

The plant is located on approximately 1700 acres of land owned by Southwestern Public Service. This acreage is on the east side of, and adjacent to, Texas Farm-to-Market Road 1055, which is an asphalt-paved, two-lane, all-weather road. The plant proper, which includes turbine-boiler buildings, auxiliary buildings, storage tanks, cooling towers and switchyards, is enclosed by a chain-link fence. Two cooling tower blowdown ponds, several power transmission lines, and several water wells are also located on the Company property outside the fence.

The four units are arranged as shown in Figure 2.6-1. The turbine building, which is about 174 m (570 ft.) long, was built one unit at a time, from west to east.

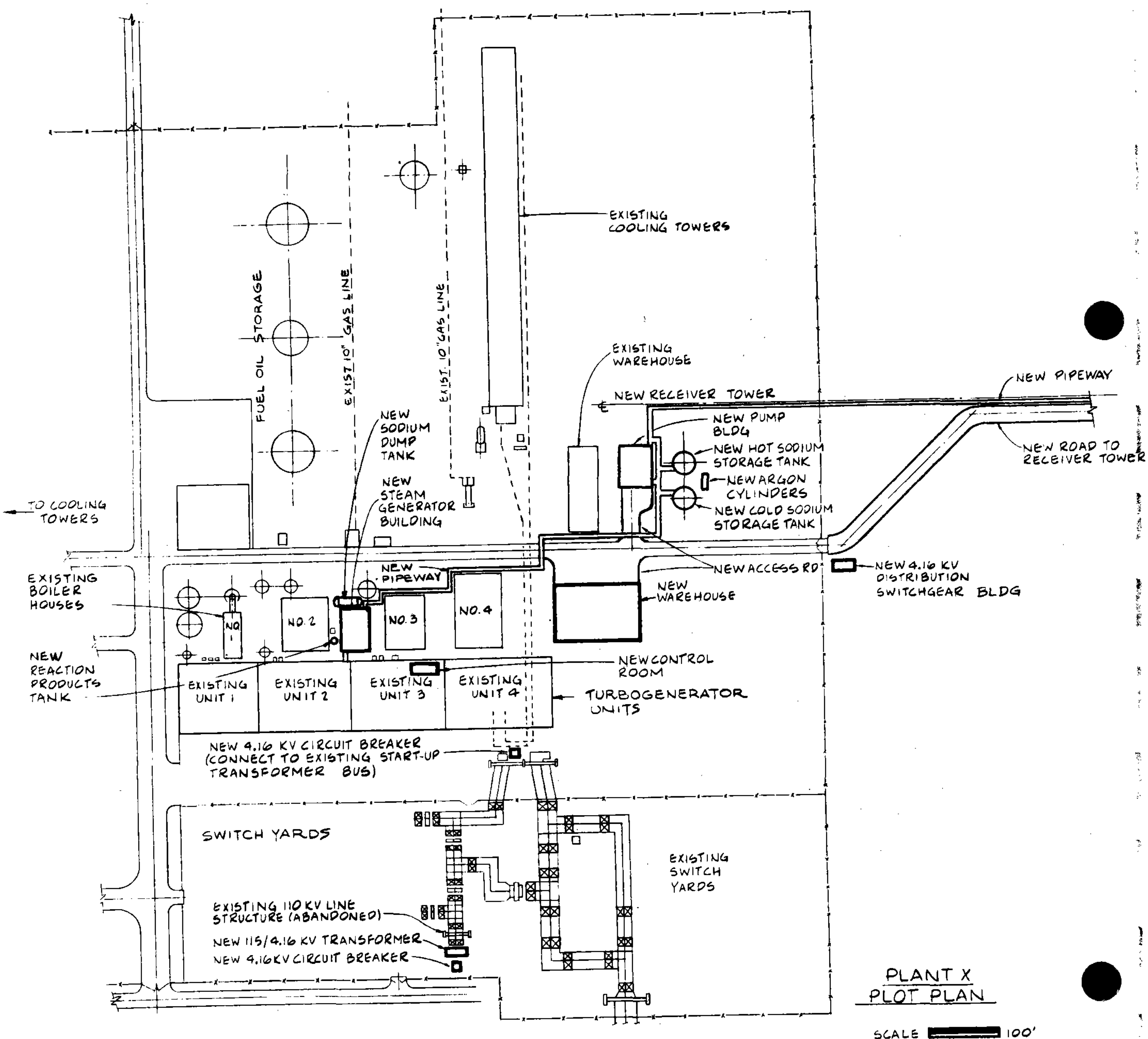


Figure 2.6-1. Plant X Unit Arrangement

2.6.1 PROCESS DESCRIPTION OF PLANT X, UNIT #3

As described in Section 2.2, the third unit at this plant was selected for solar repowering. The process by which Unit #3 generates electric power is shown schematically in Figure 2.6-2 at 112 MW load. At other load values the superheater outlet steam pressure is maintained at a constant, while reheat temperature and pressure vary considerably.

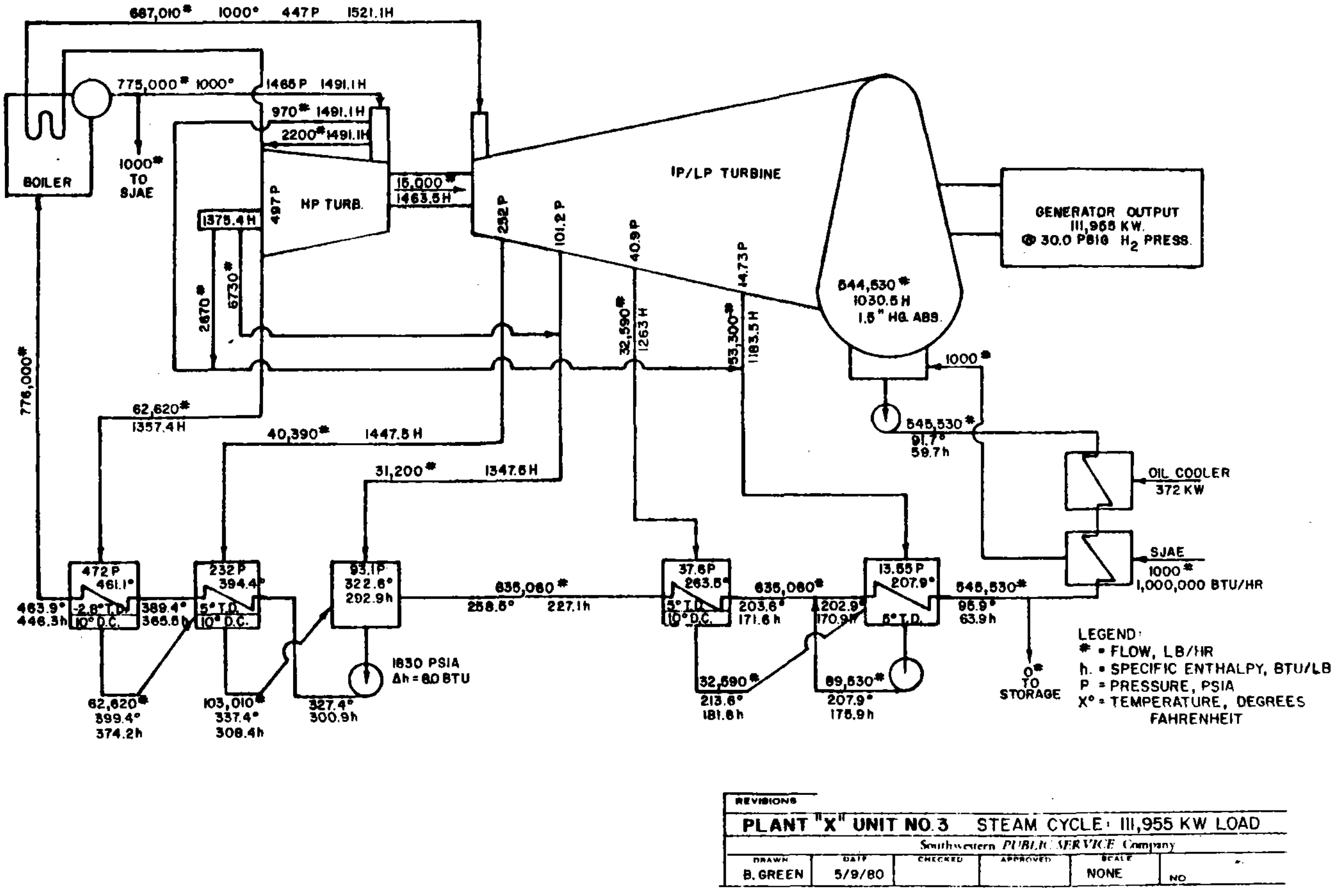


Figure 2.6-2. Plant X Unit No. 3 Process Schematic

The following process description will be useful in understanding the repowering concept.

The process employed is that of a conventional Rankine cycle, steam-electric power plant, with single reheat and five stages of regenerative feedwater heating. "Main steam" exits the high temperature superheater section of the boiler and enters the high pressure turbine at approximately 538°C (1000°F) and 10 MPa (1450 psig). As it expands through the turbine its thermal energy is converted to mechanical, rotational energy.

The steam leaves the high pressure turbine as "cold reheat steam" at about 3.4 MPa (500 psi) and 389°C (733°F) (depending on load). The steam passes through the reheater section of the boiler and emerges as "hot reheat" at about 538°C (1000°F). The hot reheat steam enters the intermediate pressure turbine, expands and then crosses over into the low pressure turbine. The expanded, cooled steam exits the low pressure turbine and enters the condenser.

In the condenser the spent steam is condensed to water, so that it will be at the proper thermodynamic state to be pumped and to accept thermal energy. The energy removed in the condensation process is rejected to the atmosphere at the cooling towers.

Condensate is pumped by single-speed condensate pumps through the oil coolers, steam jet air ejector condensers, and two low pressure feedwater heaters into the deaerating heater. The condensate picks up heat, and thus increases in temperature, as it proceeds through each of these devices. Unlike the other feedwater heaters, which are shell-and-tube type exchangers, the deaerating heater (D.A.) is a direct-contact type heater where condensate is directly mixed with steam extracted from the turbine.

The D.A., located high in the boiler structure, provides water directly to the main boiler feed pumps (BFPs). There are three such pumps, each of which has a fluid drive coupling for variable speed operation. Each BFP is rated at 1220 m (4000 ft) Total Developed Head and 4.2 m^3/min. (1100 gpm) at 3480 rpm. Each pump can supply about 60% of the flow required at full load. Water leaving the BFPs goes through two high pressure feedwater heaters and then to the economizer section of the boiler.

The boiler economizers consist of sections of tubes located in the lower temperature sections of the furnace. Feedwater is forced through these tubes where the temperature of the feedwater is increased to the boiling point. The feedwater leaves the economizers and goes into the steam drum, where the steam/water interface is maintained. Dry steam leaving the steam drum goes through a low temperature superheater and then a high temperature superheater where it becomes main stream.

2.6.2 HARDWARE DESCRIPTION OF PLANT X UNIT #3

2.6.2.1 Boiler

The boiler was manufactured by Combustion Engineering, Inc. under a contract dated February 25, 1953. It has a plain tube pressurized furnace, designed to burn natural gas or No. 2 fuel oil. The furnace proper has 1957 m^2 (21,050 ft^2) of heat transfer surface.

The superheater has two stages with spray desuperheating for temperature control between the two stages. It has a total of 2477 m^2 (26,650 ft^2) of heat transfer surface.

The reheater also employs spray desuperheating for temperature control. The reheat desuperheaters are located in the cold reheat steam lines. The reheater has 604 m^2 (6,500 ft^2) of heat transfer surface.

The economizer sections have a total of 1833 m^2 (19,725 ft^2) of heat transfer surface.

The primary control device for reheat steam temperature control is "burner tilts." The gas burners have the capability of being aimed upward to increase reheat and superheat temperature, or they may be aimed downward to increase the steaming rate and decrease temperature. In normal operation, burner tilt position is adjusted automatically to control reheat temperature. Spray attemperation is used to control main steam temperature, as operation of superheat spray does not significantly affect cycle efficiency. Since the use of reheat spray attemperation does have an effect on cycle efficiency, it is used only during abnormal load conditions, such as rapid transients, when burner tilts alone cannot keep reheat temperatures below acceptable maximums.

2.6.2.2 Turbine-Generator

The turbine-generator was supplied by the General Electric Company. It is a 3600 rpm machine. The turbine is designed to deliver 100,000 kW with main steam at 10 MPa (1450 psig) and 538°C (1000°F) reheat steam at 538°C (1000°F), and condenser back pressure of 507 Pa (1.5 Hg Abs). It is a 22-stage machine with a double flow low pressure section.

The generator is rated for 122,500 kVA at 207 kPa (30 psig) hydrogen coolant pressure and 0.8 power factor.

A scheduled overhaul and re-alignment of the turbine-generator was performed in the fall of 1979. The unit was found to be in very good condition.

2.6.2.3 Control System

The process, as illustrated in the schematic diagrams and described above, is controlled by a control system supplied by Bailey Meter Company. This system is a distributed, pneumatic system which was state-of-the-art in the mid-1950s. It was conceived and installed with the idea that Plant X Unit #3 would be a base-loaded plant.

The automatic controls can maintain steady-state control for loads in the range of 40 MWe and above. It can routinely change the load on the unit at the rate of ±3 MWe/minute. More rapid load changes may be made, up to +10 MWe/minute, but such changes require significant operator intervention. To operate in a mode that requires rapid load changes on the boiler, such as the solar hybrid mode, the control system would have to be significantly upgraded.

2.6.3 RETROFIT INTERFACE

The primary points of interface between the existing equipment and the solar-related equipment will be made in the major piping systems. Each one of these interfaces is described below.

2.6.3.1 High Pressure Feedwater Piping

This piping system carries high pressure water from the discharge of the boiler feed pumps to the boiler economizer inlet stop valves. The pipe is ASTM A-106 Gr. B material with an outside diameter of 27.3 cm (10.75 in.) and a wall thickness of 2.54 cm (1.00 in.).

High pressure feedwater to the solar steam generator will be taken from this pipe through a pipeline which will have a 20.3 cm (8 in.) diameter. The tie-in may be made just inside the north wall of the turbine building.

Besides the tie-in, the other major modification of the existing boiler feedwater piping will be the addition of dual isolation valves and a flow control valve downstream of the tie-in.

2.6.3.2 Main Steam Piping

The present main steam piping system includes a single 40.6 cm (16.0 in.) O.D. pipe, 5.7 cm (2.25 in.) wall, which conforms to ASTM A-213, T-11 material. This is a chrome-molybdenum alloy steel similar to the more usual designation ASTM A-335-P11.

Main steam from the solar superheater outlet will be tied into this line at a point just inside the north wall of the turbine building. The solar superheater outlet line will be a 35.6 cm (14 in.) O.D. approximately 4.4 cm (1.75 in.) thick alloy steel pipe.

In addition to the tie-in, the existing main steam line will be modified by the addition of dual isolation valves just upstream of the tie-in.

2.6.3.3 Cold Reheat Piping

The present cold reheat piping system includes two ASTM A-106 Gr. B pipes, each 40.6 cm (16 in.) O.D. and 1.27 cm (0.5 in.) thick. These connect the high pressure turbine outlet nozzles with the reheater inlet nozzles.

Steam going to the solar reheater inlet will be taken from these lines by a tie-in to each. The solar cold reheat lines leaving the existing cold reheat lines will be approximately 35.6 cm - 40.6 cm (14 in. - 16 in.) O.D. each. They will tie together and proceed to the solar reheater as a single line, 40.6 cm - 45.7 cm (16 in. - 18 in.) diameter.

In addition to the solar tie-ins, each of the existing cold reheat lines will require two isolation valves, one flow control valve, and one flow measuring device. This additional hardware will be installed in the lines downstream of the solar cold-reheat tie-ins.

2.6.3.4 Hot Reheat Piping

The existing hot reheat piping system includes two ASTM A-335 GR P-12 pipes. Each one has a 40.6 cm (16 in.) O.D. and is 2.1 cm (0.843 in.) thick. They connect the reheater outlet nozzles to the intermediate pressure turbine inlet nozzles (intercept valves).

Steam from the solar reheater outlet will enter each of these existing lines by way of two lines, each 35.6 cm - 40.6 cm (14 in. - 16 in.) in diameter. The tie-ins may be made just on the south side of the turbine building wall.

Immediately upstream of these tie-ins, two block valves will be installed to provide positive isolation of the boiler reheater.

2.7 EXISTING PLANT PERFORMANCE SUMMARY

Plant X, Unit #3, utilizes a General Electric steam turbine generating unit with a nameplate rating of 100,000 kW and is fired by a Combustion Engineering boiler with natural gas as the primary fuel and #2 fuel oil as standby. The full value unit net heat rate was 10,485 Btu/net kWh at the last test in January 1980. The generator nameplate rating is 122,500 kVa at 207 kPa (30 psi) hydrogen pressure. The maximum official capability is 112,500 kW. Throttle conditions are 10 MPa (1450 psi), 538°C (1000°F) superheat and 538°C (1000°F) reheat. Design turbine back pressure is 507 Pa (1.5 in. Hg).

From initial synchronization in 1955 until 1973 Plant X Unit #3 operated in a base load mode. Since 1973 it has operated in a cycling mode, that is, high load daytime and low load at night.

Lifetime hours synchronized to the system total 183,112 through December, 1979, giving a lifetime availability of 85.1%. For the calendar year 1979 the capacity factor was 35.8%.

Major maintenance on the turbine, which is scheduled every five years, was last performed in 1979 and consisted of restoring seal and packing clearances, diaphragm repair and alignment. This major maintenance to restore operating efficiency reduced the 1979 availability to 66.5%.

Operation and Maintenance costs for Plant X for the past 4 years are listed below:

1976	0.80 mills/kWh (net)
1977	0.80 mills/kWh (net)
1978	0.87 mills/kWh (net)
1979	1.53 mills/kWh (net)

2.8 PROJECT ORGANIZATION

The Southwestern Public Service Solar Repowering Program project team was composed of those three types of organizations required to take the proposed sodium repowering concept from conceptual design through construction and operation. The project team consists of General Electric Company (manufacturer-designer), Southwestern Public Service Company (owner-user), and Kaiser Engineers (architect-engineer).

2.8.1 ORGANIZATIONAL STRUCTURE

The program was led by the General Electric Company with Southwestern Public Service Company (SPS) and Kaiser Engineers, Inc. as subcontractors. This organizational structure was fully consistent with the way Southwestern Public Service conducts development engineering. SPS is uniquely qualified to follow through on this program and assume project leadership during any resulting detailed design and construction program. SPS normally acts as the prime contractor and construction manager for power plants built on its system. This technical strength was exercised throughout the program through clearly defined Southwestern Public Service areas of responsibility.

It should be noted that the tasks conducted by SPS were clearly those appropriate for the end user, specifically preparation of top level requirements specification, operating mode definition, load dispatch model, economic assumptions, development planning, and so forth. This deep utility involvement ensured that Southwestern Public Service is fully prepared to assume program leadership, if the decision is made to proceed into a construction phase.

The Solar Repowering Program was led by the General Electric Energy Systems Programs Department (ESPD). ESPD performed much of the work itself and planned and directed the activities of other participating organizations, while working closely with Southwestern Public Service. The team members consisted of Southwestern Public Service and Kaiser Engineers as subcontractors and the following other General Electric components who supported ESPD:

- Electric Utility Systems Engineering Department (EUSED)
- Advanced Reactor Systems Department (ARSD)

All three participating General Electric components are within the Energy Systems and Technology Division of the Company's Power Systems Sector. The division of technical work is shown in Table 2.8-1.

Table 2.8-1

PROJECT ORGANIZATION
• GENERAL ELECTRIC COMPANY -ENERGY SYSTEMS PROGRAMS DEPARTMENT (ESPD) PROGRAM MANAGEMENT SYSTEMS ENGINEERING PLANT INTEGRATION -ADVANCED REACTOR SYSTEMS DEPARTMENT (ARSD) LIQUID METAL ENGINEERING SODIUM COMPONENTS -ELECTRIC UTILITY SYSTEMS ENGINEERING DEPARTMENT (EUSED) ECONOMIC ANALYSIS
• SOUTHWESTERN PUBLIC SERVICE COMPANY (SPS) -PLANT X DESIGN -UTILITY INTEGRATION -DEVELOPMENT PLANNING
• KAISER ENGINEERS, INC. -BALANCE OF PLANT DESIGN -TOWER DESIGN

2.8.1 TECHNICAL REVIEW PANEL

In recognition of the near term nature of the repowering project, General Electric included a Technical Review Panel of senior technical personnel from General Electric and the electric utility industry. The makeup of the panel is shown in Table 2.8-2. Mr. Donald C. Berkey, Vice-President and General Manager of the Energy Systems and Technology Division acted as chairman. The panel strongly benefited from the participation of three different utilities (including SPS) representing a range of utility systems.

Table 2.8-2
TECHNICAL REVIEW PANEL

MEMBER NAME	POSITION	ORGANIZATION
DC Berkey, Panel Chairman	Vice President and General Manager	General Electric - Energy Systems and Technology Division
W Esler	Vice President - Engineering and Construction	Southwestern Public Service Company
JH Derr	Vice President - Power Plant Engineering and Design	Gulf States Utilities Company
J Stolpe	Engineering Supervisor	Southern California Edison Company
EF Lowell	General Manager	General Electric - Energy Systems Programs Department
F Ellert	General Manager	General Electric - Electric Utility System Engineering Department

2.9 FINAL REPORT ORGANIZATION

As discussed earlier in this introduction, the Southwestern Public Service Solar Repowering Program consisted of six technical tasks. The final report is structured to generally follow the program work flow. Table 2.9-1 shows the correlation of program tasks to report Sections 3 through 7. Section 8 provides a detailed SPS assessment of the program. A number of appendices have also been included to provide backup technical information. Appendix A provides the final version of the Southwestern Public Service Repowering Project System Requirements Specification.

Table 2.9-1

FINAL REPORT ORGANIZATION

Program Task	Report Section
Task 1 - Systems Requirements Specification	Appendix A
Task 2 - Selection of Site Specific Plant Configuration	Section 3
Task 3 - Plant Conceptual Design	Sections 4.1-4.3, 4.7-4.9,5
Task 4 - Plant Performance Estimates	Section 4.2, 4.4
Task 5.1 - Plant Cost Estimates	Sections 4.5, 4.6
Task 5.2-5.5 - Economic Analysis	Section 6
Task 6 - Development Plan	Section 7

SECTION 3

SELECTION OF PREFERRED SYSTEM

Section 3

SELECTION OF PREFERRED SYSTEM

This section describes both the proposal and program efforts undertaken to select the site-specific system configuration for the solar repowering of Plant X, Unit 3.

3.1 GENERAL SYSTEM CONFIGURATION SELECTION

The general repowering configuration, involving the paralleling of a solar reheat steam supply with an existing fossil-fired steam supply (Figure 3.1-1) was selected during the proposal phase of the program. The criteria used in the selection and the alternatives considered are discussed below.

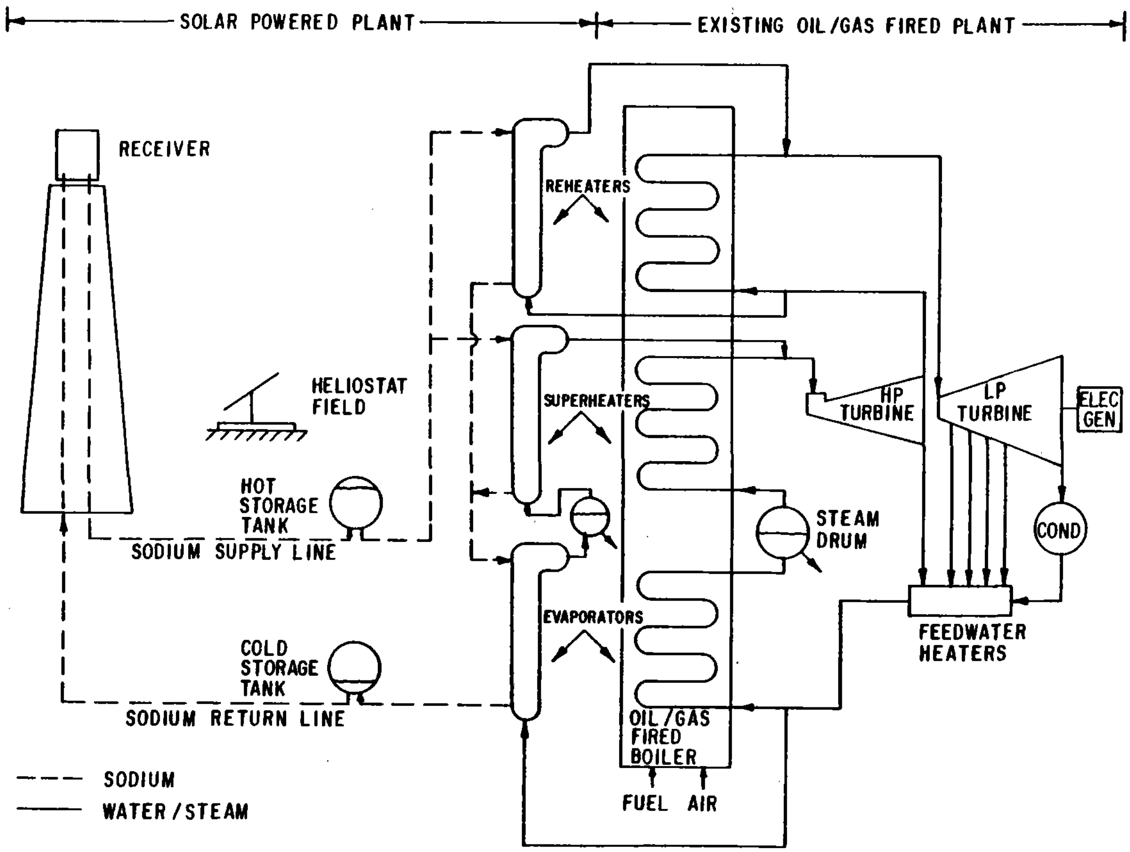


Figure 3.1-1. Repowering System Configuration

3.1.1 SYSTEM CONFIGURATION SELECTION CRITERIA AND ALTERNATIVES

The criteria for selecting the general system configuration were based on the understanding that repowering was envisioned as a near-term application of solar energy to the utility environment. The criteria evolving from that understanding are listed in Table 3.1-1.

Table 3.1-1

REPOWERING SYSTEM CONFIGURATION SELECTION CRITERIA

Criteria	Description
Fuel Displacement	The concept should allow a significant displacement of gas or oil
Near-Term Technology	The concept should be based on current and/or near-term technology to allow operation by 1985
Market Potential	The concept should be generally adaptable to existing plants representing a significant portion of gas- and oil-fired capacity
Solar Transients	The concept should allow operation under solar transient conditions (intermittent clouds) with plant output transients acceptable to the utility
Operating Mode Flexibility	The concept should ideally allow operation in fossil only, solar only, or hybrid modes

The configuration alternatives considered in the selection process (Table 3.1-2) were evaluated against the Table 3.1-1 criteria to arrive at the selected configuration. The configuration alternatives were based on the use of a sodium-cooled central receiver solar power plant that provides a near-term, flexible, experience-backed technology.

Table 3.1-2

SOLAR REPOWERING SYSTEM CONFIGURATION ALTERNATIVES

Alternative	Description
I Combustion Air Preheating	The air used for the boiler combustion process would be preheated in sodium/air heat exchangers
II Feedwater Heating	The boiler feedwater would be preheated in a solar heat exchanger rather than in turbine extraction heat exchangers
III Solar Superheating	The boiler firing would be reduced to produce only saturated steam which would subsequently be superheated in a solar-fired heat exchanger
IV Parallel Solar/Fossil Steam Supplies Without Reheat	The steam supply from the solar plant would be combined with the fossil supply upstream of the turbine throttle of a nonreheat cycle plant
V Parallel Solar/Fossil Steam Supplies with Reheat	The superheated steam supplies from the solar and fossil boilers would be combined upstream of the turbine throttle. The cold reheat steam would be split for reheating in the fossil and solar reheaters

Sodium has approximately 30 years of successful operating experience at temperatures up to and exceeding those proposed for this solar application. Based on General Electric discussions with utilities, there is little or no resistance to the use of sodium. The sodium system meets all the Table 3.1-1 criteria.

3.1.2 EVALUATION RESULTS

The system configuration selected was the Table 3.1-2 Alternative V, Parallel Solar/Fossil Steam Supplies with Reheat. The primary reason for selecting Alternative V over Alternatives I through III was its higher potential for displacing fuel. Table 3.1-3 lists the potential fuel displacement for Alternatives I through III and V. The values assume a 27% solar capacity factor and a 100% capacity factor for the combined plant.

Table 3.1-3

POTENTIAL FUEL DISPLACEMENTS
FOR REPOWERING ALTERNATIVES

Alternative		Potential Fuel Displacement
I	Combustion Air Preheating	5%
II	Feedwater Preheating	5.5%
III	Solar Superheating	7.3%
V	Parallel Solar/Fossil Steam Supply with Reheat	27%

Although the fuel displacement potential was the primary reason for rejecting Alternatives I - III, they also compared unfavorably in other areas, such as extensive fossil plant modifications, operating mode limitations and control problems.

The selection of the parallel steam supply for a reheat cycle rather than a nonreheat cycle (Alternative IV) was made on the basis of market potential. For example:

- In the Southwestern United States, reheat units have 1.5 times the available repowerable megawatts that nonreheat units have for plants of less than 200 MWe.
- Nonreheat gas- and oil-fired plants are generally pre-1955 vintage, which could limit repowered plant life. Reheat units were all built after the mid-1950s.
- The preliminary economic analysis indicates that repowering larger plants (above 200 MWe) will be economical. Plants in this size range are exclusively reheat and provide a large potential market.
- Development of the reheat concept allows application to both reheat and nonreheat plants, thereby opening up an even larger market.

In addition to meeting the fuel displacement, near-term technology and market potential criteria, the parallel reheat system alternative supplemented with a small amount of storage can respond acceptably to solar transients and allow operation in any of the desired modes.

3.2 SITE-SPECIFIC SYSTEM CONFIGURATION SELECTION

Application of the parallel solar/fossil steam supply concept to Plant X, Unit 3 involved several trade-off studies and analyses as listed below:

- Solar plant size
- Field configuration
- Field sizing
- Storage sizing

Each of these studies is discussed in the following sections.

3.2.1 SOLAR PLANT SIZE SELECTION

A preproposal analysis performed for repowering indicated that for sizes up to 100 MWe (Plant X, Unit 3 nominal rating) the cost/value ratio continues to decline as the plant size is increased. Figure 3.2-1 illustrates these analysis results, which were based on a $\$100/m^2$ heliostat cost and mathematical models of other plant components as listed in Table 3.2-1.

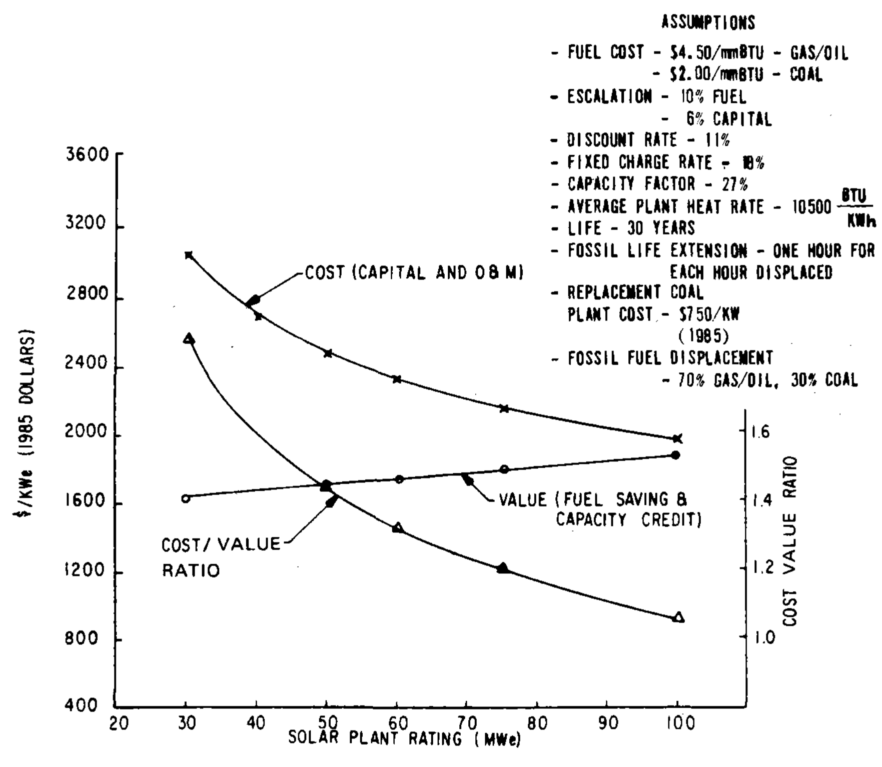


Figure 3.2-1. Trade-off Study Cost/Benefit Analysis for Repowering

Table 3.2-1

REPOWERED PLANT CAPITAL COST MODEL
(all costs in $ 1978)

Item	Mathematical Model	Item	Mathematical Model
			Other Capital Cost Elements
Heliostats	$100\ A_M$	Buildings	$3{,}975\left(\frac{P}{100}\right)^{1/3} \times 10^6$
Land	$150\ A_L$ (based on SPS input)	Control System Solar	1.3×10^6 (constant)
Land Preparation	$750\ A_L$ (based on SPS input)	Integrated	0.75×10^6 (constant)
Receiver	$[2.2-0.0875(D-16) + 0.001(A_R-804)] \times 10^6$	Tie-Ins	$3\left(\frac{P}{100}\right)^{1/4} \times 10^6$
Tower Structure and Piping	$[0.505e^{.01T} + (0.00517T-0.194)\left(\frac{P}{150}\right)^{1/2} + 1.11] \times 10^6$	Storage	$1.8\left(\frac{P}{100}\right)^{1/2} \times 10^6$
Support Structure	$0.04464\sqrt{D^2 + H^2} \times 10^6$	Balance of Plant	1.5×10^6 (constant)
EM Pumps	$0.48P^{1/2} \times 10^6$		
Steam Generators	$1.15P^{1/2} \times 10^6$	Distributables	44%
Centrifugal Pumps	$[0.026 + 0.000097T]\ P \times 10^6$		
Horizontal Piping	$9008\ (A_L P)^{1/2}$		

Legend: A_M - Mirror area (m^2)
A_L - Land area (Acres)
D - Receiver diameter (m)
A_R - Receiver area (m^2)
T - Tower height (m)
P - Plant design solar output (MWe)
H - Receiver Height (m)

Although full repowering (100 MWe) of Plant X, Unit 3 would be most economical, Southwestern Public Service required the plant to be operable in the hybrid mode at all times that steady output is required. In the hybrid mode, the fossil plant can pick up the solar load if insolation is lost, thus maintaining steady output. The minimum automatic operating level for the fossil boiler is ~ 40 WMe. Thus, to meet the requirement to operate hybrid, the solar plant must be limited to 60 MWe. Based on this logic, 60 MWe was selected as the design solar plant capability.

3.2.2 FIELD CONFIGURATION STUDY

This study was undertaken to determine if a north or surround field configuration would be optimum for the 60 MWe repowering of Plant X, Unit 3.

3.2.2.1 Method

The analysis was performed using the DELSOL (Sandia report SAND 79-8215) computer code. Table 3.2-2 lists the assumptions and input values used in the analysis. The cost model shown in Table 3.2-2 was based on detailed costs developed in the Alternate Central Receiver program modified to fit the DELSOL cost model format.

Table 3.2-2

DELSOL FIELD CONFIGURATION STUDY
ASSUMPTIONS AND INPUT VALUES

Parameter	Input Value
Design Point	Noon, Equinox
Design Point Insolation	970 W/m^2,
Site Altitude	1.11 km (3640 ft)
Heliostat	49 m^2, Second Generation
Reflectivity	0.9
Receiver Absorbtivity	0.95
Receiver Radiation and Convection Losses	0.06
Flux Limit	1.4 MW/m^2
Type of Receiver	External
Solar Multiple	1.0
Cost Model:	
Heliostats	$142/$m^2$ (equivalent to $230/$m^2$ for 1980$ when distributables are added)
Land	$0.22/$m^2$
Wiring	0 (inlcuded in Heliostat costs)
Tower	$\$2.39 \times 10^6 - (1.39 \times 10^4\ THT) + 1.41 \times 10^2 \times THT^2 + 0.76 \times RECWT$ (THT = tower height, m; RECWT = receiver weight in kg)
Receiver	$\$4.187 \times 10^6 \times \left(\frac{AREC}{509}\right)^{0.8}$ - FLAT$ $\$6.09 \times 10^6\left(\frac{AREC}{804}\right)^{0.8}$ - CYLINDER (AREC = receiver area in m^2)
Tower Pump	$\$2.89 \times 10^6 \times \left(\frac{THT \times PTH}{7.1 \times 10^{10}}\right)$ (THT = Tower ht. in meters, PTH = Thermal power in watts)
Steam Gen. Pump	$\$2.6 \times 10^6 \times \left(\frac{PTH}{2.49 \times 10^8}\right)$
Piping	$\$9 \times THT \times (2644) \times \left(\frac{PTH \times THT}{1.35 \times 10^{10}}\right)$
Storage Cost	$\$1.4 \times 10^6$ (constant)
Heat Exchangers	$\$1.19 \times 10^7 \times \left(\frac{PTH}{2.49 \times 10^8}\right)^{0.8}$
EPGS	$2.5 \times 10^6 \times \left(\frac{PTH \times 0.42}{6 \times 10^7}\right)$
Fixed Costs	6.95×10^6
Indirects:	
Contingency	12%
Spare Parts	1%
Contractor Fees (etc)	23%
General Inflation	6%
Interest During Construction	25%
FCR	18%
Discount Rate	11%
Life	30 yrs
O&M	16%
Storage	10 full power minutes

This model was exercised for both the surround and north field configurations over a power range from 20 to 100 MWe.

3.2.2.2 Results

The results of the study are illustrated in Figure 3.2-2 as a plot of bus bar energy cost (1978$) versus power level for the surround and north field configurations. The results show a breakeven point at ~25 MWe with a cost advantage of ~8% for the surround field at the 60 MWe design point. Table 3.2-3 shows system parameters for the north and surround fields at the 60 MWe design point.

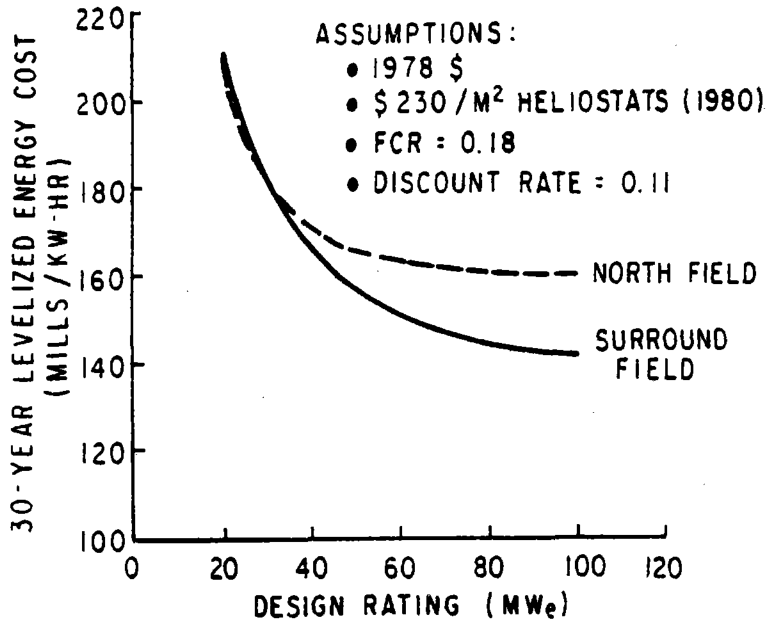


Figure 3.2-2. North versus Surround Field Energy Costs versus Rating

Table 3.2-3

DESIGN POINT (60 MWe) PARAMETERS FOR NORTH VERSUS SURROUND FIELD TRADE-OFF STUDY

Parameter	Surround Field	North Field
Heliostats	4104	4035
Tower Height	150 m (492 ft)	160 m (525 ft)
Receiver Size	14 m x 14 m (46 ft x 46 ft)	30 m x 30 m (98 ft x 98 ft)
Field Area	0.9 km^2 (222 acres)	0.918 km^2 (269 acres)
Annual Energy	152 GWe-hr	152 GWe-hr
Levelized Busbar Energy Cost	153.6 mills/kW-hr	164 mill/kW-hr

Based on the Figure 3.2-2 results, the surround field was selected for the conceptual design basis. It should be noted that the north field receiver required for a 60 MWe plant would have to be 30 x 30 m to meet the flux limit. Receiver panels of that length could not even be shipped and thus would be required to be built in multiple vertical sections. This would necessitate a major receiver development effort. In addition, the surround configuration is considered to be prototypical for future repowering efforts which will likely involve larger plants. At the higher power levels, the surround field cost advantage is more distinct.

3.2.3 FIELD OVERSIZING STUDY

The purpose of this study was to evaluate the cost effectiveness of oversizing the solar collector field. Under this concept the field would be sized to produce more than 60 MWe at the design point. Since the remainder of the solar plant (receiver, etc.) would only be sized to handle 60 MWe, a portion of the field would have to be defocused when the insolation produced more than 60 MWe. At other times, this field would produce more energy than the base case field and thus tend to flatten the output capability of the solar plant. The effect would be to increase the capacity factor of the plant for the cost of additional heliostats only without having to pay for a larger receiver, piping, storage, etc.

3.2.3.1 Method

The DELSOL code was used for this analysis together with the same sun and cost models used in the field configuration trade-off study, (Table 3.2-2) with the exception of using a 940 W/m^2 design point insolation. This insolation value is consistent with the equinox insolation levels measured by SPS near the Plant X site.

The base case (0% oversized) field receiver and tower were those identified in the collector subsystem design effort described in Section 5.3 and in Table 3.2-4.

Table 3.2-4

FIELD OVERSIZING STUDY BASE
CASE PLANT PARAMETERS

Parameter	Base Case
Field Configuration	Surround
Design Point	Noon, Equinox
Heliostats	4809 (49 m^2)
Receiver Size	12 m x 12 m (cylindrical)
Tower Height	140 m (460 ft)
Design Point Power	60 MWe

DELSOL analyses were performed with fields containing 10, 20 and 30% more heliostats than the base case. The additional heliostats were placed in the areas of highest efficiency (generally north field). Energy and cost calculations were made for the configurations studied.

3.2.3.2 Results

To illustrate the energy analysis results, the DELSOL-generated power output versus time for seven days of the year is shown in Figure 3.2-3 for the 20% oversize case. These power output versus time-of-day curves were integrated to obtain the daily energy for these seven days. These were then plotted to obtain a daily energy versus time-of-year curve. These plots for the 0% and 20% oversize cases are shown in Figure 3.2-4. Integrating these curves yielded the annual energy available for the various oversizing cases.

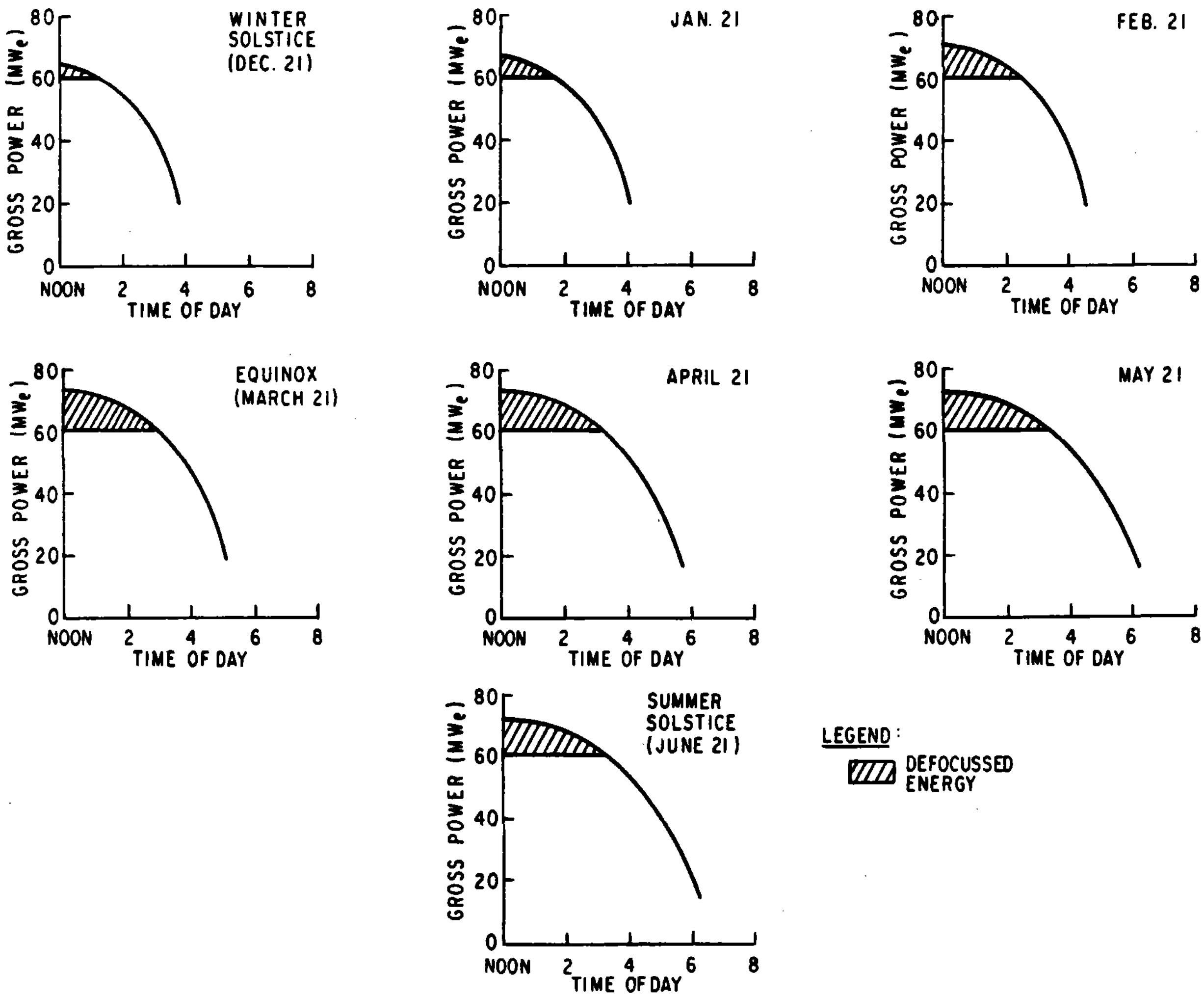


Figure 3.2-3. Power versus Time-of-Day for 20% Oversizing

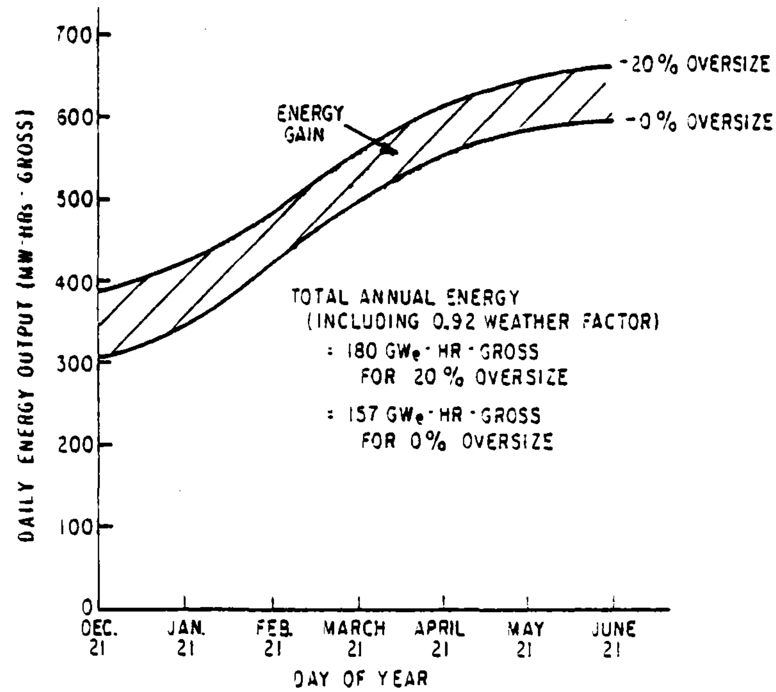


Figure 3.2-4. Daily Energy Output versus Day of Year for 0% and 20% Oversize

Table 3.2-5 shows the overall results of the field oversizing study in terms of energy and cost of electricity. For the assumed parameters, the optimum oversizing level appears to be at ~20% where there is an energy cost savings of ~4%.

Table 3.2-5

FIELD OVERSIZING STUDY RESULTS

ITEM		FIELD OVERSIZING		
	0%	10%	20%	30%
Tower Height (meters)	140	140	140	140
Heliostats	4809	5300	5786	6268
Receiver Size (meters x meters)	12 x 12	12 x 12	12 x 12	12 x 12
Total Plant Cost at Startup (1980 $)	$135 million	$142 million	$149 million	$156 million
Annual Energy (GWe-hr gross)	157	171	180	186
Capacity Factor	29.4%	32%	33.7%	34.8%
Total Cost of Electricity (mills/kW-hr net)(1980 $ - Capital and O&M - 30 year levelized)	181	175	174	176

Although there would be economic advantages in providing an oversized field, the no-oversizing option was selected for the conceptual design basis. The reasoning behind this decision is the fact that the oversized field can be added after the initial plant is built and its operation demonstrated. This results because oversizing only requires the addition of heliostats with no other plant modifications necessary.

3.2.4 STORAGE SIZING STUDY

In the pre-program phase of the study, only 10 full power minutes (10 MWe-hrs) of storage were proposed for the Plant X repowering. This is sufficient to enable the solar plant power to be ramped down from the full 60 MWe level to 0 at a rate (3 MWe/minute) consistent with the fossil boiler capability to pick up the lost solar output. Thus, the total plant output could be maintained at a steady level. Figure 3.2-5 illustrates this situation for the design operating case. The study was performed to examine the potential cost improvements associated with increasing the level of storage.

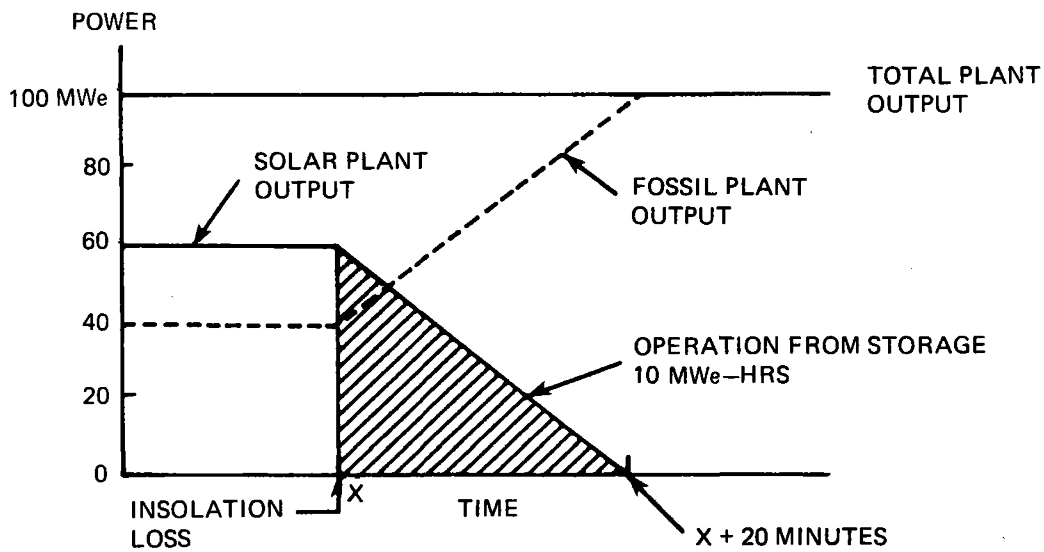


Figure 3.2-5. Plant Response to Loss of Solar Input

3.2.4.1 Method

The DELSOL computer code was again used as the main working tool for this study. The code was exercised over a range of solar multiples from 0 to 2.0. The cost and solar models used were the same as those used in the field configuration and field sizing trade-off studies (Table 3.2-2) with the exception of the storage cost model. The storage cost model was based on the Alternate Central Receiver, Phase II design which utilized double wall, field-fabricated tanks. The base case field design, as with the field oversizing study, was that developed in the collector subsystem design effort described in Section 5.3 and in Table 3.2-4.

3.2.4.2 Results

Table 3.2-6 summarizes the results of the study.

Table 3.2-6

STORAGE TRADE-OFF STUDY RESULTS

Item	Value			
Hours of storage	10 min	1.62 hr	3.23 hr	7.85 hr
Solar multiple	0	1.3	1.5	2.0
Heliostats	4809	6265	7286	9893
Receiver size (diameter x height, meters x meters)	12 x 12	13 x 13	13 x 13	14 x 14
Tower height (meters)	140	140	150	160
Total plant cost at startup (1980 $)	$135 million	$167 million	$192 million	$260 million
Annual energy output (GW-hr gross)	157	203	236	317
Capacity factor	29.4%	38%	44%	59%
Total cost of electricity (mills/kWh)	181	173	172	173

The results indicate that additional storage will reduce the cost of the solar electricity. The optimum storage size appears to be on the order of 3.2 hours where the cost of electricity is ~5% less than the base case (10 minute storage) cost.

To provide the optimum 3.2 hours of storage would raise the capital outlay by almost $57 million and provide no demonstration capabilities beyond that of the base plant. The minor improvement in cost of electricity provided by the additional storage was not considered sufficient to justify the added capital expense for the first plant. Thus, the 10 minute storage level was selected for the conceptual design basis.

It should be noted that the solar plant cannot be retrofitted with additional storage because the receiver, tower, piping, etc. would have to be enlarged. However, the cost of electricity could be reduced to almost the same level as the optimum storage case cost by retrofitting an oversized field as shown in the field oversizing study results (Section 3.2.3).

SECTION 4
CONCEPTUAL DESIGN

Section 4

CONCEPTUAL DESIGN

4.1 PLANT FUNCTIONAL REQUIREMENTS

The following sections provide a top level discussion of the functional requirements imposed on the repowering facility. The requirements include provisions for the desired output from the plant and specifications by the utility for satisfactory integration with the existing plant and utility system.

Details of the plant, individual subsystem and component requirements are included in the Appendix A, System Requirement Specifications.

4.1.1 DESIGN PERFORMANCE REQUIREMENTS

Table 4.1-1 summarizes the design performance requirements for the repowered Plant X , Unit 3 facility.

Table 4.1-1

REPOWERED FACILITY DESIGN PERFORMANCE REQUIREMENTS

Site Location	Earth, Texas
Plant Output (Solar)	60 MWe (gross) at noon, equinox
Plant Life	30 years
Maximum Solar Plant Output Transient	3 MWe/min
Peak Sodium Temperature	593°C(1100°F)
Solar Steam Temperatures	
Throttle Steam	538°C(1000°F)
Hot Reheat Steam	538°C(1000°F)
Steam Throttle Pressure	10.1 MPa(1465 psia)
Environmental Operating Conditions	
Temperature	-30°C to 45°C(-20°F to 110°F)
Wind	18 m/s(40 mph)
Environmental Design Conditions	
Temperature	20°C(68°F)
Wind	0 m/s (0 mph)
Environmental Survival Conditions	
Wind	54 m/s(120 mph)
Snow	958 Pa(20 lb/ft^2)
Ice	7.62 cm(3 in.)
Hail	5.08 cm(3 in.) @ 36.5 m/s (75 mph)
Plant Availability (exclusive of sunshine)	90%
Seismic Environment	Zone 2 (UBC)

The design requirements included in Table 4.1-1 are those necessary to meet the physical and operating limitations of the existing and proposed equipment and to enable satisfactory performance in the environment in which the plant is to be built.

Discussed in the following section are operating capability requirements imposed by the utility to ensure satisfactory integration of the solar facility into the existing plant and utility system.

4.1.2 OPERATING CAPABILITY REQUIREMENTS

Table 4.1-2 lists the operating capability requirements of the solar facility and integrated repowered facility considered necessary by Southwestern Public Service.

Table 4.1-2
OPERATING CAPABILITY REQUIREMENTS

Modes of Operation	Solar alone, Fossil alone, Solar/Fossil hybrid
Operation Within Modes	
Solar Alone	Fully automatic normal operation including response to solar transients; automatic solar plant startup; computer prompted operator assisted turbine startup
Fossil Alone	No degradation of performance or capabilities over nonrepowered plant
Hybrid	Capability to start or shutdown either solar or fossil plant with other operating; steady plant output during solar plant transients; responsive to plant dispatching system
Controls	Redundant master control and critical distributed control facilities; manual override capability; hard-wiring of controls for critical plant components
Emergencies	Automatic response to plant emergencies to put plant in safe shutdown mode and to prevent casualty from impacting other components

4.2 DESIGN DESCRIPTION AND OPERATING CHARACTERISTICS

This section includes a discussion of the Plant X, Unit 3 repowering system and describes the performance and operating characteristics of the system.

4.2.1 SYSTEM DESIGN DESCRIPTION

Figure 4.2-1 presents the Process and Instrumentation Diagram (P&ID) for the repowered facility. This diagram illustrates the overall characteristics of the solar facility and its integration into the existing Plant X, Unit 3 facility. Subsequent sections describe the overall design concept and present top level descriptions of the individual plant subsystems.

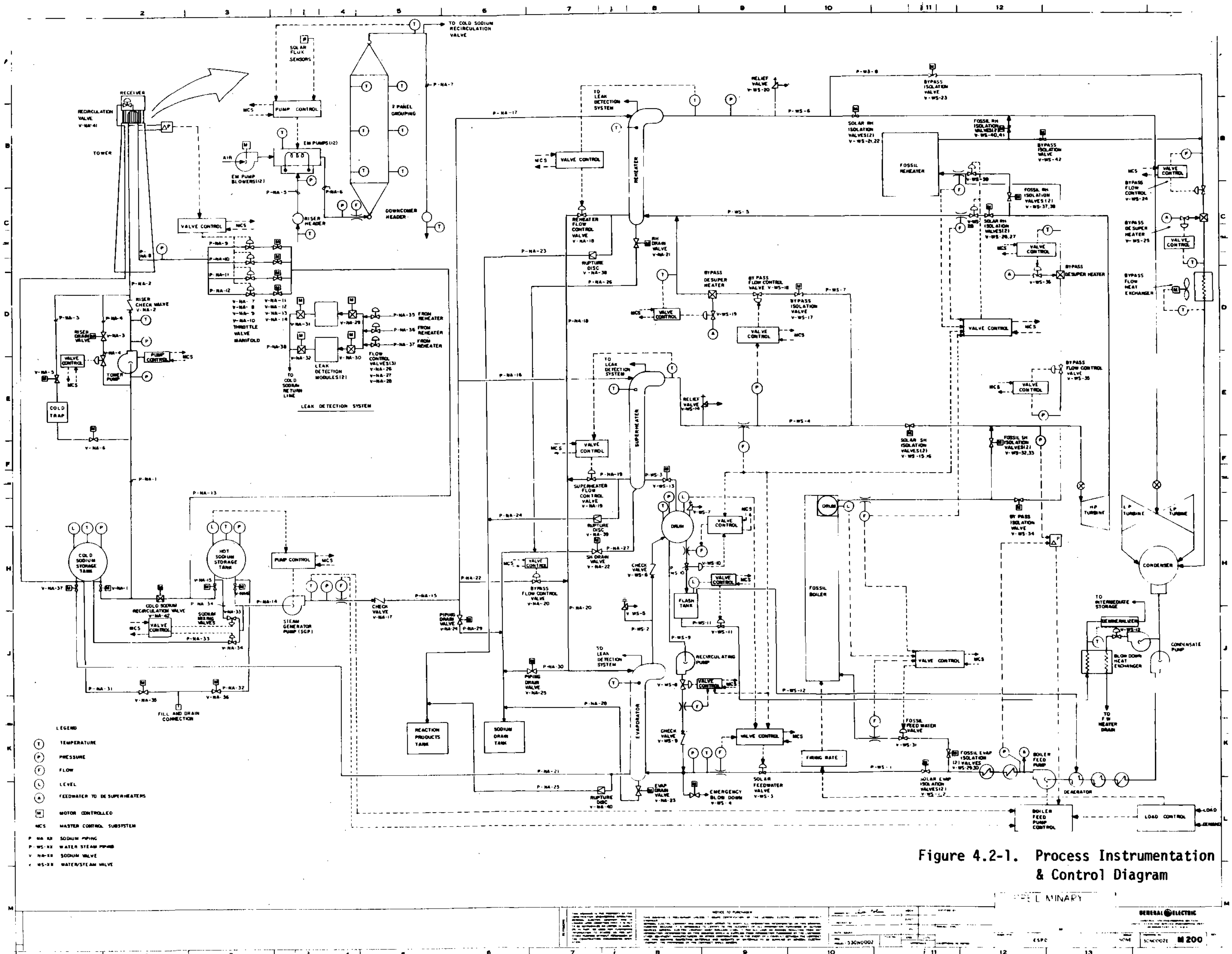


Figure 4.2-1. Process Instrumentation & Control Diagram

4.2.1.1 Overall Design Concept

Figure 4.2-2 presents a simplified schematic diagram of the integrated repowering facility conceptual design for Plant X , Unit 3. The diagram also roughly indicates the solar plant subsystem boundaries. Table 4.2-1 summarizes the baseline plant characteristics.

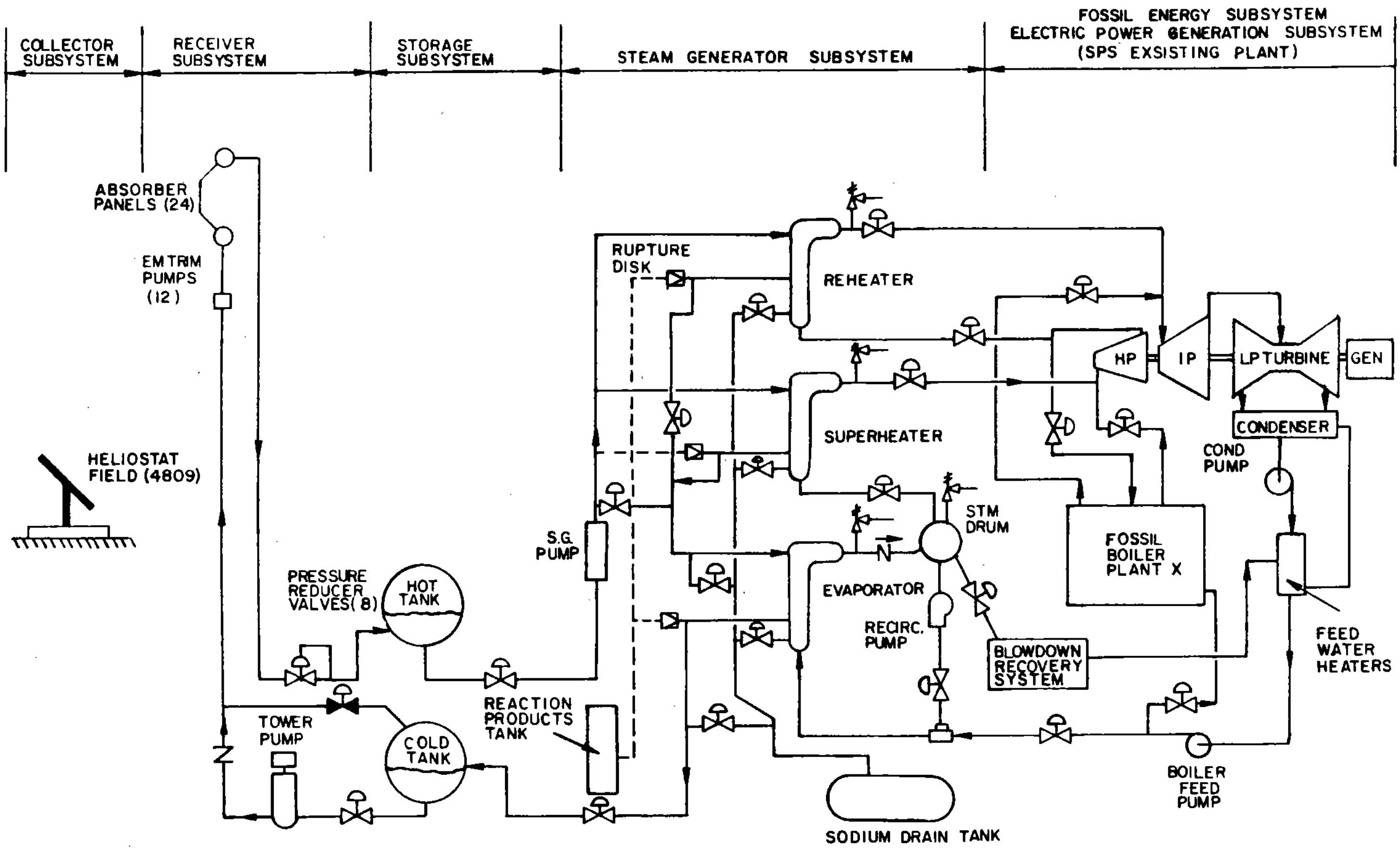


Figure 4.2-2. Plant X Repowering Schematic Diagram

The system summarized in Figure 4.2-2 and Table 4.2-1 will furnish 60 MWe to the 100 MWe reheat turbine and provide the following capabilities consistent with the utility requirements:

- Ability to operate in stand-alone (solar or fossil) or solar/fossil hybrid modes
- Steady plant output when operating in the hybrid mode
- Overnight shutdown capability without use of system trace heating
- Automatic plant operation following operator-assisted plant startup
- Automatic plant response to solar transients.

On the sodium side of the system the working fluid is heated to 593°C (1100°F) in the receiver. The hot sodium, its flow rate controlled by the throttle valves, is piped across the heliostat field to the hot storage tank. The steam generator pump transports hot sodium from the storage tank to the steam generator modules.

Table 4.2-1

BASELINE PLANT CHARACTERISTICS

Site Process	Electrical Power Generation
Cycle Configuration	Parallel, solar/fossil steam supplies to existing reheat turbine
Solar Plant Working Fluid	Liquid sodium
Solar Plant Rating	60 MWe, gross
Collector Field	4809, 49 m^2 - glass heliostats in surround configuration
Receiver	12 m x 12 m cylindrical receiver with 24 two-header, sodium-cooled panels
Tower	140 m slip-formed concrete
Receiver Flow Control	12 EM pumps (2 panels per pump)
Tower Pump	Constant speed centrifugal pump
Receiver Design Flow	1.34 x 10^6 kg/hr (2.95 x 10^6 lbs/hr)
Storage	Hot and cold tank buffer design providing 10 full power minutes (10 MWe-hrs)
Steam Generator Pump	Variable speed centrifugal
Steam Generators	86 MWth Evaporator 40 MWth Superheater 16 MWth Reheater "Hockey Stick" design
Control	Redundant master control CPU's interfacing with distributed control systems. Separate data acquisition computer.

The cold sodium returns to the cold storage tank at 293^{o}C (560^{o}F). The tower pump returns the cold sodium to the receiver for reheating.

On the steam side of the plant, feedwater from the turbine feedwater heating system is split between the fossil and solar steam generators. The ratio of the split is dependent upon the amount of solar insolation and the desired plant output. Both steam generators produce superheated steam at 538^{o}C (1000^{o}F). The flows are combined and routed to the HP turbine inlet. The cold reheat flow is taken from the HP turbine discharge and split in the same ratio as the feedwater between the solar and fossil reheaters. Both reheaters increase the steam temperature to 538^{o}C (1000^{o}F). The flows combine prior to expansion through the LP turbine. Exhaust steam is then condensed and returned to the feedwater heating system.

The solar plant design point (noon, equinox) power output is 60 MWe. This size was based on the utility requirement that the repowered unit be able to operate in a hybrid mode (combined solar and fossil) at times when reliable plant output is required. By operating hybrid, the fossil plant will be able to immediately pick up the load when the solar plant output is lost due to cloud passage.

Since the fossil plant is limited to a minimum turndown of approximately 40 MWe while still operating on automatic control and maintaining steady, satisfactory steam conditions, the maximum solar contribution would be 60 MWe based on the Unit 3 nameplate rating of 100 MWe.

Descriptions of the designs for the following subsystems are presented in subsequent sections:

- Collector Subsystem
- Receiver Subsystem
- Storage Subsystem
- Steam Generator Subsystem
- Electric Power Generating Subsystem
- Fossil Energy Subsystem
- Control Subsystem

4.2.1.2 Collector Subsystem

The collector field configuration has been developed to produce a receiver design point incident energy of 158.2 MWth. The assumed heliostats were unenclosed glass units with 49 m^2 reflective area. The characteristics of the heliostat field are summarized in Table 4.2-2.

Table 4.2-2

HELIOSTAT FIELD DESIGN PARAMETERS

Field Arrangement	Surround
Design Day	Equinox, noon
Design Day Insolation	940 W/m^2
Flux Limit	1.4 MW/m^2
Solar Multiple	1.0
Power to Receiver	158.2 MWth
Land Area	0.86×10^6 m^2 (212 acres)
Number of Heliostats	4809
Receiver Size	12 m x 12 m (cyclindrical, 24 panels)
Tower Height	140 m

Figure 4.2-3 shows how the reference collector field will be located on the Plant X site.

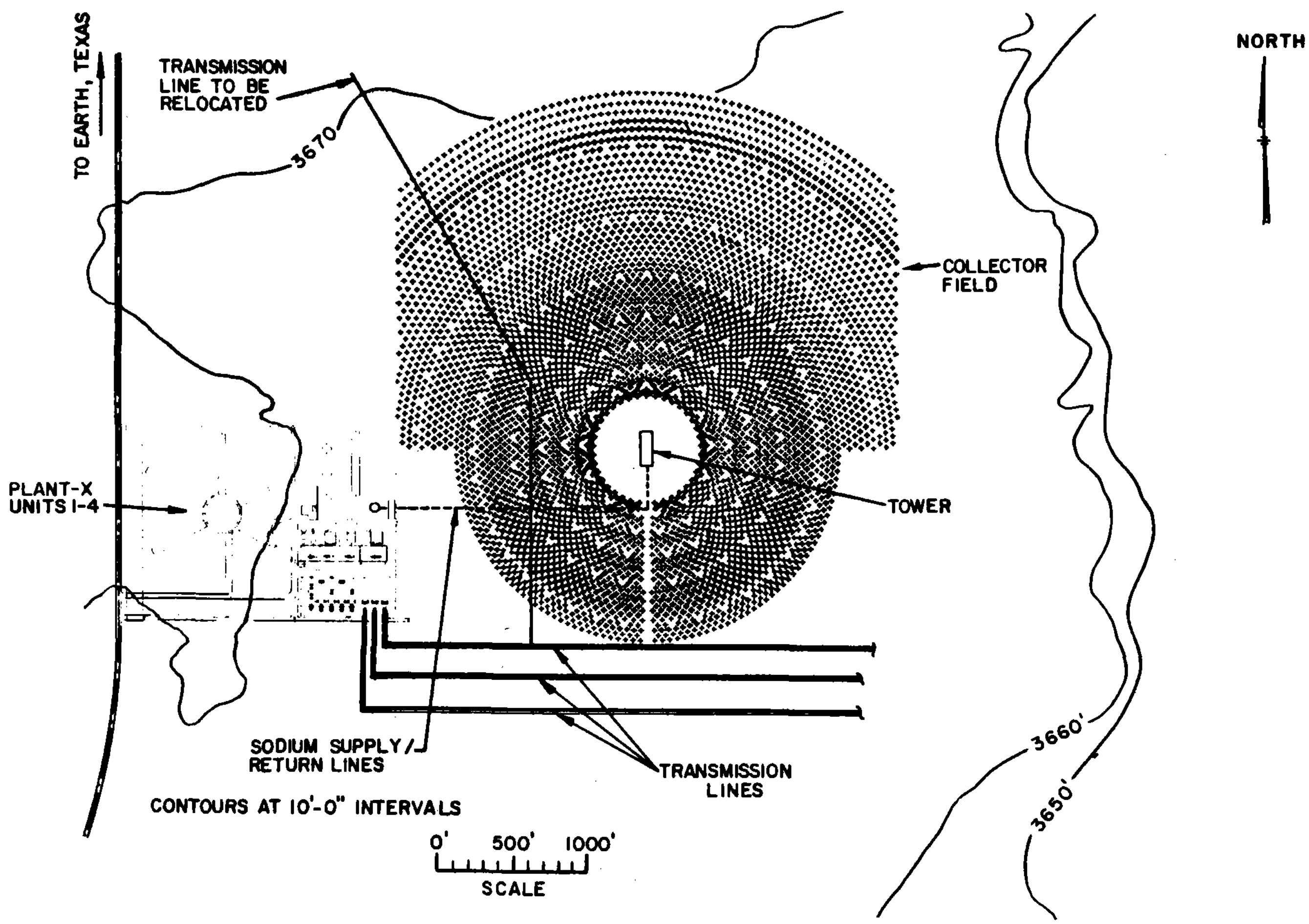


Figure 4.2- 3. Collector Field Layout

The collector field layout at Plant X was reviewed against existing site facilities. This review identified only one major modification to the physical plant, the moving of a transmission line that crosses the heliostat field.

4.2.1.3 Receiver Subsystem

A sodium-cooled, cylindrical, external receiver, has been selected for the repowering application. Table 4.2-3 summarizes the two-header receiver design features.

Table 4.2-3
RECEIVER DESIGN PARAMETERS

Receiver Size	12 m x 12 m
Number of Panels	24
Flow Distribution of Control	EM pumps
Number of EM pumps	12 (one for each pair of panels)
Design Point Incident Energy	158.2 MWth
Sodium Design Flow Rate	1.34×10^6 kg/hr (2.95×10^6 lbs/hr)
Panel Material	Incoloy 800
Sodium Outlet Temp	593°C (1100°F)
Sodium Inlet Temp	293°C (560°F)
Repowering tower	140 m slip-formed concrete

The sodium will be moved to the top of the tower by a constant speed centrifugal pump. A throttle valve in the hot leg piping will control the total system flow rate. The valve will be located near the hot storage tank outside the collector field to allow the head created by the tower to drive the hot sodium across the collector field.

4.2.1.4 Storage Subsystem

The hot and cold sodium storage tanks have been sized to provide adequate volume for 10 full-power minutes of operation, system draining and cover gas. The storage level was selected as the minimum necessary to buffer the plant output from solar transients. The existing boiler and turbine are capable of ramping up or down at a rate of 3 MWe/min. Thus, from the 60 MWe design point, it will require 20 minutes of ramp up for the fossil boiler to replace the solar plant output when insolation is interrupted. In that time, the solar plant will be ramping down, utilizing stored energy and thus requiring 10 full-power minutes or 10 MWe-hr of energy. Both tanks are sized for a volume of 376.6 m^3(13,300 ft^3).

The tanks are a field fabricated double wall design. Tank pressures are controlled with a cover gas system with an interconnect that equalizes the pressure in both tanks. A trace heating system is provided to maintain the sodium temperature at 177°C(350°F), well above the melting point of sodium, 98°C(208°F).

Both tanks are insulated with 35.6 cm (14 in) of Kaowool blanket. This thickness of insulation will permit a system standby period of up to seven days before use of the trace heating is required.

4.2.1.5 Steam Generator Subsystem

The steam generator subsystem consists of the steam generator modules, steam generator pump and equipment to support these elements. On the water/steam side, isolation valves and flow control valves are provided to control the flow split between the fossil and solar steam generators.

A leak detection system will sample the sodium side of all three steam generator modules continuously for evidence of leakage from the water/steam tubes.

The steam generator pump will be a variable speed pump of a centrifugal design. The pump will take suction on the hot storage tank and will be located in a pump building together with the tower pump.

The three steam generator modules will be housed in a building adjacent to the Number 3 Plant X boiler. A drain tank and reaction products tank will be located adjacent to the building to service the steam generator facility. Table 4.2-4 lists the major design characteristics of the three steam generator modules.

Table 4.2-4

STEAM GENERATOR CHARACTERISTICS

Item	Evaporator	Superheater	Reheater
Power Rating (MWth)	86.4	39.8	15.6
Shell Side			
Na Inlet Temp °C (°F)	477(890)	593(1100)	593(1100)
Na Outlet Temp °C (°F)	293(560)	477(890)	477(890)
Sodium Flow Rate kg/hr(lb/hr)	1.34×10^6 (2.95×10^6)	0.96×10^6 (2.11×10^6)	0.38×10^6 (0.84×10^6)
Tube Side			
Steam Inlet Temp °C (°F)	251(484)	318(605)	388(730)
Steam Outlet Temp °C (°F)	318(605)	538(1000)	538(1000)
Steam Flow Rate kg/hr(lb/hr)	215.3×10^3 (474.7×10^3)	187.2×10^3 (412.8×10^3)	165.7×10^3 (365.4×10^3)

4.2.1.6 Fossil Energy Subsystem

The existing fossil energy subsystem consists of a gas-fired Combustion Engineering boiler capable of producing steam under automatic control over a range of power from 36 MWe to 112 MWe. The plant also may be fired using #2 fuel oil if gas is not available. The boiler thermal efficiency is relatively constant over the automatic operation range between 83 and 84%.

With the exception of modifications to the fossil boiler control system, and the addition of isolation and flow control valves, no modifications to the fossil boiler will be required. The controls modifications will allow the two units to operate in parallel with the fossil unit set to pick up or shed load during solar transients. The valves are required to isolate the fossil system for the solar alone operating mode, or to control the water/steam split for the hybrid operating mode. The ability of the unit to function alone at full capacity will not be affected.

The mechanical solar/fossil interfaces will occur at the feedwater header, the steam header to the high pressure turbine throttle, the cold reheat steam header, and the hot reheat steam header. A system of flow and temperature measuring devices, flow control valves, and steam attemperators will enable steam conditions and reheat steam flows to be controlled. This control scheme design is based on control arrangements currently used for existing parallel reheat fossil boilers.

4.2.1.7 Electric Power Generation Subsystem (EPGS)

The existing EPGS is a 10.10 MPa/538°C/538°C (1465 PSIA/1000°F/1000°F) unit of 1955 vintage. The turbine-generator gross cycle efficiency at full load is 42% with load as shown in Figure 4.2-4. When the unit is operated in the hybrid mode, average efficiency will remain in the 40 to 42% range. The only EPGS modifications required are in the areas of turbine controls and the addition of turbine bypasses to allow startups.

The turbine control modifications will facilitate the integration of the turbine control system into the new master control and permit proper startup and shutdown controls required for cyclic operation.

A startup bypass system is added to permit the fossil boiler to be started while the solar steam generators are operating and visa versa. The system allows for the conservation of boiler steam flow until the pressure and temperature match those of the system already operating. At this point the bypass system can be shut down and the solar and fossil steam supplies blended.

4.2.1.8 Control Subsystem

The control subsystem is composed of the master control computers, the distributed subsystem control loops, and the individual instruments that provide an input into the control components or the data acquisition system.

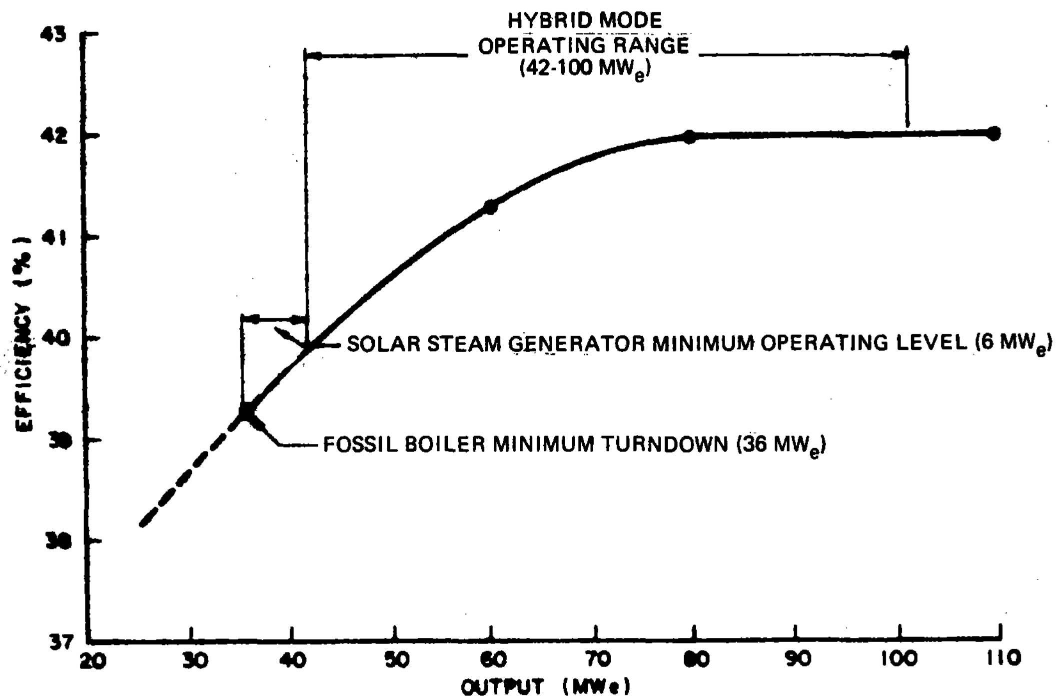


Figure 4.2- 4. Turbine Cycle Efficiency Variation

This subsystem integrates the individual solar and fossil plant control systems to produce the operating capabilities described in Section 4.2.2, System Operating Modes. The master control subsystem (MCS) has the capability of performing all of the operating modes automatically, semi-automatically, or by purely manual control. The MCS is composed of a central computer facility located in the main control room which communicates with and controls the individual distributed local control loops. The solar/fossil controls are separated to permit totally independent operation of each system. This separation is achieved by use of two central processing units (CPU's), one controlling fossil plant operations, the other controlling solar plant operations. The integration of these two CPU's into the overall plant control scheme is illustrated in Figure 4.2-5. Each computer is totally redundant to the other, and either can operate the complete plant alone in the event of a CPU failure. Each CPU communicates with local control loops by way of redundant input/output busses. Data acquisition of all major operating parameters is handled by a third, separate computer with display at the plant operator control panel. All critical/emergency functions and data acquisition parameters are redundantly controlled or measured with hardwire connections to the plant operator control panel.

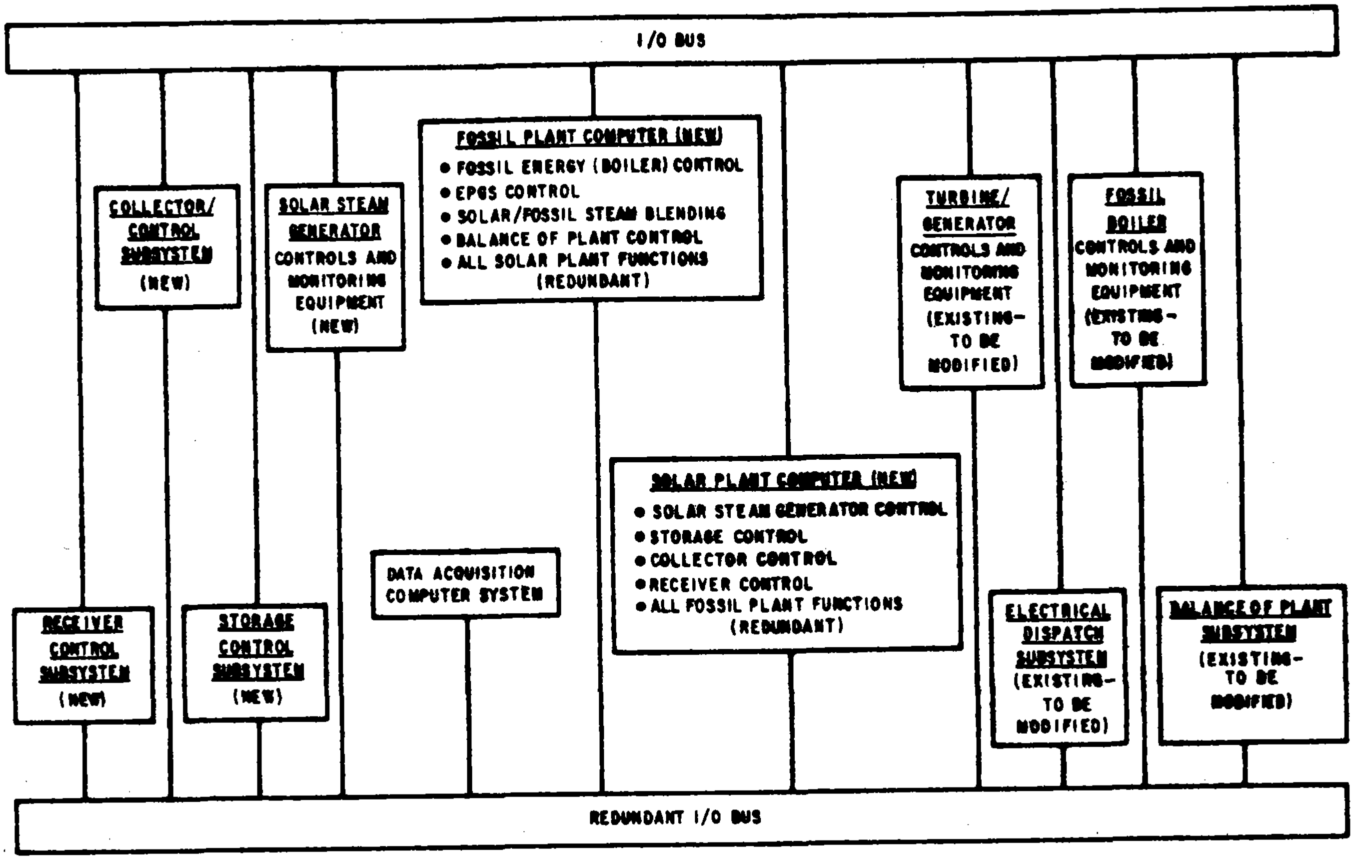


Figure 4.2-5. Computer System Block Diagram

4.2.2 OPERATING MODES

Definition of the method of operating the proposed plant and the associated control and instrumentation requirements is considered a critical element in the conceptual design. The efforts in addressing this aspect of the plant design are described in this section through a general discussion of the operating requirements and a description of the operating logic and controls.

4.2.2.1 Operating Requirements

To provide the degree of operating flexibility desired by the utility, the repowered plant must be capable of operating in a variety of modes. The operating modes identified for the repowered plant can be divided into three groups: steady state, transitional, and miscellaneous. A breakdown of these three groups appears in Table 4.2-5.

Table 4.2-5

REQUIRED REPOWERING OPERATING MODES

Steady State Modes	Transitional Modes	Miscellaneous Modes
• Operating	• Startup	• Initial Fill
Solar alone (turbine follow)	Solar alone	• Drain
Hybrid	Solar with fossil on line	
Constant plant output (boiler follow)	Fossil alone	
Constant fossil output (turbine follow)		
Fossil alone	Fossil with solar on line	
• Standby	• Shutdown	
Cloud cover (<4 hours)	Normal	
Short Term (<24 hours)	Emergency	
Intermediate term (<1 week)		
Long term (>1 week)		

4.2.2.2 Solar Alone Operating Mode

In the solar alone mode the solar portion of the plant and the turbine-generator output "follow" the level of solar insolation. The generator output varies, depending solely on the amount of thermal energy transferred by the heliostat field to the working fluid. Operation in this mode is entirely automatic, with all of the solar subsystem components being controlled by local control loops.

The major local control loops are listed in Table 4.2-6.

Table 4.2-6

LOCAL CONTROL LOOPS

Sodium loops	Water/steam loops
Tower Pump	
EM pumps	Boiler feed pump
Throttle Valves	Feedwater valve
Steam generator pump	
Sodium split valves	

The remaining control functions involve the motor operated valves which isolate the solar/fossil systems from each other and the high and low pressure steam bypass components. The active control of these components is required only during the startup/shutdown sequences. Hence, the description of their control loops will be developed as part of the overall startup/shutdown control scheme.

4.2.2.2.1 Tower Pump Control Loop - The control of the tower pump is illustrated schematically in Figure 4.2-6. The pump is a constant speed centrifugal pump that supplies sodium to the top of the tower at a pressure of approximately 207 kPa (30 psia) at full rated flow. A check valve downstream of the pump prevents reverse flow in the event of a pump failure. The check valve and pump are bypassed by a motorized valve that permits draining of the tower riser. Sodium flow, pressure, temperature and pump operating characteristics are relayed to the master control data acquisition system (MCDAS). Control of the pump (on-off) is either automatic via the master control computer or manual via the plant operator control panel. Control of the bypass drain valve is remote manual only, as it is not normally utilized in any of the previously identified steady state or transitional modes.

