DOE/SF/11439-1(Vol.2)
(DE82001921)

BLACK & VEATCH SOLAR CENTRAL RECEIVER COGENERATION FACILITY CONCEPTUAL DESIGN

Final Report

August 7, 1981

Work Performed Under Contract No. AC03-81SF11439

Black & Veatch, Consulting Engineers
Kansas City, Missouri

U.S. Department of Energy

Solar Energy

Available from the National Technical Information Service, U. S. Department of Commerce, Springfield, Virginia 22161.

Price: Printed Copy A14
Microfiche A01

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DOE/SF/11439-1(Vol.2)
(DE82001921)
Distribution Category UC-62c

SOLAR COGENERATION FACILITY
CIMARRON RIVER STATION
CENTRAL TELEPHONE & UTILITIES - WESTERN POWER

FINAL REPORT

Prepared for

DEPARTMENT OF ENERGY
CONTRACT NO. DE-AC03-81SF 11439

by
BLACK & VEATCH, Consulting Engineers
CENTRAL TELEPHONE & UTILITIES - WESTERN POWER
BABCOCK & WILCOX COMPANY
FOXBORO COMPANY

August 7, 1981

PREFACE

This report describes the conceptual design and evaluation of a solar facility addition to a cogeneration plant as part of the Department of Energy (DOE) Solar Cogeneration Program. The DOE San Francisco Operations Office issued Contract Number DE-AC03-81SF 11439 to Black & Veatch (B&V) for this effort, which was performed during the period November 10, 1980 to August 7, 1981. Significant contributions to the project were made by B&V's subcontractors: Central Telephone & Utilities-Western Power, the utility and site owner; the Babcock & Wilcox Company, designer of the solar receiver; and the Foxboro Company, designer of the solar master control system. B&V expresses appreciation for the guidance provided by Mr. Robert W. Hughey, Director of Solar Energy Division and Mr. Keith Rose, Program Manager for the DOE San Francisco Operations Office, and Dr. Al Baker, Technical Advisor for Sandia National Laboratories, Livermore, California.

The report is contained in three volumes: Executive Summary, Final Report and Appendices. The Executive Summary provides a brief overview of the conceptual design, a synopsis of the performance and economic evaluation, and an assessment of the concept from the site owner's perspective. The Final Report contains a more comprehensive description of the work performed on the project; this volume presents the trade studies, conceptual design, system performance, economic analysis, and development plan, as well as a description of the site test program. The Appendices consist of the System Specification and detailed cost estimate data.

ABSTRACT

As part of their Solar Central Receiver Program, the Department of Energy (DOE) contracted with Black & Veatch (B&V) to develop and evaluate a site-specific conceptual design of a solar central receiver system integrated with an existing cogeneration facility. The cogeneration facility studied is the Central Telephone & Utilities--Western Power (CTU-WP) Cimarron River Station (CRS) located near Liberal, Kansas. The CRS generates electricity for the CTU-WP system and delivers a portion of that electricity and process steam to the National Helium Corporation natural gas processing plant, located adjacent to CRS.

Early in the project, tradeoff studies were performed to establish key system characteristics. As a result of these studies, the use of energy storage was eliminated, the size of the solar facility was established at 37.13 MW_t, and other site-specific features were selected.

The conceptual design addressed critical components and system interfaces. The result is a hybrid solar/fossil central receiver facility which utilizes a collector system of DOE second generation heliostats with a receiver system consisting of an external, water/steam, screen tube receiver located atop a steel support tower. Other solar systems include the receiver piping system, the solar master control system, and the solar auxiliary electric system.

The value of the solar facility to CTU-WP was assessed based on performance, estimated cost, and revenue requirements over its operating life. The solar facility is expected to deliver 15 MWe net electrical output and 3.7 MW_t process steam at the design point and 66 GWh_t during its first year of operation; this translates to an annual fossil fuel displacement of 48,100 barrels of oil equivalent. The cost of the solar facility in July 1, 1980 dollars includes $33.2 million for construction and owner's cost and $136,000 annually for operating and maintenance cost. In the economic analysis, the value of the solar facility to CTU-WP was computed to be 30 per cent. This value increases to 38 per cent for a 50 per cent increase in assumed fossil fuel prices and to 31.7 per cent for an operating life of 14 rather than 15 years.

A development plan was prepared which addresses the durations and sequencing of major activities which will lead from this conceptual design study to an operational facility. These major activities include licensing, test program, detailed design, procurement, construction, checkout and startup, and performance validation. The plan is based on the solar facility beginning operation in 1986.

Finally, B&V and CTU-WP conducted a test program at the CRS site. In this test program, valuable data were collected on direct normal insolation and heliostat mirror contamination.

TABLE OF CONTENTS

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

LIST OF TABLES

TABLE OF CONTENTS (Continued)

LIST OF TABLES (Continued)

TABLE OF CONTENTS (Continued)

LIST OF TABLES (Continued)

LIST OF FIGURES

TABLE OF CONTENTS (Continued)

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TABLE OF CONTENTS (Continued)

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Section 1 is the Executive Summary and was published as DOE/SF/11439-1-Vol.1

2.0 INTRODUCTION

This document describes the site-specific conceptual design for the solar cogeneration facility at the Central Telephone & Utilities--Western Power (CTU-WP) Cimarron River Station (CRS). The work performed for the Department of Energy (DOE) is under Contract No. DE-AC03-81SF11439, entitled, "Conceptual Design of a Solar Cogeneration Facility at Liberal, Kansas." The contract amount is $411,175 for the period of November 10, 1980 to August 7, 1981. The prime contractor is Black & Veatch, Consulting Engineers. John E. Harder is the Project Manager; he fulfills the role of principal investigator. CTU-WP, the Babcock & Wilcox Company, and the Foxboro Company are subcontractors. The mailing address of the prime contractor is as follows.

Black & Veatch, Consulting Engineers
P. O. Box 8405
Kansas City, MO 64114

2.1 STUDY OBJECTIVE

The project objective is to develop the best site specific conceptual design that will fulfill the following requirements.

(1) Provide practical and effective use of solar energy for integrating a solar central receiver system with an existing cogeneration power plant.

(2) Have the potential for construction and operation by 1986.

(3) Have the potential to achieve wide commercial application and significant fossil fuel savings.

(4) Make maximum use of existing solar thermal technology.

The goal of the project is to demonstrate the technical viability and identify the economic potential of integrating solar central receiver technology into a commercial cogeneration plant.

2.2 TECHNICAL APPROACH AND SITE SELECTION

Important criteria for the technical approach and site selection were the use of proven and accepted technology and a plant whose physical condition, age, and usage are compatible with cogeneration.

The technical approach selected was a water/steam solar central receiver supplying superheated main steam to the turbine. The use of a water/steam receiver permits generation of steam whose pressure and temperature conditions match those currently used with highly efficient turbines in electricity generation, and permit the application of steam generation technology which is mature, reliable, and well-established with potential users.

The selection of CRS as a host cogeneration facility for solar augmentation was influenced by five main factors. First, it is representative of a medium size cogeneration facility with a typical industrial processing plant operating on a 24-hour basis with relatively constant electrical and thermal power demands. In addition, due to its location and direct mean daily insolation of approximately 6.1 kWh/m^2 (Figure 2.2-1), CRS is representative of a large group of other potential cogeneration facilities. Second, the proposed project organization is consistent with the established role each team member has had in prior engagements; a relationship which has proven successful over the past 20 years and includes the original design of CRS. Third, the technology required for implementation can meet the 1986 operational date specified by DOE. Fourth, the site has land available for the addition of the solar central receiver system. Fifth, the plant has an excellent energy utilization factor (approximately 51 per cent of the thermal energy delivered to the cycle working fluid is productively used).

2.3 SITE LOCATION

CTU-WP's Cimarron River Station is located about 18 kilometers (11 miles) northeast of Liberal, Kansas as shown on Figure 2.3-1. National Helium Corporation's natural gas processing plant borders the Cimarron River Station on the south. Primary access to the site is provided by US Highway 54.