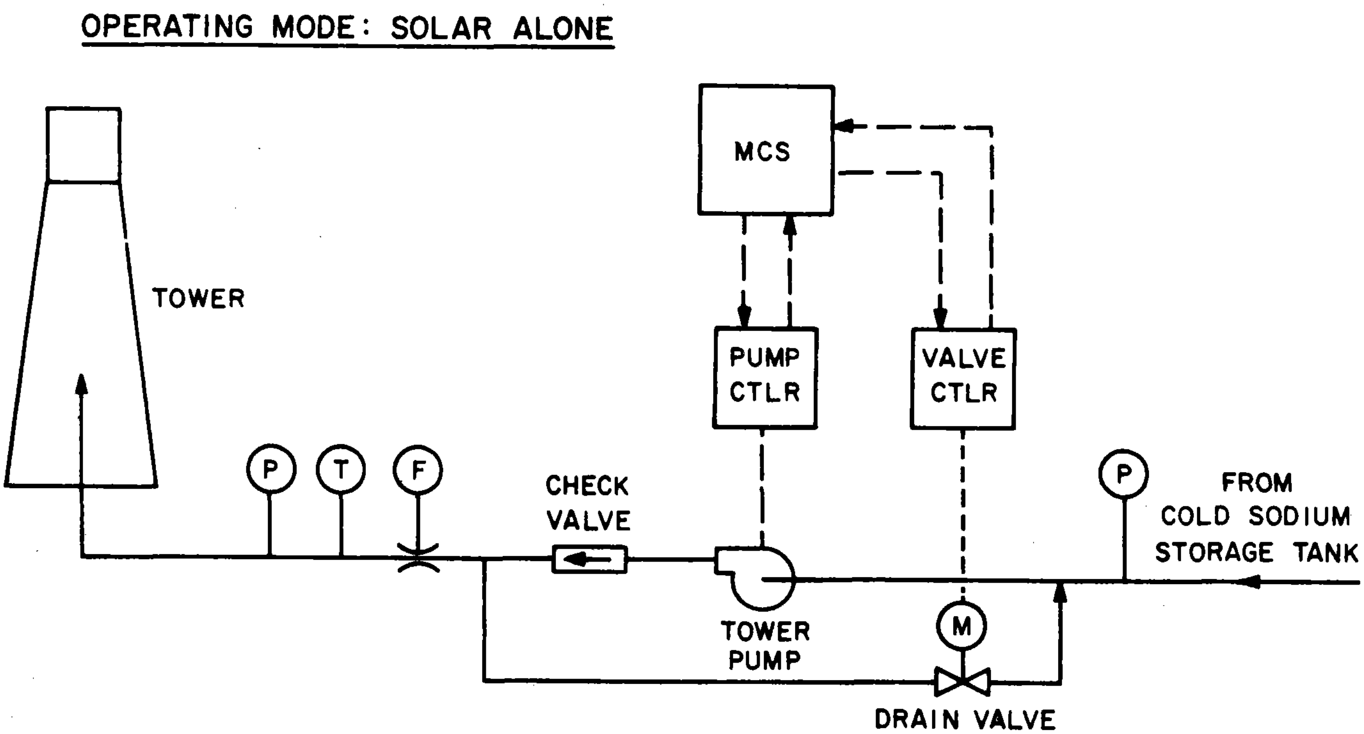


Figure 4.2-6 Tower Pump Control Loop

4.2.2.2.2 EM Pump Control Loop - The control of the receiver EM pumps is illustrated schematically in Figure 4.2-7. In this loop the pump flow rate is controlled to produce a constant sodium temperature of 593°C (1100°F) at the panel outlet header. Since solar radiation may experience large, virtually instantaneous level changes, a solar flux sensor is utilized as a feed forward signal, permitting the pump to anticipate flow changes and to make a timely response. Sodium flow, pressure, temperature and pump operating characteristics are relayed to the MCDAS.

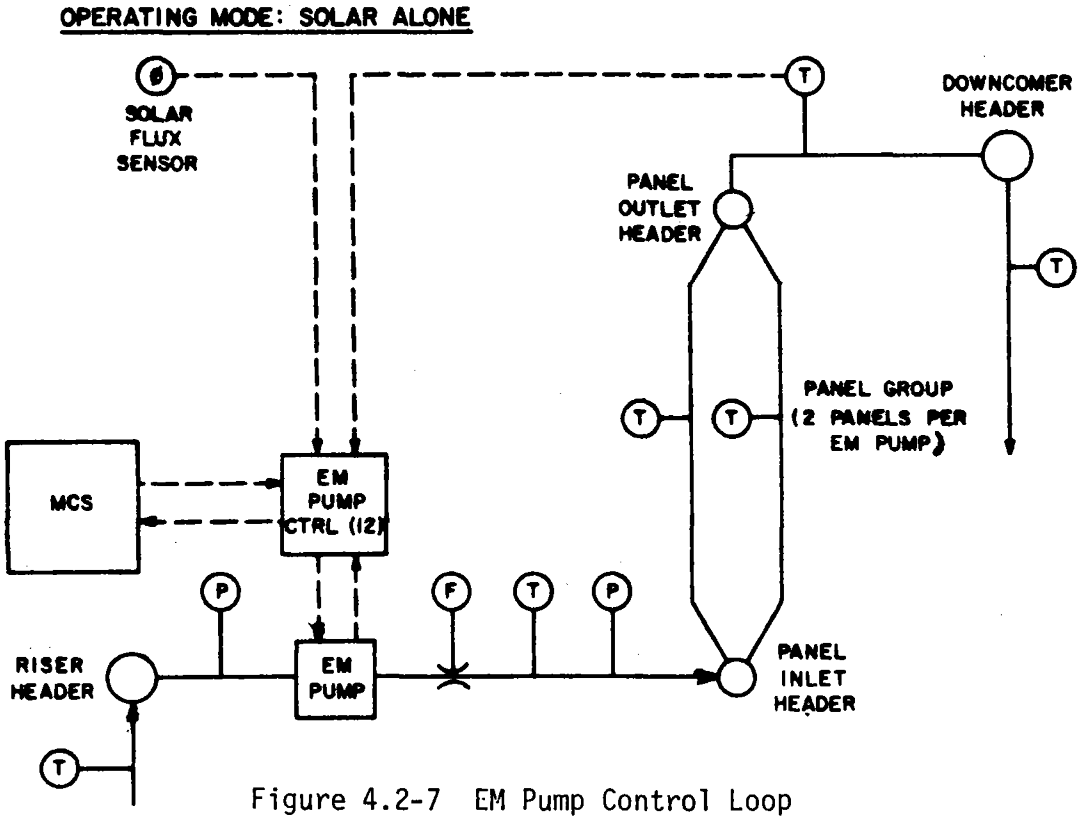


Figure 4.2-7 EM Pump Control Loop

4.2.2.2.3 Throttle Valve Control Loop - The throttle valve control loop is illustrated in Figure 4.2-8. The valve position reacts to the differential pressure signal measured between the riser and downcomer headers at the top of the tower. The valves maintain a ΔP value of zero, so that the flow in the panels is controlled by the EM pumps alone. The header differential pressure, the valve manifold inlet and outlet pressure and the valve positions are relayed to the MCDAS.

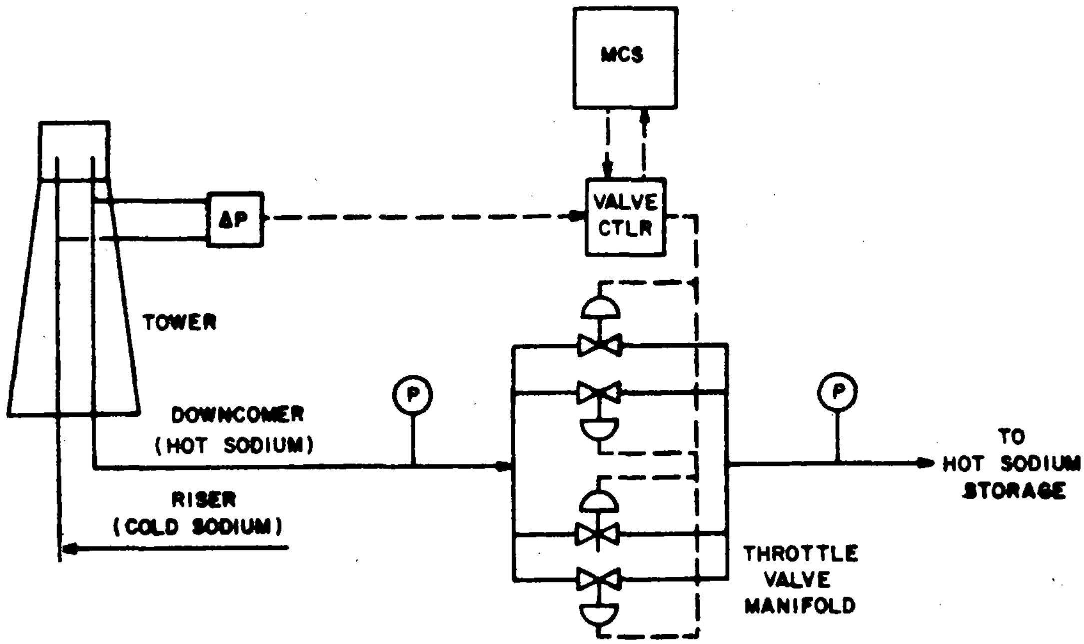


Figure 4.2-8 Throttle Valve Control Loops

4.2.2.2.4 Steam Generator Sodium Pump Control Loop - During the normal operating mode the steam generator pump responds to a signal from the hot storage tank level. This control loop is illustrated in Figure 4.2-9. When the tank is full, the pump speed is set for full rated flow. As changes in solar insolation vary the amount of sodium flow into the hot tank, the level will vary and the pump will respond to the level signal. If flow to the hot tank ceases altogether (e.g., end of day), the pump will "follow" the declining tank level until some minimum level (5% of tank volume) is arrived at, then shut down. The pump ramp rate is controlled so as not to exceed 3 MWe/minute.

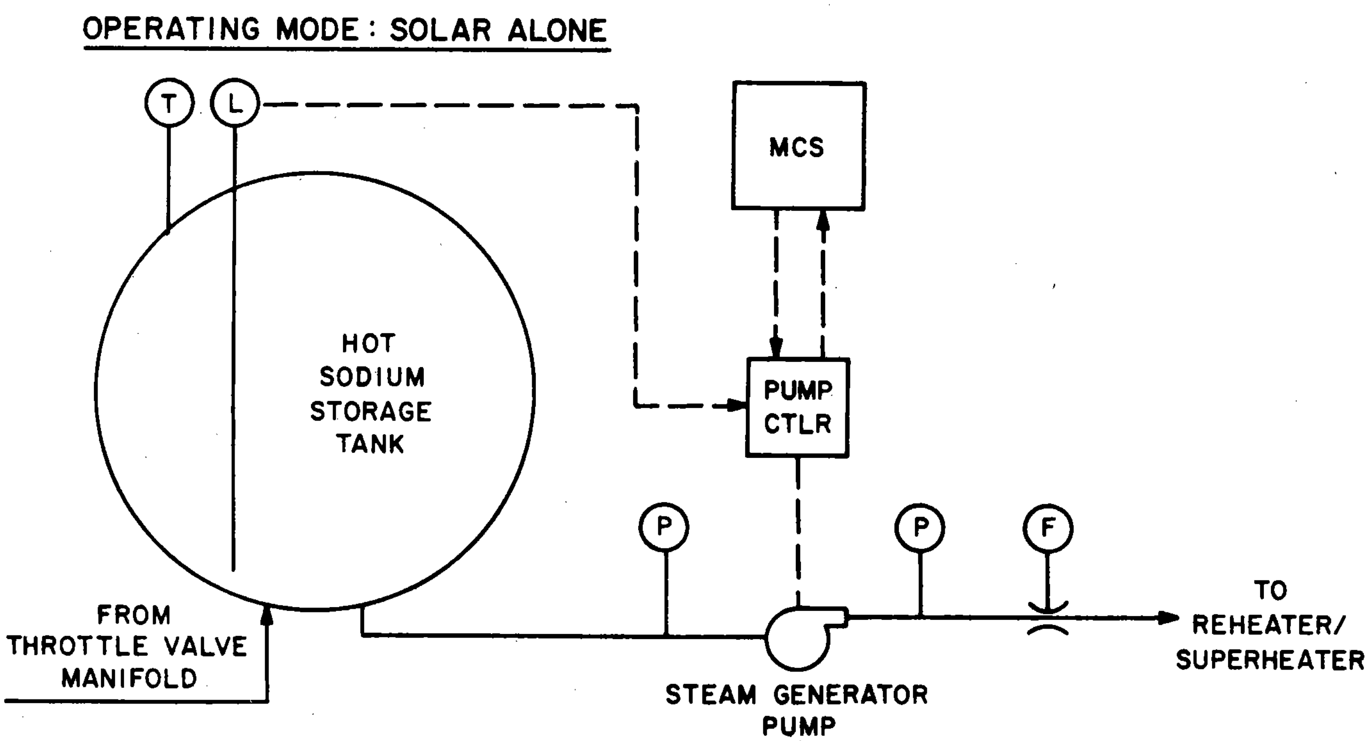


Figure 4.2-9 Steam Generator Pump Control Loop

4.2.2.2.5 Sodium Flow Split Control Loop - The steam generator pump supplies hot sodium to both the reheater and superheater. The flow split between these two components is controlled by valves at the reheater and superheater outlets. The valves respond to signals from the reheater and superheater outlet steam temperature sensors. The control loop is shown schematically in Figure 4.2-10. The reheater outlet steam temperature during normal operation should be 538^{0}C (1000^{0}) A higher temperature indicates that the reheater is receiving too much hot sodium and the valve responds to decrease the flow. Conversely, a temperature lower than 538^{0}C (1000^{0}F) causes the valve to increase the flow.

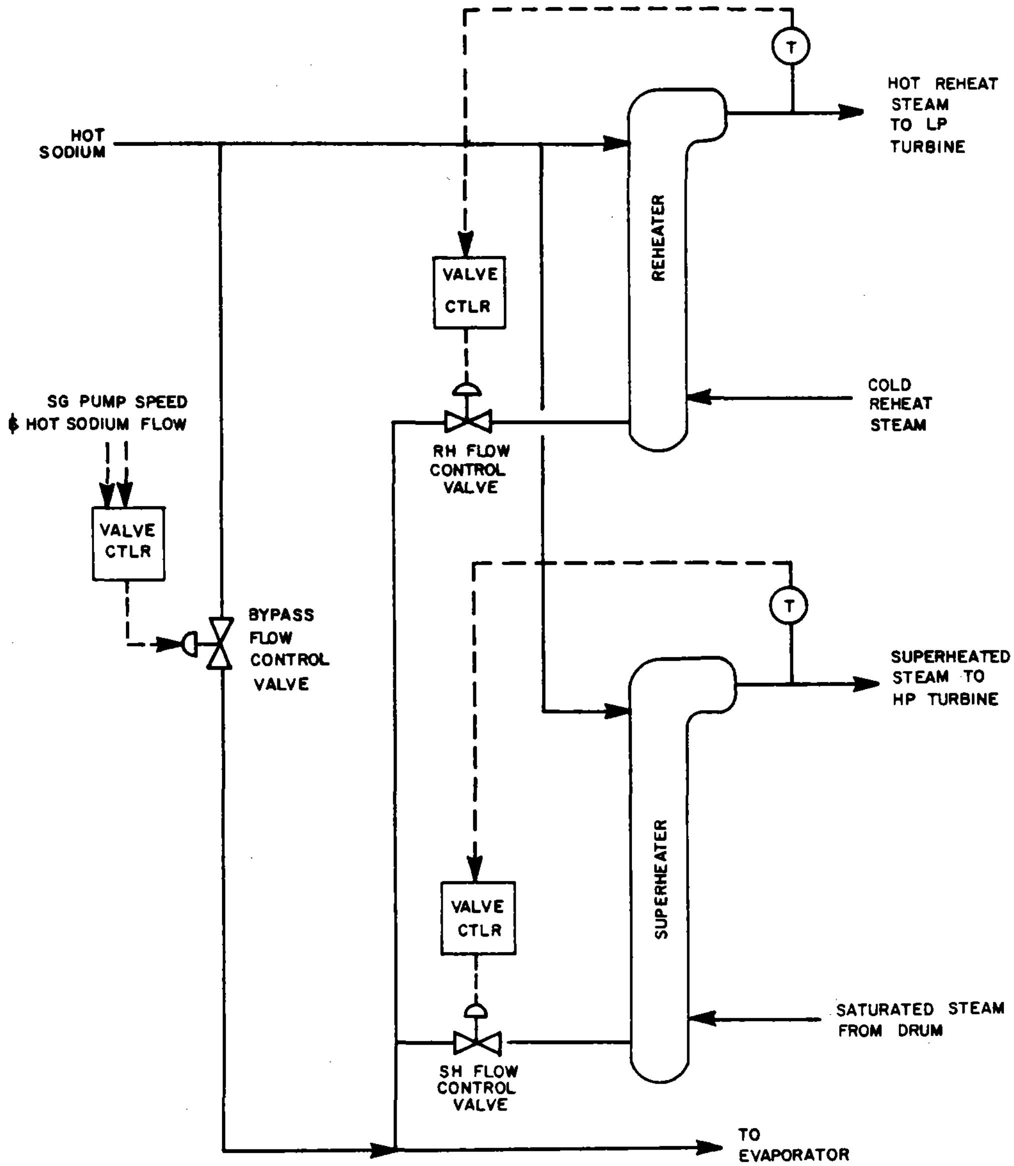


Figure 4.2-10 Sodium Flow Split Control Loop

The sodium bypass valve senses changes in the reheater/superheater flow by monitoring steam generator pump speed and flowrate. A reduction in flow to either module is compensated for by bypassing that flow to the evaporator module. Thus, a steam overtemperature condition is reacted to in two ways: a reduction in sodium flow to that module, and an increase in saturated steam flow caused by the sodium bypass to the evaporator.

4.2.2.2.6 Feedwater Flow Control Loop - The system responds to changes in the steam generator pump flow by adjusting the flow of feedwater through the evaporator/ superheater components. A sodium flow measurement taken downstream of the steam generator pump sends a feed forward signal to the variable speed boiler feed pumps. The flow is trimmed by the feedwater flow control valve which responds to signals from a three-element drum level controller. This approach is illustrated in Figure 4.2-11.

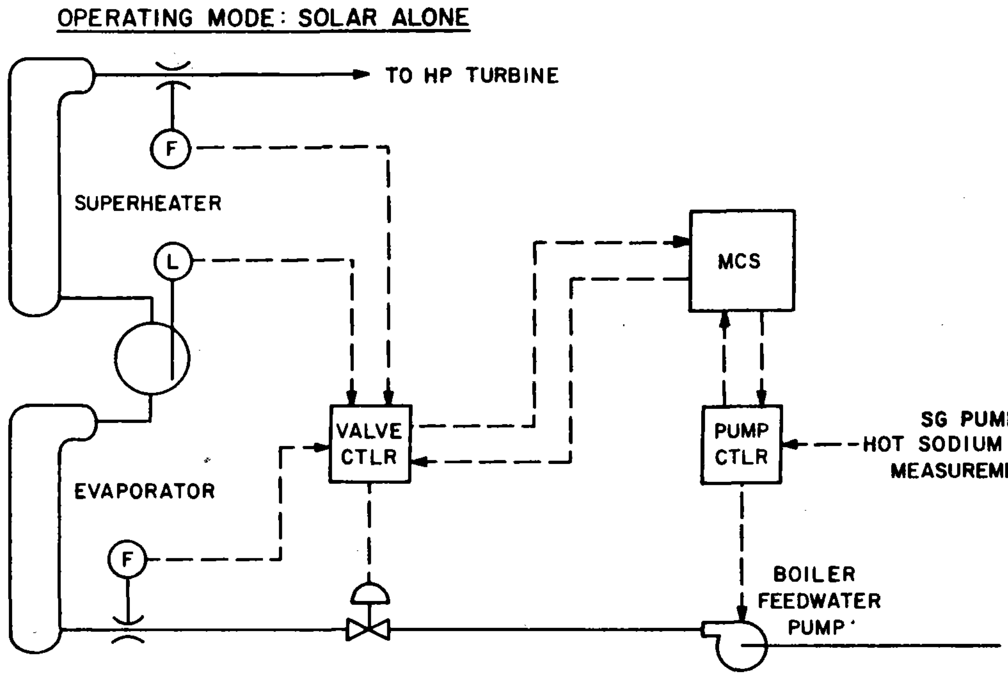


Figure 4.2-11 Feedwater Flow Control Loops

A 10% blowdown of the solar steam drum is required to maintain the desired water quality levels. The substantial flow and energy of this blowdown must be recovered if a large water consumption/performance penalty is to be avoided. A major portion of the energy is recoveredy by flashing the saturated water in a flash tank at~100 psia and routing the steam to the deaerator. Since it is desirable to maintain the deaerator at the present operating pressure and temperature levels, the addition of the flash tank steam requires the turbine extraction flow to be decreased.

The blowdown flowrate is controlled by a valve which monitors both the blowdown flow and saturated steam flow to the superheater and regulates the blowdown flow at 10% of the steam flow. Flash tank liquid level is maintained by a level sensor which controls the tank drain valve. The flow of liquid from the flash tank (saturated water at 100 psia) is cooled to the condenser operating temperature by condensate then cleaned by a demineralizer before returning to the main feedwater flow. The energy pickup by the condensate is recovered by mixing the condensate flow into the feedwater heater drain system. Flash tank pressure is controlled by the deaerator. The blowdown system is illustrated in Figure 4.2-12.

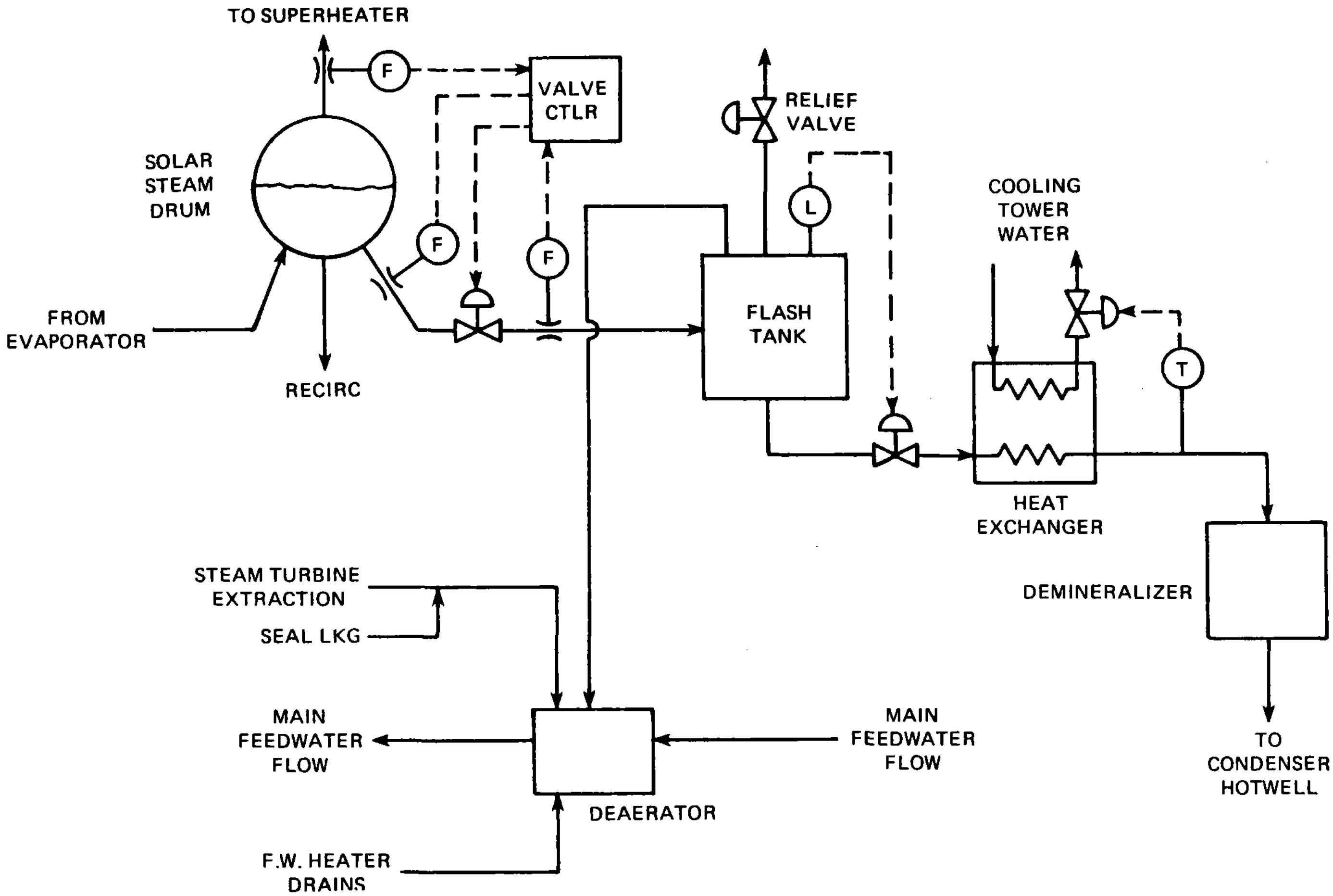


Figure 4.2-12 Solar Steam Drum Blowdown System

The evaporator module is equipped with an external water recirculation loop. The water is circulated from the drum to the evaporator inlet by the recirculation pump which operates at constant speed. The flowrate varies with power level by use of a flow control valve which maintains a constant water to steam recirculation flow ratio of 1.05. Thus, the total recirculation plus blowdown flow is 15% of the steam flow to the superheater.

4.2.2.3 Hybrid Operating Mode

Control of the sodium and feedwater components in the hybrid operating mode is identical to the solar alone mode with two major exceptions: the control of the boiler feed pump and the splitting of the cold reheat steam.

In the hybrid mode the pump supplies feedwater to both the solar and fossil boilers with the flowrate controlled by the load controller and not the SG pump flow. The flowrate is apportioned between the two systems by the individual feedwater flow control valves which respond to their separate three-element (feedwater flow, steam flow, drum level) control systems. Hence, a change in solar output, either up or down, is compensated for by the opposite change by the fossil boiler, thereby maintaining feedwater flowrate and turbine output constant. Changes in load demand are accomodated by the load controller which adjusts the fossil boiler output to the desired level.

Cold reheat steam must be split between the solar and fossil reheaters in the same ratio as the split between the solar and fossil boilers. To achieve this, a valve controller monitors four flows (solar SH, fossil SH, solar RH, fossil RH), calculates the split ratios and adjusts the flow control valves accordingly. Initially, the fossil reheater valve is full open and the split is adjusted by opening the solar CRH valve. If the solar CRH valve reaches the full open position, and the solar reheater needs more flow, then the fossil CRH valve is adjusted toward the closed position. This arrangement minimizes reheater pressure drops. The cold reheat flow control system is illustrated in Figure 4.2-13.

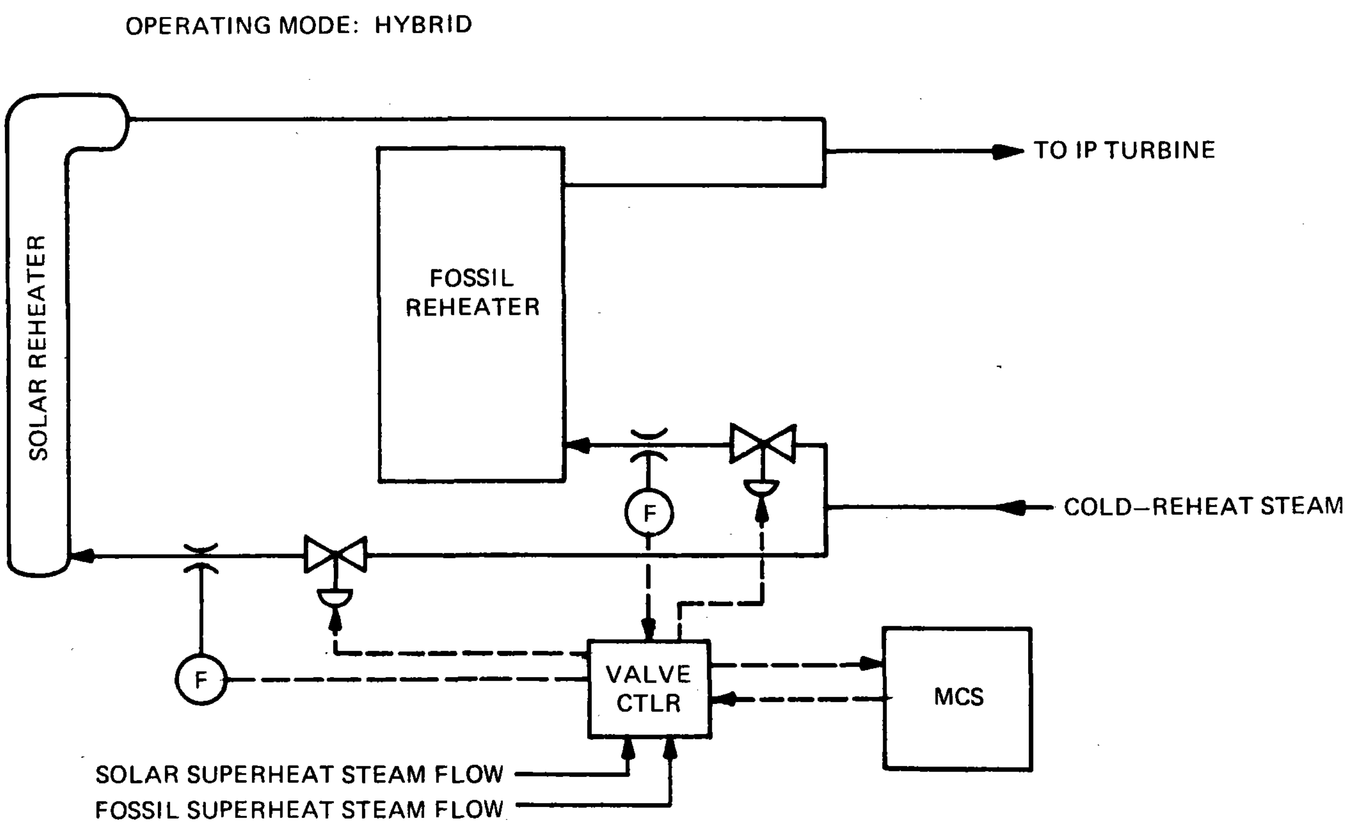


Figure 4.2-13 Cold Reheat Steam Flow Control Loops

4.2.2.4 Fossil Alone Operating Mode

One of the major design requirements of the repowered plant is that the operation of the solar and fossil system be entirely independent. Thus, the operation of the fossil plant alone is in no way different from the operation of the present Unit 3 at Plant X, other than to insure that the solar plant isolation valves are closed. Since the existing operation is standard for fossil fired steam generators, the details are not discussed in this report.

4.2.2.5 Standby Modes

The operation of the solar plant during a standby period is dependent upon the duration of the period.

During standby, the piping and storage tanks cool down as illustrated in Figure 4.2-14. Components with a nonuniform temperature, such as the receiver, superheater, and reheater cool down as shown in Figures 4.2-15 and 4.2-16.

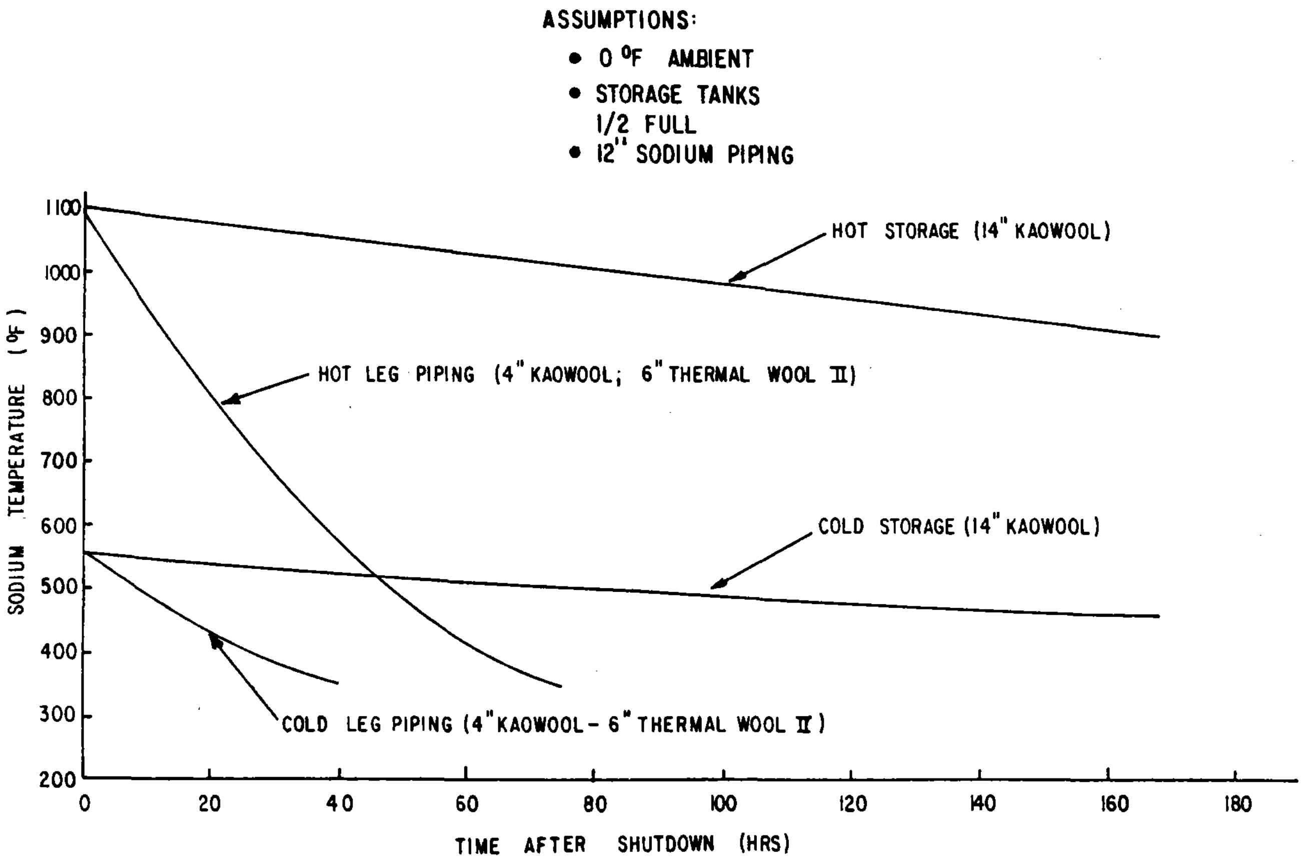


Figure 4.2-14 Sodium System Cooldown Curves

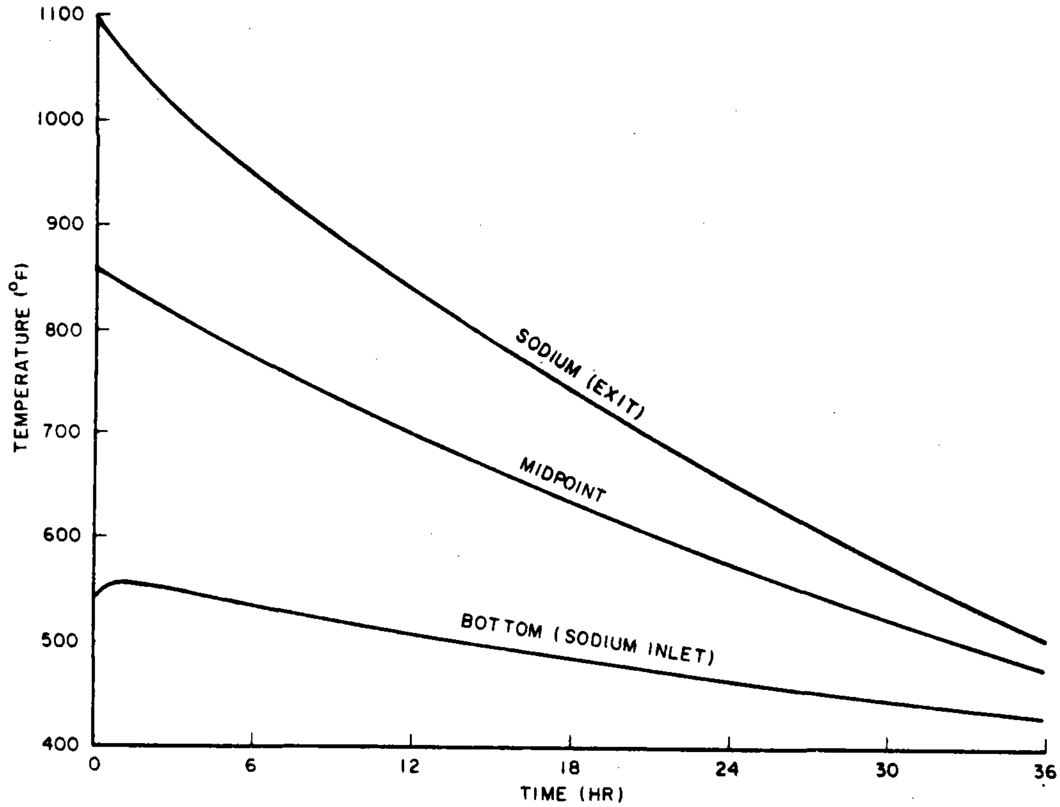


Figure 4.2-15 Cooldown of Receiver Panels

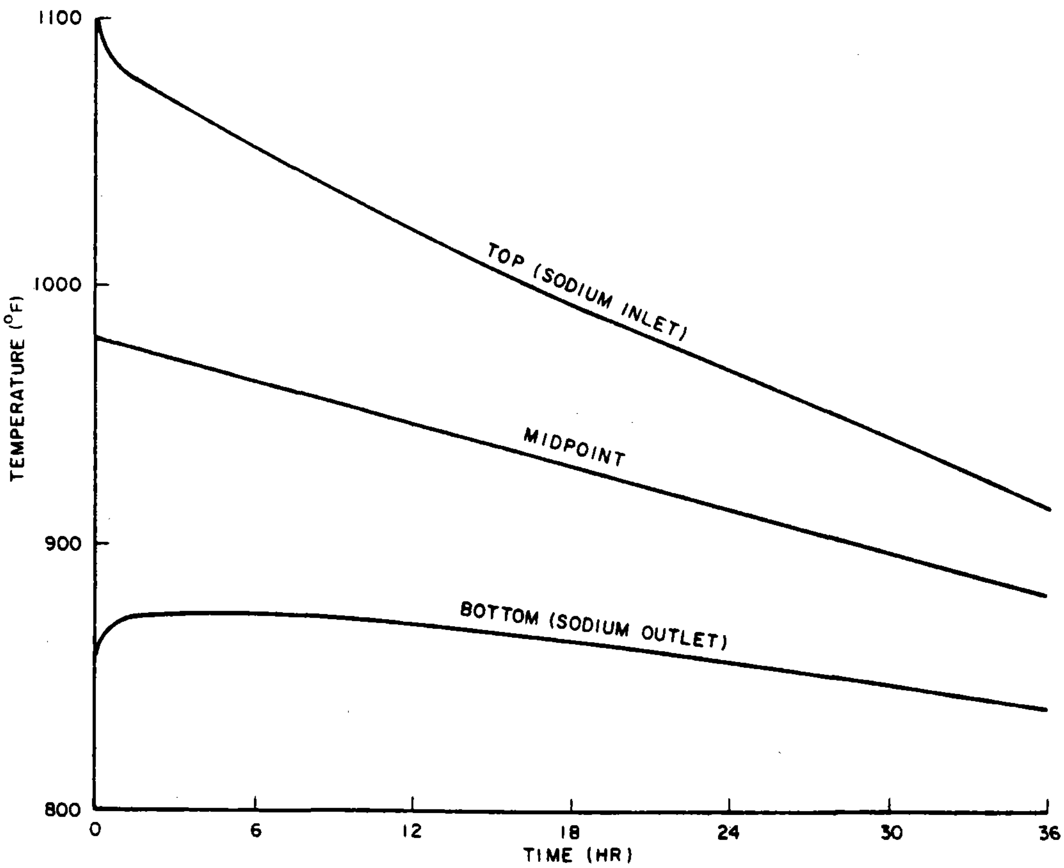


Figure 4.2-16 Cooldown of Superheater (Reheater)

4.2.2.5.1 - Cloud Cover Standby - The shortest duration standby period would be that caused by intermittent cloud cover. If it is expected that the cloud cover will pass, thereby permitting operation later in the day, the plant is configured as follows:

- Heliostats to standby position
- Receiver insulation curtain in place
- SG pumps, EM pumps, and tower pump off
- Throttle valves closed
- Feedwater and steam isolation valves closed

During the standby period the pipes and tanks cool at different rates, but the temperature differences after a few hours are small and the plant can be restarted without any warmup.

4.2.2.5.2 Short Term Standby - An overnight standby is similar to the cloud cover configuration, with the exception of the heliostats which are commanded in the stow position. Use of the Trace Heating System would not be required for either the short term or overnight standby.

4.2.2.5.3 Intermediate Term Standby - For an intermediate standby (between one and seven days) the "bottled-up" approach described for the short term standby mode will also be used. However, as shown in Figure 4.2-14 the temperature of sodium in the cold piping would approach the trace heat set point of 177^{O}C (350^{O}F) after about 24 hours. In order to avoid unnecessary use of the trace heating system, it becomes necessary to provide a way of keeping the tower loop warm for standby periods longer than 24 hours.

The selected approach is to use sodium from the cold storage tanks to replenish the sodium in the tower loop and keep the loop near 293^{O}C (560^{O}F). This operation would be repeated periodically to maintain the loop temperature. Temperature monitoring would determine when recirculation of storage sodium is required. The frequency has been estimated to be once every 12 hours. The consideration is that the sodium temperature in the cold piping would drop by about 42^{O}C (75^{O}F) in 12 hours. Larger temperature drops may create unacceptable thermal shocks in the loop piping.

The different rates of cooldown of the various parts in the tower loop require consideration. At the end of a 12-hour standby period the sodium temperature in the riser, receiver panel, and downcomer would be about 252^{O}C (485^{O}F), 260^{O}C (500^{O}F), and 482^{O}C (900^{O}F), respectively. If full system recirculation begins at this time, the downcomer would experience a temperature transient of approximately 222°C (400°F).

In order to avoid thermal shock to the downcomer, the overflow line valve would be opened and the circulating sodium would go from the receiver panel outlet header through the overflow line and back to the cold tanks. The circulation would be terminated once the sensors indicated that the temperature of the loop is near the cold storage tank temperature and the tower loop would be left idle again.

The downcomer line will continue to cool if the standby period continues and the downcomer will eventually become suitable for accepting the circulating cold sodium. At this point, approximately 48 hours into the standby mode, the overflow line would be closed and the throttle valves opened, and sodium would return to the cold tank by way of the downcomer. The periodic recirculating operation would be repeated as necessary. The dual tower recirculation loop is illustrated in Figure 4.2-17.

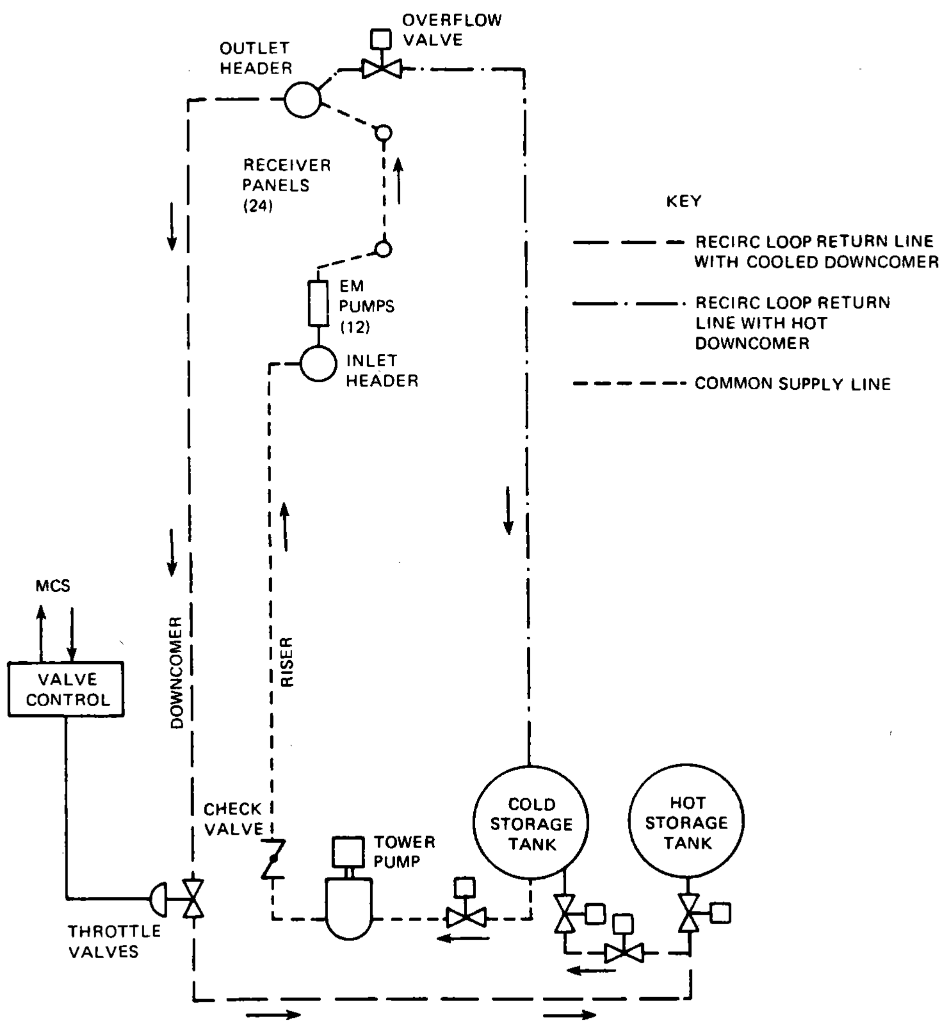


Figure 4.2-17 Tower Recirculation Loop for Intermediate Standby Mode

For the steam generator modules, the "bottled up" mode of operation with cold sodium recirculation is continued for the intermediate standby period. In this case, the cold sodium is circulated through the evaporator module as illustrated in Figure 4.2-18. The sodium in the evaporator loses its temperature faster than that in the superheater or reheater due to the presence of water in this component. Through evaporation, the water absorbs large amounts of heat from the sodium. The resulting increase in steam pressure is controlled by the drum which vents off the generated steam. This causes a flow of steam through the upper half of the evaporator, carrying away even more heat. If this cooldown is permitted to continue, the evaporator sodium cannot be introduced into the return piping or storage system without some thermal shock and its associated stress. For this reason, when the evaporator sodium bulk temperature approaches 260^{0}C (500^{0}F) a circulating flow is set up which replaces the existing evaporator sodium with an amount from the cold storage tank at 293^{0}C (560^{0}F). This circulation is repeated each time the temperature decreases approximately 33-42^{0}C (60-75^{0}) below the cold storage tank temperature. This system utilizes the same components (SG pump, bypass valve, etc.) as are required for the superheater / reheater bypass system. Calculations show that circulation through these components will not be required for intermediate hold periods.

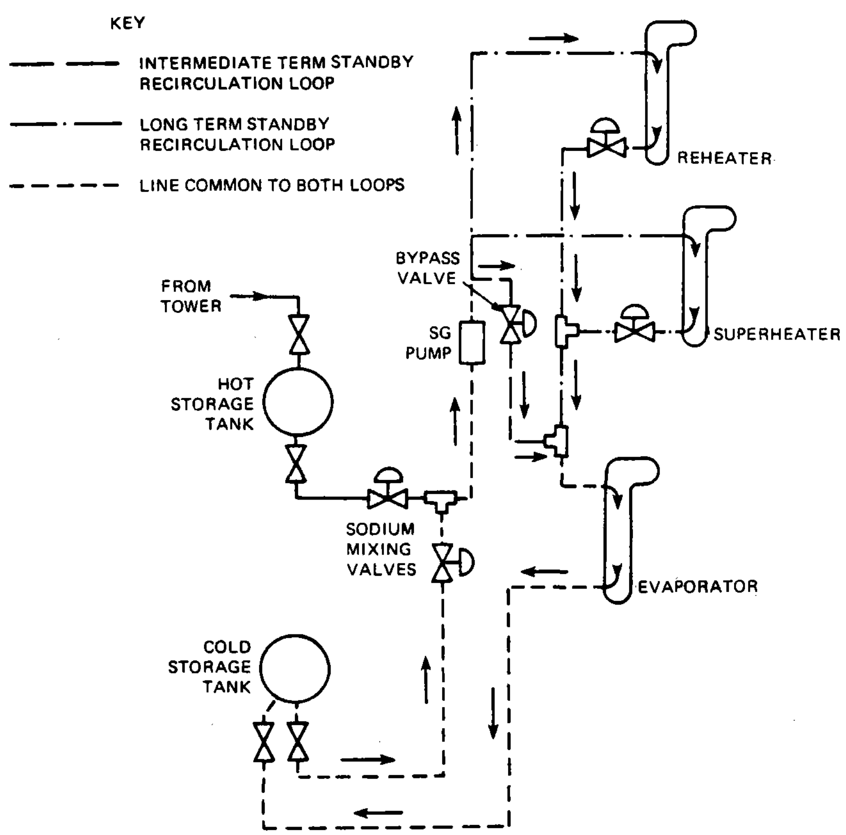


Figure 4.2-18 Steam Generator Recirculation Loop for Intermediate and Long Term Standby Modes

4.2.2.5.4 Long Term Standby - For a long term hold (>7 days) the "bottling-up with periodic recirculation" approach would continue to be used in the receiver/tower side. This mode of operation would continue until the sodium temperature in both the storage tanks reaches 177°C (350°F). Beyond this point the system temperature will be maintained by electric trace heating. It should be pointed out that during a long term standby, if the cause of the standby does not occur on the receiver/tower side of the plant, sodium in the system can be kept warm using solar energy and use of the trace heating system would not be required.

Standby periods of this duration will see the superheater and reheater temperatures approach the cold sodium storage temperature. When this happens, these components can be included in the evaporator sodium circulation loop as shown in Figure 4.2-18. The system is then maintained in this mode, recirculating as required, until the cold sodium temperature in the storage tank reaches 177°C (350°F). At this point the temperature is maintained by trace heating and no further recirculation is required.

An alternative to the above scheme is to drain the sodium in the tower and steam generator loops and fill the loops with argon cover gas. The sodium in the loops would be drained into the storage tanks which are the best insulated components in the plant and will minimize heat losses. Due to the long warmup period required after a system drain, this approach would only be appropriate for extremely long standby periods or when necessitated by maintenance or repair.

4.2.2.6 <u>Startup Sequence</u>

These modes cover the transition between the various standby modes and normal operation. The plant will be in either the hot, warm, or cold start mode depending on the duration of the standby period prior to a start. Startup procedures for these modes are described in this section.

4.2.2.6.1 Cold Start - A cold start condition exists when the plant has been shut down for more than a week. The temperature conditions of the plant prior to a cold start are:

- All sodium-containing piping and components are at temperatures near the cold storage tank temperature as a result of the recirculation scheme using cold tank sodium. The extent of temperature drop from the 293°C (560°F) normal cold tank temperature depends on the length of the shutdown period. All are kept above 177°C (350°F) by trace heaters.

- The steam turbine first stage inner metal temperature is below 149°C (300°F).

The insulation curtain covering the receiver is dropped to expose the receiver panels. The tower pump is started to establish a flow through the receiver. Selected heliostats are focused on the receiver. The temperature set point for the EM pump control is gradually ramped from the initial value to the rated temperature as the receiver sodium flow rate is slowly increased. The sodium flow rate would be ramped as necessary to accomplish an acceptable rate of change of temperature of the various system components. As the warmup progressed, more heliostats would be focused on the receiver to increase the heat input. When the rated outlet temperature of 593°C (1100°F) is achieved, the receiver is then operating under automatic control.

The return flow from the receiver can be valved to either the cold or the hot tanks, as shown in Figure 4.2-17, depending on the sodium temperature in the downcomer. As the temperature increases, the return flow would be only to the hot tank. The warmup of the cold and hot tanks to their respective normal operating temperatures must be maintained and controlled in such a way that the limits of the following parameters would not be exceeded:

- the rate of change of tank wall temperature
- the temperature differential between the inner and outer walls of the tank
- the temperature differential from the top to the bottom of the tank

The steam generator sodium pump would be started and controlled to supply sodium to the steam generation sections. The sodium to the superheater and reheater would be a mixture of the hot and cold tanks' supply to obtain the proper heating rate of 83°C/hr (150°F/hr). The sodium flow will be maintained at 10% of full flow until the steam turbine is ready for loading. The boiler feed pump is activated, establishing a flow of water through the evaporator. In this way the water in the evaporator and steam drum is heated along with the sodium. When the evaporator outlet sodium temperature reaches 293°C(560°F), it will be maintained at this level while the superheater/reheater inlet sodium temperature continues to rise at the 83°C (150°F/hr) rate. The sodium temperature at the evaporator outlet is maintained by controlling the amount of feedwater flow to the evaporator. A typical flow and temperature history for the water and sodium is illustrated in Figure 4.2-19.

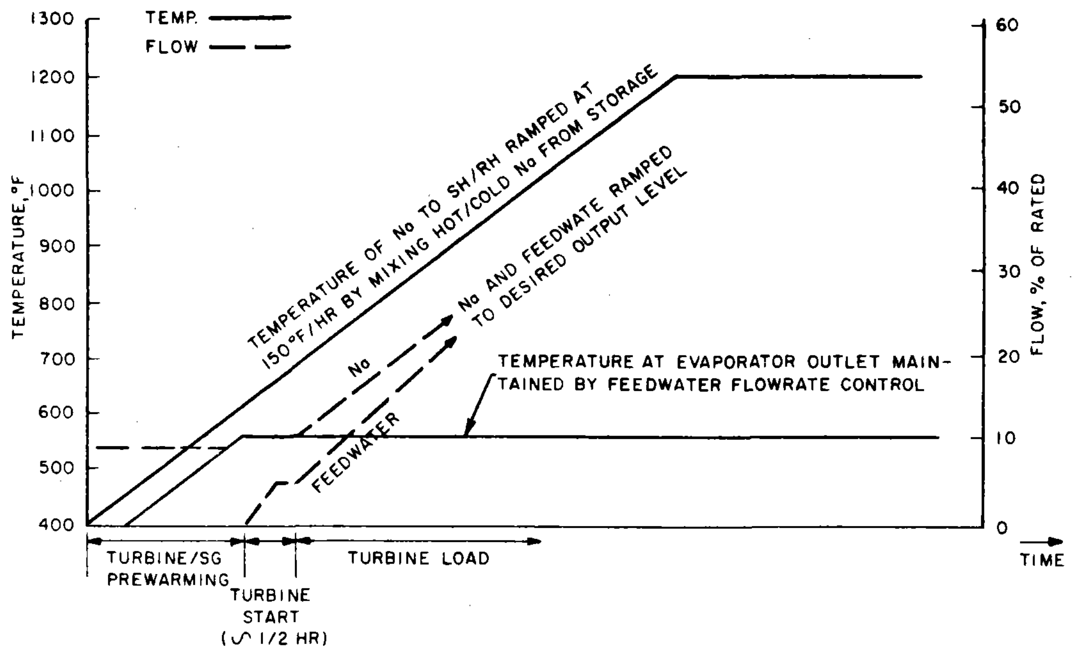


Figure 4.2-19 Flow and Temperature History of Steam Generator During Cold Start

A cold start condition for the EPGS exists when the steam turbine first stage inner metal temperature is below 149°C (300°F) and the turbine rotor must be preheated. It is assumed that the turbine lube oil system is fully operational and that the turbine generator unit has been on turning gear for a sufficient period of time to have the shaft eccentricity near a value that will be acceptable for turbine roll.

Shortly after the warmup of the steam generators is started, the warmup of the EPGS can begin. Steam for this operation is obtained from the steam drum, with the pressure being reduced to 379-483 kPa (55-70 psia) prior to admission to the turbine. The main steam line drains would be open and the turbine bypass system would be placed in the startup control mode for the warmup period. Condensate pumps, boiler feed pumps and other necessary pumps would be started. The coordinated warmup of the entire sodium and steam systems would continue until the main steam pressure has reached approximately 25% of rated. At this point the turbine steam seals would be applied and condenser vacuum established so that the turbine prewarming can be started.

After turbine rotor prewarming is completed, the warmup of the sodium and steam system would continue until steam pressure and temperature conditions are established for turbine roll. This may involve adjustment of the turbine bypass system and steam temperature controls to establish a satisfactory steam-metal mismatch for the turbine cold start requirements.

When the proper conditions for turbine roll have been established, the turbine would be accelerated and loaded based on turbine rotor stress requirements and the heating limitations for the steam generators.

If the turbine is operating on steam from the fossil boiler when the solar plant is started, then steam from the solar steam generators flows through the by-pass system until steam conditions are proper for blending. The by-pass system is illustrated in Figure 4.2-20. The fossil boiler is equipped with a similar bypass system for fossil startup when the solar plant is operating.

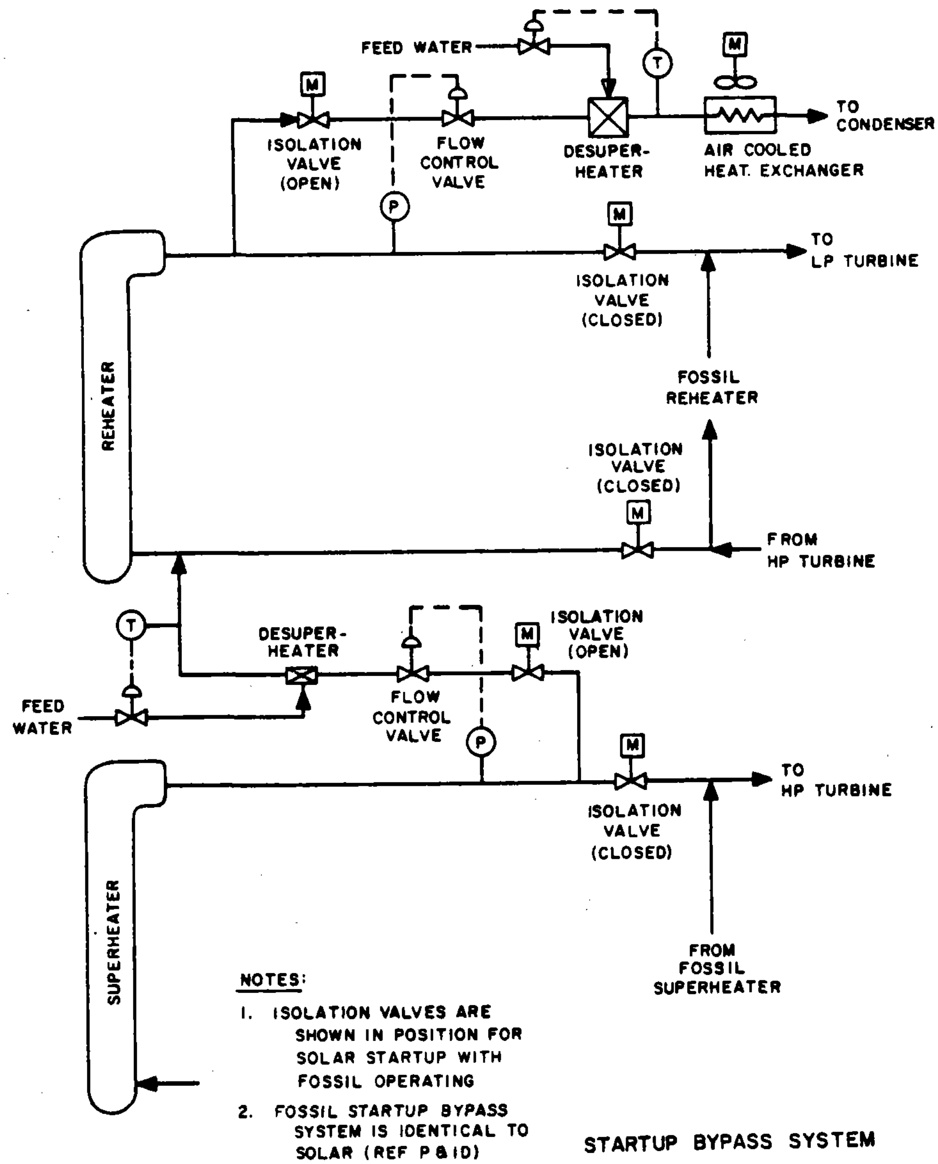


Figure 4.2-20. Startup Bypass System

4.2.2.6.2 Warm Start - A warm start condition exists when the plant has been shutdown for a period of between two and six days. The conditions of the plant before a warm start are:

- The piping and components in the sodium loops (tower side and SG side) are near the cold storage tank temperature
- The hot storage tank temperature is not much lower than 593°C (1100°F)
- The steam turbine first stage inner metal temperature is greater than 149°C (300°F)

Procedures for a warm start would be similar for a cold start with one major exception. A unique situation exists between the superheater/reheater outlets and the evaporator inlet which requires special attention. As shown in Figure 4.2-16, the sodium temperature at the bottom of the SH/RH is relatively constant at 460°C (860°F). The evaporator inlet, however, cools relatively quickly for reasons explained in the discussion of standby modes. At some time during an intermediate standby, the temperature difference between these two points exceeds 83°C(150°F) and a re-establishment of sodium flow is not possible without a substantial thermal shock to the evaporator. For this reason the sodium coming from the SH/RH outlet is mixed with sodium from the cold storage tank to match the evaporator temperature. This temperature is then ramped up by 83°C/hour (150°F/hour) until the normal operating point is reached. From this point on, all sodium flow to the evaporator comes from the SH/RH outlets and the warmup procedure is identical to that described for the cold start.

4.2.2.6.3 Hot Start - The plant is in a hot start condition after a standby period of less than one day. This condition will, in general, exist after an overnight standby. All the startup procedures will follow the warm startup sequence.

For shorter standby, such as a unit trip or some other rapid unloading of the steam turbine generator unit, the steam flow (rejected by the turbine) will be taken by the turbine bypass system for some interim period of time until the plant is shut down or the turbine generator unit can be restarted, synchronized and reloaded. To avoid severe cooling of the turbine metal during hot restart conditions, the turbine bypass system would be operated at a steam flow which will enable the superheater and reheater to operate in a region which will provide the required steam temperatures and thus avoid severe negative stresses in the turbine rotor.

4.2.2.7 Shutdown Sequence

4.2.2.7.1 Normal Shutdown - When there is a loss of insolation coincident with the end of the day, as determined by the master control clock, or when directed by the utility or the local operator, the plant is placed in the shutdown mode. The sequence of the shutdown is essentially the reverse of the startup sequence.

As insolation decreases, the hot sodium output from the receiver decreases until there is essentially no more hot sodium being generated. The tower pump is secured and the throttle valves are shut off. The tower loop is then bottled up and placed in the standby mode. Coincident with the above actions, the heliostats are all returned to the stow position, and the receiver insulation curtain is raised to cover the receiver panels.

While the tower loop has been shut down, hot sodium in the storage tanks will continue to be discharged to the steam generators and electric power produced by the EPGS. The operation will continue until the hot sodium inventory in storage is reduced to a predetermined amount (e.g. 5%) at which time the steam generators and the EPGS will be shut down.

The flow rates in the SG and EPGS will be reduced to about 10% (minimum operating range of pumps, valves, instrumentation, etc.) at which time the steam generator pump is secured and the steam generators bottled up. If the fossil plant is not operating, the steam turbine is tripped and steam is by-passed to the condenser. The system is then in the standby mode.

4.2.2.7.2 *Emergency Shutdown* — The emergency shutdown sequence will be initiated for major malfunctions or alarm indications such as the following:

Sodium Side

- Receiver panel over-temperature
- EM pump malfunction
- Loss of sodium flow to tower
- Loss of sodium flow to steam generators
- Sodium/water reaction

Water/Steam Side

- Generator breaker trip
- Turbine overspeed trip

- Steam header overpressure/loss of pressure
- Steam header loss-of-flow
- Loss of feedwater flow
- Loss of steam drum recirculation flow
- Loss of condenser vacuum
- Condenser high/low level limits exceeded
- Loss of condensate flow

The plant will be shut down in a manner similar to that used in the normal shutdown sequence. A local reset will be required prior to recommending plant startup to ensure that the cause of the emergency shutdown has been corrected and to ensure no plant damage has been incurred.

A unique emergency situation associated with the plant is that of sodium/water reaction. It occurs as a result of water/steam leakage through the tubes into the sodium side of the SG module. The resultant flame front may cause destruction of adjacent tubes or SG structure, and enough increase in pressure to rupture the rupture discs. With the rupture of one or more of the rupture discs the sodium/water reaction pressure relief system is activated. Activation of this system results in coincidental signal transmission from at least two out of three detectors, located immediately downstream of each rupture disc assembly, causing the steam generator sodium pump to trip. Concurrently, the SG modules are isolated from the steam drum and recirculation pump. Also, water/steam dump from the SG module is initiated. The resulting reduction of the amount of water available at the sodium/water leak reduces the pressure on the water side of the modules. The pressure reduction effectively reduces or stops the rate of water leakage into the sodium side of the defective modules.

When the steam pressure within the isolated SG modules and associated water/steam piping is reduced, argon gas is admitted to the affected loop. For modules with no leaks or small leaks, the pressure is maintained at the argon supply pressure. For modules with large leaks, depending the size of the leak, the module is maintained at a reduced pressure. Upon the introduction of argon to the loop, the sodium is drained from the modules and each module is subjected to one cycle of pressure reduction to full vacuum followed by back filling with argon.

If the water/steam leak is not large enough to rupture the rupture discs, the faulted module can be located by the H_2 detector.

4.2.2.8 Sodium Fill Procedures

Before a filling operation, all piping or components except the storage tanks which are filled with argon would first undergo several cycles of pressure reduction to partial vacuum followed by back filling of argon at 101 kPa (14.7 psia). This would ensure their being free from contamination and leakage. The approach is not suitable for the storage tanks since they are not designed to take external pressure. Instead, a series of argon feed and bleed purges will be used for the storage tanks.

All sodium-containing piping and components are preheated to a temperature of 177°C(350°F). This is accomplished by the trace heaters.

Initial fill of sodium into the system is accomplished by introducing sodium at a minimum of 177°C(350°F) into the storage tanks. Sodium in the tank trucks is moved through the fill lines into the storage tanks using argon gas.

Refill of sodium lines following maintenance operations utilizes sodium in the storage tanks. Sodium in the cold tanks is pumped into the tower loop to displace the cover gas (the throttle valves at the bottom of downcomer are closed). A filled loop is detected by the overflow of sodium from the overflow line at the top of the receiver. The throttle valves are then opened and the flow from the receiver returns to the cold tanks, thus establishing a flow through the tower loop. The tower loop is then ready for a cold start.

In preheating the steam generators, care must be exercised to minimize temperature differentials between the steam generator module shell and the tubes.

Before initiating the warmup, the steam generators are subject to several cycles of pressure reduction to partial vacuum followed by back filling of argon, while the tubes are filled with nitrogen.

After the vacuum cycles are completed, and it is determined that there are no leaks, the tube side of the SG is filled with ambient temperature water. The water is circulated through the steam generators which are in series with an auxiliary boiler. The temperature of the circulating water is heated at 6°C (10°F) per hour using the fossil boiler. The heat of the circulating water is increased from ambient temperature until the inlet water of the SG is 204°C(400°F). The temperature of the inlet water is maintained for approximately 62 hours to soak the outer shell of the SG module to obtain a nominal shell temperature of 177°C (350°F). At the end of the soak period, the inlet water temperature is reduced at $6^{o}C$ ($10^{o}F$) per hour until the approximately isothermal conditions of $177^{o}C$ ($350^{o}F$) exist in the SG modules. The shell side of the modules is then subjected to one pressure reduction to full vacuum cycle followed by back filling with argon to 101 kPa (14.7 psia). The SG modules are then filled with $177^{o}C$($350^{o}F$) sodium, and are in a position for a cold start.

4.2.2.9 Drainage Procedures

Hot sodium in the receiver, downcomer, superheater and reheater is drained into the hot storage tank and the cold sodium in the riser and the evaporator is drained into the cold storage tank.

To overcome the gravity heads, pressurized argon will be used at two locations: the top of the receiver and the high point in the steam generator system.

All sodium in the remaining piping and components will be drained by gravity force into the drain tank. It is proposed to use one drain tank made of 316SS to accommodate both hot and cold sodium. Care must be exercised in putting the hot/cold sodium into the drain tank because of the big difference in their temperatures. A sequence that would drain the cold sodium first is recommended. This will warm the drain tank prior to the draining of the hot sodium, thereby minimizing the thermal shock to the tank/piping.

4.2.3 SYSTEM STATE PARAMETERS AND THERMAL ENERGY BALANCE

The following sections describe the sodium and water/steam system state parameters (flow, pressure, temperature) and the balance of input and output energies to the cycle.

4.2.3.1 Sodium Loop

In the repowered plant, solar energy will be used to displace a significant portion of the gas or oil presently consumed by the fossil boiler. The collection and delivery of the solar energy will be accomplished by the solar thermal power plant described in Section 4.2.1. Figure 4.2-21 illustrates the design point (equinox, noon) mass and energy flows involved in the collection and delivery of the solar energy to the steam generator modules.

The system input and output energy flows are designated as Qx. The sodium loop energy balance at the design point is detailed on Table 4.2-7 . The energy incident on the collector field (Q_1) represents the design point insolation level of 940 W/m^2 over the 49 m^2 reflective area of the 4809 heliostats. The field

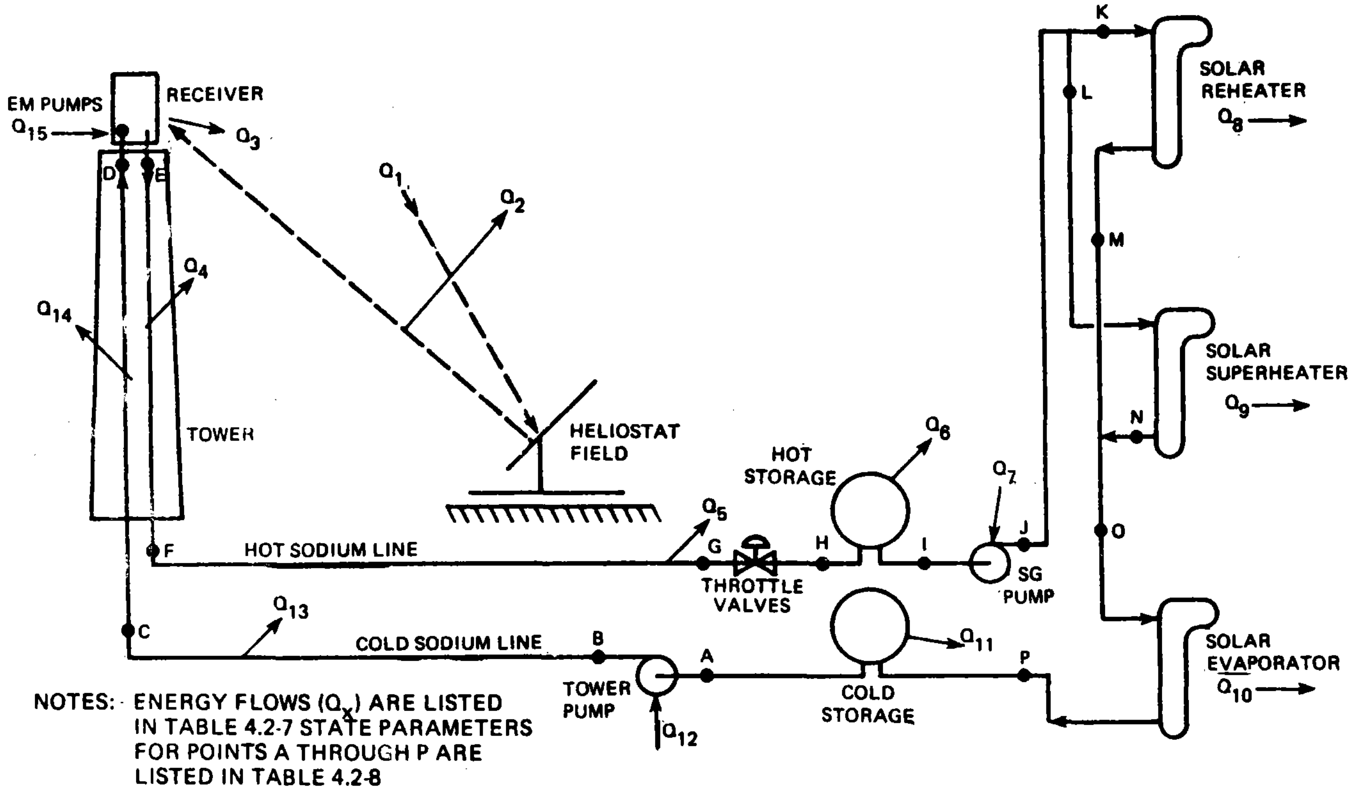


Figure 4.2-21 Sodium Loop Mass Flows and Energy Balance

losses (Q_2) are calculated by the DELSOL computer code and include cosine losses, shading, blocking, reflectivity, attenuation and spillage. A detailed breakdown of these losses is presented in Section 4.4.1, "Design Point Performance." The receiver losses (Q_3) include reflection, radiation and convection. These losses, calculated by a General Electric computer code developed in Phase I of the Advanced Central Receiver Program, are a function of receiver size, metal temperature, wind speed and ambient temperature. A detailed breakdown is given in Section 4.4.1. The thermal losses incurred by the transport and storage of the sodium (Q_4, Q_5, Q_6, Q_{11}, Q_{13}, and Q_{14}) take into account the fluid temperature, the pipe and tank insulation, and the ambient temperature at the design point. The sodium pumps add a small amount of thermal energy (Q_7, Q_{12}, Q_{15}) to the fluid, the value being dependent upon the power draw and the mechanical efficiency of the pump. Motor and coupling inefficiencies are assumed to be lost to the surroundings. Pumping thermal power inputs are calculated in Appendix C.

Table 4.2-7

SODIUM LOOP ENERGY BALANCE AT THE DESIGN POINT

• Energy Inputs

Designation *	Description	Value (MWt)
Q_1	Energy Incident on Heliostat Field	221.50
Q_7	SG Pump Input	0.16
Q_{12}	Tower Pump Input	1.10
Q_{15}	EM Pump Input	0.12
	TOTAL INPUT=	222.88 MWt

• Energy Outputs

Designation *	Description	Value (MWt)
Q_2	Field Losses	63.34
Q_3	Receiver Losses	17.28
Q_4	Downcomer Losses	0.05
Q_5	Hot Sodium Line Losses	0.28
Q_6	Hot Storage Tank Losses	0.03
Q_8	Reheater - Thermal Power To Steam	15.60
Q_9	Superheater - Thermal Power To Steam	39.80
Q_{10}	Evaporator - Thermal Power To Water/Steam	86.40
Q_{11}	Cold Storage Tank Losses	0.01
Q_{13}	Cold Sodium Line Losses	0.08
Q_{14}	Riser Losses	0.01
	TOTAL OUTPUT=	222.88 MWt

* REF Figure 4.2-21

The sodium flows, pressures and temperatures are listed for 16 locations, designated A through P on Table 4.2-8. A detailed explanation of the calculation of the system pressure drops is contained in Appendix B.

Table 4.2-8

SODIUM LOOP STATE POINTS AT THE DESIGN POINT

Designation *	Location	Flow, Kg/Hr (PPH)	Pressure, KPa (PSIA)	Temperature °C (°F)
A	Tower Pump Inlet	$1.34 \times 10^6 (2.95 \times 10^6)$	144.1(20.9)	293(560)
B	Tower Pump Discharge		2078.8(301.5)	
C	Riser Inlet		1463.1(212.2)	
D	EM Pump Inlet		206.9(30.0)	
E	Downcomer Header		206.9(30.0)	593(1100)
F	Downcomer Outlet		1145.3(166.1)	
G	Throttle Valve Inlet		675.0(97.9)	
H	Throttle Valve Outlet		224.1(32.5)	
I	SG Pump Inlet		224.1(32.5)	
J	SG Pump Outlet		462.0(67.0)	
K	Solar Reheater Inlet	$0.38 \times 10^6 (0.84 \times 10^6)$	199.3(28.9)	
L	Solar Superheater Inlet	$0.96 \times 10^6 (2.11 \times 10^6)$	199.3(28.9)	
M	Solar Reheater Outlet	$0.38 \times 10^6 (0.84 \times 10^6)$	254.4(36.9)	477(890)
N	Solar Superheater Outlet	$0.96 \times 10^6 (2.11 \times 10^6)$	254.4(36.9)	
O	Solar Evaporator Inlet	$1.34 \times 10^6 (2.95 \times 10^6)$	153.1(22.2)	
P	Solar Evaporator Outlet		234.4(34.0)	293(560)

* REF Figure 4.2-21

4.2.3.2 Integrated Solar-Fossil Steam Loop

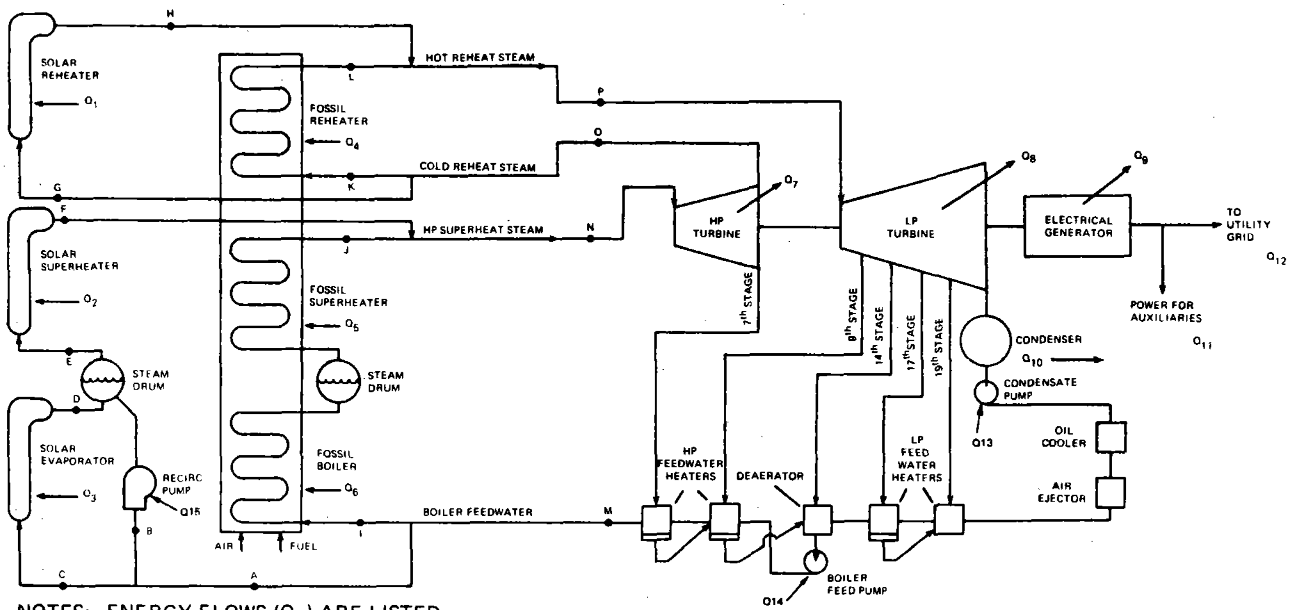
The repowered plant will generally be operated in a hybrid mode to insure reliable plant output. Figure 4.2-22 illustrates the mass and energy flows for the hybrid operating mode. Tables 4.2-9 and 4.2-10 list the energy balance values and the system state parameters (flow, pressure, temperature) respectively for the full load design point operating condition. The full load net plant output is set at 100 MWe. The energy inputs to the solar steam generators (Q_1, Q_2, Q_3) are consistent with the energy balance described in the previous section, (Table 4.2- 7). The energy input to the fossil boiler (Q_4, Q_5, Q_6) is that required to supply sufficient steam to generate the 100 MWe.

The calculation of auxilliary power requirements (Q_{11}) and the pump thermal inputs (Q_{13}, Q_{14}, Q_{15}) is explained in detail in Appendix C. The accuracy of the balance can now be checked against the known thermal to electrical conversion efficiency of the turbine generator set, which is 42% at full load, as follows:

$$N_{tg} = \frac{\text{Gross Generator Electrical Output}}{\text{Total Steam Generator Thermal Input}}$$

$$= \frac{Q_{11} + Q_{12}}{Q_1 + Q_2 + Q_3 + Q_4 + Q_5 + Q_6}$$

$$= \frac{103.55 \text{ MWe}}{246.07 \text{ MW}_t} = 0.4200$$



NOTES: ENERGY FLOWS (Q_x) ARE LISTED IN TABLE 4.2-9. STATE PARAMETERS FOR POINTS A THROUGH P ARE LISTED IN TABLE 4.2-10.

Figure 4.2-22 Water/Steam Loop Mass Flows and Thermal Energy Balance

Table 4.2-9
WATER/STEAM LOOP ENERGY BALANCE

• Energy Inputs		
Designation *	Description	Value (MW)
Q_1	Solar Reheater	15.60
Q_2	Solar Superheater	39.80
Q_3	Solar Evaporator	86.40
Q_4	Fossil Reheater	11.47
Q_5	Fossil Superheater	29.27
Q_6	Fossil Evaporator	63.53
Q_{13}	Condensate Pump	0.02
Q_{14}	Boiler Feed Pump	1.58
Q_{15}	Recirc Pump	0.004
	Total	247.67
• Energy Outputs		
Designation *	Description	Value (MW)
Q_7	HP Turbine Losses	144.32
Q_8	LP Turbine Losses	
Q_9	Elec Generator Losses	
Q_{10}	Condenser Heat Rejection	
Q_{11}	Aux Power Req'mts	3.35
Q_{12}	Power to Grid	100.00
	Total	247.67

* REF Figure 4.2-22

Table 4.2- 10

WATER/STEAM LOOP DESIGN POINT STATE CONDITIONS

Designation *	Location	Flow,Kg/Hr(PPH)	Pressure MPa(PSIA)	Temperature,°C(°F)
A	Solar Feedwater	187,200(412,800)	11.72(1700)	240(464)
B	Recirc Flow	28,100(61,900)	11.72(1700)	318(605)
C	Solar Evap Inlet	215,300(474,700)	11.72(1700)	251(484)
D	Solar Evap Outlet	215,300(474,700)	11.03(1600)	318(605)
E	Solar SH Inlet	187,200(412,800)	11.03(1600)	318(605)
F	Solar SH Outlet	187,200(412,800)	10.10(1465)	538(1000)
G	Solar RH Inlet	165,700(365,400)	3.43(497)	388(730)
H	Solar RH Outlet	165,700(365,400)	3.08(447)	538(1000)
I	Fossil Boiler Inlet	137,100(302,300)	11.72(1700)	240(464)
J	Fossil SH Outlet	137,100(302,300)	10.10(1465)	538(1000)
K	Fossil RH Inlet	121,800(268,500)	3.43(497)	388(730)
L	Fossil RH Outlet	121,800(268,500)	3.08(447)	538(1000)
M	Combined Feedwater	324,300(715,100)	11.72(1700)	240(464)
N	HP Turbine Inlet	324,300(715,100)	10.10(1465)	538(1000)
O	HP Turbine Disch	287,500(633,900)	3.43(497)	388(730)
P	LP Turbine Inlet	287,500(633,900)	3.08(447)	538(1000)

*REF Figure 4.2-22

Note: Recirc flow (B) includes solar steam drum blowdown flow. This simplificiation is permissible for a mass and heat balance calculation as all of the blowdown flow and energy is recovered in the feedwater heating system.

4.3 SITE REQUIREMENTS

Figure 4.3-1 shows a plot plan for the repowered Plant X facility. Discussed below are the major facility changes and additions which will be required to arrive at this final configuration.

4.3.1 SITE IMPROVEMENTS

The site improvements consist of general site preparations and facility relocations to accomodate the repowering. The general site improvements consist of those elements listed below:

- Heliostat field grading
- Upgrading of site utilities (water, air, communications)
- Road additions (for heliostat field)

The facility relocations will consist of the following:

- Relocating the existing transmission line currently running east of the Plant X facility to the west side of the plant
- Relocating the condensate storage tank located to the northwest of the Unit 3 boiler to the east side of the Unit 3 boiler
- Relocating the three power transformers between the Unit 3 boiler and the turbine building to the space between boilers 3 and 4

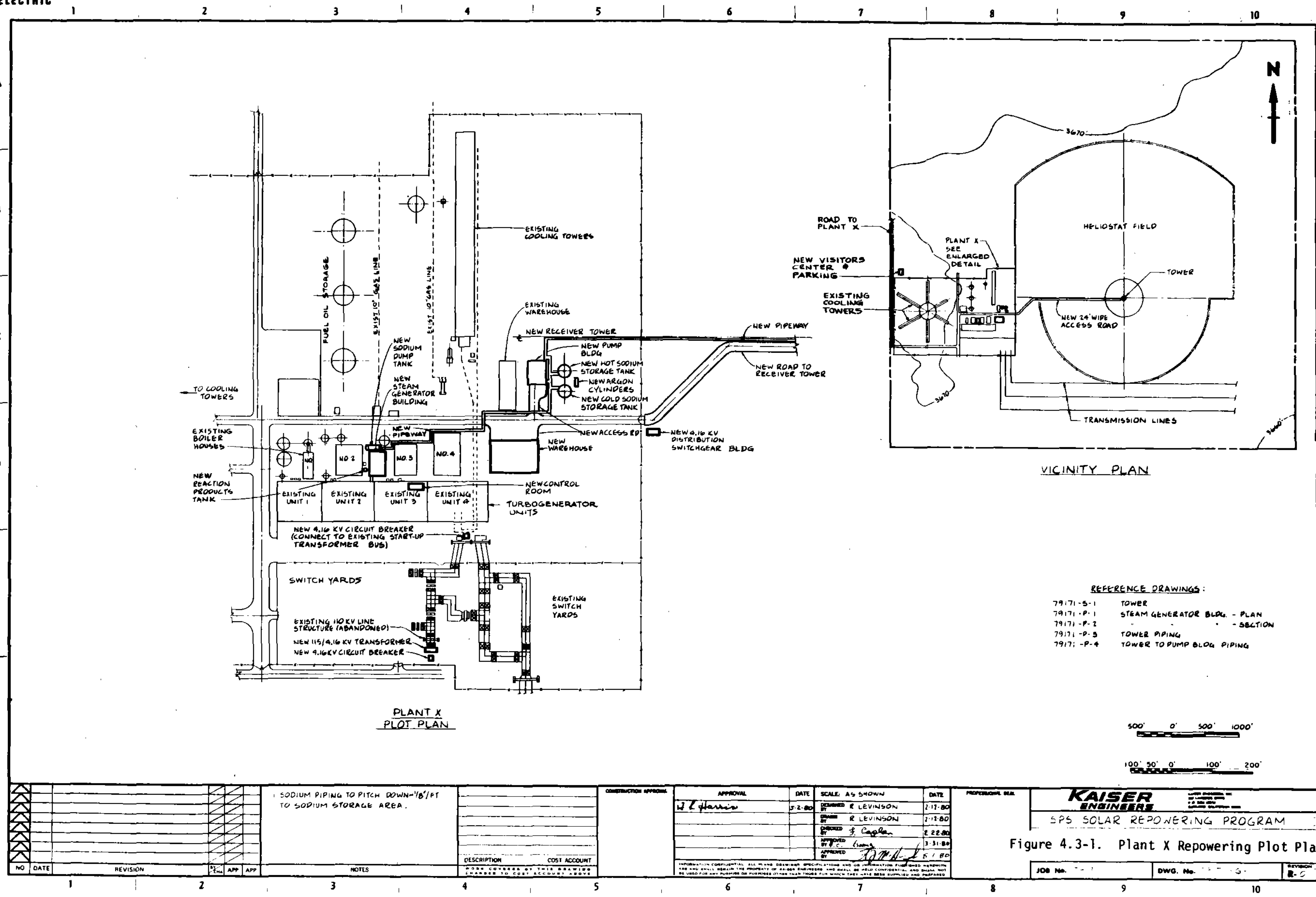


Figure 4.3-1. Plant X Repowering Plot Plan

More detailed discussion of these site improvements is in Section 5.1.

4.3.2 SITE FACILITIES

The new site facilities will consist of building additions, security modifications, and electric plant additions. A general discussion of these items is provided in the following sections with additional details provided in Section 5.2.

4.3.2.1 Buildings

Four new buildings and one building modification will result from the repowering.

A pump building will be added to the northeast of the Unit 4 boiler building. This facility will house the main sodium pumps and sodium purification equipment.

The steam generator building which will contain the steam generator modules and related equipment will be located between boiler buildings 2 and 3. This will minimize the pressure drop in the steam piping.

A warehouse will be added to the east of the No. 4 boiler to house spare parts and maintenance equipment for the solar plant.

A visitors center located on the west side of the Plant X site has been provided in the design.

The turbine deck level conference room in the turbine building will be modified to accomodate the new Unit 3 control room. The existing Unit 3 controls are housed together with the Unit 1 and 2 controls. Insufficient room exists in this area to add the new control equipment.

4.3.2.2 Security

Security in the form of fencing, lighting, and an intrusion alarm system will be provided around the collector field perimeter.

4.3.2.3 Electric Plant

Power distribution equipment in the form of transformers and switchgear will be added to supply the required power to the solar plant facilities. Primary power will be provided from the Plant X, 115 kV ring bus. Backup power will be provided from the 115 kV startup transformer for the number 4 unit.

4.4 SYSTEM PERFORMANCE

System and subsystem performance has been calculated for the repowered plant concept at the design point and on an annual basis. The results are discussed in the following sections.

4.4.1 DESIGN POINT PERFORMANCE

Early in the conceptual design phase the design point was chosen as equinox, noon. This choice provides a design point at which the receiver experiences the maximum thermal input for a collector field which is heavily skewed to the north. Adjustments to the field since that time have resulted in a design point energy flow slightly less than maximum but still representative of the system capabilities and capacities.

The design point insolation level is 940 W/m^2. This value was taken from actual measurements of direct normal insolation in the Earth, Texas, area on the 1979 autumnal equinox and confirmed by readings on the 1980 vernal equinox. Other design point specifications are in Table 4.4-1.

Table 4.4-1
DESIGN POINT SPECIFICATIONS

Reference Site:	Earth, Texas
	34^{o} N. Latitude
	102^{o} W. Longitude
Temperature:	20^{o}C (68^{o}F) dry bulb
	10^{o}C (50^{o}F) wet bulb
Sun Position:	55^{o} evaluation
	0^{o} azimuth
Operating Mode:	hybrid, 100 MWe net output

The power incident on the heliostat reflective surface is determined as follows:

$$P_{TC} = Sc \cdot I = 221.5 \text{ MWth}$$

where: P_{TC} = power to collector field

Sc = collector area = $4809 \cdot 49 m^2$ = $235{,}641\ m^2$

I = direct normal insolation level= $940 \times 10^{-6}\ MW/m^2$

The performance of the field in transporting the incident energy to the receiver has been calculated by the MIRVAL computer code for the design point conditions and the field configuration described in Section 4.2.1. Collector field losses are specified in Table 4.4-2. at

Table 4.4-2

COLLECTOR FIELD LOSSES AT THE DESIGN POINT

Cosine + shading	29.7
Collector reflectivity	19.1
Blocking	3.0
Attenuation	8.5
Spillage	3.0
Total	63.3 MWth

The power to the receiver can then be determined by:

$P_{TR} = P_{TC} - L_C = 158.2$ MWth

where P_{TR} = power to receiver

P_{TC} = power to collector field = 221.5 MWth

L_C = collector field losses = 63.3 MWth

A portion of the energy arriving at the receiver is reflected back to the surroundings. Other receiver losses are incurred by radiation and convection. The radiation and convection losses are calculated by the receiver loss code developed by General Electric for the Advanced Central Receiver Program. Power absorbed by the liquid sodium working fluid can be found from:

$P_{TWF} = E_R P_{TR} - L_R = 140.9$ MWth

where P_{TWF} = power to working fluid

E_R = reflectivity coefficient = 0.95

P_{TR} = power to receiver = 158.2 MWth

L_R = receiver losses = 7.7 MWth radiation

+1.7 MWth convection

9.4 MWth total

A portion of the thermal energy in the working fluid is lost to the surroundings through the insulation on the pipe runs, storage tanks, and steam generator modules. The working fluid experiences a thermal input from the pumps in the sodium loop which includes all of the pump power not lost to electric motor inefficiencies or EM stator cooling. This assumes that all of the mechanical pumping input is dissipated in viscous losses in the loop. A detailed calculation of these thermal inputs is contained in Appendix C.

Piping insulation losses and pump thermal inputs are summarized in Table 4.4-3.

Table 4.4-3

THERMAL LOSSES AND GAINS AT THE DESIGN POINT

• Thermal Losses Through Insolation	
Downcomer	-0.046
Hot Field piping	-0.226
Hot Storage	-0.026
Hot Storage to SG Modules	-0.058
SG Modules to Cold Storage	-0.015
Cold Storage	-0.012
Cold Field Piping	-0.062
Riser	-0.011
Total	-0.456 MWth
• Thermal Gains Through Pumping	
Tower Pump	+1.095
EM Pumps	+0.121
SG Pump	+0.158
Total	+1.374

Power delivered to the steam generators is calculated as follows:

$P_{TSG} = P_{TWF} + L_I + P_P = 141.8$ MWth

where P_{TSG} = power to steam generators

P_{TWF} = power to working fluid = 140.9 MWth

L_I = insulation losses = -0.456 MWth

P_P = pumping power = +1.374 MWth

At the design point, the hybrid operating mode net output of 100 MWe allows the turbine to convert the thermal energy delivered to the steam at a 42.0% efficiency. Thus, the gross power generated by the solar plant is shown to be:

$$P_{GS} = P_{TSG} \times \eta_{SG} = 59.6 \text{ MWe}$$

where P_{GS} = power, gross solar

P_{TSG} = power to steam generator = 141.8 MWth

η_{SG} = steam turbine/generator thermal to electrical conversion efficiency = 42.0%

The auxiliary power requirements of the solar plant, calculated in Appendix C , are summarized in Table 4.4-4.

Table 4.4-4

AUXILIARY POWER REQUIREMENTS AT THE DESIGN POINT

Heliostats	0.118 MWe
EM Pump	0.151
EM Pump Blower	0.005
Tower Pump	1.153
SG Pump	0.171
FW Recirc Pump	0.004
Condensate Pump	0.018
Boiler Feed Pump	1.660
	3.350 MWe

Of this total, the solar portion of the plant is charged with 100% of the power for the heliostats, the sodium pumps, and the FW recirc pump and 60% of the power required by the condensate and boiler feed pumps.

Thus, the net output of the solar portion of the repowered plant is:

$$P_{NS} = P_{GS} - P_{AUX} = 57.0 \text{ MWe}$$

where P_{NS} = power, net solar

P_{GS} = power, gross solar = 59.6

P_{AUX} = solar auxiliary power req'mts = 2.6

The energy cascade described by the preceding calculations is illustrated by Figure 4.4-1. The cross-hatched area illustrates the contribution required of the fossil plant to bring the total net output to 100.0 MWe.

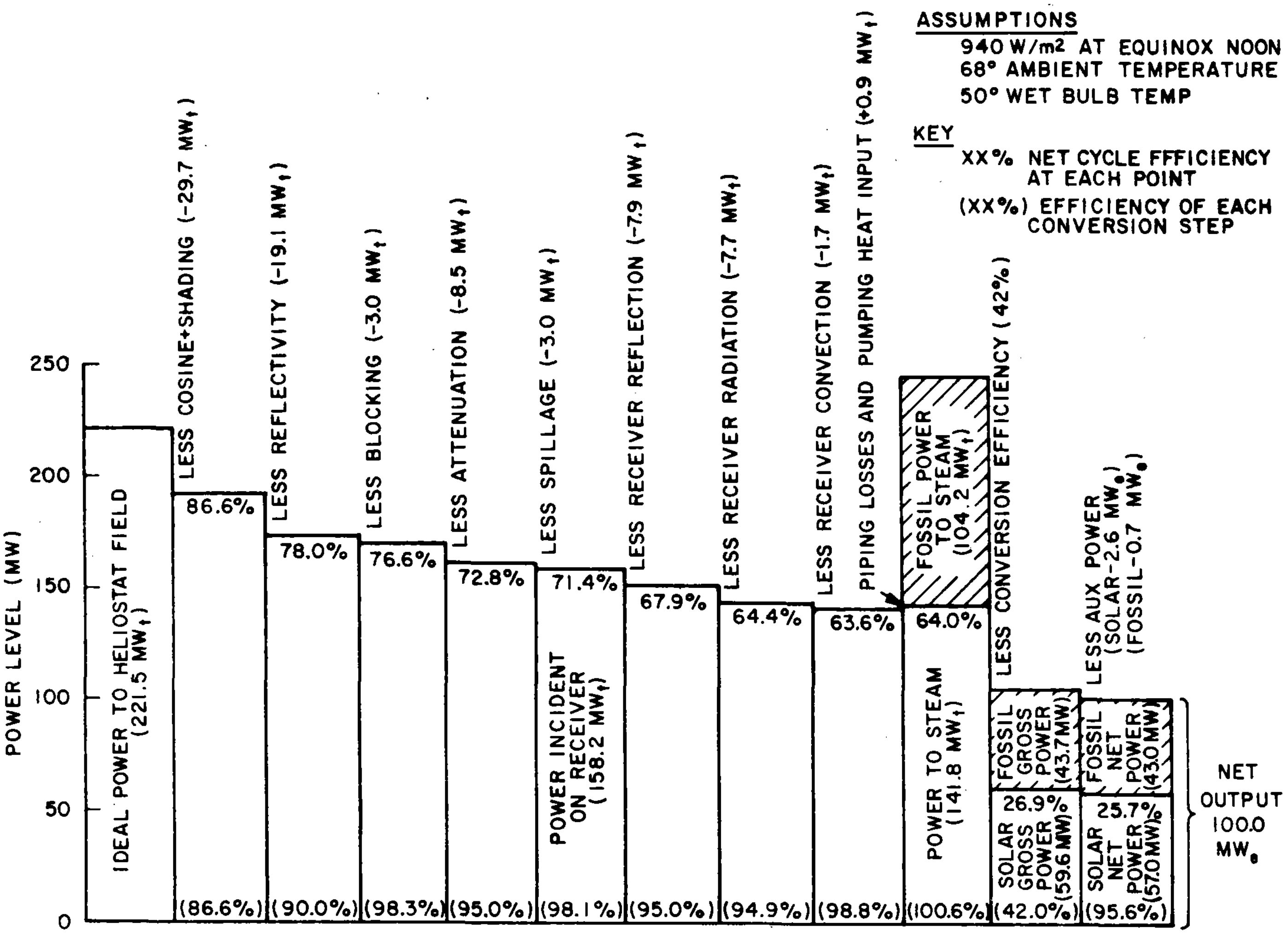


Figure 4.4-1. Design Point Energy Cascade

4.4.2 ANNUAL PERFORMANCE

The annual performance of the repowered plant was calculated using the Sandia-Generated STEAEC (reference SANDIA report, SAND 77-8278) computer code. The principal output of this code is the net annual energy production from the solar portion of the hybrid plant. This information is required as the major input for the calculation of the value of the repowering concept, described in Section 4.4.3.

Inputs to the STEAEC program are illustrated by Figure 4.4-2. The development of those inputs is described in the following sections.

4.4.2.1 Insolation and Weather Data

Since no complete solar insolation data is available for the Plant X site, a method has been developed for simulating the insolation characteristics using available data for other locations. Albuquerque direct insolation information obtained from SOLMET (reference NOAA, Solmet Report TD-9724) tapes was utilized.

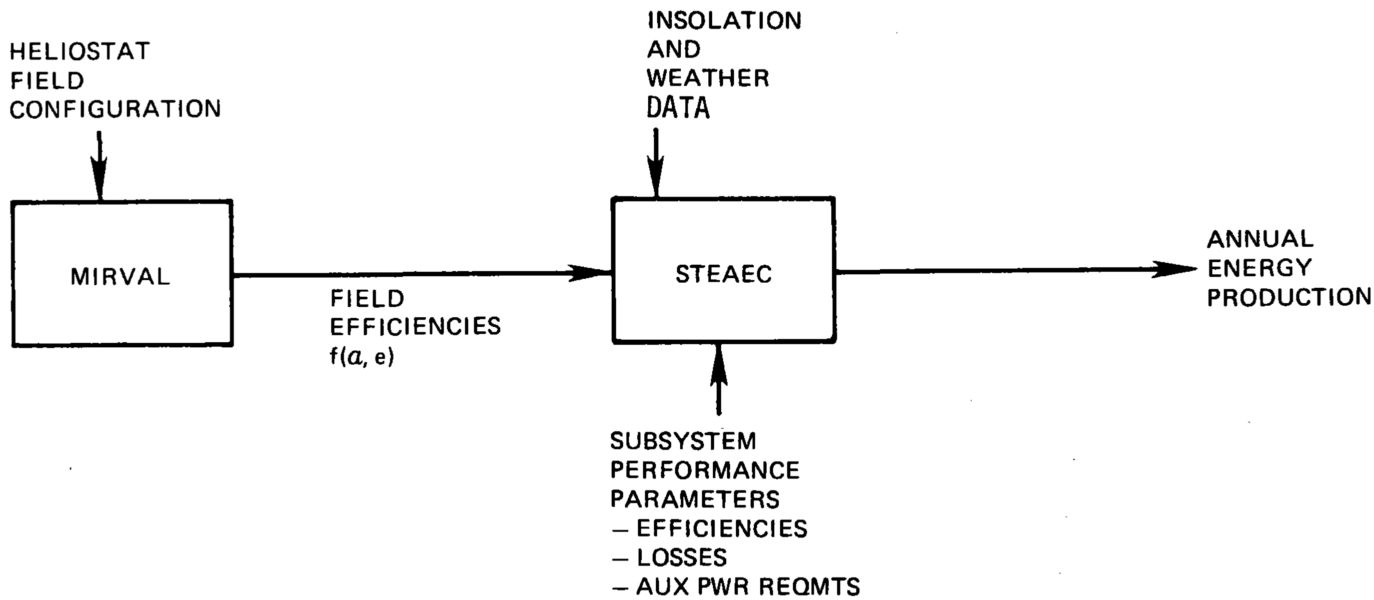


Figure 4.4-2. STEAEC Computer Code Block Diagram

The Plant X site and Albuquerque are at approximately the same latitude, which will provide the correct time and sun elevation information. The fraction of available sunshine received by the two sites is also similar (~76%). Since the two locations are at different altitudes, an adjustment must be made in the magnitude of direct insolation. To determine the level of the required adjustment, the Albuquerque data was compared to the insolation data from the SPS insolation monitoring station near Earth, Texas. Although the measured data is available only since August, 1979, it does provide sufficient information for comparison to determine the altitude adjustment factor.

The Albuquerque insolation data was reduced by a factor of 0.95 as a result of differences seen in the peak insolation on the Albuquerque tape and peak insolation measured near the Plant X site by SPS monitoring equipment. This adjusted data was combined with surface meterological data (temperature, wind speed, etc.) from Lubbock, Texas (~ 40 miles from Plant X) to provide complete data for the Plant X evaluation.

4.4.2.2 Field Efficiencies

The efficiency of the heliostat field in transmitting incident energy to the receiver is dependent on sun position and field configuration. The configuration of the field, described in 4.2.1, was input to the MIRVAL (reference Sandia Report SAND 77-8280) program, which was run for a matrix of sun positions. The results are listed in Table 4.4-5 and plotted in Figure 4.4-3. For reference, the actual position of the sun on the design point day is also shown on Figure 4.4-3.

Table 4.4-5

COLLECTOR FIELD EFFICIENCIES

ELEVATION	AZIMUTH ±0°	±25°	±50°	±75°	±90°	±105°	±115°
10°	0.3846	0.3755	0.3717	0.3614	0.3531	0.3400	0.3314
20°	0.5784	0.5676	0.5424	0.5300	0.5181	0.4960	0.4798
30°	0.6595	0.6538	0.6498	0.6162	0.5948	0.5822	0.5742
45°	0.7128	0.7066	0.6960	0.6592	0.6568	0.6422	0.6305
65°	0.7153	0.7293	0.6847	0.6845	0.6805	0.6819	0.6623
80°	0.6973	0.6950	0.7019	0.6870	0.6769	0.6755	0.6644

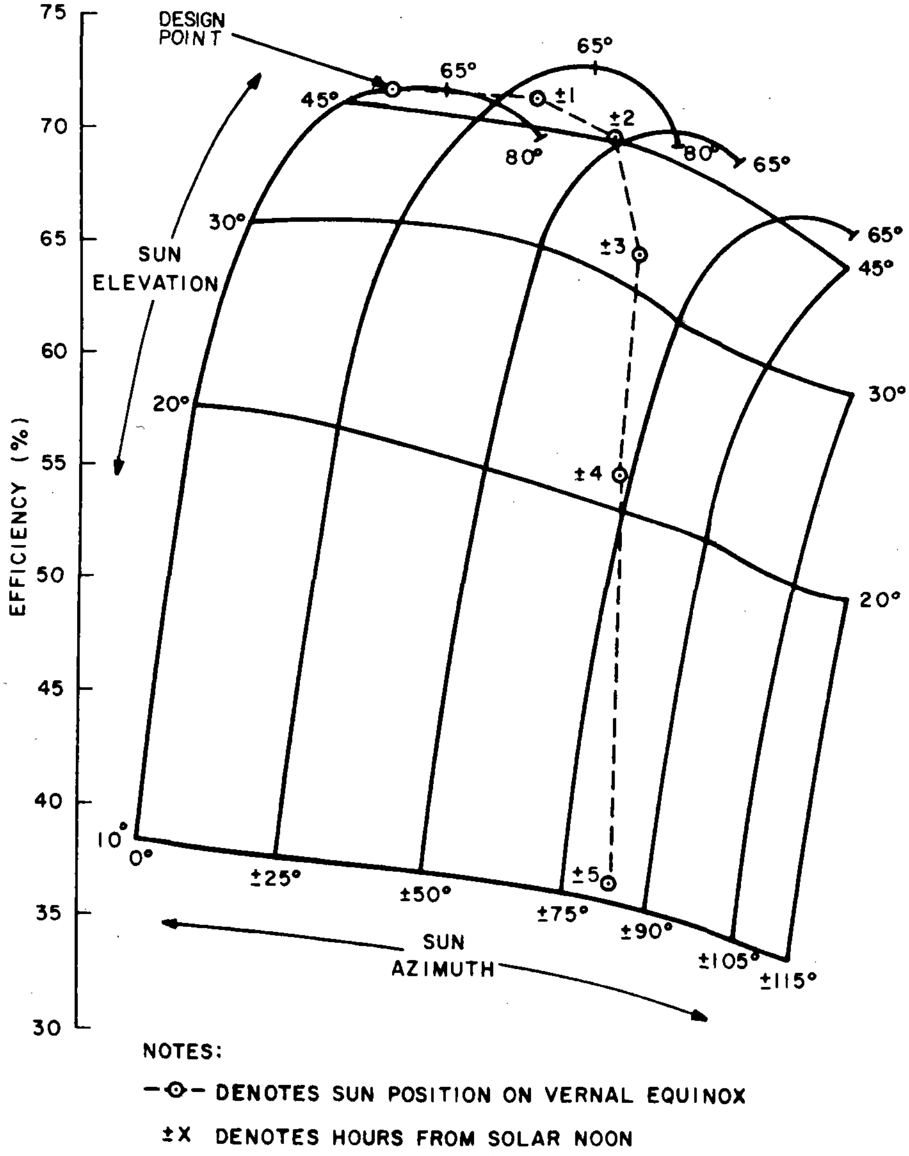


Figure 4.4-3. Collector Field Efficiency versus Sun Position

The field efficiencies generated by the MIRVAL code do not account for wind speed effects. In actuality, the wind has a significant effect on the performance of an unenclosed heliostat, and this effect is accounted for by the field efficiency correction factors listed in Table 4.4-6. The values are obtained from the STEAEC default input, which was developed for the Barstow field and is applicable to the second generation heliostats proposed for the repowered plant.

Table 4.4-6

WIND SPEED CORRECTION FACTOR

Wind Speed (m/s)	Correction Factor
0	1.0
2	0.999
4	0.998
6	0.996
8	0.994
10	0.985
12	0.964
13.4	0.942

The performance of the heliostat field over the course of a year is illustrated by Figure 4.4-4. As might be expected, the cumulative monthly field efficiency line indicates that performance is best in the summer months when the sun elevation is high and poorest in the winter when elevation levels are lower.

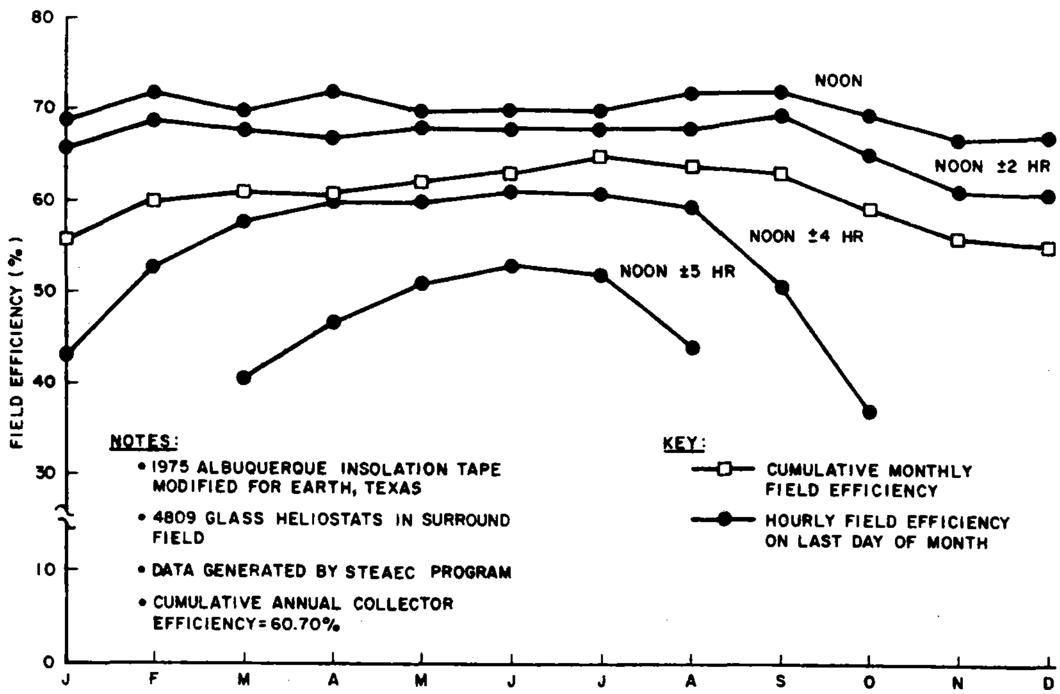


Figure 4.4-4. Collector Subsystem Performance

4.4.2.3 Receiver Efficiencies

A portion of the energy impinging upon the receiver is reflected back to the surroundings. It is assumed that 5% of the incident energy is reflected, based on data from receiver coating tests using Pyromark paint. Of the energy absorbed, losses occur by convection and radiation from the receiver surface. Radiation is a function of receiver size and metal temperature, both of which are constant. Convection losses are functions of wind speed and ambient temperature. The trends of all receiver losses combined, at various power levels, are illustrated in Figure 4.4-5. The actual receiver performance over the course of a year is listed on a month-by-month basis in Table 4.4-7. Note that the low performance numbers occur in those months (e.g. Jan., Dec.) of low output and low ambient temperature. Conversely, high output, high ambient temperature months (e.g. Aug., Sept.) produce the best receiver performance.

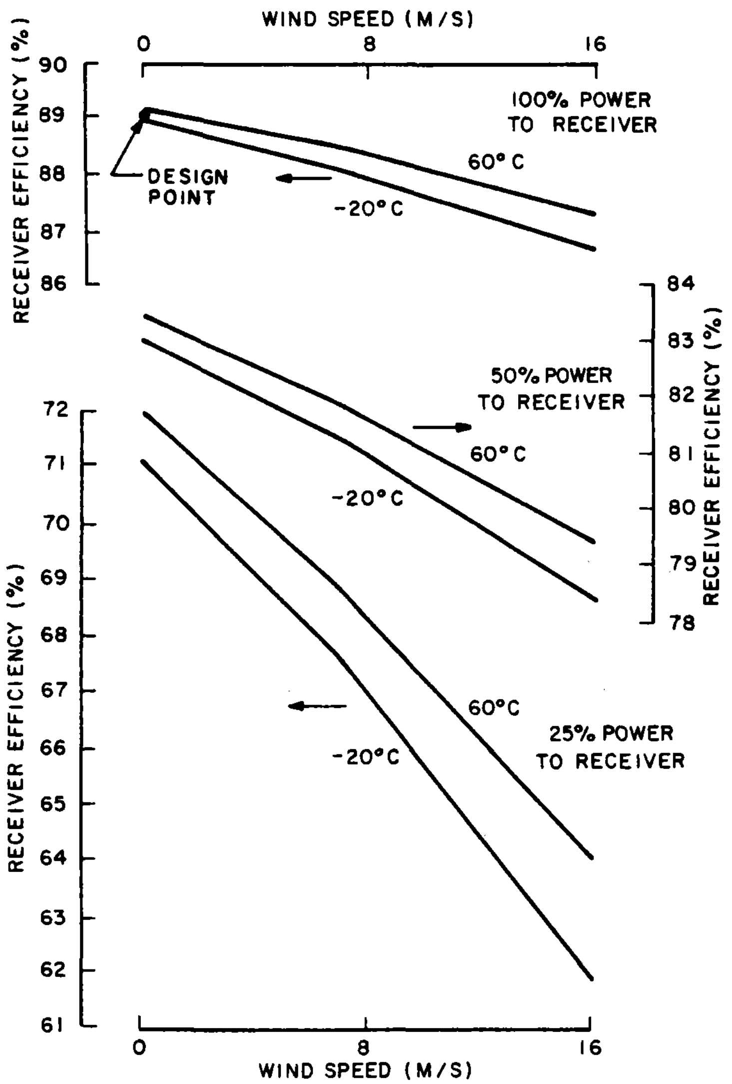


Figure 4.4-5. Receiver Efficiency Trends.

Table 4.4-7

RECEIVER SUBSYSTEM PERFORMANCE

JAN	0.820	JULY	0.826
FEB	0.831	AUG	0.849
MAR	0.826	SEPT	0.836
APR	0.828	OCT	0.851
MAY	0.842	NOV	0.846
JUNE	0.837	DEC	0.824

4.4.2.4 Thermal Losses/Gains

Thermal losses through the pipe insulation at the design point ambient temperature of 20°C (68°F) was calculated to be 0.456 MWth (Section 4.4.1, Table 4.4-3). Changes of this value due to real time ambient temperature changes were calculated by the same method. The results are listed in Table 4.4-8.

Table 4.4-8

THERMAL LOSSES VERSUS AMBIENT TEMPERATURE

T (°C)	T (°F)	Loss (MWth)
-20	-4	-0.496
0	32	-0.475
+20	68	-0.456 Design Point
40	104	-0.437
60	140	-0.415

Thermal inputs by the sodium pumps are independent of ambient temperature.

4.4.2.5 EPGS Efficiencies

The parameters that have the strongest influence on the performance of the EPGS components are the load level and condenser back pressure. The condenser back pressure is a function of the ambient wet bulb temperature, which is calculated by the STEAEC code from relative humidity and dry bulb temperature obtained from the Lubbock weather tape. The relationship of the two variables is listed in Table 4.4-9.

Table 4.4-9

CONDENSER BACK PRESSURE VERSUS
AMBIENT WET BULB TEMPERATURE

T_{WB} (^oC)	T_{WB} (^oF)	P_{cond} (inches Hg_a)
0	32	1.5
5	41	1.5
10	50	1.5
15	59	1.85
20	68	2.44
25	77	3.16

The variation of the turbine efficiency as a function of the load level and back pressure variables is illustrated in Figure 4.4-6. Note that the efficiency is significantly limited by operating in the solar alone mode. This is due to the design rating of the solar plant (60 MWe) which is only 60% of the design rating of the turbine generator set.

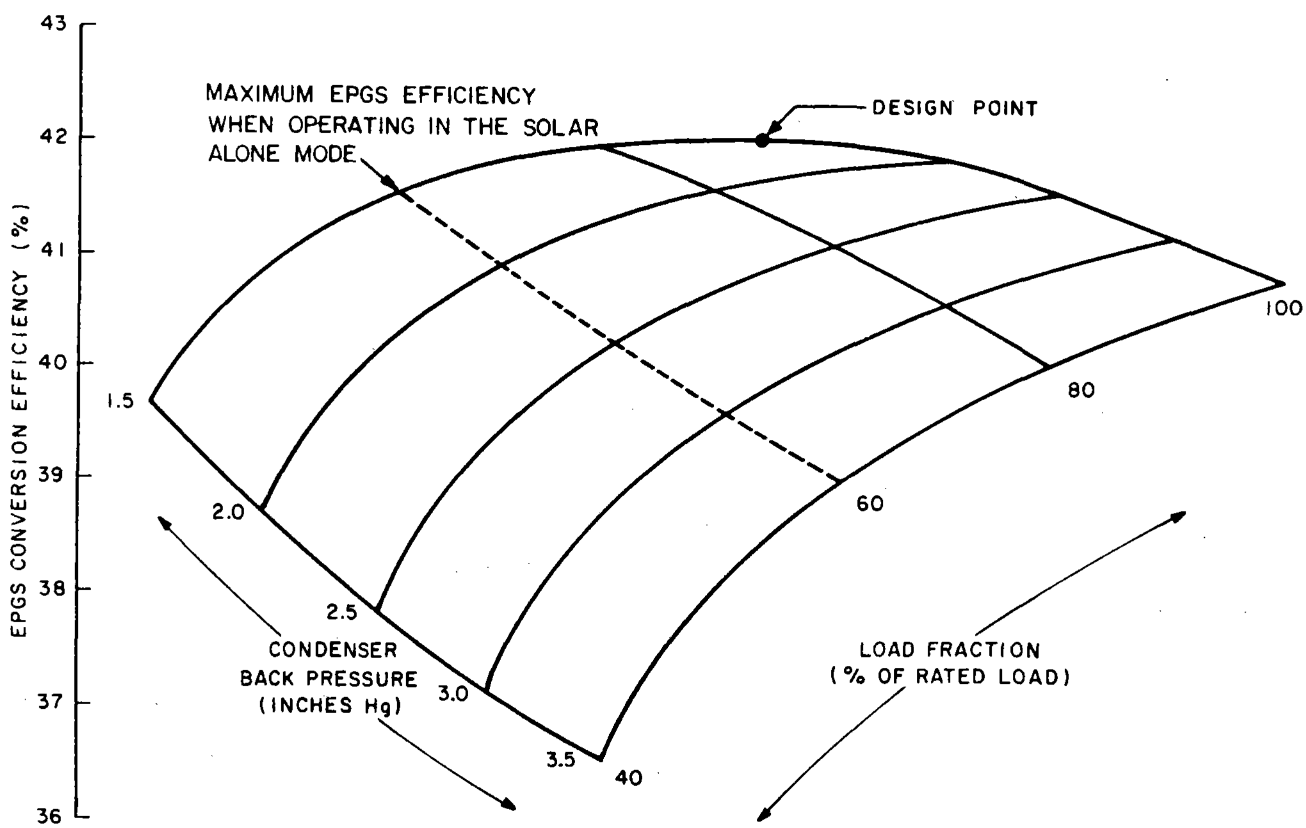


Figure 4.4-6 EPGS Performance Trends

4.4.2.6 Annual Performance Results

The preceding sections have defined the inputs to the STEAEC program. Two operating modes were considered:

- Hybrid with the fossil plant at minimum turndown
- Solar-alone

The results are illustrated on a month-by-month basis in Figure 4.4-7. As

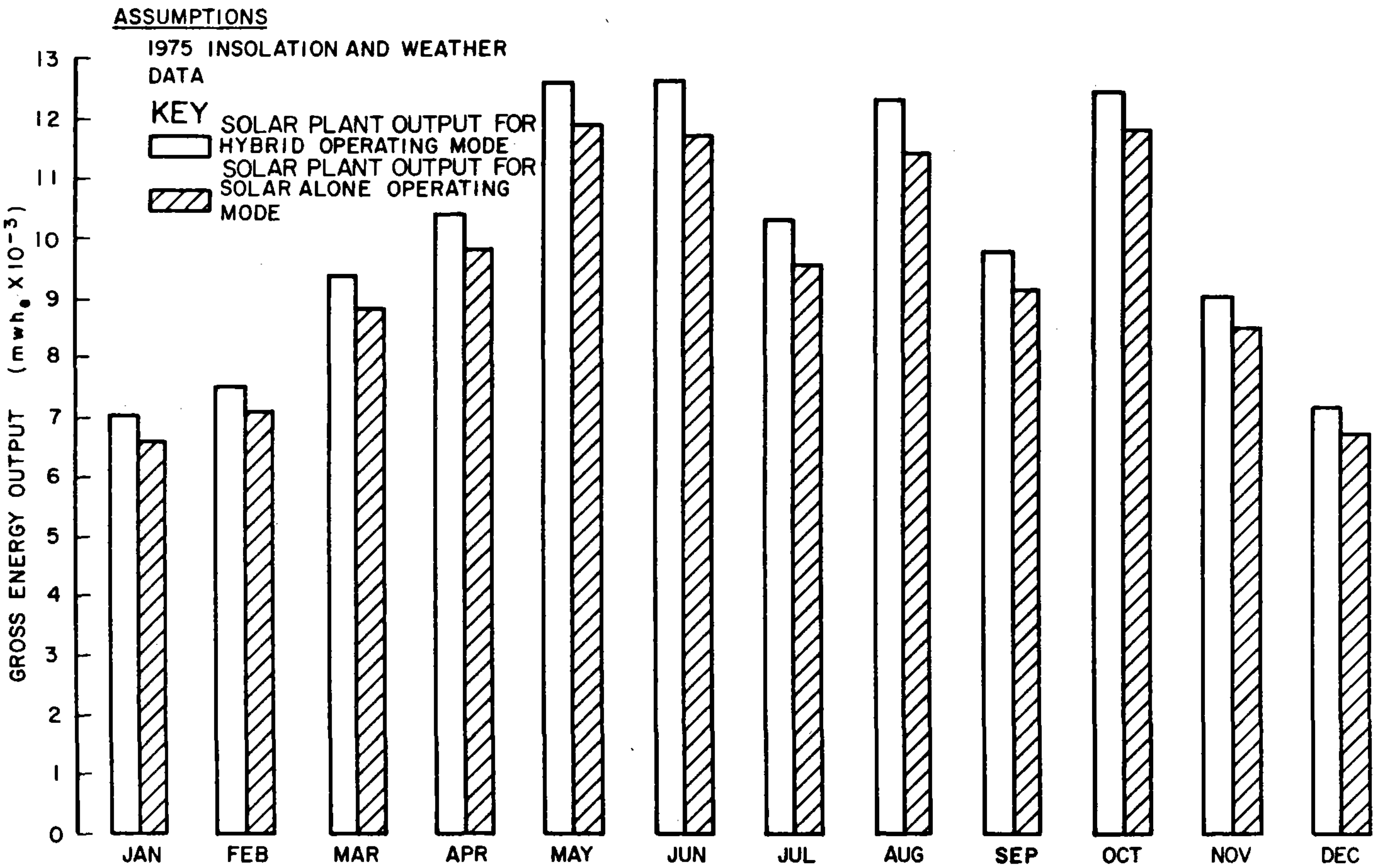


Figure 4.4-7. Monthly Gross Energy Output

expected, the solar portion of the plant consistently produces more electrical energy when operating in the hybrid mode. This is due to the higher EPGS efficiency as discussed in the previous Section 4.4.2.5.

The energy cascade for the repowered system annual performance is illustrated in Figure 4.4-8. The capacity factor based on the solar plant gross output of 60 MWe is 23.0% for the case shown.

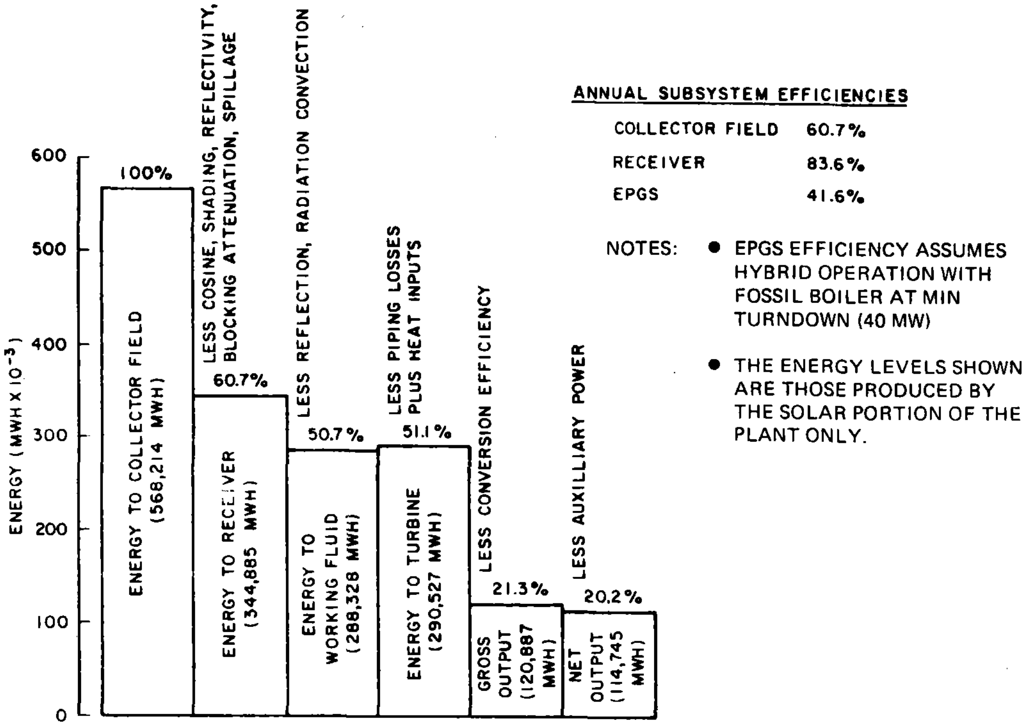
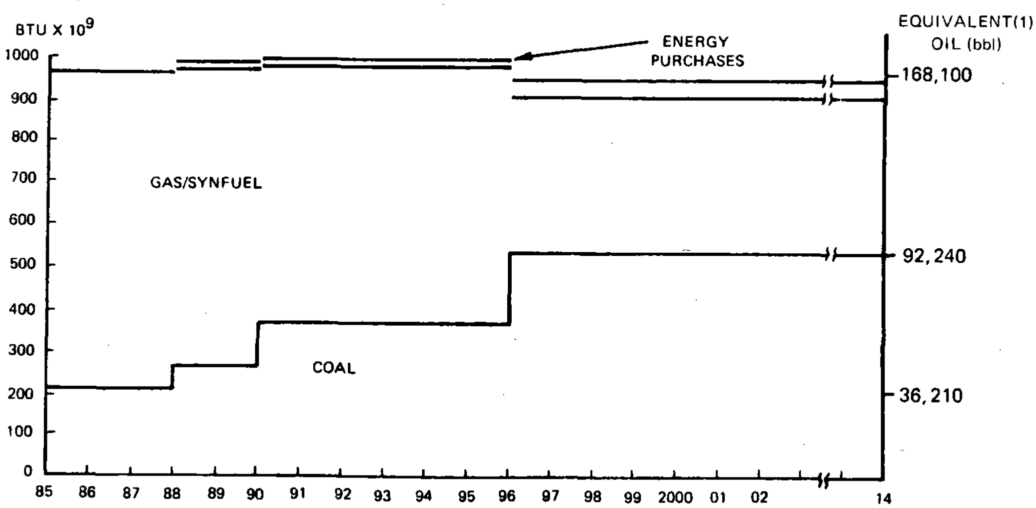


Figure 4.4-8. Energy Cascade-Annual Summary

4.4.3 FUEL DISPLACEMENT ANALYSIS

Figure 4.4-9 shows the Southwestern Public Service Company fuel displaced by solar operation of Plant X, Unit 3, in British thermal units and equivalent barrels of oil. The circled values are the values computed by use of a detailed utility economic operation simulation. This computer program is described in Appendix D. The economic data and other program details are discussed in Section 6.



(1) #2 oil at 5.8x10^{6}Btu/Bbl

Figure 4.4-9 Annual Solar Plant Fuel Displacement

The physical units of fuel displaced are presented in Table 4.4-10.

Table 4.4-10
SOUTHWESTERN PUBLIC SERVICE COMPANY
Sources of Electric Energy Production (1)(2)

Year	Without Solar Repowering Gas/Synfuel MCF	Coal T	Purchases MWh	With Solar Repowering Gas/Synfuel MCF	Coal T	Purchases MWh	Difference Gas/Synfuel MCF	Coal T	Purchases MWh
1985	38,816,199	8,084,483	366	38,051,185	8,072,403	303	765,014	12,080	63
1988	36,948,476	10,092,238	2,003	36,227,198	10,077,252	1,769	721,278	14,986	234
1990	28,670,629	11,900,850	7,677	28,054,768	11,879,652	7,012	615,861	21,198	665
1996 (Without Plant X Unit 3) boiler)	18,226,635	16,634,403	44,031	17,841,159	16,603,488	41,205	385,476	30,915	2,826
1996 (With Plant X Unit 3 boiler)	18,326,360	16,633,395	31,190	17,930,713	16,602,650	29,030	395,647	29,745	2,160

(1) Less steam purchased at Celanese plant, utilized in 30MW unit, and solar energy production.

(2) Gas/Synfuel = $1.\text{x}10^6$Btu/MCF
Coal = $17.4\text{x}10^6$Btu/T
Purchases = $14.\text{x}10^6$Btu/MWh

21.5% of displaced energy (input) is coal-fired in the year 1985; 78.4% in gas and emergency purchases are negligible. In the year 1996, the fuel displacement has changed to the following: 55.7% coal, 41.1% gas/synfuel, 3.2% emergency energy purchases. These results are predicated on a timely construction of coal-fired plants to satisfy a load growth occurring as forecast. These details are further discussed in Section 6.

4.4.4 UTILITY DYNAMIC PERFORMANCE WITH SOLAR REPOWERING

4.4.4.1 Introduction

Solar generating plants with no storage (beyond that necessary to override short energy source reduction transients) or with turbine valves fully open do impose upon the generating system a requirement upon loss of the energy source to pick up the generation ordinarily provided by solar plants when the energy source is available. This should pose no problem as long as these sources represent a small percentage of total generation and sufficient ability to change loading exists in operating reserve units. The U.S.A. interconnection, which includes all utilities except those comprising the Electric Reliability Council of Texas, is operated with the ability to withstand the sudden loss of large base-load nuclear units of approximately 1100 MW rating. Only if all the following events shown in Table 4.4-11 occur would it possibly be necessary to disconnect some electric load.

Table 4.4-11

UTILITY SYSTEM EMERGENCY EVENTS
WHICH COULD REQUIRE ELECTRIC LOAD DISCONNECTION

1. Loss of a major generating unit in a given area, <u>and</u>
2. Loss of all transmission lines into the area perhaps because of line overloading, <u>and</u>
3. Electric load in "island" greater than the available generation which can be increased before the electrical frequency drops too low.

The severity of such an emergency depends on the timing of the events and the magnitude of the difference between load and generation. Some emergencies would require the interruption of service even with the presence of storage capacity in solar and wind generating units.

Following is a discussion of the operation of interconnected systems to account for sudden losses of generation such as the sudden loss of steam from the solar heat exchanger and storage. Because economic operation of gas-fired generation implies such generation will decline in future years, system central center monitoring of solar output will be required.

4.4.4.2 <u>Load Characteristics and Unit Governing</u>

Control of frequency for the purpose of maintaining small frequency errors is obtained by the addition of a frequency feedback signal to valves located near a steam turbine which control the admission of steam to the turbine (see Figure 4.4-10. The device that provides the frequency control is called the speed governor. The gain or proportionality between frequency change and valve position that results in a change of turbine generator shaft mechanical power is called regulation and is generally designated as

$$R = \frac{\Delta \text{ Frequency}}{\Delta \text{ Power}}$$

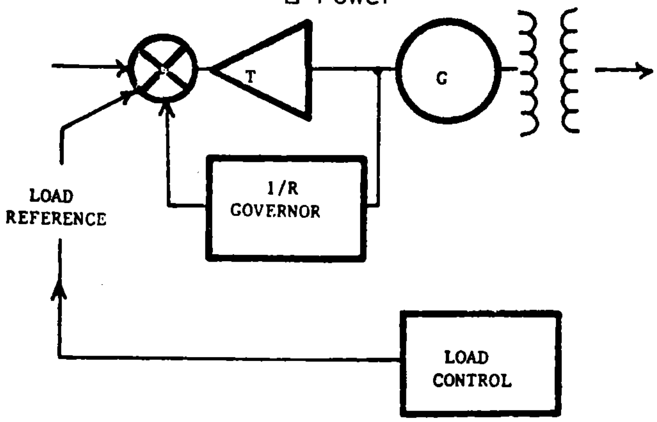


Figure 4.4-10 Schematic Turbine Speed Control Diagram

Most steam unit governors are set with 5% regulation, which means that a 1% change in frequency will cause all steam units to increase output by 20% of full output rating. In order to bring the frequency back to 60 Hz, an additional control is built into the turbine control system which allows the governor to reset the operating point or load reference to the desired level. Thus increased mechanical power can be obtained when frequency returns to 60 Hz. The order of changes is illustrated in Figure 4.4 -11. As generation in the U.S. interconnection is lost, the increased electrical load placed on the remaining generators causes the turbine-generator shaft speed to decrease (due to reaction torque imposed by the generator electromagnetic field). As the shaft speed decreases, the governors increase mechanical torque by changing control valve position according to the initial load setting and regulation. This is shown by movement from point 1 in Figure 4.4 -11 to point 3. The new setting of the governor operating point, event 4, causes shaft mechanical power to increase. This is shown in movement from point 3 to point 5. But since the U.S. interconnection electrical load has not changed since the loss of generation, the mechanical power now causes shaft speed to accelerate. Frequency will increase until mechanical torque equals reaction torque. This is shown as movement from point 5 to point 6. The proper final setting of the governor operating point is the point at 60 Hz where the desired amount of the initial generation loss is carried by this particular turbine-generator unit. All turbine-generators in the U.S.A. interconnection see the same frequency excursions, be they located in Kansas or New York.

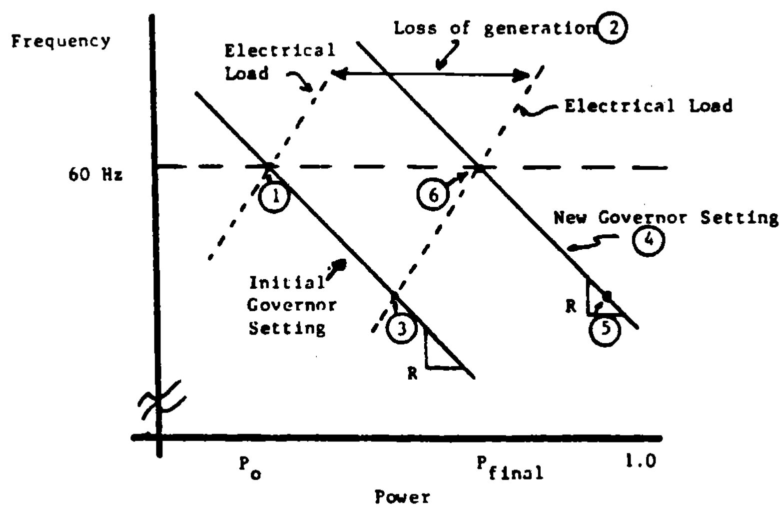


Figure 4.4 -11 Frequency versus Unit Output.

Only the turbine-generator governors of the area affected by the loss of generation will perform the settings changes illustrated as event 4. The remaining turbine-generators will return to their initial output preceding the loss of generation. The time allowed to perform the load setting change and obtain the required response is 10 minutes, since some transmission lines may be overloaded and begin to anneal if the proper flow of power is not restored within this time.*

Figure 4.4-12 is an example of a frequency trace on the U.S. interconnection following the loss of a generating unit. The drop in frequency to 59.91 Hz occurs due to the time lag for steam flow through the steam turbines and the water starting time in hydro turbines. The arrest of frequency drop at 59.96 Hz occurs from governor action of all U.S.A. interconnection units. The change in frequency from 59.96 Hz to 60.00 Hz is the result of changing the load reference on the remaining steam units in the area in which the loss of generation occurred.

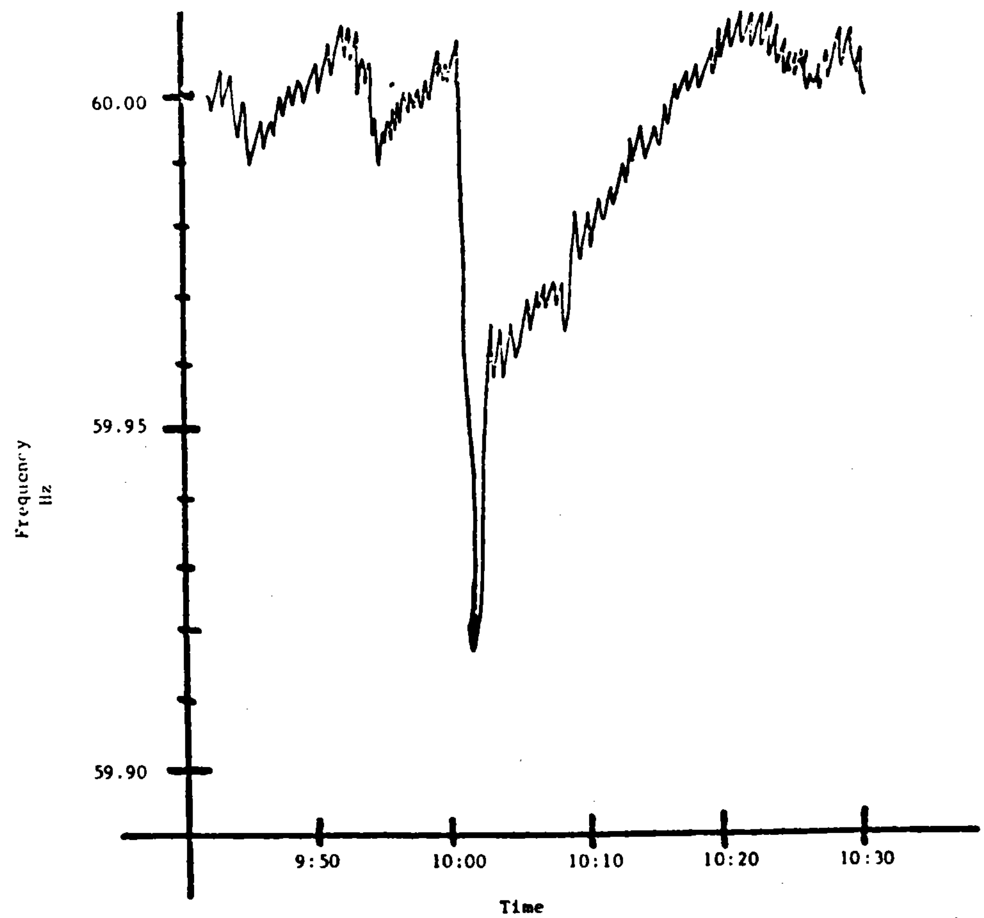


Figure 4.4 - 12 Trace of Frequency on U.S. Interconnection Following Loss of a Large Unit

* NAPSIC (North American Power Systems Interconnection Committee) Minimum Performance Criteria, June 1, 1972, Supplement to the Operating Manual, p.9

Presently, the U.S.A. interconnection, less the Western Systems Coordination Council and neglecting the effect of transmission ties with Canada, represents a generating system of approximately 350,000 MW. The following equation describes frequency deviation:

$$\Delta F = \frac{\Delta L}{(1/R + D)}$$

where ΔL = additional electrical load, equivalent to loss of generation

$1/R$ = inverse of speed regulation = 20 p.u.

D = load versus frequency slope = 1.0 p.u.

Thus the sudden loss of 60 MW of solar generation, with all transmission in place, would result in a frequency drop of $\frac{60/350000}{21} \times 60$ or 0.0005 Hz. By comparison, the deadband allowance for governors on large steam turbines is 0.036 Hz.* The loss of this amount of solar generation would not be noticed by frequency metering. Only local transmission metering would detect such a small change in power flow.

4.4.4.3 Implication for Solar Power Plant Design

It is not absolutely necessary to maintain constant output from solar generating sources. With minor design considerations to override cloud-passing transients, the lack of solar insolation and corresponding loss of power from solar plants with minimal storage can be accommodated by the U.S. interconnection units on governor control. As tie-line flows change, other generation can be increased to bring frequency back to 60.00 Hz. Utility operating practice is to have backup generation with turbine-generators spinning to provide for such transients in transmission line flows.

Since the Southwestern Public Service Company's interconnection with the remainder of the Southwest Power Pool is in a relatively small area and since the Plant X, Unit 3, gas-fired boiler is not required for a significant period for economic electric energy production, system control center monitoring and responsiveness to solar output at Plant X, Unit 3, will be needed to avoid potential system frequency distrubances should interconnection tie-lines be lost.

*"Recommended Specification for Speed-Governing of Steam Turbines Intended to Drive Electric Generators Rated 500 kW and Larger,"IEEE Standards No. 122.

4.5 PROJECT CAPITAL COST

The total project capital cost is estimated at $121,662,314. The project capital cost is broken down into owner's cost and construction costs. Each of these elements is discussed in subsequent sections and full cost data is presented in Appendix A.

The ability and desire of Southwestern Public Service to engineer and to manage its own construction results in some differences in the cost estimate from those with a normal utility construction job in which an Architect-Engineer (A-E) plays a significant role. There is no A-E fee included; the construction management home office and overhead charges are two-tiered (SPS and general contractor) rather than three-tiered (owner, A-E, and general contractor). This arrangement significantly reduces overhead costs.

4.5.1 OWNER'S COST

The owner's costs include the site owner's expenses related to the construction project. Under the program RFP (DE-RP03-79SF10506) specification, the Owner's Costs included the elements shown in Table 4.5-1.

Table 4.5-1

RFP SPECIFICATION OWNER'S COST ELEMENTS	
A.	Land
B.	Consulting services for site studies
C.	Environmental studies
D.	Public relations activities
E.	Licensing and permits
F.	Public agency relations
G.	Site owner's management, engineering and other home office services
H.	Plant consumable supplies and startup costs
I.	Taxes and insurance during construction
J.	Sales tax
K.	Interest during construction

The elements of Owner's Costs applicable to the SPS project are listed in Table 4.5-2 along with their values. The differences in owner costs result primarily because DOE will be funding a significant portion of the effort.

Table 4.5-2

SPS SOLAR REPOWERING OWNER'S COST

Element	Cost
Consulting services for site studies	$ 10,000
Public relations activities	20,000
Public agency relations	10,000
Taxes and insurance during construction	250,000
Sales tax	198,884
Environmental assessment	500,000
	$988,884

With SPS acting as the construction manager and engineer, the management, engineering, startup costs, etc. (items G and H of Table 4.5-1) provided by SPS will be the primary contributions in this area for the whole project, i.e., not just monitoring functions. Thus, these elements are considered part of the construction costs. (Section 4.5.2).

Since DOE will be funding a significant portion of the project, "the interest during construction" item in the owner's cost is uncertain. Its actual value will depend on the amount of DOE funding and when the utility contribution to the cost will be incurred. Because of this uncertainty and because its impact on the overall project cost is envisioned as relatively minor because of the DOE cost sharing, the interest during construction was assumed to be 0.

No cost for land is included because it is already owned by SPS. Table 4.5-2 summarizes the costs assumed for the owner's cost directly applicable to this project.

4.5.2 CONSTRUCTION COST ESTIMATE

The construction cost estimate is broken down into three elements: direct field costs, major equipment procurements, and indirect costs. A discussion of each of these elements in the following sections is followed by a top level summary of these costs for the project. Details of the costs are included in the Appendix A, System Requirements Specification.

4.5.2.1 Direct Field Costs

- Construction labor
- Subcontracts
- Field materials

The construction labor is costed at scale. It includes factors for the facility location, high-level work where applicable (e.g.,tower) and direct supervision for the craft labor. The productivity is based on Amarillo, Texas.

The original labor rates used in calculating the plant labor costs were late 1979 rates. A 10% adder (termed Scale Adder on detailed sheets) was subsequently added to bring the labor rates up to mid-1980 levels. This adjustment was based on recent local union adjustments.

The subcontracts cover general tasks that general contractor personnel would probably not handle. Insulation and trace heating are the major items in this category.

Field materials include all construction and plant materials with the exception of major components. The major components are discussed in Section 4.5.2.2.

4.5.2.2 Major Equipment Procurements

These items include the costs of the major equipment of the construction effort. The costs are the delivered cost of the component with the exception of the collector field, which is an installed, checked out cost. The cost of installation of the other major components is included in the direct field costs.

These major equipment procurements were broken out from other construction materials to remove their cost (other than installation) from consideration in calculating indirect costs such as contractor profit. These components will be purchased and controlled by Southwestern Public Service. Costs for the SPS efforts involving their activities with respect to these components is included in the engineering and construction management elements of the indirect costs.

Table 4.5-3 lists the major equipment procurements and their costs.

4.5.2.3 Indirect Costs

The project indirect costs include:

- Temporary construction facilities
- Construction services, supplies and expense
- Field staff, subsistence and expense
- Craft benefits, payroll burdens and insurances
- Equipment rental
- Contractor profit
- Engineering
- Construction management
- Contingency

Table 4.5-3

MAJOR EQUIPMENT PROCUREMENTS

Component	Cost (1980$ - millions)
Collector Subsystem	$54.2
Receiver	5.1
Tower Pump	1.1
Steam Generator Pump	1.1
Evaporator	5.7
Superheater	3.0
Reheater	3.2
Sodium Dump Tank	0.1
Steam Generator Leak Detectors	0.3
Reaction Products Tank	0.1
Steam Drum	0.2
Recirculation Pump	0.08
Air Cooled HX	0.5
Sodium	0.3
TOTAL	$75.1

4.5.2.3.1 Temporary Construction Facilities (4% of Field Direct Costs) - This account includes such items as field office facilities, material layout areas, pre-fab work spaces, etc.

4.5.2.3.2 Construction Services, Supplies and Expense (4% of Field Direct Costs + Craft Benefits,etc.+ Equipment Rental) - This account includes the cost of required field electricity, water, fuel, paper supplies, etc.

4.5.2.3.3 Field Staff, Subsistence and Expense (7% of Field Direct Costs + Craft Benefits,etc.+ Equipment Rental) - This item includes top level contractor staff costs together with subsistence pay for field staff and labor required for work in the relatively remote work area.

4.5.2.3.4 Craft Benefits, Payroll Burdens and Insurance (43% of Field Direct Labor) - The field direct labor costs were computed at scale only. The adders for payroll taxes, insurance, vacations, etc. are included in this account.

4.5.2.3.5 Equipmental Rental (Varied, as discussed below) - The cost of renting equipment to support the construction labor efforts (e.g., cranes, earthmovers, etc.) is included in this account. For equipment-intensive efforts such as site grading, this cost was computed directly on a per unit of work basis. For other efforts such as pipe laying, building erection, etc., the cost was computed at 17% of the direct field labor cost.

4.5.2.3.6 Contractor Profit (5% of Total Field Direct and Indirect Costs) - This is the fee to the project general contractor.

4.5.2.3.7 Engineering (Varied as discussed below) - This account covers the engineering fees for Southwestern Public Service and their selected subcontractors for system related engineering costs including system design, drawings, specification preparation, quality control, vendor following, procurement plant startup, etc. This account does not include the cost of major component design engineering which is included in the cost of major component procurements.

For project elements other than the collector field, the engineering costs were estimated at 10% of the total field costs. For the collector field layout, specification preparation and procurement, the engineering cost was a lump sum estimate of $1.6 million.

4.5.2.3.8 Construction Management (Varied as discussed below) - Construction management costs are those of Southwestern Public Service, which will act as the project construction manager.

Once again the collector field is treated separately from the balance of the plant. The collector field costs assume that the collector field vendor will be doing the detailed construction management with SPS acting primarily as a monitor of field installation and checkout activities. This cost was estimated as a lump sum, $900,000.

The construction management cost for the balance of plant was calculated at 5% of total field cost.

4.5.2.3.9 Contingency (Varied as discussed below) - The contingency for all elements of the project with the exception of the collector field was calculated at 15% of total cost. This is based on a Southwestern Public Service estimate based on the complexity of the project and the relatively new status of some of the plant components.

No contingency was included in the collector subsystem costs since the estimate was based on the DOE projected cost for heliostats.

The project indirect costs are summarized in Table 4.5-4. Details of indirect costs by subsystem are provided in the Appendix A, System Requirements Specification.

Table 4.5-4

CONSTRUCTION COST SUMMARY
(1980$ - Thousands)

Account	Description	Direct Field Cost			Indirect Field Cost + Contractor Profit	Engineering	Major Equipment Procurement	Construction Management	Contingency	Total
		Labor	Subcontracts	Material						
5100	Site Improvements	690	--	832	1631	315	--	158	544	4171
5200	Site Facilities	351	159	1548	663	272	--	136	470	3600
5300	Collector Subsystem	--	--	--	--	1600	54197	900	0	56697
5400	Receiver Subsystem (Includes Steam Generator Subsystem)	1764	2118	5198	3116	1220	20057	610	5112	39195
5500	Control Subsystem	270	275	2096	744	339	--	169	584	4477
5600	Fossil Energy Subsystem	83	--	871	256	121	--	61	209	1601
5700	Energy Storage Subsystem	164	486	495	352	150	--	75	258	1979
5800	EPGS	171	84	767	331	135	510	68	310	2376
5900	Miscellaneous Items	29	153	126	85	39	300	20	113	865
	TOTAL	3523	3275	11933	7178	4191	75065	2195	7559	114959

4.5.2.4 Project Construction Cost Summary

Table 4.5-4 presents a top level construction cost summary for the project. The account numbers refer to the detailed cost breakdowns included in the Appendix A, System Requirement Specification.

4.6 OPERATING AND MAINTENANCE COST (O&M)

This section presents the O&M cost estimate for the Plant X, Unit 3 repowering.

The operations and maintenance cost are divided into three categories (Table 4.6-1) as follows:

- Operations (OM100)
- Maintenance Materials (OM200)
- Maintenance Labor (OM200)

plant.

Table 4.6-1

OPERATING AND MAINTENANCE COST ACCOUNT STRUCTURE

OM100 Operations
- OM110 Operating Personnel
- OM120 Operating Consumables

OM200 Maintenance Materials
- OM210 Spare and Repair Materials
  - OM211 Collector Equipment
  - OM212 Balance of Plant Equipment

OM300 Labor

Table 4.6-2 summarizes O&M cost estimates for the 30 year life of the plant

Table 4.6-2
OPERATING & MAINTENANCE COST SUMMARY
(1980$ X 10^{-3})

	OM100		OM200	OM300	Total ($K)
Year	OM110	OM120			
1	336	0	386	170	892
2-30	215	30	262	143	650

Operating cost (OM100) is broken down into payroll costs (OM110) and consumables (OM120). The present and future operating and staff personnel at Plant X are listed in Table 4.6-3. During the first year of operation and shake down, a solar operating and staff crew of 13 is anticipated. In subsequent years this staff will be reduced to 8. The costs for these personnel are summarized in Table 4.6-4.

Table 4.6-3
PERSONNEL BREAKDOWN

Present Staff	1st Year Solar Staff	2nd-30th Year Solar Staff
Plant Manager (1)		
Assistant Plant Manager (1)		
Plant Engineer (1)	Solar Engineer (1)	Solar Engineer (1)
Clerks (2)		
Safety (1)		
Technical Forman (1)		
Chemist (2)		
Operating Labor-3 Shifts/Day (5 Crews)	Operating Labor-3 Shifts/Day (4 Crews)	Operating Labor-3 Shifts/Day (4 Crews)
Control Room Operators A (10)	Control Room Operators A (4)	Control Room Operator A (4)
Control Room Operators B (5)	Plant Operators A (8)	Plant Operators A (3)
Plant Operators A (10)		
Maintenance Labor	Maintenance Labor	Maintenance Labor
Supervisor (1)		
Mechanical	Mechanical	Mechanical
Foremen (2)	Journeymen (3)	Journeymen (2)
Journeymen (7)		
Apprentice (4)		
Janitors (3)		
Electrical	Electrical	Electrical
Foreman (1)	Computer & Control Technician (3)	Computer & Control Technician(3)
Journeymen (3)		
Instrument		
Foreman (1)		
Journeymen (3)		

Table 4.6-4
COST DETAIL, ACCOUNT OM100

OM110 Operating Personnel	Cost 1st Year($)	Annual Cost 2nd-30th Year($)
Solar Engineer	25	25
Control Room Operator A	80	80
Plant Operator A	144	54
Fringes And Borden (35%)	87	56
OM110 Total	336	215
OM120 Operating Consumables		
General Supplies (Office and Shop)	0	31

The operating consumables (OM120) for the first year of operation have been set at 0 since this material has been capitalized as part of the startup cost. For subsequent years these costs have been estimated at 14% of payroll cost as shown in Table 4.6-4.

The maintenance materials cost estimate (OM200) is shown in Table 4.6-5. The collector subsystem element of this cost (OM212) was based on data developed in the Prototype Heliostat Program. The failure rate was used in conjunction with the projected heliostat cost of $\$230/M^2$ to arrive at the \$27.36/heliostat/year maintenance materials cost.

Table 4.6-5
COST DETAIL, ACCOUNT OM200

		Annual Cost ($)
OM210 Spare And Repair Materials		
OM211 Collector Equipment		
1st Year ⋮ 30th Year	\$27.36/Heliostat/Year	135,000
OM212 Balance of Plant		
1st Year		250,000
2nd Year ⋮ 30th Year		126,500

The balance of plant maintenance material costs were estimated at 1% of the plant material costs (less piping and structures) for the first year. The level then drops to 0.5% for subsequent years. The high first year cost is to account for "infant mortality" and system fine tuning.

The maintenance labor estimate (OM300) is based on the projections shown in Table 4.6-3. As with the operating personnel, the maintenance staff after first year operation will be reduced. Table 4.6-6 summarizes the costs for the maintenance crew. No distinction is made between scheduled and corrective maintenance since the same crews will be used for both.

TABLE 4.6-6

COST DETAIL, ACCOUNT OM300

Maintenance Labor		Annual Cost (000$)
Mechanics, Journeyman		
1st Year	3 Persons	60
2nd Year ⋮ 30th Year	2 Persons	40
Computer & Control Technicians		
1st Year ⋮ 30th Year	3 Persons	66
Fringes And Burden (35%)		
1st Year		44
2nd ⋮ 30th Year		37

4.7 SYSTEM SAFETY CONSIDERATIONS

The safety aspects of the SPS solar repowering plant are almost identical to those of the stand-alone sodium cooled central receiver power plant designed by General Electric Company during the conceptual design of Advanced Central Receiver Power Systems Phase I. The safety analysis performed as part of that conceptual design study was thoroughly documented[1] and provides the basis for the following discussion.

4.7.1 ASSESSMENT

Based upon years of sodium facility operating experience, the analysis performed for the stand alone plant, the failure analysis of the sodium test re-

1. "Conceptual Design of Advanced Central Receiver Power Systems Final Technical Report, " General Electric Company, Report SAN/20500-1, June 29, 1979, Volume III, Section 6.5.

ceiver currently under fabrication, and a survey of the repowering plant unique characteristics, it is the opinion of General Electric and Southwestern Public Service Company that the solar repowering project does not pose significant additional risk to the public or equipment. A detailed failure mode and effect analysis would be performed prior to actual plant construction in order to more precisely quantify the safety related events associated with the plant; however, a general evaluation of the hazards is provided in the following subsection.

4.7.2 HAZARD EVALUATION

There are eight repowering plant hazard classifications that could give rise to equipment damage or to potential injuries of Table 4.7.1:

- High Pressure Steam
- Rotating Machinery
- Conventional Fires
- Electrical Hazards
- Inert Gas
- Solar Radiation
- High Temperature Exposed Surfaces
- Sodium

The hazards associated with steam, rotating machinery, conventional fires, and electric equipment are well understood and currently already exist at Plant X. Appropriate design features, procedures, and personnel training are in place to accomodate the small incremental increase in these hazards due to the addition of the solar plant.

Table 4.7.1
POTENTIAL INJURIES TO PERSONNEL/PUBLIC

Eye Damage (ED)
Lung Damage (LD)
Thermal Burns (TB)
Chemical Burns (CB)
Broken Bones and Contusions (BBC)
Electrocution (EL)
Electrical Burns (EB)
Asphyxiation (AS)

The Plant X solar plant would present some new hazards in the form of concentrated solar radiation, high temperature exposed surfaces, sodium, and inert gas. The various events, potential results, types of injuries, and prevention methods are summarized in Table 4.7-2.

A safety concern somewhat unfamiliar to the general public is the use of liquid sodium which, if exposed to air or water, can present hazards. The 25 years of experience with large quantities of sodium in industrial and governmental applications is proof that liquid sodium can be handled and utilized safely. Recovery from leaks has been found not to be a major problem.

The key factors leading to good safety experience are proper plant design and rigorous adherence to established procedures. The plant concept is designed to ASME Codes and, where necessary, a degree of redundancy is provided to assure high reliability. In addition, equipment is included to detect leaks should they occur, and equipment and procedures have been included to handle leaks and spills, thereby minimizing their impact on other equipment and the environment.

Sodium in its solid state is a silvery white metal that can be cut easily with a knife. Sodium oxidized in air turns to a dull gray. Pure sodium melts at ~208°F (96°C), and when liquid, combines or reacts quite readily and violently with water. Liquid sodium exposed to air at ~260°F (126°C) or above will often ignite.

Burning sodium is characterized by a very small or nonexistent flame, depending on the oxygen content of surrounding materials. Elimination or suppression of free oxygen will extinguish or drastically reduce the combustion process. A sodium fire is likely to be less destructive than a gasoline or fuel oil fire. Sodium has both a lower heat of combustion per unit volume and a much lower vapor pressure than gasoline or fuel oil. Because of these differences a burning pool of gasoline releases heat 15 times faster than the same size pool of sodium. Similarly, a burning spray of gasoline releases much more heat than an equal size sodium spray.

A second hazard due to sodium is caused by the heat and hydrogen given off by the sodium/water reaction which could explode. The primary methods for preventing injury or equipment damage are:

- Application of sound design principles
- Rigid Quality Control during manufacture
- Personnel training in operating limits and procedures
- Emergency auxilliary systems to mitigate effects of a failure

Table 4.7-2

SOLAR REPOWERING PLANT HAZARD SUMMARY

Hazard	Events	Potential Results	Potential Injuries	Prevention Techniques
Solar Radiation	Heliostat Control Error During Slewing	Two or More Heliostats Focused on Ground Based Observer	ED	Restrict Access to Tower and Field During Operation Normal Blinking Response is Probably Adequate Protection
	Personnel Enter Absorber During Operation	Exposure to Direct Beam, Spillage Flux, or Reflected Flux	ED TB	Restrict Access to Absorber During Operation
	Airplane Flies Close To Absorber	Exposure to Spillage Flux or Reflected Flux	ED	Create Airplane Exclusion Zone Around Plant
	Gross Aiming Error in Collector	Structural Damage to Absorber and Tower Release of Sodium	ED LD TB CB BBC	Ablative Thermal Shields Around Top of Tower Sensing of Overheating and Automatic Field Shutdown, Emergency Reservoir
High Temperature Receiver Surface Hazard	Personnel Enter Receiver During Operation	Exposure to Receiver Thermal Radiation or Convection Currents	TB	Restrict Access to Tower
Sodium	Rupture in Absorber Piping, Valves, or Pumps	High Temperature Sodium Spill, Fire, Caustic Fumes, Explosion (if water present)	ED LD TB CB BBC	ASME Section VIII and ANSI B31.1 Codes Operating Limits and Procedures Instrumentation and Inspection for Advanced Warning Drip Pans and Drains with Inert Gas Purge Chemical Fire Extinguisher Sodium Dump Tank Non-Reactive Insulation Material Sodium Purity Control (corrosion)
	Rupture in Storage Tanks	Same as Above	ED LD TB CB BBC	Double Walled Tank Design Sodium Transfer to Other Tanks
	Rupture of Tube in Steam Generator	Sodium/Water Reaction Generating Hydrogen, High Pressure and Temperature, Caustic Liquids, Potential Explosion	ED TB CB BBC	ASME Section VIII Code Plus Analysis and Quality Assurance Burst Discs and Reaction Products Dump System Operating Limits and Procedures Instrumentation for Advanced Warning Steam and Water Purity Control (corrosion)
	Spills of Sodium During Transfer or Maintenance	Low Temperature Sodium Spill (no fire unless contacts water) Caustic Contamination, Liquid Caustic Contamination, Airborne	CB LD ED	Personnel Training in Safe Handling and Cleanup Chemical Fire Extinguisher Protective Clothing and Breathing Apparatus for Personnel
Inert Gas	Cover Gas Leak	Argon Fills Room or Low Lying Work Area, Driving Out Air	AS	Restrict Access to Areas of Potential Danger Supply All Maintenance and Inspection Personnel with Self-Contained Breathing Apparatus

The design of the sodium systems will be consistent with the ASME pressure vessel codes and the ANSI power piping codes. These codes have a proven history of success in preventing accidents in high pressure steam systems. In addition to these code requirements, there will be thermal fatigue analyses performed on the most highly vulnerable sodium components, i.e., the absorber panels and the steam generators. Wherever practicable, piping and storage vessel joints would be designed to be butt-welded; no flanged, socket-welded, or threaded joints would be used because these provide crevices where corrosion and cracking can occur. Full penetration welds with consumable inserts rather than backing rings are planned. Only materials with proven sodium compatibility would be used, such as 2-1/4 Cr - 1 Mo, carbon steel, and Incoloy 800. Sodium purity will be maintained at a high level to prevent corrosion. Smoke detectors will be installed on sodium equipment to warn of leaks while they are small. Similarly, hydrogen detectors in the steam generators would warn of low-level sodium/water leaks.

A condition that could result from a receiver sodium leak is the burning of sodium in air and the resultant release of combustion product to the atmosphere. Recent experimental studies have been conducted by Rockwell Energy Systems Group under DOE contract at the Air Research Laboratory in Idaho. Releases of 22 kg to 75 kg (50-160 lbs) of sodium were made.

A total of seven atmosphere sodium release tests were conducted with the first five tests at release elevations ranging from ground level to 30 meters under unstable meteorological conditions. The last two tests were conducted under stable conditions where the natural humidity content was high (47 to 96%).

In general, it was found that sodium releases result in rapid local fallout under all conditions. This rapid fallout is attributed to rapid agglomeration of particles in the plume near the release point. Analysis of particles collected closer than 200 meters downwind were predominantly sodium oxide with traces of sodium carbonate (without the presence of sodium hydroxide). The conversion from the hydroxide or hydroxide-hydrate is suspected to be rapid. Airborne concentrations measured beyond 200 meters were near or below the NIOSH inhalation limit for sodium hydroxide.

As indicated above, these experiments used very large quantities of sodium for the releases, yet the ground level damage was not significant, and would not have extended beyond the collector field area.

4.8 ENVIRONMENTAL IMPACT ESTIMATE

Investigation into the necessary permits and licenses reflect a minimal impact of the repowering of Plant X Unit 3 on the environment. A review of state regulations indicates no permits or licenses will be required to retrofit Plant X, since no additional sources of water or air contamination are added. The additional load on the Plant X waste water disposal system posed by the solar drum blowdown is easily handled and represents almost no increase into the existing Plant X waste water disposal system.

The major adverse impact of the repowering will be on terrestial resources caused by the disruption of some 212 acres of uninhabited prairie. This could cause wind and water erosion and jeopardize the habitats of plant and animal life native to the area. The conceptual design has attempted to minimize these effects by proper surface preparation and coverage. A technique used with great success by SPS in reducing the permeability of soil is the mixing of fly ash into the top six inches. Fly ash has been used in this application to seal waste water ponds and stabilize the soil bed at a nearby construction site. As a measure to reduce wind erosion, the surface will be covered with a layer of asphalt sealant. Drainage will be incorporated into the collector field to handle runoff during occasionally heavy rains.

The collector field would be of minimal impact to the total vegetation and wildlife population of this semi-arid region. Studies (beyond the scope of this conceptual design) will be conducted to fully assess the impact on the unique terrestrial resources of wildlife species. However, surveys conducted in connection with other projects in the area indicate the absence of endangered species, both plant and animal. The perimeter fence will protect large range animals and other mammals from the dangers inherent in the collector field. The specific impact on birds and flying insects will warrant additional study. They might be attracted to the bright surfaces and be harmed by the concentrated solar rays. This problem is common to all solar concentrating systems.

A cursory examination of the potential visual pollution caused by the collector field and the tall receiver tower indicates these structures will not degrade the existing aesthetic qualities of the scenery. This agricultural area has accepted the existence of other tall structures such as radio towers, grain elevators, and agro-industrial facilities.

Another environmental problem is the potential for sodium leaks and ensuing fires. This hazard is minimized by use of doublewall storage vessels and drip containment systems. Any catastrophic leaks would be contained to the immediate area by the use of revetments, berms and sumps. As discussed in Section 4.7, reacting products from a leak from towers components would be confined inside the plant area. A plan for recovery and cleanup of any leakage will be formulated. Adequate sodium handling equipment will be required as will special training for plant personnel.

The positive environmental aspects are substantial when considering the boost to the local economy. Local commerce in the surrounding communities will benefit from the influx of construction personnel and families required to complete the project. Additionally, a large amount of small equipment, tools, and materials will be purchased from area vendors. These effects are hard to quantify but should be in the magnitude of ten million dollars. Local services such as shipping, concrete, and lumber will benefit directly. Another positive benefit is the added revenue brought into the local community from tourists and other visitors to the site. This activity would be in addition to present industrial construction activities in the area; therefore, the additional influx of construction workers and visitors will not have an adverse sociological and economic impact on the surrounding communities.

The second beneficial economic impact to the area will be an increase in the amount of available natural gas. The solar plant will reduce the consumption of almost 1 billion cubic feet of natural gas that could be made available for other purposes. An excellent example of this benefit is meeting the annual fuel requirement of 800 irrigation wells (30 hp) or 8000 gas-fueled homes with this 1 billion cubic feet of gas.

The successful operation of the repowering concept could have a very long term beneficial effect on the environment and quality of life in the entire Sunbelt. If solar repowering proves economical, a large number of fossil units could be repowered; this would reduce the total emmissions caused by fossil fuels.

Southwestern explained the repowering concept and possible construction implications in community briefings held at Plant X. Preliminary indications are that social acceptance of the repowering project will not be a problem. The local communities are enthusiastic and supportive for the project as evident from letters received from citizens of that area. Several of those letters have been included in the appendix.

4.9 INSTITUTIONAL AND REGULATORY ISSUES

Examination of the institutional and regulatory requirements for installation of a repowering demonstration facility at Plant X, Unit 3, is made keeping in mind that the existing fossil facility meets all the current regulatory requirements. In other words, the institutional problems and barriers that are raised for a fossil-fired facility have been dealt with. The only institutional issue still pending at this time is the question of continued use of natural gas for fuel.

In this section, existing environmental standards for water resources, waste water, air emissions and ambient air quality will be discussed. Additional items will be identified to reflect the institutional and regulatory needs associated with the solar repowering.

4.9.1 ENVIRONMENTAL

The necessary permits for acquiring water rights for existing groundwater in the Plant X area have been obtained. Southwestern Public Service Company owns approximately 43,000 acres of water rights which will adequately supply water for the entire Plant X facility and a new coal-fired facility, Tolk Station (now being built eight miles west of Plant X), for the more than 40-year expected life of these plants. No additional requirement for water resources due to the addition of a solar steam source is anticipated.

The Plant X facility has a water disposal permit from the Texas Department of Water Resources, Waste Water Control Order No. 01842. The wastewater permit is a zero discharge type and does not require U.S. Environmental Protection Agency NPDES approval.

Groundwater taken to the power plant is concentrated in a cooling cycle which evaporates water to the atmosphere. The evaporation process concentrates salts in the water and these concentrated salts are discharged from the cooling tower system. The cooling tower discharge and the low volume waste streams generated from other water treating processes at the plant are combined and transferred into a sealed pond. The water from the sealed pond is utilized for irrigation of salt tolerant crops on adjacent farm land. The addition of the solar facility is not expected to expand requirements for the wastewater permit.

The air quality adjacent to and around the site proposed for the solar repowering has no ambient air quality problems. The only existing ambient air difficulty arises from fugitive dust generated from natural sources. Because this fugitive dust occurs several times a year, the Plant X area is considered in noncompliance for the national ambient air particulate standards. However, this noncompliance status is not a result of either stationary or mobile sources. The operation of the repowered facility is not expected to increase ambient air concentrations. In fact, the operation of the solar steam source would reduce boiler emissions of flue gas and could result in a reduction of ambient air concentrations. These concentrations are not expected to be significant enough to measure.

The Unit 3 boiler is registered with the Texas Air Control Board as a source of boiler flue gas emissions. It has been tested for concentrations of emissions being discharged into the atmosphere. The natural gas-fired boiler presents no air quality problems and requires no emission control devices.

Other than the existing environmental regulations discussed above, there are no pending or anticipated environmental regulations that would potentially affect the permitting process of the repowering demonstration plant being proposed for Plant X, Unit 3. Nor are there any local construction or building codes that would affect the proposed construction and operation of the plant.

The only additional permit application that will be required is a permit from the Federal Aviation Administration for the central receiver tower. No problem is anticipated in securing this permit. The tower would be over 200 ft above ground level, and an aircraft warning light would be installed.

4.9.2 INSTITUTIONAL

The institutional issues that will result from the construction and operation of a solar repowered facility deal principally with the agencies that control utilities' operation. One of these controlling agencies is the State Utility Commission. (Southwestern Public Service Company operates in four states and therefore must deal with each state's public utility commission.) The State Utility Commission's primary charge is to represent the rate payer. Consequently, any capital that would be spent by the utility and placed in the rate base, thus affecting the rate charged for electricity, has to be justified by obtaining a Necessity and Convenience Certificate from the Public Utility Commission. There is difficulty justifying expenditures for facilities that are capital intensive and have technical uncertainties, as the solar repowering plant would. However, capital funds supplied by the Federal Government would not be placed in the rate base.

The Federal Government could establish certain financial incentives to encourage the utility to invest company funds to install solar powered generation facilities. However, the state utility commissions would have to clarify the effect of these incentives on their determination of allowable rate of return and establishment of the rate being charged for electricity. The utility would have to consult the Federal Energy Regulatory Commission on any issue that affected the marketing and selling of electricity across state lines or the wholesale rates charged to other utilities.

Another institutional factor that should be mentioned is compliance with the Fuel Use Act of 1978. Implementation of this particular set of statutes and regulations is being reviewed by the Energy Regulatory Administration, an agency within the Department of Energy. Southwestern Public Service Company is one of the few utilities that plans to apply for a system compliance option whereby the company would be permitted to use certain percentages of natural gas beyond the prescribed deadlines within the existing regulations.

Institutional issues that deal with local counties and cities present no problem at this time. Letters from local individuals and community governing bodies indicating an acceptance of the proposed repowering project at Plant X are included in the appendix of this report. Also, local tax issues that may be affected by any additional capital added to the area by Southwestern's construction activities have been examined. Southwestern has successfully dealt with local tax issues at its construction locations in the past, and does not anticipate any new tax problems to be associated with this project.

The final institutional issue that has been examined is the potential need for an environmental assessment which would examine any sensitive environmental issue that might result from adding the solar components to the existing gas-fired facility. This particular environmental assessment should more than likely be made a part of the programmatic statement that would be prepared by the agency proposing to use significant federal funding. Half of the environmental assessment would deal with generic issues that could be applied to any solar thermal facility located in the southwestern part of the United States. The other half of the report would deal with site specific issues. These include the following:

- System planning - the impact of the demonstration plant on system demand and stability
- Hydrology - availability of water and water rights
- Land use and availability
- Demography - population distribution

- Geology - survey of foundation support
- Ecology - impact on habitat, identification of endangered species to sensitive natural areas
- Transportation - aircraft safety, access roads
- Socio-economic - impact on local economy
- Archaeological - the impact of plant construction on important cultural resources

Southwestern's previous environmental assessment experience would be useful in appraising the solar demonstration plant site. The company does not anticipate any negative impact.

4.9.3 FINANCIAL INCENTIVES

Various financial incentives instituted by the Federal Government to encourage the user utility to select the solar-thermal alternative as a generation alternative have been examined. Such financial incentives directly or indirectly generate within the financial structure of the utility some internal or external cash flow which allows economic justification for the selection of the solar-thermal option as a generation alternative. Some of these incentives would give the solar-thermal alternative enough additional benefit to compete with coal, gas, oil or nuclear as a viable form of generation.

Federal Government incentives are justified because the selection of solar-thermal as a generating alternative would have national benefit in helping to achieve the nation's energy independence goal. The local benefits of such an alternative would be limited, and therefore extra burden should not be placed on the local rate payer or utility user of solar-thermal generation.

Some of these government financial incentives deal with tax credits in the form of investment tax credits, or tax relief for the investor's return on his solar invested capital. Another Federal financial incentive would permit accelerated depreciation and write-off of equipment over a shorter period. The Federal Government might also encourage the state utility commissions to permit the utility to earn a better rate of return on capital used for investment in solar components and equipment for electric generation.

SECTION 5
SUBSYSTEM CHARACTERISTICS

Section 5
SUBSYSTEM CHARACTERISTICS

This section provides details of the design, operating and performance characteristics of the various repowered plant subsystems and facilities.

5.1 SITE

The site includes those elements of the overall repowering effort necessary to prepare the Plant X site for the addition of the facilities necessary to integrate in the solar plant. These include:

- General site preparation
- Facility relocations

5.1.1 GENERAL SITE PREPARATIONS

Areas designated for buildings, roads, and outdoor equipment such as heliostats, power transformers, etc., other structures and structural or nonstructural fills will be stripped of brush and top soil and graded to provide a level surface suitable for construction of the solar repowering facility. Areas not affected by construction activity will be left in their natural state.

5.1.1.1 Heliostat Field

The initial site preparation activity will consist of clearing and grubbing the sage brush and native grass from approximately 212 acres of pasture land required for the heliostat field. All vegetation will be stripped to at least a 10.2 cm (4 in.) depth to remove surface soil containing organic materials.

The second phase in preparation of the site will be the rough grading and compaction of the native soils for construction and installation of an array of heliostats and a receiver tower. Approximately one-half of the site consists of 3.05 m (10 ft.) high hills which will be graded into adjacent depressions to produce a roughly level field. All fill will be placed in 15.2 cm (6 in.) maximum lifts, processed to near optimum moisture, and compacted to 95% of maximum dry density (ASTM Designation: D698-70).

The site selected for the heliostat field immediately east of Plant X has a slight natural slope of less than 1% in a southerly direction. The topsoil on the site, as well as most of the other soil to a depth of 12.2 m (40 ft) is a free draining (highly permeable) type of soil and will readily accept standing water. Therefore, an important consideration in site preparation will be the provision of adequate drainage. Grading for site drainage will be on the basis of overland sheet flow. A mixture of 20% (by weight) of fly ash and native soil together with the addition of moisture and compaction to at least 95% of maximum dry density will be used to stabilize the top 15.2 cm (6 in.) of surface of the field and reduce the permeability to approximately 1.0×10^{-7} cm/sec (4×10^{-8} in/sec). In addition, similarly stabilized drainage ditches and swales, and collection piping, culverts, and other drainage structures will be provided to carry the collected storm water discharge to the nearest natural drainage channel for disposal.

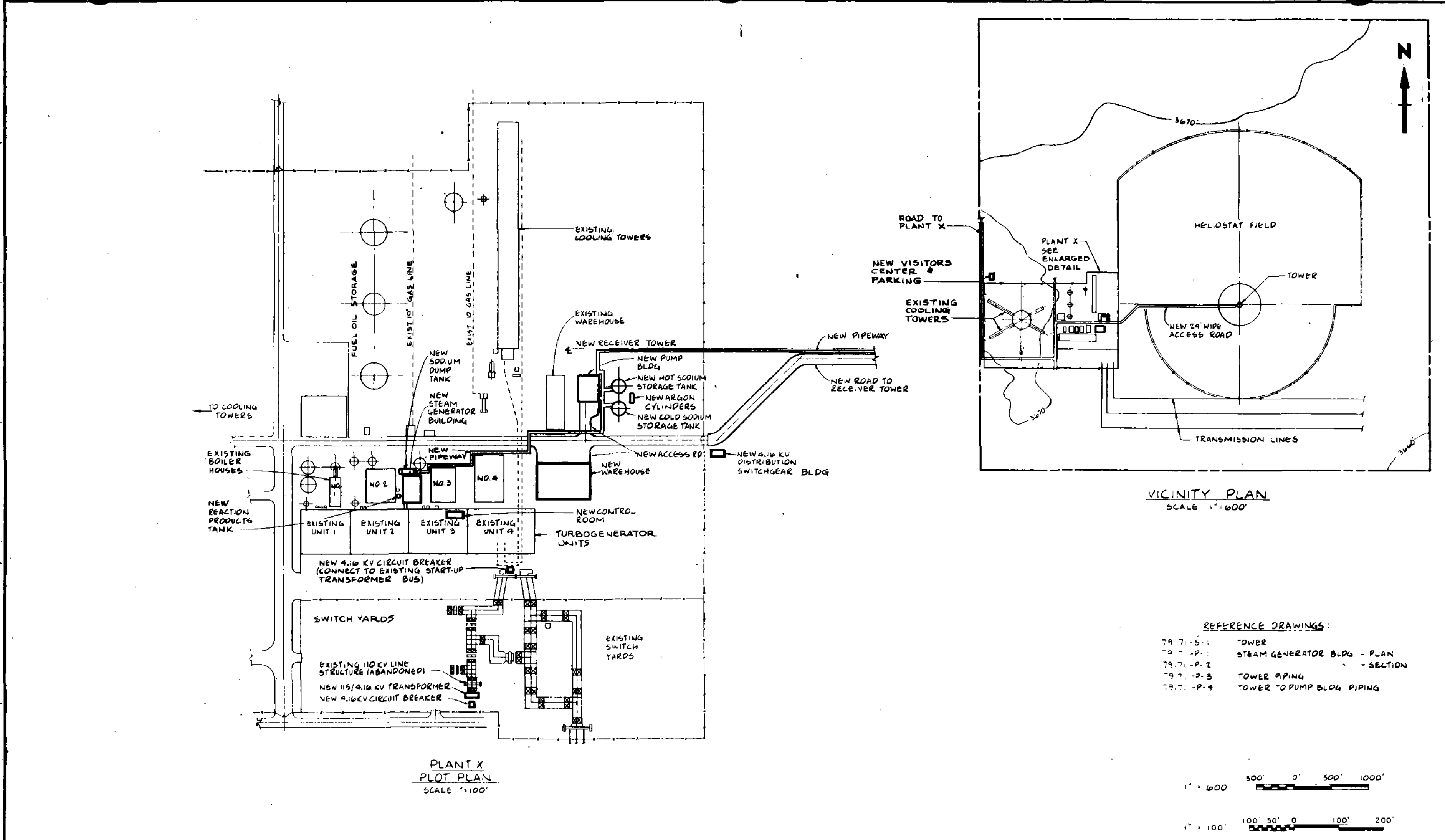
A final surface treatment of rock chips and asphalt sealer will be applied to the surface of the graded field to minimize erosion and to allow occasional vehicular maintenance traffic between the heliostat rows without raising dust.