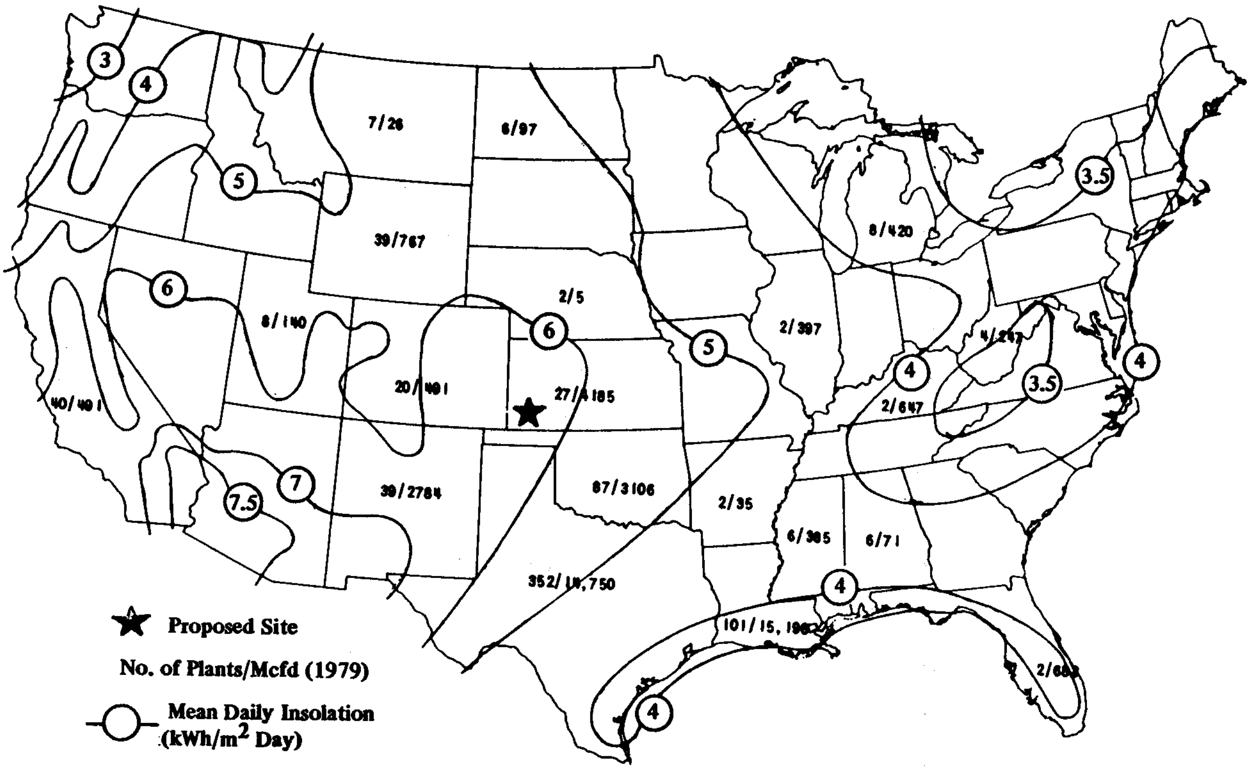

FIGURE 2.2-1. NATURAL GAS PROCESSING PLANTS BY STATE

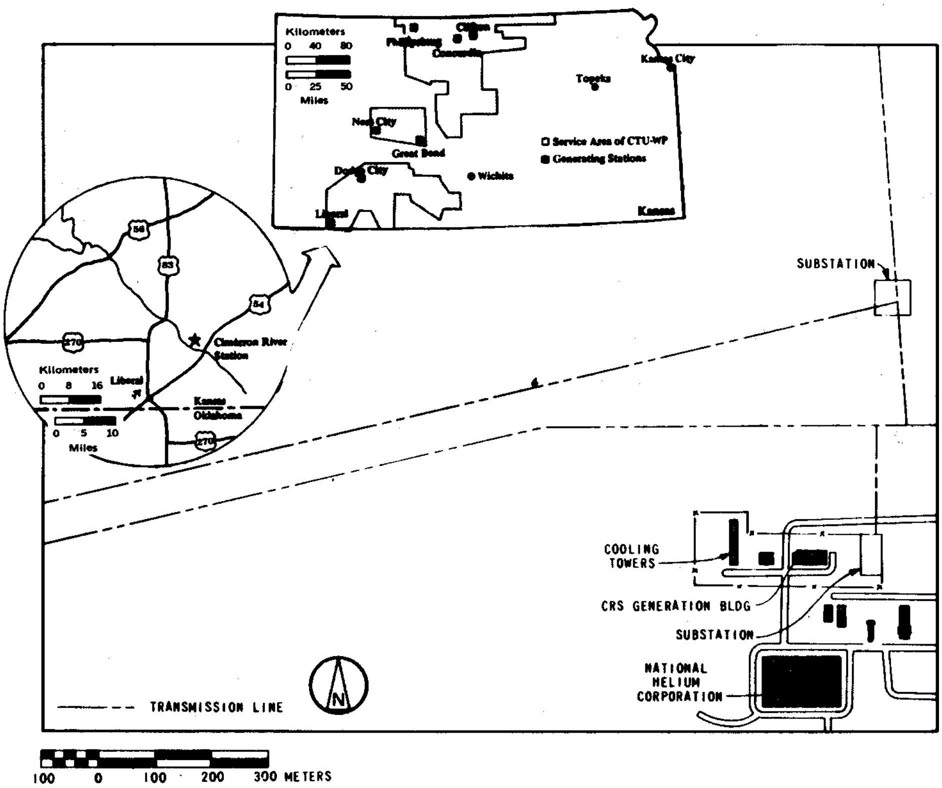

FIGURE 2.3-1. PLANT LOCATION AND SITE ARRANGEMENT--CIMARRON RIVER STATION, NATIONAL HELIUM CORPORATION

2.4 SITE GEOGRAPHY

Two generating units are located on the 162 x $10^3 m^2$ (40 acre) site currently owned by CTU-WP. National Helium Corporation owns additional land to the north, west, and south of the CTU-WP property. Together, the land presently owned by CTU-WP and NHC would provide for all the land required for the proposed heliostat field, receiver tower, and receiver piping system.

The topography of the site, including the possible heliostat field areas, slopes irregularly to the north. Test borings, performed during the original station design, indicate that the site is underlaid by sandy loam of various grades. The site area contains water wells, underground pipelines, and transmission lines. The site is located at 37° 10' north latitude and 100° 45' west longitude. The ground elevation of the station is 801.6 meters (2,630 feet) above sea level.

The Cimarron River Station is situated in a region of minor to moderate seismic risk. The site area is classified by the Uniform Building Code (UBC) as Zone I of seismic risk for the contiguous United States. In this zone, minor damage from earthquake activity may occur. Zone I includes an earthquake with a maximum intensity of VI on the Modified Mercalli Scale occurring within the tectonic region.

2.5 CLIMATE

The climate of southwestern Kansas is classified as semiarid. Although Liberal is nearly 500 kilometers (300 miles) east of the Rocky Mountains, the weather reflects the influence of the mountains. The mountains form a barricade against all except high level moisture from the southwest, west, and northwest. Relatively dry air, predominating with an abundance of sunshine, contribute to broad diurnal temperature ranges.

Based on 71 per cent average annual sunshine measured at Dodge City, Kansas, the area has 260 equivalent clear days each year. The average daily direct nominal insolation for the site is 6.1 kWh/m^2; this was calculated using the ASHRAE clear air model and average annual per cent sunshine for Dodge City.

The average annual precipitation for Liberal accumulates to approximately 48.3 cm (19 in.). Thunderstorms during the growing season contribute most of the moisture. Thunderstorms are occassionally accompanied by hail and strong winds, but due to the local nature of the storms, damage to crops and buildings is spotted and variable. Winter is the dry season; however, severe winter storms with drifting and blowing snow occasionally occur.

The extreme temperatures recorded for Liberal range from 45 C to -28 C (113 F to -19 F). July is the warmest month, with a normal temperature range from a high of 36 C (96 F) to a low of 19 C (67 F). January is the coldest month with a normal temperature range from a high of 9 C (48 F) to a low of -6 C (21 F).

The average annual wind speed is 6.3 m/s (14.0 mph).* March has the highest average wind speed with a value of 7.1 m/s (15.8 mph). August is the least windy month with an average wind speed of 5.7 m/s (12.7 mph). The maximum wind recorded was 34.9 m/s (78 mph) in July 1951. An annual wind rose for Dodge City is provided on Figure 4.1-1 of Appendix A.

2.6 EXISTING PLANT DESCRIPTION

The Cimarron River Station cogeneration facility (Figure 2.6-1) contains three major elements: a natural gas fueled conventional steam power plant (Unit 1), a combustion gas turbine (Unit 2), and a natural gas fueled process steam generator. Unit 1, which became operational in 1963, utilizes a 44 MWe General Electric tandem compound, double flow, non-reheat turbine generator with design steam inlet conditions of 8.72 MPa (1,265 psia) and 510 C (950 F) and overpressure operating conditions of 9.58 MPa (1,390 psia). The turbine generator is normally operated at the overpressure condition for improved cycle efficiency and has a maximum capability

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*Wind speed has not been recorded at Liberal, Kansas. Therefore, data from Dodge City, Kansas, the closest station with wind data, is utilized.