A "no dust" two-lane service road will be provided running east-west from Plant X to the receiver-tower. The road will have a load carrying capacity of approximately 27×10^3 kg (30 tons) under all weather conditions.

The road will have two 3.7 m (12 ft) wide lanes with 1.85 m (6 ft) wide shoulders. Pending design analysis based on field and laboratory soil tests, the road section has been assumed to be 3.8 cm (1-1/2 in.) of asphaltic concrete over a 20.3 cm (8 in.) compacted aggregate or bottom ash subbase. This section will be founded on not less than 15.2 cm (6 in.) of compacted subgrade made from suitable native material. The shoulders will consist of 15.2 cm (6 in.) of compacted aggregate or bottom ash base course material on compacted subgrade with a single bituminous surface treatment. Drainage slope of 2% for the traveled way and 5% for the shoulders will be used.

5.1.1.2 Plant X

The ground surface within the existing Plant X perimeter fencing is relatively level with adequate provisions for surface drainage. However, the addition of the load bearing structures and paving shown on Figure 5.1-1, (Plot Plan) and additions to the drainage system(s), will require some general site preparation work.



NO.	DATE	REVISION	APP	APP	NOTES
					SODIUM PIPING TO PITCH DOWN-1/8"/FT TO SODIUM STORAGE AREA.

SCALE: AS SHOWN

KAISER ENGINEERS

SRS SOLAR REPOWERING PROGRAM

Figure 5.1-1. Plot Plan

JOB No. — DWG. No. — REVISION R-0

Any area to receive a fill, structural foundation on grade or paving, etc., will be stripped of vegetation to a depth of at least 10.2 cm (4 in.). The area(s) will be plowed or scarified to a minimum depth of 15.2 cm (6 in.), processed to near optimum moisture and compacted to 95% of maximum dry density. Placement of fill will be limited to a maximum of 15.2 cm (6 in.) lifts.

Facilities requiring at least limited site preparation will include the area(s) for the new warehouse, pump building, 4160 V switchgear building, sodium storage tank area, etc., and various locations within the existing electrical switchyard for new equipment slab-on-grade foundations. Service access roads will be paved to the pump house and warehouse areas. A site adjacent to the Plant X access road from Earth, Texas, near the northwest corner of the cooling tower area fence will also be prepared for a visitors' center and paved parking for 25 cars.

Drainage of the visitors' parking area, access roads, and building service aprons, etc., will be by sheet flow into adjacent natural soil.

5.1.1.3 Landscaping

Landscaping will be limited to restoration of ground cover in those areas disturbed during the construction operation. The ground cover used will consist of local grasses to provide protection against erosion. Adequate topsoil, fertilizer, and mulch will be supplied, if necessary, to assure ground coverage.

5.1.1.4 Utilities

The Plant X utilities that will be expanded to serve the new solar repowering facilities include:

- The domestic and fire protection water system
- The sanitary waste disposal system
- Plant and instrument air
- Communication systems
- Drain and waste collection system
- Argon flooding system

5.1.1.4.1 Domestic and Fire Protection Waste - the water requirements for the solar repowering facility(ies) will be provided by an extension(s) of the existing Plant X combined supply and distribution system for both domestic and fire protection water. Laterals from this system will supply the individual new facilities. The water supply source will be the Plant X well system.

The domestic water system will provide an adequate supply of potable water at service pressures to all sanitary, utility, and process use points. Outside hose stations will be provided with freeze-proof sill cocks. Hot water will be provided by small packaged hot water boilers located in or near the user buildings. Insulation will be provided on all hot and cold water lines.

Branch connections to process uses will be made through an air gap or an approved reduced-pressure-principle backflow preventer, to preclude contamination of the potable water.

The fire protection system will be designed in conformance with the National Fire Codes of the National Fire Protection Association for an occupancy classification of Ordinary Hazard (Group 1).

Documents applicable to the system design include:

- DOE Design Criteria Appendix 6301
- National Fire Codes of the National Fire Protection Association (NFPA)
- Standards listed in DOE Manual, Chapter 0552, Industrial Fire Protection
- SPS Plant Fire Protection

A wet pipe sprinkler system supplemented by portable fire extinguishers will be provided for the visitors' center, and portions of the new warehouse/maintenance building.

Sprinkler heads will be rated for 73.8°C (165°F). All sprinkler heads, piping, and valves exposed to possible mechanical damage will be protected with guards. Flow switches in the sprinkler branches will initiate alarms.

Potable extinguishers mounted in wall recesses or enclosed cabinets will be strategically located in building corriders and working spaces.

5.1.1.4.2 Sanitary Waste Disposal System - A sanitary waste disposal system will be provided to collect and dispose of all sanitary waste generated at the solar repowering facilities. The sanitary waste system(s) will discharge into the existing Plant X sewerage system. A separate 5.7 m^3 (1500 gallon) septic tank and leach field system will be provided for the visitors' center.

5.1.1.4.3 Plant and Instrument Air - The existing plant and instrument air systems will be extended to supply compressed air at a nominal pressure of 0.7 MPa (100 psig) to utility stations and maintenance tools as well as dry, oil-free air at reduced pressure for instruments, controls, and operators in the utility systems and the heating, ventilating, and air conditioning systems.

5.1.1.4.4 Communication Systems - Communication for the solar repowering facility will consist of a combined telephone-intercommunication system of dial-type telephones served from the local telephone exchange incorporated into the existing Plant X communication system. For backup service, an existing microwave radio communication system will allow voice communication between Plant X and other SPS power plants.

The fire alarm system will be activated by either ionization smoke detectors, sprinkler system flow detectors, or fire alarm pull boxes. The fire alarm signals will be transmitted over the paging system to the central control room. Additional assistance, if required, may be provided by telephone contact with nearby municipal fire departments.

5.1.1.4.5 Drain and Waste Collection System - The industrial drain and waste collection systems for the interior of the buildings will collect liquid wastes and discharge them into an existing system for transport to ponds located east of the heliostat field. Roof drains will discharge storm water to surface drainage.

The waste from plumbing fixtures and floor drains will be drained by gravity through building waste systems that will be connected to underground waste system piping at a point 1.52 m (5 ft) outside the building walls.

Floor drains in the warehouse component maintenance and repair area will normally be plugged. Chemical solutions and rinses used for decontamination will be drained into special hold-up tanks.

5.1.1.4.6 Argon Flooding System - Argon sources will be provided to flood collection areas for sodium in the event of leaks. The argon is heavier than air and will displace the air over the surface of the sodium and eliminate or reduce the severity of the fire. The argon will be supplied from the two storage facilities (see Section 5.9).

5.1.2 FACILITY RELOCATIONS

Although an attempt was made to avoid relocating existing facilities, in siting the new facilities required for repowering, a minimal number of relocations were necessary.

5.1.2.1 Unit 3 Condensate Storage Tank

Figure 5.1-2 shows an existing 150 m^3 (42000 gal.) condensate storage tank to the northwest side of the Unit 3 boiler. As will be discussed in Section 5.2, the steam generator will be located between the Unit 2 and 3 boilers. The condensate tank will interfere with free access for both construction and subsequent servicing of the new building. The tank will thus be relocated to the east side of the Unit 3 boiler.

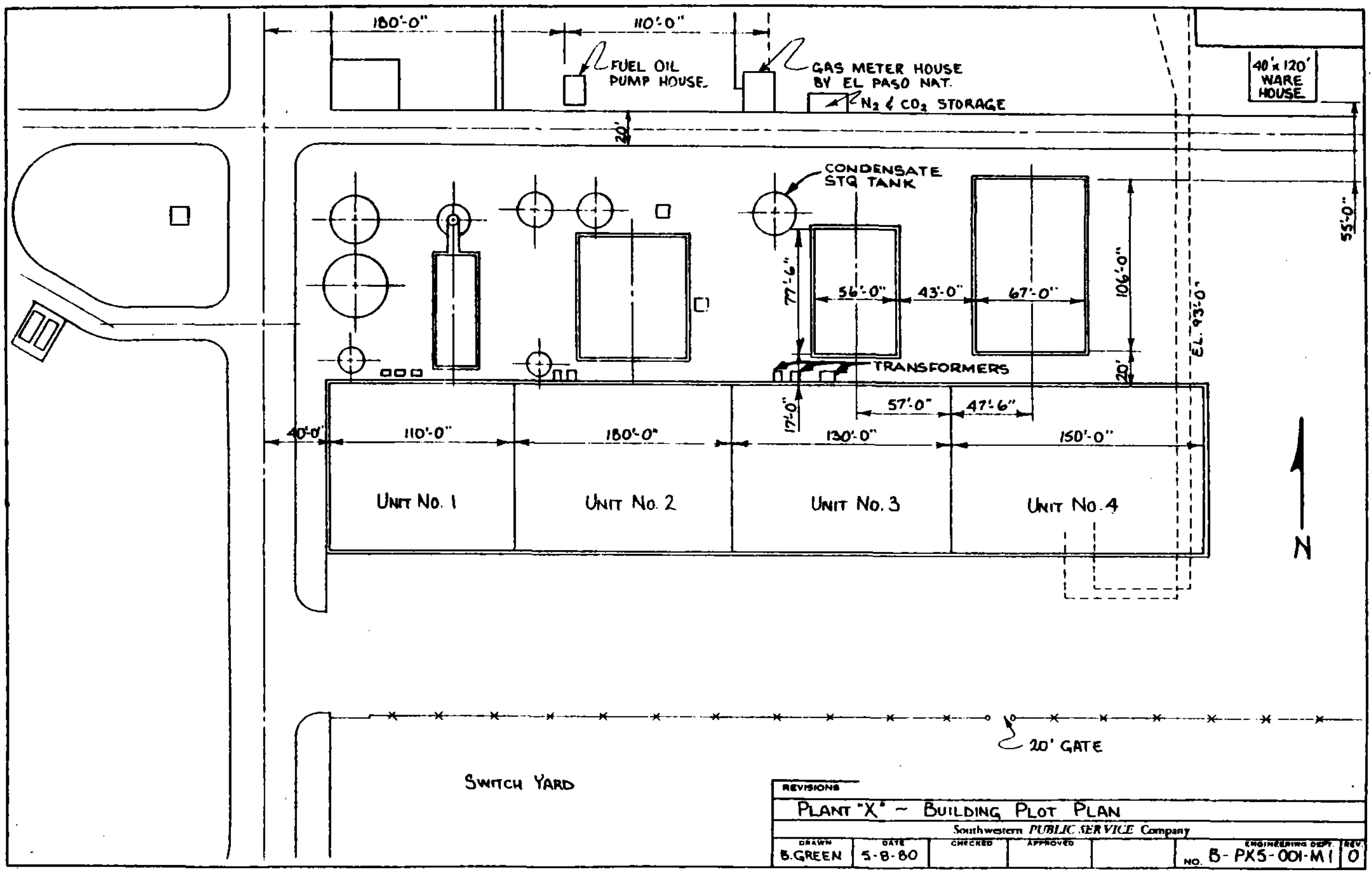


Figure 5.1-2. Plant X Building Plot Plan

5.1.2.2 115 kV Transmission Line

A power transmission line traverses the collector field in a north-south direction between the receiver tower and the existing plant east fence. There is insufficient clearance to ensure safe heliostat erection, operation and servicing with the line in its present location. To remedy the condition, several alternatives for relocating the line were considered. The most cost effective, and the one selected, was to relocate the line to the west side of the road running west of the Plant X site. The line will be relocated in the winter to minimize the impact on SPS system operations.

5.1.2.3 Unit 3 Service Transformers

Figure 5.1-2 shows three transformers located immediately north of the Unit 3 section of the turbine building. With the new steam generator to be located between the Unit 2 and 3 boilers, there will be insufficient access to service these transformers. They will be relocated to the area between the Unit 3 and 4 boilers.

5.1.3 COST ESTIMATE

The cost estimate for preparation of the site and relocation of the existing facilities is detailed in account 5100 (Site Improvements) of the Appendix A, System Requirements Specification. The total cost estimate for the efforts discussed above is $4,170,628.

5.2 SITE FACILITIES

Site facilities include those new structures and facilities required to support the operation of the repowered facility. Included are

- Buildings
- Security
- Electric Plant

5.2.1 BUILDINGS

The repowering facilities will include both new structures and modifications to existing structures within the Plant X facility. The proposed facilities, as indicated on Figure 5.1-1, Plot Plan, include the following:

- Pump Building
- Steam Generator Building
- Warehouse/Maintenance Building
- Switchgear Building
- Visitors' Center
- Computer/Control Additions

All new buildings will be insulated, heated, ventilated, and lighted to allow access at all times. All buildings will conform to DOE and Southwestern Public Service architectural requirements.

Sprinkler systems will be provided in part of the new warehouse and the visitors' center. However, fire protection in the switchgear building and the control room and buildings which contain sodium systems, e.g., the pump and steam generator buildings will be provided with portable nonaqueous or dry type fire protection equipment.

5.2.1.1 Pump Building

The pump building, located as shown on Figure 5.1-1, will house the steam generator and tower sodium pumps, sodium cold trap, sodium drain tank, piping, controls, and auxiliary electrical systems and equipment. (See Figure 5.5-5 for building layout.)

The building will be an engineered 12.2 m by 12.2 m (40 ft by 40 ft) steel structure with an insulated metal-concrete roof deck and metal siding. A 12.2 m (40 ft) high bay roof over the 6.1 m by 12.2 m (20 ft by 40 ft) pump area will be provided to accommodate an 18.2 by 10^3 kg (20 ton) overhead bridge crane for servicing the sodium pumps. The roof over the 6.1 m by 12.2 m (20 ft by 40 ft) low bay auxiliary area will be 4.9 m (16 ft) high.

A conventional slab on grade concrete floor system and column footings will be provided to support the steel structure. Curbing will be provided for drainage control or containment of any minor sodium leakage. A below-grade drain tank pit will also be provided.

A gravity ventilation system will be provided for removal of equipment and piping heat losses. Electrical resistance type space heaters will be provided, as required, in selected work areas.

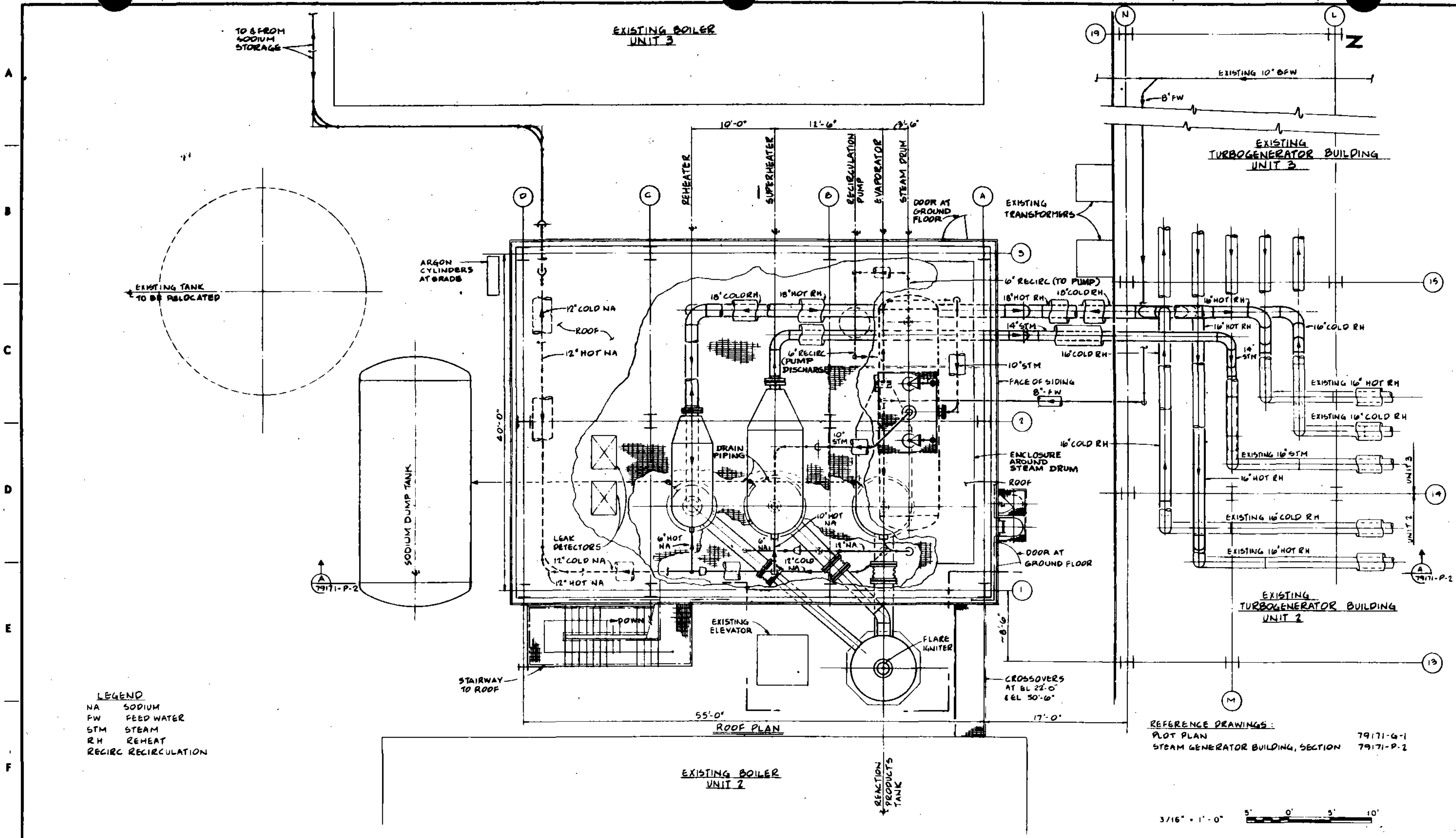
Fire protection within the pump building will consist of ionization type smoke detectors, nonaqueous portable extinguishers and argon for inert gas blanketing.

5.2.1.2 Steam Generator Building

The steam generator building, located between the Unit 2 and 3 boilers will house the steam generators (evaporator, superheater and reheater), circulation pump(s) and associated piping in a 12.2 m by 16.8 m by 27.4 m (40 ft by 55 ft by 90 ft.) engineered steel structure with insulated metal-concrete deck and metal siding. The steam generator building plan and section are shown in Figures 5.2-1 and 5.2-2, respectively. The steam drum will be housed on top of the generator building in a 4.6 m by 11 m by 5.8 m (15 ft by 36 ft by 16 ft) penthouse structure.

Platforms and stairs will be provided at various levels for operation and maintenance access to the equipment, piping, and instrumentation. A slab-on-grade concrete floor system and column footings will be provided to support the building steel structure. Curbing will be provided, as required, for containment of minor sodium leakage.

An existing storage tank presently located near the north end of the proposed steam generator building will be relocated by SPS to provide space for a sodium dump tank adjacent to the north end of the generator building.



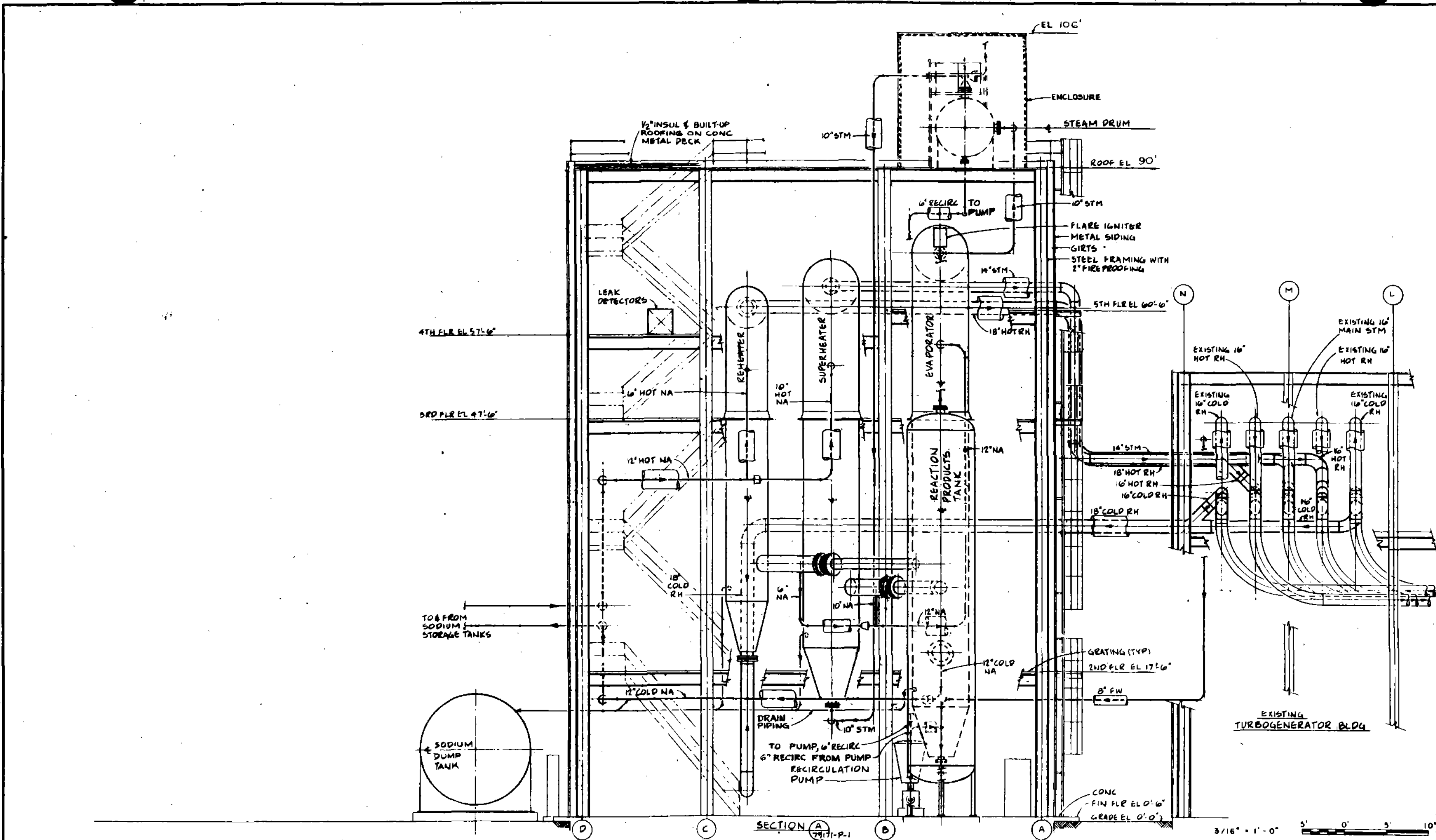
1. ONLY MAIN PIPE LINES ARE SHOWN, VALVES ARE NOT SHOWN
2. PLATFORMS AT 2ND & 3RD FLRS EXTENDS ONLY FROM COL LINE TO COL LINE 2

SCALE	3/16" = 1'-0"
DESIGNED BY	R LEVINSON 3-10-80
DRAWN BY	R LEVINSON 3-10-80
CHECKED BY	3-13-80
APPROVED BY	3-16-80

KAISER ENGINEERS

Figure 5.2-1. Steam Generator Building Plan

JOB No. 79171 DWG. No. 79171-P-1 REVISION 0



APPROVAL	DATE	SCALE: 3/16" = 1'-0"	DATE
	5-2-80	DESIGNED BY R. LEVINSON	3-12-80
		DRAWN BY R. LEVINSON	3-12-80
		CHECKED BY	3-13-80
		APPROVED BY	3-26-80
		APPROVED BY	5-1-80

KAISER ENGINEERS

SPS SOLAR REPOWERING PROGRAM

Figure 5.2-2. Steam Generator Building Section

JOB No. 79171 DWG. No. 79171-P-2 REVISION R-0

Building access for operation and maintenance personnel will be provided by exterior stairs in an enclosed stair well and overhead walkway cross-overs to an existing elevator serving the adjacent Boiler Building No. 2. In addition, an exterior caged safety ladder will be provided between the roof, interior service levels, and ground level.

Local chain fall hoists will be provided for maintenance of the building heat exchangers.

Gravity ventilation will be provided for removal of equipment and piping heat losses. Electric resistance type heaters will be provided, as required, in selected work areas.

Fire protection within the generator building including the steam drum penthouse will consist of ionization type smoke detectors, nonaqueous portable extinguishers and argon for inert gas blanketing.

5.2.1.3 Warehouse/Maintenance Building

The warehouse/maintenance building, located as shown on Figure 5.1-1, will house the repowering plant spare parts and maintenance area. Adequate maintenance space and equipment will allow maintenance on the largest plant component that can be removed for local maintenance. Sodium cleaning equipment will be provided for the largest removable, repairable sodium component. Lifting and handling equipment will also be provided in all storage and maintenance areas.

The above activities will be housed in an 24.4 m by 36.6 m by 7.6 m (80 ft by 120 ft by 25 ft) high engineered steel building with insulated metal deck and siding. A 9.1 m by 9.1 m by 12.2 m (30 ft by 30 ft by 40 ft) high bay area will be provided at the warehouse entrance to the center, north side of the building. A door 9.1 m by 6.1 m (30 ft by 20 ft) high will be provided for access to the high bay area. Supports for a 4500 kg (5 ton) chain-fall will be provided at the center of the high bay. Interior platforms and stairs will be provided, as required, for equipment maintenance activities.

Gravity ventilation will be provided for natural airflow through the building. However, powered ventilation equipment will be provided for sodium cleaning operations. Electrical resistance type local heating will be provided, as required, in selected work areas.

Fire protection within the warehouse building will consist of ionization type smoke detectors. In addition, nonaqueous portable extinguishers or dry chemical equipment will be provided in equipment cleaning areas. Areas used for storage of combustibles will be provided with a sprinkler system served by the existing Plant X water system.

5.2.1.4 Visitors' Center

A single story, air conditioned visitors' center will be located northwest of the existing plant outside the cooling tower area fence. (Figure 5.1-1)

The visitors' center will consist of an engineered structure 12.2 m by 15.2 m by 4.3 m (40 ft by 50 ft by 14 ft) high with a metal-concrete roof deck and metal siding. An enclosed stairway will be provided for access to an observation deck on the roof.

A conventional slab-on-grade concrete floor and foundation will be provided to support the building steel structure.

The existing Plant X water supply system will be extended to feed a sprinkler system for fire protection of the visitors' center.

5.2.1.5 4160 Switchgear Building

An engineered reinforced concrete structure, 7.6 m by 15.2 m (25 ft by 50 ft), will be provided to house the 4160-V switchgear. A conventional slab-on-grade floor and foundation system will be provided for support of the structure.

The building will be slightly pressurized for dust control by a fan-filter system. Electrical spot or local heaters will be provided, as required, for heating selected work areas.

Ionization type smoke detectors will be provided and portable inert gas type extinguishers or dry chemicals will be provided for fire protection.

5.2.2 SECURITY

An intrusion detection system and fencing will be provided around the heliostat field.

5.2.2.1 Fencing

A chain link fence 2.4 m (8 ft) high topped with three strands of barbed wire on brackets, angled outward, 3 m (1 ft) high, for a total height of 2.7 m (9 ft) will be provided around the heliostat field as shown on Figure 5.1-1. A swing-type vehicular gate at the Plant X end of the tower service road will be provided to limit and control access to the heliostat field to authorized personnel. Man barriers will be provided at points where the perimeter fence crosses surface drainage system ditches.

The existing fencing around the Plant X facility is assumed to be adequate and will not require modifications. All fencing will be grounded in accordance with DOE Appendix 6301 and SPS Plant Grounding Practices Specification No. 0541-1.

5.2.2.2 Lighting

Single fixture light poles will be located along the inside of the fence to maintain a nominal security lighting level of 2 to 3 foot candles along the fence line. Approximately 39 poles and fixtures along the fence line will be supplied with power from six pad mounted transformers.

Each transformer station will include a weatherproof distribution panel for circuits to the poles and fixtures. Three separate direct burial No. 10 AWG circuits will be run from each panel to the poles served. The transformers will be fitted with "safe-break" terminals for high voltage connections.

High voltage service to the transformers will consist of 5 kV No. 4 AWG cable buried in concrete-encased, 10.2 cm (4 in.) diameter polyvinyl chloride (PVC) conduit. The conduit run will include 26 precast concrete boxes.

The primary service to the pad mounted transformers will include a 2400-V single phase, grounded loop circuit with two 25-kVA 4160/2400-V single phase transformers located in the new 4160-V switchgear building. The 5-kV cable for this circuit will be a single conductor type URD with concentric neutral over the jacket.

5.2.2.3 Intrusion Detection

Inside the fence, a microwave security system will be provided for intrusion detection. Twenty-six equally spaced sets of transmitter/receiver (TX) units on pedestals will be spaced 152.4 m (500 ft) apart and mounted on concrete pads.

Each TX set will be served by twisted, shielded 18-pair cabling from a monitoring station in the Plant X control room to a weatherproof telephone type terminal box at each TX set. The cable will be installed underground in PVC conduit. Precast concrete sidewalk type boxes will be provided between pedestals.

5.2.3 ELECTRIC PLANT

5.2.3.1 Power Supply

The electrical power supply to the solar repowering facilities will be provided by the SPS Plant X generating plant. However, a number of modifications and/or additions will be required for distribution of the power. An electrical one line diagram for the additional facilities is shown in Figure 5.2-3.

Normal power service will be provided by the addition of a 5,000 kVA 115 kV/

4160 V transformer in the switchyard connected to an abandoned line position of the existing 115 kV ring bus.

Backup power will be obtained from the existing 10 MVA-115 kV/4160 V start-up transformer at turbine-generator unit No. 4.

Outdoor metal-clad circuit breakers will be provided on the 4160-V terminals of the new normal service transformer and existing start-up transformer for protection of the feeder cables to a 4160V indoor metal-clad switchgear located in a new switchgear building near the Plant X east fence. The feeders between the transformers and switchgear and distribution cables will be installed underground in concrete encased PVC conduit.

A double ended 480-V load center will be located at grade level in the receiver-tower. The load center transformers will each have sufficient capacity to serve both the tower and heliostat field demands consisting of the following:

- Tower absorber panel electromagnetic sodium pumps
- Tower lighting and power service (service elevator, hoists, derrick crane, welding outlets, etc.)
- Heliostat control power
- Tower welding receptacles

A medium voltage starter assembly will be located in the electrical equipment room of the Pump Building. The assembly will include starters for the steam generator and tower sodium pump drives and a fused switch for service to a transformer supplying 480 V power to the system auxiliaries in the pump building.

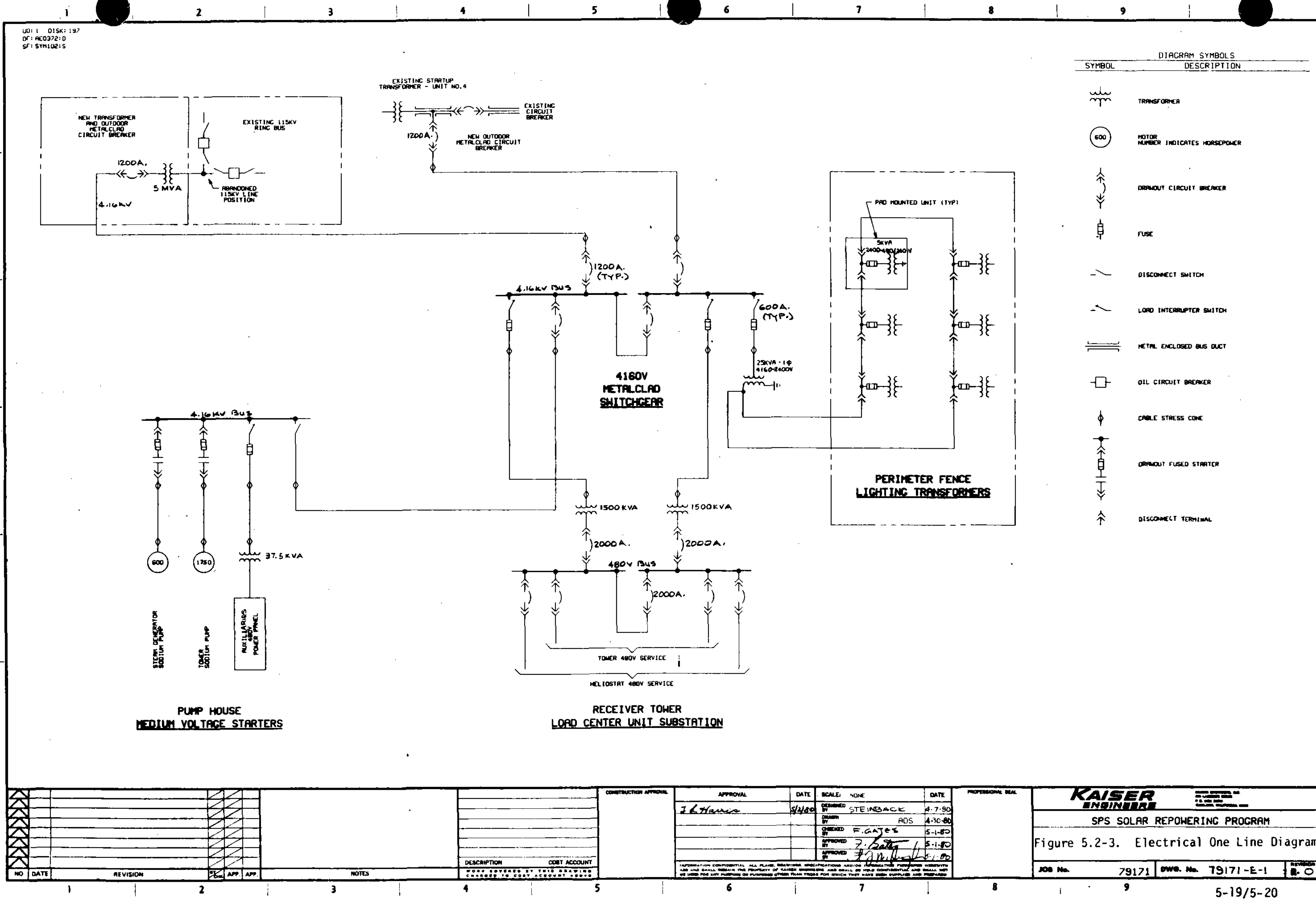
The heliostat field perimeter fence lighting and radar security system will be served from the 4160 V switchgear with 5 kV cable circuits and pad mounted transformers.

Power for welding and field lighting during heliostat maintenance and repair operations will be provided by mobile engine-driven generators.

Power for the visitors' center lighting and air conditioning will be taken from the existing 12 kV overhead transmission line paralleling the plant access road to a transformer located near the visitors' center.

5.2.3.2 Uninterruptable Power Supply (UPS)

A 120-V battery station will be provided to maintain the emergency control and lighting, and data acquisition functions of the solar repowering master control subsystem. In addition, battery packs energized by the fence lighting system power sup-


UDI: 1 DISK: 197
DF: AC0372:D
SF: SYM102:S
DIAGRAM SYMBOLS
SYMBOL
DESCRIPTION
TRANSFORMER
MOTOR
NUMBER INDICATES HORSEPOWER
DRAWOUT CIRCUIT BREAKER
FUSE
DISCONNECT SWITCH
LOAD INTERRUPTER SWITCH
METAL ENCLOSED BUS DUCT
OIL CIRCUIT BREAKER
CABLE STRESS CONE
DRAWOUT FUSED STARTER
DISCONNECT TERMINAL
NEW TRANSFORMER AND OUTDOOR METALCLAD CIRCUIT BREAKER
EXISTING 115KV RING BUS
1200A.
5 MVA
4.16KV
ABANDONED 115KV LINE POSITION
EXISTING STARTUP TRANSFORMER - UNIT NO.4
EXISTING CIRCUIT BREAKER
1200A.
NEW OUTDOOR METALCLAD CIRCUIT BREAKER
1200A. (TYP.)
4.16KV BUS
600A. (TYP.)
25KVA - 1Φ 4160-2400V
4160V METALCLAD SWITCHGEAR
PAD MOUNTED UNIT (TYP)
5KVA
PERIMETER FENCE LIGHTING TRANSFORMERS
4.16KV BUS
600
1750
37.5KVA
STEAM GENERATOR SODIUM PUMP
TOWER SODIUM PUMP
AUXILIARIES 480V POWER PANEL
PUMP HOUSE MEDIUM VOLTAGE STARTERS
1500KVA
1500KVA
2000A.
2000A.
480V BUS
2000A.
TOWER 480V SERVICE
HELIOSTAT 480V SERVICE
RECEIVER TOWER LOAD CENTER UNIT SUBSTATION
NO
DATE
REVISION
APP
APP
NOTES
DESCRIPTION
COST ACCOUNT
CONSTRUCTION APPROVAL
APPROVAL
DATE
J L Harris
5/2/80
SCALE: NONE
DATE
DESIGNED BY STEINBACK 4-7-80
DRAWN BY ADS 4-30-80
CHECKED BY F. GATES 5-1-80
APPROVED BY F. Gates 5-1-80
APPROVED BY 5-1-80
PROFESSIONAL SEAL
KAISER ENGINEERS
SPS SOLAR REPOWERING PROGRAM
Figure 5.2-3. Electrical One Line Diagram
JOB No. 79171
DWG. No. 79171-E-1
REVISION R. 0

ply will be located on each of the lighting system transformer pads to provide uninterruptable power to the microwave intrusion detection system. A schematic of the UPS is provided in Figure 5.2-4.

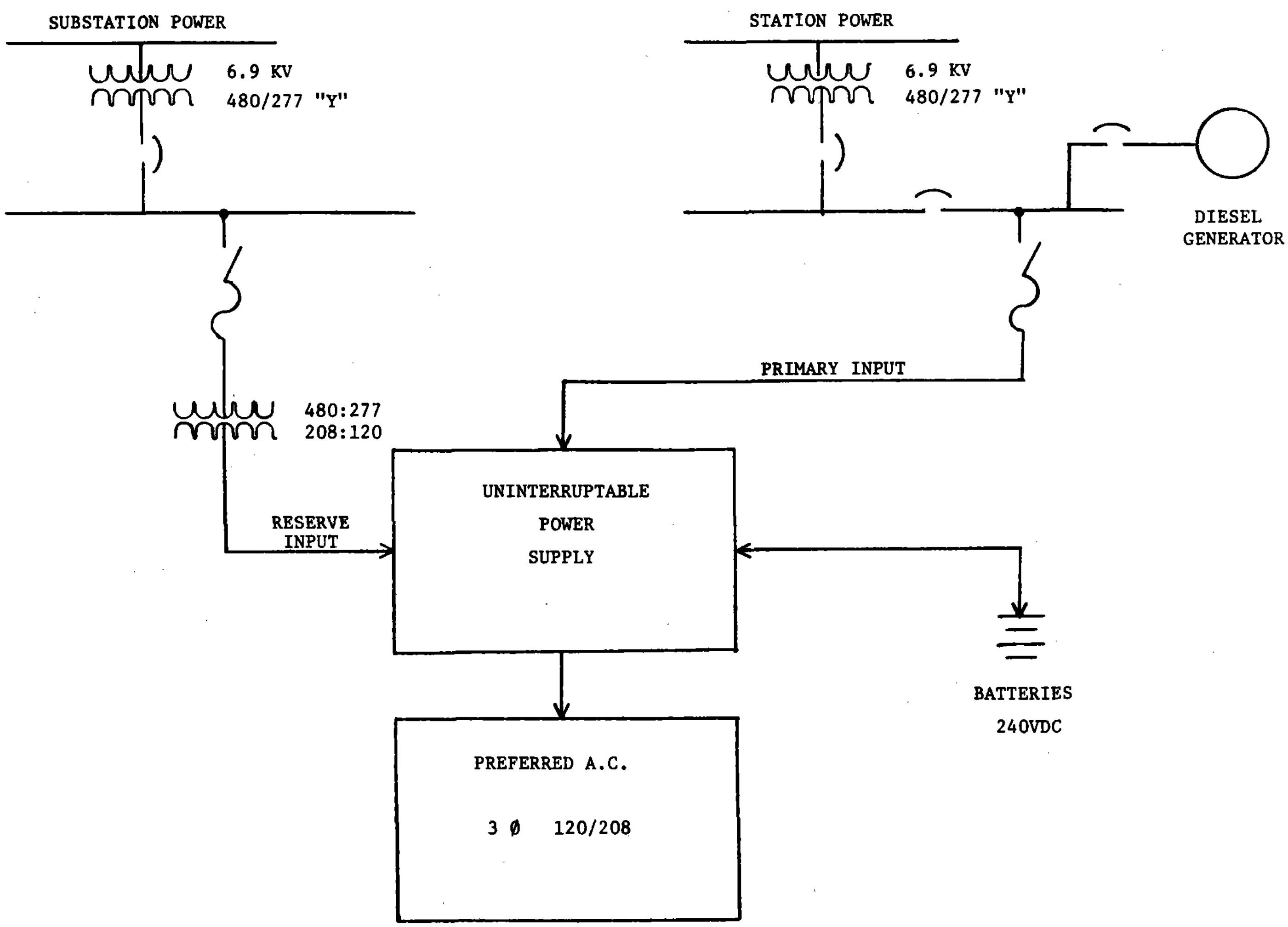


Figure 5.2-4. Schematic of Uninterruptable Power Supply

5.2.3.3 Grounding System

All new structures and equipment for the solar repowering facility(ies) will be connected to a grounding system in accordance with the SPS Plant Grounding Practices Specifications No. 0541-1. The existing grounding system will be expanded to include the solar system structures and equipment at Plant X.

The receiver-tower will be provided with separate copper grounding cables from the metal receiver roof and structural steel at the top of the tower to an underground copper ring around the tower.

The grounding grid for the heliostats, fencing, tower and new Plant X structure and equipment will be connected to the existing Plant X grid continuous grounding system to maintain the total facility at the same potential.

New ground wells will be drilled to an average depth of 60.98 m (200 ft) into water bearing sands. Ground cables will be installed to the bottom of each grounding well. A grid of 1000 MCM copper grounding cable will interconnect the grounding wells to provide multiple paths for fault currents to earth.

5.2.4 COST ESTIMATE

The total cost for the site facility additions discussed above is estimated at \$3,600,107. Details of the estimate are contained under account 5200 in the Appendix A, System Requirements Specification.

5.3 COLLECTOR SUBSYSTEM

The collector subsystem functions to reflect the incident insolation to the tower-mounted receiver. To adequately perform this function the individual heliostats must track the sun and position themselves properly to reflect the energy to the intended target. The following sections discuss the development of the collector subsystem design for the repowering of Plant X, Unit 3.

5.3.1 REQUIREMENTS

To attain the desired 60 MWe design point gross output from the Plant X , Unit 3 turbine, the collector field will be required to deliver ~142.8 MWth energy to the receiver working fluid at noon on the equinox. In addition to this requirement, the collector subsystem must also meet two requirements resulting from receiver operating limitations:

- The flux shall not exceed 1.4 MW/m^2
- At all operating times the flux shall be sufficient to achieve the 593°C(1100°F) panel outlet temperature

The first limit will avoid exceeding structural limits on the receiver and the second will prevent the problem of negative panel efficiencies which would require periodic starting and stopping of panel flow when insolation is too low. These requirements are summarized in Table 5.3-1.

Table 5.3-1

COLLECTOR SYSTEM PERFORMANCE REQUIREMENTS

Parameter	Requirement
Absorbed Power on Noon Equinox	142.8 MWth
Peak Receiver Flux	1.4 MW/m^2
Minimum Flux	Adequate to achieve positive efficiency on all panels at all times sun is above 10° over horizon

With respect to individual heliostat performance, the requirements for the prototype heliostat program were imposed for design point performance. These are summarized in Table 5.3-2.

Table 5.3-2

HELIOSTAT DESIGN PERFORMANCE REQUIREMENTS

Parameter	Requirement
Reflectivity	0.90
Beam Quality (Reflected Beam)	±2 mr
Pointing Accuracy (Reflected Beam)	±1.5 mr
Focusing	Canted

The above defined requirements formed the basis for the collector subsystem design described below.

5.3.2 SYSTEM DESIGN DESCRIPTION

The collector subsystem will consist of 4809 heliostats in a 212 acre surround configuration located east of the existing Plant X facility. A layout of the proposed field is shown in Figure 5.3-1. The evolution of this field design is described in the following section.

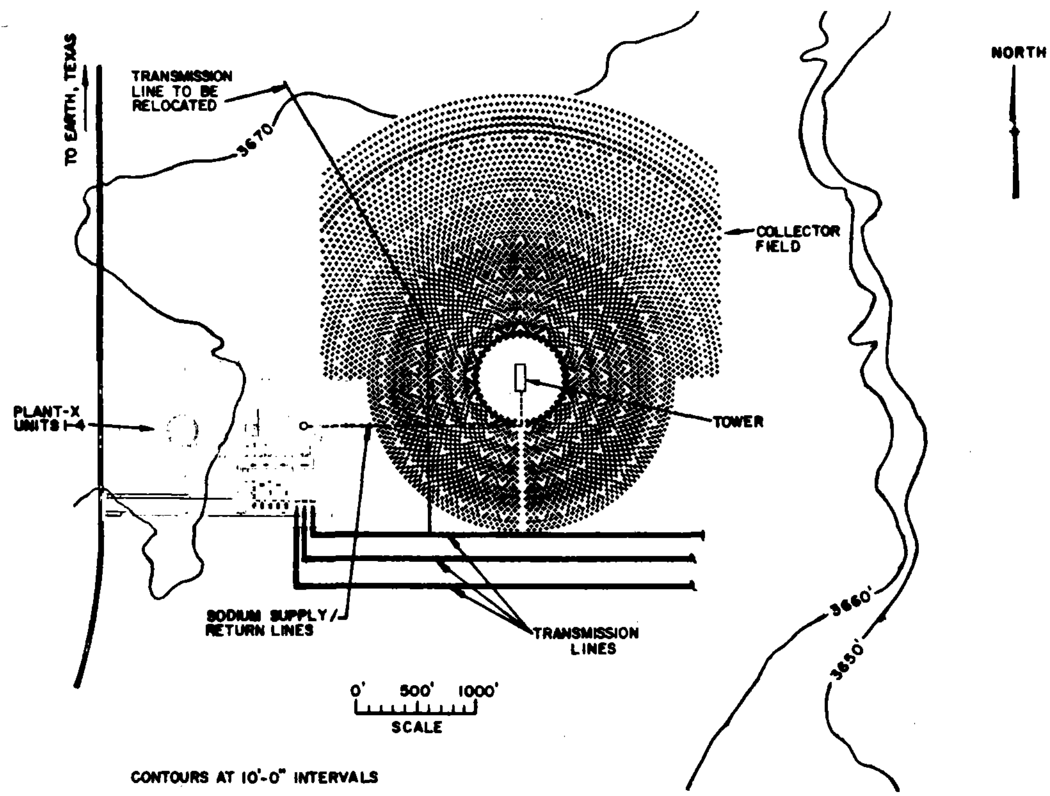


Figure 5.3-1. Plant X Repowering Field Layout

5.3.2.1 <u>Collector Field Design Model</u>

The heliostat, cost,solar and receiver models used in the analysis were the same as those described in Table 3.2-2. This model information was input to the DELSOL computer code optimization routine. The code is designed to optimize the plant configuration in terms of collector field size and arrangement, tower size and receiver size based on overall cost of energy.

5.3.2.2 <u>Collector Field Design Results</u>

5.3.2.2.1 DELSOL-Optimized Field - The collector field configuration developed by DELSOL consists of 4104 heliostats reflecting energy to a 14 m by 14 m (46 ft x 46 ft) cylindrical receiver mounted on a 150 m (492 ft) tower. This field is skewed radically to the north (Figure 5.3-2), which appears to result from the high heliostat cost. The field design data is shown in Table 5.3-3.

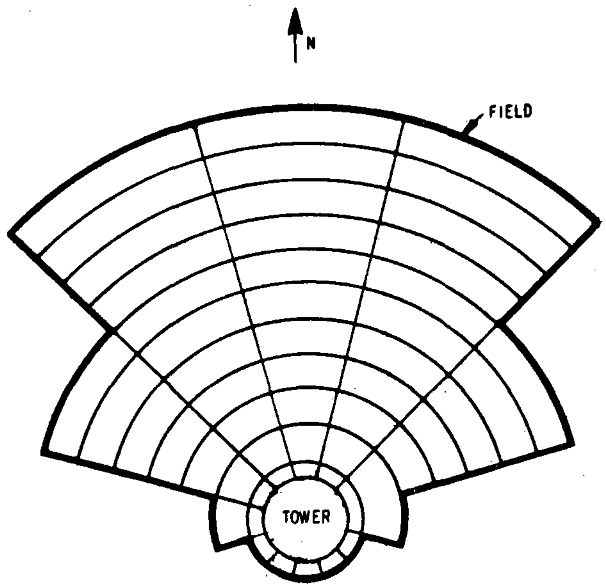


Figure 5.3-2. DELSOL - Optimized Field Configuration

Table 5.3-3

DELSOL - OPTIMIZED FIELD DESIGN

Parameter	Design Value
Noon Equinox Power	142.86 MWth
Number of Heliostats	4104
Tower Size	150 m (492 ft)
Receiver Size	14 m by 14 m (46 ft x 46 ft)
Peak Flux	1.28 MW/m^2
Design Point Minimum Average Panel Flux	25 kW/m^2 (South Panel)

The DELSOL-optimized field meets the power delivered and maximum flux requirements set for the collector field. To assess whether the 25 kW/m^2 minimum average panel flux is adequate to maintain positive panel efficiency, further analysis was required.

To assess the design point south panel performance, the Receiver Loss Code, developed in the Alternate Central Receiver, Phase I Program, was utilized. This code calculates panel by panel receiver performance based on incident flux and detailed receiver design characteristics. Further discussion of this code is in Section 5.4. The code indicated the south panel performance at noon on the equinox would have a negative efficiency, that is, more heat would be lost from the panel than would be gained. With the code, it was determined that a minimum average panel flux of 40 kW/m^2 was required to achieve a positive panel efficiency. For this reason, the DELSOL-optimized collector field design was considered unsatisfactory.

5.3.2.2.2 Collector Field Design Iteration - To obtain a collector field design that would meet all the requirements, an iterative process was undertaken using the DELSOL performance routine. To bring the south side flux level up, some of the north field heliostats from the DELSOL optimized arrangement were shifted to the south field. Because the design point efficiency of the heliostats is reduced in making the shift to the south field, more heliostats were also required to achieve the required 60 MWe design output. In addition, because the radius of the north field is reduced due to the shift of heliostats to the south field, the receiver size and tower height could be somewhat reduced. The iterative process resulted in identification of the collector field layout shown in Figure 5.3-3 and described in Table 5.3-4.

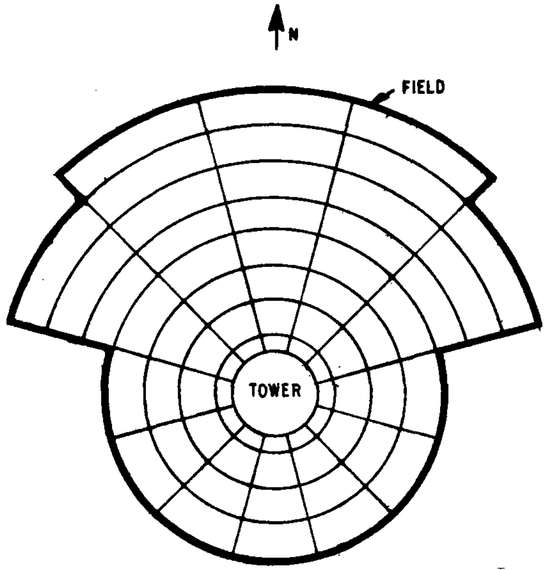


Figure 5.3-3. Revised Collector Field Configuration

Table 5.3-4

REVISED COLLECTOR FIELD DESIGN

Parameter	Design Value
Noon Equinox Power	146.6 MWth
Number of Heliostats	4809
Tower Size	140 m (460 ft)
Receiver Size	12 m by 12 m (39.4 ft x 39.4 ft)
Peak Flux	1.13 MW/m^2
Design Point Minimum	
Average Panel Flux	178 MW/m^2 (South Panel)
North Field Radius	700 m (2296 ft)
South Field Radius	375 m (1230 ft)

Although the design point average panel flux is quite acceptable, consideration had to be given to off-design points to ensure that the minimum average panel flux stays above the minimum 40 kW/m^2. The point examined to assess this requirement was 4 P.M. on the winter solstice, which was judged to be as bad as anything of the year in terms of south field performance. The flux at that time on the south panels was still in excess of 60 kW/m^2 and thus the revised field design was deemed acceptable.

5.3.2.2.3 Revised Insolation Model - Following completion of the field layout, revised insolation data was made available. Southwestern Public Service Company's direct insolation monitoring station, located 5 miles from Plant X and in operation since August 1979, revealed that the peak insolation around the fall 1979 equinox was ~940 W/m^2. As indicated in Table 3.2-2, the solar model assumed for the collector field design had an equinox insolation level of 970 W/m^2 based on the Meinel insolation model. The impact of the reduced insolation is to drop the design point power level by a factor of 940/970. Thus, the design point receiver absorbed power is reduced to 142.06 MWth. This corresponds to a gross electric output of 59.6 MWe, which was considered sufficiently close to the design target of 60 MWe.

5.3.3 COMPONENT DESCRIPTION

Development of components for the collector subsystem is a part of the overall DOE heliostat development program. Rather than duplicate the efforts of that program, the heliostat and collector subsystem performance assumptions provided by DOE for the repowering conceptual design were utilized. These assumptions are discussed in Section 5.3.1 (Heliostat Performance) and Section 5.3.4 (System Performance). For the detailed design and construction phase of the program, an evaluation of available hardware will be required to make the selection of physical equipment to be used.

5.3.4 OPERATING CHARACTERISTICS

Since the collector subsystem component design is not a part of this program, the operating characteristics of the subsystem have been based on the DOE assumptions provided together with published data available for the prototype heliostat program. Those operating characteristics that will affect the design of the remainder of the repowering facility and the assumed values are shown in Table 5.3-5.

Table 5.3-5

PLANT X REPOWERING COLLECTOR SUBSYSTEM OPERATING CHARACTERISTICS

Parameter	Performance	Source
Defocus Time	20 s	DOE/Sandia
Time Average Power Draw	39 W/heliostat	McDonnell Douglas
Electrical Draw (480 V)	1.5 A (running)	" "
	3.0 A (start)	" "
Drive Rate	15^{o}/minute	" "

5.3.5 PERFORMANCE ESTIMATES

The collector subsystem performance can be described in terms of the receiver flux distribution and the field efficiency variation with time. These two parameters allow the effect of the collector field design on the overall plant performance to be calculated. The flux impacts the structural integrity of the receiver and the field efficiency variation allows calculation of plant energy performance.

5.3.5.1 Receiver Flux

The collector field design for the Plant X repowering, described in Section 5.3.2, will deliver a peak flux of 1.13 MW/m^2 at the design point (noon, equinox). This flux level is based on a multiple vertical point aiming strategy. The distribution of the flux over the receiver surface at the design point is listed in Table 5.3-6. A plot of the "beltline" circumferential flux and the axial hot panel flux is provided in Figure 5.3-4.

Performance in terms of east and west panel fluxes was also examined. At all times during the year, adequate flux is incident on all panels to maintain positive panel efficiency.

Table 5.3-6

DESIGN POINT RECEIVER FLUX
(PANEL CENTERLINE FLUX IN MW/m^2)

	NORTH					PANEL NUMBER						SOUTH
Panel Elevation (meters)	1	2	3	4	5	6	7	8	9	10	11	12
11.625	0.063	0.060	0.060	0.055	0.047	0.037	0.030	0.026	0.024	0.024	0.026	0.023
10.875	0.193	0.188	0.182	0.170	0.150	0.123	0.098	0.089	0.081	0.074	0.079	0.070
10.125	0.390	0.379	0.365	0.335	0.290	0.237	0.191	0.172	0.156	0.146	0.148	0.136
9.375	0.598	0.581	0.559	0.513	0.434	0.348	0.280	0.247	0.226	0.211	0.210	0.195
8.625	0.795	0.780	0.738	0.672	0.564	0.439	0.341	0.302	0.277	0.267	0.265	0.240
7.875	0.960	0.936	0.882	0.799	0.655	0.498	0.376	0.324	0.300	0.294	0.298	0.272
7.125	1.062	1.031	0.969	0.869	0.702	0.528	0.389	0.332	0.310	0.310	0.310	0.280
6.375	1.112*	1.082	1.014	0.903	0.728	0.541	0.395	0.340	0.319	0.318	0.320	0.288
5.625	1.108	1.076	1.010	0.900	0.721	0.533	0.391	0.339	0.319	0.318	0.318	0.287
4.875	1.050	1.022	0.955	0.852	0.688	0.510	0.378	0.329	0.309	0.308	0.308	0.280
4.125	0.941	0.916	0.862	0.775	0.628	0.473	0.357	0.314	0.299	0.293	0.289	0.262
3.375	0.763	0.749	0.706	0.639	0.527	0.406	0.318	0.287	0.269	0.252	0.244	0.220
2.625	0.562	0.552	0.515	0.475	0.391	0.309	0.244	0.227	0.208	0.191	0.183	0.162
1.875	0.355	0.349	0.329	0.294	0.242	0.197	0.158	0.149	0.132	0.120	0.113	0.110
1.125	0.167	0.162	0.153	0.139	0.114	0.089	0.072	0.069	0.060	0.053	0.054	0.046
0.375	0.053	0.052	0.048	0.042	0.033	0.025	0.020	0.019	0.018	0.016	0.014	0.013

* North edge panel flux = 1.13 MW/m^2

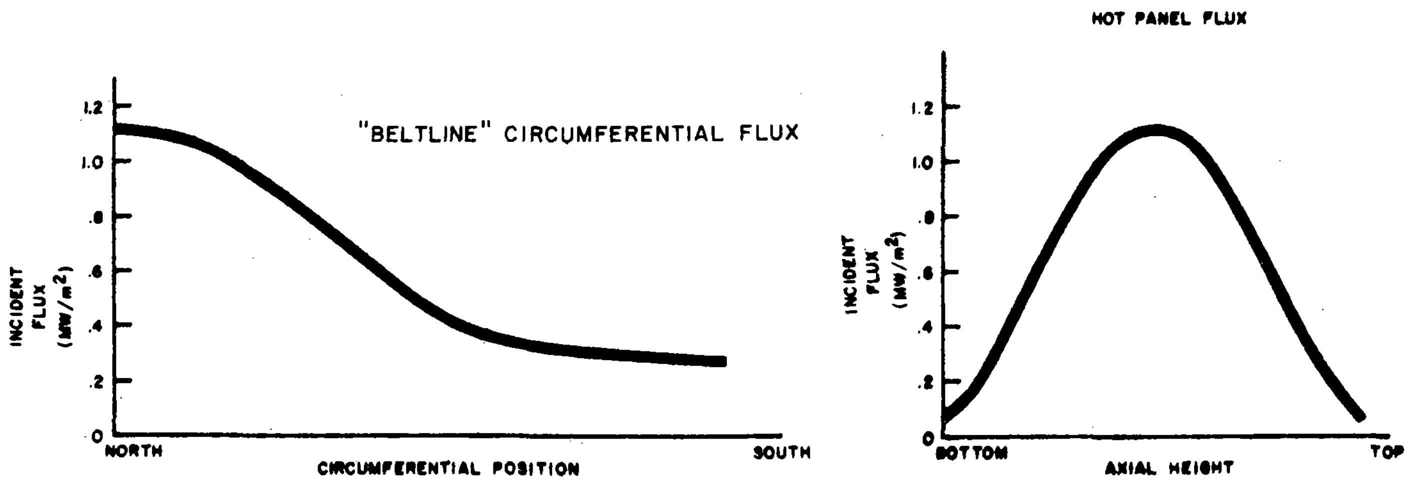


Figure 5.3-4. Repowering Receiver Design Fluxes
(Equinox Noon)

5.3.5.2 Field Efficiency

Field efficiency is defined as:

$$\text{Field Efficiency} = \frac{\text{Power Incident on Receiver}}{\text{Total Reflector Surface Area x Normal Flux}}$$

At the design point, the field efficiency is 71.4%. The variation of field efficiency with time is shown in Figure 5.3-5.

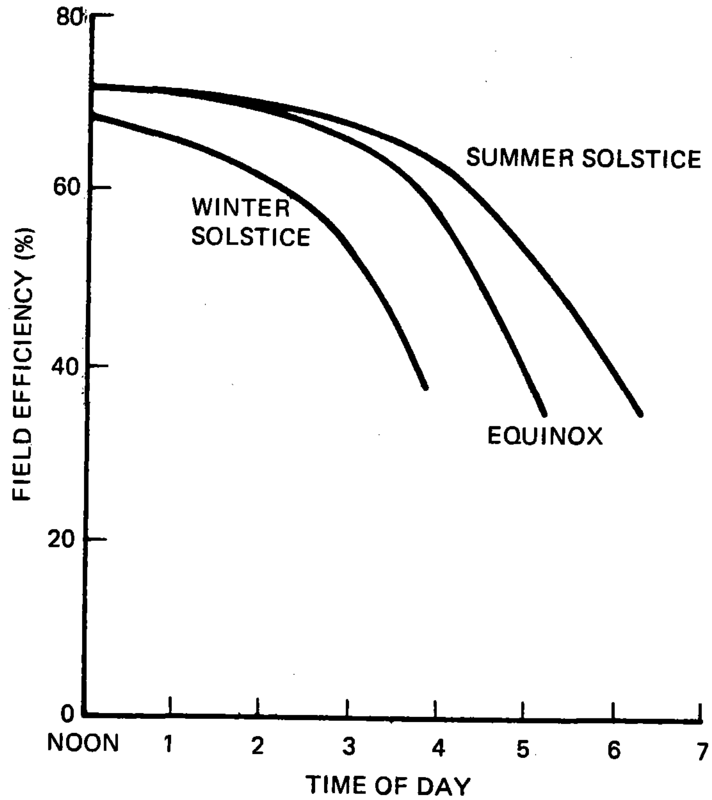


Figure 5.3-5. Field Efficiency Variation With Time

5.3.6 COST ESTIMATE

The collector subsystem cost estimate was based on the DOE-provided assumption of $\$230/m^2$. This cost is an installed cost for the heliostat field including the field wiring and control computer equipment. This direct cost totals $54,197,430.

Because the heliostat installation will in essence be a turnkey effort on the part of the collector field vendor, the approach taken in calculating indirect costs was different from other subsystems. Lump sum estimates of the cost of engineering (field layout and specification work) and construction management (monitoring of vendor performance by SPS) were made as opposed to the conventional percentage approach. The lump sum estimates are best guesses by General Electric and SPS based on time and material considerations for these efforts. The results are summarized in Table 5.3-7. No contingency is included for the collector subsystem since they are based on DOE projections based on numbers already including some contingency.

Table 5.3-7

COLLECTOR SUBSYSTEM COST SUMMARY

Collector Subsystem Purchase		$ 54,197,430
Engineering		1,600,000
Construction Management		900,000
	Total	$ 56,697,430

Additional cost details are provided in the Appendix A, System Requirements Specification.

5.4 RECEIVER SUBSYSTEM

The receiver subsystem includes the receiver, tower, riser/downcomer piping, field piping, tower pump throttle valve assembly and cold trap. Figure 4.2-1, the plant P&ID, illustrates how this subsystem interfaces with the remainder of the plant.

This section describes in detail the design, performance and operating characteristics of the subsystem and its components.

5.4.1 SYSTEM REQUIREMENTS

Table 5.4 -1 provides a list of receiver subsystem requirements. These requirements evolve from the overall plant performance requirements and also from the collector subsystem design discussed in Section 5.3 and the steam generator subsystem design to be discussed in Section 5.5.

Table 5.4-1

RECEIVER SUBSYSTEM DESIGN REQUIREMENTS

Parameter	Requirement
Nominal Power	142.8 MWth (60MWe)
Receiver Size	12m x 12m (39.4 ft x 39.4 ft) cylindrical
Tower Height	140m (460 ft)
Working Fluid	Sodium
Inlet Temperature	293^{o} C (560^{o} F)
Outlet Temperature	593^{o} C (1100^{o} F)

In addition to the design requirements listed in Table 5.4-1, the following operational requirements were also imposed on the design of the receiver subsystem.

- Upon loss of pump power provide for emergency sodium flow in receiver until the relative movement of the sun removes the incident energy from the receiver

- Provide system draining capability to the storage subsystem
- Provide capability of overnight shutdown without system draining and rapid startup in the morning
- Provide facility for maintaining sodium purity

5.4.2 SYSTEM DESIGN DESCRIPTION

Figure 5.4-1 presents a schematic diagram of the receiver subsystem. Described in the subsequent sections are the general system function, the design characteristics of the overall subsystem and a description of the system arrangement.

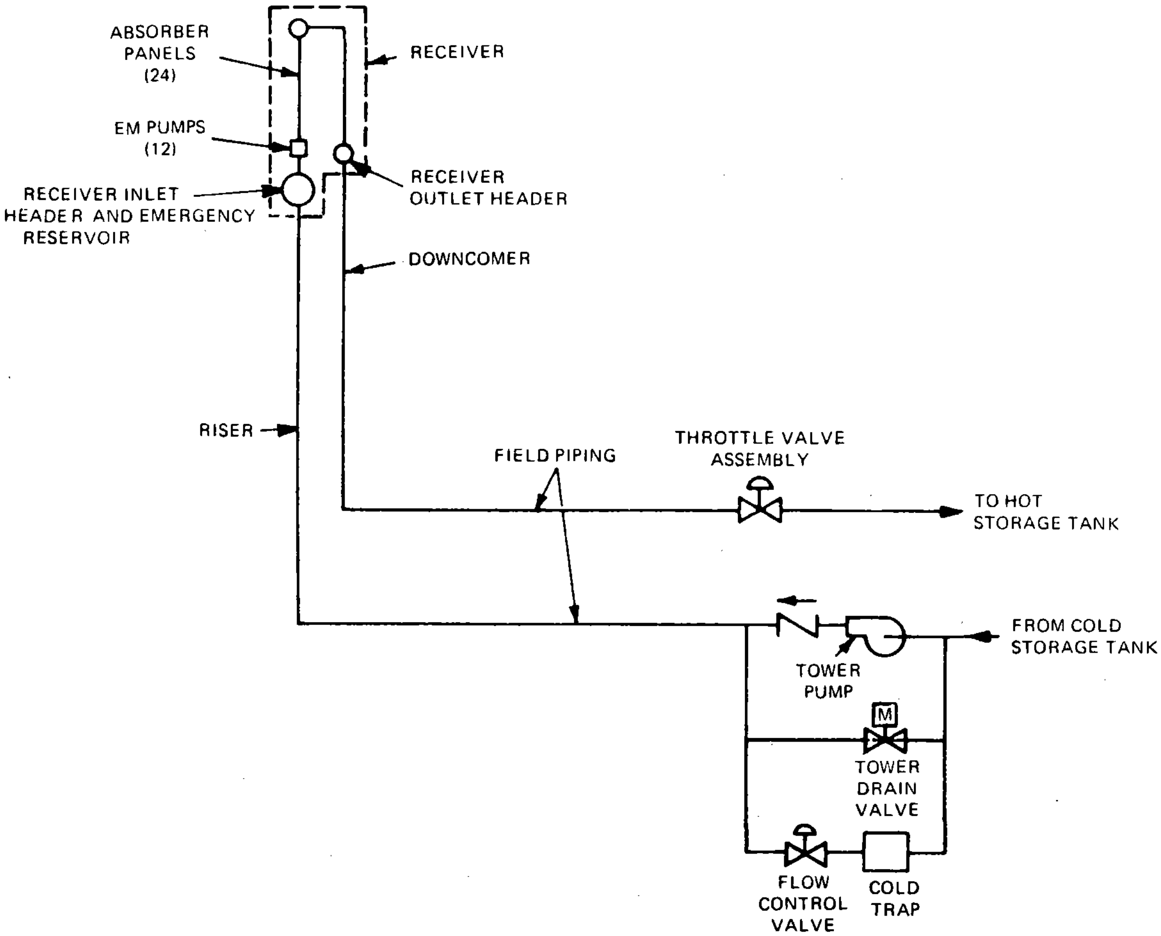


Figure 5.4-1. Receiver Subsystem Schematic Diagram

5.4.2.1 System Function

The receiver tower pump takes suction on the 293° C (560° F) cold storage tank sodium and pumps the fluid to the receiver inlet header at the top of the tower. At that point the 12 electromagnetic (EM) pumps take suction on the inlet header and distribute the flow of sodium to the 24 absorber panels. Each EM pump supplies enough flow to its pair of panels to achieve the desired 593° C

(1100°F) outlet temperature. The panel flows recombine at the receiver outlet header. The hot sodium returns down the tower and across the collector field to the hot sodium storage tank. A throttle valve assembly in the hot leg piping controls the total receiver subsystem flow.

In a simultaneous, peripheral function, part of the tower pump discharge is passed through a cold trap to remove sodium impurities.

5.4.2.2 Receiver Subsystem Design Characteristics

Table 5.4-2 lists the design characteristics of the receiver subsystem for design point operation.

Table 5.4-2

RECEIVER SUBSYSTEM DESIGN CHARACTERISTICS

Parameter	Design Value
Absorbed Power	140.9 MWth
Power Delivered to Hot Storage Tank	141.8 MWth (includes energy gained from pumping and pipe losses)
Inlet Temperature	293^{0} C (560^{0} F)
Outlet Temperature	593^{0} C (1100^{0} F)
Receiver Flow Rate	1.34×10^{6} kg/hr (2.95×10^{6} lbs/hr)
Tower Height	140m (460 ft)
Tower Design	Slip-formed concrete
Receiver Design	
- Total Receiver Weight (Including structure, pumps, etc.)	210,000 kg (461000 lbs)
- Shape	Cylindrical
- Size (Active area)	12m x 12m (39.4 ft x 39.4 ft)
- Flow control	EM pumps
- Absorber Material	I800
- Number of Panels	24
- Panel Design	Once through, two header brazed-tube
Tower Pump Design	Constant Speed Centrifugal
- Pump Discharge Pressure	2.08MPa (302 psia)
- Pump ΔP	1.93MPa (280 psi)
Hot Leg Piping	30.5cm (12 in) dia., 304H SS
Cold Leg Piping	30.5cm (12 in) dia.,A106B C.S.

More detail on the design of the various receiver components is presented in the discussion of the subsystem components (Section 5.4.3).

5.4.2.3 Subsystem Arrangement

Figure 5.1-1, the site plan, illustrates the position of the receiver, tower and field piping components of the receiver subsystem. However, the remaining components are housed within facilities shown on the figure. Table 5.4-3 lists these components and the facilities on the plot plan that contain them.

Table 5.4-3
RECEIVER SUBSYSTEM COMPONENT LOCATIONS

Component	Location (Reference Figure 5.1-1)
Tower Pump	Pump Bldg
Cold Trap	Pump Bldg
Throttle Valve Assembly	Pump Bldg
EM Pumps	In Receiver
Riser/Downcomer	In Tower

5.4.3 MAJOR COMPONENTS

This section describes the major components of the receiver subsystem and describes the design and analysis efforts associated with each.

5.4.3.1 Receiver

The receiver includes the following major components:

- Absorber Panels
- EM Pumps and Receiver Flow Control System
- Inlet Header/Emergency Reservoir
- Receiver Structure
- Insulating curtains

Figures 5.4-2 and 5.4-3 illustrate the receiver design concept in total. Each of the major components is discussed below.

5.4.3.1.1 Absorber Panels - The absorber panel design is based on the Alternate Central Receiver, Phase II design. Each panel is a once-through, two header arrangement with flow entering the panel at the bottom and leaving from the top. The design characteristics of a single panel are shown in Table 5.4-4.

Table 5.4-4

REPOWERING ABSORBER PANEL DESIGN CHARACTERISTICS

Number of Panels	24
Panel Width	1.48m (4.85 ft)
Panel Length (Active)	12m (39.4 ft)
(Overall-Header to Header)	13.53m (44.4 ft)
Number of Tubes	
Tube Material	I800
Tube Diameter (OD)	1.9 cm (0.75 in)
Tube Wall Thickness	0.13 cm (0.050 in)
Panel Inlet Header Diameter (OD)	30.5 cm (12 in)
Panel Outlet Header Diameter (OD)	30.5 cm (12 in)
Header Wall Thickness	0.64 cm (0.25 in)
Design Pressure	690 kPa(100 psig)
Tube-Tube Joint Design	Brazed with insert
Tube Coating	Pyromark

As shown on Figure 5.4-2, the receiver panels will be hung from the receiver structure by the outlet header. Sixteen pairs of equally spaced linkages will connect the back of the panel to the receiver structure to provide support against panel distortion due to wind loading. The links will allow panel growth downward as the unit heats up. A flexible heat resistant shield will be placed between the panels to prevent the insulation from impinging on the receiver structure.

The panel headers and back surface of the panels themselves will be insulated with a Fiberfax type of insulation. Approximately one foot of insulation will be used.

A detailed analysis was performed of the tube joint design to ensure that satisfactory life could be expected. The analysis was based on the joint design shown in Figure 5.4-4 with a peak flux of $1.13 MW/m^2$. The Figure 5.4-4 design is

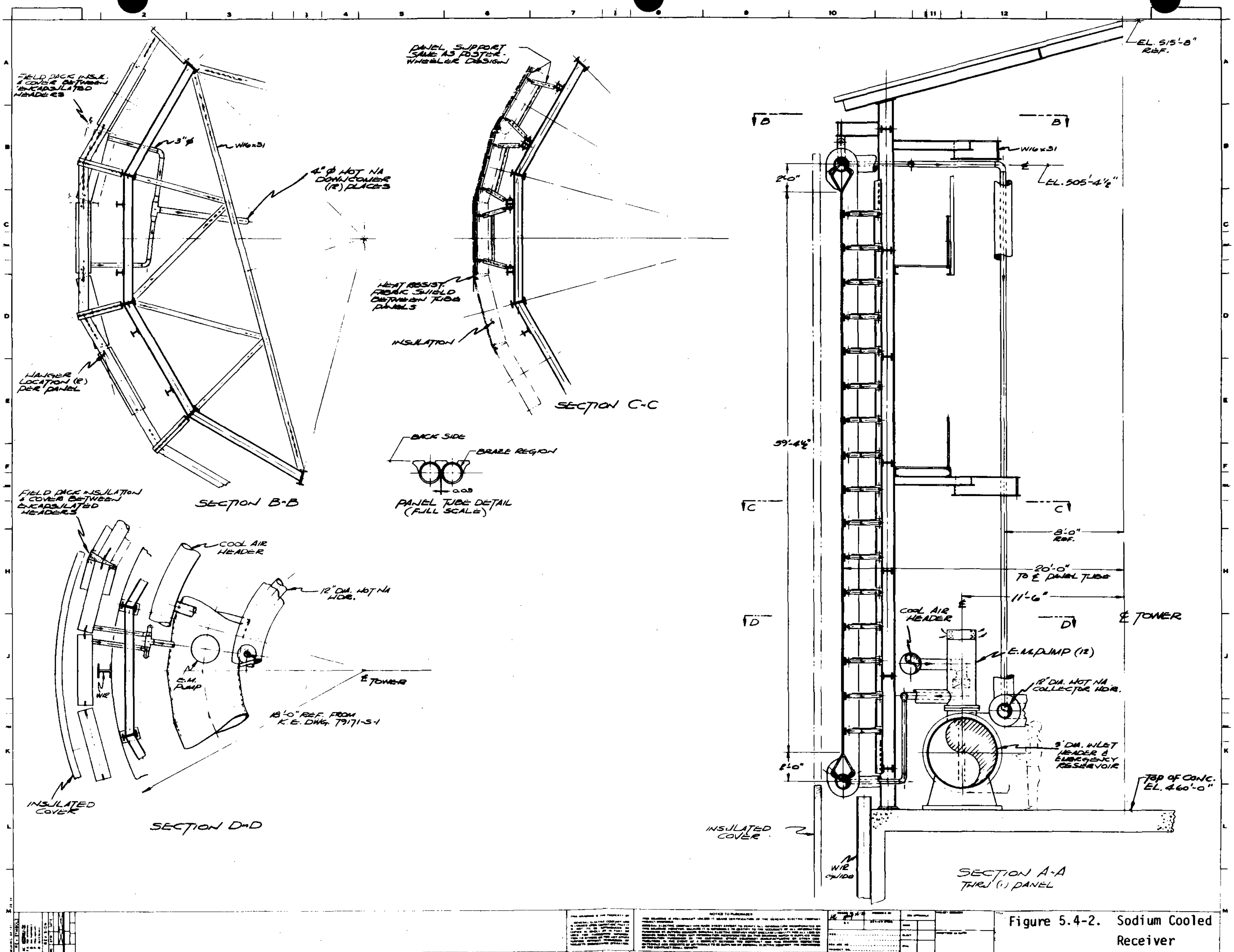


Figure 5.4-2. Sodium Cooled Receiver

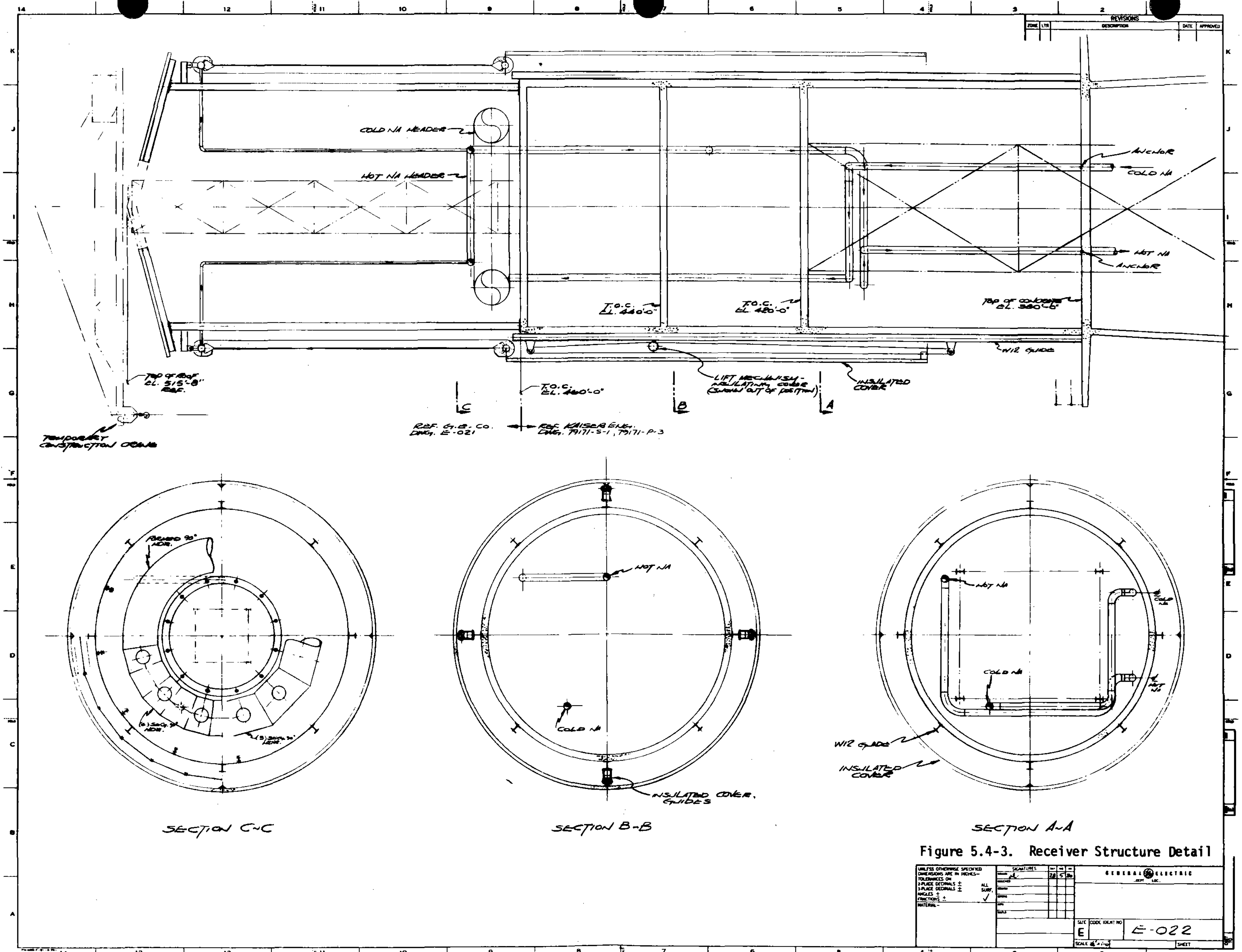


Figure 5.4-3. Receiver Structure Detail

a departure from the Alternate Central Receiver, Phase II design also shown in Figure 5.4-4.

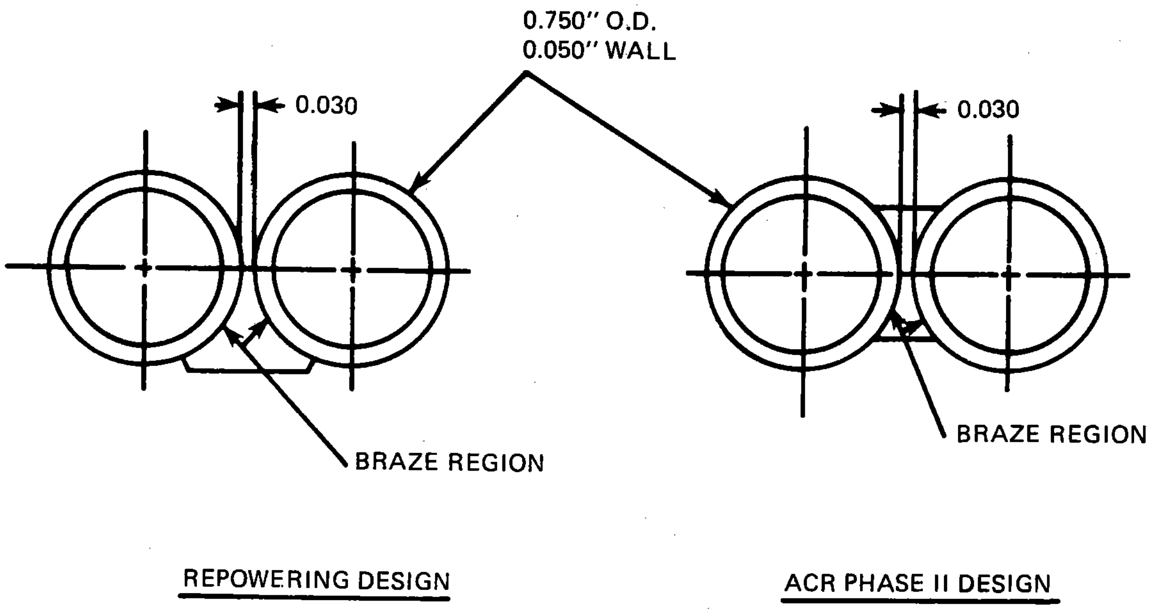


Figure 5.4-4. Panel Tube Joint Designs

The ACR-II design, when exposed to the 30-year repowering cycling, showed a damage factor in excess of 1.0, meaning the tube joints would experience unsatisfactory cyclic damage. The repowering joint design, however, showed a damage factor of only 0.407, well within the acceptable range. Details of the analysis and results are presented in Appendix E.

5.4.3.1.2 EM Pumps and Receiver Flow Control System - The electromagnetic pumps provide variable flow capability and are the heart of the overall receiver flow control system.

Electromagnetic pumps were selected over flow control valves because of their high reliability and favorable operating experience in the required size range. Electromagnetic pumps have no seal bearings or moving parts, and can regulate flow from 0 to full flow to maintain a required outlet temperature. Zero flow is achieved by reversing the field in the stator causing the pump to pump backwards. The field can be adjusted to zero flow conditions.

A typical annular linear induction (ALIP) type EM pump with a center return pipe is shown in Figure 5.4-5. The center return design was selected to aid the piping layout and to allow the stator to be removed and replaced without cutting into the sodium pressure boundary.

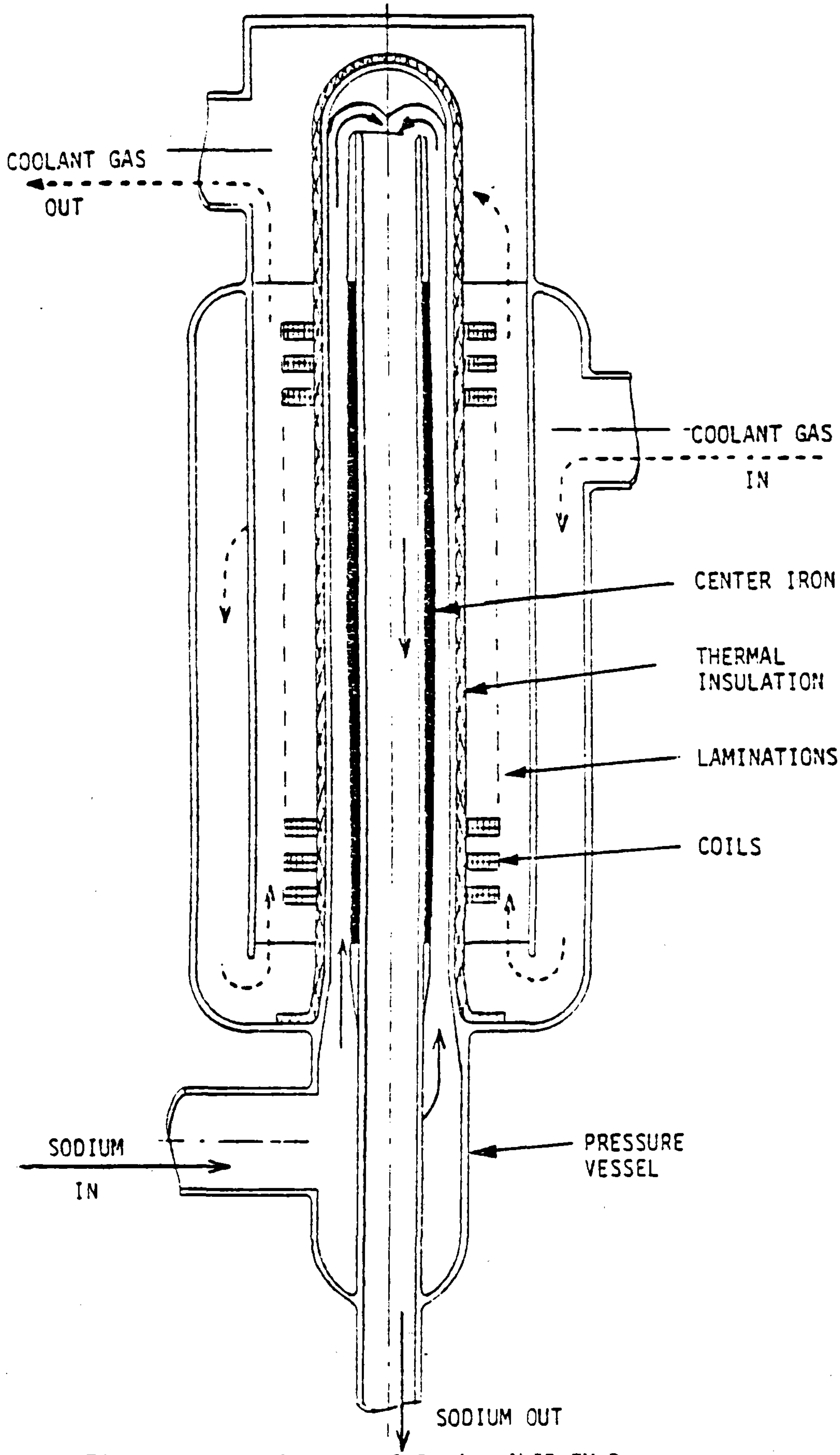


Figure 5.4-5. Conceptual Design ALIP-EM Pump

Each of the 12 EM pumps serves one pair of adjacent receiver panels, as illustrated in Figure 5.4-6. The pumps are mounted on the receiver inlet header and take suction on the bottom of the header as shown in Figure 5.4-2. Each pump provides flow to its panel pair such that the average outlet temperature from the panels is 593^0 C (1100^0 F). The control on the pump output will come from a combination of insolation flux sensors and temperature readings of the combined panel outlet flow. The pump speed will be controlled primarily by the incident flux level with fine tuning based on the panel outlet temperature. Appendix F presents analysis results which illustrate this control scheme's capability to maintain steady control of the critical receiver parameters (sodium temperature, tube temperature). Further demonstration of this control scheme will occur in the Alternate Central Receiver, Phase II test at CRTF in early 1981. The CRTF test will also provide input to demonstrate the best way of measuring incident flux, panel mounted thermocouples, or flux sensors. For this conceptual design, flux sensors were assumed.

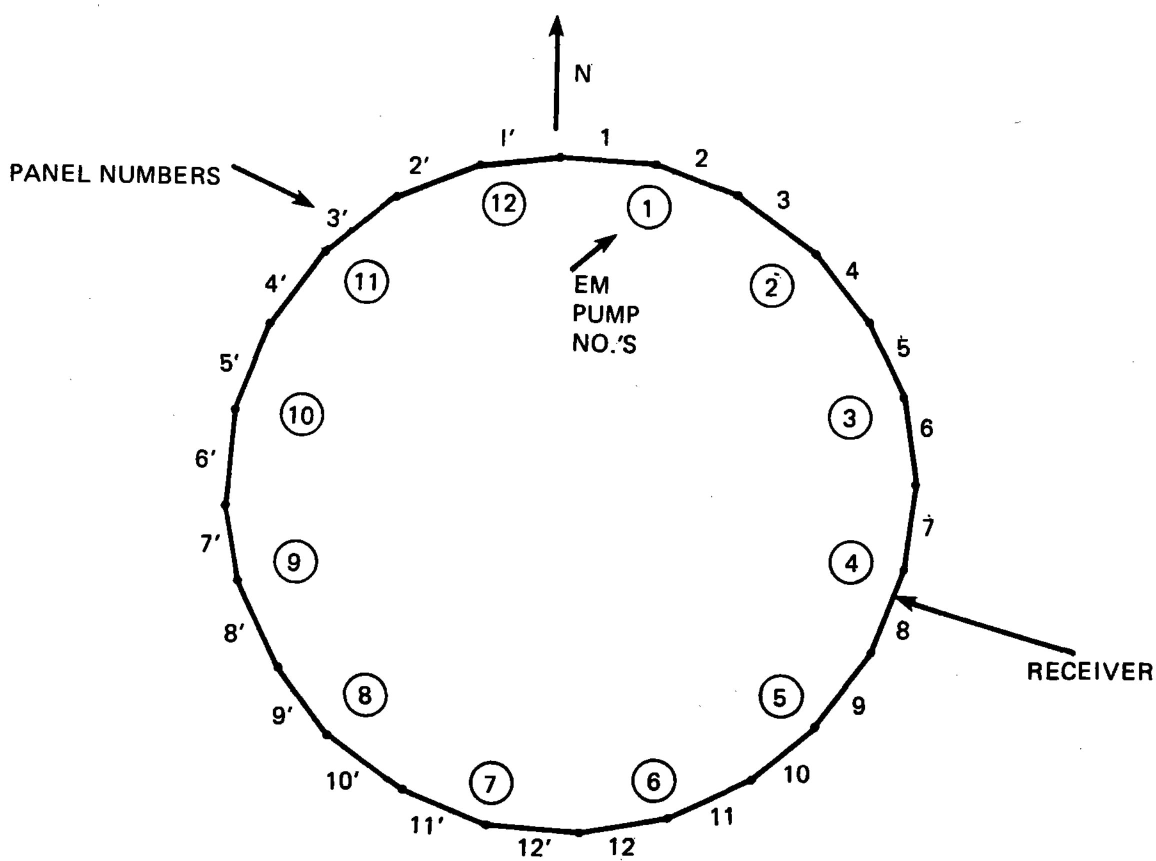


Figure 5.4-6. Receiver and EM Pump Numbering Sequence

Table 5.4-5 shows the design point characteristics of the 12 EM pumps. The table also shows the assumed design flows for each pump. The difference in the design point (noon, equinox) and design flows results because the east and west side panels will not receive maximum insolation at noon but rather later and earlier in the day respectively. Thus the design point flow for other than the north pumps will be considerably lower than the maximum flow. Details of the pump ΔP calculations are shown in Appendix B.

Table 5.4-5
EM PUMP DESIGN CHARACTERISTICS

Pump No.	Panels Served	Design Point Flow 10^3kg/hr (10^3lb/hr)	Design Point ΔP kPa (psi)	Design Flow 10^3kg/hr(10^3lb/hr)
1	1,2	197 (433)	134 (19.5)	214 (470)
2	3,4	174 (382)	110 (15.9)	198 (435)
3	5,6	117 (257)	66 (9.5)	133 (293)
4	7,8	70 (154)	41 (5.9)	84 (184)
5	9,10	59 (129)	37 (5.3)	76 (168)
6	11,12	55 (120)	35 (5.1)	70 (155)
7	11',12'	55 (120)	35 (5.1)	70 (155)
8	9',10'	59 (129)	37 (5.3)	76 (168)
9	7',8'	70 (154)	41 (5.9)	84 (184)
10	5',6'	117 (257)	66 (9.5)	133 (293)
11	3',4'	174 (382)	110 (15.9)	198 (435)
12	1',2'	197 (433)	134 (19.5)	214 (470)

The EM pumps have a pumping efficiency of only 25%. However, 80% of the remaining 75% input energy is recovered in the form of heat input into the sodium. To remove the remaining 15% of the pump input energy, cooling air is provided to avoid overheating the pump. A common cooling air header is provided as shown in Figure 5.4-2

5.4.3.1.3 Inlet Header/Emergency Reservoir - The receiver inlet header provides a second function as a supply of emergency sodium for loss of flow accidents. The header, illustrated in Figures 5.4.2 and 5.4-3, is a 1.52-meter (5-foot) diameter torus located at the top of the tower within the confines of the receiver. The torus will be fabricated from either curved piping sections or welded straight sections. Both concepts are illustrated in section C-C of Figure 5.4-3.

The concept was developed to handle the "total loss of site power" accident which would normally require a large emergency power supply (e.g. a ~3.5 MWe diesel generator) to permit the timely defocusing of heliostats. An emergency power supply was considered unacceptable for this accident situation. In addition to the high cost of such an emergency power source, its startup time together with the 20-second field defocus time would result in a tube burn through before the insolation could be removed. An analysis performed during the study showed that for a transient with a 10-second flux decay from the design point insolation following a one-second initiation of defocus activity (nonconservative transient) sodium boiling would take place within six seconds. Transition from liquid to sodium vapor would result in reaching the melting point for the tube within seconds. This nonconservative analysis indicated the central emergency power supply approach to defocusing on loss of site power was inadequate.

The approach selected to handle this condition was the provision for an emergency sodium reservoir in receiver.

Analysis showed that the relative motion of the sun will totally remove the insolation from the receiver with fixed heliostats in approximately three minutes. If the emergency reservoir is pressurized to 345 kPa (50 psia) on a loss of flow signal, adequate sodium flow through all the receiver panels can be provided to limit the peak sodium temperature to less than 815°C (1500°F) which is 67°C (120°F) below the sodium boiling point. All panels would receive the same flow and thus the hot (north) panel would experience a temperature this high. The flow would decay linearly with time over the three minutes by reducing the argon pressure. The required sodium for this transient is ~ 31800 kg (70,000 lbs). The inlet header is sized to provide this capacity.

In subsequent program phases, this concept would be refined to provide some distribution pipe orificing to make the distribution of sodium more in line with that necessary for each panel. This will reduce the amount of sodium required.

5.4.3.1.4 Receiver Structure - The receiver structure design concept is illustrated in Figures 5.4-2 and 5.4-3. The structure design was developed to maximize the amount of ground level prefabrication. It consists of 12 identical prefabricated, welded wall framing sections which will form the backing and hanging structure for the receiver panels. Each of these sections will be lifted into place and bolted to a tower top mounting collar.

Once a set of four wall framing sections is in place, the stiffening trusses will be bolted to the framing. Section B-B of Figure 5.4-2 illustrates this stiffened one-third section of the receiver structure.

A pedestal for a derrick-type crane will be included in the receiver housing. This crane will be used for lifting both the structure and panels into place. The crane pedestal will remain after construction to allow reinstallation of the crane should panel replacement be necessary.

An analysis of this structure was performed which demonstrates its ability to withstand the environmental loadings (wind, earthquake, etc.).

5.4.3.1.5 Insulating Curtain - A concept for the insulating curtain is shown in Figure 5.4-3. The curtain will be raised and lowered with a motor drive. The curtain will be guided by multiple roller guides mounted on I-beams around the straight section of the tower.

The curtain will be fabricated using structural steel framing, insulation and sheet metal sheathing. Although detailed analysis was not performed for this application, the curtain is expected to be ~ 0.3 to 0.6m (1 to 2 ft) thick. A sealing method will be developed for the top and bottom of the curtain when it is in the closed position to minimize convective losses during shutdown.

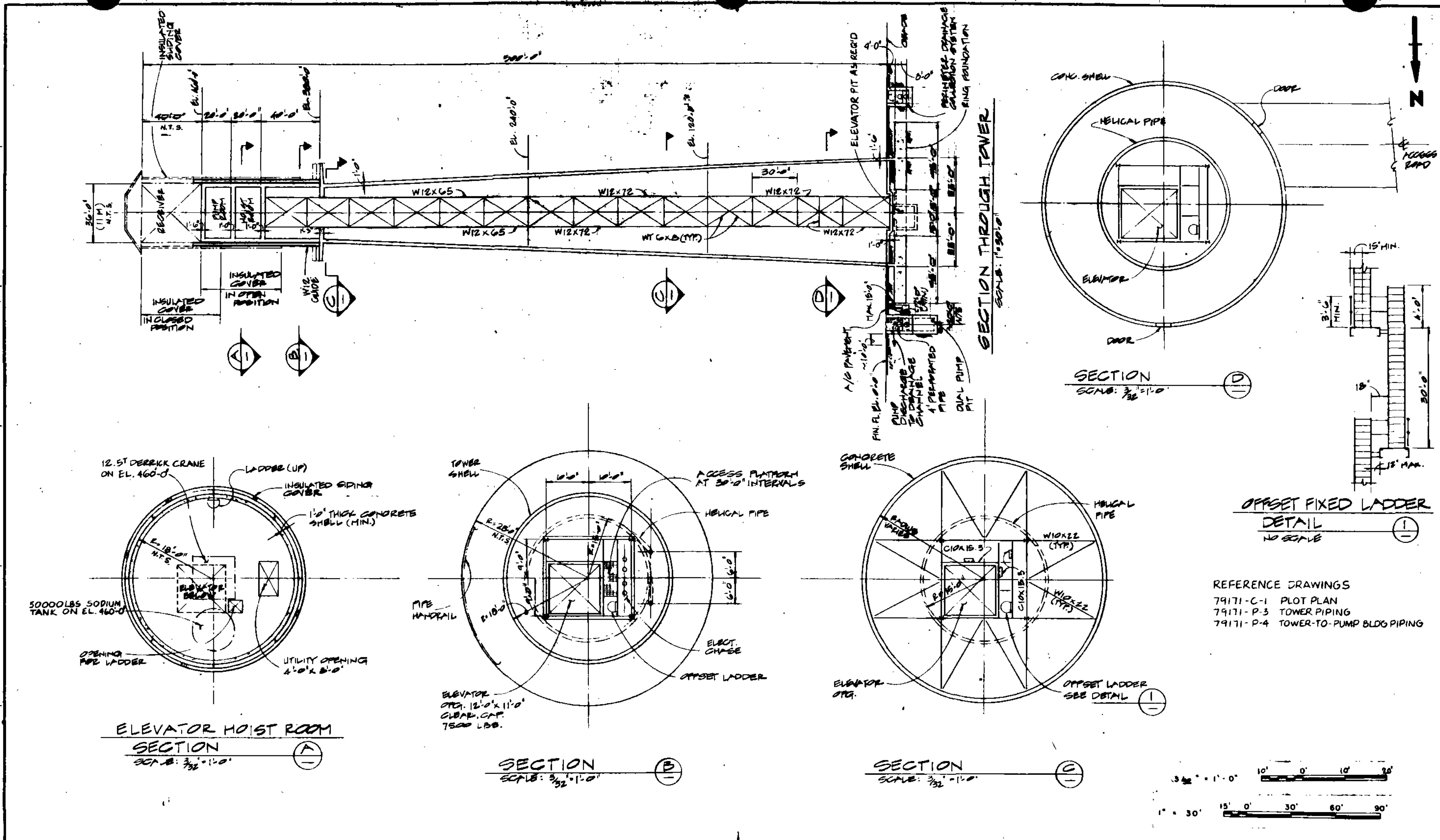
5.4.3.2 <u>Tower</u>

The tower supporting the receiver for the 60 MWe heliostat field array will consist of a slip-formed reinforced concrete structure with a height of approximately 140m (460 ft). An additional 12.2m (40-ft) for the receiver structure on top of the tower will extend the overall height of the receiver-tower to approximately 152.4m (500 ft). Figure 5.4-7 illustrates the tower design.

The outer diameter of the tower will taper from 21.3m (70 ft) at ground level to 11.6m (38 ft) at the 115.9m (380 ft) elevation. The thickness of the tower concrete wall will vary from 45.7 cm (18 in) at the base to 30.5 cm (12 in) at elevation 380. Above this elevation, a straight cylindrical reinforced concrete section will be utilized up to the 140m (460 ft) elevation.

A derrick type crane foundation will be provided on the top of the concrete tower (elevation 460) for a panel maintenance crane capable of lifting 11400 kg (25,000 lbs).

Two rooms will be provided in the upper tower section for receiver curtain



NOTES:
1. ASSUME 300 LBS. OF REINF. STEEL PER CUBIC YARD OF CONCRETE
2. CONCRETE ULTIMATE STRENGTH AT 28 DAYS = 4000 P.S.I. FOR TOWER, 3000 P.S.I. FOR FOUNDATION
3. STRUCTURAL STEEL TO BE ASTM A36

SCALE	AS NOTED	
DESIGNED BY	M. KUO	
DRAWN BY	R. H. FARIA	
CHECKED BY	K. N. JACOBSON	
APPROVED BY	T. LEE	

KAISER ENGINEERS

SPS SOLAR REPOWERING PROGRAM

Figure 5.4-7. Receiver Tower Plan & Sections

JOB No. 79171 DWG. No. 79171-S-1 REVISION R-0 hoisting equipment, absorber panel circulation pumps, and auxiliaries. A platform or deck around the outside of the tower at the 116 m (380 ft) elevation will be provided for maintenance access to the receiver panels and insolation curtains.

A summary of the weights of major structural elements of the tower used in its design is given in Table 5.4-6. These weights were based on preliminary estimates and are higher than the actual component weights.

Table 5.4.-6

TOWER WEIGHT

Element	Weight 1000 kg (1,000 lb)
Receiver	341 (750)
Derrick Crane Capacity	11.4 (25)
Toroidal Storage Header	22.7 (50)
Equipment and Piping	105 (230)
Tower Concrete (Excl. FDN)	6864 (15,100)
Subtotal	7343 (16,155)
Tower Foundation	5784 (12,725)
Total Tower Weight*	13127 (28,880)

*Excluding Soil Overburden And Central Core Surcharge

Inside the tower, a steel structure will support a central elevator and service shaft providing maintenance access to the receiver from the base of the tower. In addition to a 3410 kg (7,500 lb) capacity elevator, this structure within the tower will also provide vertical chases for electrical power and instrumentation conduit, and piping and a caged safety ladder with maintenance platforms at various levels to facilitate access and maintenance operations. Lateral stability of the 128m (420 ft) high central core structure will be provided by steel framing between the structure and the tower shell at two intermediate levels.

The tower structural design will comply with applicable federal government and current state, and local and industry building construction codes. The principal codes and design criteria for the tower are summarized in Table 5.4.-7. The results of a structural analysis of the tower conceptual design compared to the allowable code limits and/or design criteria are given in Table 5.4-8.

Table 5.4-7

SUMMARY OF TOWER STRUCTURAL DESIGN CRITERIA

A. Natural Phenomena	
Earthquake	UBC Zone 2
Wind Gusts	Up to 54m/sec (120 mph)
Snow	0.96kPa (20 lb/ft^2)
Ice	7.6cm (3 in) thick buildup
B. Material Strength	
Tower Shell Concrete $-f'_c$	27.6MPa (4,000 psi)
Tower FDN Concrete $-f_c$	20.7MPa (3,000 psi)
Reinforced Steel $-f'_c$	414MPa (60 ksi)
Structural Steel $-f_y$	248MPa (36 ksi)
Soil Bearing $-f_y$	-192kPa (-4,000 psf) to 1.8m (6 ft) -216kPa (-4,500 psf) 2.1 to 12.2m (7 to 40 ft)
C. Codes	
1. UBC - 1979	
2. NRC Regulatory Guides 1.60 and 1.61	
3. ACI 319-77 Building Code Requirements for Reinforced Concrete	
4. Act 307-69 Design And Construction For Reinforced Concrete Chimneys	
5. American National Standard A58.1 - 1972	

Table 5.4-8

STRUCTURAL ANALYSIS OF TOWER

Loading Condition	Code Allowable Or Design Criteria	Calculated Design
A. Receiver		
• Wind Displacement	1 m (3.28 ft)	5.6cm (2.2 in.)
• Seismic Displacement	-	13.7cm (5.4(in.)
B. Tower Concrete		
• Compressive Stress - DL + Wind	12.4MPa (1.8 ksi)	4.2MPa (0.61 ksi)
• Compressive Stress - DL + Seismic	12.4MPa (1.8 ksi)	4.3MPa (0.62 ksi)
C. Tower Ring Foundation		
• Shear	759kPa) 110 psi)	690kPa (100 psi)
• Compressive Stress - DL + Wind	286kPa (5.98 ksf)	217kPa (4.54 ksf)
• Compressive stress - DL + Seismic	286kPa (5.98 ksf)	284kPa (5.93 ksf)

Based on an analysis of soil samples taken from several borings in the proposed tower location by an Amarillo, Texas, soils laboratory, the tower foundation will be designed for an allowable bearing load of 216 kPa (4,500 lbs/ft^2). The proposed ring type continuous footing or foundation designed for this bearing allowable will have an outside diameter of 36.6m (120 ft), an inside diameter of 9.1m (30 ft), and a thickness of 2.4m (8 ft) under a soil overburden of 1.2m (4 ft) as shown on Figure 5.4-7. The soils laboratory concluded that this bearing allowable for the design will limit the total structure settlement to less than one-half inch.

A profile of the soil in the area of the tower is indicated in Figure 5.4-8. As in many areas of the Southwest, the local sandy clay material is a free draining, permeable type of soil. This type of soil, if confined and dry, will normally support substantial loads. Therefore, special efforts will be made in the design to enhance the stability of the soil through the use of additives such as fly ash and provision of storm water drainage systems.

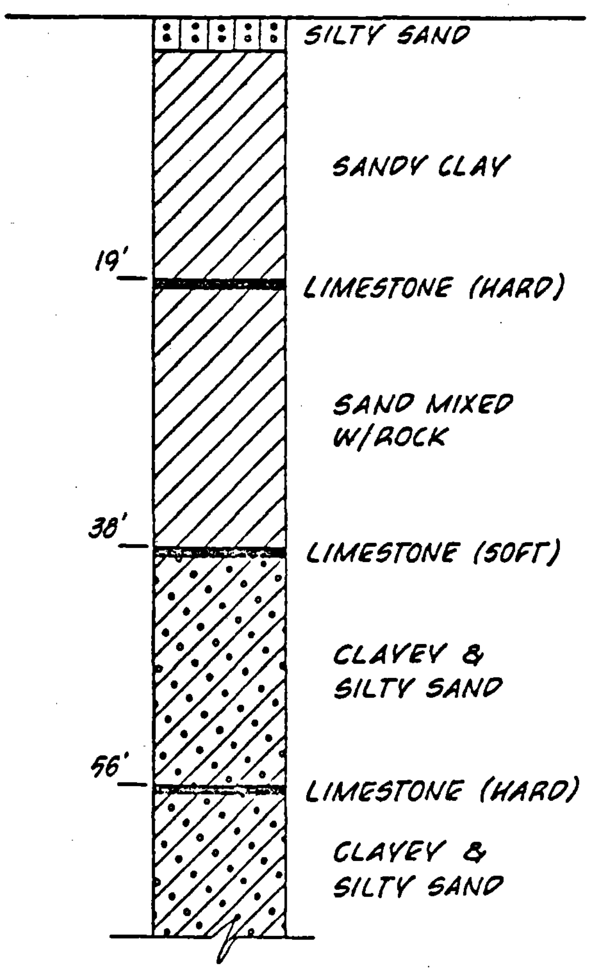


Figure 5.4-8. Receiver Tower Soil Profile

A rock-filled perimeter drainage collection trench will be provided to intercept and dispose of sub-surface water flowing through the soil due to rainfall or melting snow to protect the soil structure supporting the tower from the intrusion and deteriorating effect of water. The ground surface around the tower will also be stabilized with fly ash and paved with an asphalt seal coat and two layers of rock chips to prevent the intrusion of surface water and provide erosion and wear-resistance for maintenance vehicle traffic.

5.4.3.3 Piping

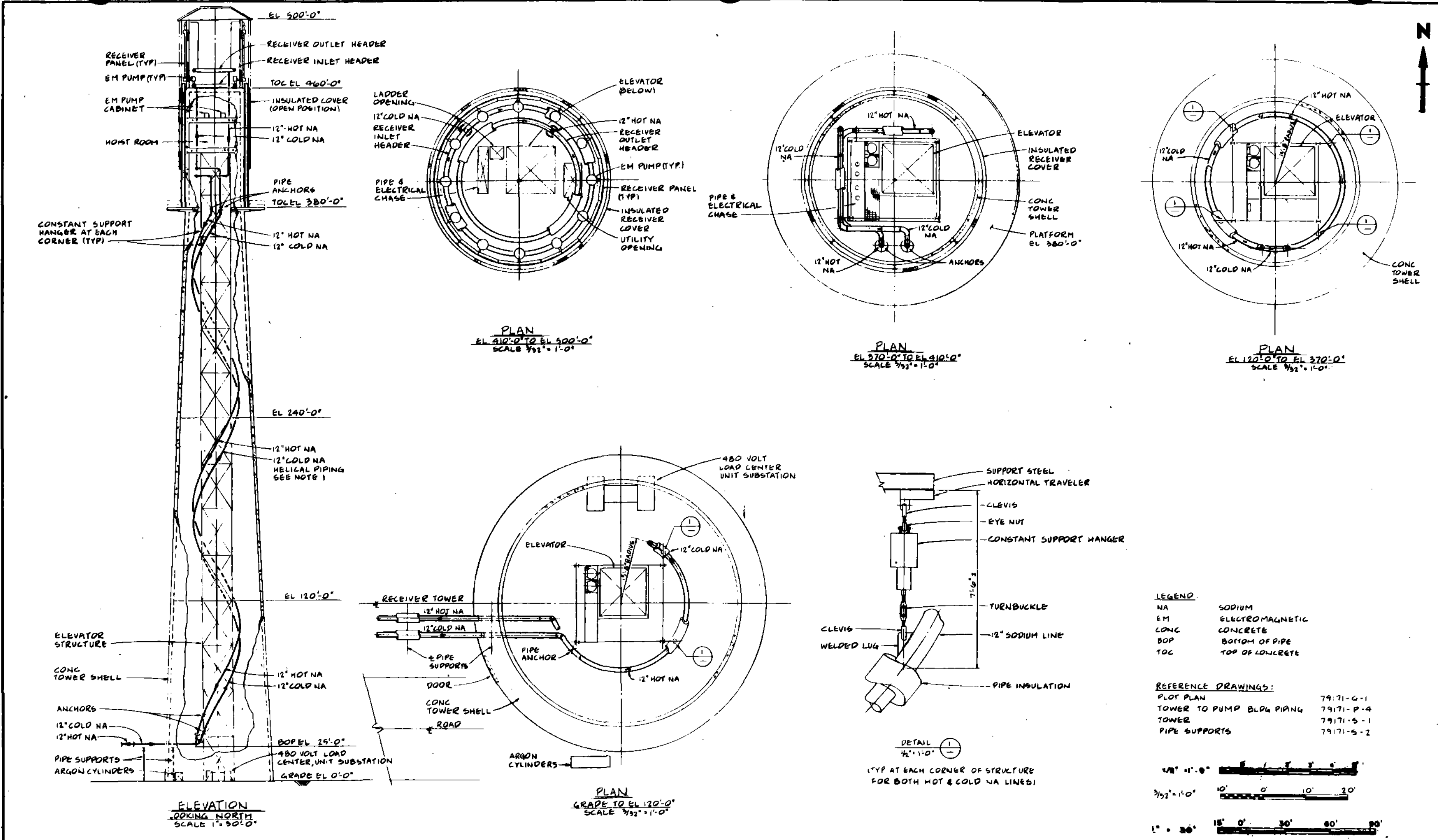
This section describes the main receiver subsystem piping, the tower riser/downcomer and the field piping (tower-to-pump building).

5.4.3.3.1 Tower Riser-Downcomer - The tower riser (supply)-downcomer (return) piping will provide the means of transporting sodium between the ground and the receiver at 293° C (560° F) in the riser and 593° C (1100° F) in the downcomer piping. A 30.5cm (12 in) nominal diameter has been established for both the riser and downcomer piping based on a maximum sodium design velocity of 7.6m/sec (25 ft/sec).

Investigation of various alternative methods of providing for thermal expansion of the riser-downcomer piping resulted in an all-welded helical configuration as the most reliable and cost effective design. The piping will encircle the central core service structure in the tower as indicated in Figure 5.4-9. The 9.1m (30 ft) diameter of the helix will follow an angle of 60 degrees to provide a helix pitch of approximately 49.7m (163 ft). The sodium piping mains, penetrating the tower wall 7.6m (25 ft) above the ground, will be anchored and supported by spring-loaded constant support pipe hangers from the tower concrete and the corner columns of the service structure steel.

Materials to be used for the valves and piping were selected for compatibility with sodium at temperatures of 321°C (610°F) and 621°C (1150°F) and a pressure of 1.72MPa (250 psig). The temperature and pressure ratings include an allowance of 28°C (50°F) over the maximum transient or steady state operating temperature and 10% over the maximum transient or steady state operating pressure.

Since an upper temperature code limit for carbon steel is approximately 399° C (750° F), a seamless carbon steel material (ASTM A-106B) will be provided for the cold sodium riser piping and stainless steel (ASTM 304H) for the hot downcomer piping. Although a light weight wall thickness would satisfy the design



NOTES: 1. 60° HELIX ANGLE; 170'-6" PITCH.

SCALE: AS NOTED
DESIGNED BY R LEVINSON 2-26-80
DRAWN BY R LEVINSON 2-26-80
CHECKED BY J Coglan 2-27-80
APPROVED BY P.C. Eswey 3-6-80

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Figure 5.4-9. Tower Piping Plan & Elevation

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requirements, a standard weight wall thickness will be used for greater assurance of structural integrity.

The piping will be provided with sufficient insulation for a 40-hour shutdown without allowing local sodium temperatures to drop below 177° C (350° F) when normal and standby procedures (excluding trace heating) are utilized. Trace heating will be provided on all sodium systems and components to maintain a 177° C (350° F) minimum sodium temperature during prolonged shutdowns. More details on the piping insulation and trace heating are provided in Section 5.10.

5.4.3.3.2 Tower-To-Storage Sodium Piping - The riser and downcomer piping exiting the tower at approximately 7.6m (25 ft) above the ground will slope down at about one percent to the sodium storage tanks and pump building at Plant X . Approximately 610m (2,000 lineal feet) of electrically traced, insulated 30.5cm (12in nominal) diameter sodium tower supply and return piping will be supported overhead on steel support and anchor structures spaced approximately 6.1m (20 ft) apart between the tower and sodium storage tanks and pump building. Figure 5.4-10 shows this piping arrangement. The piping design conditions are the same as the riser-downcomer piping.

Thermal expansion will be accommodated by welded pipe expansion loops which were found to be less expensive and to offer greater system integrity than a system of multiple expansion joints.

5.4.3.4 Tower Pump

The tower pump, located in the pump building, moves the sodium to the top of the tower from the cold storage tank.

Table 5.4-9 shows the design requirements for the tower pump.

Table 5.4-9

TOWER PUMP DESIGN REQUIREMENTS

Parameter	Value
Flow Rate, kg/hr (lb/hr) x 10^{-6}	1.35 (2.97)
Head Rise, m (ft)	244 (800)
Design Temperature, °C (°F)	343 (650)
Design Pressure, MPa (psig)	2.4MPa (350)
Mech Efficiency %	75
Design Code	ASME Section VIII
Drive Motor Power kW (hp)	1300 (1750)

The tower pump will be a constant speed centifugal design similar to that illustrated in Figure 5.5-10. Table 5.4-10 lists the pump physical characteristics.

Table 5.4-10

TOWER PUMP PHYSICAL CHARACTERISTICS

Pump Dia., cm (in)	49
Pump Height, m (ft)	11
Drive Motor Dia, cm (in)	42
Overall Height, m (ft)	17.5
Impeller Speed, RPM	1725

The flow rate from the tower pump will be controlled by the throttle valves located in the sodium hot leg piping.

5.4.3.5 Throttle Valve Assembly

The throttle valve assembly consists of two sets of 5.1cm (2 in) and 203cm (8 in) motor-operated flow control valves and isolating valves as shown in the Figure 5.4-11 schematic diagram.

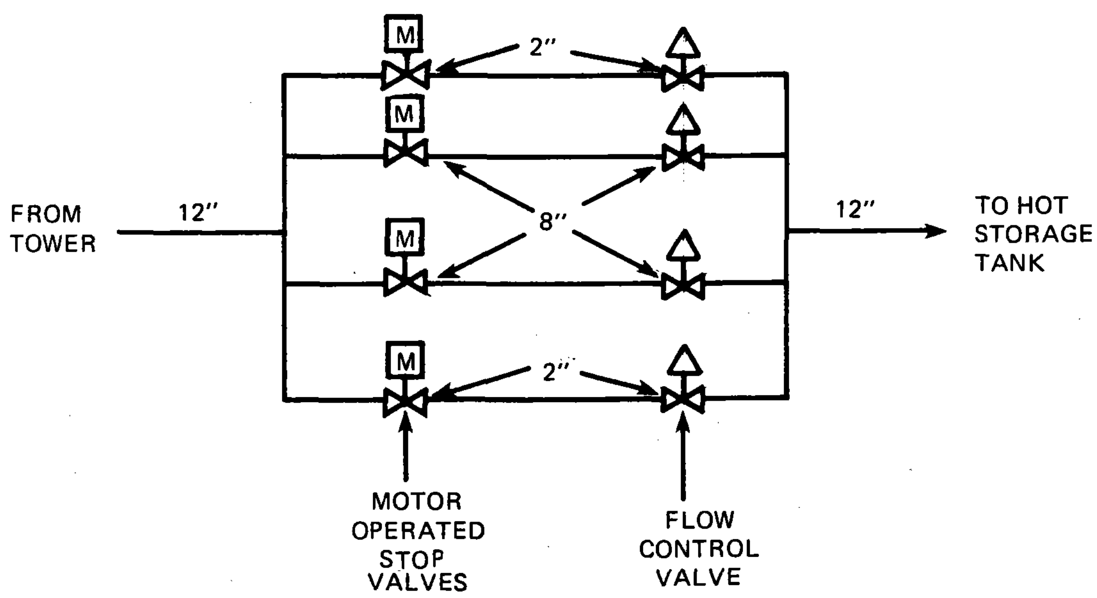
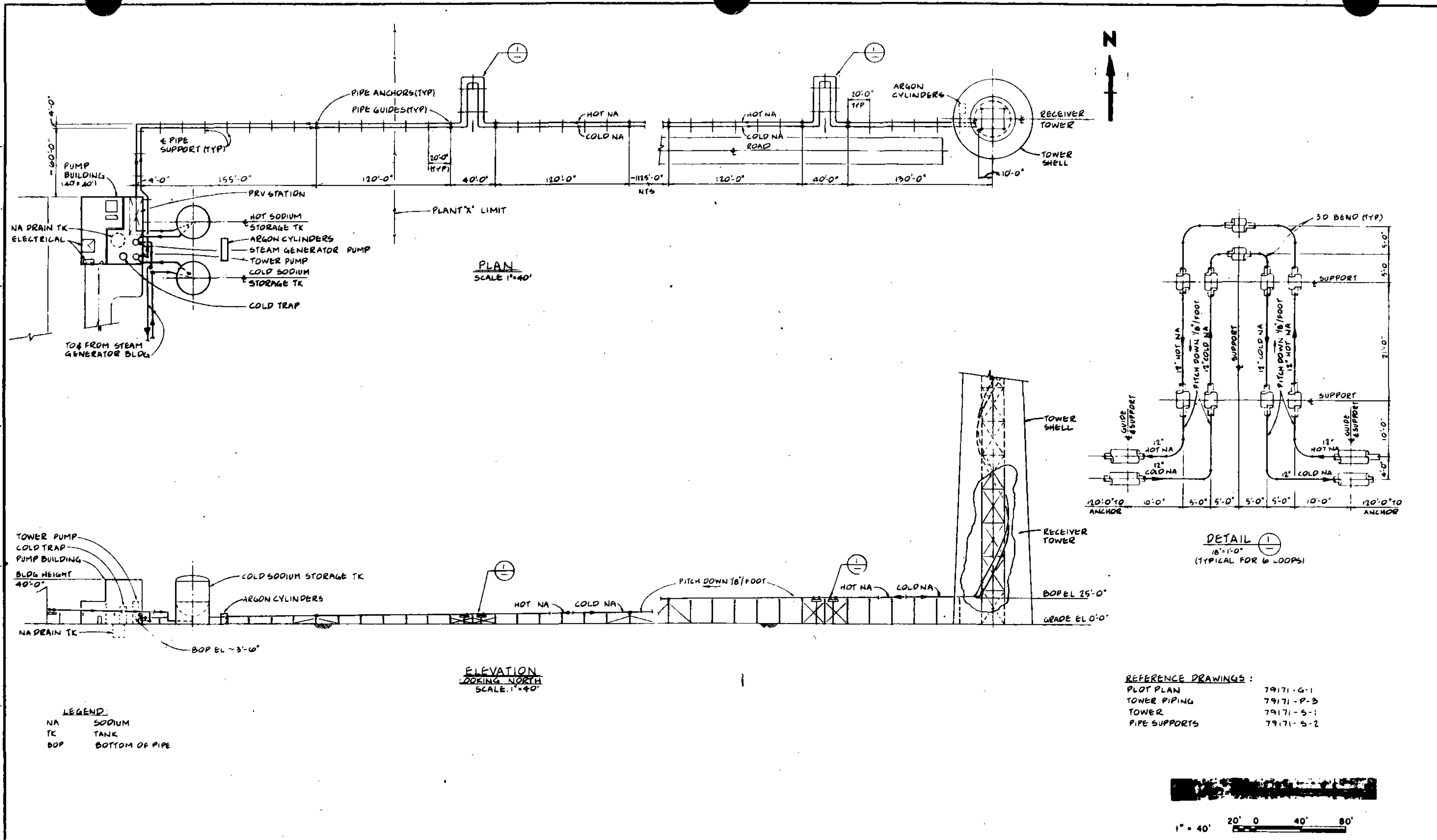


Figure 5.4-11. Throttle Valve Assembly

The assembly is located in the pump building in the main sodium line from the receiver to the hot storage tanks. The assembly functions to control the subsystem sodium flow to a rate consistent with the insolation level. At any one



NOTES: AT SUPPORTS EACH PIPE WILL REST ON A TETRAFLUOROETHYLENE SLIDE PLATE.

NO	DATE	REVISION	APP	APP

APPROVAL: 5-2-80
SCALE: AS SHOWN
DESIGNED BY R LEVINSON 2-27-80
DRAWN BY R LEVINSON 2-27-80
CHECKED BY 2-27-80
APPROVED BY 3-31-80
APPROVED BY 5-1-80

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Figure 5.4-10. Tower to Pump Building Piping Plan & Elevations

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time only one set of control valves, one 5.1cm/2 in and one 20.3cm/8 in, will be active. The other set is a backup.

The assembly will be able to control flow over the full range from zero to 1.34×10^6 kg/hr (2.95×10^6 lbs/hr). The valves will be positioned by controllers receiving an indication of the ΔP between the top of the user and the top of the downcomer. The valves will be positioned to maintain this ΔP at 0. With this ΔP at 0, the control of flow through the panels will be strictly by the EM pumps.

The design point (full flow) ΔP across this assembly will be 450 kPa (65.3 psi). The assembly will have an overall length of approximately 4.9m (16 ft).

5.4.3.6 Sodium Purification System

In the course of startup and operation of the large storage and sodium-heated steam generator loops, various impurities will get into solution in the hot sodium. Impurities will result from the accumulation of oxygen, hydrogen, carbon and other materials on the large surface areas of tankage and piping, and from unplanned leakage of water/steam/air into the loop. The conventional method of removing these impurities from the hot circulating sodium is by use of cold trapping.

It is expected that impurity contamination will be high during initial sodium fill and startup operations. Initial cleanup can be accomplished by use of throw-away filters or possibly a high efficiency sacrificial cold trap.

For normal sodium purification, one large counterflow heat exchanger cold trap would be used (Figure 5.4-12). The cold trap is installed in parallel in a loop around the cold leg tower pump. The cold trapping temperature is expected to be ~121^{o} C to 149^{o} C (250^{o} to 300^{o} F) (equivalent to about 0.7 ppm to 2.1 ppm of dissolved oxygen) during normal operation with the cold leg sodium temperature at 293^{o} C (560^{o} F). The cold trap is designed for a flow rate of 60 gpm.

5.4.4 OPERATING CHARACTERISTICS

5.4.4.1 Normal Operation

The receiver subsystem will function automatically to produce the required 593^{o} C (1100^{o} F) sodium at a rate corresponding to the insolation level. Under normal operations its function and control is independent of the remainder of the solar plant.

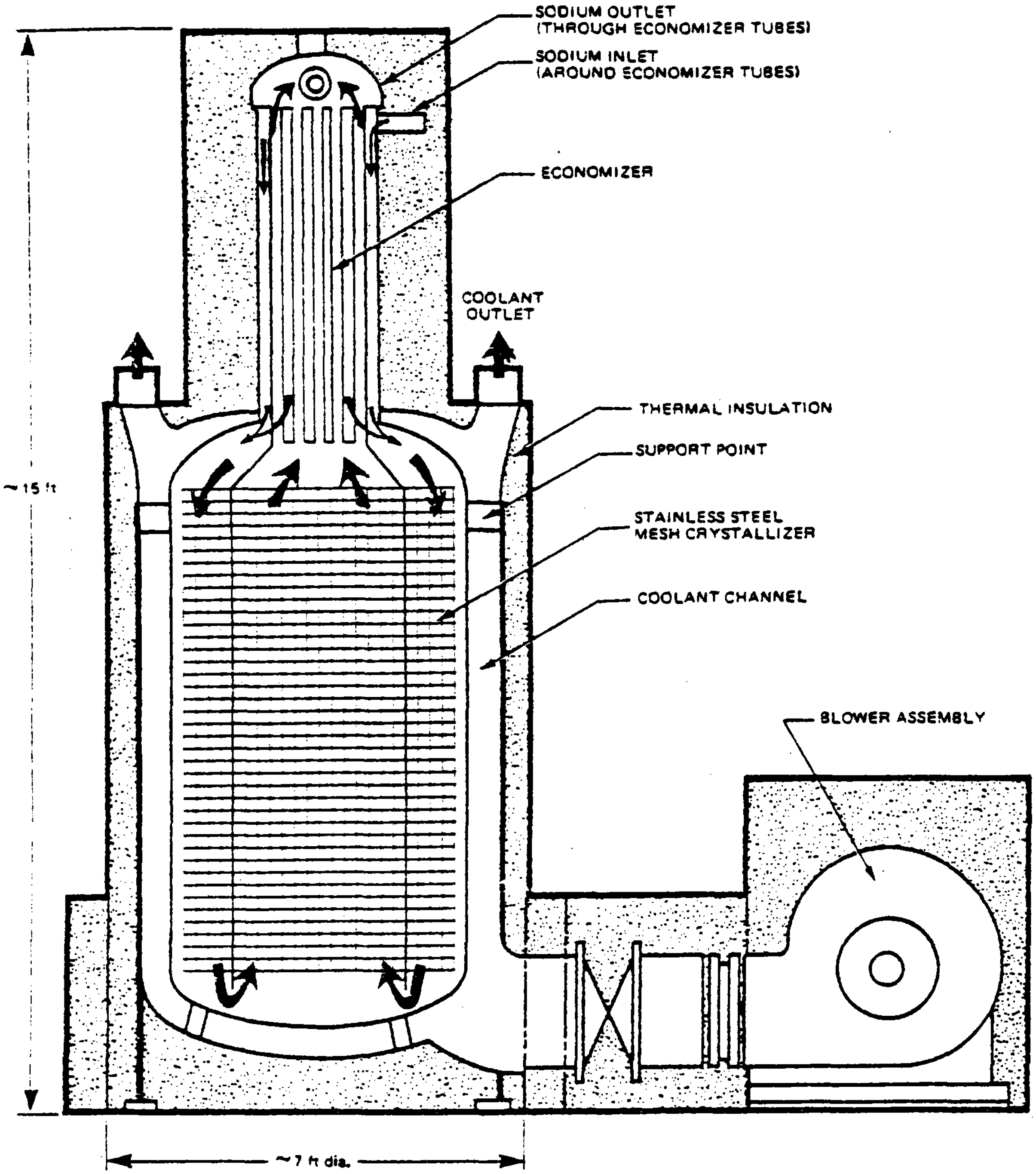


Figure 5.4-12. Cold Trap Design

The constant speed centrifugal tower pump moves the sodium to the top of the tower. The flow rate from the pump is controlled by the hot leg throttle valve assembly which acts to maintain a 0 ΔP between the top of the riser and top of the downcomer. At the tower top, the 12 EM pumps take suction on the receiver inlet header and distribute flow to the panels so as to maintain the desired outlet temperature of 593^{0} C (1100^{0} F). Because there is a 0 ΔP across the receiver, the panel flow is exclusively controlled by the EM pumps.

The EM pump output is adjusted by controllers which obtain signals from flux and temperature sensors associated with each panel pair. If the flux level rises, the EM pump output will increase. This would cause the downcomer pressure to increase relative to the riser pressure causing the throttle valve assembly to open more thus resulting in higher overall system flow. The EM pumps have a control range from 0 (or even reverse) flow to their design output.

5.4.4.2 Emergency Operation

Provision has been made to handle a total loss of system flow situation by providing an emergency reservoir of sodium in the receiver inlet header. In the event of a total loss of plant power (worst case) where the heliostats would remain focused, this inlet header would be automatically pressurized with argon. The resulting flow through the panels would last long enough to allow the relative motion of the sun to remove the flux from the receiver without causing receiver damage.

This reservoir would also be used as an emergency sodium supply in the event the tower or EM pumps lost flow.

5.4.4.3 Startup and Shutdown

A discussion of the startup and shutdown of the receiver subsystem is provided together with a description of the startup of the remainder of the plant in Section 4.2.2.

5.4.5 PERFORMANCE ESTIMATES

5.4.5.1 Subsystem Flows, Temperatures, Pressures (noon, equinox)

The design point system flows, temperatures and pressures are illustrated in Figure 5.4.-13. Local pressures and flow rates within the receiver itself are listed in Table 5.4.-11.

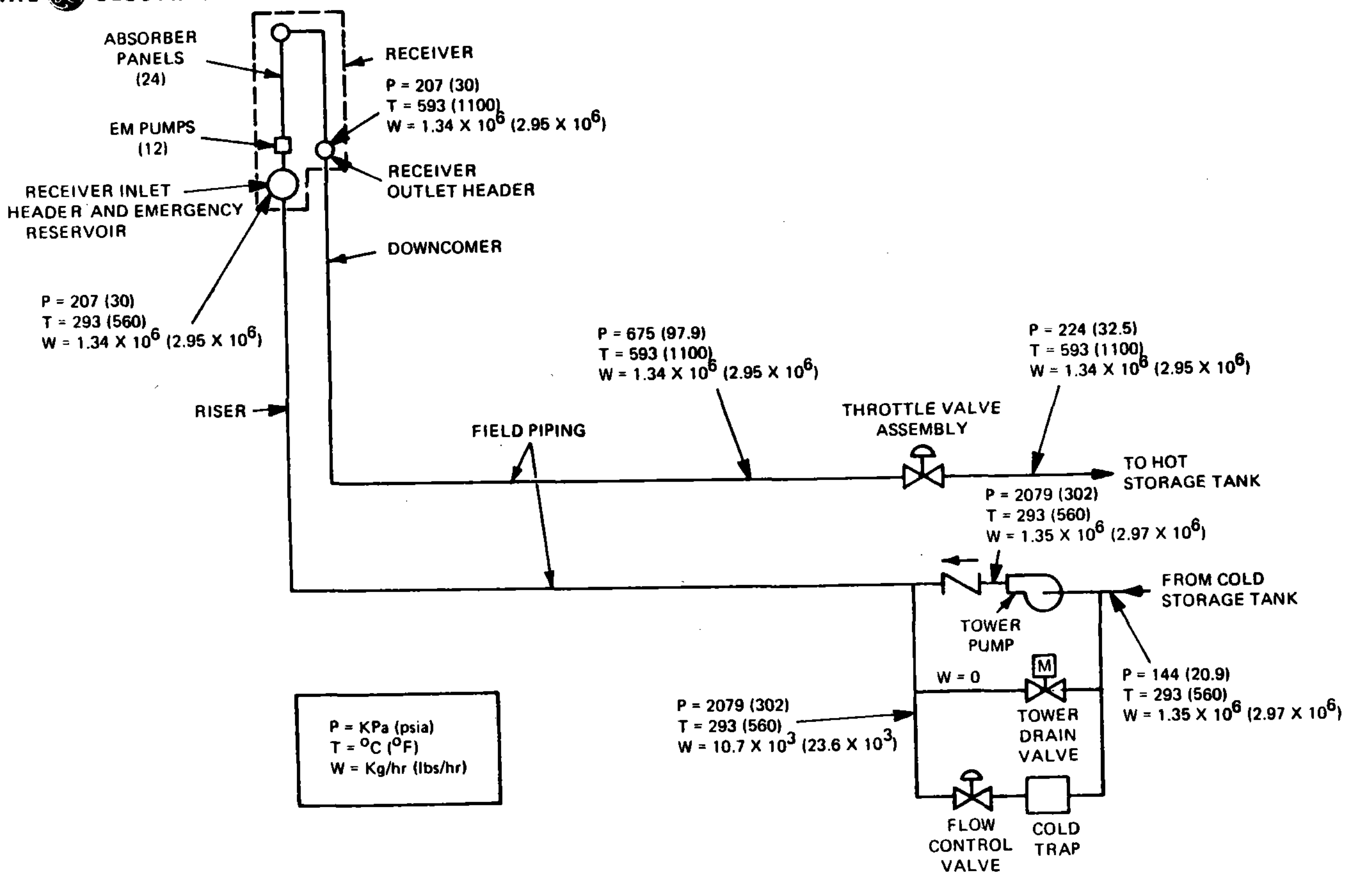


Figure 5.4-13. Design Point System Flows, Temperatures, and Pressures

Table 5.4-11

RECEIVER DESIGN FLOWS AND PRESSURES

EM* Pump No	Panel* No	Pump Suction Pressure	Pump Discharge Pressure	Panel Discharge Pressure	Receiver Outlet Header Pressure	Flow in Each Panel
		kPa (psia)	kPa (psia)	kPa (psia)	kPa (psia)	kg/hr(lbs/hr) x10^5
1	1,2	192(27.8)	323(46.9)	192(27.9)	196(28.4)	98(216.5)
2	3,4	192(27.8)	299(43.3)	175(25.4)	196(28.4)	87(191)
3	5,6	192(27.8)	254(36.9)	142(20.6)	196(28.4)	58(128.5)
4	7,8	192(27.8)	230(33.3)	125(18.1)	196(28.4)	35(77)
5	9,10	192(27.8)	226(32.7)	122(17.7)	196(28.4)	29(64.5)
6	11,12	192(27.8)	224(32.5)	121(17.5)	196(28.4)	27(60)
7	11',12'	192(27.8)	224(32.5)	121(17.5)	196(28.4)	27(60)
8	9',10'	192(27.8)	226(32.7)	122(17.7)	196(28.4)	29(64.5)
9	7',8'	192(27.8)	230(33.3)	125(18.1)	196(28.4)	35(77)
10	5',6'	192(27.8)	254(36.9)	142(20.6)	196(28.4)	58(128.5)
11	3',4'	192(27.8)	299(43.3)	175(25.4)	196(28.4)	87(191)
12	1',2'	192(27.8)	323(46.9)	192(27.9)	196(28.4)	98(216.5)

*See Figure 5.4-6 for panel numbering scheme

The flows described above are those necessary to achieve an average outlet temperature of 593°C (1100°F) from each pair of receiver panels. The flows were determined based on an analysis of the receiver using the Receiver Loss Program developed by General Electric in the Advanced Central Receiver, Phase I program. Details of the code function and logic are presented in the final report of that program (SRD-79-035-4). The code was also used in the determination of the thermal performance of the receiver discussed in the next section.

5.4.5.2 Receiver Thermal Performance

The receiver thermal performance analysis was based on the DELSOL-generated receiver flux pattern. It should be noted that the STEAEC analysis discussed in Section 4.4 was based on MIRVAL-generated field performance which produced slightly different incident power results (~ 1% less at design point). Thus, although the results presented in this section are different from the STEAEC results, the magnitude of the difference is considered insignificant.

The parameters used in the calculation of the design point thermal performance are summarized in Table 5.4-12.

Table 5.4-12

DESIGN POINT THERMAL ANALYSIS PARAMETERS

Flux	940W/m^2
Temperature	20^{o}C (68^{o}F)
Wind	0
Receiver Reflectivity	0.95
Receiver Emissivity	0.9

The incident flux resulting from the field design discussed in Section 5.3 is shown in Table 5.3-6. The resulting overall receiver thermal performance is shown in Table 5.4-13.

Table 5.4-13

RECEIVER THERMAL PERFORMANCE

Incident Energy	159.88 MWth
Reflection Loss	7.99 MWth
Radiation Loss	7.70 MWth
Convection Loss	2.37 MWth
Absorbed Energy	141.8 MWth
Receiver Efficiency	0.887
Receiver Flow	1.34x10^{6}kg/hr (2.95x10^{6}lbs/hr)

A breakdown of receiver performance by panel at the design point is shown in Table 5.4-14. The panel numbering is consistent with that shown in Figure 5.4-6. Only the east side panels are shown. The west is symmetrical. The low south panel efficiencies reflect the heavily north-skewed field design.

Table 5.4-14

DESIGN POINT PANEL PERFORMANCE

Panel No	Incident Energy (MWth)	Panel Efficiency (%)	Panel Outlet Temperature °C (°F)
1	11.6	91.1	598 (1109)
2	11.3	91.1	591 (1095)
3	10.6	90.7	609 (1129)
4	9.6	90.7	578 (1073)
5	7.9	88.9	633 (1172)
6	6.0	88.9	553 (1028)
7	4.6	85.7	612 (1133)
8	4.06	85.6	574 (1065)
9	3.8	84.1	598 (1109)
10	3.6	84.1	588 (1090)
11	3.6	83.4	608 (1126)
12	3.3	83.4	578 (1073)

The efficiency of the receiver as a function of input level is shown in Figure 5.4-14.

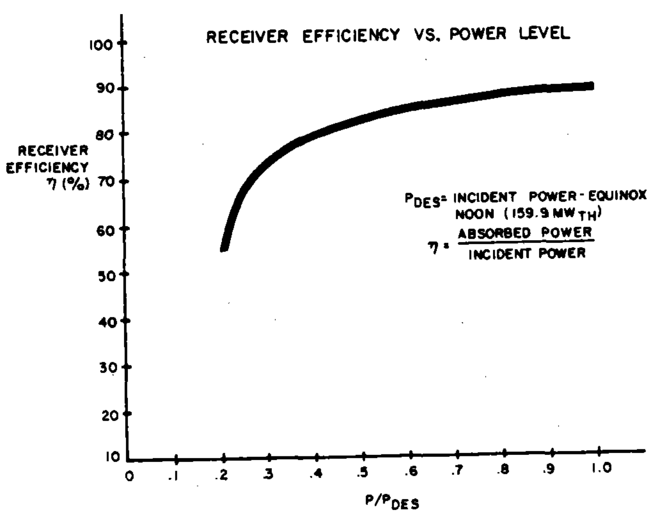


Figure 5.4-14. Efficiency of Receiver as a Function of Input Level

5.4.5.3 Other Performance Characteristics

Details of additional receiver subsystem performance parameters such as receiver performance as a function of wind speed, temperature, etc., and thermal inputs and losses from other subsystem components are presented in Section 4.4.

5.4.6 COST ESTIMATES

The receiver subsystem is carried as cost account 5400 in the Appendix A System Requirements Specification. Account 5400 also includes the steam generator subsystem (Accounts 5470, 5480 and 5490). In the cost summary, Table 5.4-15, the steam generator subsystem accounts have been excluded since they are treated separately in Section 5.5.6 of this report.

Table 5.4-15
RECEIVER SUBSYSTEM COST (1980$)

Account No. 5400 (less accts 5470, 5480, 5490)	
Total Cost	$18 588 190

Details of the receiver subsystem costs are included in the System Requirements Specification.

5.5 STEAM GENERATOR SUBSYSTEM

The steam generating subsystem consists of those elements of the repowering plant between the hot storage tank outlet valve and the cold storage tank inlet valve on the sodium side, as shown schematically in Figure 5.5-1. The steam side piping and components are also included, as shown in the schematic. Details of the subsystem design and performance are provided in this section.

5.5.1 Requirements

The steam generator subsystem functions to deliver energy in the form of steam to the existing Plant X, Unit 3 turbine generator in parallel with the existing fossil boiler. The source of energy used in producing the required steam is liquid sodium in the hot storage tank. Table 5.5-1 lists the functional design parameter requirements on which the subsystem design is based.

In addition to the specific requirements outlined in Table 5.5-1, the following general requirements were established for the steam generator subsystem.

- Protective equipment is to be provided to minimize the consequences of a sodium/water reaction in the subsystem.
- The power split of the three steam generator modules is to be in proportion to the split in the corresponding fossil elements.
- The steam generator system is to be capable of operating at as low as 20% of rated power.

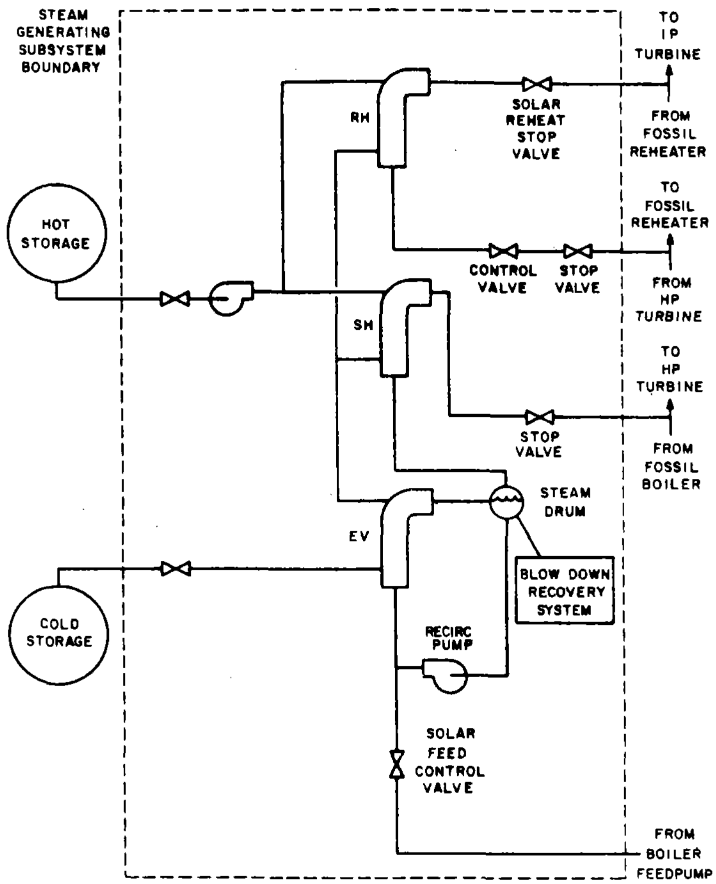


Figure 5.5-1. Steam Generating Subsystem Boundaries

Table 5.5-1

STEAM GENERATOR SUBSYSTEM
DESIGN REQUIREMENTS

Parameter	Requirement
Design Thermal Power	142 MW
Sodium Side:	
Hot Sodium Temperature	593°C (1100°F)
Cold Sodium Temperature	293°C (560°F)
Steam Side:	
Turbine Throttle Pressure	10.1 MPa (1465 psia)
Reheat Pressure (Inlet)	3.4 MPa (497 psia)
Feedwater Pressure	11.72 MPa (1700 psia)
Throttle Steam Temperature	538°C (1000°F)
Cold Reheat Temperature	388°C (730°F)
Hot Reheat Temperature	538°C (1000°F)
Feedwater Temperature	240°C (464°F) (without recirc or blowdown recovery)

5.5.2 SYSTEM DESIGN DESCRIPTION

5.5.2.1 System Function

On the sodium side, the steam generator pump takes suction on the hot storage tank sodium and pumps the 593°C (1100°F) sodium to the superheater and reheater modules. The sodium flows leaving these two modules (477°C/890°F) recombine and enter the evaporator module. The cold sodium leaving the evaporator (293°C/560°F) returns to the cold storage tank.

On the steam side, the solar portion of the feedwater supply enters the evaporator mixed with a small quantity of flow recirculated from the steam drum. The wet steam leaving the evaporator is separated in the steam drum. The saturated steam passes to the superheater and the saturated liquid is split between the aforementioned recirculated flow and a blowdown flow used to control drum impurity levels. The steam entering the superheater is raised to the 538°C (1000°F) design inlet temperature of the high pressure (HP) turbine, mixed with any fossil steam being produced and enters the HP turbine. The HP turbine exhaust is split using control valves in the same proportion as that used for the solar and fossil systems to produce the superheated steam. The solar portion enters the solar reheater, is raised to the 538°C (1000°F) design temperature, mixed with the fossil hot reheat steam, and enters the low pressure end of the turbine.

Support equipment for the basic elements of the steam generator subsystem and their function are described in Section 5.5.3.

5.5.2.2 System Arrangement

The steam generator subsystem and its relation to the interfacing systems is shown schematically in Figure 5.5-2. The major components of the subsystem are found in or near either the steam generator or pump buildings. A conceptual layout of the sodium piping was shown previously in Figure 5.1-1. The steam generator building area contains the sodium heated evaporator, superheater, and reheater; the sodium-water reaction relief piping; rupture discs; reaction products tank; sodium dump tank; steam-to-sodium leak detectors; steam drum; recirculation pump and related instrumentation.

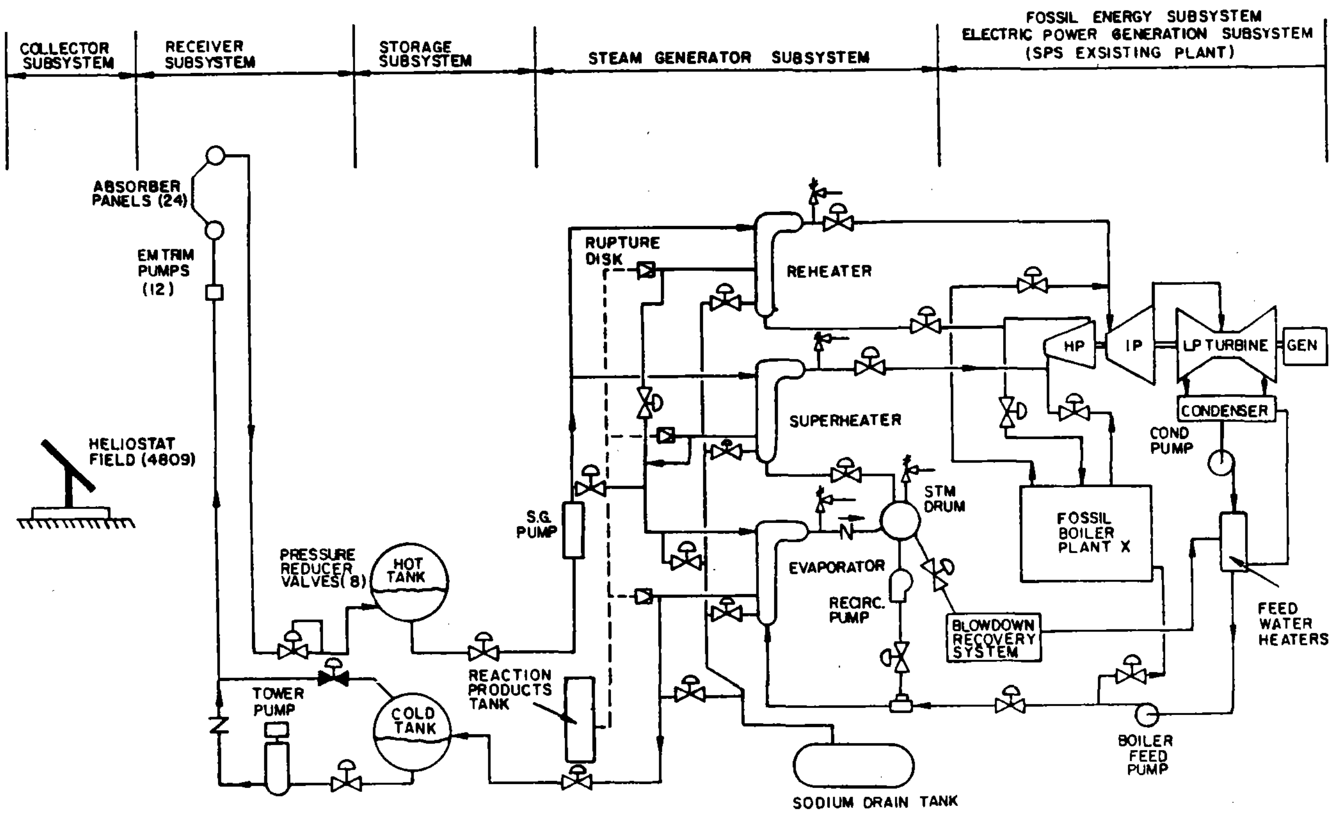


Figure 5.5-2

Steam Generator Subsystem and Its Relation to the Interfacing Systems

The pump building contains the tower and steam generator pumps, the sodium purification cold trap, the reducing valve station, a sodium drain tank, and associated instrumentation.

The steam generator building conceptual isometric is shown in Figure 5.5-3. The hockey stick type sodium-heated steam generators (reference design) are arranged facing in the east-west direction with the units supported by collars from the same level (~50 ft level). The units are located adjacent to the west wall where the rupture discs would relieve directly into the reaction products tank located outside the building. The steam drum is located on the roof in a weatherproof enclosure. More details of the steam generator building arrangement are shown in Figures 5.2-1 and 5.2-2. These figures also show the arrangement of the steam piping and its tie-ins to the existing plant piping.

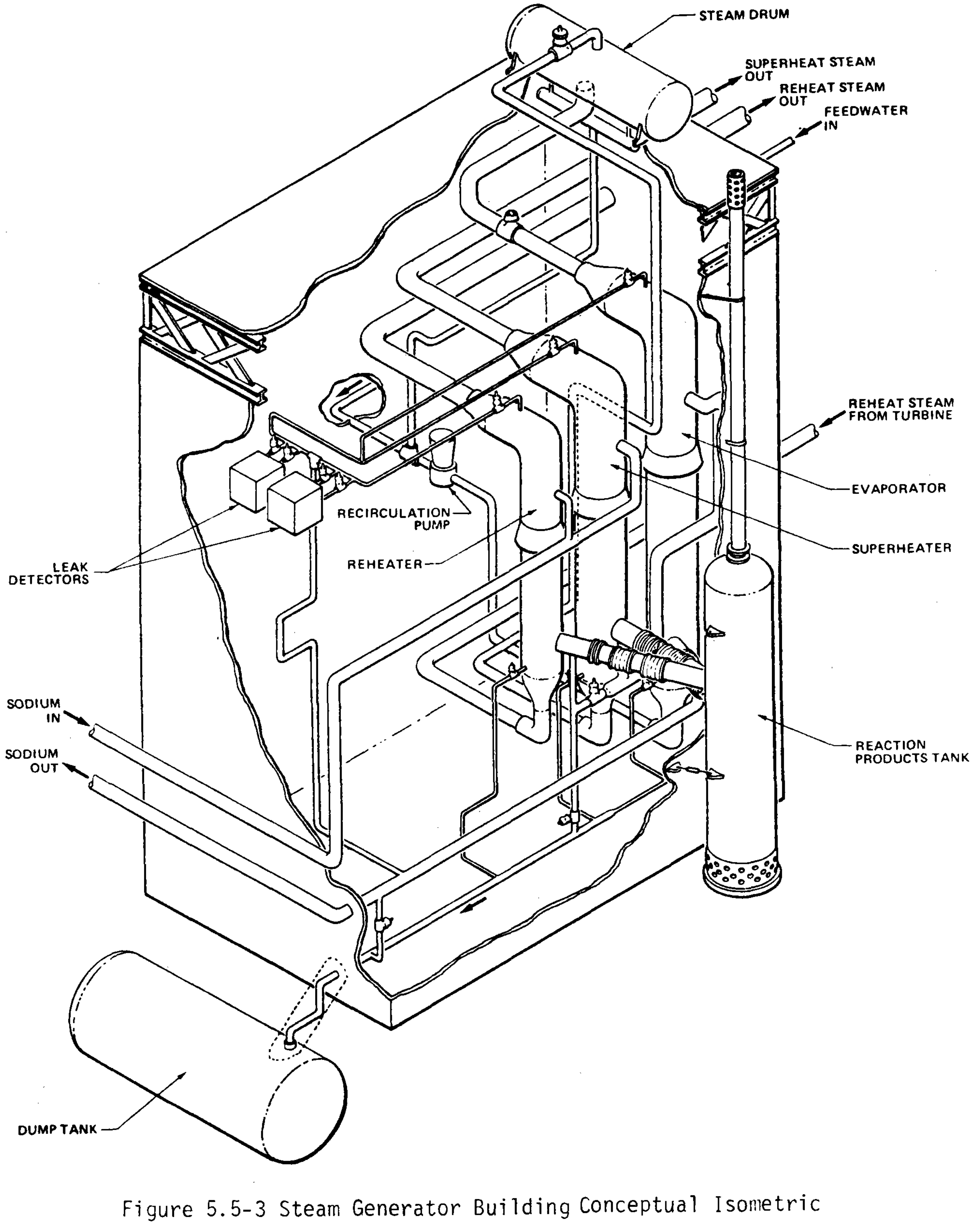


Figure 5.5-3 Steam Generator Building Conceptual Isometric

The pump building arrangement is illustrated in the Figure 5.5-4 schematic layout.

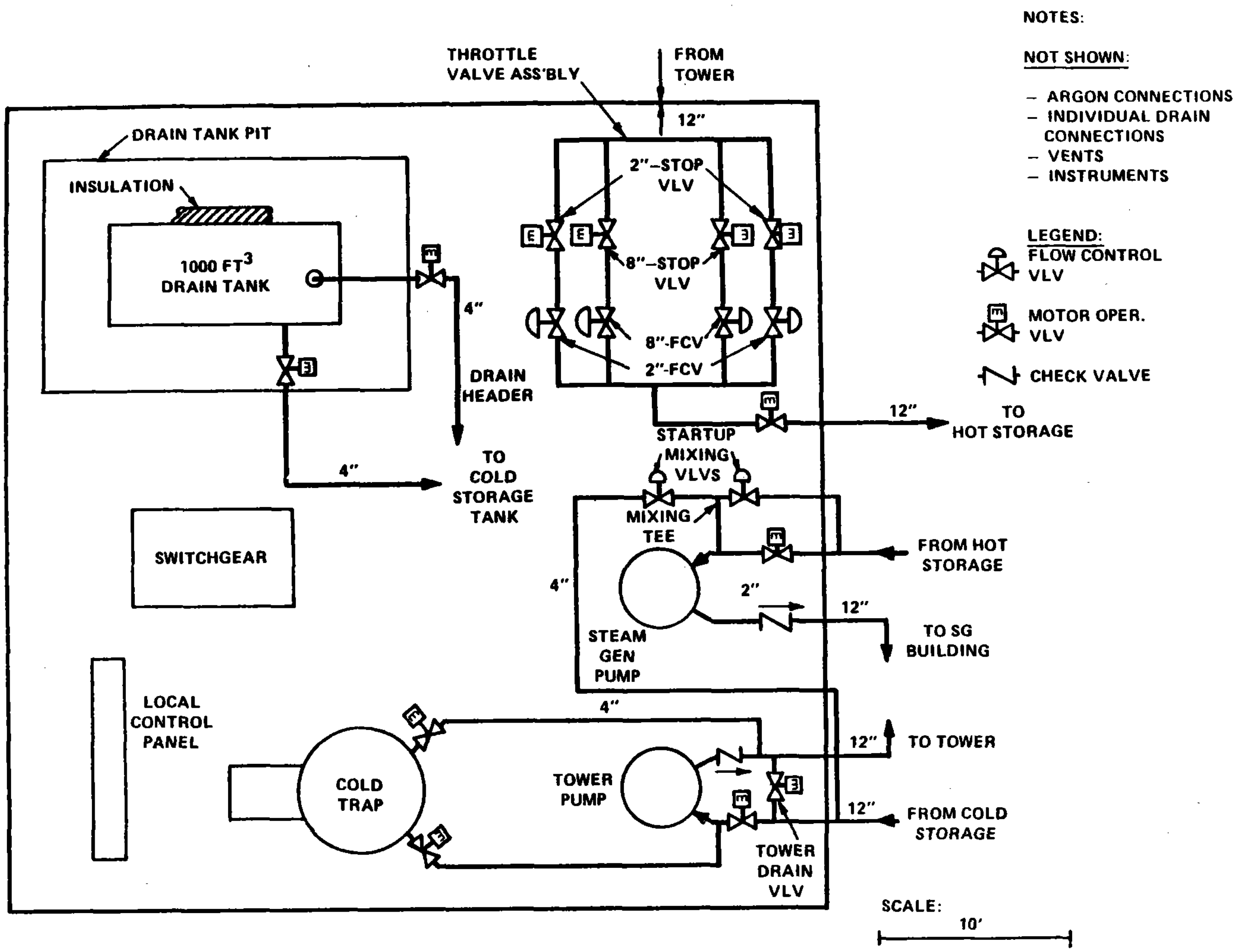


Figure 5.5-4. Pump Building Schematic Layout

5.5.3 MAJOR COMPONENT DESCRIPTION

5.5.3.1 Steam Generator Modules

The steam generators selected as the reference design for repowering are of the hockey stick design developed for the Clinch River Breeder Reactor program. A detailed description of the units and their operation is provided below.

5.5.3.1.1 Mechanical Design of Steam Generators - The evaporator, superheater, and reheater are vertically oriented shell and tube heat exchangers arranged in a hockey stick configuration with a 90° bend in the shell and tubes to provide for differential thermal expansion between the tubebundle and shell. A detailed section of a typical module is shown in Figure 5.5-5.

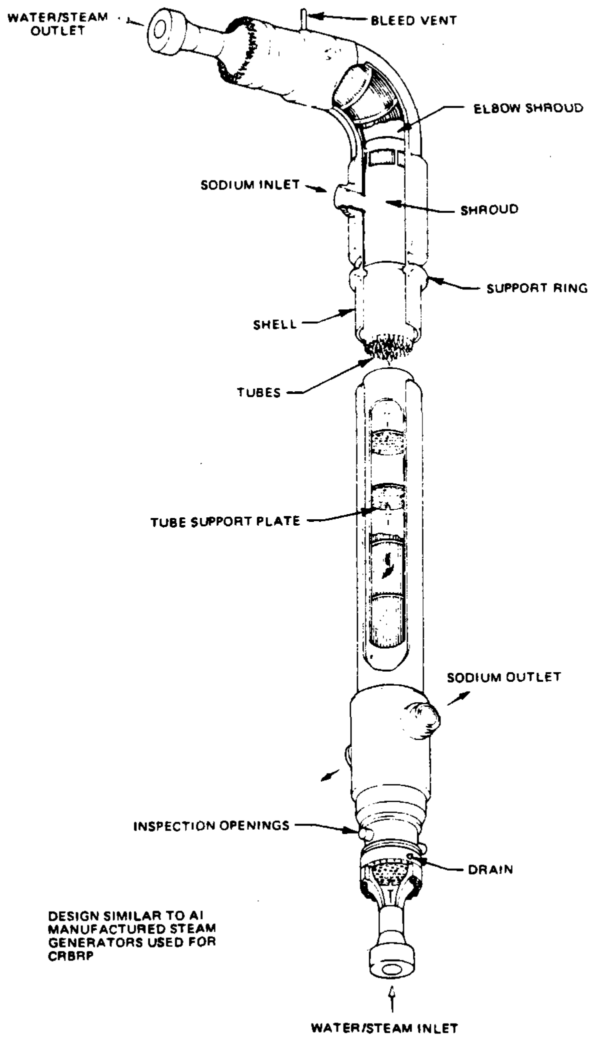


Figure 5.5-5 Hockey Stick Steam Generator Module

Each tube bundle is enclosed in a shroud along the active heat transfer length to ensure proper flow distribution. Sodium enters each unit through the upper sodium nozzle and turns up into the flow distributing annulus. Sodium enters the tube bundle through six rectangular windows in the shroud and flows down through the tube bundle. At the lower end, sodium leaves the tube bundle through the lower flow windows in the shroud, turns up and flows through the flow distributor annulus and out the exit nozzles.

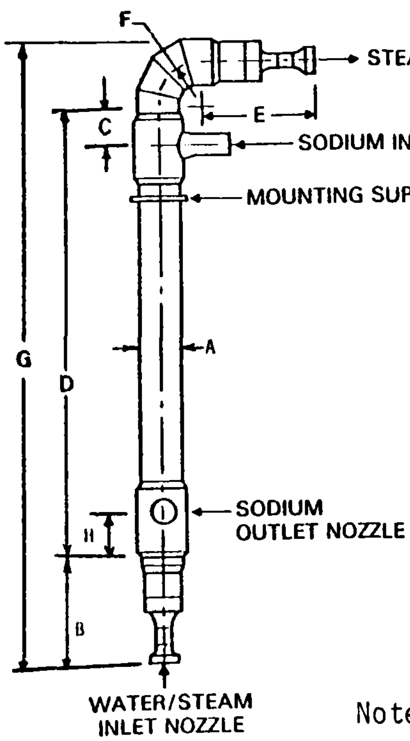
The tubes are supported along their length by 19 tube spacers in the active heat transfer region, by a spacer arrangement directly above and adjacent to the inlet shroud flow windows, and by one vibration suppressor in the upper horizontal region.

The shell connects to upper and lower tube sheets. The shell components would be sized to withstand the peak sodium/water reaction pressures resulting from a hypothetical leak equivalent to one instantaneous double-ended guillotine tube rupture.

Thermal liners are provided as part of each sodium nozzle assembly to protect the nozzle from rapid temperature changes that may occur during transients. Additional nozzles are provided for inspection ports during fabrication and for drainage and venting of the units.

Full penetration internal bore welds (IBW) join the tubes to the machined bosses of the tube sheets. Removable water/steam heads provide direct access to the tube ends at the tube sheets for in-service inspection and (if necessary) plugging of the tubes from the water/steam side.

A detailed section of a steam generator module is shown in Figure 5.5-5 Figure 5.5-6 lists the module shell sizes for the repowering application based on the sizing calculations described in the next section.



Note: Table units in feet. Divided by 3.28 to obtain values in meters.

MODULE	A	B	C	D	E	F	G	H
EVAPORATOR	3.8	10.3	4.5	56.2	11.3	4.0	75.9	4.0
SUPERHEATER	3.0	10.4	4.1	33	10.2	4.0	49.1	3.6
REHEATER	3.4	10.3	4.8	39.2	12.2	4.0	54.4	4.3

Figure 5.5-6 Steam Generator Configurations

The steam generator design pressure and temperature conditions are shown in Table 5.5-2. The sodium design temperature conditions were selected based on nominal operating conditions, expected variations under off-design conditions (e.g., fouled evaporator) and uncertainties in temperature control. The design steam/water pressures were selected as 20% above the nominal operating conditions to minimize leaking relief valves under steady-state conditions and to accommodate the mild transients expected in the solar steam plant without lifting the relief valves. The vessels would be designed and fabricated to meet the requirements of Section VIII of the ASME Boiler and Pressure Vessel Code.

Table 5.5-2

STEAM GENERATOR DESIGN CONDITIONS

	Evaporator	Superheater	Reheater
Sodium Side			
Temperature, °C (°F)	499 (930)	621 (1150)	621 (1150)
Pressure, MPa (psig)	1.72 (250)	1.72 (250)	1.72 (250)
Flow, kg/hr (lb/hr) x 10^{-6}	1.45 (3.20)	1.07 (2.35)	0.48 (1.05)
Water/Steam Side			
Temperature, °C (°F)	499 (930)	621 (1150)	621 (1150)
Pressure, MPa (psig)	13.4 (1950)	12.4 (1800)	4.1 (600)
Flow, kg/hr (lb/hr) x 10^{-6}	0.32 (0.70)	0.27 (0.60)	0.25 (0.55)

5.5.3.1.2 Steam Generator Module Sizing — The STMGEN computer code was used to size the evaporator, superheater, and reheater of the hockey stick design. A summary of the results is presented in Table 5.5-3.

Table 5.5-3

STEAM GENERATOR DESIGN DATA

	Evaporator	Superheater	Reheater
Performance Data			
Power Rating, MWt	86.4	39.8	15.6
Active Heat Transfer Area, m^2 (ft^2)*	601 (6462)	174 (1867)	190 (2044)
Shell Side Parameters			
Sodium Inlet Temp. °C (°F)	477 (890)	593 (1100)	593 (1100)
Sodium Outlet Temp,°C (°F)	293 (560)	477 (890)	477 (890)
Sodium Flow Rate, kg/hr (lb/hr) x 10^{-6}	1.34 (2.95)	0.96 (2.1)	0.38 (0.84)
Vessel OD/Length, m (ft)	1.2/23.1 (3.8/75.9)	0.91/14.9 (3.0/49.1)	1.04/16.6 (3.4/54.5)
Tube Pitch	1.22	1.22	2.07
Shell Side Pressure Loss, KPa, (psi)	33 (4.8)	16.5 (2.4)	2.7 (.4)
Tube Side Parameters			
Tube OD/Thickness, cm (in.)	1.59/0.28 (.625/.109)	1.6/.28 (.625/.109)	2.7/0.24 (1.06/0.095)
Number of Tubes	663	346	188
Active Tube Length, m (ft)	18.2 (59.6)	10.1 (33)	11.95 (39.2)
Steam Inlet Temp, °C (°F)	251 (484)(water)	318 (605)	388 (730)
Steam Outlet Temp, °C (°F)	318 (605)	538 (1000)	538 (1000)
Steam Flow Rate, kg/hr (lbs/hr) x 10^{-5}	2.15 (4.75)	1.9 (4.13)	1.7 (3.65)
Tube Side Max. Velocity, m/sec (ft/sec)	15.2 (50)	57.9 (190)	73.2 (240)
Tube Side Pressure Loss, KPa (psi)	267 (38.7)	941 (136.5)	256 (37.1)
Outlet Steam Quality, %	87	N/A	N/A
Material of Construction	2-1/4 Cr - 1 Mo	Incoloy 800**	Incoloy 800**

*Based on OD
**Incoloy 800 tubes and tube sheets with 316H SS vessel

The nominal heat transfer correlations used in the design of the steam generators are listed in Table 5.5-4. To accommodate design uncertainties in heat transfer correlations, tube fouling and tube plugging, the following allowances were added to the STMGEN calculated active tube lengths.

	Length from STMGEN M (ft)	% Length for Design Allowances	Design Length M (ft)
Evaporator	13.3 (43.5)	37	18.2 (59.6)
Superheater	8.3 (27.3)	21	10.1 (33.0)
Reheater	9.9 (32.4)	21	11.9 (39.2)

Table 5.5-4

HEAT TRANSFER CORRELATIONS
USED IN STEAM GENERATOR SIZING CALCULATIONS

Region	Correlations Used	Authors	Reference
Sodium Side	$Nu = 12.35 + 0.0555\,(Pe)^{0.753}$	Gräber and Rieger	1
Water Side Preheat	$Nu = 0.0204\,Re^{0.805}\,Pr^{0.415}$	Engineering Sciences Data Unit - British	2
Subcooled Boiling and Nucleate Boiling	$h = \left[\frac{e^{P/1260}}{0.072}\right] (q'')^{0.5} \left[\frac{T_w - T_b}{T_w - T_{sat}}\right]$	Thom, et al.	3
Water Side DNB	$x_{DNB} = \frac{18.85}{h_{fg}(\rho_g/\rho_\ell)\sqrt{G/10^6}}$	Special AI-MSG Formulation	4
Film Boiling	$Nu_f = 0.80\,[0.0193\,Re_f^{0.8}Pr_f^{1.23}]$ $[x + (1-)(\rho_g/\rho_\ell)]_b^{0.68} \left[\frac{\rho_g}{\rho_\ell}\right]^{0.068}$	Bishop, Sandberg and Tong	5
Superheat	$Nu_f = 0.0133\,Re_f^{0.84}Pr_f^{0.333}$	Heineman	6
Tube Thermal Conductivity	$K = C_1 - C_2^T$	Use refefence values for C_1 and C_2 from materials data	

NOTE: Except for subscript f which denotes "average film," parameters are evaluated at "stream bulk" conditions.

1. V.H. Gräber, M. Rieger, Atomikerenergi 19, p. 23, 1972.
2. Engineering Sciences Data Unit Item 67016, "Forced Convection Heat Transfer to Circular Tubes - Part 1: Correlation for Fully Developed Turbulent Flow — Their Scope and Limitations," Inst. Mech. Engrs., London, 1967.
3. J.R.S. Thom, W.M. Walker, T.A. Fallon, and G.F.S. Reising, "Boiling in Subcooled Water During Flow Up Heated Tubes or Annuli," Symposium on Boiling Heat Transfer in Steam Generating Units and Heat Exchangers, Inst. Mech. Engrs., Manchester, 1965.
4. R.B. Harty, Atomic International Document TR-097-330-008, "MSG Test Report - Steady-State Heat Transfer," May 28, 1974.
5. A.A. Bishop, P.O. Sandberg, and L.S. Tong, "Forced Convection Heat Transfer at High Pressure After the Critical Heat Flux," ASME 65 HT-31, 1965.
6. J.B. Heineman, "An Experimental Investigation of Heat Transfer to Superheated Steam In Round and Rectangular Channels," ANL 6213, 1960.

These factors will enable operation of the units at design power for an acceptable length of time between cleanings (at least five years).

The STMGEN data for the temperature profile in the three steam generators are plotted in Figure 5.5-7.

The results are based on assuming an evaporator 19.4^{o}C (35^{o}F) pinch point which in the Alternate Central Receiver, Phase I program was found to be the optimum value for this range of sodium ΔT.

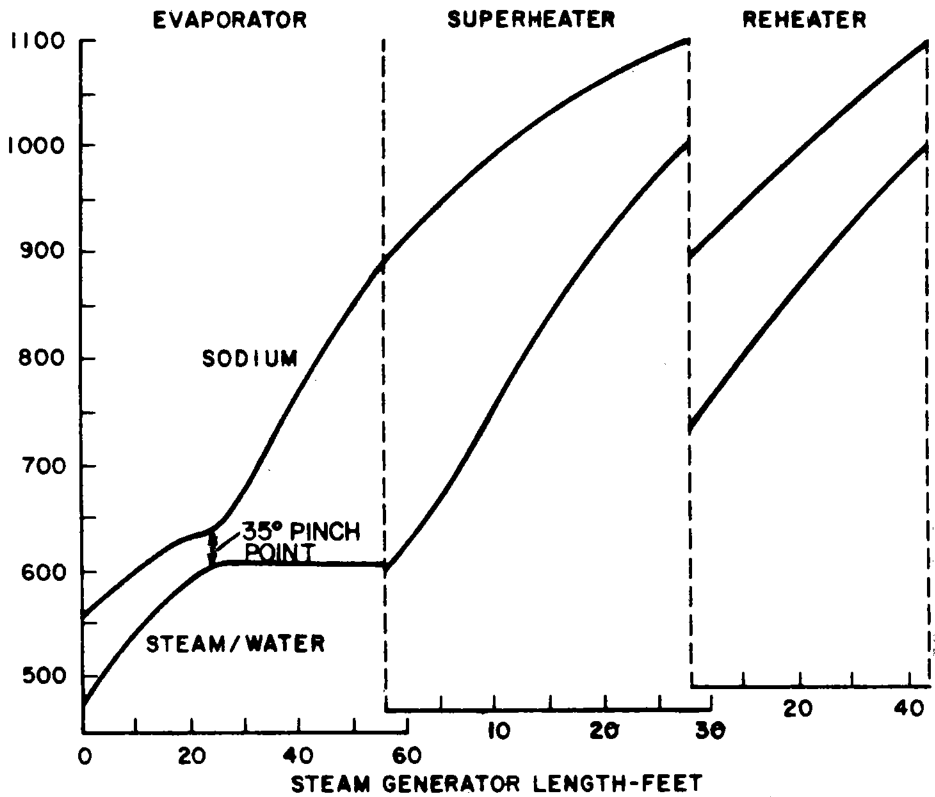


Figure 5.5-7. Steam Generator Temperature Profiles

The steam generators were sized with the following objectives and considerations:

- Minimize steam generator design and fabrication cost, which implies:
  - Minimizing tube-to-tube sheet weld development/qualification (using same size tubes where possible)
  - Minimizing number of tube-to-tube sheet welds (minimizing number of tubes)
  - Using proven and tested design (hockey stick design)

- Limit maximum steam generator overall length to less than 22.9 m (75 ft) to limit the building size.
- Limit tube length to available lengths to avoid joints: 1.59 cm (0.625 in) OD $\leq$ 28.9 m (95 ft), 2.69 cm (1.06 in) OD $\leq$ 21.3 m (70 ft)
- Limit steam/water and sodium velocities to achieve acceptable erosion and minimize flow induced tube vibrations.

Water	$\leq$ 6.1 m/s (20 ft/s)
Steam/Water	$\leq$ 15.2 m/s (50 ft/s)
Saturated Steam	$\leq$ 38.1 m/s (125 ft/s)
Superheated Steam	$\leq$ 76.20 m/s (250 ft/s)
Sodium	$\leq$ 7.62 m/s (25 ft/s)

5.5.3.1.3 Evaporator Water Chemistry Requirements — The evaporator water chemistry requirements for the steam generator subsystem are based on achieving acceptable rates of general corrosion, DNB corrosion, and fouling. The water chemistry requirements shown in Table 5.5-5 are based on equilibrium steady-state operation. It is recognized that due to the transient nature of the solar repowering plant, certain water chemistry parameters (e.g., total dissolved solids and cation conductivity) are expected to fluctuate and may exceed limits for a period.

Table 5.5-5

SOLAR REPOWERING WATER CHEMISTRY REQUIREMENTS

Feedwater Specifications[1]	
Total Dissolved Solids	100 ppb
Dissolved Oxygen	7 ppb
Silica	20 ppb
Iron	15 ppb
Copper	15 ppb
pH at 77°F	8.7 — 9.1
Hydrazine (residual)	5 — 15 ppb
Conductivity (cation) at 77°F	1.0 micro-mho/cm
Sodium	4 ppb
Steam Drum Water Specifications[1]	
Total Dissolved Solids	150 ppb
pH at 77°F	8.5 — 9.0
Conductivity (cation) at 77°F	1.5 micro-mho/cm
Sodium	6 ppb

[1] Operation above these limits is allowable at less than 10% power level and for a period of time yet to be defined when above this power level.

General corrosion is minimized when makeup and feedwater are free of gases and maintained at the proper pH level, reducing iron and copper pickup. In addition to the deaeration process, which reduces the oxygen level in the water, the water must be treated chemically to achieve these conditions. An all volatile treatment (AVT) system is recommended for maintaining the water chemistry of the solar repowering plant. The AVT consists of hydrazine and ammonia hydroxide additions. The hydrazine scavenges oxygen while the ammonia maintains the proper pH level. Based on experiments under water chemistry conditions similar to that in the solar repowering plant evaporator, a general corrosion rate of 0.8 mils/year for 2-1/4 Cr-1Mo steel units is expected.

Corrosion due to departure from nucleate boiling (DNB) conditions, which is permitted in the evaporator design, is recognized as a potential corrosion problem which could lead to rapid corrosion rates in 2-1/4 Cr-1Mo tubing material if proper water chemistry control is not maintained. GE experiments conducted in support of the CRBRP steam generator design, under DNB conditions with normal and off-specifications of water chemistry with respect to sodium ion, exhibited no appreciable localized corrosion effects. However, to guard against localized high concentrations of sodium hydroxide in the dry-out DNB region, sodium concentrations in the recirculation water should be maintained at a low level.

In order to maximize operating time, proper attention should be given to the water treatment to prevent excessive scaling. Deposition of water-borne impurities— measured by total dissolved solids (TDS) and cation conductivity— must be controlled to minimize thermal performance degradation. Control of TDS is maintained with a continuous blowdown of the steam drum of 8 - 10% based on a 1.15 recirculation ratio. A water side cleaning interval of five years is anticipated.

Chemical descaling to remove "fouling" deposits from water side surfaces is recommended using ammoniated EDTA and citric acid solution. This solution, based on bench testing, yielded better cleaning control than other cleaning solutions and would ensure not getting chlorides in the Incoloy 800 superheater and reheater, which could cause stress corrosion problems.

Continuous monitoring by on-line instrumentation should be provided for measurement of residual hydrazine, pH, dissolved oxygen, sodium ion concentration, and conductivity of both the recirculation and feedwaters. This will require a continuous sample of about 100 lb/hr, which will be returned to the makeup system after passing through a demineralizer.

5.5.3.2 Water Recirculation Loop

The evaporator module is equipped with an external water recirculation loop as shown in Figure 5.5-2. The recirculation loop contains an evaporator, a pump, a control valve, and a horizontal steam drum. The water is circulated from the drum to the evaporator by the recirculation pump, which operates at constant speed. The flow rate varies with power level by use of the flow control valve to maintain a constant recirculation to steam flow ratio of 1.15. The evaporator exit steam quality at design conditions is 87% by weight. The steam/water mixture from the evaporator is returned to the drum, where it is separated into water and dry steam. Dry steam is delivered from the drum to the superheater, where it is heated and sent to the high pressure (HP) turbine.

The centrifugal pump required for circulating the feedwater through the evaporator is a conventional design pump with extensive operating history in fossil fueled power plants. The design parameters are shown in Table 5.5-6.