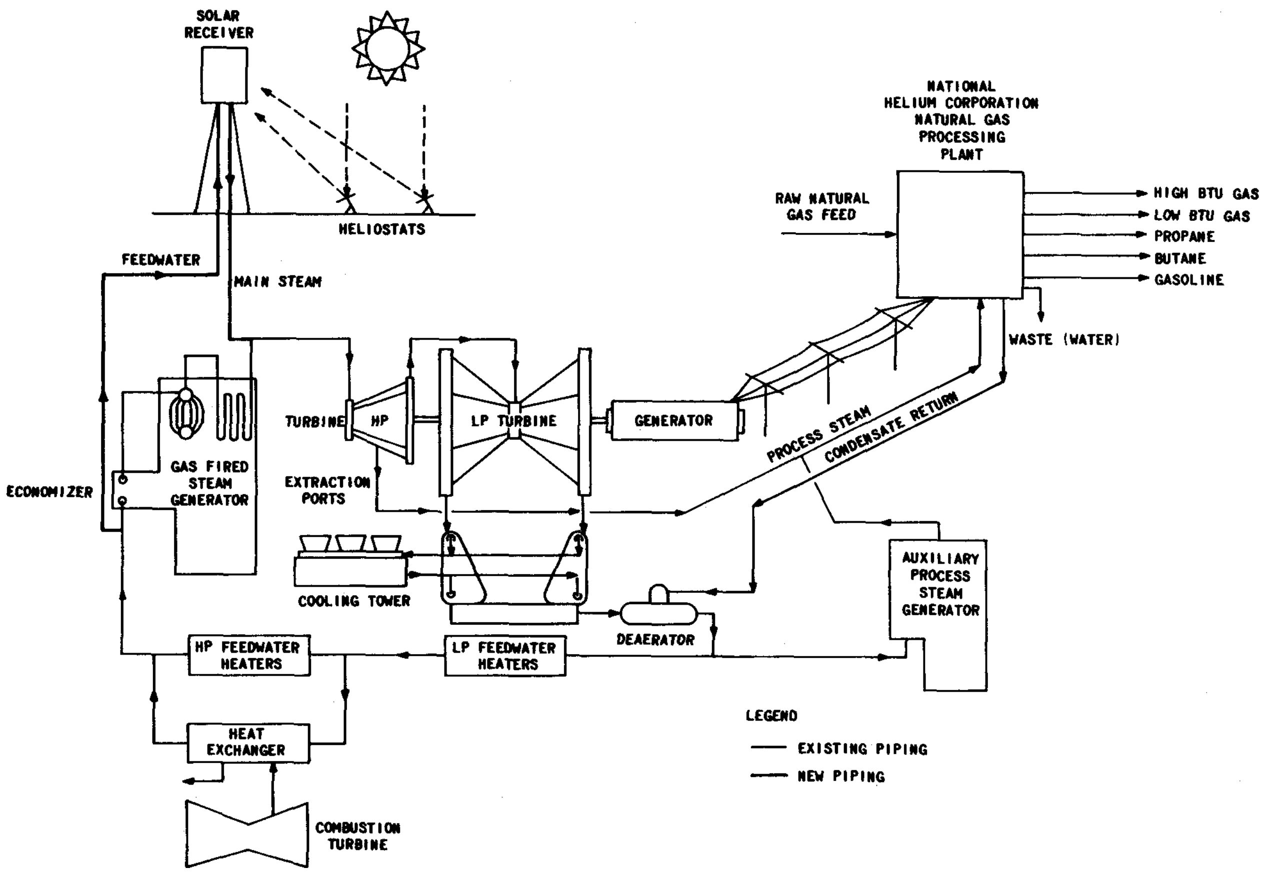


FIGURE 2.6-1. SIMPLIFIED SCHEMATIC OF COGENERATION FACILITY

of 60 MWe. The Unit 1 steam generator was built by Babcock & Wilcox and is a two drum Stirling, natural circulation, pressurized furnace, with a design rating of 192,740 kg/h (425,000 lb/h), 9.06 MPa (1,315 psia), 513 C (955 F) superheated steam. The maximum extended capability is 226,760 kg/h (500,000 lb/h), 9.99 MPa (1,450 psia), 513 C (955 F). The Unit 1 cycle configuration includes five stages of feedwater heating. The steam cycle also employs a horizontal, two pass, surface type condenser and a mechanical draft wet cooling tower. The plant control systems were supplied by the Foxboro Company.

The combustion turbine (Unit 2), which became operational in 1969, is rated at 14 MWe. It is provided with an exhaust heat recovery heat exchanger. When Units 1 and 2 are operating in a combined cycle mode, the

Unit I high pressure feedwater heaters are taken out of service and feedwater heating is provided by the exhaust heat recovery heat exchanger. The combustion turbine is normally only operated during the summer peaking season in a combined cycle mode with Unit I.

The process steam generator, built by Babcock & Wilcox, has a design pressure of 1.83 MPa (265 psia) and has a capability of 27,000 kg/h (60,000 lb/h) of steam. This steam generator is utilized to provide process steam to National Helium Corporation (NHC) when Unit I is shut down.

Service water and makeup water for the circulating water system is provided from five wells located onsite. Cooling tower blowdown is directed to an onsite evaporation pond.

The cogeneration facility provides electricity to the Western Power system and process steam and electrical energy to the adjacent NHC plant. Process steam is taken from the first two extraction ports of the steam turbine through pressure regulating valves to maintain .65 MPa (95 psia) steam for delivery to NHC. In addition, this steam is desuperheated to 204 C (400 F). The electric energy supplied to NHC may be provided from either the CRS or the Western Power grid. The NHC plant processes the raw natural gas entering the Panhandle Eastern Pipeline for transportation to the Detroit, Michigan area. A refrigeration process is utilized to remove the propane, butane, and gasoline (pentane and greater fractions) products. At the same time, water and carbon dioxide are removed from the gas stream. The refrigeration process used requires both electric and thermal energy in the ratio of approximately 3:1, thermal equivalent.

The solar addition to Unit I will take a portion of the feedwater from the discharge of the highest pressure feedwater heater to generate steam in the solar receiver, and will deliver this steam to the turbine through a connection to the existing main steam line. No modifications to the NHC plant, Unit 2, or the process steam generator will be required.

2.7 EXISTING PLANT PERFORMANCE

Unit I of the Cimarron River Station is operated continuously throughout the year, with the exception of the scheduled and unscheduled outages.

The combustion gas turbine, Unit 2, is operated only during the summer peaking season. The process steam generator is generally operated only when Unit 1 is not on line. The following summary lists the annual plant performance for the preceding two complete years.

	1979	1980
Operating Time, hours		
Unit 1	7564	8305
Unit 2	3132	2574
Process Boiler	1230	441
Gas consumption, 10^6 m^3 (10^7 ft^3)		
Unit 1	130 (466)	140 (501)
Unit 2	17.7 (63.2)	9.83 (35.1)
Process Boiler	2.02 (7.23)	.846 (3.02)
Output, MWh		
Unit 1	377,017	430,375
Unit 2	37,877	21,857
Process steam delivered To National Helium, 10^8 kg (10^8 lb)	1.79 (3.94)	1.63 (3.58)

During the two previous years the following outages occurred.

Date	Scheduled	Reason
1979		
January 12	No	Electronic module failure
February 25 through April 13	Yes	Maintenance Inspection
May 4 and 5	No	Boiler tube leak
September 11 and 12	No	Steam valve failure

Date	Scheduled	Reason
1980		
March 1 through March 17	Yes	Maintenance
June 10	No	Forced outage
August 27 and 28	Yes	Maintenance
September 29 through October 3	Yes	Maintenance

The annual operating and maintenance cost in 1980 dollars for the Cimarron River Station, based on the projected operation to plant retirement without solar, is calculated to be $378,800.

2.8 PROJECT ORGANIZATION

The team which developed the conceptual design of the solar cogeneration facility consists of Black & Veatch Consulting Engineers, Central Telephone & Utilities--Western Power, Babcock & Wilcox Company, and the Foxboro Company. The Project Organization Chart, Figure 2.8-1, shows the team member relationships and responsibilities, as well as the key personnel involved in the project.

Black & Veatch, in the role of prime contractor, provided overall project management and coordinated all technical and reporting efforts. Black & Veatch also provided the design engineering, analysis, and cost estimating for the collector system, receiver piping system, solar master control system, plant integration, receiver tower, and site facilities; Black & Veatch also had responsibility for the performance evaluation of the integrated system, economic analysis pertinent to the fuel displacement and value of the solar cogeneration facility, and development plan which will result in commercial operation of the solar cogeneration facility. Western Power, in the role of owner and operator of the Cimarron River Station, provided utility direction and reviewed and developed engineering criteria for the design and operation of the solar cogeneration facility. Babcock & Wilcox had responsibility for providing data used in tradeoff studies, design, cost estimate, and implementation procedures for the receiver system; also, Babcock & Wilcox was responsible for evaluating the existing fossil steam generator for its use in a hybrid solar-fossil mode. The Foxboro Company provided consultation on the design of the solar master control system and prepared a cost estimate for that system.