Table 5.5-6

RECIRCULATION PUMP DESIGN PARAMETERS

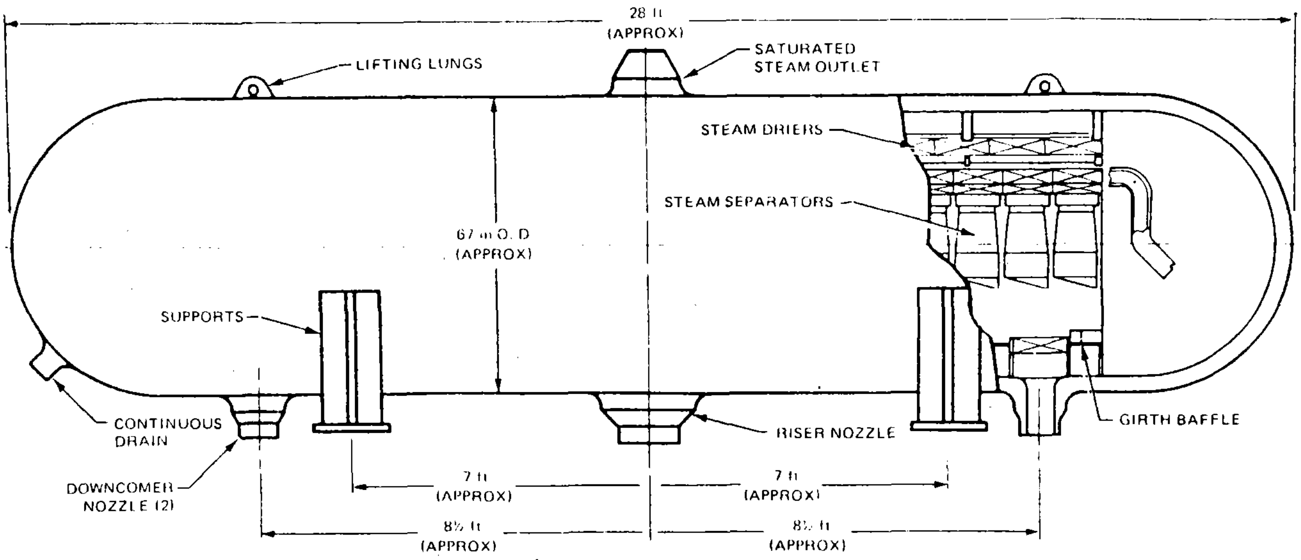
Parameter	Value
Flow Rate kg/hr (lb/hr) x 10^{-5}	0.095 (0.21)
Head Rise m (ft)	45.7 (150)
Temperature °C (°F)	343 (650)
Pressure MPa (psig)	13.8 (2000)
Mechanical Efficiency (%)	75
Design Code	ASME VIII
Drive Motor Power kW (HP)	3.7 (5)

The steam drum is shown in Figure 5.5-8.

5.5.3.3 Blowdown Recovery System

The 10% steam drum blowdown represents a significant fraction of the energy (~ 3%) produced in the steam generator. In addition, the 1.9×10^4 kg/hr (4.2×10^4 lb/hr) represents a large amount of water in this area of the country. Therefore, the water and energy must be recovered for acceptable plant operation.

To recover the water and return it to the condensate train, it must be cleaned of its impurities. This can be effectively accomplished by demineralization but requires that the blowdown water be cooled to $\leq$ 48.9°C (120°F).



OUTLET STEAM FLOW	480,000 lbs/hr
STEAM QUALITY	0.87
DESIGN PRESSURE	2050 psi
OPERATING PRESSURE	1550 psi
DESIGN TEMPERATURE	650°F
OPERATING TEMPERATURE	603°F
MATERIAL	HS CARBON STEEL

DESIGN SIMILAR TO
BARCOCK AND WILCOX CO. STEAM DRUM

Figure 5.5.-8 Steam Drum

The system designed to perform this function is illustrated in Figure 5.5-9. The system allows recovery of all the energy and water. The blowdown flow, controlled by a valve, is allowed to partially flash to steam in a flash tank. The steam flows to the existing condensate system deaerator and the blowdown condensate flows to a heat exchanger. The heat exchanger, cooled by condensate from the main condenser, cools the blowdown liquid to $\leq$ 48.9°C (120°F). The cooled liquid can then be cleaned in a demineralizer and sent to a condensate storage tank for a subsequent return to the condensate train.

5.5.3.4 Sodium Steam Generator Pump

The steam generator pump, located in the pump building, circulates sodium through the steam generator modules. A centrifugal pump was selected for this application. Consideration was given to the use of an electromagnetic (EM) pump; however, its relatively low efficiency and high initial cost made it less attractive

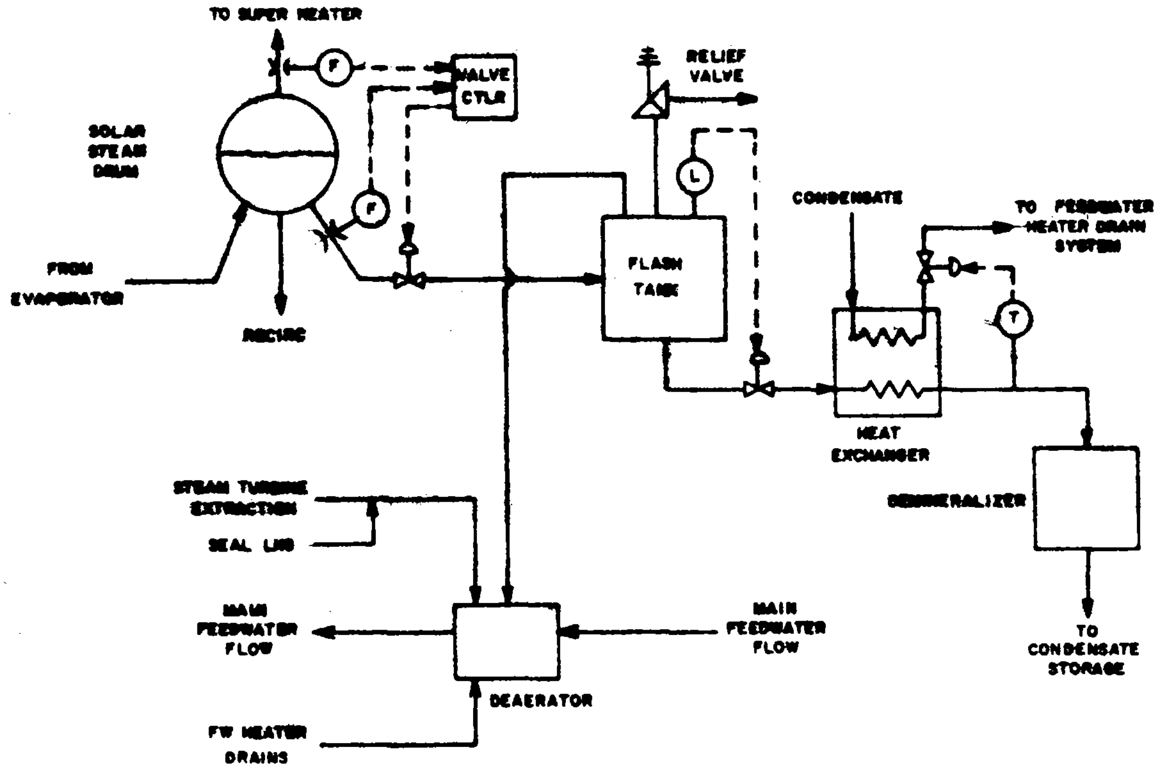


Figure 5.5-9. Solar Steam Drum Blowdown System

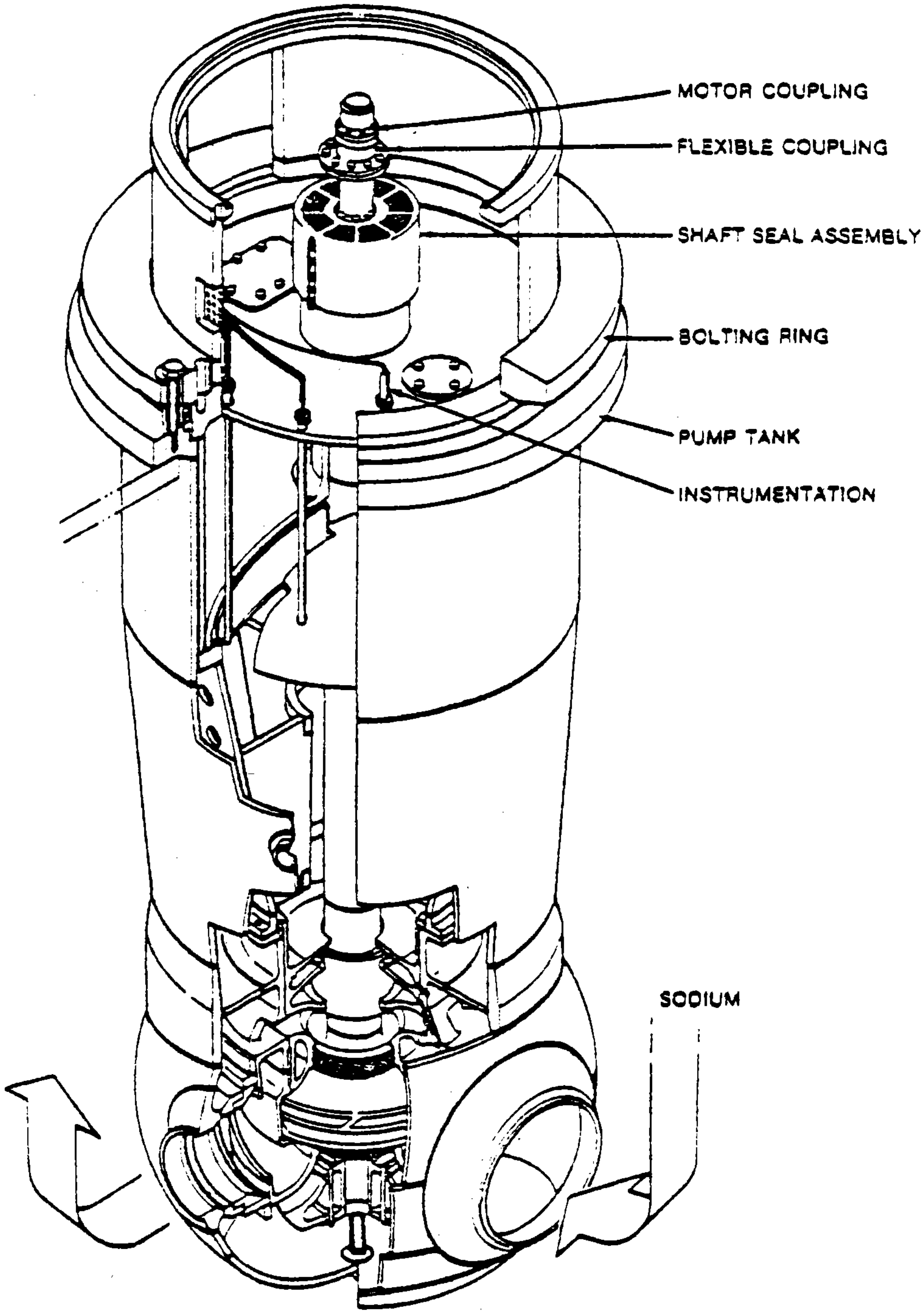
than the centrifugal design. Appendix G presents the results of a trade-off study comparing EM and centrifugal pumps for both the steam generator and tower pump applications.

Table 5.5-7 shows the steam generator pump design parameters. Figure 5.5-10 illustrates a typical centrifugal sodium pump with the approximate overall dimensions of the pump for this application.

Table 5.5-7

STEAM GENERATOR SODIUM PUMP DESIGN PARAMETERS

Parameter	Value
Flow Rate kg/hr (lb/hr) x 10^{-6}	1.45 (3.20)
Head Rise m (ft)	57.9 (190)
Design Temperature °C (°F)	621 (1150)
Design Pressure MPa (psig)	0.69 (100)
Mechanical Efficiency (%)	75
Design Code	ASME VIII
Drive Motor Power kW (HP)	446 (600)



	Steam Generator Sodium Pump
Pump Dia., cm (in)	127 (50)
Pump Height, m (ft)	3.4 (11)
Drive Motor Dia., cm (in)	60.96 (24)
Overall Height, m (ft)	4.57 (15)
Motor Horsepower kW (H_p)	446 (600)
Impeller Speed, rpm	1150

Figure 5.5.10. Repowering Steam Generator Sodium Pump

The steam generator pump is a variable speed, single stage, double suction pump. The 28.4 m^3/min (7500 gpm) flow and 57.9 m (190 ft) head requirements closely match those of the Hallam sodium pumps 32 m^3/min (7200 gpm), 48.8 m (160 ft) head. It may be possible to use an existing Hallam pump on the solar repower project. Two such pumps, which are government owned, are presently in storage: one at Energy Technology Engineering Center (ETEC) and the other at Westinghouse (Waltz Mills), as last reported. This possibility would be researched further during the next phase of the program.

The steam generator pump is speed controlled to match the power plant load demands. The pump speed is controlled by an eddy current coupling and a speed controller. The eddy current coupling is located between the drive motor and pump. This speed control method is the same as that used for the main sodium pump in the 70 MW SCTI test facility located at ETEC.

A motor generator set with a fluid coupling was also considered as a speed control method by controlling the ac frequency to the pump drive motor. The eddy current method appears more attractive, since it requires less equipment and the initial cost is much lower.

5.5.3.5 Sodium Loop Relief and Drain

The sodium loop relief system is designed to accommodate the effects of a large sodium-water reaction which could occur either in the evaporator, superheater, or reheater.

During normal plant operation, the relief system remains passive. In the event of a large sodium-water reaction (low probability), the rupture disc associated with the affected module will burst, allowing sodium and reaction products to be ejected into a reaction products tank. Hydrogen gas vented from the reaction is passed through the tank, ingited and burned at the exit of a flare stack. The dense reaction products are accumulated in the bottom of the reaction products tank. Following such a sodium-water reaction, sodium remaining in the piping loop and steam generators can be drained into the sodium dump tank to prevent solidification of reaction products within the piping system.

The rupture disc assembly, which is close coupled to the sodium outlet of each steam generator, is shown in Figure 5.5-11. The assembly consists of a 35.6cm (14 in) reverse buckling Inconel double-disc mounted in front of a knife edge. The disc is designed to collapse against the knife blades when the burst pressure exceeds 1.7 MPa(~250 psi).

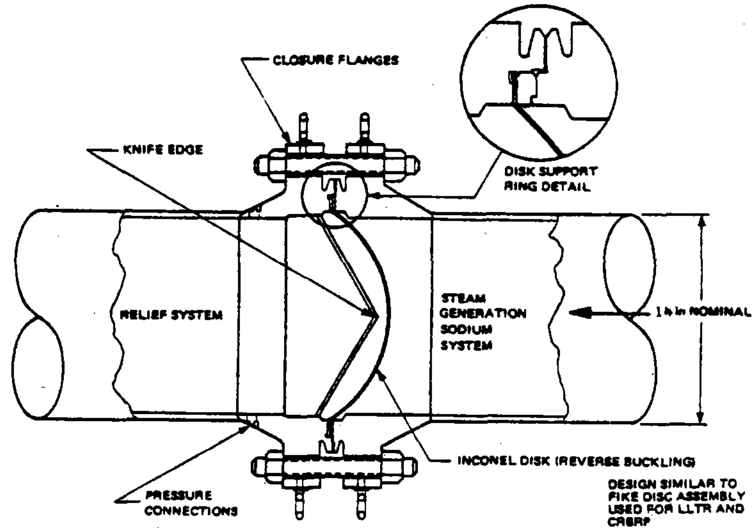
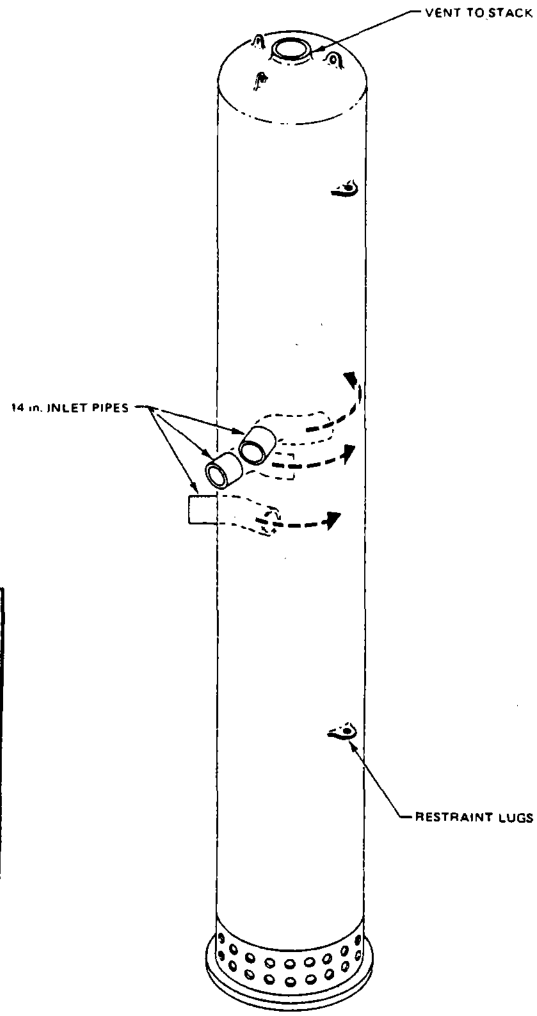


Figure 5.5-11. Sodium-Water Reaction Relief System-Rupture Disk Assembly

The reaction products tank (RPI) is designed to accept three inlet pipes ing from the three steam generators. Reaction products are retained in the bottom of the tank. This tank is shown in Figure 5.5-12.



APPROX SIZE	8 ft. dia x 48 ft. HIGH x ½ in. WALL THICKNESS
CAPACITY	2300 ft.^{3}
DESIGN PRESSURE	125 psig
DESIGN TEMPERATURE	800°F
MATERIAL	HS CARBON STEEL SA 533

Figure 5.5-12. Sodium Reaction Products Tank

The relief piping is designed with short, direct runs to the reaction products tank (Figure 5.5-3) to minimize fluid induced thrust loadings on the piping and tank nozzles. To accommodate thermal growth of the steam generator vessels, universal bellows assemblies are used in the relief piping. The sodium/water reaction relief system piping is sized to accommodate the flow associated with the equivalent of seven double-ended guillotine tube failures without exceeding allowable pressure stresses in the sodium system piping.

A sodium drain/dump tank is provided at the lowest point in the steam generator piping loop. The $114m^3$(4010 cuft) tank is located at the north end of the steam generator building with all the sodium piping of the steam generator building designed to drain to that point. The tank is trace-heated and insulated. Normally,the tank remains 20% ful for thermal buffering purposes. For periods of maintenance, the tank is designed to store the sodium inventory in the piping and steam generators.

5.5.3.6 Leak Detection

To allow the quickest detection of any steam generator tube leak, two oxygen/hydrogen leak detector modules are incorporated in the sodium piping near the steam generator outlets. This provides sufficient protection against steam/water-to-sodium leaks in the steam generators to ensure that extensive system and steam generator damage would not occur and that plant downtime would be minimized. The leak detector modules (Figure 5.5-13) are the same design as those being developed for the Clinch River Breeder Reactor Plant (CRBRP). The module is designed to be attached to loop piping and, with its own pump, extract a small amount of sodium from the loop to continuously measure its hydrogen and oxygen content. Alarms can be set so that manual, semi-automatic, or automatic action can be taken. Figure 5.5-3 shows the orientation of the leak detectors in the steam generator building.

5.5.3.7 Piping and Valves

The steam and sodium piping and valves are listed with their design characteristics in Section 4.2.1.

5.5.3.8 Insulation and Trace Heating

All sodium piping valves and components are provided with trace heating and insulation to prevent freezing of sodium. The insulation will consist of a 10.2cm (4 in) layer of B&W Kaowool and a 15.2cm (6 in) layer of J-M Thermal Wool Type II. Adequate trace heating is provided to maintain a minimum temperature of 177^oC (350^oF)

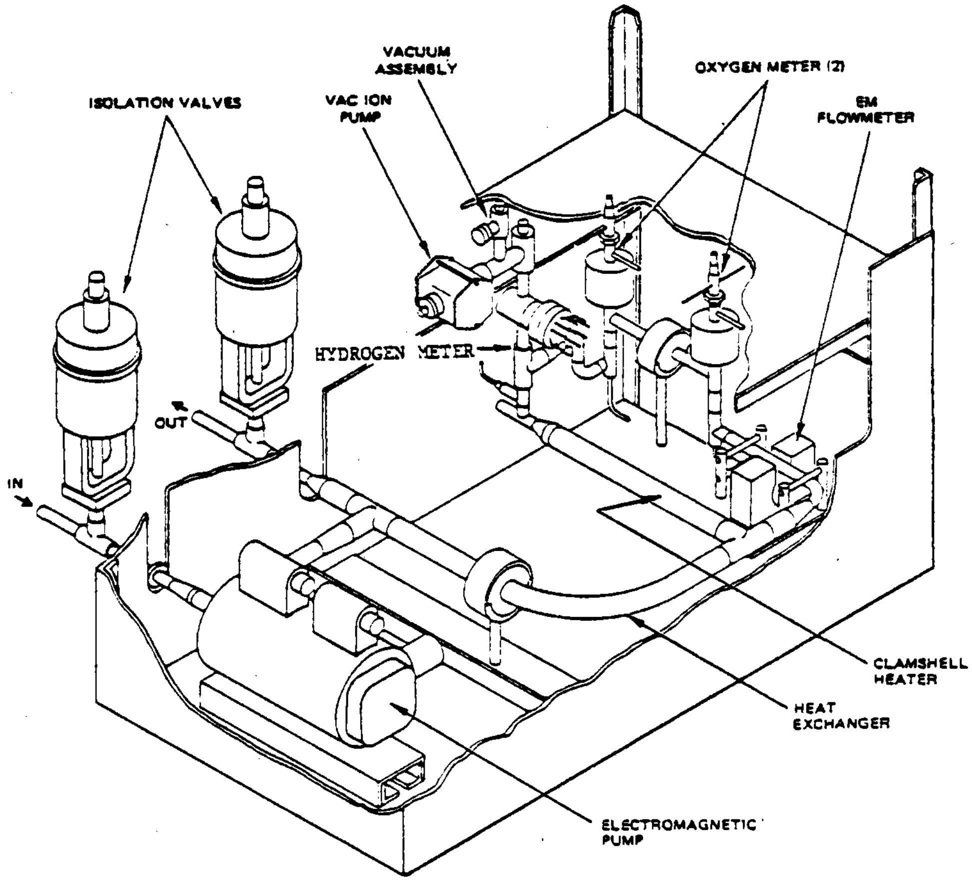


Figure 5.5-13. Oxygen-Hydrogen Detection Module

5.5.3.9 Instrumentation and Control

The instrumentation and control of this and other subsystems is described in Section 5.6.

5.5.4 OPERATING CHARACTERISTICS

5.5.4.1 Normal Operation

The steam generator subsystem will automatically produce steam for the Plant X, Unit 3 turbine corresponding to the energy available from the sun. The central control parameter for determining output will be the hot tank level. When the hot tank is nominally full, the steam generator pump will operate at a speed to deliver 60 MWe equivalent to the steam generator modules. If the level drops, the pump speed will drop to a corresponding level to maintain adequate sodium in the hot tank so that the power to the EPGS can be dropped at a rate no greater than 3 MWe per minute without expending all the sodium in the tank. Thus, the sodium flow in the system will lead any response to solar transients.

On the steam side, the steam flow will be controlled by adjusting the solar feedwater control valve in response to the steam drum level. Thus, if sodium flow drops in response to an insolation change, the drum level will rise and the feed control valve will adjust to reduce flow.

Although the steam generators are balanced by design to produce the required 538°C (1000°F) steam from the superheater and reheater, some imbalance may be generated over time by differential fouling, etc. To ensure that the 538°C (1000°F) conditions are maintained, a system of sodium flow control and bypass valves has been included in the system design. Both the superheater and reheater have outlet flow control valves that will respond to steam temperature deviations from normal. Any changes in the superheater or reheater flow will be compensated for by adjusting the bypass flow valve, which allows sodium to bypass the superheater and reheater and mix with the evaporator inlet flow. This will maintain the overall system flow versus pump speed relation and also will increase or decrease the evaporator steam production to balance the powers in the three modules.

5.5.4.2 Startup and Shutdown

Steam generator system shutdown will be accomplished automatically by allowing the pump to reduce sodium flow at a maximum rate of 3 MWe per minute. When flow reaches approximately zero, the system valves will shut to "button up" the system, which will be the standby status for the steam generator subsystem.

Because the steam generator subsystem piping and component will cool faster than the sodium in the storage tanks, and because their sodium side heatup rates must be limited to ~ 83°C (150°F) per hour, some provision for variable sodium temperatures for startup (warmup) is required.

A system for mixing hot and cold sodium (Figure 5.5-4) from the storage tanks has been included to provide the required variable temperature capability. Flow control valves in the mixing lines will proportion the flow from the hot and cold storage tanks to produce the desired sodium temperature to be pumped by the steam generator pump to the modules. The master control computer will monitor steam generator and sodium temperatures and position the flow control valves.

5.5.5 PERFORMANCE ESTIMATES

The design point system flow diagram illustrating the flows, temperatures and pressures of the working fluids in the steam generator subsystem is shown in Figure 5.5-14. Because the output power will be controlled by the sodium flow rate, the sodium temperatures at the design point will not change significantly during off-design, steady-state conditions.

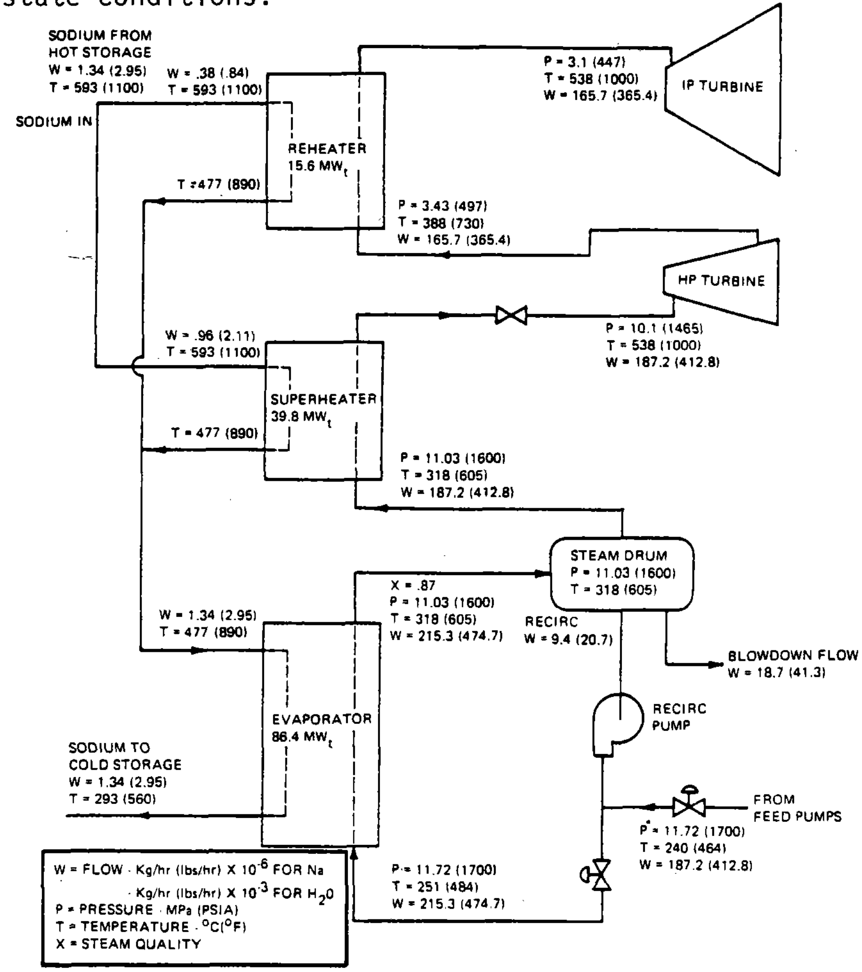


Figure 5.5-14. Steam Generator Subsystem Design Point (Hybrid) Heat Balance

5.5.6 COST ESTIMATES

The steam generator subsystem was costed as part of the receiver subsystem, account 5400 in the Appendix A, System Requirements Specification (SRS). The specific subsystems and their respective costs from account 5400 which apply to the steam generator subsystem are shown in Table 5.5-8.

Table 5.5-8

STEAM GENERATOR SUBSYSTEM COSTS

Account	Description	Cost ($)
5470	Miscellaneous Piping and Equipment (Pump Building)	$ 433,378
5480	Steam Generator Subsystem (Sodium Side)	17,628,753
5490	Steam Generator Subsystem water side	2,544,303
	TOTAL STEAM GENERATOR SUBSYSTEM	$20,606,434

The SRS provides cost details.

It should be noted that the cost of the steam generator modules totals \$11,919,000. The validity of this assumption is enhanced by comparing it with a quotation for a helical coil steam generator design obtained from the Babcock and Wilcox Corp. (see Appendix O). Their price for the helical coil design for the same duty (60 MWe) is \$18,000,000. A good deal of this difference results from the helical coil design being behind the hockey stick design in development. Although these costs are not directly comparable, it does show that the General Electric estimate for the hockey stick design is in the proper range for large heat exchanger equipment.

5.6 CONTROL SUBSYSTEM

The control subsystem consists of the distributed control loops, master control system, and all plant instrumentation required to monitor and control the operation of the repowered plant facility.

5.6.1 REQUIREMENTS

The preliminary requirements for the control subsystem have been developed based on the plant operating requirements generated by Southwestern Public Service. The control philosophy used in developing the requirements for control system is based on the following design guidelines:

- Solar and fossil controls will be separated to permit totally independent operation.
- Capability to operate the plant completely automatically will be provided by the master control system (MCS).
- Semi-automatic operation using manual set-points will be provided from the operator's console.
- Completely independent manual control for all major drive units will be provided.
- Redundant control and instrumentation will be provided for all critical components and parameters in order to eliminate single point failure effects where cost effective.
- All critical/emergency functions and critical data will be hard-wired to operator's console.
- Data display and recording will be provided for those parameters pertinent to evaluation of plant performance, operation, and safety.
- Control system will use in its design proven off-the-shelf components of the type currently in use.

The control subsystem will have the capability of operating the fossil plant alone, the solar plant alone, or both together as a hybrid. Specifically, it will operate the plant in the following modes:

CASE 1: FOSSIL PLANT ALONE
- Boiler Follow Mode
- Turbine Follow Mode
- Coordinated Mode

CASE 2: SOLAR PLANT ALONE
- Turbine Follow Mode

CASE 3: SOLAR/FOSSIL HYBRID PLANTS
- Fossil Follow Mode
- Solar Swing Mode

For operation of the fossil plant alone, the standard control functions will be provided by the master control system for computer prompted start-up, operation in the three modes, and shutdown. The control drives automatic valves, and instruments required to perform these functions will be added to the current fossil plant.

When controlling the solar plant alone, the system will utilized the maximum solar power available at all times and will put the turbine control in the Turbine-Follow Mode such that the electrical plant output will be directly proportional to the solar power available. The solar plant controls will be by distributed control loops with master control monitoring and supervision.

The Hybrid (Solar/Fossil) Mode of operation is expected to be the normal operating situation with the fossil plant matching the difference between the electrical demand and the equivalent electrical output being supplied by the solar plant. Swinging the plant output by keeping the fossil output constant is another mode possible with the hybrid plant operation. The method of paralleling the solar and fossil plants is based on existing, proven techniques developed for paralleling separate fossil steam supplies to a single turbine.

5.6.2 CONTROL SUBSYSTEM DESIGN DESCRIPTION

5.6.2.1 Plant Controls

The design of the control subsystem is based on proven hardware components that will provide high reliability, cost effectiveness, and overall simplicity. The hardware/software system selected to implement the plant control and monitoring system can best be described as a hierarchial functionally distributed computer system. This type of system is similar to one currently being used on a

300 MW coal-fired power plant at Harrington Station by Southwestern Public Service. It is expected that the experience obtained on that system will be directly applicable to the implementation of the repowered system.

The control system to be implemented for the repowered plant is shown functionally on the diagram of Figure 5.6-1. All communication between master control system (MCS) and the subsystems is via dual redundant data link. The data transmission is parallel from the subsystems to a centrally located (within 500 ft) LINKPORT and from there through dual redundant serial data link back to the MCS which is resident in the main central processing units (CPU).

Direct communication between subsystems for coordination purposes and interlock purposes is via the LINKPORT if permitted by the MCS. As shown, it is expected that two LINKPORTS will be required: one to handle the solar receiver and storage subsystems, and one to handle the solar steam generator plus the fossil plant.

Two computers are utilized in the system solely for control calculations and, except for some higher level MCS functions, would also contain the majority of the MCS logic. Each computer (CPU) would be sized to be able to control the entire hybrid plant, but in reality one CPU would control the solar plant and one CPU the fossil plant with the master control functions repeated on both. Each CPU has dual I/O port capability and will utilize redundant sensors to minimize single point failures where cost effective. In general, critical sensors and controls will be only dual redundant with computer logic determining the failed sensor by monitoring sensor performance indirectly using other sensors. In a few critical cases, such as fossil boiler pressure and solar receiver tower panel temperature, triple redundancy will be used in conjunction with a "voting algorithm" to determine the failed element. In all cases, sufficient manual hard-wired backup will be provided to the plant operator to safely shutdown the plant if required, or if possible to operate it until the problem has been cleared up.

Use will be made of 16 bit micro-processors (i.e., Intel 8086 or others) in the field to perform certain of the more critical control algorithms, such as the control and monitoring of the receiver panels heat flux and sodium temperatures. In this case operator interface would be through on emergency shut-off control on the EM pumps to be used in the case of a complete failure of primary and back-up controls. The degree of control that will be made available to the operator on the solar side of the plant will be in direct proportion to the control interfaces

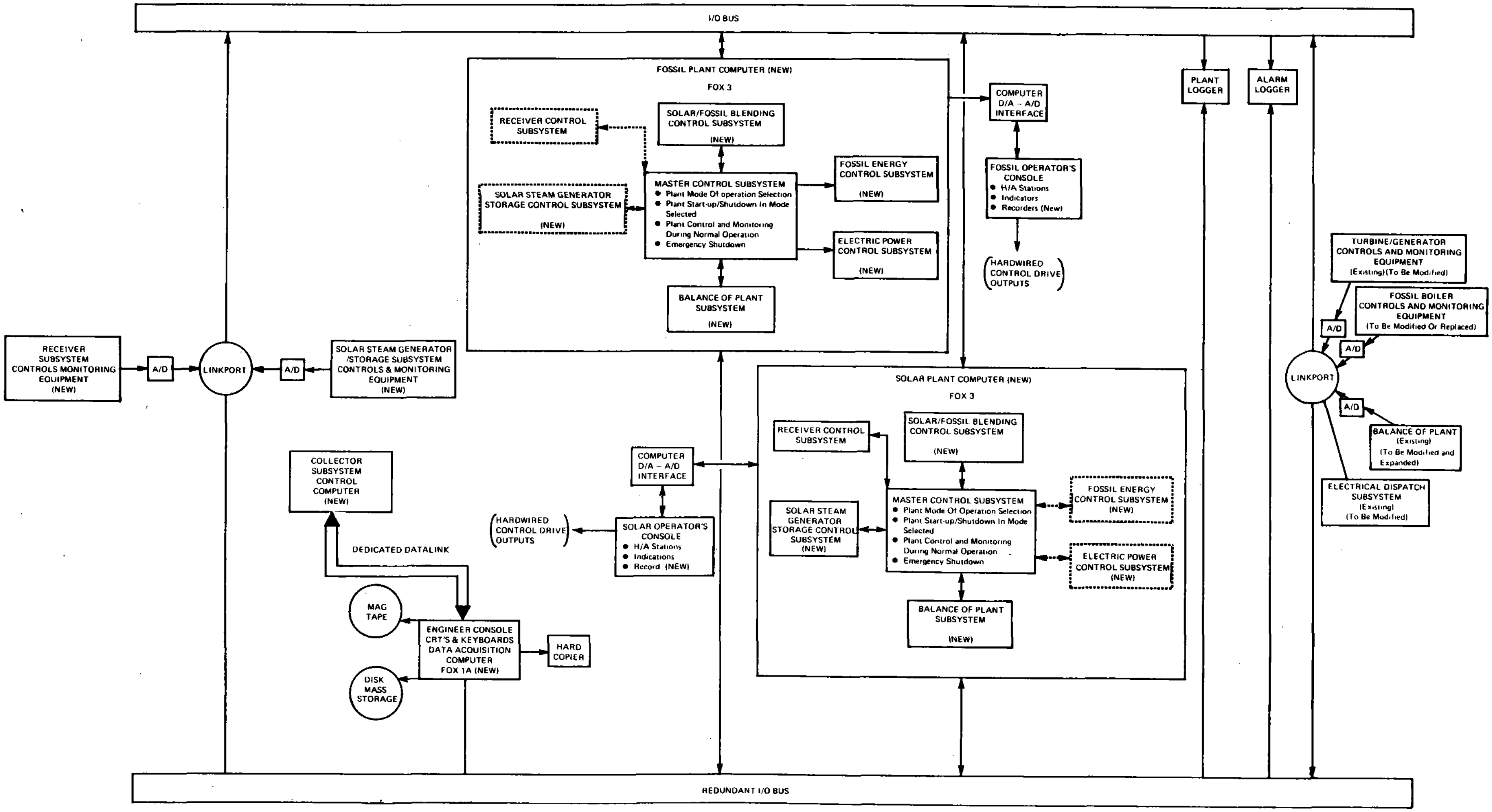


Figure 5.6-1 Functional Control System Diagram

required to start, operate and shut down the plant automatically with or without operator assistance.

A third computer will be utilized exclusively for data acquisition, display and storage. This computer will be larger than the control computers and will provide immediate data display in the form of bar graphs, historical logs, trend graphs, and various page formats. Data gathered by this computer will be conditioned, converted, reduced, and stored on disk or mag tape for later recall. Some MCS functions that do not directly affect plant control may be resident on this computer also. An example of a typical function might be generation of an operator's options for starting the turbine-generator, utilizing controls on the operator's console.

Operator interface with the computer system is via H/A control stations, push-buttons, and switches located on the operator's consoles and through the I/O typer located on the engineer's console. Plant and system response can be monitored from status lights, indicators, and recorders on the operator's console and the CRT displays generated by the data acquisition computer. A hard copier will be used to provide permanent record of these displays.

In exception to the above, the controls for the heliostat field will be resident in the heliostat control computer located at the base of the receiver tower. Operator interface will be via dedicated data link (it will not go through the LINKPORT) except for a few emergency controls (i.e., stow and de-focus), which will be hard-wired. A separate CRT and keyboard mounted on the solar operator's console will be used to communicate directly with the heliostat field using a separate micro-processor control.

A sequence events recorder (hardwired micro-processor) is used as an independent monitor of the repowered plant operations and transmits critical data to the plant operator via a dedicated alarm CRT. The system also provides signals to drive back-lighted annunicators for certain critical parameters requiring immediate operator attention. A direct interface into the plant control computers is provided to allow the MCS to perform an unscheduled or emergency shutdown if necessary.

A final control element that is provided by the system is the active graphic display located in front of the engineer's console. On it the active status of key control elements is indicated by back-lighted symbols on a plant process flow diagram. This diagram is of particular use when operating in the automatic-manual assist and the manual modes of operation.

Alarm logging is provided by the sequence events recorder (SER) and the plant alarm printer. Plant logs are recorded on the plant log printer. A card leader, card punch, and hi-speed printer are provided in the computer room for program generation and software de-bugging and/or modification.

An artist's concept of the plant control room is shown in Figure 5.6-2. Sizes and locations of components are represented for illustrative purposes only; actual size and location will be determined during the preliminary and final design phases. The overall design concept will, however, remain the same; namely, separation of the solar and fossil parts of the plant on an operator interface level with overall integration of control of the hybrid plant (solar and fossil) will remain the responsibility of the master control subsystem.

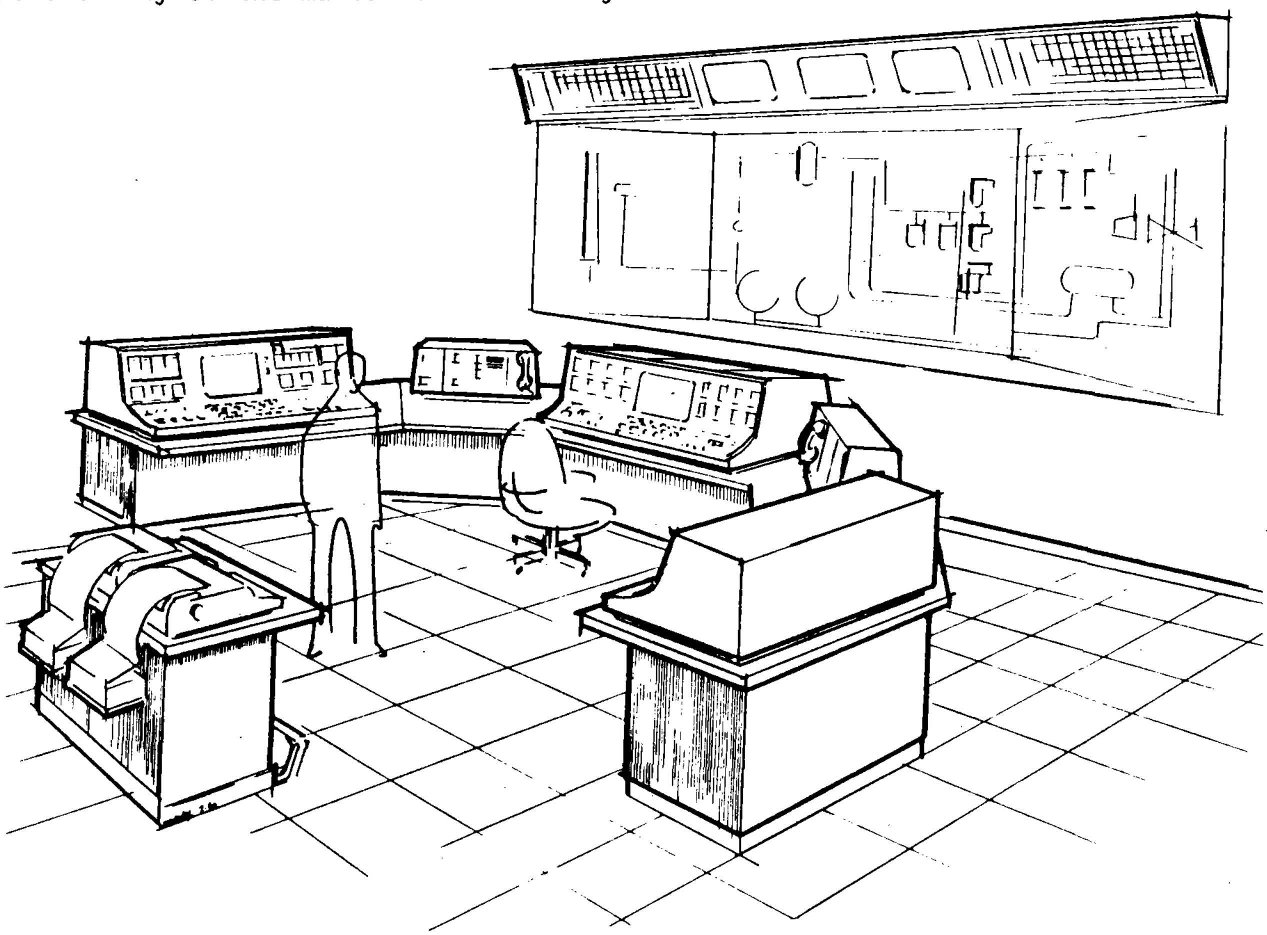


Figure 5.6-2. Artist's sketch of plant control room

5.6.2.2 Plant Instrumentation

The plant instrumentation consists of various flow, temperature, pressure, level, position and on-off controls and monitors that provide input to the local and master control elements. The various instrumentation to be added to the facility in the repowering effort is illustrated in the plant P&ID, (Figure 4.2-1). The Figure also illustrates the main input points for the data obtained by the instrumentation.

As indicated in Section 5.6.2.1, some critical instrumentation will be redundant. All of the instruments have been selected from available existing hardware. No development of instrumentation is required.

5.6.3 CONTROL SUBSYSTEM OPERATING CHARACTERISTICS

In the plant operation, the control subsystem has the following general functions to perform:

- Plant mode of operation selection
- Automatic plant start-up and shutdown in mode selected
- Plant control and monitoring during normal operation
- Plant alarm monitoring and initiation of emergency shutdown procedures (when required).

In performing its various functions, the transition from one mode to the other must be capable of being handled by MCS management even though sufficient back-up manual/automatic control will be provided to assure safe passage from mode to mode by direct operator intervention. Various mode changes are possible during normal plant operation and a smooth transition from one mode to the other is required to prevent unscheduled plant output perturbations. Table 5.6-1 lists the various operating modes possible for this solar/fossil plant. Modes requiring MCS transitional control are indicated with an "x."

Table 5.6-1

SOLAR/FOSSIL HYBRID PLANT
TYPICAL TRANSITIONAL MODES

From \ To	Solar Alone	Solar Start-up	Solar Hybrid	Intermittent Cloud Cover	Solar Hot Shutdown < 2 Hours	Short Term Shutdown < 48 Hours	Fossil Start-up	Fossil Alone
Solar Alone				X			X	
Solar Start-up	X		X		X			
Hybrid	X			X	X			X
Hot Standby < 4 Hours		X				X	X	
Short Term Standby < 48 Hours		X						
Fossil Start-up			X					X
Fossil Alone			X					

The MCS system interfaces with all the major subsystems in the plant as shown in the logic block diagram in Figure 5.6-3. The actual coordination and management of the subsystem involves manipulation of set-points on controllers, discrete signals for valve openings and closings, process monitoring, opening and closing process control loops and direct control of process drives. With the exception of the heliostat field, all control computations are performed in the main CPUs; the collector field is controlled by its own central computer system, and MCS interface with it is by dedicated data link.

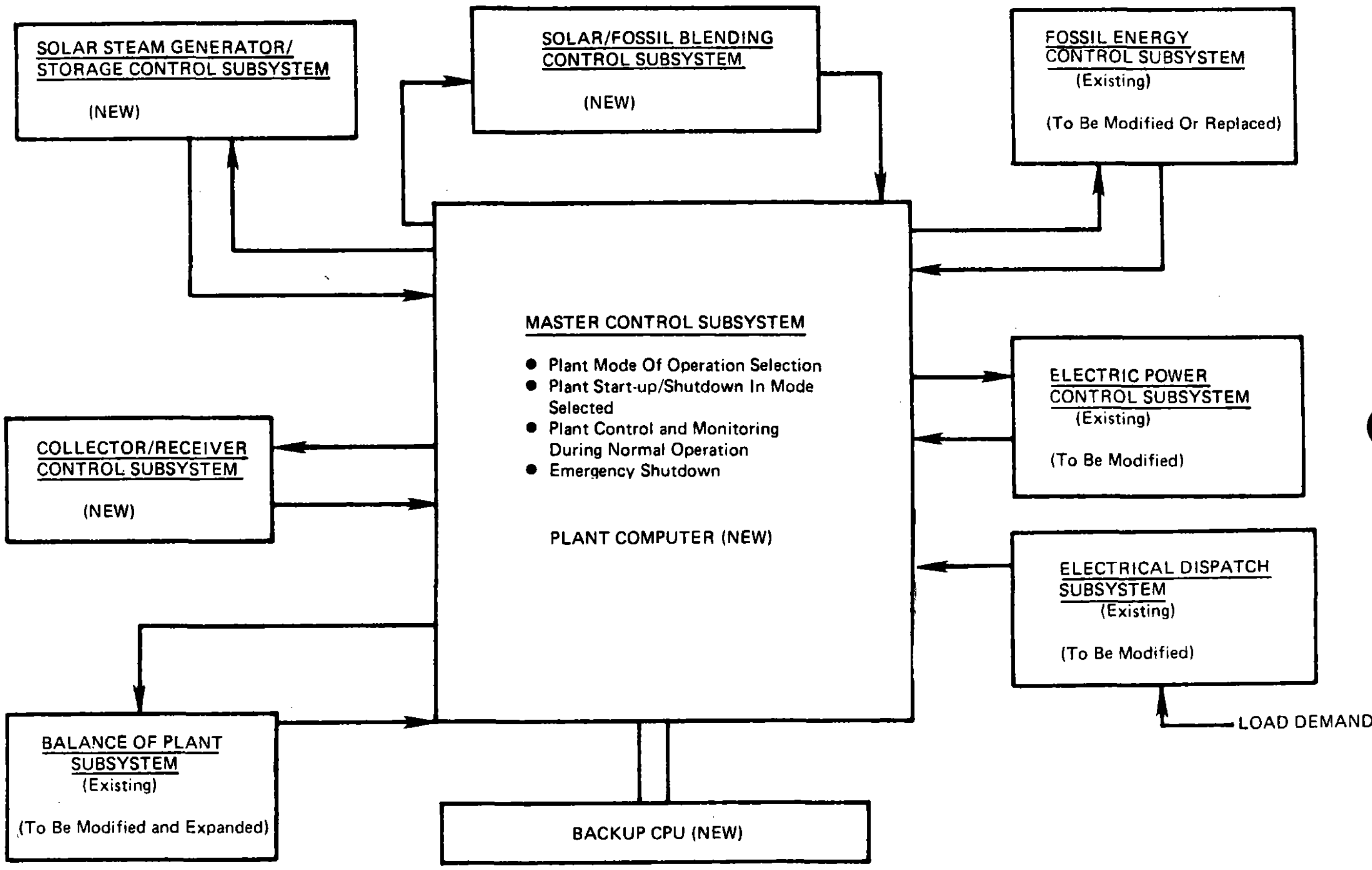


Figure 5.6-3. Logic Block Diagram

Individual Subsystem Control Functions are as follows:

- Collector, Figure 5.6-4
  - -- Start-up and shutdown commands
  - -- Partial focus/defocus commands
  - -- Solar capacity potential assessment
  - -- Emergency sensing, slew and stow
  - -- Monitor, display and alarm appropriate data for all heliostats
- Receiver Figure 5.6-4

-- Start-up and shutdown sequencing of valves, blowers and pumps and set-points

-- Emergency sensing and shutdown coordination with the collector

-- Coordination of EM pump control with solar flux and panel temperature measurements

-- Emergency draining in conjunction with emergency collector de-focus

-- Monitor, display and alarm appropriate data

- Storage, Figure 5.6-5

  -- Thermal charge control

  -- Steam generator pump control

  -- Cold and hot mixing control

  -- Monitor, display and alarm appropriate data

- Solar Steam Generator, Figure 5.6-5

  -- Drum level control

  -- Solar feedwater flow control

  -- Turbine by-pass and blending control

  -- Superheater and reheater temperature control

  -- Recirculation pump control

  -- Sodium by-pass valve control

  -- Monitor, display and alarm appropriate data

- Solar Blending and Control, Figure 5.6-6

  -- Turbine by-pass/warming

  -- Steam blending/solar stop valve control

  -- De-superheater control

- Fossil Energy Control

  -- Turbine start-up and shutdown in accordance with an optimum life algorithm by computer prompting of the operator

  -- Fossil output control to meet electrical grid demands (hybrid or fossil alone)

  -- Monitor, display, and alarm appropriate data.

5.6.4 COST ESTIMATE

The cost of the control subsystem is estimated to be $4,476,664. Details of the estimate are presented in the Appendix A System Requirements Specification under Account 5500, Control Subsystem.

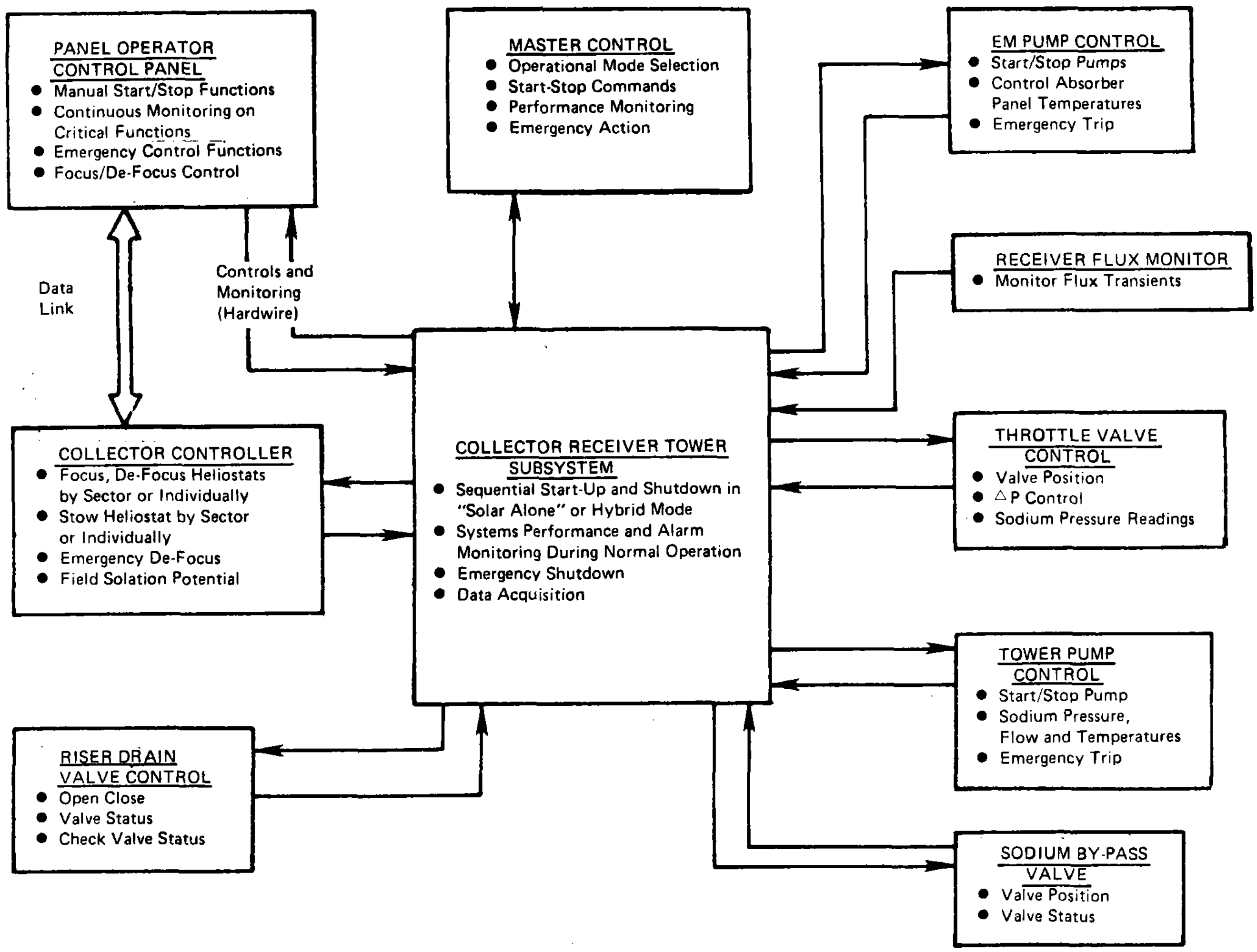


Figure 5.6-4. Collector and Receiver Control Functions

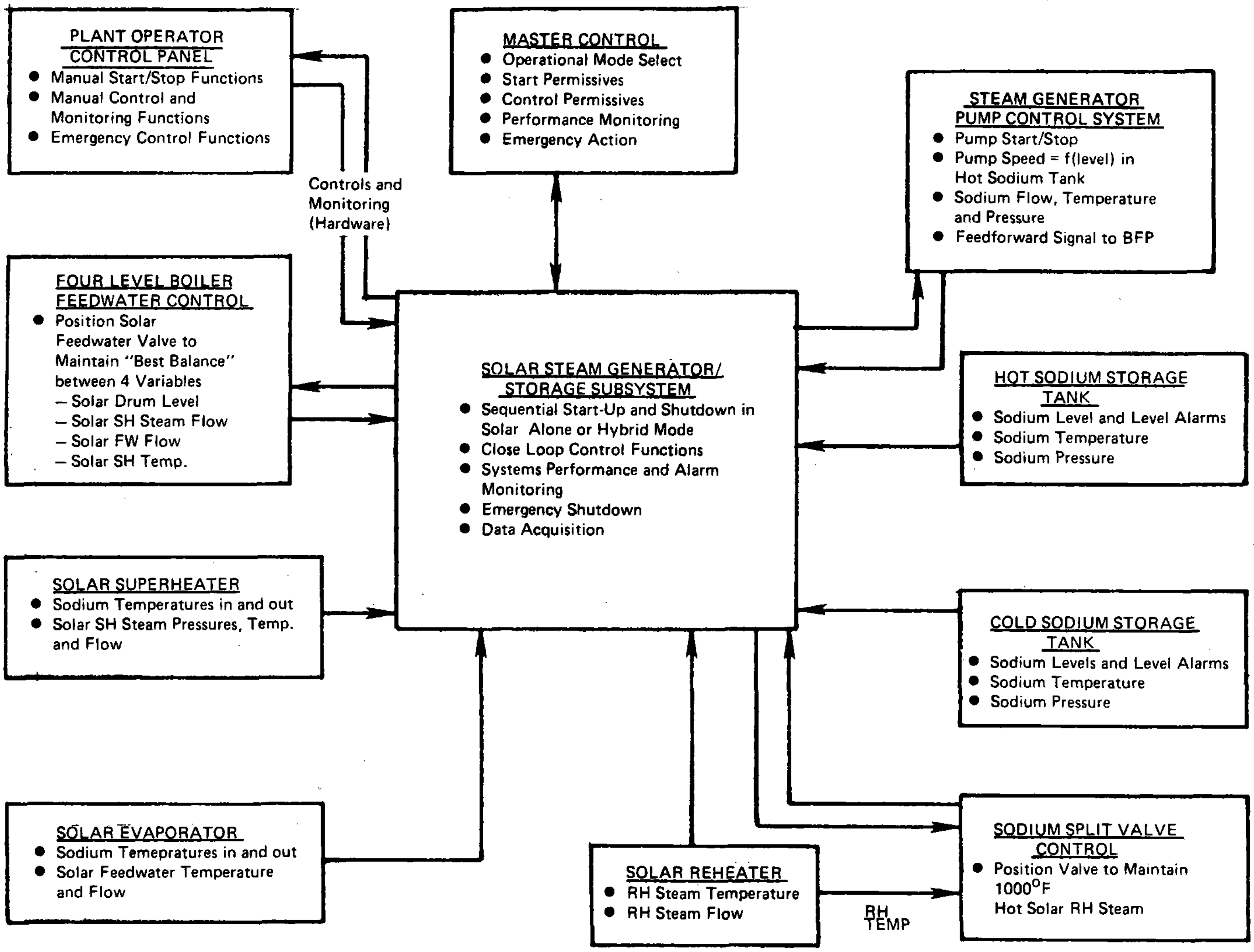


Figure 5.6-5. Storage and Solar Steam Generator Controls

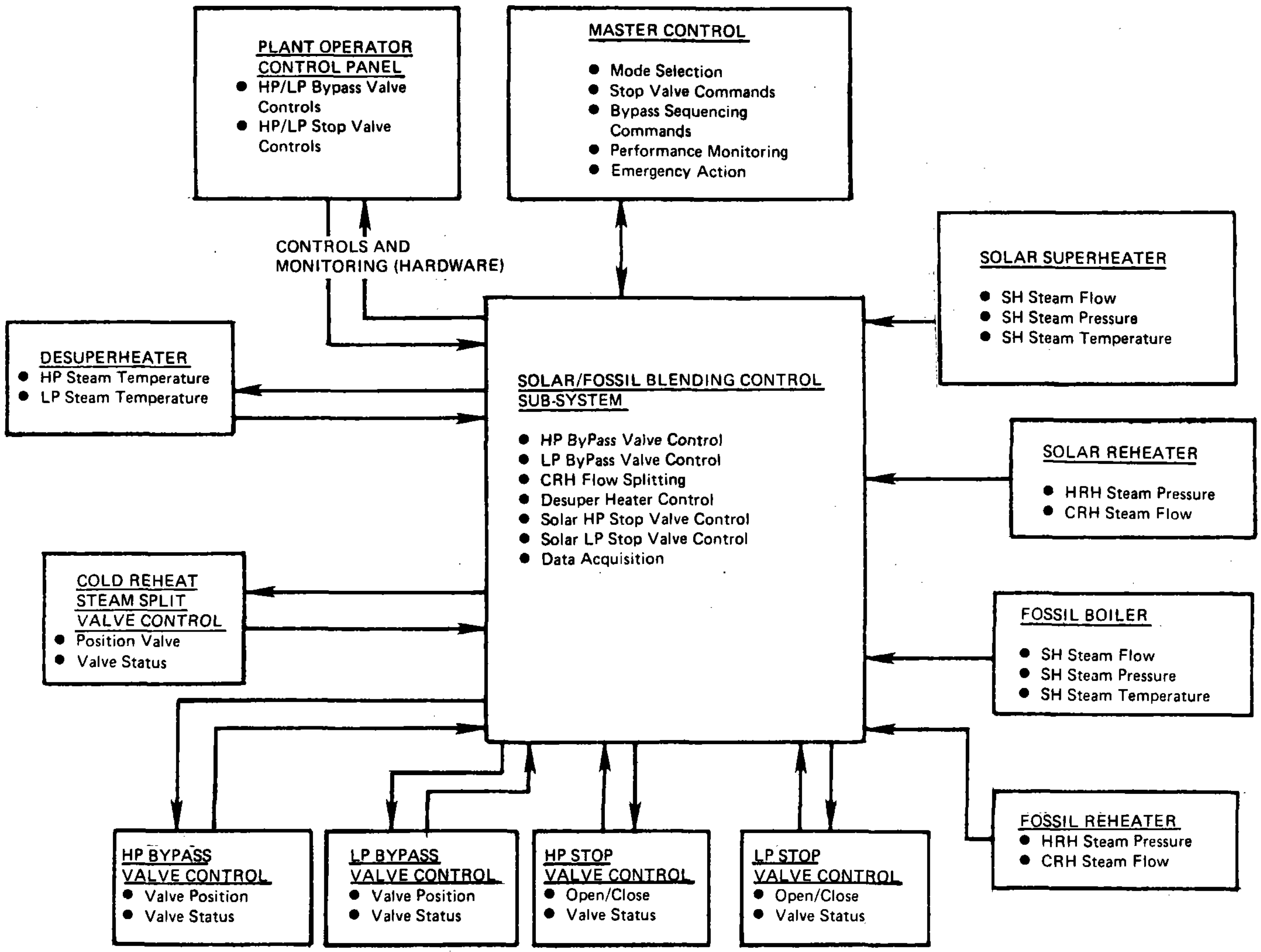


Figure 5.6-6. Solar Blending and Control Functions

5.7 FOSSIL ENERGY SUBSYSTEM

This section describes the modifications that are required to the existing fossil boiler to permit satisfactory operation in the repowered plant.

5.7.1 DESIGN REQUIREMENTS

The existing fossil energy subsystem will be modified to have the following capabilities:

- Automatic or manual startup regardless of whether the solar plant is operating
- Operation in a "Fossil Alone" mode which will not impact any operations on the solar portion of the plant
- Operation in a hybrid mode in either a "Boiler Follow" or "Turbine Follow" configuration
- Ability to maintain a constant plant output by compensating for solar plant transients while operating in a hybrid mode
- Respond to functional commands from master control subsystem computers
- Provide system operation information in a format compatible with the new data acquisition computer

5.7.2 DESIGN DESCRIPTION

Changes to the existing fossil boiler to achieve the design requirement described in Section 5.7.1 include the following:

- An upgrade of the fuel firing system by adding a remote manual burner sequencing system
- An upgrade of data transmitters to electronic state-of-the-art components
- New LVDT or slidewire drive position feedback devices
- Improved integrated boiler-turbine-generator control system
- New fossil boiler TV system for the steam drum and firebox
- Addition of boiler header isolation valves at the four solar-fossil-interface points (feedwater, main steam, cold reheat, hot reheat)
- Improved steam attemperation hardware
- Addition of feedwater flow control valves to split feedwater flows to the solar and fossil boilers during hybrid operation

Addition of cold reheat flow control valves to split steam flows to the solar and fossil reheaters during hybrid operation

5.7.3 OPERATING CHARACTERISTICS

Modifications to the fossil energy subsystem will permit the boiler functions to be totally independent of the solar portion of the plant. Operations in the fossil alone mode will be identical to those presently in use at Plant X. Double isolation valves will permit the solar-fossil plants to be physically and functionally separated so that either can be run with the other down for maintenance.

In the hybrid mode, feedwater and cold reheat steam flow control valves will split the flow between the solar and fossil plants. The feedwater flow control valve responds to a standard three-element flow control loop that monitors feedwater flow, steam flow and drum level. The cold reheat steam valve control system adjusts the split to match the feedwater flow ratios.

The boiler will respond to solar transients through commands from the load controller which controls boiler feed pump flows and the boiler fuel firing rate.

The fossil energy subsystem, through its ties with the master control subsystem computers will be capable of being operated in any of the modes described in either an automatic, semi-automatic (computer"prompted") or manual method.

A test which verified the suitability of the fossil reheater for nybrid operation is described in Appendix H.

5.7.4 COST ESTIMATE

The total cost of the required Fossil Energy Subsystem Modification is \$1,600,821. Details of the costs are contained in the Appendix A System Requirements Specification in Account 5600.

5.8 <u>ENERGY STORAGE SUBSYSTEM</u>

The energy storage subsystem consists of the storage tanks and interfacing piping with the receiver and steam generator subsystems. It provides the means of buffering the solar plant output from solar transients.

5.8.1 SUBSYSTEM REQUIREMENTS

As discussed in Section 3.0, it was concluded that for the repowering of Plant X, the proper amount of storages is 10 full-power minutes or 10 MWe-hrs This amount of storage is adequate to allow the solar plant output to be ramped down from the 60 MWe level to 0 after a loss of insolation at a rate (3 MWe/min) consistent with the fossil boiler capability to pick up the load. In providing the required storage, the subsystem design was subject to the requirements listed in Table 5.8-1.

Table 5.8-1

STORAGE SUBSYSTEM REQUIREMENTS

Parameter	Requirement
Basic Design	Hot/Cold Storage Tank Buffer Arrangement
Working Fluid	Liquid Sodium
Hot Fluid Temperature	593°C (1100°F)
Cold Fluid Temperature	293°C (560°F)
Pressure	Operating pressure never to drop below atmospheric
Insulation	Limit heat loss to 2.5% per day (nominally full tank) at 0°F ambient

5.8.2 SYSTEM DESIGN DESCRIPTION

The storage subsystem final design consists of two double-wall tanks, one hot and one cold, located adjacent to the pump building, as shown in the site plot plan, Figure 5.1-1. The sodium from the receiver enters the hot storage tank (Figure 5.8-1). The hot sodium is pumped from the tank by the steam generator pump (part of steam generator subsystem) and passes through the steam generator modules. The cooled sodium is returned to the cold storage tank where it provides the source of fluid for the tower pump (part of the receiver subsystem) to return to the receiver for heating. The system also includes an argon cover gas supply to ensure that tank pressure remains above atmospheric. A more complete illustration of the storage subsystem interelationship with the remainder of the system is shown in the P&ID, Figure 4.2-1.

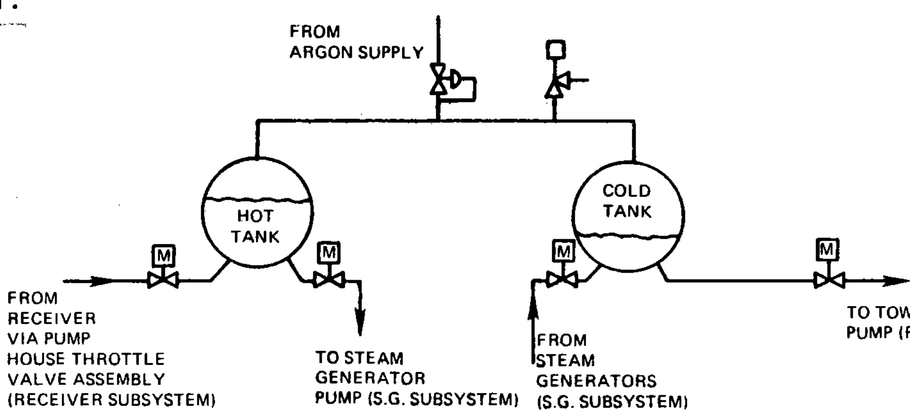


Figure 5.8-1. Storage Subsystem Schematic Diagram

Additional details of the storage subsystem design and its evolution are provided in the following sections.

5.8.2.1 Storage Volume

The hot and cold sodium storage tanks have been sized to provide adequate volume for 10 full-power minutes of operation, system draining and cover gas. Table 5.8-2 shows a breakdown of the required volume for the hot storage tank.

Table 5.8-2

HOT STORAGE TANK VOLUME REQUIREMENTS

Element	Volume Required
Storage Sodium (10 minutes)	276 m^3 (9795 ft^3)
5% Margin (to prevent loss of pump suction)	14 m^3 (490 ft^3)
System Draining (1/2 of system)	68 m^3 (2384 ft^3)
Subtotal	358 m^3 (12669 ft^3)
5% Cover Gas	18 m^3 (633 ft^3)
TOTAL VOLUME	376 m^3 (13300 ft^3)

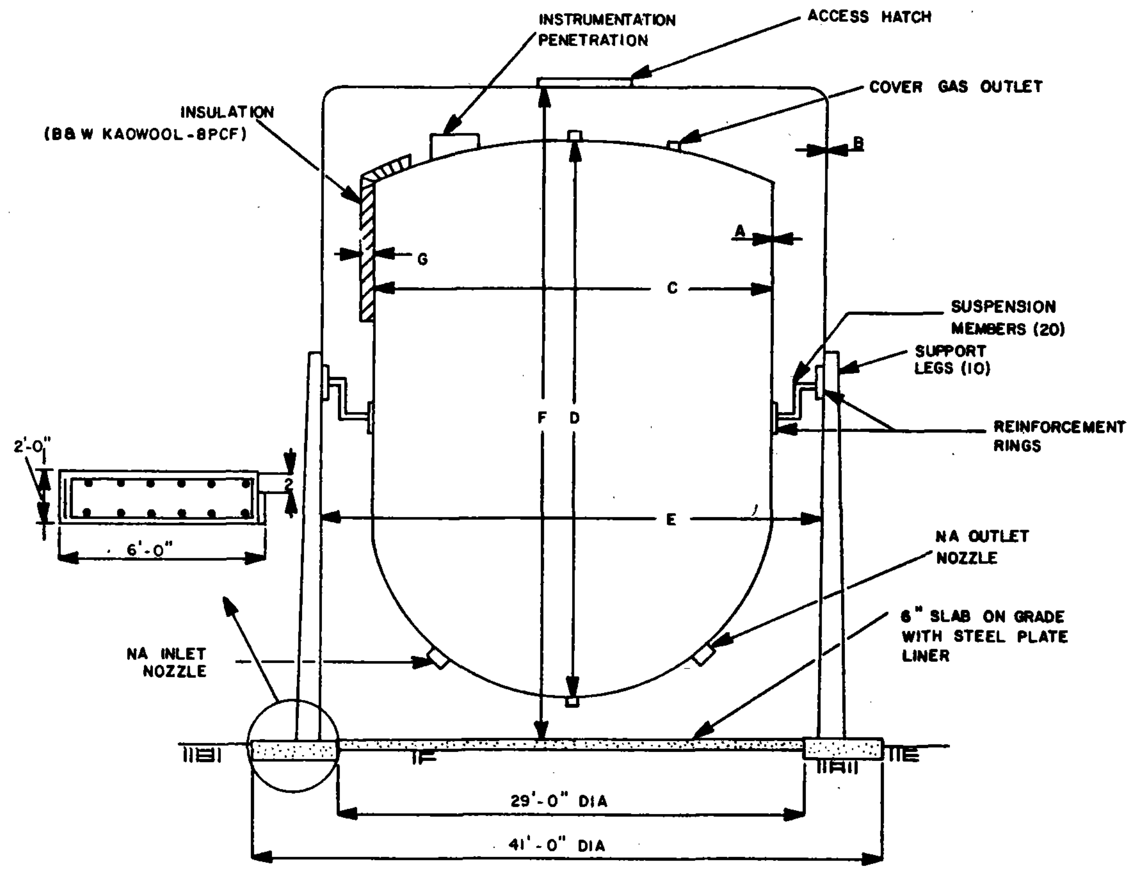
Although the cold storage tank could be sized slightly smaller than the hot tank, it was sized identically to simplify the production process.

5.8.2.2 Structural Design

The storage tank configuration is illustrated in Figure 5.8-2. The figure also lists the tank specifications.

The tanks are of a double wall field fabricated construction with the insulated inner tank suspended by arms from the outer tank wall. This design was developed for cryogenic application and has been shown to be adaptable to solar plant applications in the Alternate Central Receiver, Phase II program.

316H stainless steel was selected for the inner hot tank wall to provide the necessary strength and resistance to sodium at the 593°C (1100°F) operating temperature. For the cold tank, the inner tank wall will be A515 GR70 carbon steel, which



DIMENSIONS

Dimension	Item	Hot Tank	Cold Tank
A	Inner Tank Wall Thickness	1.905 cm (0.75 in.)	1.27 cm (0.5 in.)
B	Outer Tank Wall Thickness	0.635 cm (0.25 in.)	0.635 cm (0.25 in.)
C	Inner Tank Dia.	7.84 m (25.7 ft)	7.84 m (25.7 ft)
D	Inner Tank Ht.	9.15 m (30 ft)	9.15 m (30 ft)
E	Outer Tank Dia.	10.06 m (33 ft)	10.06 m (33 ft)
F	Outer Tank Ht.	13.11 m (43 ft)	13.11 m (43 ft)
G	Inner Tank Insulation Thickness	35.6 cm (14 in.)	35.6 cm (14 in.)

SPECIFICATIONS

Item	Hot Tank	Cold Tank
Materials		
Inner Tank	316H	A515 GR70
Outer Tank	C.S.	C.S.
Design Temp.		
Inner Tank	621°C (1150°F)	321°C (610°F)
Outer Tank	60°C (140°F)	60°C (140°F)
Design Pressure	50 psig	50 psig
Volume (Inner Tank)	376 m^3 (13,300 ft^3)	376 m^3 (13,300 ft^3)

Figure 5.8-2. Storage Tank Configuration and Specifications

will provide satisfactory performance at its 293°C (560°F) operating temperature. The outer walls of both tanks will be carbon steel.

5.8.2.3 Alternatives Considered

Consideration was given to an alternative tank design — factory fabricated cylindrical tanks. Because shipping restrictions would limit the size of factory fabricated tanks, four of these tanks (two hot, two cold) would be required. Each tank would be 3.96 m (13 ft) in diameter and 16.6 m (54.4 ft) long. The materials would be the same as the field fabricated tanks.

To meet the utility requirement to provide a double barrier between the storage sodium and water (from rain), the cylindrical tank would be housed in an extension of the pump building with a revetment around the tanks to avoid damaging other pump house equipment should a leak develop.

In a cost study of the field versus factory fabricated designs, it was found that the four factory fabricated tanks would cost ~10% more than the double wall field fabricated design. The cost factored in the added pump building space required for the factory fabricated design.

Based on the cost difference, the field fabricated design discussed in the previous section was selected.

5.8.2.4 Insulation

As described in Section 4.2.2, the sodium in the storage tanks will be used as a source of heat to maintain the system above the temperature requiring trace heating during prolonged shutdown (up to seven days). The tanks have been provided with adequate insulation to limit their heat losses to less than 3%/day to provide this capability.

The insulation selected for use is B&W's Kaowool, which provides excellent insulating properties at the high temperatures associated with this application.

For both the hot and cold tanks, 35.6 cm (14 in.) of 8 pcf Kaowool blanket has been specified. With this insulation, the hot tank, when full, will lose $\sim \frac{1.8\%}{\text{day}}$ ($95.8 \frac{\text{K Btu}}{\text{hr}}$) under -18°C (0°F) ambient conditions. The cold tank under similar conditions would lose ~2.5%/day ($36.6 \frac{\text{K Btu}}{\text{hr}}$).

The effect of this insulation level on tank cooldown rate is shown in Section 4.2.2.

5.8.2.4 Trace Heating

Electrical trace heating will be provided for both the hot and cold storage tanks for initial system warmup and to maintain the sodium in a liquid state for shutdowns (>7 days). The trace heating will be adequate to maintain a 177°C (350°F) temperature with an ambient temperature of -18°C (0°F).

To provide this level of heating, each tank will have tubular electrical trace heaters with stainless steel sheaths spaced at ~1.2m (4 ft) intervals around the sides and bottom of the tank. The total electrical input for each tank will be ~8000W.

5.8.2.5 Cover Gas

The argon cover gas for the storage tanks will be provided from the central storage facility located adjacent to the pump building.

The pressure of the argon in the tanks will vary depending on the sodium level in each tank and the temperature in each tank. A criterion was set that no argon should have to be added or removed from the system except during system draining or filling. Thus the tanks must remain above atmospheric over a range covering a full hot tank (full in the sense that all the storage sodium is in it) to a full cold tank and temperatures ranging from normal operating down to 177°C (350°F).

The minimum argon pressure for the closed system will occur when the tanks are cooled to 177°C (350°F). At that time, the pressure must be 101.4 KPa (14.7 psia). To determine the pressure under normal operating conditions, the following procedure was used.

It was assumed that the cold tank holds only its ullage volume of sodium and the hot tank holds the remainder of the storage sodium. When temperatures are brought to normal operating, 293°C (560°F) for cold tank and 593°C (1100°F) for hot tank, the sodium expands by ~6% and the pressure of the gas due to temperature change will increase by ~43%. This brings the gas pressure to 154 KPa (22.3 psia), which would be the lowest pressure during normal operations. The equation that describes the pressure during normal operation as a function of tank level is:

$$Pg = 22.3/[0.751 + 1.94 \times 10^{-5}\ Vch]$$

where:

Pg = argon pressure

Vch = cold tank gas volume (in ft^3)

The pressure will be maximum when the cold tank is at its high normal operating level (V_{ch} = 3843 ft^3). The pressure at that time will be 186 KPa (27 psia).

5.8.3 OPERATING CHARACTERISTICS

The storage subsystem is basically passive in its function within the total system. Its only active role will be as an indicator to the steam generator pump as to the proper flow rate during normal operations. As discussed in detail in Section 4.2.2, the steam generator pump flow rate will be controlled by the hot storage tank level. When the tank is nominally full, the pump will operate at the speed corresponding to 60 MWe. If the level drops, indicating the receiver is delivering less than the pump is removing, the pump speed will decrease proportionally until a steady level is maintained. This scheme ensures sufficient hot sodium in the tank to ramp down the solar plant output at 3 MWe/min should insolation be lost totally.

5.8.4 Cost Estimate

The cost of the energy storage subsystem has been estimated at $1.979 million. Details of this estimate are included in the Appendix A, System Requirements Specification under account 5700.

5.9 ELECTRIC POWER GENERATING SUBSYSTEM

This section describes the modifications that are required to the existing EPGS to allow it to function satisfactorily when Plant X is repowered.

A description of the existing EPGS is provided in the Appendix A System Requirements Specification.

5.9.1 REQUIREMENTS

The existing EPGS (and in particular the turbine) was designed as a base load type of unit. Thus, the turbine controls and hardware were not designed for the type of cycling that will be required in the solar application. In addition, some provision must be made to by-pass the turbine when trying to start up either the fossil or solar steam sources with the other operating.

Thus, the two requirements with respect to the EPGS are:

- Convert turbine to cycling unit
- Provide turbine by-passes to allow startup of fossil or solar boilers with the other steam source operating

5.9.2 SYSTEM DESCRIPTION

5.9.2.1 Turbine Modifications

The turbine modifications to allow the required cycling for solar application are listed in Table 5.9-1.

Table 5.9-1

TURBINE MODIFICATIONS TO ALLOW CYCLING

Convert to full arc admission
Replace thrust bearings
Add bearing thermocouples
Add vibration monitors
Add inlet moisture monitors

The major change is the conversion of the turbine steam inlet to a full arc design. This will enable more uniform heating and cooling of the front end of the turbine to reduce stresses as inlet steam conditions change.

The additional changes are primarily to allow monitoring of the turbine condition to insure that no damaging conditions develop.

In addition to the modifications required to allow cycling, additional changes are required to allow the turbine control system to interface with the new plant control system and to allow some current operations which are manual to be done remotely. These include adding the following to the existing plant controls:

- Transducers and transmitters
- Drive position feedbacks
- Remote turbine drain valve operators

These modifications in total will enable the turbine to operate in a manner consistent with the utility requirements.

5.9.2.2 Startup By-pass System

A system that allows the superheater/reheater discharge flows to by-pass the turbine is required during the startup sequence. The by-pass is only required when one system, either solar or fossil, is started while the other system is on the line. The by-pass system is in operation only until the steam/pressure/temperature of the system being started approaches within allowable limits of the pressure/temperature of the operating system.

The by-pass system permits the fossil superheater flow to by-pass the HP turbine and enter the reheater inlet. The pressure and temperature of the bypass flow is controlled to the desired reheater inlet conditions by desuperheater and pressure control valve. The by-pass system also allows the discharge of the reheater to bypass the low pressure turbine. This flow is also pressure controlled and desuperheated, then condensed in an air cooled heat exchanger prior to mixing with the main feedwater flow in the condenser. Both the fossil and solar turbine by-pass systems share the same air cooled heat exchanger. Startup of the fossil system with solar on line produces the maximum flow through the by-pass system, approximately 10% of full flow, or 31818 kg/hr (70,000 pph). The by-pass system is illustrated schematically on the P&I Diagram, Figure 4.2.1.

5.9.3 COST ESTIMATE

The total cost of the required EPGS modifications and additions is $2,375,871. Details of the costs are contained in the Appendix A System Requirements Specification under account 5800.

5.10 SYSTEM PIPING AND VALVES

This section provides a system-wide description of the new piping and valves being added for the repowering estimate.

A visual reference for the location of the piping and valves discussed below is the plant P&ID, Figure 5.10-1, with the valves and pipes labeled.

5.10.1 PIPING

Table 5.10-1 lists the sodium piping and Table 5.10-2 lists the water/steam piping being added to the existing Plant X, Unit 3 facility as a result of the re-powering. The tables also list the design characteristics of the piping.

5.10.1.1 Sodium Piping

All the sodium piping is being sized at Schedule 40, which is more than adequate to handle the system pressures. This was done per Southwestern Public Service's request to ensure that high reliability welds could be made in all piping.

All pipe diameters were chosen so that the sodium flow velocities would be less than 7.6 m/sec (25 ft/sec) to achieve reasonable pressure losses in the sodium system and to minimize flow induced pipe vibrations. In most cases the velocities are in the 6.1 m/sec (20 ft/sec) range at design flow conditions.

Materials

The high temperature sodium piping will utilize 304H stainless steel. In pre-

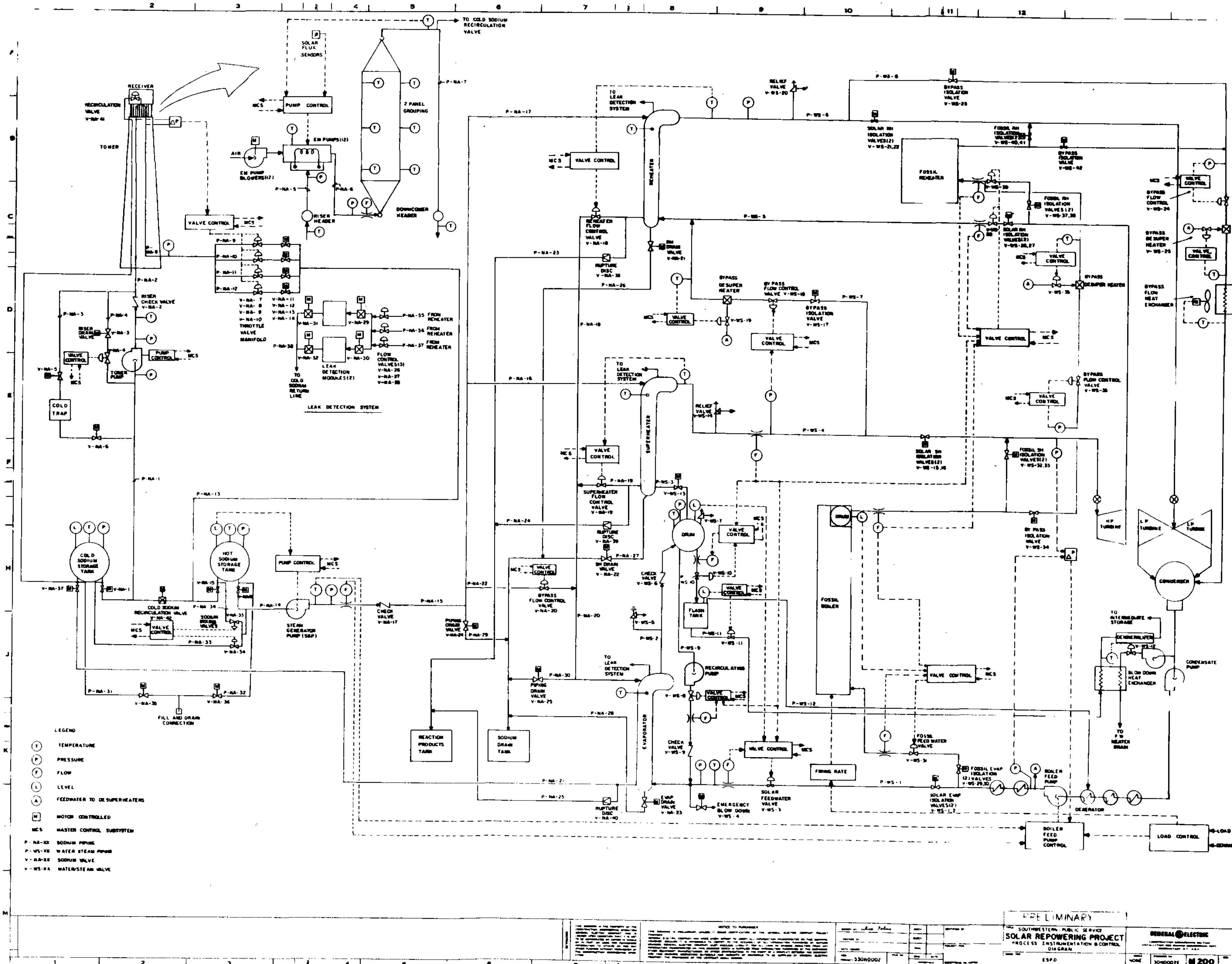


Figure 5.10-1. Repowering P&ID

5-109/5-110

Table 5.10-1 SODIUM PIPING LIST

Designation	From	To	Design Temp °C(°F)	Design Pressure KPa(PSIA)	Pipe* Size m(in)	Material	Comments
P-NA-1	Cold Storage Tank	Tower Pump Suction	329(625)	621(90)	.305(12)	A-106B-CS	
P-NA-2	Tower Pump Discharge	Riser Header	329(625)	2345(340)	.305(12)	A-106B-CS	
P-NA-3	Tower Pump Discharge	Cold Trap	329(625)	2345(340)	.102(4)	A-106B-CS	Sodium Purification
P-NA-4	Tower Pump Discharge	Riser Drain Valve	329(625)	2345(340)	.305(12)	A-106B-CS	
P-NA-5	Riser	Em Pump Suction	329(625)	690(100)	1.524(60)	A-106B-CS	Sodium Reservoir
P-NA-6	EM Pump Discharge	Panel Inlet Header	329(625)	690(100)	.102(4)	A-106B-CS	12 Parallel Lines
P-NA-7	Panel Discharge Header	Downcomer Header	621(1150)	690(100)	.102(4)	304H-SS	12 Parallel Lines
P-NA-8	Downcomer Header	Throttle Valve Manifold	621(1150)	2345(340)	.305(12)	304H-SS	
P-NA-9	Manifold Inlet	Manifold Discharge	621(1150)	2345(340)	.051(2)	304H-SS	
P-NA-10	Manifold Inlet	Manifold Discharge	621(1150)	2345(340)	.203(8)	304H-SS	
P-NA-11	Manifold Inlet	Manifold Discharge	621(1150)	2345(340)	.051(2)	304H-SS	Redundant Line
P-NA-12	Manifold Inlet	Manifold Discharge	621(1150)	2345(340)	.203(8)	304H-SS	Redundant Line
P-NA-13	Manifold Discharge	Hot Storage Tank	621(1150)	2345(340)	.305(12)	304H-SS	
P-NA-14	Hot Storage Tank	SG Pump Suction	621(1150)	621(90)	.305(12)	304H-SS	
P-NA-15	SG Pump Discharge	SG Building	621(1150)	1828(265)	.305(12)	304H-SS	
P-NA-16	SG Supply Line	Superheater Inlet	621(1150)	1828(265)	.254(10)	304H-SS	
P-NA-17	SG Supply Line	Reheater Inlet	621(1150)	1828(265)	.152(6)	304H-SS	
P-NA-18	Reheater Outlet	Mixing Tee	510(950)	1828(265)	.152(6)	304-SS	
P-NA-19	Superheater Outlet	Mixing Tee	510(950)	1828(265)	.254(10)	304-SS	
P-NA-20	Mixing Tee	Evap Inlet	510(950)	1828(265)	.305(12)	304-SS	
P-NA-21	Evap Outlet	Cold Storage Tank	329(625)	1828(265)	.305(12)	A-106B-CS	
P-NA-22	SG Supply Line	Evap Inlet Line	621(1150)	1828(265)	.051(2)	304H-SS	SH/RH Bypass
P-NA-23	RH Rupture Disc	Reaction Products Tank	510(950)	1828(265)	.356(14)	304-SS	
P-NA-24	SH Rupture Disc	Reaction Products Tank	510(950)	1828(265)	.356(14)	304-SS	
P-NA-25	Evap Rupture Disc	Reaction Products Tank	510(950)	1828(265)	.356(14)	304-SS	
P-NA-26	RH Drain Valve	Drain Tank	621(1150)	1828(265)	.102(4)	304H-SS	
P-NA-27	SH Drain Valve	Drain Tank	621(1150)	1828(265)	.102(4)	304H-SS	
P-NA-28	Evap Drain Valve	Drain Tank	510(950)	1828(265)	.102(4)	304-SS	
P-NA-29	SG Supply Piping	Drain Tank	621(1150)	1828(265)	.102(4)	304H-SS	
P-NA-30	Evap Inlet Piping	Drain Tank	510(950)	1828(265)	.102(4)	304-SS	
P-NA-31	Fill/Drain Connection	Cold Tank	329(625)	621(90)	.152(6)	A-106B-CS	
P-NA-32	Fill/Drain Connection	Hot Tank	329(625)	621(90)	.152(6)	A-106B-CS	
P-NA-33	Cold Stg Tank	Mixing Valve	329(625)	621(90)	.102(4)	A-106B-CS	
P-NA-34	Hot Stg Tank	Mixing Valve	621(1150)	621(90)	.102(4)	304H-SS	
P-NA-35	Reheater	Leak Detection Module	621(1150)	1828(265)	.051(2)	304H-SS	
P-NA-36	Superheater	Leak Detection Module	621(1150)	1828(265)	.051(2)	304H-SS	
P-NA-37	Evaporator	Leak Detection Module	621(1150)	1828(265)	.051(2)	304H-SS	
P-NA-38	Leak Detection Module	Cold Sodium Return Line	621 (1150)	1828(265)	.102(4)	304H-SS	

*Schedule 40 for all piping

Table 5.10-2

WATER/STEAM PIPING LIST - SOLAR STEAM GENERATOR

Designation	From	To	Design Temp °C(°F)	Design Pressure KPa(PSIA)	Pipe Size m(in)	Material	Comments
P-WS-1	Solar Evap Iso Valve	Solar Evap Inlet	241(465)	11722(1700)	.203(8)SCH 120	A-106B-CS	Feedwater Supply
P-WS-2	Solar Evap Outlet	Steam Drum	329(625)	11032(1600)	.254(10)SCH 120	A-106B-CS	
P-WS-3	Steam Drum	Solar SH Inlet	329(625)	11032(1600)	.254(10)SCH 120	A-106B-CS	
P-WS-4	Solar SH Outlet	Solar-Fossil Mixing Tee	538(1000)	11032(1600)	.356(14)t=1.5	A335-P22	
P-WS-5	Solar RH Iso Valve	Solar RH Inlet	399(750)	3965(575)	.457(18)SCH 40	A-106B-CS	
P-WS-6	Solar RH Outlet	Solar-Fossil Mixing Tee	538(1000)	3792(550)	.457(18)SCH 80	A335-P12	
P-WS-7	Solar SH Outlet	Solar RH Inlet	538(1000)	11032(1600)	.102(4)SCH 80	A335-P22	HP Turbine Bypass
P-WS-8	Solar RH Outlet	Condenser	538(1000)	3792(550)	.152(6)SCH 80	A335-P12	LP Turbine Bypass
P-WS-9	Steam Drum	Evap Inlet	329(625)	11032(1600)	.051(2)SCH 140	A-106B-CS	Evap Recirc
P-WS-10	Steam Drum	Flash Tank	329(625)	11032(1600)	.051(2)SCH 80	A-106B-CS	Drum Blowdown
P-WS-11	Flash Tank	Demineralizer	329(625)	690(100)	.051(2)SCH 40	A-106B-CS	
P-WS-12	Flash Tank	Deaerator	329(625)	690(100)	.152(6)SCH 40	A-106B CS	

vious General Electric sodium plant designs, 316H has been used for hot leg piping because of its high strength at the elevated temperatures. However, in this design the use of Schedule 40 for all pipes has provided sufficient margin to allow the use of the less expensive 304H material with its lower strength at high temperatures. 304H is approximately 30% cheaper than 316H.