In addition to the four principal team members, two groups provided valuable input to the project. The Technical Advisors contributed their expertise through review and consulting functions. The other group, the

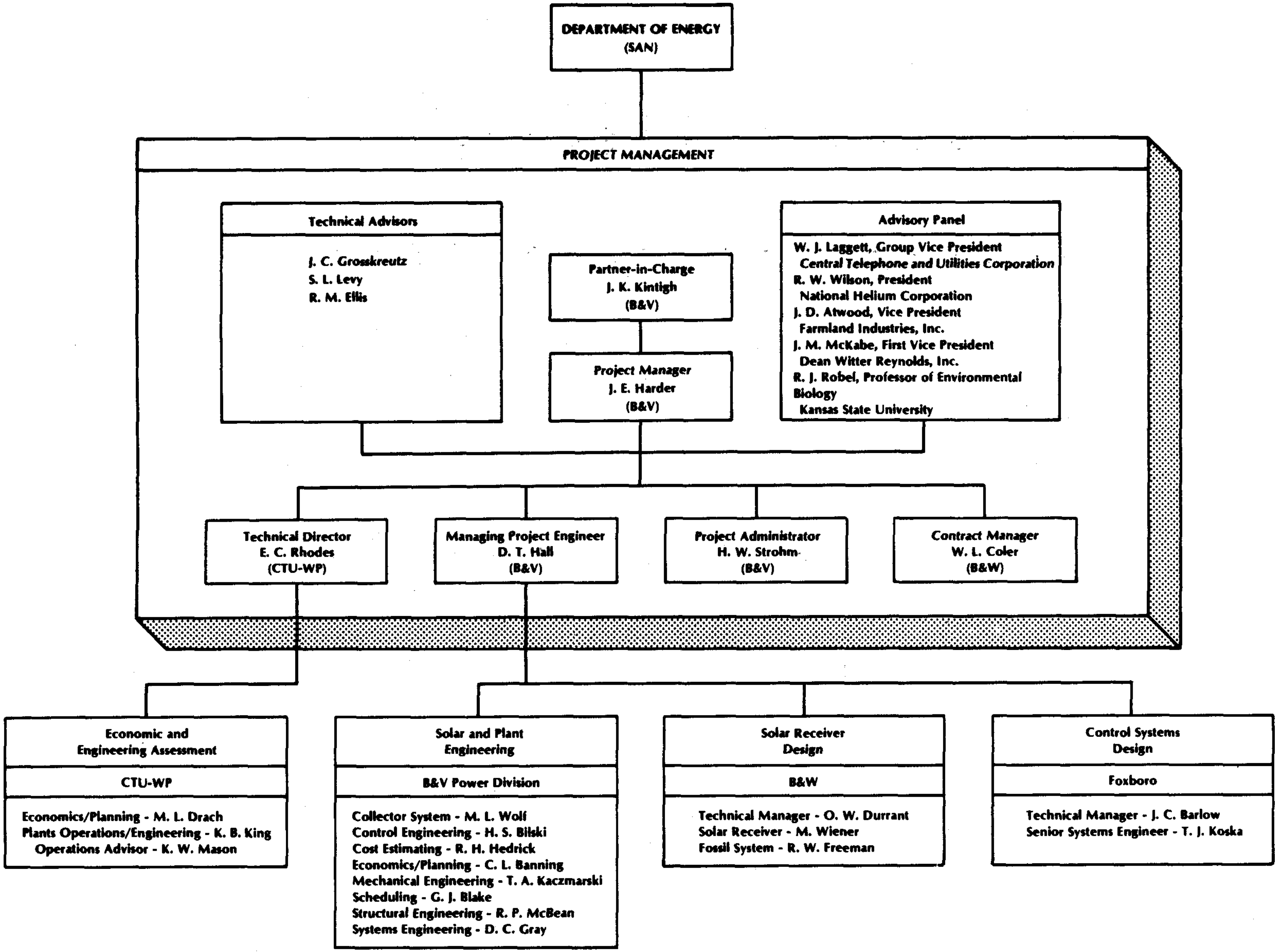


FIGURE 2.8-1. PROJECT ORGANIZATION CHART

Advisory Panel, provided independent perspectives from a variety of roles, including utility executive, utility customer, industrial user, financial consultant, and state government representative.

2.9 FINAL REPORT ORGANIZATION

The organization of the final report basically follows the flow of effort on the project. That is, as the project began with system trade studies aimed at identifying major system characteristics, the body of the report begins (Section 3.0) with a description of the process used to select the preferred systems. The next major task was to develop the conceptual design; correspondingly, that design is presented in the next two sections: Section 4.0 deals with the overall system design requirements and features, and Section 5.0 describes the individual system characteristics. The value of the solar conceptual design was then assessed; Section 6.0 presents the economic analysis. The final major project task was the preparation of a development plan to identify the sequence of activities necessary to transform the conceptual design into a successfully operating solar cogeneration facility; this plan is discussed in Section 7.0. In addition to the previous project tasks and report sections, Black & Veatch conducted a test program at the CTU-WP Cimarron River Station site; that program is described in Section 8.0. Section 9.0 contains the list of references for the preceeding final report sections. Two appendices are included in a separate volume of the final report. Appendix A consists of the System Specification which provides a concise summary of the conceptual design, including design input requirements, design parameters, performance data and cost estimate data. Appendix B provides the detailed backup for the facility construction cost estimate.

3.0 SELECTION OF PREFERRED SYSTEMS

Prior to the development of specific conceptual designs for the various systems comprising a solar cogeneration facility at CRS, a series of broadly based assessments and analyses were performed to identify, in a descriptive engineering manner, the preferred system. The studies address fundamental issues relative to system configuration and result in the definition of a design framework for subsequent, more detailed, conceptual design activities.

3.1 INTRODUCTION TO TRADE STUDIES

Trade studies are intended to develop information that provides a basis for engineering decisions on the basic nature and operation of the facility. Therefore, the trade studies must consider a range of issues, including performance, technical feasibility, operational characteristics, and economics. Further, because the trade studies led to design configuration decisions, the criteria for decisions must also be developed and clearly recorded so that the logic and basis of the system configuration are apparent.

The trade studies conducted for CRS solar cogeneration, and the rationale for the topic selection, are as follows.

(1) Role of Energy Storage--The need for and the appropriate type of energy storage are factors that strongly impact all other elements of the facility.

(2) Amount of Cogeneration--The size of the solar facility must be determined.

(3) Site Preparation--A large fraction of the facility cost is associated with the heliostat field. This study investigated alternatives for minimizing total system cost by considering the site-specific terrain and soil characteristics.

(4) Field Layout and Flux Patterns--Heliostat field size and shape considerations dominate the site layout, and redirected flux patterns and intensities establish design requirements for the solar receiver.

(5) Steam Conditions--Plant performance is influenced by the thermodynamic conditions of the solar generated steam. Further, design requirements for the solar receiver and heliostat field are dependent upon the steam conditions. By way of these trade studies, the major issues of system configuration, technology, and system size are addressed as they relate to the solar cogeneration facility.

Certain assumptions and site-specific criteria were used as a basis for a portion or all of the trade studies. Major assumptions and criteria are as follows.

(1) Economic Criteria--Economic criteria used for trade study economic analyses (e.g., fuel costs, capital costs, etc.) are provided in Table 5.4-1 in the System Specification (Appendix A).

(2) Fuel Gas Supply--At present the CRS natural gas fuel supply from the Anadasko system has a limited capability to meet a fluctuating load demand because gas production and delivery facilities are not automated. However, in response to anticipated future fuel costs, system electrical demand, and Western Power generation expansion plans, CRS should be operated in "swing" and peaking modes of operation for economic dispatch purposes following the mid-1980's. Discussions with Anadasko indicate that there are no gas supply system technical limitations which would prohibit such an operation by CRS. Therefore, it was assumed that CRS will have load change capability during the lifetime of the solar facility.

3.2 ROLE OF ENERGY STORAGE

Energy storage systems were considered for CRS to identify their potential value to all applications within the CRS operation.

3.2.1 Objectives and Scope

The purpose of this study was to select the energy storage alternative, if any, best suited for implementation with solar cogeneration at the Cimarron River Station (CRS). A number of storage alternatives which would allow the CRS to operate during periods of no sunshine were identified and evaluated. The evaluation and selection criteria for determining the preferred alternative were technical, operational, and economic feasibility.

Four categories of energy storage concepts were investigated. These categories are as follows.

(1) Zero storage--For this alternative, the fossil portion of CRS Unit 1 must compensate for all swings in receiver steam flow.

(2) Overnight storage--These concepts provide large storage (and large collector fields to provide energy for that storage) so as to allow continuous solar operation of the CRS.

(3) Buffer storage--These concepts provide short-term (approximately 1/2 hour) storage aimed at eliminating or tempering solar steam flow transients due to intermittent cloud cover.

(4) Storage for process steam--This option would allow the solar facility to provide process steam to the National Helium Corporation (NHC) night and day during the annual 4-week CRS outage for scheduled maintenance.

3.2.2 Relevant Factors

Several utility-related and technology-related factors exist which are relevant to the evaluation and selection of CRS energy storage. The following subsections will address those factors as a background for the discussion of the evaluation approach and analyses in Subsection 3.2.3.

3.2.2.1 Utility Related Factors. A major factor influencing the need for energy storage is that Western Power (WP) desires, as a general principle consistent with the Fuel Use Act, to minimize the consumption of natural gas at CRS and to avoid displacing coal-fired generation elsewhere on the WP system; the coal-based capacity will provide much of the base load for the WP system for most of the year in the 1986 to 2000 period. In other words, WP intends to minimize the cost of electric generation through the use of inexpensive fuels and, when possible, through the avoidance of expensive fuels. To that end, the CRS solar installation, given a sufficiently large storage system capacity, could provide main steam energy to operate the turbine generator throughout the 24-hour day. Thus, the use of the gas-fired CRS steam generator to provide main steam to the turbine would not be necessary. Alternatively, operating the CRS solar installation without thermal storage would require at least a minimum of steam generation from the gas boiler to maintain the turbine generator operational readiness; without thermal storage or steam generation from the fossil boiler, transients induced by weather conditions would be directly reflected in CRS output, with potential for the unit to trip off-line due to cloud conditions. Relevant to those characteristics that, as pointed out in Section 3.1, Western Power plans to convert CRS to a swing unit and will operate CRS year-round to provide swing load capability on the Western Power grid. Consequently, the addition of a solar system without thermal storage to the CRS system, even with its requirement of at least a minimum of steam generation from the fossil boiler, will not significantly increase the consumption of natural gas at CRS beyond that already planned by Western Power in the absence of a solar facility.

Cloud transients represent a key concern in operating any solar facility without thermal storage. Transients induced by weather conditions would be directly reflected in the steam flow to the turbine. It has been estimated that a rapidly approaching cloud shadow could substantially interrupt steam flow from the CRS solar receiver in approximately one minute. As a result, assuming the solar receiver had a capacity equivalent to 25 MWe, the electrical output of the proposed CRS solar installation could drop by 25 MWe in a matter of minutes. Because the boiler has a load change rate limit of about 10 per cent per minute, CRS would not be able to instantly correct output changes, but would be capable of compensating for cloud induced solar power transients within a matter of minutes. During this short period of transition, the balance of the WP system or its interconnected power pool will make up any power shortfall.

Another utility-related factor impacting storage design is that for an average of 4 weeks each year, the CRS is shut down for scheduled maintenance. During that time, process steam supply to NHC, which is essentially constant year-round, is provided by a package boiler. One useful role for the energy storage system would be to provide process steam to NHC during the annual CRS maintenance outage. Although the system would only be used several weeks each year, it may be more economical to invest in the storage system and to utilize the solar facility during those periods than to generate steam from natural gas.

3.2.2.2 Technology-Related Factors. A basic issue potentially relevant to the topic of energy storage is the receiver technology used in the design, i.e., water/steam versus molten salt. Water/steam systems offer advantages in terms of operating experience and a strong technological base, while molten salt systems more readily lend themselves to the inclusion of thermal storage.

Incorporation of storage with a water/steam system typically uses a parallel (or side) storage concept. In this concept, a portion of the steam from the receiver is input directly to the turbine during periods of adequate sunshine. Likewise, a portion of the receiver outlet steam is used to charge the thermal storage system by transferring energy from the steam to an intermediate storage medium (typically oil or molten salt). During non-sunshine periods, the storage is discharged by generating steam with energy in the storage medium. The disadvantage of this storage concept is that, due to the principles of heat transfer, steam from storage is produced at a lower temperature and pressure than that initially generated by the receiver. Ramifications of this steam quality degradation are as follows.

(1) In order for the storage system to provide even modest steam inlet conditions [5.4 MPa (780 psia)/482 C (900 F)] to the CRS turbine, receiver outlet steam conditions must be upgraded considerably [16.6 MPa (2,400 psia)/538 C (1,000 F)] from the basic requirements of the steam cycle [9.6 MPa (1,390 psia)/510 C (950 F)]. These elevated design conditions add to the receiver cost and reduce receiver efficiency slightly. Moreover, because the 16.6 MPa (2,400 psia)/538 C (1,000 F) receiver steam would require throttling to match the turbine cycle conditions, considerable energy would be wasted in pressure reduction during "normal" solar operation.

(2) Turbine capacity and efficiency are reduced when the lower quality steam from storage is used to drive the system.

An additional disadvantage for parallel storage systems is a finite response time when the storage system is called upon to generate steam. Estimates for the Barstow pilot plant storage system place response time for the storage system in "hot standby" as 5 minutes, while response time for the system in "cold standby" is 30 minutes.[1]

These factors related to a water/steam system with parallel storage indicate that such a storage option, while technically feasible, is not attractive operationally.

In contrast, the series (or "through") storage concept, utilized with a molten salt receiver system, is very attractive from an operations vantage point. In that concept, which uses molten salt as both the receiver working fluid and the storage medium, turbine-generator operation is essentially isolated from solar operation. At any time, steam conditions are independent of cloud-induced receiver transients and turbine derating is not required.

3.2.3 Approach and Analyses

The approach taken in the role of the energy storage trade study was to group storage options in appropriate size/function categories, to select the "winner" in each of these categories, and then to select the best from among the category winners. This methodology, discussed in the remainder of this section, is illustrated on Figure 3.2-1.

3.2.3.1 Evaluation Within Storage Categories. Four size/function categories have been defined in order to aid in the selection of the preferred storage concept. The four categories are as follows.

(1) Zero storage.

(2) Overnight (16 hour) storage.

(3) Buffer storage.

(4) Storage for process steam generation.

In selecting the "winner" from each of these categories, cost of energy and technical/operational feasibility were evaluation criteria.

3.2.3.1.1 Zero Storage. Two solar system types have been considered for the "zero storage" category: a water/steam receiver system and a molten salt receiver system. For both types the CRS fossil boiler can vary its steam output to compensate for fluctuations in solar receiver steam flow induced by clouds or diurnal solar variations.

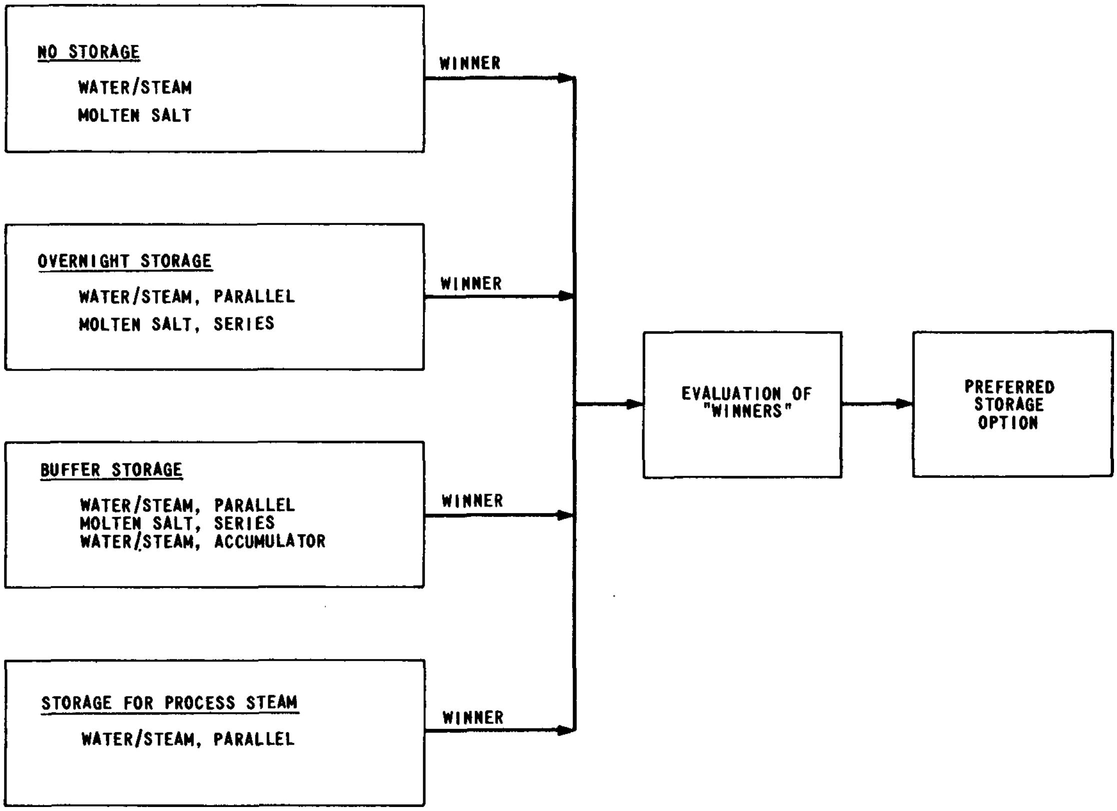


FIGURE 3.2-1. ENERGY STORAGE TRADE STUDY METHODOLOGY

From a performance viewpoint, the salt and water/steam receivers are comparable, with both showing design point efficiencies close to 89 per cent. The higher temperatures required for the salt receiver are achieved at that efficiency level by utilizing a cavity receiver design.