For the cold leg piping, A106 Gr B carbon steel will be used.

Insulation

All sodium piping will be insulated with a 10.2 cm (4 in.) layer of B&W Kaowool covered by a 15.2 cm (6 in.) layer of Thermal Wool-II. As discussed in Section 4.2.2, this is sufficient insulation to allow a rapid morning startup after an overnight shutdown. Aluminum jacketing will be provided to protect the insulation.

Trace Heating

All sodium piping will be trace heated to enable pipe warming during initial startup. Trace heating also will keep the sodium at 177°C (350°F) during prolonged shutdowns (>7 days) when the stored energy in the system is no longer adequate to maintain the total system above that temperature.

For the main sodium pipes, the level of trace heating required has been determined to be ~30 W/linear ft.

5.10.1.2 Water/Steam Piping

The water/steam piping wall thicknesses have been set in accordance with the B31.1 Power Piping code. Pipe diameters were set to limit fluid velocities to those listed in Table 5.10-3.

Table 5.10-3
WATER/STEAM PIPING VELOCITY LIMITS

Fluid	Velocity Limit
Wet Steam	<15.2 m/s (50 ft/s)
Water	< 6.1 m/s (20 ft/s)
Saturated Steam	<38.1 m/s (12.5 ft/s)
Superheated Steam	<76.2 m/s (250 ft/s)

Materials

The materials selected for the water/steam piping are listed in Table 5.10-2 and conform to the materials used by Southwestern Public Service in similar applications.

Insulation

Insulation of the water/steam piping will be consistent with that currently used in Plant X . J-M Thermo 12 in varying thicknesses with aluminum jacketing will be used. For large steam piping, 20.32 cm (8 in.) of insulation has been specified. For hot water piping (e.g. feedwater), 7.6 cm (3 in.) of insulation will be used.

5.10.2 VALVES

Table 5.10-4 lists the sodium valves to be included in the repowered facility and Table 5.10-5 lists the new water/steam valves. The valve numbers refer to Figure 5.10-1, P&ID. A discussion of the characteristics of these valves is provided below.

5.10.2.1 Sodium Valves

The sodium valves, with the exception of check valves, will all be electric motor driven. This is possible since none of the valves is required to be fast-acting. It will also enable the valves to fail "as-is," which is the desired mode of failure for all the sodium valves.

Table 5.10-4 SODIUM VALVE LIST

Designation	Subsystem	Type	Location	Nominal Size m(in)	Nominal Flowrate $\frac{Kg}{HR}(\frac{LB}{HR})$	Comments
V-NA-1	Receiver	Shutoff	Cold Storage Tank Output	.305(12)	$1.34x10^6(2.95x10^6)$	
V-NA-2	Receiver	Check	Tower Pump Discharge	.305(12)	$1.34x10^6(2.95x10^6)$	
V-NA-3	Receiver	Shutoff	Tower Pump Recirc Line	.305(12)	------	Riser Drain
V-NA-4	Receiver	Flow Control	Tower Pump Recirc Line	.305(12)	------	Riser Drain
V-NA-5	Receiver	Shutoff	Cold Trap Inlet	.102(4)	$12.0x10^3(26.5x10^3)$	Sodium Purification
V-NA-6	Receiver	Shutoff	Cold Trap Outlet	.102(4)	$12.0x10^3(26.5x10^3)$	Sodium Purification
V-NA-7	Receiver	Flow Control	Throttle Valve Manifold	.051(2)	$1.34x10^6$ $(2.95x10^6)$	
V-NA-8	Receiver	Flow Control	Throttle Valve Manifold	.203(8)		
V-NA-9	Receiver	Flow Control	Throttle Valve Manifold	.051(2)	------	Redundant
V-NA-10	Receiver	Flow Control	Throttle Valve Manifold	.203(8)	------	Redundant
V-NA-11	Receiver	Shutoff	Throttle Valve Manifold	.051(2)	$1.34x10^6$ $(2.95x10^6)$	
V-NA-12	Receiver	Shutoff	Throttle Valve Manifold	.203(8)		
V-NA-13	Receiver	Shutoff	Throttle Valve Manifold	.051(2)	------	Redundant
V-NA-14	Receiver	Shutoff	Throttle Valve Manifold	.203(8)	------	Redundant
V-NA-15	Receiver	Shutoff	Hot Storage Tank Inlet	.305(12)	$1.34x10^6(2.95x10^6)$	
V-NA-16	Stm. Gen.	Shutoff	Hot Storage Tank Outlet	.305(12)	$1.34x10^6(2.95x10^6)$	
V-NA-17	Stm. Gen.	Check	SG Pump Discharge	.305(12)	$1.34x10^6(2.95x10^6)$	
V-NA-18	Stm. Gen.	Flow Control	Solar RH Outlet	.152(6)	$.38x10^6(.83x10^6)$	
V-NA-19	Stm. Gen.	Flow Control	Solar SH Outlet	.254(10)	$.96x10^6(2.12x10^6)$	Steam Temp Control
V-NA-20	Stm. Gen.	Flow Control	SH/RH Bypass Line	.051(2)	------	
V-NA-21	Stm. Gen.	Shutoff	Reheater Drain	.102(4)	------	
V-NA-22	Stm. Gen.	Shutoff	Superheater Drain	.102(4)	------	
V-NA-23	Stm. Gen.	Shutoff	Evap Drain	.102(4)	------	
V-NA-24	Stm. Gen.	Shutoff	Piping Drain	.102(4)	------	
V-NA-25	Stm. Gen.	Shutoff	Piping Drain	.102(4)	------	
V-NA-26	Stm. Gen.	Flow Control	Reheater Vent	.051(2)	$.91x10^4(2.0x10^4)$	
V-NA-27	Stm. Gen.	Flow Control	Superheater Vent	.051(2)	$.91x10^4(2.0x10^4)$	Leak Detection
V-NA-28	Stm. Gen.	Flow Control	Evap Vent	.051(2)	$.91x10^4(2.0x10^4)$	
V-NA-29	Stm. Gen.	Shutoff	L.D. Module Inlet	.013	$2.72x10^4(6.0x10^4)$	
V-NA-30	Stm. Gen.	Shutoff	L.D. Module Inlet	.013	------	Redundant
V-NA-31	Stm. Gen.	Shutoff	L.D. Module Outlet	.013	$2.72x10^4(6.0x10^4)$	
V-NA-32	Stm. Gen.	Shutoff	L.D. Module Outlet	.013	------	Redundant
V-NA-33	Stm. Gen.	Flow Control	Hot Stg Tank Outlet	.102(4)	------	Sodium Mixing System
V-NA-34	Stm. Gen.	Flow Control	Cold Stg Tank Outlet	.102(4)	------	
V-NA-35	Stm. Gen.	Shutoff	Cold Stg Fill Line	.152(6)	------	
V-NA-36	Stm. Gen.	Shutoff	Hot Stg Fill Line	.152(6)	------	
V-NA-37	Stm. Gen.	Shutoff	Cold Stg Return Line	.305(12)	$1.34x10^6(2.95x10^6)$	
V-NA-38	Stm. Gen.	Rupture Disc	Reheater Outlet Line	.356(14)	------	
V-NA-39	Stm. Gen.	Rupture Disc	Superheater Outlet Line	.356(14)	------	
V-NA-40	Stm. Gen.	Rupture Disc	Evap Outlet Line	.356(14)	------	
V-NA-41	Receiver	Flow Control	Receiver Outlet Header	.102 (4)	$.134x10^6(.295x10^6)$	Standby Recirculation
V-NA-42	Storage	Shutoff	Cold Storage Fill Line	.102 (4)	$.134x10^6(.295x10^6)$	Standby Recirculation

Table 5.10-5

WATER/STEAM VALVE LIST - SOLAR STEAM GENERATORS

Designation	Subsystem	Type	Location	Nominal Size m(in)	Nominal* Flowrate Kg/HR (LB/HR)	Comments
V-WS-1	Stm. Gen.	Shutoff	Solar Evap FW Supply Line	.203(8)	207295(457,000)	Solar Evap Isolation
V-WS-2	Stm. Gen.	Shutoff	Solar Evap FW Supply Line	.203(8)	207295(457,000)	
V-WS-3	Stm. Gen.	Flow Control	Solar Evap FW Supply Line	.203(8)	207295(457,000)	
V-WS-4	Stm. Gen.	Shutoff	Solar Evap FW Supply Line	.203(8)		Emergency Blowdown
V-WS-5	Stm. Gen.	Relief	Solar Evap Outlet Line	.254(10)	------	
V-WS-6	Stm. Gen.	Check	Solar Evap Outlet Line	.254(10)	------	
V-WS-7	Stm. Gen.	Relief	Solar Steam Drum	.254(10)	------	
V-WS-8	Stm. Gen.	Flow Control	Solar Drum Recirc Loop	.051(2)	9435(20,800)	
V-WS-9	Stm. Gen.	Check	Solar Drum Recirc Loop	.051(2)	9435(20,800)	
V-WS-10	Stm. Gen.	Flow Control	Solar Drum Blowdown	.051(2)	18,900(41,700)	
V-WS-11	Stm. Gen.	Flow Control	Solar Drum Blowdown	.051(2)	18,900(41,700)	
V-WS-12	Stm. Gen.	Flow Control	Solar Drum Blowdown	.051(2)	18,900(41,700)	Condensate Flow Control
V-WS-13	Stm. Gen.	Shutoff	Solar SH Inlet	.254(10)	188,380(415,300)	
V-WS-14	Stm. Gen.	Relief	Solar SH Outlet	.356(14)	------	
V-WS-15	Stm. Gen.	Shutoff	Solar SH Outlet	.356(14)	188,380(415,300)	Solar SH Isolation
V-WS-16	Stm. Gen.	Shutoff	Solar SH Outlet	.356(14)	188,380(415,300)	
V-WS-17	EPGS	Shutoff	HP Bypass Line	.102(4)	18,840(41,530)	
V-WS-18	EPGS	Flow Control	HP Bypass Line	.102(4)	18,840(41,530)	
V-WS-19	EPGS	Flow Control	HP Bypass Line	.102(4)	------	Desuperheater Condensate
V-WS-20	Stm. Gen.	Relief	Reheater Outlet	.457(18)	------	
V-WS-21	Stm. Gen.	Shutoff	Reheater Outlet	.457(18)	167,016(368,200)	Solar RH
V-WS-22	Stm. Gen.	Shutoff	Reheater Outlet	.457(18)	167,016(368,200)	Isolation
V-WS-23	EPGS	Shutoff	LP Bypass Line	.152(6)	18,840(41,530)	
V-WS-24	EPGS	Flow Control	LP Bypass Line	.152(6)	18,840(41,530)	
V-WS-25	EPGS	Flow Control	LP Bypass Line	.152(6)	------	Desuperheater Condensate
V-WS-26	Stm. Gen.	Shutoff	Solar RH Inlet	.457(18)	167,016(368,200)	Solar RH
V-WS-27	Stm. Gen.	Shutoff	Solar RH Inlet	.457(18)	167,016(368,300)	Isolation
V-WS-28	Stm. Gen.	Flow Control	Solar RH Inlet	.457(18)	167,016(368,200)	Solar/Fossil Flow Split
V-WS-29	Fossil Energy	Shutoff	Fossil Boiler FW Supply Line	.254(10)	351,994(776,000)	Fossil Boiler Isolation
V-WS-30	Fossil Energy	Shutoff	Fossil Boiler FW Supply Line	.254(10)	351,994(776,000)	
V-WS-31	Fossil Energy	Flow Control	Fossil Boiler FW Supply Line	.254(10)	351,994(776,000)	
V-WS-32	Fossil Energy	Shutoff	Fossil Superheater Outlet Line	.406(16)	351,994(776,000)	Fossil Boiler Isolation
V-WS-33	Fossil Energy	Shutoff	Fossil Superhetaer Outlet Line	.406(16)	351,994(776,000)	
V-WS-34	EPGS	Shutoff	HP Turbine Bypass Line	.152(6)	35,200(77,600)	
V-WS-35	EPGS	Flow Control	HP Turbine Bypass Line	.152(6)	35,200(77,600)	
V-WS-36	EPGS	Flow Control	HP Turbine Bypass Line	.152(6)	35,200(77,600)	Desuperheater Condensate
V-WS-37	Fossil Energy	Shutoff	Fossil Boiler Cold Reheater Line	.406(16)	311,623(687,000)	2 Parallel Lines
V-WS-38	Fossil Energy	Shutoff	Fossil Boiler Cold Reheater Line	.406(16)	311,623(687,000)	
V-WS-39	Fossil Energy	Flow Control	Fossil Boiler Cold Reheater Line	.406(16)	311,623(687,000)	
V-WS-40	Fossil Energy	Shutoff	Fossil Boiler Hot Reheater Line	.406(16)	311,623(687,000)	
V-WS-41	Fossil Energy	Shutoff	Fossil Boiler Hot Reheater Line	.406(16)	311,623(687,000)	
V-WS-42	EPGS	Shutoff	LP Turbine Bypass Line	.406(16)	35,200(77,600)	

*at max power (112 MWe)

The larger sodium valves will have a freeze seal stem seal design. The smaller valves (2 in. and under) will have a bellows seal.

Cost information on the valves was obtained through quotation from a representative of the Crane Co. Valve delivery was quoted as 12 to 18 months from receipt of order.

5.10.2.2 Water/Steam Valves

The water/steam valves will be of a proven typical design for their service. Actuators will be electric or hydraulic as the service requires. Cost information for these valves was obtained from the Crane Co.

Double valves have been provided in the interface lines between the solar and existing fossil system to allow safe maintenance to be conducted on either the solar or fossil steam plants while the other system operates. This feature will also limit the existing plant down time during construction. The modifications to the fossil plant can be made and isolated based on plant availability with the tie-ins to the solar plant accomplished while the fossil plant continues to operate.

5.10.3 COST ESTIMATES

The piping and valves for the plant are costed within the individual subsystems in which they occur.

5.11 MISCELLANEOUS SYSTEMS AND EQUIPMENT

This section describes those systems and material that transcend subsystem boundaries and thus were not covered in the individual subsystem descriptions. These include:

- Cover gas supply system
- Sodium

5.11.1 COVER GAS SUPPLY SYSTEM

Argon gas will be used to fill voids in the sodium system (e.g., storage tanks) to ensure the system remains at or above atmospheric pressure; to provide a pressure source for system draining and to purge the system for initial fill and after maintenance operations which breech the sodium boundary.

For the initial system purge and for purges of major sections of the plant after maintenance, argon will be hauled in by truck. The amount of gas required for the purges is significantly greater than required to be on hand for day to day normal and emergency activities and thus does not warrant providing storage facilities for these rare occurrences.

Two storage facilities will be provided to supply argon for normal operations. One will be located at the tower and the second at the pump building.

5.11.1.1 Tower Argon Supply

The argon supply at the tower will provide the source for pressurizing the emergency sodium reservoir in the receiver in the event of a loss of slow accident and will also supply argon for pressure draining the total receiver subsystem to the storage tanks.

Adequate argon is to be furnished for two emergency pressurizations at 345 KPa (50 psia) and one total receiver subsystem drain at 207 KPa (30 psia). The total argon volume required is ~498 standard cubic meters (17600 SCF). This will be supplied by a "three pack" high pressure cylinder storage facility. It consists of three cylindrical, pad-mounted, horizontal tanks pressurized to 16.6 MPa (2415 psia) with appropriate pressure regulators. The total capacity of the "three pack" is ~709 SCM (25000 SCF). The piping to distribute this argon is included in the receiver subsystem design.

5.11.1.2 Pump Building Argon Supply

The pump building argon supply will provide argon for blowing down the sodium from the steam generators in the event of a tube leak, draining the steam generator subsystem to the dump and storage tanks, and for storage tank cover gas.

The supply has been sized to provide enough argon for two steam generator blowdowns at 689 KPa (100 psig) and one storage tank volume at 207 KPa (30 psia) to be used to replace the argon vented in two total system drainings. The required volume is ~1253 SCM (44200 SCF). The argon will be stored in the same type of cylinders described for the tower supply, only in a "six-pack" arrangement holding 1417 SCM (50,000 SCF).

The piping to distribute the argon is included in the steam generator and storage subsystem designs.

5.11.2 SODIUM

The total repowering facility will require approximately 318000 kg (700,000 lbs) of nonreactor grade sodium.

Discussion with one of the nation's major suppliers of sodium, Ethyl Corp., indicated more than adequate facilities will exist to provide this sodium in the 1984 time frame.

The sodium would be delivered to the site in tank trucks holding approximately 36364 kg (80,000 lbs). The sodium would be shipped in the solid form and melted at the site with heaters immediately prior to transfer.

The sodium deliveries would start when the storage tank construction was completed and would take place over the course of six months to a year.

5.11.3 COST ESTIMATE

Costs for the cover gas supply system and the sodium (including initial fill) total $865,061. Details of the estimate are in the Appendix A, System Requirement Specification cost section under account 5900.

SECTION 6
ECONOMIC ANALYSIS

Section 6
ECONOMIC ANALYSIS

6.1 INTRODUCTION

The purpose of this section is to show how the cost of solar repowered plants* might compare with other types of electric generating plants and to discuss the method of calculating the justifiable capital investment, or value, in such solar power plant. The economics comparison and evaluation method are based on the revenue requirements discipline commonly used by electric utilities as opposed to discounted rate of return methods used by other industrial firms.**

Section 6.2 discusses the difference in approach between a mills/kWh comparison of generating types and the justifiable capital investment or value calculation. Also discussed is the reason why the latter approach is the preferable method for evaluating solar power generation. Section 6.3 discusses a busbar energy cost comparison using Electric Power Research Institute data, Southwestern Public Service Company data, and Department of Energy data. Section 6.4 is a general discussion of production cost (fuel cost plus variable operation and maintenance cost) saving. Section 6.5 is a general discussion of capacity displacement such that generation system reliability, as measured by the probability of insufficient system-owned generation capacity, is equal with and without the solar unit under consideration. Section 6.6 contains data for the case study of solar repowering of Plant X, Unit 3, of Southwestern Public Service Company. Section 6.7 contains details of the cost/value approach. Section 6.8 presents the results of the case study. Section 6.9 concludes the economic analysis.

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* Solar repowered plants are those power plants wherein solar steam generating equipment is installed such that the steam is utilized by an already-installed steam turbine-generator. The existing fossil-fired boiler may be maintained in place or retired.

** However, if the discount rate is chosen as the "tax-adjusted cost of capital" rather than the average cost of capital, the two methods will achieve the same result of justifiable capital investment in solar equipment. See Table 6.3-1 for a comparison of discount rates.

6.2 EVALUATION METHODS -- DIFFERENCE BETWEEN BUSBAR ENERGY COST AND COST/VALUE METHOD

Comparative costs of generation are often expressed in the units "mills/kWh" where generation cost is computed as shown in equation 6.2-1.

$$\frac{\text{mills}}{\text{kWh}} = \frac{\$/\text{kW}\cdot\text{FCR}}{8760\text{H}\cdot\text{CF}} \cdot 10^3\,\frac{\text{mills}}{\$} + \frac{\$}{\text{kW-yr}} \cdot \frac{1}{8760\text{H}\cdot\text{CF}} \cdot 10^3\,\frac{\text{mills}}{\$} \qquad (6.2\text{-}1)$$

$$+ \frac{\text{Btu}}{\text{kWh}} \cdot \frac{\$}{10^6\,\text{Btu}} \cdot 10^3\,\frac{\text{mills}}{\$} + \frac{\text{mills}'}{\text{kWh}}$$

where: $/kW = Capital cost or installed cost

FCR = Fixed charge rate,* per unit per year. This is a rate which, when multiplied by capital cost, yields the annual revenue required to cover the utility's obligation to pay interest on debt, return on equity, depreciation, taxes, and insurance.

CF = Capacity factor = $\frac{\text{kWh}_{\text{generated}}}{\text{kW}_{\text{rated}} \times 8760\text{H}}$

$\frac{\$}{\text{kW-yr}}$ = Fixed operating and maintenance cost independent of actual operating hours

$\frac{\text{Btu}}{\text{kWh}}$ = Thermal generating unit heat rate = $\frac{3412}{\eta_{th}}$

η_{th} = full load power plant efficiency

$\frac{\$}{10^6\,\text{Btu}}$ = Fuel price

$\frac{\text{mills}'}{\text{kWh}}$ = Variable operating and maintenance cost

It is extremely important that the rating used in determining capacity factor is the same rating used to compute $/kW. A consistent rating throughout any evaluation must be used.

To recognize the fact of an inflationary economy, the second, third, and fourth terms of Eq. 6.2-1 are multiplied by a "levelizing factor" to recognize that these terms are not constant but likely to increase during plant lifetime. The levelizing factor produces a uniform annual equivalent cost such that the present worth or discounted value of the uniform series is equal to the present worth or discounted value of the inflating series. It is important to include a levelizing factor because the fixed charge rate includes an implicit assumption regarding future inflation.

*Further explanation is contained in Marsh, W.D., Economics of Electric Utility Power Generation, Oxford University Press, 1980.

The levelizing factor is shown below: *

$$L_f = \frac{1 - \left(\frac{1 + a}{1 + r}\right)^n}{r - a} \times \frac{r\,(1 + r)^n}{(1 + r)^n - 1}$$

where L_f = dimensionless levelizing factor

a = inflation rate, per unit per year

r = discount rate, or "present worth" rate, per unit per year

n = number of years

Inclusion of the levelizing factor and use of a levelized fixed charge rate yields a result called "levelized busbar energy cost."

The capacity factor of a solar repowered plant depends on the plant rating and the solar insolation. The capacity factor of a thermal generating unit depends on the thermal unit capacity rating and also on the economic loading or operation of the thermal unit performed so as to minimize the variable cost of operating the entire system of generating units. Thus the capacity factor of a thermal unit is especially difficult to estimate since it depends on heat rate, fuel price, the existing mix of unit types, the future installation of other thermal units, and the utility electric load.

Because of the difficulty of estimating thermal unit capacity factor, a comparison of solar versus thermal units on the basis of mills per kilowatt hour is invalid. ** Either differing energy production is ignored or the comparison is made assuming the utility system would install a competing thermal unit which would operate at precisely the same capacity factor as the solar unit under consideration. This would only coincidentally be true. The effect of each alternative on operation of the entire generating system must be ascertained to compute the electric consumers' cost or utility revenue requirement.

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* This factor differs from the recent EPRI Technical Assessment Guide, EPRI PS-1201-SR, July, 1979, p. 3-26, in that costs are quoted as of the date to be paid. The EPRI levelizing factor assumes quoted costs are subject to inflation prior to the date of the first payment.

** There are other reasons such a comparison is invalid. The simplest mills/kWh computation, as described, neglects differences in unit rating and unit reliability. It also neglects the decrease of thermal unit efficiency at part load and any operational peculiarities or characteristics of the alternatives. All of these differences affect total system cost of electricity and therefore affect consumer cost.

However, it is possible to estimate the cost of fuel saved by operation of the solar-repowered unit under consideration. The fuel saved would be the fuel cost of the thermal unit which would operate had the solar production equipment under consideration not been installed. The fuel saved would vary hour by hour in most interconnected systems from nuclear fuel at low-load periods to oil burned in combustion turbines in peak-load periods.

Computer programs which simulate utility operation on an hour-by-hour basis can calculate precisely the fuel savings. This is accomplished by performing the economic operation simulation twice -- once without the candidate solar equipment and once with the candidate solar equipment. The cost of fuel saved can be capitalized by dividing the equivalent uniform annual fuel savings by the fixed charge rate. This would be compared to the solar equipment capital cost estimate to determine if ownership is justified by the fuel savings.

Although the latter approach of comparing capitalized fuel savings to installed cost is the valid method of deciding whether or not to make the investment in solar equipment, a discussion of comparative generating costs will be given since such a calculation is so easy to perform and often is performed in discussion with utilities.

6.3 COMPARATIVE GENERATION COSTS - BUSBAR ENERGY COST COMPARISON

The data for comparing solar costs with thermal generating units was obtained from the Electric Power Research Institute Technical Assessment Guide, EPRI PS-1201-SR, July, 1979 for the EPRI South Central data region, from Southwestern Public Service Company, and from the Department of Energy.* The corresponding busbar energy costs on a 30-year levelized basis are computed both with average cost of capital and tax-adjusted cost of capital as discount rates. Choosing the tax adjusted cost of capital is advantageous in that the discounted cash flow method for determining the rate of return and the revenue requirement method for justifiable or breakeven capital cost can be shown to be equivalent. Bear in mind that the generally incorrect assumption of a competing thermal unit with the same capacity factor as the solar unit makes this method invalid for deciding whether to build a solar plant or another type of plant.

* Solar Repowering/Industrial Retrofit Technical Information Memo No. 6, from J.C. Gibson, dated Jan. 18, 1980.

Rather than calculate mills per kilowatt hour as given in Eq. 6.2-1, generation cost will be calculated in terms of \$/kW-year. This allows the comparative costs to plot as straight lines on a graph of annual cost versus operating hours. Generation cost in \$/kW-year is given by Eq. 6.3-1.

$$\$/\text{kW-yr} = \$/\text{kW} \cdot \text{FCR} + \$/\text{kW-yr}' + \frac{\text{Btu}}{\text{kWh}} \cdot \frac{\$}{10^6\text{Btu}} \cdot \text{H/yr} + \frac{\text{mills}'}{\text{kWh}} \cdot \frac{1\$}{10^6\text{mills}} \cdot \text{H/yr} \qquad (6.3\text{-}1)$$

where: \$/kW = Capital cost

FCR = Fixed charge rate

\$/kW-yr' = Fixed operating and maintenance cost

Btu/kWh - Thermal generating unit heat rate

$\$/10^6$Btu = Fuel price

H/yr = Operating hours per year

$\frac{\text{mills}'}{\text{kWh}}$ = Variable operating and maintenance cost

Operating and maintenance cost and fuel price are subject to inflation over the plant lifetime and will be "levelized". Note that busbar cost in mills/kWh can be obtained from the screening curve by dividing \$/kW-yr by hours (and then multiply by 1000).

Figure 6.3-1 shows an example plot of annual generation cost, \$/kW-yr, versus annual operating hours. These curves are called "screening curves" because the one valid use of these graphs is to show if a competing generation technology never has lowest cost at any operating hour mode (such as the coal alternative). Hence it would be "screened out" from further consideration. In order for the solar-repowered plant to be competitive in this economic analysis, the cost in \$/kW-yr must be below the envelope of lowest cost as indicated by the heavier lines.

These curves have also been called "static break point analysis". It is nevertheless a requirement that as long as any competing generation type has lowest cost in some range of operating hours, a system production cost simulation is required to determine what type of generation should be chosen.

To illustrate the need for ascertaining the effect of the operation of existing system units, consider the following example. When a system operation simulation is performed two times, once for alternative A and once for alternative B, the capacity factor obtained for these two alternatives might be as indicated on an hours per year basis as the points H_A and H_B on Figure 6.3-2. One does not conclude that alternative A should be chosen since the energy which alternative B provided as a candidate had to be served by the operation of other units when alternative A was simulated in the system as a candidate. As an approximation, if the equivalent operating cost of these units lies above point (H,Y) in Figure 6.3-2, then alternative B is the preferred choice, neglecting any differences in system reserve capacity requirements, since the owning and operating cost of alternative B results in lowest system total cost and lowest consumer cost. If the equivalent operating cost of the other system units lies below point (H,Y) then alternative A is the preferred choice, again assuming no difference in system reserve capacity.

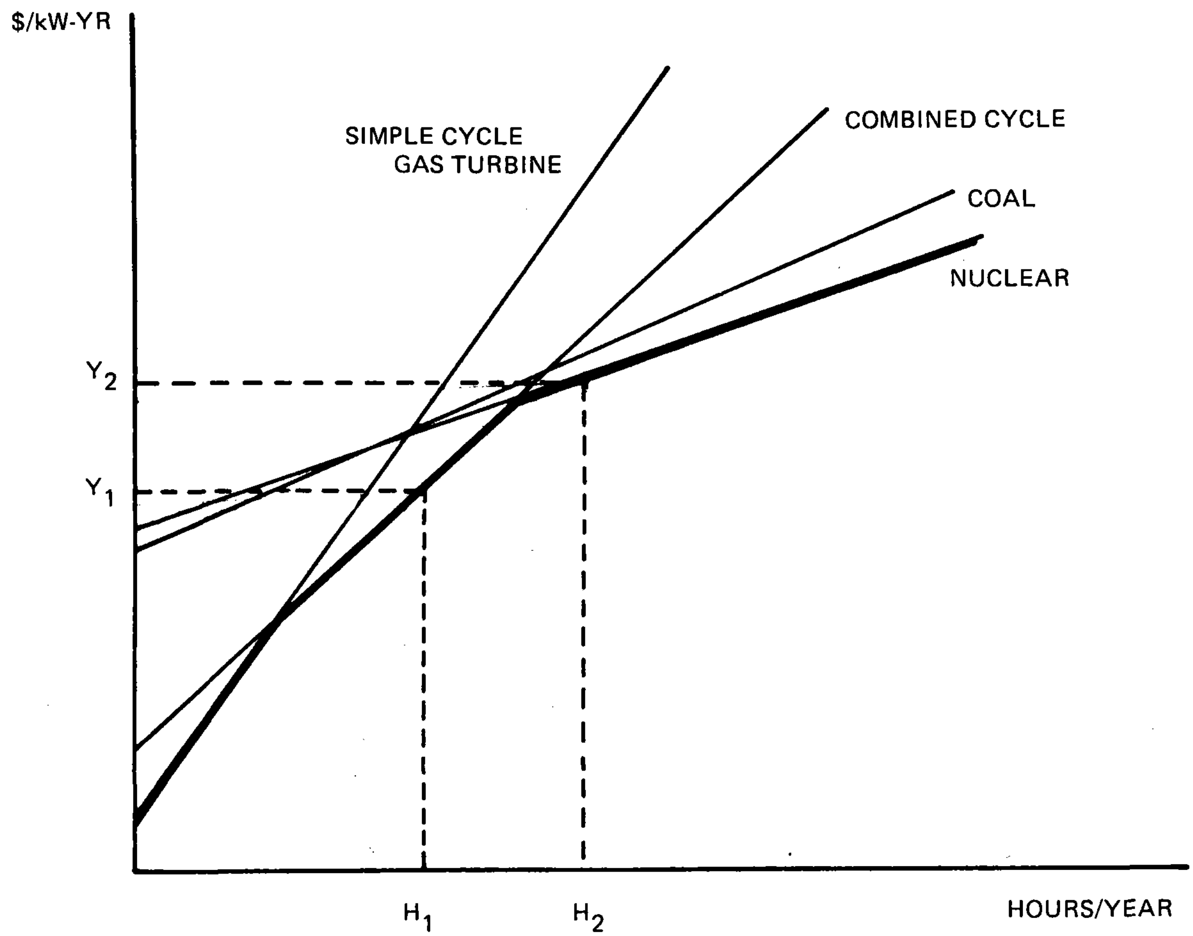

Figure 6.3-1. Example Screening Curves

H_1 and H_2 are possible solar plant operating modes.
Y_1 and Y_2 are the corresponding fixed costs for which the solar plants would be competitive.

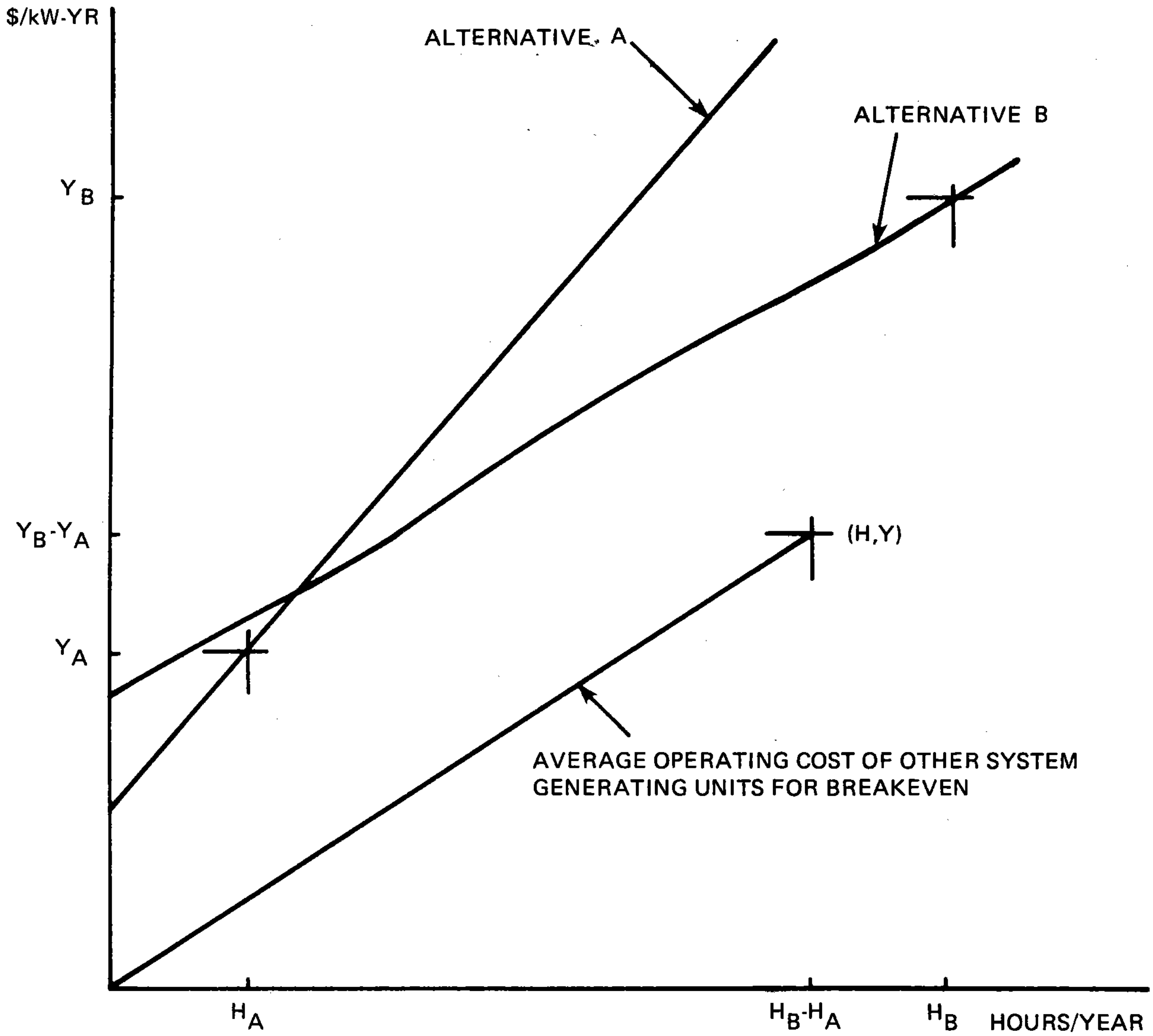

Figure 6.3-2. Screening Curve Analysis of Alternatives A and B Including System Energy Cost Breakeven such that Alternative A Energy Production and Cost are Equivalent to Alternative B Energy Production and Cost

One can appreciate that if a production cost simulation with alternative B showed operation of Alternative B averaging at some hours per year less than H_B and H_A remained in the same position as shown, the possibility of alternative A as the economic choice is enhanced since the slope of the line (0,0) to (H,Y) for breakeven would increase.

The fixed charges of existing or other system owned units need not be considered; these are sunk costs that exist no matter which of the candidate units is selected.

A possible range of solar plant operating hours is indicated in Figure 6.3-1 as H_1 to H_2. The corresponding fixed costs are given by Y_1 and Y_2 neglecting variable operating and maintenance cost. The breakeven capital cost in each case is obtained by dividing the ordinate* by the solar plant fixed charge rate. The lower the solar plant fixed charge rate the higher the breakeven capital cost.

Thus obtaining the correct solar plant fixed charge rate** is important. (This is also true for the capitalized fuel savings versus plant cost methodolody.) It is important to ascertain whether the fixed charge rate includes an allowance for fixed operating and maintenance cost. It is also important to recognize the rate of future inflation inherent in the rate of return; and it is important to recognize the lower cost of capital available to some utilities and any income tax credits. See Figure 6.3-3.

Data for the screening curve analysis of Figures 6.3-4 to 6.3-9 is shown in Table 6.3-1 to Table 6.3-5.

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* The ordinate is total annual fixed costs including fixed operating and maintenance cost. The corresponding capital cost is obtained by first subtracting fixed O&M cost from total fixed cost then dividing by fixed charge rate. A correction for solar plant reserve capacity requirement (when the repowered boiler is retired) should be performed in addition to the fixed operating and maintenance cost correction.

**For further information on fixed charge rate see Marsh, W.D., Economics of Electric Utility Power Generation, Oxford University Press, 1980.

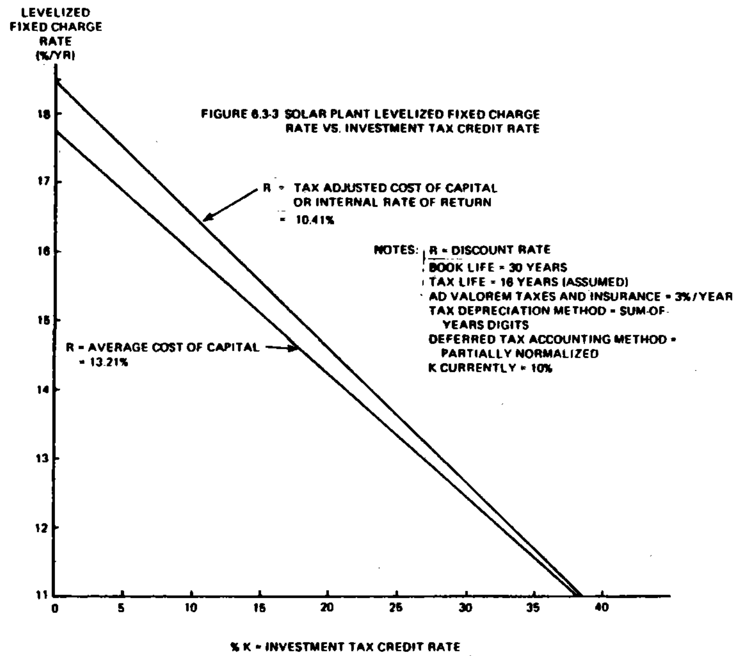


Figure 6.3-3. Solar Plant Levelized Fixed Charge Rate vs. Investment Tax Credit Rate

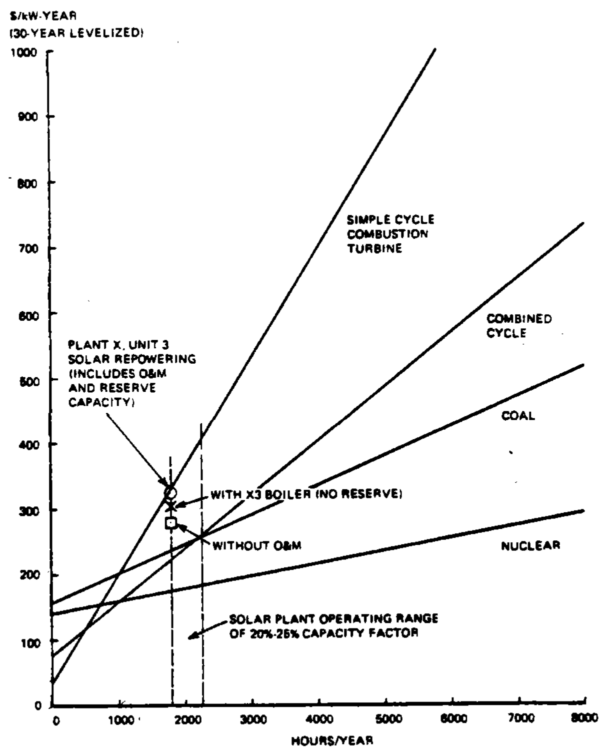


Figure 6.3-4. January 1980 Screening Curves - EPRI Data for Southwest Power Pool Region. Discount Rate = Average Cost of Capital

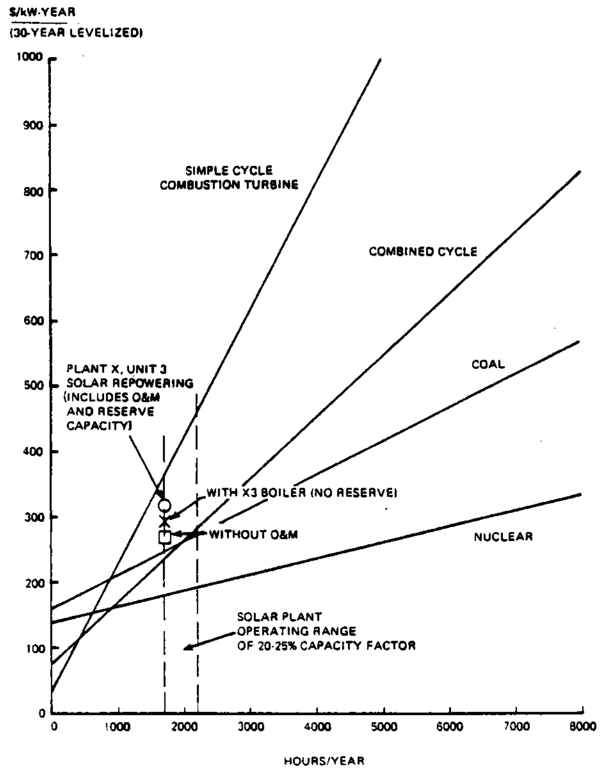


Figure 6.3-5. January 1980 Screening Curves - EPRI Data for Southwest Power Pool Region. Discount Rate = Tax Adjusted Cost of Capital

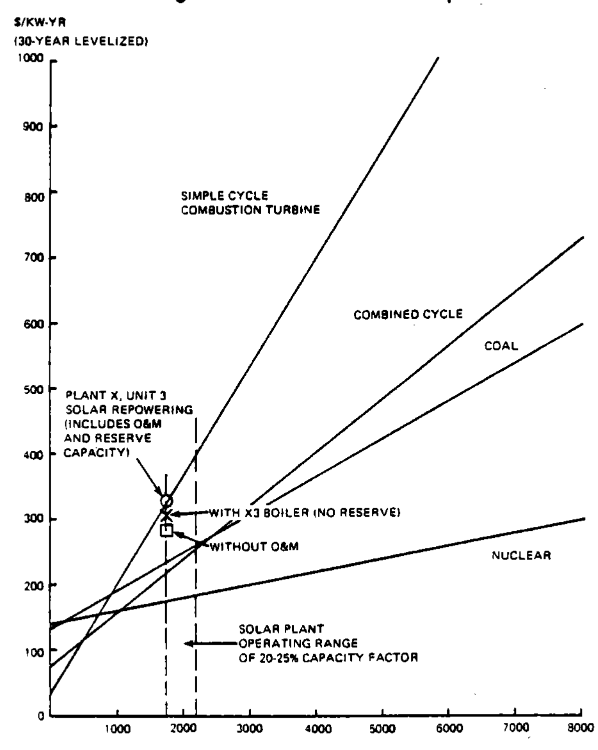


Figure 6.3-6. January 1980 Screening Curves - Southwestern Public Service Company Data. Discount Rate = Average Cost of Capital

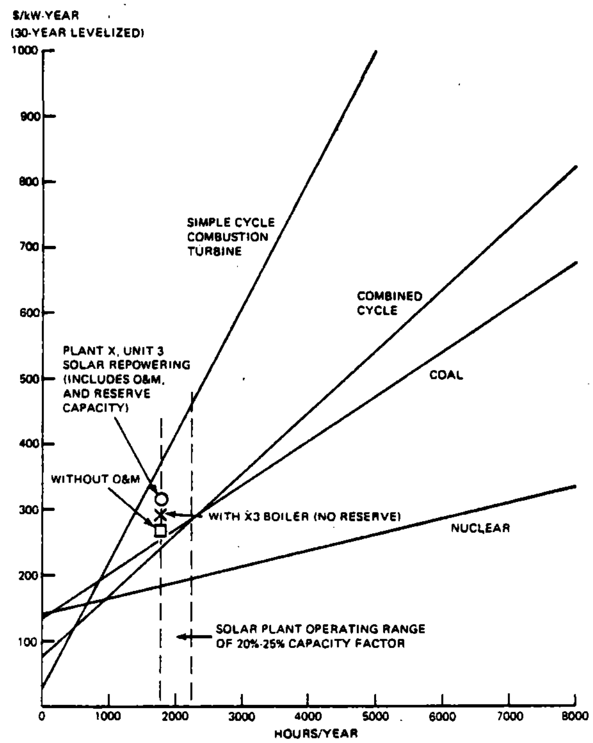


Figure 6.3-7. January 1980 Screening Curves - Southwestern Public Service Company Data. Discount Rate = Tax Adjusted Cost of Capital

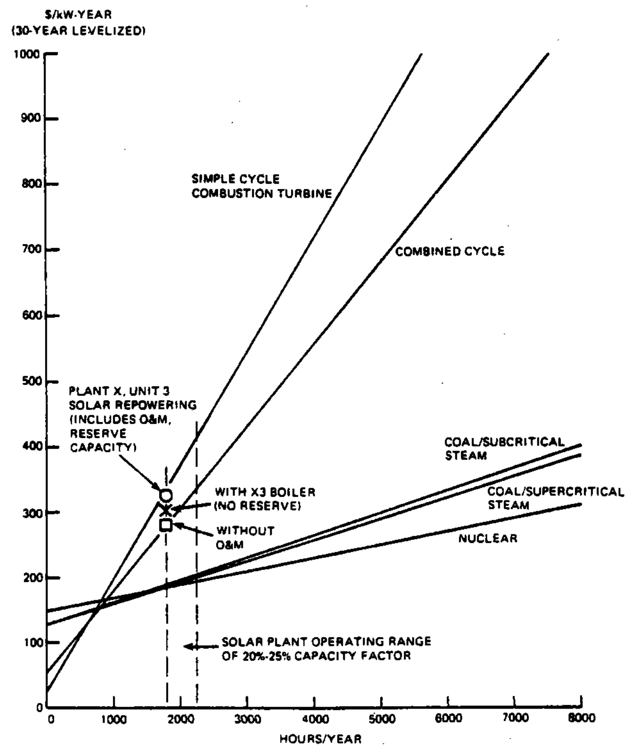


Figure 6.3-8. January 1980 Screening Curves - DOE Data. Discount Rate = Average Cost of Capital

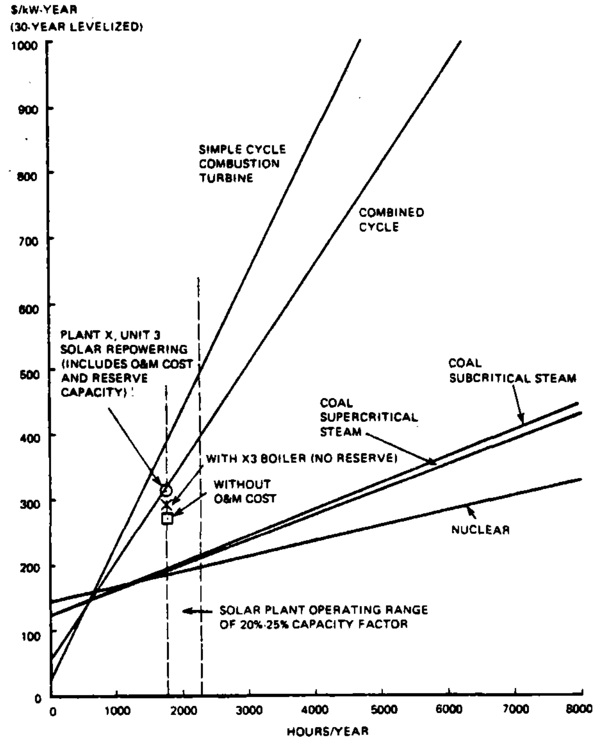


Figure 6.3-9.

January 1980 Screening Curves - DOE Data. Discount Rate = Tax Adjusted Cost of Capital

Table 6.3-1

DATA COMMON TO ALL SCREENING CURVE CALCULATIONS

1. Discount rate
   Private utility, average cost of capital = 13.2%; tax adjusted cost of capital = 10.4%*
2. Levelized fixed charge rate, 10% investment tax credit
   Private utility, with 13.2% discount rate, fixed charge rate = 14.9%; with a 10.4% discount rate, fixed charge rate = 14.4%
3. Screening curve $/kW-yr are Jan. 1980, deflated by the inflation rate of 8%/year.
4. All plants startup is in 1985. Hence, Jan. 1980, fuel price is escalated by the "real escalation rate" given by $(1+e_r)$.
5. Total "apparent escalation rate" = $(1+e_r)$ $(1+0.08)$
6. Real escalation rate on operation and maintenance cost = 0.
7. Costs are levelized over a 30 year period.
8. Full load net plant heat rate
   Nuclear plant = 10,400 Btu/kWh
   Coal plant, supercritical steam condition = 9910 Btu/kWh
   Coal plant, subcritical steam conditions (per Southwestern Public Service Company planning) = 10,240 Btu/kWh
   Combined cycle (heavy coal derived liquid fueled) = 8430 Btu/kWh
   Combustion turbine (distillate oil fueled)= 11,500 Btu/kWh

*Computed as follows:

$$r = i - tbB$$

where

r = discount rate
i = average cost of capital
t = income tax rate
b = interest rate on long-term debt
$B = \dfrac{\text{long term debt}}{\text{long term debt plus equity}}$

Table 6.3-2

SOUTHWEST POWER POOL REGION LIGHT WATER REACTOR (LWR) POWER PLANT COST

(January 1980 Costs)

	Data Source: EPRI Guide * and Southwestern Public Service Company	Data Source: Department of Energy **
Capital cost, \$/kW	904.5 (mid-range)	1000
Fixed operation and maintenance cost, \$/kW-yr	2.94	---
Variable operation and maintenance cost, mills/kWh	1.47	---
Fuel cost, $\$/10^6$ Btu	0.54	0.85
Real escalation rate, %/year	2.48 (without reprocessing)	1.0

Table 6.3-3

SOUTHWEST POWER POOL REGION COMBUSTION TURBINE PLANT COSTS

(January 1980 Costs)

	Data Source: EPRI Guide* and Southwestern Public Service Company	Data Source: Department of Energy **
Capital cost, \$/kW	205	190
Fixed operation and maintenance cost, \$/kW-year	0.27	---
Variable operation and maintenance cost, mills/kWh	2.92	---
Fuel cost, $\$/10^6$ Btu	5.36	4.00
Real escalation rate, %/year	1.7	4.0

* Electric Power Research Institute Technical Assessment Guide, EPRI PS-1201-SR, July, 1979.

** Solar Repowering/Industrial Retrofit Technical Information Memo No. 6, J. C. Gibson, Jan. 18, 1980.

Table 6.3-4

SOUTHWEST POWER POOL REGION COAL PLANT COSTS

(January 1980 Costs)

	Data Source		
	EPRI Guide *	Southwestern Public Service Company	Department of Energy **
Capital cost, $/kW	826	530 (without SO_2 removal) 680 (with SO_2 removal)	860
Fixed O&M cost, $/kW-yr	12.20	12.20	---
Variable O&M cost plus consumables, mills/kWh	2.11	2.11	---
Coal price	1.59	1.90	1.25
Real escalation rate, %/year	1.43	2.0	2.0

Table 6.3-5

SOUTHWEST POWER POOL REGION COMBINED CYCLE PLANT COST

(January 1980 Costs -- Coal-derived-fuel fired)

	Data Source		
	EPRI Guide * and	Southwestern Public Service Company	Department of Energy **
Capital cost, $/kW		410	360
Fixed O&M cost, $/kW-yr		5.62	---
Variable O&M cost, mills/kWh		1.40	---
Coal derived fuel price, $\$/10^6$ Btu		4.45	4.00
Real escalation rate, %/year		0.4	4.0

* Electric Power Research Institute Technical Assessment Guide, EPRI PS-PS-1201-SR, July, 1979.

** Solar Repowering/Industrial Retrofit Technical Information Memo No. 6, J. C. Gibson, Jan. 18, 1980.

On each of the screening curves (Figures 6.3-4 to 6.3-9), a typical annual operating hour performance of a solar plant is shown. This typical performance is for a solar plant with a 20% to 25% capacity factor with plant rating based on the solar insolation at the time of vernal equinox. The justifiable solar capital cost (busbar cost analysis) is computed as follows:

$$V = \left[\$/\text{kW-yr}_c - \left(\frac{\text{mills}}{\text{kWh}_s} \times \frac{1\$}{10^3 \text{ mills}} \times \frac{H}{Yr}\right) - \$/\text{kW-Yr}_s - \left(\frac{(1 - L_S)}{(1 - L_p)} \times \frac{\$}{KW_p} \times \overline{fcr}_p\right)\right] \frac{1}{\overline{fcr}_s} \tag{6.3-2}$$

where V = Breakeven solar cost, \$/kW (busbar cost analysis)

$\$/\text{kW-Yr}_c$ = Annual cost of competing generation type

$\frac{\text{Mills}}{\text{kWh}}$ = 30-year-levelized solar variable operating and maintenance cost

H/Yr = Hours per year for which competing cost found

H/Yr = 8760 x solar capacity factor

$\$/\text{kW-Yr}_s$ = 30-year-levelized solar fixed operating and maintenance cost

L_s = Effective capacity of solar plant, per unit. For explanation of effective capacity, see Section 6.5 and Appendix J

L_p = Effective capacity of unit supplying reserve capacity. For explanation of effective capacity, see Section 6.5 and Appendix J.

$\$/\text{kW}_p$ = Installed cost of unit supplying reserve

$\overline{fcr}_p$ = 30-year-levelized fixed change rate of unit supplying reserve

$\overline{fcr}_s$ = 30-year-levelized solar plant fixed change rate

The Plant X Unit 3 solar project cost is also shown on each screening curve analysis. The data is as follows (January 1980 costs):

Installed cost = 2034 \$/kw

Reserve requirement = 64.9% of solar capacity (with gas-fired boiler retired); i.e. solar plant effective capacity = 35.1%

Reserve requirement = 0% with gas-fired boiler not retired. This is Southwestern Public Service Company's most likely case. Solar plant with gas boiler for back-up implies effective capacity = effective capacity of "conventional" generation.

Solar plant fixed operating and maintenance cost = 11.4 \$/kW-Yr.

Solar plant variable operating and maintenance cost = 0 mills/kWh

Solar plant capacity factor = 20%

With 10% investment tax credit, the Plant X, Unit 3, solar plant 30-year-levelized busbar costs (January, 1980) are as follows:

Discount rate = average cost of capital

Plant cost = 172.95 mills/kWh

Fixed operating and maintenance cost = 12.78 mills/kWh

Reserve capacity cost = 12.57 mills/kWh

Discount rate = tax adjusted cost of capital

Plant cost = 167.18 mills/kWh

Fixed operating and maintenance cost = 14.35 mills/kWh

Reserve capacity cost = 12.15 mills/kWh

6.4 CAPITALIZED ELECTRIC PRODUCTION COST SAVINGS

The capitalized energy savings is computed using equation 6.4-1 as follows:

$$V_E = \frac{\text{mills}}{\text{kWh}} \times \text{H/yr} \times \frac{1\$}{10^3\text{mills}} \times \frac{1}{\text{FCR}} \qquad 6.4\text{-}1$$

where: V_E = \$/kW, capitalized fuel and net variable operating and maintenance cost saving

$\frac{\text{mills}}{\text{kWh}}$ = Annual average levelized variable cost of thermal generating units which would have been required to serve the load the candidate solar unit served, net of solar variable operating and maintenance cost

H/yr = Annual operating hours of the solar unit

FCR = Solar plant fixed charge rate

Again the fuel cost of the thermal units which is saved by solar unit operation varies hour-by-hour, is subject to inflation, and is also subject to the mix of thermal unit types. To illustrate the latter point, the 1979 USA average oil-fired generation, as given by the August, 1979, National Electric Reliability Council (NERC) 9th Annual Review, is 16% of total generation. It ranges from a low of 1.3% in the Mid Continent Region (MARCA) to a high of 52.5% in the Northeast (NPCC). This percentage could decrease in future years if nuclear and coal plants are installed on a timely basis (as well as increase if the load growth rate increases and nuclear and coal plants are not installed on a timely basis).

Figure 6.4-1 is a plot of capitalized fuel saving for a private utility with solar plant fixed charge rates of 14.9% per year (discount rate = 13.2%) and 14.4% per year (discount rate = 10.4%) versus annual average fuel cost saving. A capacity factor range is shown.

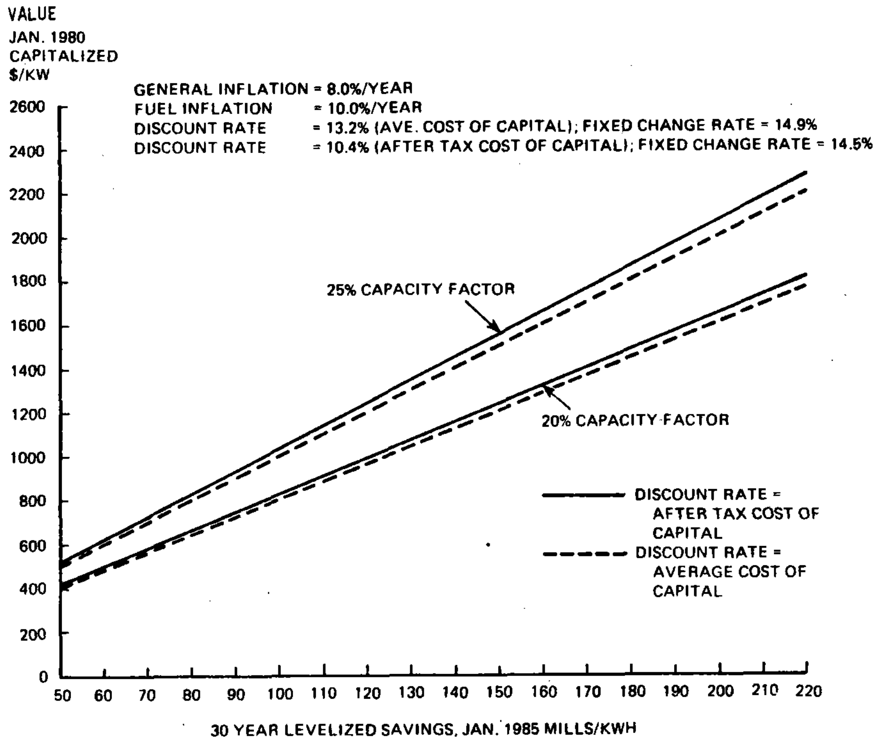


Figure 6.4-1. Value of Fuel Savings

6.5 CAPACITY CREDIT

In addition to fuel savings, the solar plant has value to a utility because the addition of such capacity improves the reliability of service -- particularly the addition of solar capacity or any type of capacity reduces the probability of having capacity outages of such magnitude that a utility's own capacity is less than its hourly integrated load. The capacity credit or value of a solar plant is computed as shown in Eq. 6.5-1.

$$V_C = \frac{LCC_S}{LCC_R} \cdot \$/kW_R \qquad (6.5\text{-}1)$$

where: V_C = Capacity credit, \$/kW

LCC_S = Load-carrying capability of the solar plant, per unit

LCC_R = Load-carrying capability of the thermal plant not required because of the installation of the solar plant, per unit

$\$/kW_R$ = Capital cost of the thermal plant not required because of the installation of the hydro plant.

"Load carrying capability" is also called "effective capacity" and should not be confused with "dependable capability." It is a measure of the plant's ability to reduce the chance of system-owned available capacity being less than hourly load.

The details of solar plant capacity credit calculations are contained in Appendix J. It is suggested that this capacity credit be included if the fuel savings calculation is not sufficient tojustify solar plant ownership. Many small utilities would only perform such a calculation if they are members of a power pool to which a reserve capacity obligation is required. Other utilities may calculate a capacity credit if it is shown that installation of solar capacity reduces the probability of requiring the use of transmission tie-lines to neighboring utilities.

Furthermore, if indeed a planned thermal unit installation is replaced, capitalized fuel savings would change with each type of thermal unit displacement.

6.6 COST/VALUE METHODOLOGY -- DATA

The value of the solar repowering concept has been calculated for the specific case of the solar equipment addition operating parallel to the gas-fired boiler of Unit 3 of Plant X of the Southwestern Public Service Company. Southwestern Public Service Company has the sixth largest peak load of those utilities comprising the Southwest Power Pool region of the National Electric Reliability Council. The Southwestern Public Service Company has only two points of interconnection with other utilities. Economy energy (energy not immediately required because of an emergency) is presently exchanged over this interconnection. It is nevertheless expected that the future generation mix of Southwestern Public Service Company and the other members of the Southwest Power Pool will be similar. This implies that the interchange may be negligible; therefore, no economy interchange costs and data are provided.

6.6.1 LOAD DEMAND AND ENERGY FORECAST

Load data is presented in Table 6.6-1. Load drop in February is to 63.5% of the annual peak. The winter peak is significantly lower than summer peak. Annual load factor is typical of most utilities. The hourly load and hourly solar production for the summer peak-load day is shown in Figure 6.6-1; the winter peak-load day is described in Figure 6.6-2. The solar output shown is the actual output for these days from the insolation tape used in the evaluation.

Table 6.6-1

SOUTHWESTERN PUBLIC SERVICE COMPANY LOAD DEMAND AND ENERGY FORECAST

Year	Peak Load Demand MW	Energy MWh	Annual Load Factor %	%/Year Growth
1979	2197	12,284,377	63.8	---
1985	3411	18,035,864	60.4	9.2
1988	4043	21,407,629	60.4	5.8
1990	4502	23,797,562	60.3	5.5
1996	5757	30,515,657	60.5	5.0

Monthly Peaks in Per Unit of the Annual Peak

(Same for All Years)

Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
0.655	0.635	0.686	0.748	0.735	0.894	1.000	0.960	0.802	0.665	0.664	0.729

Monthly Load Factor (average of Monthly Peak) = 0.763

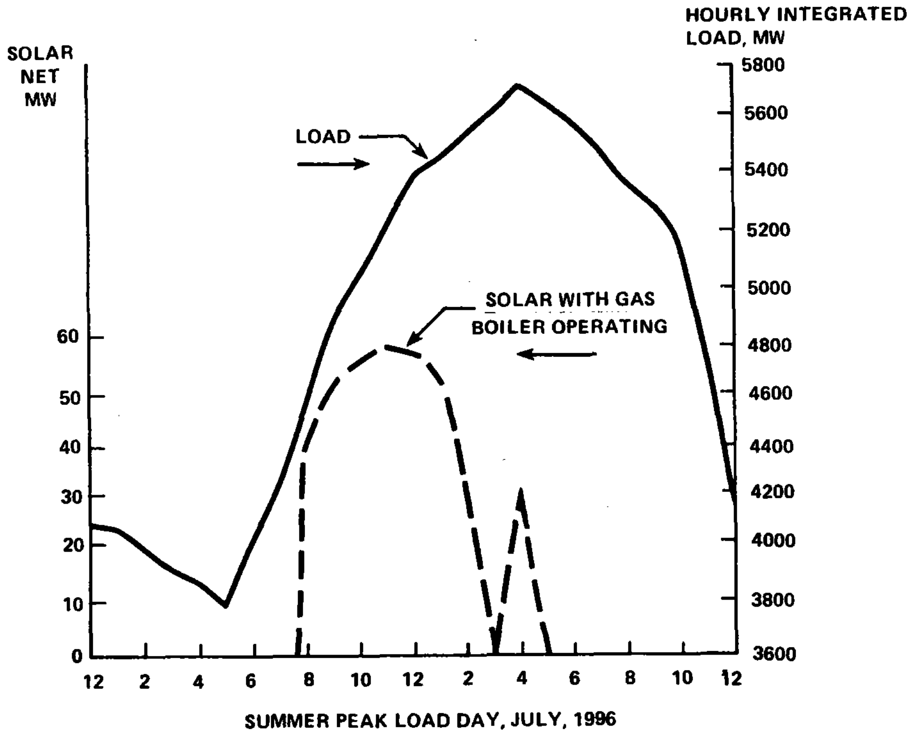


Figure 6.6-1. Summer Load/Insolation Coincidence

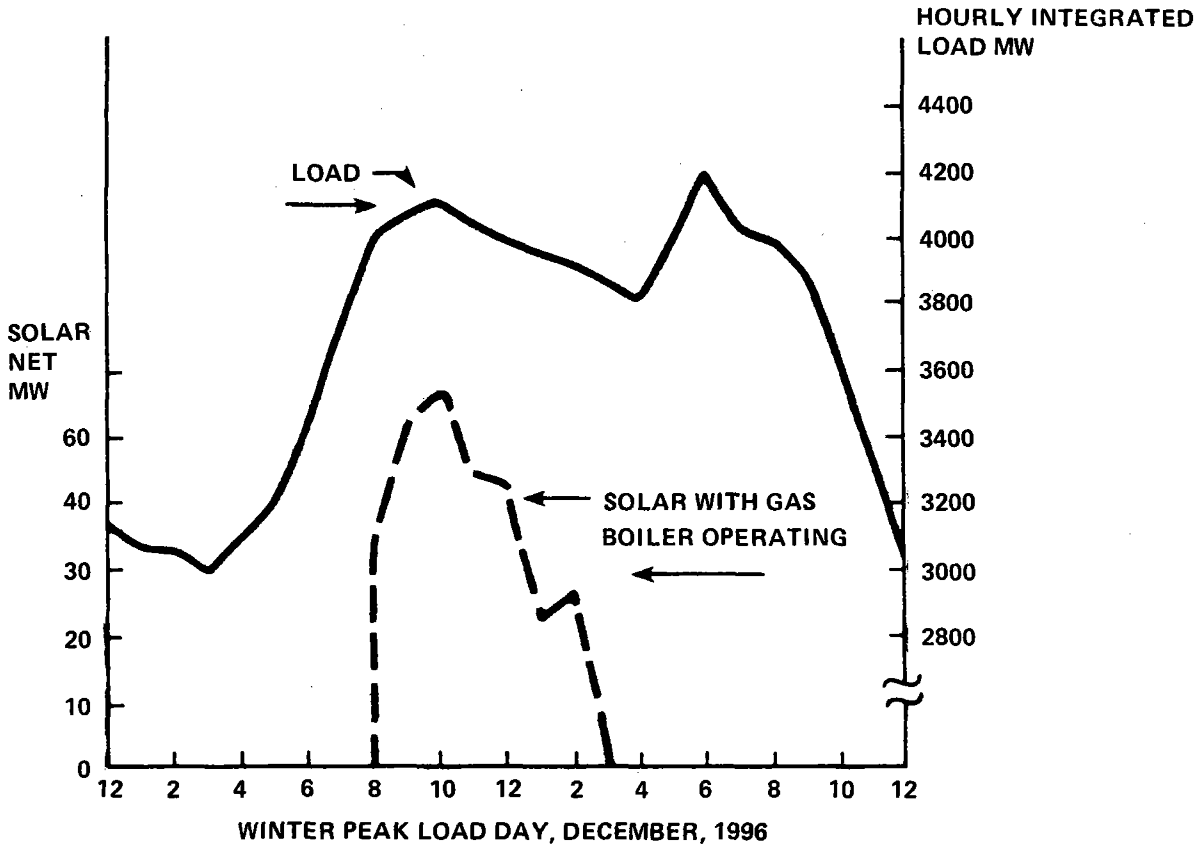


Figure 6.6-2. Winter Load/Insolation Coincidence

6.6.2 THERMAL UNIT DATA

Characteristics of the generating units studied are presented in Table 6.6-2. Southwestern Public Service Company's generation mix is presently (1980) 65.4% gas-steam, 33.5% coal, and a small percentage of capacity in co-generation. As shown in Figure 6.6-3, the generation mix changes dramatically toward coal such that by 1996 the generation mix is 24.0% gas-steam and 75.5% coal. Electric production mix is also shown in Figure 6.6-3.

Table 6.6-3 shows the 1985 system commitment list. The least expensive gas-fired unit is 11.6% more expensive in variable fuel cost than the most expensive coal-fired unit. In 1996 the commitment list is as shown in Table 6.6-4. Beginning in 1996, the least expensive gas fired unit is only 5.5% more expensive than the most expensive coal-fired unit in variable cost.

Table 6.6-2

SPS POWER GENERATION UNIT DATA

Unit	Rating (MW)	Fuel Type[1]	Service Year	Retirement Year	Min Down Time (HRS)	Forced Outage Rate	Var. Fuel Cost (1980 $/10⁶BTu)	O&M Cost (1980 $/kW/Yr)	Sched Maint Time (Weeks/Yr)	Full Load Heat Rate (BTu/kWhr)
MOOR 3	49.5	1	1954	1994	5	.0088	1.95	22.8	5	11200
MOOR 2	20.0	1	1950	1991	5	.0124	1.95	22.8	5	14550
RIVE 6	24.0	1	1974	1998	5	.0190	2.34	39.0	6	16442
EPLT 5	39.0	1	1951	1985	5	.0170	2.42	22.8	4	13764
CARL 3	18.4	1	1949	1989	5	.0170	2.82	22.8	4	13977
RIVE 5	29.3	1	1948	1988	5	.0170	2.34	22.8	4	12188
HARR 1	333.0	2	1976	2016	24	.0759	1.90	15.6	7	10300
HARR 2	338.0	2	1978	2018	24	.0310	1.90	15.6	4	10195
HARR 3	338.0	2	1980	2020	24	.0670	1.90	15.6	7	10195
NICH 1	106.0	1	1960	2000	5	.0272	2.42	8.4	5	10160
NICH 2	106.0	1	1962	2000	5	.0071	2.42	8.4	4	9927
NICH 3	244.0	1	1968	2000	5	.0157	2.42	8.4	4	9432
TOLK 1	508.0	2	1982	2022	24	.0810	1.90	31.1	7	10006
TOLK 2	508.0	2	1985	2025	24	.0810	1.90	31.1	7	10006
PLTX 1	49.5	1	1952	1992	5	.1519	2.51	5.26	4	11260
PLTX 2	106.0	1	1953	1994	5	.0112	2.51	5.26	5	11618
PLTX 3	106.0	1	1955	1995	5	.0100	2.51	5.26	4	9971
PLTX 4	200.0	1	1964	2000	5	.0022	2.51	5.26	5	9820
JONES 1	244.0	1	1971	2000	5	.1425	2.38	11.03	4	9654
JONES 2	244.0	1	1974	2000	5	.0095	2.38	11.03	7	9573
DENC 4	49.5	1	1955	1990	5	.0083	2.67	13.9	2	11300
CNHM 1	75.0	1	1957	1997	5	.0005	2.80	10.9	8	10196
CNHM 2	200.0	1	1965	2000	5	.0108	2.80	10.9	3	9968
CELGT 1	12.0	1	1964	1990	24	.0048	.35	11.5	2	5665
CEL 2	30.0	3	1979	1999	24	.0310	3.12	15.0	2	4800
DENC 2	11.3	1	1946	1986	5	.0170	2.67	13.9	4	16201
DENC 3	19.5	1	1948	1988	5	.0170	2.67	13.9	8	15623
NOPL 1	600.0	2	1987	2027	24	.1152	1.90	31.1	8	9782
NOPL 2	600.0	2	1989	2029	24	.1152	1.90	31.1	8	9782
SOPL 1	720.0	2	1991	2031	24	.1790	1.90	12.43[3]	8	10238
SOPL 2	720.0	2	1993	2033	24	.1790	1.90	12.43[3]	8	10238
SOPL 3	720.0	2	1995	2035	24	.1790	1.90	12.43[3]	8	10238

(1) 1 = Gas/Synfuel; 2 = Coal; 3 = Purchased Steam

(2) Based on current plans. SPS projects retirement in 2014 if plant is repowered. The effect on production cost is negligible since the fossil boiler capacity factor beyond 1995 is only 4%.

(3) 2.14 mills/kWh variable O&M cost is added to fixed O&M cost to account for operation of SO_2 removal equipment.

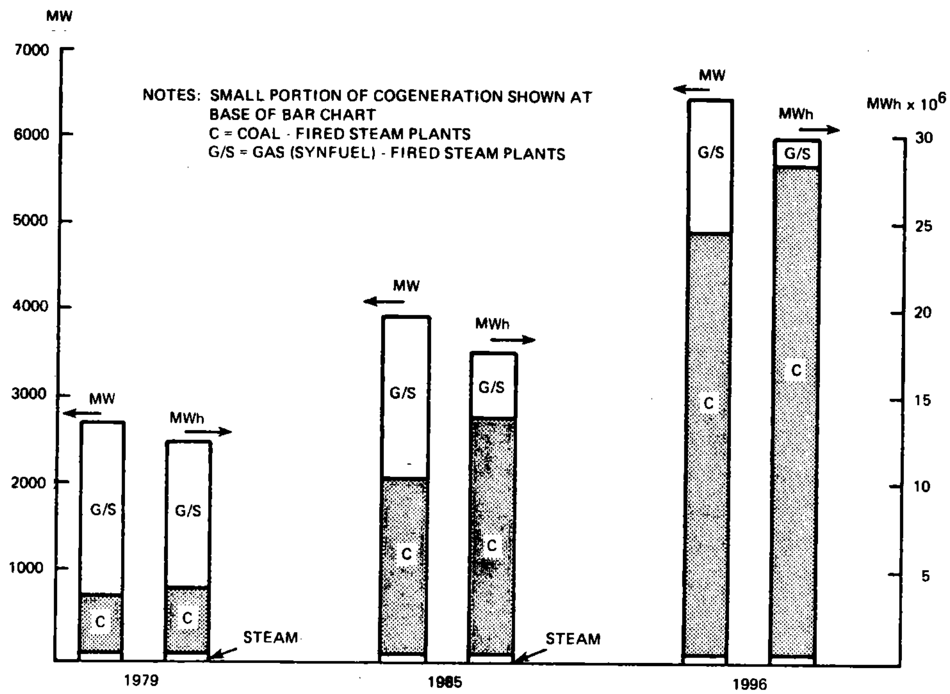


Figure 6.6-3. Southwestern Public Service Company Generation Mix

Table 6.6-3

1985 STARTUP PRIORITY

Priority	Name of Unit	Capacity	Generation Type	Full Load Cost ($/MWHR) (1985)	Min. Down Time (Hours)
1	CELGT 1	12.	Gas Turbine	3.1937	24
2	CEL 2	30.	Steam Gas	24.1190	24
3	TOLK 1	508.	Steam Coal	30.6178	24
4	TOLK 2	508.	Steam Coal	30.6178	24
5	HARR 2	338.	Steam Coal	31.1971	24
6	HARR 3	338.	Steam Coal	31.1971	24
7	HARR 1	333.	Steam Coal	31.5177	24
8	MOOR 3	50.	Steam Gas	35.1736	5
9	JONES2	244.	Steam Gas	36.6935	5
10	NIC 3	244.	Steam Gas	36.7637	5
11	JONES1	244.	Steam Gas	37.0040	5
12	NIC 2	106.	Steam Gas	38.6898	5
13	NICH 1	106.	Steam Gas	39.5979	5
14	PLTX 4	200.	Steam Gas	39.6956	5
15	PLTX 3	106.	Steam Gas	40.3083	5
16	CNHM 2	200.	Steam Gas	44.9500	5
17	PLTX 1	50.	Steam Gas	45.5173	5
18	MOOR 2	20.	Steam Gas	45.6942	5
19	RIVE 5	29.	Steam Gas	45.9310	5
20	CNHM 1	75.	Steam Gas	45.9781	5
21	PLTX 2	106.	Steam Gas	46.9641	5
22	DENC 4	50.	Steam Gas	48.5907	5
23	EPLT 5	39.	Steam Gas	53.6454	5
24	RIVE 6	24.	Comb Cycle	61.9620	5
25	CARL 3	18.	Steam Gas	63.4814	5
26	DENC 3	20.	Steam Gas	67.1826	5
27	DENC 2	11.	Steam Gas	69.6663	5
28	ROS 6	20.	Gas Turbine	55.5669	2

Table 6.6-4

1996 STARTUP PRIORITY

Priority	Name of Unit	Capacity	Generation Type	Full Load Cost ($/MWHR) (1996)	Min. Down Time (Hours)
1	CELA 2	30.	Steam Gas	68.8143	24
2	NOPL 1	600.	Steam Coal	85.4013	24
3	NOPL 2	600.	Steam Coal	85.4013	24
4	TOLK 1	508.	Steam Coal	87.3560	24
5	TOLK 2	508.	Steam Coal	87.3560	24
6	HARR 3	338.	Steam Coal	89.0091	24
7	HARR 2	338.	Steam Coal	89.0091	24
8	HARR 1	333.	Steam Coal	89.9237	24
9	SOPL 1	720.	Steam Coal	99.2149	24
10	SOPL 2	720.	Steam Coal	99.2149	24
11	SOPL 3	720.	Steam Coal	99.2149	24
12	JONES2	244.	Steam Gas	104.6907	5
13	NICO 3	244.	Steam Gas	104.8911	5
14	JONES1	244.	Steam Gas	105.5767	5
15	NICO 2	106.	Steam Gas	110.3866	5
16	NICH 1	106.	Steam Gas	112.9775	5
17	PLTX 4	200.	Steam Gas	113.2561	5
18	PLTX 3	106.	Steam Gas	115.0043	5
19	CNHM 2	200.	Steam Gas	128.2475	5
20	CNHM 1	75.	Steam Gas	131.1809	5
21	RIVE 6	24.	Comb Cycle	176.7847	5

Thermal unit commitment is performed prior to correction of load by solar output. It is prudent to provide full operating reserve to accommodate potential loss of solar output. A thermal unit commitment example is shown on Figure 6.6-4. The total committed capacity is higher in Zones 1, 2, and 3 for the case of 100% solar plant back-up than the case of allowing full credit for solar plant capacity. This means system production cost will be higher; fuel saving by solar generation will be lower.

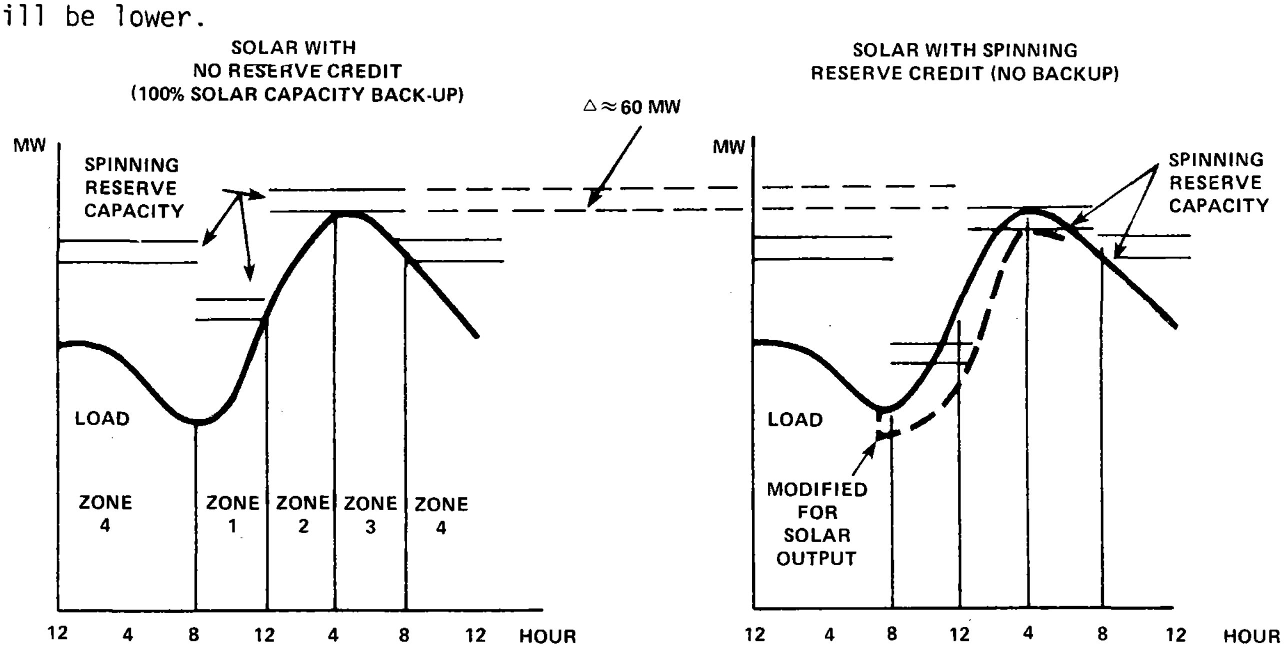


Figure 6.6-4. Spinning Reserve Policy -- Effect of Solar Capacity Back-Up

Plant X, Unit 3, has a turbine-generator overhaul annually of 31 days which is assumed to occur each January. Thus no credit for solar output will occur for the entire month.

6.6.3 OTHER STUDY DATA

Plant X, Unit 3, Solar Equipment Life = Year 1985 to Year 2014

Detailed Simulation of Four Years = 1985, 1988, 1990 and 1996

Fuel Inflation Rate = 10%/year

Operation and Maintenance Cost Inflation Rate = 8%/year

Average Cost of Capital = 13.21%

Tax Adjusted Capital Cost = 10.41%

Levelized Fixed Charge Rate with 10% Investment Tax Credit with
Annual Fixed Charges Discounted at Average Cost of Capital = 14.90%
Annual Fixed Charges Discounted at Tax Adjusted Capital Cost = 14.46%

Levelized Fixed Charge Rate with 25% Investment Tax Credit * with
Annual Fixed Charges Discounted at Average Cost of Capital = 12.08%
Annual Fixed Charges Discounted at Tax Adjusted Capital Cost = 11.70%

System dispatch simulation includes effect of forced outages.

Energy purchase cost = 100 mills/kWh (January, 1980). This is an assumed cost reflecting peaking generation cost, transmission charge, and a selling rate incentive.

Operating reserve requirement is computed as equal to the largest committed unit minus tie-line capacity. The values for each year are constant throughout the year and are as follows:

1985 = 409 MW	1988 = 460 MW
1990 = 410 MW	1996 = 492 MW

6.7 COST/VALUE METHODOLOGY -- STUDY APPROACH

The value of addition of solar capacity is two-fold. First, solar generation can reduce the system probability of insufficient capacity. Even though the source of energy is intermittent, a finite amount of time the source (i.e., the sun) does exist. Solar generation has a nonlinear effect on the probability of insufficient total system capacity. One important parameter is the coincidence of solar insolation at the solar plant site and system peak load. Depending on annual load duration, approximately 50 to 100 days of the year may account for almost all of the system's yearly expected value or average days per year of insufficient capacity. If the sun shines most of the day-time hours of these critical load days, solar generation may significantly enhance the generation system reliability. It may therefore be possible to displace some planned capacity with solar generation and obtain the same generation system reliability. This provides a credit to solar or a "value" because of a reduction in plant cost of planned additions (or a reduced need for purchase of capacity).

*Not currently available for public utility property.

Secondly, after the amount of potential capacity deferral is determined, the reduction in electric production cost because of the displacement of fuel burned in thermal generating units may be ascertained. Depending on the timing of solar insolation, peak load, and the mix of types of thermal generating units, the fuel displaced may range from relatively low cost nuclear fuel to high cost oil in combustion turbine units.

A study approach diagram is presented in Figures 6.7-1 and 6.7-2. To determine each of these capacity and energy values for the case of repowering of Southwestern Public Service Company's Plant X, Unit 3, the first step was to determine the effect of solar insolation on hourly integrated solar-electric production. This was accomplished by creating an hour-by-hour electric capacity data file from a detailed plant performance computer simulation program called STEAEC described in Section 4. This is an additional input to the detailed hourly generation system reliability program, HPP, further described in Appendix J,and the detailed hourly system electric production simulation program,MPS, further described in Appendix D.