Both receiver types are considered technically feasible; however, the molten salt receiver may have greater technological risks. Furthermore, water/steam systems are able to draw upon a long history of conventional fossil-fired steam generator experience.

Because neither operational or technical feasibility considerations provide a decisive indication of the preferred system type, an economic evaluation was utilized to select the zero-storage "winner." Capital costs were projected for systems providing equal amounts of annual generation based on clear days and 92 per cent availability. Cost projections were based on preliminary field and receiver sizes, with heliostat costs assumed to be $\$230/m^2$ and receiver costs estimated by Babcock & Wilcox. Other system costs were adjusted from recent B&V solar system designs. Resultant capital costs were 53.5 million dollars for the water/steam system and 57.3 million dollars for the molten salt system. The water/steam system was found to be less expensive, despite a more costly receiver, due to the additional heat exchanger required by the molten salt system. Further details of the cost/performance comparison are given in Subsection 3.2.3.2.

Because annual energy generation of the two systems is identical, the lower capital cost for the water/steam system results in a lower cost of energy for the water/steam system than that of the salt system. Therefore, the water/steam system has been selected as the preferred zero storage option.

3.2.3.1.2 Overnight Storage. As with the "zero storage" category, "overnight" storage options include two system types: a water/steam system (with parallel storage) and a molten salt receiver system (with series storage). Both storage options were designed to provide 73 MWt of steam to the turbine at the design time point, while also providing for overnight (16 hour) operation from storage.

As discussed in Subsection 3.2.2.2, both storage options are technically feasible with the water/steam system having possibly less technical risks; however, from an operational standpoint, the molten salt system appears to offer advantages.

An economic comparison of the options has been conducted; capital cost projections have been determined for the two solar systems sized to provide identical, 147 GWhe annual energy outputs. Annual energy outputs were based on clear sky conditions and 92 per cent availability. Capital cost projections were based on heliostat costs of $\$230/m^2$, Babcock & Wilcox receiver and storage cost estimates, and B&V experience in recent solar projects. Capital costs for the water/steam and molten salt overnight storage systems were 141 million dollars and 126 million dollars, respectively. With identical energy outputs, the lower capital cost for the molten salt system results in a lower cost of energy for that system.

Based on operational and economic advantages, the molten salt system is preferred for overnight storage.

3.2.3.1.3 Buffer Storage. Although buffer storage is not required at CRS due to capability of the existing boiler to compensate for cloud transients, buffer storage options were considered. The following system concepts were evaluated.

(1) Water/steam with parallel storage.

(2) Molten salt with series storage.

(3) Water/steam with an off-line steam accumulator.

The water/steam system with parallel storage was eliminated for the same reasons as discussed for overnight storage in the previous section, i.e., the elevated receiver temperature and pressure requirements add significantly to the system cost, while lower quality steam from storage reduces turbine capacity and efficiency. In comparison, the molten salt system exhibits better operational characteristics as well as lower costs.

The water/steam receiver with an off-line steam accumulator was also considered as a buffer storage concept. The concept consisted of a 4,500 m^3 (160,000 cu ft) tank (30 minute supply) connected to the main steam line via a regulating valve. When charged, the tank would contain 13.8 MPa (2,000 psia) steam at 510 C (950 F). When totally discharged, steam in the tank would be at turbine throttle steam conditions. The costs of such a system are exorbitant, primarily due to the large tank wall thickness necessary to withstand the high pressures at high temperature. Because of the infeasibility of the storage vessel, as well as the 13.8 MPa (2,000 psia) pressure impacts on the receiver, the steam accumulator concept was discarded.

The molten salt thermal storage system was considered the "winner" for the buffer storage category since it exhibits technical, operational, and economic feasibility.

3.2.3.1.4 <u>Storage for Process Steam</u>. A final storage system investigated in this study would allow the solar installation to operate during annual CRS maintenance to provide process steam [65 MPa (95 psia), 204 C (400 F)] to National Helium Corporation. The system would displace the natural gas normally burned in a package boiler during maintenance periods. The estimated cost of a low temperature oil and rock thermal storage system designed specifically for that purpose is about $2.9 million. (The water/steam receiver was selected for this application because prior analysis showed it to be less costly, by more than $2.9 million, than molten salt in the "zero storage case" and because its technical shortcomings vanish at the modest storage conditions required by NHC process steam). The expected cost of burning natural gas to supply process steam during the period from 1986 through 2000 is only $1.2 million (present worth). Although a storage system would reduce the consumption of natural gas, it would not be cost effective; therefore, it was eliminated from consideration.

3.2.3.2 Evaluation of Energy Storage Role and Concepts. The proper role of energy storage was evaluated in part by comparing the economics of the water/steam receiver, the "winner" for zero storage concepts, and the molten salt receiver, the "winner" for overnight storage. Buffer storage is not required due to the capability of existing CRS equipment to absorb cloud transients. The comparison factor between the water/steam, zero storage system, and the molten salt overnight storage system was the cost of energy for identical amounts of annual energy generation. The results of the economic evaluation are shown on Table 3-1.

Systems with overnight storage naturally generate more energy annually than do those with no storage. Therefore, in order for a direct economic comparison to be meaningful, the perspective of the total WP system must be used--i.e., the total cost to WP to provide equal amounts of electrical energy to the grid. To accomplish this, it was assumed that the "generation shortfall" of the zero storage system as compared to the overnight storage system would be made up by additional generation by coal-fired units on the WP system; this assumption is consistent with the operating plans of WP.

The contributions of solar, gas, and coal for the various alternatives in Table 3-1 were determined as follows.

(1) The solar contribution was based on clear sky conditions with a 92 per cent plant availability. Overnight storage systems have 16 hours of storage at 73 MWt on the design day (March 21).

(2) Gas-fired generation for zero storage systems is an average of 15 MWe for a total of 48 weeks. (The CRS undergoes 4 weeks of scheduled maintenance outage each year.)

TABLE 3-1. COMPARISON OF STORAGE SYSTEM ALTERNATIVES

	Water/Steam Systems		Molten Salt Sytems	
	Zero Storage	Overnight Storage	Zero Storage	Overnight Storage
Solar Capital Cost (1980, Million $)	53.5	141.0	57.3	126.1
Annual Energy Generated From Solar (GWhe)	50.9	147.2	50.9	147.2
Levelized Annual Solar Cost (1980, Million $)	6.48	17.09	6.95	15.29
Cost of Energy From Solar (Mills/kWhe)	127	116.1	136	104
Annual Energy From Gas (GWhe)	121.3	43.0	121.3	43.0
Levelized Annual Cost of Gas (1980, Million $)	3.07	1.09	3.07	1.09
Cost of Energy From Gas (Mills/kWhe)	25.3	25.3	25.3	25.3
Annual Energy From Coal (GWhe)	18.0	0.0	18.0	0.0
Levelized Annual Cost of Coal (1980, Million $)	0.191	0.0	0.191	0.0
Cost of Energy From Coal (Mills/kWhe)	10.6	0.0	10.6	0.0
Total Energy Generated (GWhe)	190.2	190.2	190.2	190.2
Levelized Annual Cost (1980, Million $)	9.74	18.18	10.21	16.38
Total Cost of Energy (Mills/kWhe)	51.2	95.6	53.7	86.1

NOTES: The "zero storage" systems burn gas at 15 MWe for 48 weeks; the solar system was sized such that the receiver delivers 73 MWt at the design point. Overnight storage systems burn gas at 15 MWe for 17 weeks; the solar system was sized to provide 16 hours of storage at 73 MWt on the design day.

(3) Gas-fired generation for the overnight storage systems was zero except during the 17 weeks in the summer when it was increased to 15 MWe for summer peaking duty. This has the effect of forcing the peak output of both the storage and zero storage options to be the same during the peak demand summer months (zero storage always has the 15 MWe gas "base"). The effects of multiple, successive cloudy days are not considered.

(4) The difference in total annual energy generation between overnight storage and zero storage systems was assigned to coal-fired generation.

The costs of the solar contributions were computed as the present worth, levelized annual fixed charge for the 1986 to 2000 plant lifetime. Costs of gas and coal were computed as the present worth, levelized annual fuel costs over the 15 year plant life. Fuel costs were escalated in accordance with Western Power gas and coal escalation rate projections.

As can be seen from Table 3-1, the levelized cost of energy for the water/steam system with zero storage is significantly lower than that for the molten salt system with overnight storage (51.2 mills/kWhe versus 86.1 mills/kWhe). From an operational perspective, as previously discussed, storage is not required to eliminate cloud-induced CRS power transients since the CRS fossil boiler will compensate for fluctuations in solar receiver steam flow. As such, the water/ steam system appears to be operationally acceptable and economically superior to the molten salt, overnight storage system.