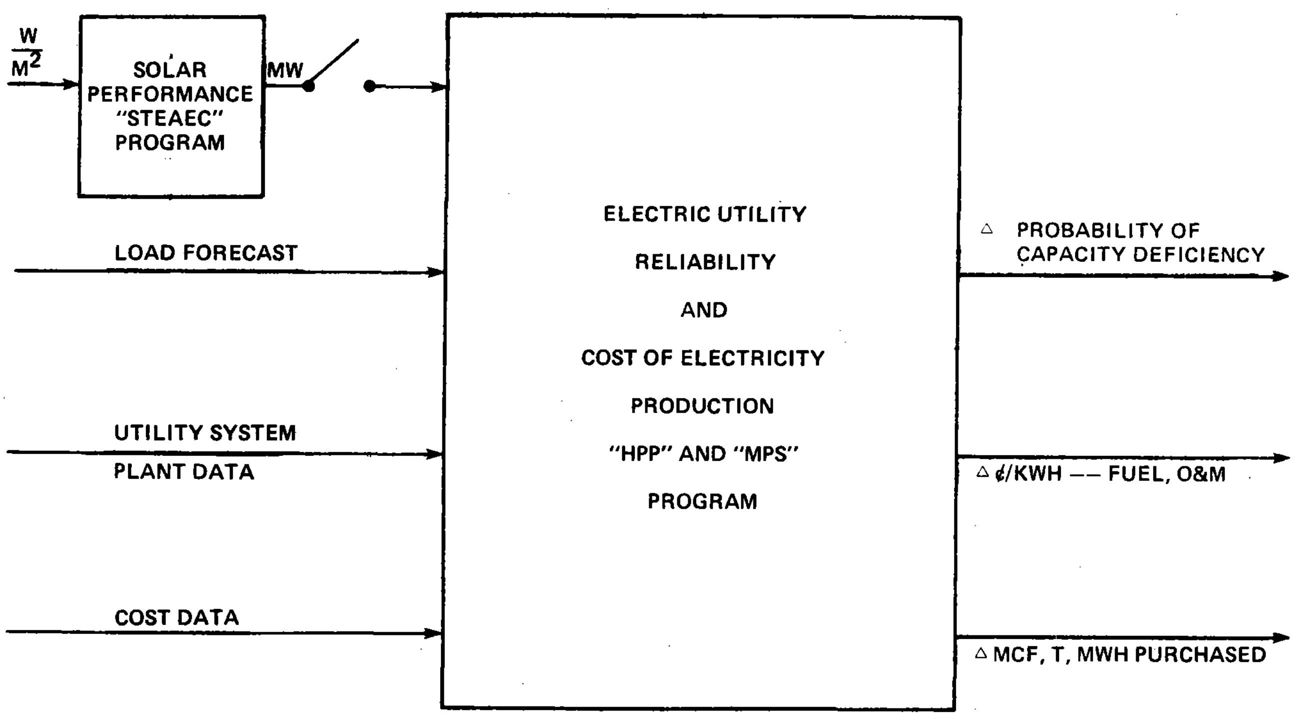


Figure 6.7-1. Southwestern Public Service Company Plant X Unit 3 Solar Repowering Study Approach - Part I

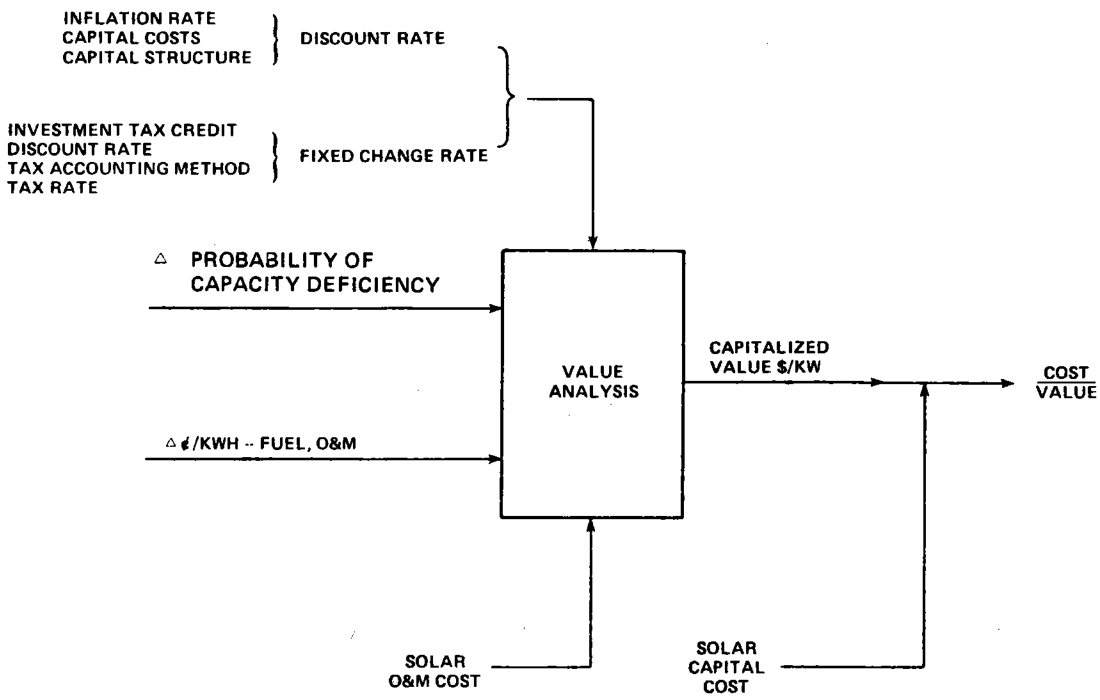


Figure 6.7-2. Southwestern Public Service Company Plant X Unit 3 Solar Repowering Study Approach - Part 2

The solar performance was determined using Albuquerque, New Mexico, insolation data which was modified for estimated performance at Earth, Texas. The hour-by-hour electric capacity data was obtained from STEAEC also based on assumed minimum firing of the gas-fired boiler of Plant X, Unit 3 (i.e.,assuming that the gas-fired boiler is committed every hour to satisfy load plus operating reserve requirement). This is a poor assumption for the particular case of Plant X, Unit 3, since the production cost simulation determined Plant X, Unit 3, is on-line only 2498 hours in 1985. Operating hours declines to 1068 hours by 1996.

The STEAEC program output was also obtained based on solar-alone (no gas firing) performance since this is the state required for capacity value determination as further explained in Appendix J. Solar performance is affected by steam-turbine generator part-load efficiency. This is illustrated in Figure 6.7-3.

The next step in determining capacity value is to compute the effect of a parallel steam-turbine source in Plant X, Unit 3, because of the addition of solar equipment, on system generation reliability. The improvement in system reliability, specifically "load carrying capability" as described in Appendix J, was assumed to afford a reduction in purchased capacity necessary to achieve the Southwest Power Pool requirement for 15% reserve capacity.*

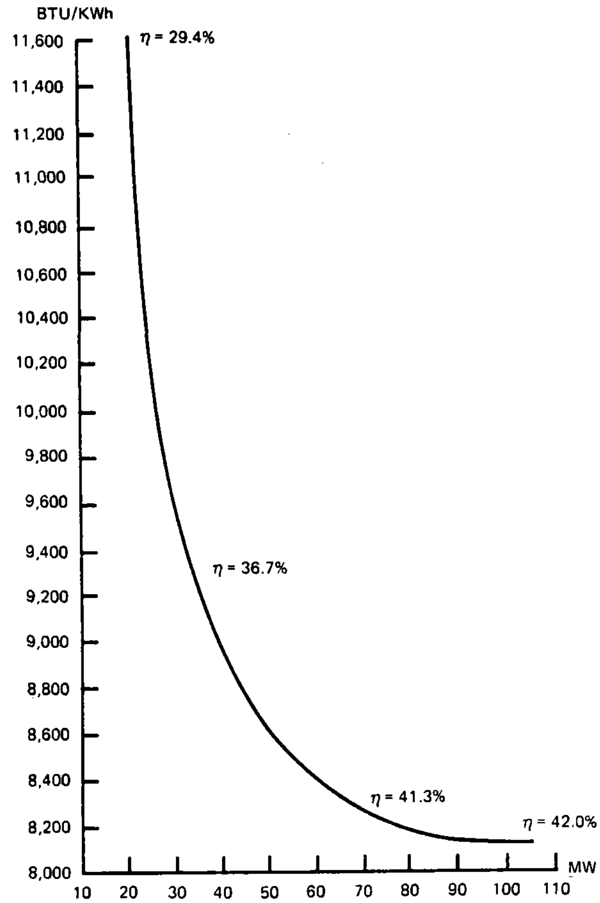


Figure 6.7-3. Plant X Unit 3 Turbine Room Heat Rate Versus Loading

*Turbine room heat rate describes the plant cycle efficiency prior to accounting for boiler and some plant electrical auxiliary load losses.

Next, two cases of gas-fired boiler retirement were considered. In the first case, the gas-fired boiler was retired in the year 1995. The capacity value of entirely solar-alone performance is computed as described in Appendix J and is likewise considered as a reduction of purchased capacity. In the second case, the gas-fired boiler is never retired during the life time of the solar equipment. Hence,

*Southwest Power Pool Regional Reliability Council Coordinated Bulk Power Supply Program, April 1, 1979, Report to the Economic Regulatory Administration, Section IIIB.

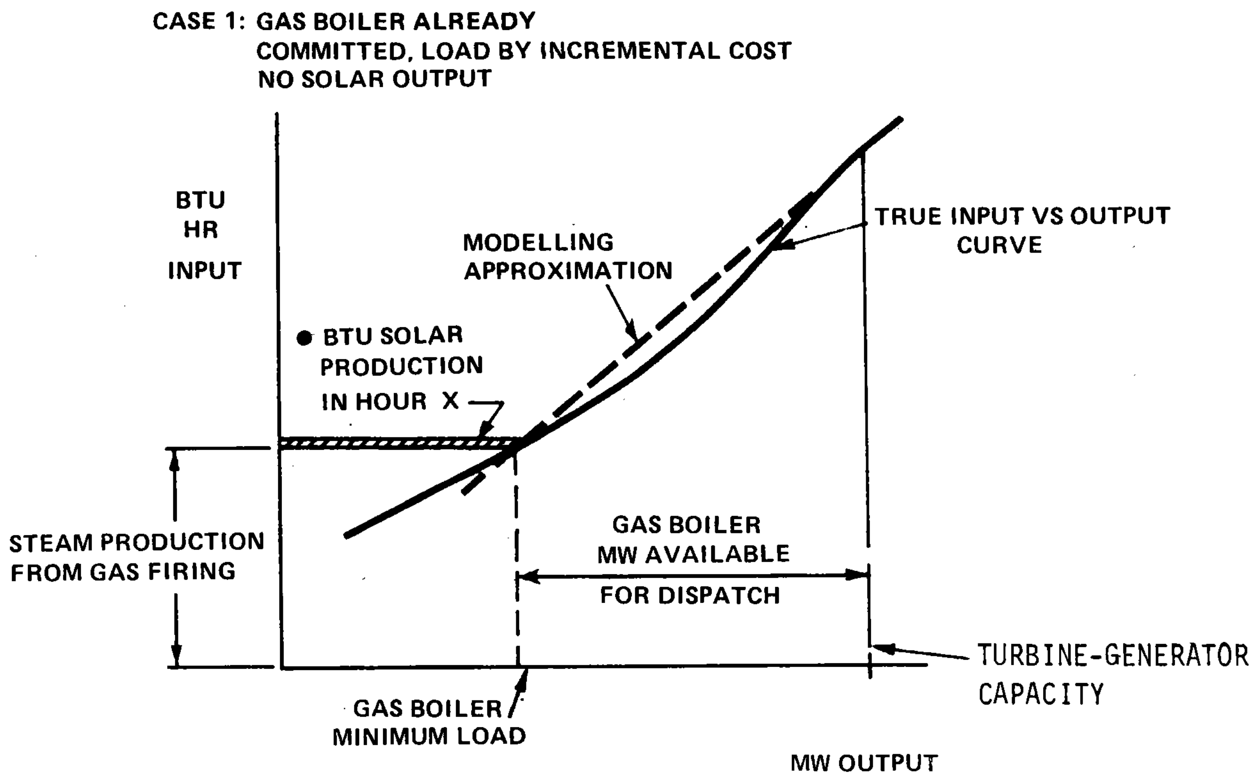
no additional capacity value is computed. This second case is the planning of Southwestern Public Service Company.

The determination of production cost saving was accomplished by a detailed economic operation simulation of the years 1985, 1988, 1990,and 1996 with and without solar repowering. The computer program used is described in Appendix D. To account for the effect of the parallel gas-boiler operation on solar electric production (since the total loading of the steam turbine determines turbine efficiency), additional logic was written for the production cost program. The production cost program determined if the gas-boiler really was committed for each hour of solar energy production. If it was not, the electric capability computed by the STEAEC solar performance program was corrected by the ratio of turbine-room heat rate at the STEAEC-computed output plus 40 MW output from minimum gas-fired boiler operation to the turbine-room heat rate at the STEAEC-computed output. This correction is slightly conservative because of somewhat reduced plant auxiliary power requirement at partial plant load.

If the gas-fired boiler was committed at minimum load in a given hour of solar energy production, the remaining gas-boiler capability available for dispatch was corrected for solar energy production. As shown in Figure 6.7-4, the input-output curve was assumed linear for this unit in order to avoid recomputing incremental input-output, the slope of the input-output curve,each hour. It is widely recognized practice to ensure minimum production cost by loading committed units in ascending order of incremental costs.

The production cost savings for the remaining years (1986-1987, 1989, 1991-1995, and 1997-2014) were assumed to be of the amount computed from the earlier year simulated but increased by the fuel cost inflation rate. The January,1985, present worth of the lifetime production cost savings was computed by discounting the future savings at both the average cost of capital and the "after-tax" cost of capital or internal rate of return, since both discount rates are used by the utility industry.*

*AIEE Paper 61-57, December, 1961, AIEE Transactions, p. 775-788; F. M. Heck, "The Cost of Capital in Economic Studies" and discussion by C. W. Bary and W. T. Brown.



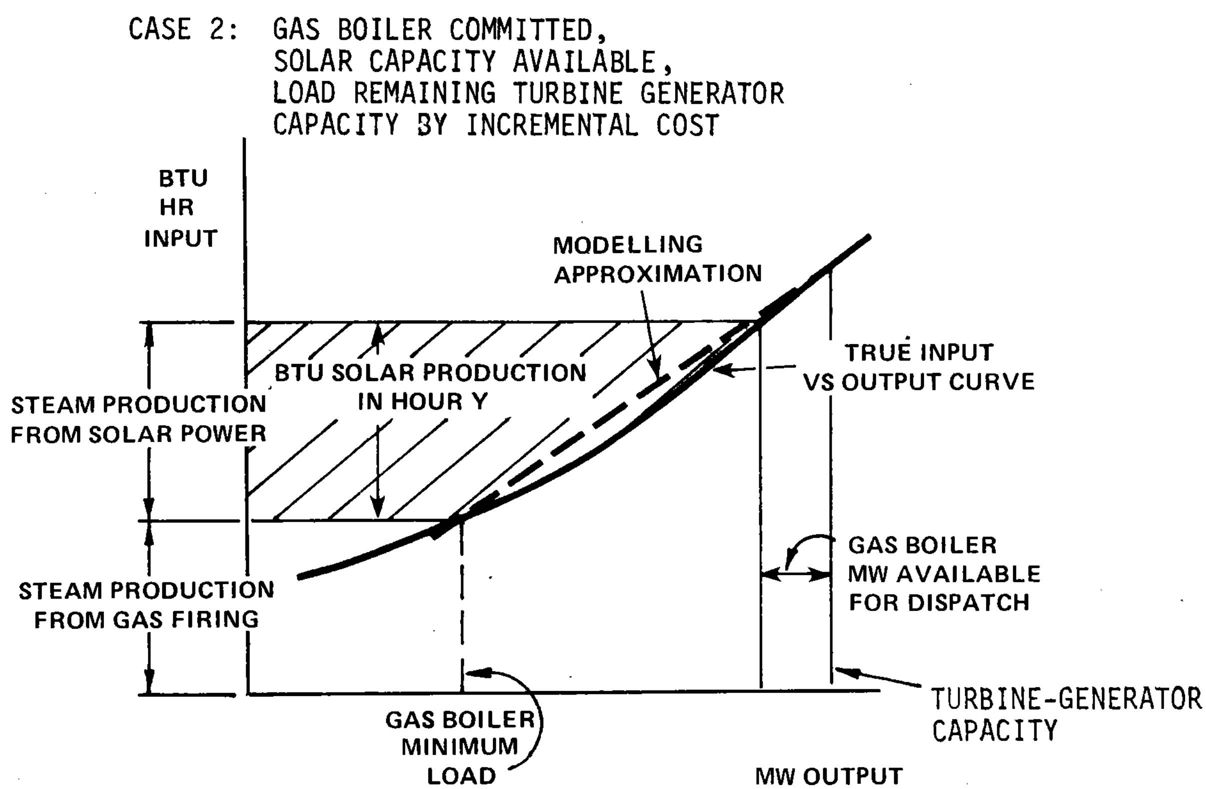


Figure 6.7-4. Repowered Plant Dispatch From Slope of Input Versus Output (Incremental Cost Is Slope of Input Versus Output Multiplied by Fuel Price)

The present worth is converted to an equivalent annuity by multiplying the present worth by the capital recovery factor (also computed with both discount rates). The annuity is divided by the levelized fixed charge rate, a rate applied to capital investment which yields the equivalent uniform revenue requirement necessary to depreciate the investment, give minimum acceptable return to investors, and pay taxes and insurance. (The levelized fixed charge rate is analagous to the "PIT" principal-interest-taxes computation of lenders of home mortgage funds.) The result is the capitalized value of production cost savings.

The "windfall profits tax legislation" PL96223 increased the additional investment tax credit for business for investment in solar or wind equipment to 15%. (Utility property is excluded by Section 222 i 1.) This yields a total investment tax credit of 25% for business other than utilities. It is available through 1985. The fixed charge rate was computed both for a 10% credit and a 25% credit to show the effect of income tax on solar plant value.

The capitalized solar operation and maintenance cost is subtracted from capitalized system production cost saving to yield net value of production cost saving. The sum of values of capacity credit and net production cost savings can be compared to project cost to determine if the project is feasible.

6.8 COST/VALUE METHODOLOGY -- RESULTS

6.8.1 CAPACITY CREDIT

The result of the hourly loss-of-load probability program for the year 1985 was a very small credit. Less than one MW of capacity credit is obtained because of the excellent forced outage rate of the gas-fired boiler at Plant X, Unit 3. The result of the hourly loss-of-load probability program for the year 1996 with the gas-fired boiler retired is shown in Figure 6.8-1. A 20-MW capacity credit for solar equipment is obtained in 1996 for the case of gas-boiler retirement.

Consideration of the economics of retirement of the gas-fired boiler is beyond the scope of this study. Southwestern Public Service has retired plants with as short a lifetime as 18 years (Clovis 3) and has planned one unit for a lifetime of 53 years (East Plant 3). Plant X Unit 3 will be in service for 40 years in 1995. Plant X Unit 3 boiler is presently planned not to be retired during the solar plant lifetime.

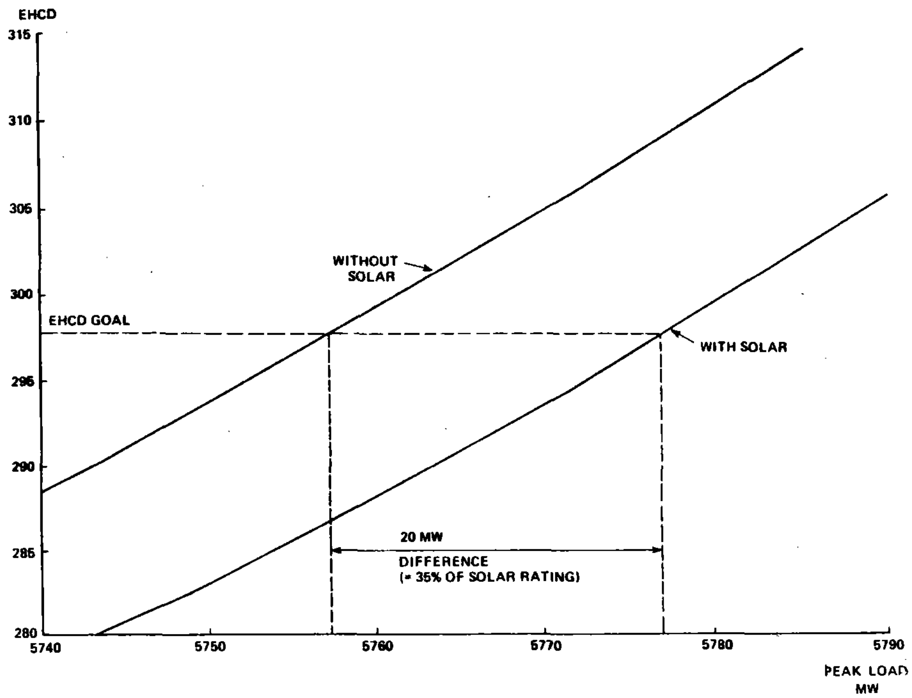


Figure 6.8-1. Year 1996 Expected Hours of Capacity Deficiency (EHCD) versus Peak Load - Solar Capacity Credit if "Stand-Alone" Configuration

The value of displacement of less than 1 MW of capacity purchased in 1985-1995 and displacement of 20 MW of capacity purchased in 1996-2014 is 87.8 \$/kW (January, 1980). This value was computed based on a purchased capacity cost of 38 \$/kW-year (January, 1980). The discount rate was chosen as average cost of capital and 10% investment tax credit was assumed.

6.8.2 NET PRODUCTION COST SAVINGS AND TOTAL VALUE

The effects of differing fuel inflation rates and differing cost of capital on value were investigated. These cases are presented in Table 6.8-1. The value of net production cost savings is illustrated in Figure 6.8-2 and Table 6.8-2 for a 10% investment tax credit. The value of net production cost savings is illustrated in Figure 6.8-3 and Table 6.8-3 for a 25% investment tax credit.

In each figure and for each case, three values are presented. The most significant is the energy credit for fuel displacement and this is the largest positive amount. To this value is added the capacity credit for potential deferral of some planned additional peaking capacity purchases. From these values one must subtract the solar operating and maintenance cost to obtain net value.

Table 6.8-1
TOTAL VALUE OF SOLAR REPOWERING DATA SUMMARY

Case No.	Fuel Inflation Rate %/Year	Years Applicable	Discount Rate %/Year	30 Year Levelized Fixed Charge Rate %/Year 10% Investment Tax Credit	30 Year* Levelized Fixed Charge Rate %/year 25% Investment Tax Credit
1	15.4% - Gas	1980 - 1989	10.41	14.46	11.70
	12.0% - Coal	1980 - 1989			
	10% - Gas and Coal	1990 - 1999			
	8% - Gas and Coal	2000 - 2014			
2	10% - Gas and Coal	1980 - 2014	10.41	14.46	11.70
3	8% - Gas and Coal	1980 - 2014	10.41	14.46	11.70
4	15.4% - Gas	1980 - 1989	13.21	14.90	12.08
	12.0% - Coal	1980 - 1989			
	10.% - Gas and Coal	1990 - 1999			
	8% - Gas and Coal	2000 - 2014			
$\boxed{5}$	10% - Gas and Coal	1980 - 2014	13.21	14.90	12.08
6	8% - Gas and Coal	1980 - 2014	13.21	14.90	12.08

$\boxed{}$ = Base case for detailed simulation and executive summary results

*Public utility property excluded from 25% investment tax credit per section 222 i 1 of PL 96 223.

Table 6.8-2
TOTAL VALUE OF SOLAR REPOWERING PLANT X UNIT 3
AND COST/VALUE RATIO--10% INVESTMENT TAX CREDIT
(January, 1980 $/kW; Cost = 2034 $/kW)

Case No.	Energy Value $/kW	Capitalized Solar O&M Cost $/kW	Net Energy Value $/kW	Cost ÷ Net Energy Value	Capacity Value $/kW	Capacity Value Plus Net Energy Value $/kW	Cost ÷ Total Net Value
1	1058	178	880	2.3	120	1000	2.0
2	869	178	691	2.9	120	811	2.5
3	610	178	432	4.7	120	552	3.7
4	907	156	751	2.7	88	839	2.4
5	726	156	570	$\boxed{3.6}$	88	658	3.1
6	528	156	372	5.5	88	460	4.4

$\boxed{}$ = Base Case -- Capacity value = 0.

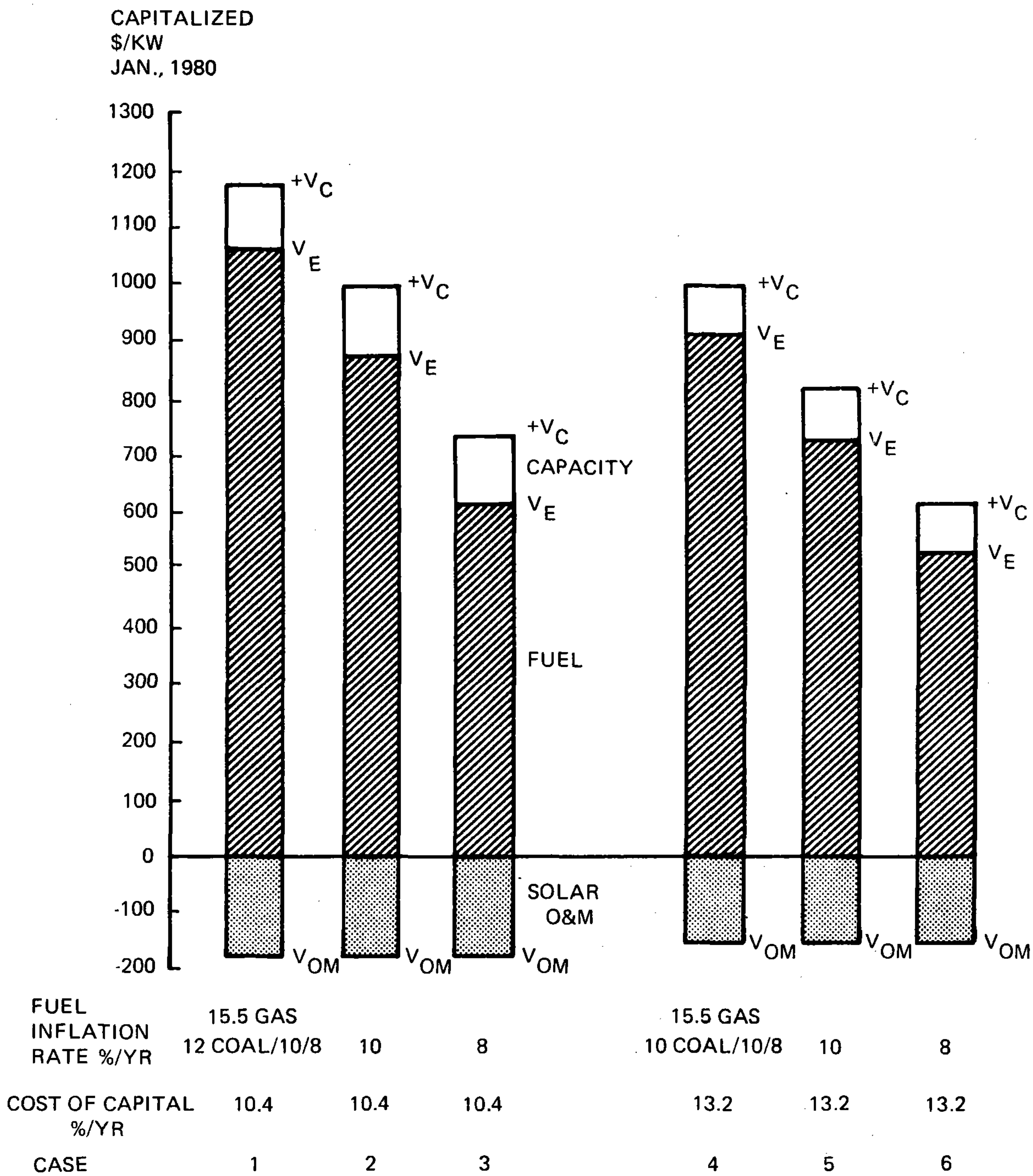


Figure 6.8-2. Solar Repowering Value, Plant X Unit 3
Southwestern Public Service Company
10% Investment Tax Credit

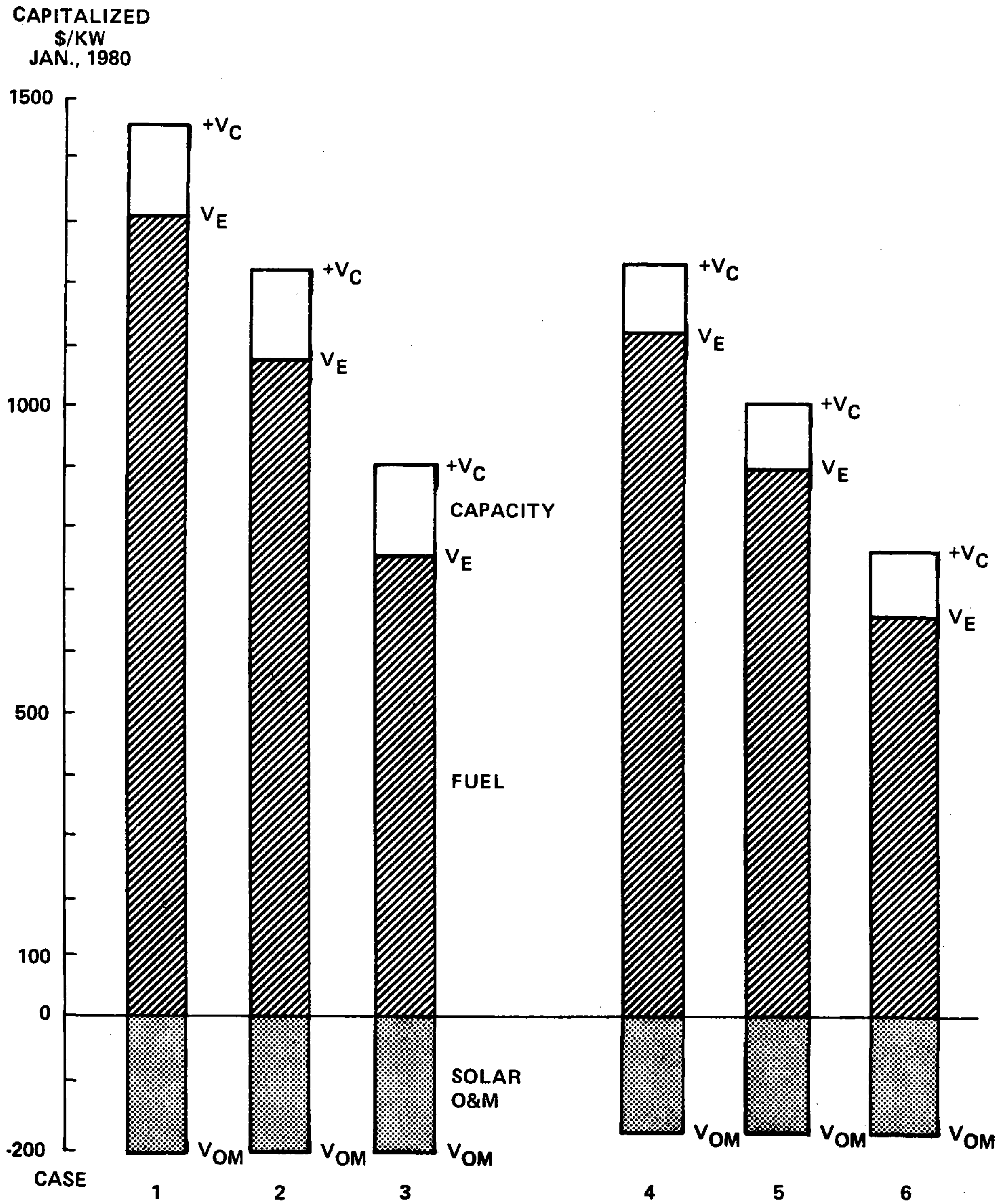


Figure 6.8-3. Solar Repowering Value, Plant X Unit 3
Southwestern Public Service Company
25% Investment Tax Credit

Table 6.8-3
TOTAL VALUE OF SOLAR REPOWERING PLANT X UNIT 3
AND COST/VALUE RATIO--25% INVESTMENT TAX CREDIT*
(January, 1980 $/kW; Cost = 2034 $/kW)

Case No.	Energy Value $/kW	Capitalized Solar O&M Cost $/kW	Net Energy Value $/kW	Cost ÷ Net Energy Value	Capacity Value $/kW	Capacity Value Plus Net Energy Value $/kW	Cost ÷ Total Net Value
1	1308	220	1088	1.9	148	1236	1.6
2	1074	220	854	2.4	148	1002	2.0
3	754	220	534	3.8	148	682	3.0
4	1118	192	926	2.2	108	1034	2.0
5	895	192	703	2.9	108	811	2.5
6	651	192	459	4.4	108	567	3.6

*Public utility property excluded from 25% investment tax credit per section 222 i 1 of PL 96 223

Cost/value for the solar repowering of Plant X Unit 3 ranges from 2.0 to 5.5 for the 10% investment tax credit case. If utility plant qualified for the 25% investment tax credit, cost/value would range from 1.6 to 4.4. This higher investment tax credit is presently not available to utility property per section 222 i 1 of PL 96 223.

6.9 SUMMARY AND CONCLUSION OF THE ECONOMIC ANALYSIS

1. Computation of solar power plant fixed charges and operating cost in mills/kWh is meaningless if the result is intended to be used as a means of deciding whether a solar plant should be installed in place of some other type of generation.

2. Solar electric production plant, whether placed in service with a parallel fossil-fired boiler or as "stand-alone" capacity, affects the generation system's reliability as measured by chance of insufficient system capacity.

3. Solar plant output will save fuel hourly from the highest incremental cost units needed to serve load each hour. The cost of these units ranges from coal-fired generation cost to purchased energy cost. Purchased energy cost may be distillate - oil fired combustion turbine generation cost plus transmission charges plus a selling rate incentive. In some systems even nuclear generation may be displaced by solar energy production.

4. Solar repowering of Plant X Unit 3 of Southwestern Public Service Company has been studied using a solar performance program, a generation reliability program, and a production cost program.

5. The solar performance is computed using a solar insolation schedule of Albuquerque, New Mexico, modified for estimated performance at Earth Texas. Daily peak load is not coincident with maximum solar insolation.

6. Since the gas-fired boiler at Plant X Unit 3 is not to be retired, and since the boiler has an excellent forced outage rate, the effect of the solar equipment on generation system reliability is unnoticeable.

7. A significant percentage of solar production is displacing coal-fired generation on the presently planned Southwestern Public Service Company system.

8. Other parameters which have had a significant effect on the solar plant output are turbine-generator maintenance schedule and turbine-generator part-load efficiency.

9. Another parameter which has had a significant effect on the type of generating production displaced by solar output is the spinning reserve policy.

10. The value of the production-cost savings is significantly influenced by investment tax credit, discount rate, and the difference between fuel inflation rate and general inflation rate. The net value of production cost saving is influenced by solar plant operation and maintenance cost.

11. Because of the relatively low cost of coal-fired generation, the low capacity factor of solar equipment, and the income tax requirement, the value of the production cost savings is exceeded by the Plant X Unit 3 solar project cost.

SECTION 7
DEVELOPMENT PLAN

Section 7
DEVELOPMENT PLAN

The previous sections of this final report have described the engineering conducted during the SPS Solar Repowering Program. The resultant conceptual design can be evolved into an operating power plant through the development plan described in this section.

7.1 GENERAL DESCRIPTION

The development plan prepared during the program is based upon one basic assumption: the SPS Solar Repowering Plant, if constructed, will be built using the techniques that have allowed Southwestern Public Service to build fossil power plants at less than half the national average cost.

The plan has been based upon the assumptions listed in Table 7.1-1 in order to ensure that the SPS Solar Repowering Plant is built in the most cost-effective manner. This requirement has resulted in a plan that is not phased, i.e. there is no clear time distinction between preliminary and detailed design. Design and construction activities are conducted in parallel, as necessary, to ensure the most economical critical path. It should be made clear that SPS does not use phased design and construction planning, due to the resultant arbitrary duplication of effort and accompanying cost penalty.

Table 7.1-1

DEVELOPMENT PLAN ASSUMPTIONS

Item	Assumption
Project Start	May 1, 1981
Procurement	Critical Path Materials Advance Ordered in 9/81
Government Involvement	Minimized, i.e. activities scheduled and procurements placed as dictated by effective project management practices
Heliostats	Competitive Procurement Selection made by SPS
Technology	Sodium technology does not require any further research and development activities. Prototype Receiver test data available by summer 1981
Scheduling	Dictated by standard SPS planning methodology. No arbitrary phases

If construction were to actually occur, General Electric will work as the solar plant engineer; however, SPS would use its strong engineering and construction skills to actually purchase large components and heliostats, as well as managing the construction effort. SPS and GE have assumed minimum government involvement in design and procurement activities in order to ensure control of schedule and cost.

The general development plan that results in an operational repowering plant at the end of 1985 is shown in Figure 7.1-1.Site construction would start in January 1982 and be completed by the middle of 1985. The critical path is controlled by the steam generator fabrication. Heliostats are the next controlling item. The following sections describe the development plan in more detail.

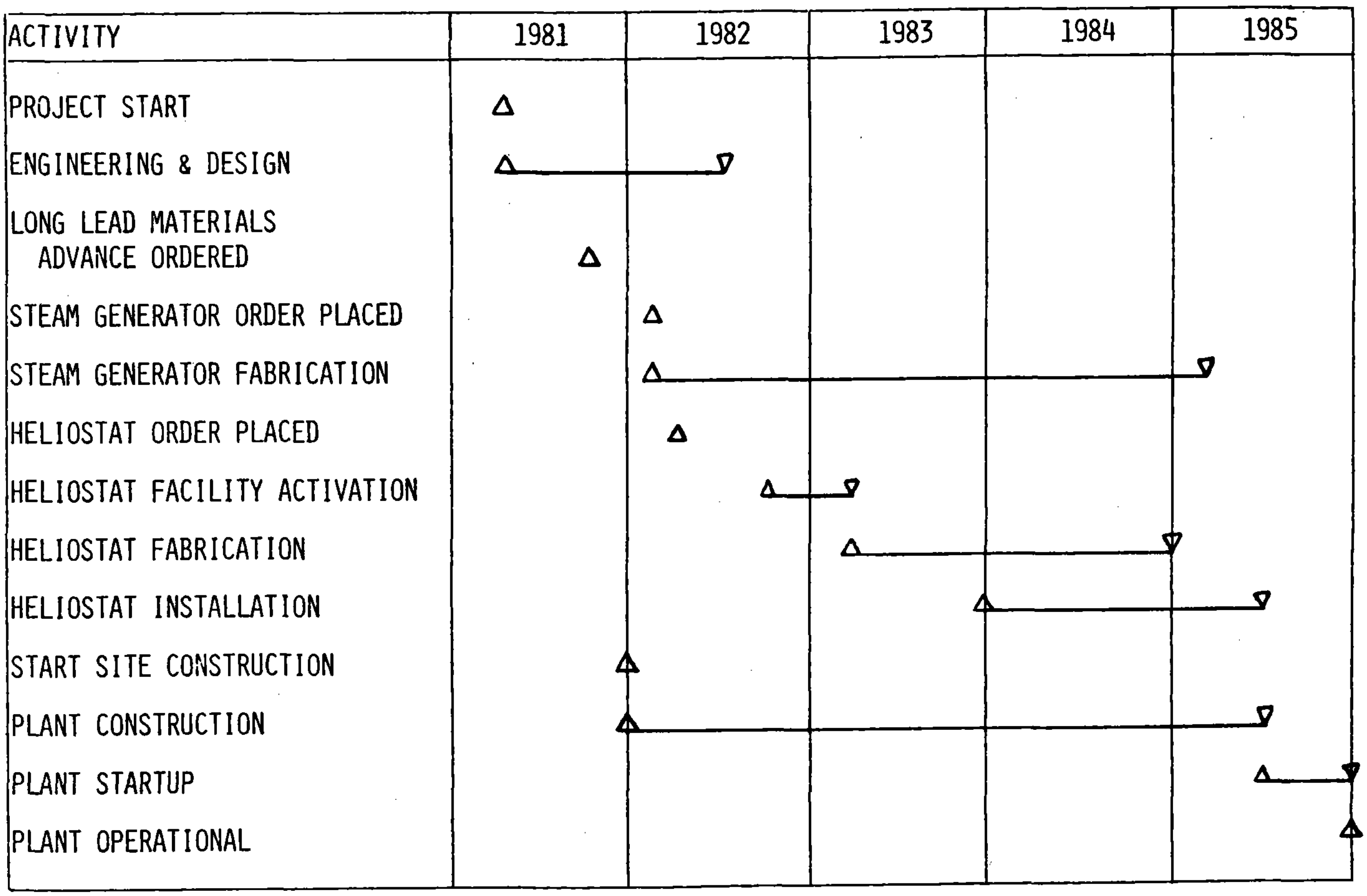


Figure 7.1-1. Summary Development Schedule and Milestone Chart

7.2 PROJECT ORGANIZATION

Southwestern Public Service Company intends to be the prime contractor for the Department of Energy to design, procure, and install systems and equipment for the solar repowering of Plant X, Unit 3.

The most time-efficient and cost-effective method for design and construction of the repowered plant will be for Southwestern to accept total project responsibility to the DOE. Under such an arrangement, Southwestern will be bound to deliver an operational solar-fossil hybrid power plant as specified. DOE, acting in the national interest, will provide funding and technical support as required and as described in the Repowering Contract. The constraints imposed by national energy goals and by this project's schedule will not allow time to engage in joint procurement decisions for all equipment. Neither will there be time for extraordinary component analysis prior to installation, other than that needed to verify a safe and functional design. Component performance characteristics will be intensively studied and characterized during the Joint User/DOE Operations Phase.

Organization charts showing the general project structure and the SPS functional structure are shown in Figures 7.2-1 and 7.2-2, respectively.

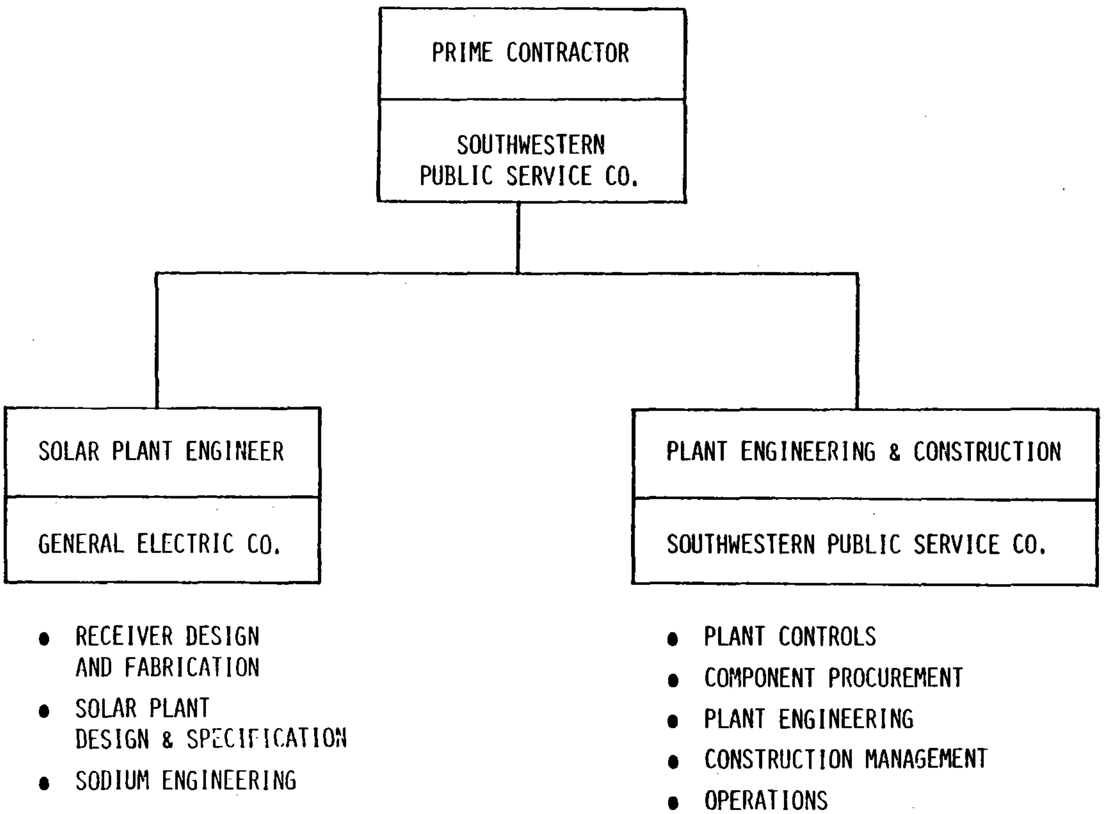


Figure 7.2-1. General Construction Project Organization

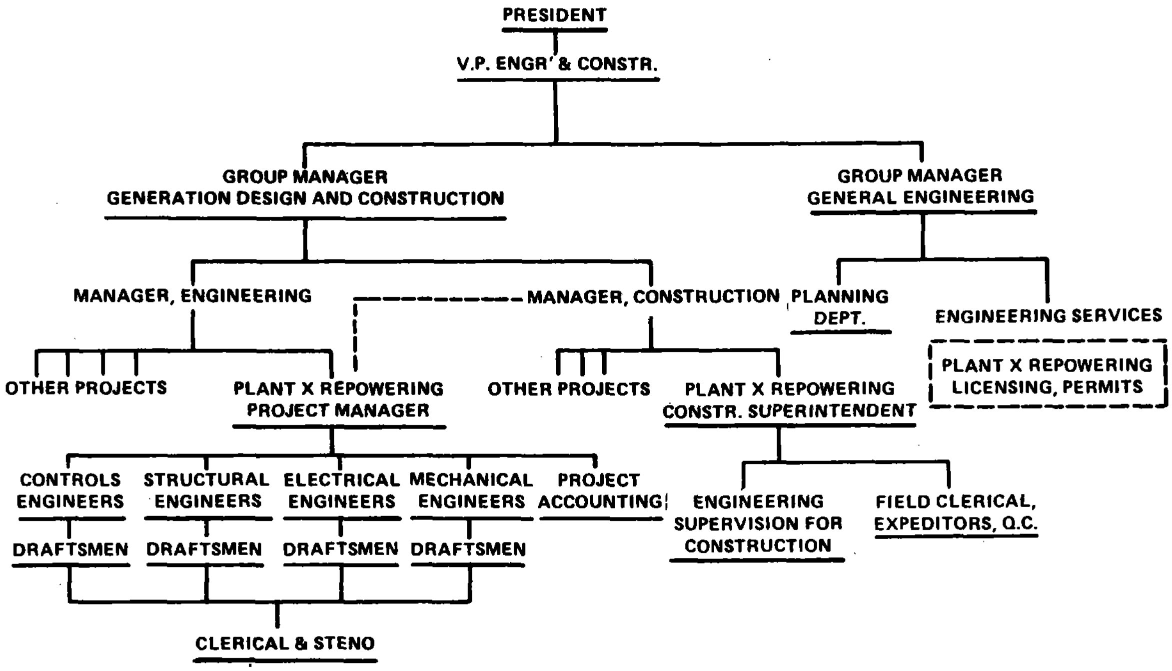


Figure 7.2-2.
SPS Organization for Plant X Repowering

This organization will operate under the same philosophies presently employed in Southwestern's Generation Plant Design Department. These philosophies include: (1) Performing all engineering in-house, except when the necessary expertise does not exist, (2) merging the design, procurement, and construction functions into an integrated activity, and (3) procuring equipment and services on a free-market basis and not being bound to necessarily accepting the lowest bid, but, instead, the lowest evaluated bid.

This approach has proven very successful for Southwestern. The Generation Design and Construction Department has designed and managed the construction of 27 separate generating units since 1950. These range in size from 20-MWe gas turbine units to 350-MWe coal-fired units. Southwestern is presently designing and constructing two 543-MWe class coal-fired generating units which will start up in 1982 and 1985.

The Generation Design and Construction Department acts as an Architect-Engineer in designing new generating capacity. The Production Department acts as a customer who owns and operates the new plants. The close working relationship between the two departments has created lines of communication which keep the Generation Design and Construction Department aware of operating problems and which promote the design of well laid-out, maintainable facilities.

This performance record and description of relationships is in support of Southwestern's policy of total project responsibility.

7.3 PLANT DESIGN AND CONSTRUCTION

The development plan was prepared by General Electric and Southwestern Public Service using the following methodology.

7.3.1 METHODOLOGY

General Electric identified that either the sodium steam generators or the heliostats would be the controlling activity and therefore solicited order cycle estimates from relevant vendors. These estimates were evaluated to select the best estimate cycles and finally to identify the critical path. Southwestern Public Service then superimposed its estimated schedule for plant design and schedule.

7.3.1.1 Steam Generators

Foster Wheeler Corporation and Babcock & Wilcox Company were asked to provide rough estimates of the fabrication cycle for "hockey stick" sodium steam generators. The estimated fabrication cycle was found to be between 33 and 40 months. General Electric's extensive experience with procurement of the Clinch River Breeder Reactor steam generators was used as a weighting factor. With success oriented assumptions, advance order of materials, and optimized procurement practices, it is estimated that a 36 month cycle could be achieved.

7.3.1.2 Heliostats

The five companies currently participating in the DOE sponsored Preproduction Heliostat Program were each contacted for rough estimates of the required order cycle. The estimates ranged between 21 and 36 months from order through subsystem installation and checkout. These schedules were judged by GE and SPS to be somewhat optimistic and a best estimate of 39 months was used in the development plan.

7.3.1.3 Receiver

The receiver fabrication was not found to be a critical path activity. The test receiver fabrication currently being performed by General Electric and Foster Wheeler in the parallel DOE sponsored Alternate Central Receiver Program has indicated that critical activities associated with absorber panel brazing will require erection of some special facilities. These facilities are unique only in their geometry and do not require any special research and development. The erection times are not critical path and the costs have been estimated as modest, specific examples are listed below.

- Long nickel plating facility - Low cost tanks and liners planned
- Long brazing furnace - Modification of the GE temporary brazing furnace planned

7.3.2 DESIGN AND PROCUREMENT PHASE

For most projects, Southwestern's Generation Design and Construction Department combines the functions of design and procurement into an integrated activity. Southwestern believes that this approach is instrumental in maintaining its excellent record of installing plants on-schedule and at a relatively low cost per installed killowatt.

The design and construction schedule which appears in Section 7.6 reflects this philosophy. For example, a piping fabricator must be selected in mid-1982 so that fabrication can begin on the large steam and sodium piping systems. It is recognized that some of the smaller piping systems, such as solar steam drum blowdown, may not be completely designed by that time. This philosophy will also be used in some of the smaller systems, such as the cover gas system, where potential vendor input will be an important source of design information.

As discussed above, the critical path item for design/procurement and construction will be the steam generators. The quoted 36-month lead time from order to delivery makes it necessary to shorten the specification and procurement time to 10 months. In order to maintain a December 1985 start-up date, the specification and procurement process for these modules must be complete in this time frame.

It may also be possible to compress the fabrication time for the steam generators by making bulk purchases of the Incoloy 800 material prior to final design. This would allow material suppliers to have the materials readily available at the time they receive a contract for fabrication.

The design and construction schedule calls for heliostats to be ordered in April of 1981. This incorporates an approximate four-month delay from the time that they could possibly be ordered. Southwestern desires to delay the purchase of heliostats as long as possible to benefit from the rapidly-changing technology in this field.

The Conceptual Design has identified several areas that will require careful attention during the design phase:

- Final steam generator location
- Final specification for sodium storage tanks
- Building specifications
- Steam temperature controls
- Solar steam drum blowdown system
- Solar steam generator water treatment
- Start-up bypass and control system
- Compatability of copper-based alloys in the existing feedwater system
- Reflectivity degradation due to cooling tower overspray

The conceptual design has addressed each of these areas within the scope of this contract. Additional engineering and design time has been allowed in the project schedule to address each area in more depth.

Control systems design for the repowering project will benefit from Southwestern's considerable experience in power plant control technology. Southwestern is recognized as a leader in control innovations, having installed the first digital-electro-hydraulic turbine control system in 1971 and one of the first digitally-based plant control systems on Harrington Unit 3 in 1980. Southwestern intends to work closely with each supplier of controls hardware to assure that the systems are compatible and that the overall control strategy is implemented.

7.3.3 CONSTRUCTION PHASE

Southwestern Public Service Company intends to be the construction manager for the solar repowering of Plant X-3. Construction will begin in January 1982 and will be complete by July 1985. In order to meet this schedule, design and construction must overlap. For example, the warehouse, visitors' center, and site preparation work will begin as soon as those designs and plans are complete, even though the design of other systems and equipment is not complete. This has proven to be the best approach for shortening a schedule and reducing costs.

Southwestern will have a project superintendent on the construction site beginning in January 1982. He will have additional field engineers as needed to monitor and coordinate the contractors' progress. In consultation with the project manager, he will have the authority to make some procurements and to make minor design changes, as necessary, to expedite construction progress. He and his staff will also be heavily involved in expediting equipment deliveries.

The critical schedule path is the completion of the steam generator installation. In order to make this activity fit into the scheduled time frame, care must be taken in steam generator building erection. Steam generator modules will not arrive on the construction site until the first quarter of 1985. By that time, most of the steam generator building construction will be complete. To accommodate this, openings must be left in the top of the steam generator building so that the modules themselves can be lowered from the top. The heaviest lift will be about 70 tons, which will require considerable rigging and hoisting equipment. The present location of the steam generator building, between the existing units 2 and 3 boiler buildings, will be studied further to be sure that there is sufficient clearance to make such lifts.

Heliostat components will begin arriving at the site in June 1983. The erection and installation of about 5000 heliostats over a two-year period will necessitate an average of about 12 complete heliostat assemblies installed per working day.

The fossil plant controls, water quality control system, steam piping, and other systems are comparable to systems which Southwestern presently designs and procures for fossil-fueled power plants. Southwestern intends to procure this equipment through its usual sources and manage its construction according to well-established procedures.

The necessary modifications to the existing plant, such as conversion to full-arc admission and upgrading the extraction steam system, are the same modifications which would be required for any unit which was being converted to cyclic duty. Southwestern has converted other turbines in its system to full-arc admission for the purpose of improving cycle performance under frequently varying load conditions.

An important construction constraint is the fact that Southwestern desires to keep Plant X Unit 3 operational for a maximum possible amount of time during repowering construction. Feedwater and steam piping tie-ins, which will require about six months of down time for the unit, will be performed during the winter of 1984-85. Southwestern's system has a high summer load peak, so that a winter outage will have a minimal impact. Similarly, the relocation of a transmission line that crosses the collector field will be performed in the winter when this line is not critically needed.

There are several schedule paths which, with only minimal delays, could become critical. Delays in heliostat installation, central receiver delivery and installation, or centrifugal sodium pumps delivery and installation could cause project delay.

7.3.4 SYSTEM CHECKOUT AND START-UP PHASE

The checkout of equipment will be performed, as much as possible, as soon as each item is ready for checkout. For example, an integral part of plant control installation is a checkout of each component as it is installed.

A six-month period is allowed in the last half of 1985 for complete system checkout. Proper focusing and alignment of heliostats will be verified during this time. Sodium melting and pumping systems will be operated for the first time during this period. All other plant systems and equipment will be started to confirm proper operation and to correct operational deficiencies.

During this period, piping systems will be flushed, hydrostatically tested, and steam-cleaned where necessary. Rotating machinery will be operated to insure proper rotation, alignment, balance, and to confirm power requirements. Pipe hangers and other structural components will be given their maximum loadings. Control software will continue to be de-bugged, as necessary.

Plant operations personnel will become involved during this time. A start-up engineer will be assigned from the production group to coordinate start-up activities. He will work closely with the project manager and the construction superintendent. The start-up engineer and his direct staff will ultimately be involved in plant operations.

7.3.5 SYSTEM PERFORMANCE AND VALIDATION PHASE

One important purpose of this solar repowering project is to provide data to the electric utility industry for use in subsequent solar-electric design. The system performance and validation phase, which will encompass the first twelve months of operation, will measure component performance and evaluate the system design.

Extensive testing programs will be developed and carried out on the collector field, central receiver, and steam generators, as well as the control systems which supervise these components and allow them to operate jointly with existing plant components. Testing programs will be formulated throughout the design, construction, and checkout periods. These tests and analyses will be performed under separate contracts.

Southwestern desires to have an operational solar-fossil hybrid plant available for load dispatching at the earliest possible date. The most meaningful tests will be those conducted during normal operational modes. Therefore, plans for tests during the system performance and validation phase will call for the completion of all tests that require disruption of operations to be complete within one year of plant start-up.

Southwestern will maintain authority for plant operations during this time. DOE, and its agents, will be on site for data collection and analysis.

7.3.6 JOINT USER/DOE OPERATIONS PHASE

The objective of this phase will be to assess the value of solar repowering as a viable option for electric utilities. The assessment will be performed by DOE while working intimately with Southwestern plant operations and maintenance personnel. The Department of Energy will be an observer in the repowered plant's operation for a period of four years from the end of the performance and validation phase so that the national interests will be served to the maximum. DOE, along with its agents, as an agency familiar with the plant's design and one capable of influencing future solar activities, will be a recipient of all operational data, and will be able to observe the plant operation.

The details of financial support and decision-making authority during this phase are described in Section 7.7.

Since the plant will be a first-of-a-kind, it is expected that DOE will desire data collecting, reduction and dissemination beyond that normally associated with plant operation. No provision has been included in the hardware or operational costing for such activities. It has been assumed that DOE will provide the resources for any such extraordinary activities.

7.4 SCHEDULE AND MILESTONE CHART

Figure 7.4-1 is a detailed schedule and milestone logic diagram for the 56 month period following the repowering contract award. This schedule has been developed and reviewed by both GE and Southwestern and reflects input from several equipment vendors.

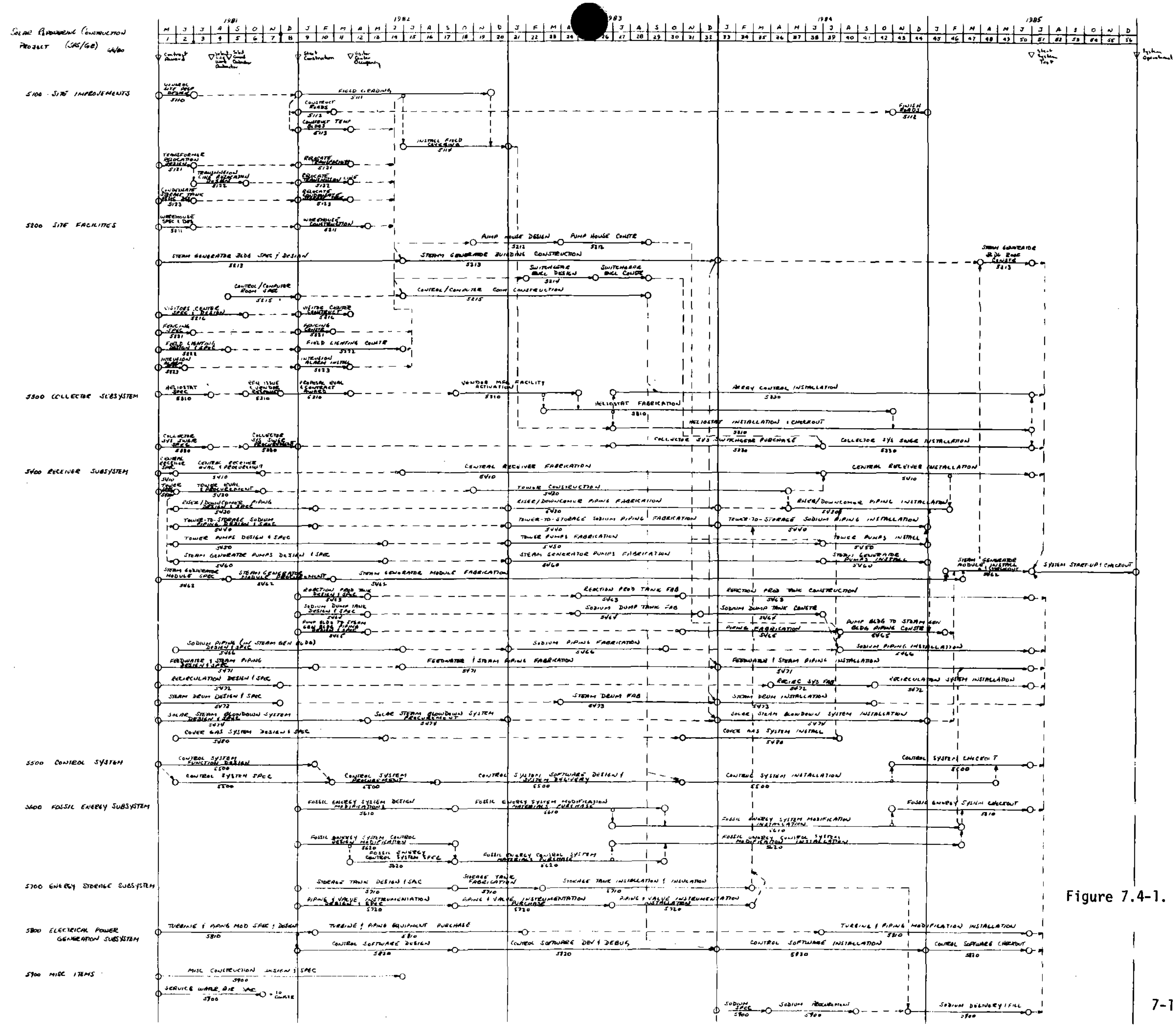


Figure 7.4-1. Detailed Schedule and Logic Network

7.5 ENGINEERING SUPPORT ACTIVITIES

The extensive industrial experience with design and fabrication of sodium hardware makes additional R&D activity unnecessary. Limited engineering support effort will be required in support of SPS Solar Repowering Plant construction. These efforts are confirmatory experiments in support of Incoloy 800 use at 593^{o}C (1100^{o}F), manufacturing development for the absorber panels, data accumulation for code qualification, and engineering development for improved reliability. The identified engineering support is summarized in Table 7.5-1.

Table 7.5-1
ENGINEERING SUPPORT ACTIVITIES

Component	Activity
Absorber Panel	• Braze Joint Fatigue Data Experiments • Braze Joint Mechanical Strength Data Experiments
Steam Generator Superheaters & Reheater	• Incoloy 800 tube spacer plate fretting & wear experiments • Incoloy 800 corrosion and corrosion fatigue data experiments • Incoloy 800 Fatigue Crack growth experiments. • Carbon Transport Experiments for Incoloy 800

7.6 HELICAL STEAM GENERATOR OPTION

To expand the number of technical options available for the plant, a contract was placed with Babcock and Wilcox Company for evaluation of the B&W helical steam generator being developed under DOW sponsorship. The B&W Report is included in Appendix K. Points to note are that the helical steam generator takes longer to procure at a somewhat higher cost than the hockey stick concept. The report provides a good check on costs and schedule for large complex heat exchange equipment. Helical steam generators provide an alternate approach that could be exercised, depending upon the actual time period for any future construction project.

7.7 ROLES OF SITE OWNER, GOVERNMENT AND INDUSTRY

The development plan proposes a single-source responsibility project. Its objective is to successfully demonstrate the capability of a solar electric generating plant to make electric power. Such a demonstration could help to determine whether or not solar technology can satisfy the performance criteria of the electric utility industry. An acceptable performance would encourage commercialization of repowering as an energy alternative. The demonstration will also expose sensitive areas where additional research and engineering could improve performance and economics, thereby enhancing acceptance and commercialization.

The collective efforts of Southwestern, the Federal Government, and participating industries should result in a team effort which permits each entity to operate within its normal realm of expertise. It is mandatory that a coordinated effort be made to keep each of the team members fully informed of activities conducted to meet project objectives and accomplish tasks initially agreed to. Each team member, functioning within its specified role, can best remove uncertainties which restrain widespread use of solar electric generating plants.

Southwestern would be expected to maintain support of local officials for the project. The utility's management and engineering staff would be responsible for the completion of the solar repowered demonstration facility. The Federal Government and its agents would be expected to provide the necessary support of its agencies and supply information to justify tax payer funding of the project. Industry would be asked to support the project with well-designed equipment manufactured in an efficient manner at a reasonable cost. Industry's support for the project could result in new free enterprise opportunities for commercialization of solar technology.

The proposed development plan would allow Southwestern to continue in its traditionally progressive role of equipment user and utility plant operator. As indicated previously, Southwestern selects, designs, constructs, and operates power generating equipment; therefore, the role of Southwestern Public Service Company is to contract with the Federal Government to manage a project in which Southwestern would select, design, construct, and operate a solar repowered plant that had been specified to accomplish a certain task. Southwestern would continue to operate the plant after the demonstration period, maintain long-term performance records and collect standard operation and maintenance data.

The role of the Federal Government in this proposed development plan would be to define the objectives needed to accomplish the demonstration and commercialization of solar power within the framework of the government's other activities. The definition of the objective would include specifying tasks or direction but not detailed methodology; this should be accomplished by those who usually perform this type of activity.

The overall benefit of demonstrating solar power generation is national in scope. The commercial use of solar could assist in energy independence. Therefore, the initial financial support of the solar repowering demonstration should be by the taxpayer. The Federal Government would use the tasks' definition of the objectives and specifications set out in the development plan to select a contractor who could carry out the objectives of the program. The acceptance of a contractor would lead to construction of a demonstration facility to be operable within a certain time frame. During the design and construction of the facility, the Federal Government and its agents would review and report the progress of the project toward meeting its objectives. After construction and start-up, the Federal Government and its agents would test and collect data, and report on the performance of the demonstration project. This would lead to decisions on additional development for commercialization of the solar repowering concept.

Industry's role in the demonstration program is to provide efficient manufacturing of components and equipment at a reasonable cost. This project could most benefit from industry's ability to reduce production cost and time of solar equipment. Industry would act as a supplier providing services in the area of solar equipment selection and supply.

In summary, the authority to select the contractor rests with the government. The authority to manage and complete the project should be with the contractor. The contractor's authority will be used to select and work with industry to complete a successful demonstration project.

SECTION 8
USER'S ASSESSMENT

Section 8

USER'S ASSESSMENT

8.1 GENERAL

8.1.1 ENDORSEMENT

The Department of Energy's concern about the utility user's perspective being reflected in the conceptual design was evident in the request for proposal. At the onset of the study, Southwestern Public Service Company was also concerned about the report reflecting the utility's viewpoint. Southwestern agreed to participate in the study only if allowed to review all work conducted in connection with this conceptual design study and to comment on the applicability and adequacy of the design selected. This final report does reflect Southwestern's utility perspective; however, several items beyond the scope of the conceptual design will require detailed study. These items are specified in this assessment.

Southwestern is perhaps in a better position than most utilities to review and critique the proposed design. The Company is among the few electric utilities in the nation that design and supervise construction of their own generating facilities; in effect, Southwestern is its own Architect and Engineer Consultant. Southwestern, therefore, has assumed a much more active part in the actual design than most utilities would. General Electric exhibited a cooperative attitude in seeing that Southwestern's design preferences were expressed, even to the extent of redoing some of the work that had been completed, which Southwestern felt should have been done differently.

The conceptual design is an excellent launching point for additional design activities. Some items have been left as they were proposed by GE and Kaiser, even though Southwestern would have designed them differently. The final impact of changing these design items on total project cost and performance was not significant. However, in future design phases, these areas will be examined in greater detail and engineering trade-off studies which were beyond the scope of the conceptual design phase will be performed. Some of the possible study areas are described below.

(1) Steam Generator Building Location: The location of the steam generator building proposed in the conceptual design causes access problems to the existing

units #2 and #3 boiler buildings. Other locations are available requiring only slightly longer steam piping routings.

(2) Double wall storage vessels: Additional study will be needed to determine whether single wall storage vessels enclosed in a building may be advantageous over the double-wall storage vessels developed in the conceptual design. The costs appear to be equal.

(3) Building construction: Metal covered, structural steel buildings were proposed in the conceptual design. Southwestern is currently using "T-Beam" construction at an equivalent cost. In "T-Beam" construction, the building's walls and roof are formed by prestressed concrete beams, which have a double "T" cross section. The Company would investigate using this type of construction as a potential alternative for the solar plant.

(4) Controls: The exact final controls configuration will be determined as final process details become known and as Southwestern's development of direct digital control (DDC) technology matures on existing projects.

(5) Water Quality Control: The conceptual design is adequate. However, additional suitable process schemes have been proposed. The detailed design will depend on trade-off studies conducted in the next phase.

(6) Metallurgical Compatability: A more detailed investigation is required to determine possible compatibility problems between the existing unit's feedwater heater and condenser tubes and the water treating process.

(7) Cooling Tower Overspray: The effect of cooling tower overspray on the heliostat's mirrored surfaces requires detailed investigation. A testing program is required to measure the reflectivity degradation of test mirror panels caused by overspray from the adjacent cooling towers. The final collector field location and layout will be based on these test results.

(8) Steam Generators: The hockey stick steam generators were chosen for the conceptual design. Investigation into other alternatives such as helical tube designs should be investigated prior to selection of the final design. Additionally, the advantages of using a higher recirculation ratio on the waterside of the sodium-fired steam generators should be investigated.

8.1.2 COST ESTIMATE

Southwestern has reviewed the cost estimate in detail. It is Southwestern's opinion that the cost estimates are in line for this type of study.

A significant portion of the existing plant modification costs and all the indirect project costs were supplied by Southwestern. The design and engineering, home office, and construction management costs were taken from actual Southwestern construction experience and were substantially increased due to the engineering uncertainty inherent in this type project. The contingency figure was arrived at by the same method.

Southwestern supplied actual union craft rates effective at Company construction sites. Southwestern reviewed the productivity figures supplied by Kaiser Engineers and takes exception to the 11%-below-Houston productivity figure sited for this area. Southwestern's experience in construction of generation facilities disputes the validity of this productivity figure for its construction. However, the lower productivity figure was left in the cost estimate as the worst case cost.

8.2 ASSESSMENT OF PROJECT WORTH

8.2.1 PERFORMANCE MODELING AND ECONOMICS

Southwestern is able to build its power plants for about half the national average cost for comparable plants. Comparing Southwestern's estimate of $530 per installed kW for 1985 coal-fired units with the predicted repowering cost of $2034/installed kW, it becomes mandatory that fuel savings estimates be as realistic and accurate as possible for proper user assessment.

By utilizing several existing computer codes, Southwestern has confirmed that the fuel savings calculated by GE's performance modeling program can be achieved under the given assumptions. However, there is a degree of uncertainty that affects operation and maintenance cost projections, due to lack of data for a comparable project.

Southwestern maintains that no capacity credit can be assigned to the solar repowering of Plant X Unit 3. Therefore, the total value excludes the cost benefit given for capacity credit (refer to section 8.9).

The performance model which is used for the fuel displacement and cost analysis reflects Southwestern's system under current construction plans and load growth projections with two possible exceptions. First, no contractual problems with natural gas have been factored into the model. The contracts that Southwestern has with its gas suppliers specify one or more take-or-pay constraints (refer to section 8.8). In order to utilize fuel in the most economical manner, each of these contract provisions must be met, thus requiring modifications to the typical economic dispatch which adjusts fuel use to provide for the lowest instantaneous cost of generating power. The effect of this consideration, however, can be minimized since some of the current contracts with natural gas suppliers will expire before the start-up of the solar repowering. Second, no consideration was given to limited use of natural gas as dictated by the Fuel Use Act (refer to section

8.8). Neglect of this problem can be justified, however, if one assumes that synfuel will be available as a replacement fuel for the gas-fired units.

Attempts to forecast the economic benefits of a first-time project in today's economy is no simple task. However, given the assumptions on fuel escalation, load growth, construction, and expansion plans along with the economic parameters utilized, Southwestern agrees that the performance modeling and economic analysis of this study is accurate and attainable. Further sensitivity analysis on the economics of the project is recommended. Varying the following parameters would perhaps be beneficial for further economic analysis.

(1) Expected plant life: what effect would an expected life of less than 30 years have on plant value?

(2) Operation and maintenance cost: how much does a higher/lower O & M cost for the solar repowered unit affect the economics of the project?

(3) Unavailability of synfuel: how would the analysis change if the assumption is made that gas-fired units would be abandoned if no synfuel were available?

(4) Fuel escalation: although it is agreed that 10% fuel escalation (2% over 8% general inflation) is not an unreasonable assumption for the near future, some doubt is expressed that this rate will be applicable for the assumed 30 year life of the project. What effect would disappearance of the fuel escalation factor after 3 or 4 years have on the value of the project?

(5) Storage: what is the value of additional storage?

8.2.2 DEMONSTRATION OF TECHNOLOGY

The real worth of the first repowering is not fuel savings, but demonstration of solar technology. This project is valuable because of its size. The repowering design is of adequate size to allow existing technology to be applied to a realistic power plant scale and be charged with the responsibility of producing reliable electric output. The cost of construction of the first plant will be excessive. However, the utility industry will view this cost with considerable interest, since it will be an indicator of the cost of the first usable-size solar plant and the difficulties involved with construction, start-up and operation.

Every effort should be made to manage the design and construction of a solar facility just like any other power plant built by Southwestern. In order to be a realistic accurate demonstration of solar-thermal repowering implemented by a utility, the project must be insulated from excessive design changes, disruptions in funding, and lengthy approval procedures which cause cost overruns and schedule delays.

From an operational standpoint, the project will be of considerable value to the utility industry. Actual performance can be monitored, and actual generation and capacity factors can be measured rather than estimated. The industry will also be interested in demonstrated relability. Furthermore, this demonstration plant will be no problem to integrate into the Company's electric system. Current dispatch philosophy will optimize the fuel savings brought about by a solar facility.

The demonstation plant will stimulate the growth of solar component businesses. An order of 5,000 heliostats will present opportunities for manufacturers to improve fabrication techniques and lower costs. Of more importance to the utility industry is the full-scale demonstration of solar technology. Completion of the project on time and budget with a successful operation verification period will have a very positive benefit for solar repowering. If the project is not conducted in a manner acceptable to the utility business, the worth of the demonstration is severly reduced. The nation and the utility industry cannot profit from another solar project that suffers from excessive cost overruns and construction delays caused by ineffectual procurement procedures and long,complicated lines of approval.

8.3 POTENTIAL REPOWERING STUDY

Numerous studies concerning repowering potential within the electric utility industry have been conducted. These studies indicate a high value of solar repowering to the utilities; however, to be accepted by the utility industry repowering must be judged economically viable.

Southwestern conducted a preliminary repowering survey of its own system to identify and rank additional repowering sites. Although limited in scope because of time and budget constraints, this survey identified existing generating facilities on Southwestern's system which have potential for being repowered. The potential of each site was assessed by the following criteria:

1. Unit fuel and cycle characteristics
2. Unit age
3. Available land
4. Operation and maintenance considerations
5. Social and political climate

Based on the above constraints a significant potential for repowering exists within Southwestern's system. Eight of the 32 gas-fired units now in operation on the electrical grid offer a repowering potential of approximately 1,000 MW. Those units qualifying are shown in Table 8.3-1.

Table 8.3-1
SUMMARY OF SURVEY RESULTS SPS SOLAR REPOWERING SITES

Plant	Years Before Retirement	Land Acres Available	Solar Capacity (MWe)
Nichols		1039	249
1	20	260	65
2	22	296	74
3	28	483	110
Jones		1492	300
1	31	746	150
2	34	746	150
Cunningham		1400	200
2	25	1400	200
Plant X		1612	260
3	15	212	60
4	24	1400	200
Total			1009

* Underlined numbers represent plant totals.

Jones Station would be the next candidate power plant to be repowered, following successful operation of Plant X, Unit #3. This potential for repowering 300 MW of the 488 MW of gas-fired capacity at Jones Station would exist in 1990-92. However, to be seriously considered, repowering must become economically viable, and relief from provisions of the Fuel Use Act must be granted.

Of the other three units at Plant X, only Unit #4 has significant potential for repowering. The first two units are nonreheat and have a limited service life. Unit #4 is a 200 MW, 12.4 MPa/538°C/538°C (1800 psi/1000°F/1000°F) reheat unit put into service in 1964.

Adequate and suitable land exists east of the plant to repower 100% of Unit #4's capacity.

8.4 OPERATIONAL IMPACT

The addition of a repowered unit on Southwestern's electric grid presents no unique system operating problem. In fact, the economic dispatch algorithm already implemented will maximize the displacement of natural gas generation whenever adequate solar energy is available. In other words, whenever solar is available, it should be used to displace fossil fuel. Although Southwestern agrees that the solar portion of the plant may possess a small amount of capacity credit, the Company will be very conservative toward granting the "solar-alone" mode any capacity credit.

Additional personnel will be required to operate and maintain the solar installation. Special training, tools and equipment must be provided. The system overhaul and maintenance schedule must be developed with this consideration in mind.

To reap the maximum fuel savings of the solar plant it must operate during the periods of peak sunshine. Therefore, any brief maintenance outages should be scheduled at night. Scheduling of the annual overhaul, which requires several weeks of outage, will be dictated by the maintenance activities throughout the entire system. After gaining operating experience, the solar plant's maintenance can be scheduled to optimize the economic operation of the entire electric system.

8.5 SAFETY ASPECTS

The solar repowering presents two classes of possible hazards: (1) those resulting from the exposure of concentrated sunlight, and (2) those inherent in handling soldium.

Evidence indicates that the energy from one heliostat can be hazardous to unprotected personnel; however, safety techniques developed at the Central Receiver Test Facility (CRTF) seem adequate for preventing insolation-related personnel accidents. Safety procedures will be instituted at the repowering plant, such as prohibiting access to certain areas while the heliostat field is in operation. The collector field will be surrounded by a radar-type intrusion detecting system. This system will be installed at the beginning of construction to minimize vandalism and pilfering of construction materials, and will be maintained after start-up to alarm any intrusion into the collector field.

Further safety research is warranted if the project is awarded. Expertise developed at Sandia will be utilized along with Southwestern's safety practices to develop adequate safety procedures.

Another area of concern is the exposure of low-flying aircraft to glare of the concentrated sunlight. The site is remote from all major airports, but is located in a predominantly agricultural area where there is considerable aerial spraying activity. The closest airport is Muleshoe, Texas. The 500-foot tower will probably present more hazard to local air traffic than any effect from concentrated sunlight. The tower will be marked with high intensity aircraft warning devices. The CRTF practice of keeping all mirrors pointed at a known spot is acceptable and a good approach. Southwestern would implement a similar safety procedure of keeping all mirrors pointed at known locations, such as standby points just off the receiver. Additional study of this problem will be done in the next design phase.

The hazards involved in handling sodium can be divided into three phases: transportation to the site, construction and start-up, and normal operation.

Transportation: No outstanding hazards associated in shipment of the sodium to the site have been identified. Adequate methods and equipment for handling large quantities of sodium are currently practiced by the chemical transportation industry. The required sodium inventory (700,000 lbs) will be shipped in solid form in no more than 15 truck loads.

Construction and Start-up: Certainly the time of greatest exposure to sodium-related accident is during construction and start-up. All piping joints and connections will require hydrostatic testing. Personnel in protective suits will monitor the sodium system during initial fill. A requirement for the initial sodium fill of any portion of the system will be the installation of smoke and fire detectors, and the availability of suitable fire fighting equipment. This equipment will be a permanent addition to the plant in all sodium areas.

Normal Operation: The hazards of sodium leaks and fires during normal operation will be reduced by installing adequate smoke and fire detecting systems and proper fire fighting equipment, by implementing operator training, by using berms and revetments to contain the molten sodium, and by using an argon cover gas. The storage vessels will be double-walled and be sized to hold the entire capacity of the sodium system. The procedure to be followed in the event of a sodium leak and any resulting fire will be to drain the entire system to storage and let the fire extinguish itself with minimal interference by plant personnel.

This procedure has been developed from over 30 years of experience at GE's liquid metal facility, and appears to be a rational and acceptable approach.

The conceptual design includes provision for a cover gas system, double-walled storage vessels, fire detection system, and reaction product tank to handle a sodium accident.

The collection and documentation of sodium handling information will continue as the project progresses.

8.6 ENVIRONMENTAL ASPECTS

The solar repowering design can be implemented at the Plant X site with minimal detrimental effect upon the environment. The largest negative impact will be the disruption of some 212 acres of semi-arid prairie. This land use would not be unique to the area, in light of the existence of local cattle feedlots occupying similar tracts. The conceptual design provides for surface covering and proper drainage. These two practices minimize the impact on the terrestrial resource.

Another potential adverse effect would be a large sodium spill and fire. The proper use of berms, double-walled storage vessels, and sodium sumps should limit any potential adverse impact to the environment.

The installation of this solar thermal generating facility will not result in any air or water quality degradation. Also, the impact of visual obstruction on the environment is minimal.

Economic impact on the surrounding area will be beneficial in that both construction and service related commerce will create more jobs.

Performance estimates conducted by this study indicate that one billion cubic feet of natural gas/year will be displaced by the solar plant. This natural gas will be available for other beneficial uses. That amount of gas could supply the annual fuel requirement of 800 30-HP irrigation wells or meet the annual heating requirement for 8000 average gas-fueled homes.

The social acceptance of the repowering project by the local citizens poses no problem. The attitude exhibited at meetings conducted to brief the local people about the project has been very positive and enthusiastic. Included in Appendix L are letters from the surrounding communities indicating their support for this project.

8.7 DEVELOPMENT PLAN

The development plan that appears in the final report has been organized to achieve a realistic time schedule, to minimize cost, and to promote the quality of the finished plant. By adhering to this development plan, the project will be an excellent demonstration of the current cost to build a solar plant, the time required for construction, and operation under the constraints of reliability and maintainability established and accepted by an electric utility industry.

Southwestern Public Service will act as the prime contractor and construction manager in the same manner as it does in constructing its coal-fired generating facilities. These facilities exhibit a high standard of engineering and an enviable reliability record and are built at less than half the national average cost per installed kW.

The Generation Design and Construction Department of Southwestern Public Service Company has designed and supervised construction of all major generating facilities for the Company for more than 35 years. The close relationship between Operating Department as the customer and Generation Design and Construction Department as the Architect and Engineering Consultant has contributed to very operable and maintainable power plants.

Southwestern will also employ the expertise of GE and others in the design of solar power plant subsystems. Throughout the nine-month conceptual design study, Southwestern has developed a functional relationship with GE and expects to maintain this relationship throughout the project.

Southwestern has developed the reputation and credentials of being a well engineered and operated utility. As ultimate owner and operator of this facility, Southwestern would be expected to maintain its responsibilities, obligations and liabilities for the safety and success of the operation. This responsibility includes supplying a reliable source of power to the customers on its grid. The Company must have the commensurate authority to administer those responsibilities. Southwestern, therefore, requires final approval over all design, equipment, and materials to be used in the project.

The long fabrication and delivery time for steam generators causes the components of that subsystem to be on the critical path. The development plan outlines the simultaneous production research, design and construction program which will allow completion within DOE's proposed 1985 time frame.

Southwestern urges a free market solicitation of heliostats which would allow selection of heliostats best suited to the Plant X environment at an attractive price. The selection of the heliostats should be postponed until the latest date permitted by the schedule to allow full benefit from ongoing heliostat development programs.

The acceptance of total project responsibility by Southwestern will be advantageous to both DOE and the utility. The Company would like to be commissioned by DOE to design, construct, start-up and operate the solar repowered unit, thereby avoiding unnecessary approvals, delays, and changes in design and equipment selection.

Management of the actual construction will be by employees of Southwestern Public Service in consultation with GE and others resident at the site. It is essential that resident field personnel be given the authority to make on-the-spot decisions.

The plant will be checked out and started up under the supervision of Southwestern personnel, with representatives from GE, DOE and others as required, and will be conducted in consideration of system constraints.

A one-year system verification period will follow the start-up. The plant will be operated in the most economical fashion as dictated by system operating constraints. Representatives from DOE, with assistance from Southwestern personnel, will collect data and monitor all plant operations necessary to verify component performance.

A period of four years following the system verification phase will be the joint user/DOE operational phase, where the plant will be operated in the most economical and efficient manner; that is, displacing the largest quantity of natural gas possible.

The development plan is contiguous and not phased. There would be no preliminary design phase, detail design phase, construction phase, start-up phase or checkout phase as such. This is the only possible way the very optimistic proposed 1985 completion date can be met.

8.8 ENERGY PROBLEMS FACING THE SITE OWNER

Southwestern Public Service, like all utility companies, is faced with rising fuel costs compounded by Government regulation. To comply with the Fuel Use Act, the Company must reduce its national gas consumption by 1990 to 20% of that used in 1976. This presents a dilemma concerning repowering. The principal advantage of repowering is not only displacement of fossil fuel when solar energy is available, but also having a firm capacity for meeting peak demand. Compliance with the Fuel Use Act provisions might rule out the possibility for having the gas-fired capacity available to backup extensive solar repowering installations.

Because of take-or-pay contracts, Southwestern is forced at times to burn natural gas when it could otherwise meet its generating demands by burning coal. According to the terms of such take-or-pay contracts, the Company is forced to pay for an amount of gas whether it is burned or not. This places the Company in the position of not always burning the least expensive fuel, but always operating in the most economical fashion.

Curtailments of natural gas supplies by the supplier and the ever increasing cost of gas have forced Southwestern to convert to coal as its primary fuel source for new generation. Coal is a dependable energy resource that can be obtained less expensively than natural gas. Coal technology is proven and the reserves are abundant and available. However, coal plants cost three times as much to construct as natural gas plants. Freight rates, severance taxes and environmental regulation also add to the cost of coal.

Inflation, the high cost of borrowing money, and the conversion to coal have required Southwestern to apply for rate increases more often than the Company or the public would like. The four State Public Utility Commissions that Southwestern operates under do not always hold the same perspective on energy problems as DOE and other proponents of solar energy.

Government regulations, which are in a continual state of transition, affect utility operation. At the same time that one department of the Government is encouraging utilities to save energy and lower costs, another department is passing environmental regulations which force the Company to install costly control systems. These systems, which will be built in the future, will raise dramatically the cost of generation capacity.

8.9 ROLE OF REPOWERING/RETROFIT IN CORPORATE PLANNING

Southwestern cannot at this point consider repowering an economically viable option. With costs approaching $2,100/installed kW, solar repowering cannot presently compete favorably with new coal-fired plants. While certain components of repowering are proven, and adequate operating experience exists, the successful operation of a repowered facility must be demonstrated and repowering technology must undergo considerable development before that technology can be considered in corporate planning. Southwestern is not willing to allow any additional capacity credit to a repowered unit for the solar part of the installation. There is no guarantee that the solar portion would be available when that capacity is needed. Southwestern feels the primary value of repowering is in fuel savings.

With the Company's ambitious coal plant construction program dictated by its annual rate of growth, and by compliance with the Fuel Use Act, Southwestern would find it difficult to raise the necessary revenues to build solar plants at their current cost for fuel savings alone.

At this point it is not clear if the Public Utility Commission would approve spending by a utility of large amounts of the rate-payer's money to build a plant of unproven design and performance.

8.10 ALTERNATIVES TO REPOWERING

Southwestern has an active alternate energy research program. It has been selected as a candidate site for large wind turbine generator installation and wind data have been collected during the past three years. The data indicate that the mean wind velocity is 13.5 mph on an annual basis.

The Company is involved in a three-year study with Texas A&M University to investigate the use of cotton gin trash as a boiler fuel. Enough cotton gin trash is produced in the Tolk Station area alone to provide an energy equivalent to nine billion cubic feet of gas/year.

Southwestern has also participated with the Texas A&M Agricultural Extension Service in characterizing feedlot waste for use as a boiler fuel. The 4.8 million head of cattle fed in Southwestern's service area produce an estimated 2.5 million tons of feedlot waste per year. That waste has an energy equivalent of 27 billion cubic feet of natural gas per year. The Company has studied utilization of municipal waste for the same purposes; however, adequate resources are not available.

Despite the promise of potential energy alternatives available to Southwestern, the principal and most reliable alternative to repowering is the continued use of the existing gas-fired plants and the construction of additional coal-fired generation facilities. Coal is a known technology with plentiful reserves that can be obtained at an attractive price.

8.11 ACCEPTABILITY OF CENTRAL RECEIVER TECHNOLOGY

When evaluated in the light of other energy alternatives and other forms of solar technology, the central receiver design is most promising. Most of its components are available in prototype form, but currently are too high in price. Southwestern feels the central receiver is particularly acceptable and adaptable to repowering situations. The following comments pertain to the various components of the central receiver concept.

Heliostats: As previously mentioned, the Sandia specification for second-generation heliostats is not totally applicable to Southwestern's area. These heliostats will need to be tailored to the requirements of each individual plant site. There is no definite evidence (and by "evidence" it is meant actual experience) that the mirrors will last 30 years. For the central receiver technology to become widely accepted, the cost of the heliostats must be drastically reduced. Mass production scenarios promise such reductions; however, utilities are concerned with the next plant to be built and not the "nth" plant.

Sufficient potential for cost reduction exists in other heliostat concepts. This warrants considerable continued R&D effort.

Receiver: The solar central receiver is essential to the success of the project. A scaled demonstration needs to be tested before any attempt is made to build the full-size component. The GE test receiver is of sufficient size that scale-up is reasonable. More demonstration is needed in the area of cycling life at rated pressure, as is additional research concerning temperature transients caused by cloud passages.

Liquid Sodium: It is Southwestern's opinion that liquid sodium is very acceptable to a repowering application. It lends itself very well to almost any geometry dictated by an existing fossil-fuel plant; i.e., the collector field may be located fairly remotely from the fossil generator.

When repowering reheat units, liquid sodium technology offers many advantages over water-steam technology. For instance, the use of liquid sodium requires fewer piping runs between the central receiver and the fossil plant. Furthermore, smaller diameter pipes with a thinner wall thickness than would be necessary for a water-steam system can be used in piping runs. Storage systems for liquid sodium are also less complex than the energy storage systems usually designed for water-steam units. Finally, control of superheat and reheat steam temperatures is more direct than in a water-steam installation.

Although molten salt has many of the advantages of sodium and costs less, more operating experience exists with liquid sodium at temperatures above 538°C (1000°F). Furthermore, liquid sodium allows the use of electro-magnetic (EM) pumps that have very favorable maintenance requirements. Sodium equipment has been developed and is in use in the nuclear industry. However, the same excessively stringent quality control requirements applicable to nuclear equipment are not necessarily needed for sodium equipment for solar power plant components, and should not burden their cost.

Steam Generator: The steam generators employ exotic alloys not usually found in power plants. Additional consideration will be required in selection of fabrication and handling techniques and field installation due to these alloys. Potential metallurgical compatability problems will require detailed investigation.

The possibility of using a higher recirculation ratio on the water side of the sodium-fired steam generator has been mentioned. Further effort to assess this was beyond the scope of the conceptual design. By raising this ratio the potential for problems with departure of nucleate boiling and water treating compatibility could be reduced.

Storage: The benefits of storage are well documented and acknowledged; however, for the demonstration plant Southwestern believes that the amount of storage should be kept to a minimum. This will reduce the overall cost of the first plant, but will still allow a demonstration of all storage components. The Company has maintained throughout the entire project that, in repowering, the main source of storage when solar energy is not available is the natural gas pipeline.

Control System: The integration of the solar plant into the existing fossil plant presents some challenging opportunities in the design of a control system. While the conceptual design has proposed a feasible system of control, more development work in this area is needed. The necessary control equipment exists and is available. This same type of equipment (digital computer based) has been applied to the boiler controls of Harrington Station #3. Any control system must be operator-acceptable. The operator, while controlling a fairly complex and unusual system, must be presented with a control display which is similar to the existing fossil-fueled control systems to which he is accustomed.