3.2.4 Conclusion

As a result of investigating the need for energy storage at CRS and a number of supporting design options for the CRS solar facility, it was determined that energy storage was not required nor justified for the CRS application. Neither the operational characteristics of the WP system nor the economics of the system alternatives favored energy storage. Given the absence of a clear need for energy storage, the water/steam receiver technology was affirmed as the most cost effective method of satisfying the cogeneration needs of electricity and process steam.

3.3 SITE PREPARATION

Site preparation alternatives for the heliostat field were identified and evaluated for the CRS facility.

3.3.1 Objectives and Scope

The objective of the site preparation trade study was to identify and examine means of enhancing the solar plant cost and/or performance by way of collector field location and contour. The study scope included alternate field locations, alternate field contours, and alternate means of achieving field contours--i.e., terrain grading and variable heliostat pedestal heights. A determination of the type and amount of site preparation is the result of the study, with cost effectiveness being the selection criteria.

3.3.2 Relevant Factors

The base line conceptual design (73 MWt) of the proposed CRS solar cogeneration facility utilizes approximately 48.6 hectares (120 acres) of land for the collector system; adequate land is available both north and west of the CRS generation buildings and cooling towers. A number of factors influence the preferred collector field location, including the cost of smoothing the local terrain, the cost of the receiver piping system, the mirror degradation due to deposits from the cooling tower plume, and the cost of relocating electrical transmission lines and underground pipelines.

As Figure 3.3-1 illustrates, sufficient land is available to locate the proposed collector field entirely to the north or to the west of the CRS turbine building and cooling towers. In either location, the collector field would have an overall slope to the north due to basic site topography. However, the local terrain for the north site is more rugged, and may require the movement of a larger volume of soil.

The receiver piping system represents a major cost factor in the site selection of the collector field. As Figure 3.3-1 illustrates, the tower location for the west field is a longer distance from the turbine building than the tower location of the north field. As a result, the west field would require longer main steam, feedwater, and condensate return lines, resulting in higher costs and greater pressure losses.

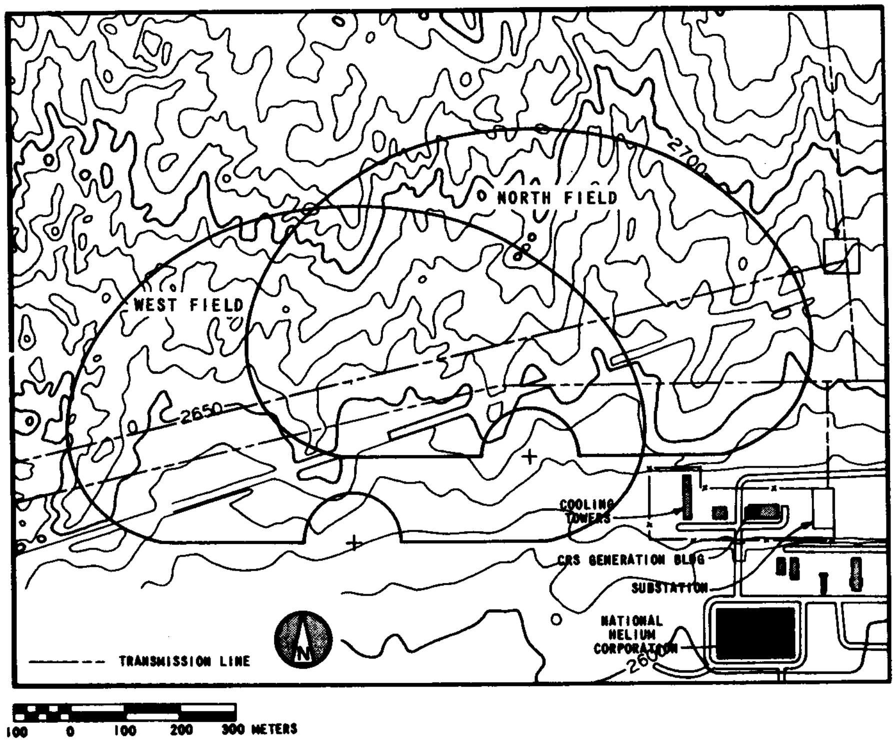


FIGURE 3.3-1. ALTERNATE COLLECTOR FIELD LOCATIONS

Drift from the CRS cooling tower could present more of a problem for the north field than for the west location. Since wind data for the Liberal, Kansas area indicates the predominant wind direction is from the south, heliostats north of the cooling tower will experience more reflectivity degradation due to the deposit of dissolved solids, and may require more frequent washings. A related concern is the periodic shadowing of portions of the collector field by the plume.

Overhead transmission lines and underground water and gas pipelines lie to the east and north of the turbine building. In either field location it will be necessary to relocate some of those lines during site preparation.

The major criterion for site preparation decisions was least economic cost consistent with good operating practice.

3.3.3 Approach and Analysis

The approach used for this trade study was to identify the basic characteristics and to estimate the major costs associated with various site preparation alternatives; this permitted the design decision to be based upon economics. The purpose of site preparation is to eliminate excessive heliostat shadowing and blocking by providing a means for systematically obtaining necessary heliostat elevations. The major alternatives which were considered are as follows.

(1) Adjust heliostat pedestal height to compensate for site topography.

(2) Grade site to obtain the necessary site topography.

Investigations of the CRS topography details revealed that the terrain was quite rough; rolling peaks and valleys with fairly steep slopes and localized elevation differences of 1.5 to 6 m (5 to 20 feet) are common. Because the local terrain exhibits such wide variance, it is clear that heliostat pedestal heights cannot economically offset variances of that magnitude. Estimates for changing the pedestal height 0.6 to 1 m (2 to 3 feet) are about $100 per heliostat, with larger changes experiencing more rapid cost increases due to foundation revisions to accommodate larger wind-induced loads.

The characteristic soil at CRS is loose sand; no rock or severely compacted material is expected near the existing grade. Therefore, because grading costs per unit volume are relatively low and because even minor heliostat pedestal height changes are costly, pedestal adjustments are not practical at CRS.

The cost of grading the site depends not only on the location of the field but also on the amount of earth moving necessary to obtain the desired field topography. From an optical standpoint, a flat collector field shape is preferred over a rolling topography since it results in less shadowing and blocking for the same heliostat spacing. However, site preparation of the flat field requires larger cuts and fills and a correspondingly larger earth moving cost. To evaluate those costs, site grading plans were developed for the 73 MWt collector field positioned in two separate locations north and west of the CRS turbine building. Contour maps for those two plans, sketched on Figure 3.3-2, show the fields are level from east to west and slope to the north. In both cases, it was found that a 3.3 per

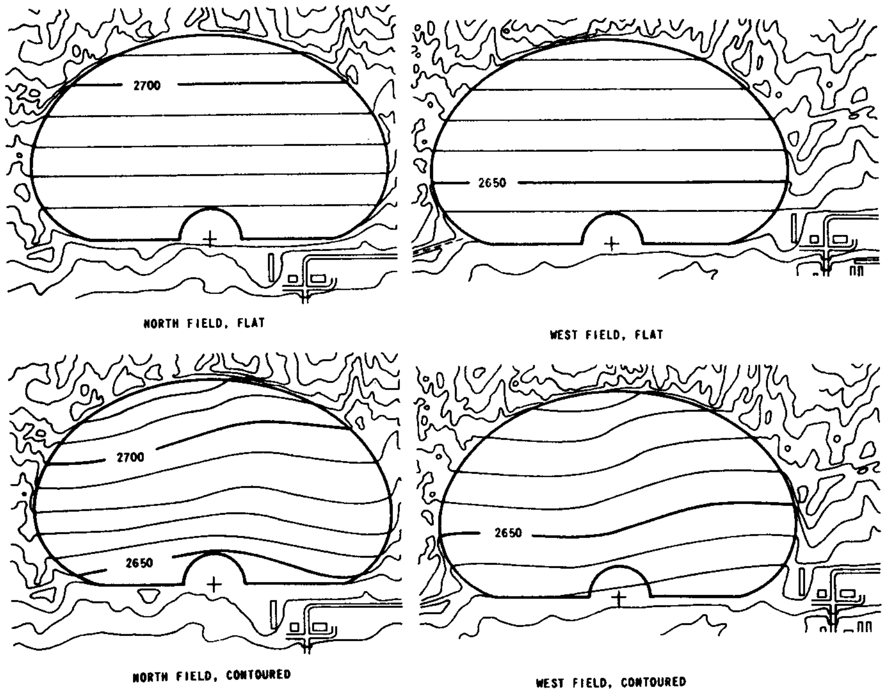


FIGURE 3.3-2. ALTERNATE SITE GRADING PLANS

cent grade to the north would match the amounts of cuts and fills so that no material would be moved offsite. The volume of material to be moved is larger for the north field due to its rougher terrain. The total volume is 610,000 m^3 for the north field location and 440,000 m^3 for the west location.

To obtain the flat contour, cuts and fills of up to six meters are necessary. To reduce the amount of earth moved, a pair of alternate site grading plans were developed for the north and west field locations based on a gently rolling collector field shape. As shown on Figure 3.3-2, the underlying contour of the site topography remains, but the terrain is smoothed to avoid excessive shadowing among heliostats. This "rolling" topography will have little impact on the total daily solar energy redirected to the receiver. A maximum field slope limit of 4° was imposed during the development of the site plans so that, for the "rolling" cases, shadowing effects resulting from the gentle contour hills would only be experienced during extremely low sun elevations. At these times, insolation is low and of little value for power generation. Again, as with the flat cases, the north field requires a larger volume of earth moving due to the rougher terrain. The total volume to be moved was estimated at 445,000 m^3 for the north field and 310,000 m^3 for the west field.

The estimated cost of site preparation for the four site grading plans is represented in Table 3-2. Costs include both direct and indirect costs associated with moving material and compacting it to permit the use of a standard heliostat foundation throughout the field. As expected, site preparation costs are lowest for the two fields with rolling collector field topography. Leveling the field from east to west to produce a flat collector field costs an additional $0.47-0.59 million. The cost estimates also show that the north field location will require up to $0.6 million more in site preparation costs than the west field due to its rougher terrain.

TABLE 3-2. COST OF ALTERNATE SITE GRADING PLANS (1980$)

Field Location	Site Grading Plan	Cost of Site Preparation million $	Cost of Piping million $	Total Cost of Piping and Site Preparation* million $
North of CRS	Flat Field	2.20	2.18	4.38
North of CRS	Contoured Field	1.61	2.18	3.79
West of CRS	Flat Field	1.60	3.30	4.90
West of CRS	Contoured Field	1.13	3.30	4.43

*Both direct and indirect costs are included, excluding ownership costs.

In order to select a site preparation plan which is based on economics, the additional costs of the receiver piping system, heliostat washing, and relocation of transmission lines and underground piping were considered. The costs of the receiver piping system have been estimated for the two field locations and are presented in Table 3-2. Those costs are based on the proposed 73 MWt collector/receiver system, and include the direct and indirect costs of main steam and feedwater piping, insulation, and supports. Although the north field required more site preparation, its cost of piping is $1.1 million less than for the west field. Consequently, the cost savings of approximately $0.64 million in total site preparation, and piping costs will be achieved if the collector field is located north of the turbine building.

Both the west and north field locations contain electrical transmission lines and underground water and gas pipelines. The cost of relocating the transmission lines and water piping are small compared to the cost of site preparation and the receiver piping system. The relocation of the gas pipelines can be avoided entirely by contouring the collector field and locating the heliostat so that the present pipelines are not disturbed. Further, it appears that the degree of piping and/or transmission line relocation required for either location is similar; thus, that cost component can be regarded as a constant.

The north field location is preferred over the west field on the basis of site preparation and piping costs. However, the north field may experience greater mirror reflectivity degradation due to cooling tower drift. Since the predominant wind direction in that area is from the south, heliostats just north of the cooling tower may require more frequent washings to remove deposits from the cooling tower plume. These frequent washings would increase the life-cycle cost of the north field, tending to offset the first cost advantages in piping and site preparation. Based on cost estimates developed for a similar solar repowering project[2], the cumulative present worth washing cost over the lifetime of the CRS collector field is $0.3 million, assuming one washing per month for the entire field. With the $0.64 million savings in site preparation and piping cost, washing frequency for the entire field could be increased to 2.2 times per month (every 1.8 weeks) before the economic choice of field location changed.

Although the required washing frequency of heliostats is not well known and the particular effects of cooling tower drift are not well established, the problem has been studied in site test programs for other solar projects[3]. The worst phenomenon observed is a process in which moisture and dissolved solids from cooling tower drift combine with wind-blown deposits of soil forming a soil cement on the mirror surfaces. After a month of exposure, the mirrors can be cleaned by normal methods. However, after longer exposures (3 to 4 months), the cementing process is irreversible, and the deposits become impervious to normal cleaning methods. This phenomenon is not expected to be a problem at the CRS site since the "cementing" involved a daily (or more frequent) alternate wetting and drying process resulting from significant liquid moisture carryover from an industrial cooling tower. (Cooling tower moisture carryover is not present to the same degree at CRS. Initial test data on mirror soiling at CRS became available late in the project and is reported in Section 8.)

In practice, only those heliostats close to the cooling tower would likely require washing more than monthly, with individual heliostats being cleaned at different intervals depending upon their location in the field. This would have the effect of permitting those relatively few heliostats lying in the path of the cooling tower drift to be washed several times per week if necessary, while the large balance of heliostats would be cleaned monthly. Such a cleaning approach would have a present worth cost well below the $640,000 cost advantage attributable to the north collector system site.

3.3.4 Summary

The conclusion drawn in this site preparation study is that the most economical location for the collector field is just north of the CRS turbine building and cooling tower. Although a collector field located to the west of the plant would require a lower site preparation cost, the north field offers the cost advantage of a much shorter receiver piping system. It is expected that the cost savings of locating the field north of the plant will offset any additional O&M costs associated with more frequent heliostat washing, should that prove necessary. The gently rolling terrain option (a typical east to west grade variance would be less than 4 per cent) to minimize grading costs is also preferred since the collector field performance impacts are not expected to be significant.

3.4 AMOUNT OF SOLAR COGENERATION

The size of the solar cogeneration facility was determined by assessing a range of alternatives.

3.4.1 Objectives and Scope

A major decision in the conceptual design of the solar cogeneration system is the selection of the preferred amount of solar contribution. The objective of this trade study was to make that determination, considering such relevant factors as land availability, plant operational characteristics, and Western Power system requirements. The criteria for the size selection was minimum cost-of-energy and satisfaction of the basic solar cogeneration program objective, i.e., the meaningful demonstration of solar thermal technology in an industrial setting.

3.4.2 Relevant Factors

In determining the preferred amount of solar contribution to CRS generation, a range of factors, including physical, operational, and economic issues, must be considered. This section identifies those issues and their relevance to solar sizing. Some of the factors are pertinent for initially establishing the range of practical solar sizes, while others are pertinent to the final determination of a specific solar size.

Several factors were considered in establishing the upper limit for the solar size range; those factors are as follows.

(1) Land availability--It was established that sufficient land can be acquired to accommodate any solar system sizes which might be considered for CRS.

(2) Minimum boiler and turbine-generator load, and maximum turbine generator load--The minimum boiler and turbine generator loads serve to define the minimum gas-fired generation; that value, coupled with the maximum turbine generator load, defines the absolute upper limit for solar contribution. The minimum load due to existing equipment limitations is in the 10 to 15 MWe range; turbine generator nameplate capacity is 44 MWe, with an overpressure capability of 60 MWe. This implies a maximum solar contribution of approximately 45 MWe.

(3) Ability of CRS plants to compensate for cloud-induced solar transients. Due to the inherent maximum load change rate of the CRS boiler, its response time will not be sufficient to maintain a constant turbine inlet steam flow under large rapid cloud-induced solar transients. The temporary generation transient that will result is a function of solar size and must be accomodated by the WP grid. Western Power has indicated that 25 MWe power swings are the largest that WP is willing to impose on the CRS boiler and/or grid on a potentially frequent basis.

From the above factors, an upper limit of 25 MWe was set for the solar contribution.

The factor influencing the lower limit of the size range was Western Power's assessment of the minimum "meaningful" amount of solar contribution from operational and experimental vantage points. Selection of that power level was based on the following criteria.

(1) It should be sufficiently high to test components, control systems, etc.

(2) It should provide a significant fuel reduction for unit operation.

(3) It should be large enough to provide representative operational experience.

(4) It should be meaningful to the operators, i.e., big enough that operators will not turn it off because it is too much bother.

Based on these criteria, Western Power's evaluation was that 15 MWe should be the lower limit on solar size.

From consideration of the above factors, an allowable size range of 15 MWe to 25 MWe was established; selection of the preferred system size within that range was based on an evaluation of system cost/performance considerations. Two key factors included in those considerations were CRS operating strategies over the next 20 years and heliostat cost versus system size.

The integration of solar into CRS operating strategies impacts overall plant energy generation and fuel consumption, and thereby, plant cost effectiveness. Operating modes for the solar CRS (discussed in Subsection 3.4.3.1) were defined so as to be reasonable adaptations of projected non-solar operation of CRS. One potential operational constraint is that operating the CRS solar installation without thermal storage will require at least a minimum of steam generation from the gas boiler to maintain the turbine generator readiness. Since, in the absence of a solar facility, Western Power plans to operate CRS as a swing unit on a year-around basis to provide swing load capability on the Western Power grid, the addition of solar to the CRS system, with its requirement of at least a minimum of steam generation from the fossil boiler, will not significantly increase the consumption of natural gas beyond that already planned by Western Power.

A second cost/performance factor which was considered as having possible impact on solar sizing was heliostat cost versus quantity ordered. The total number of heliostats for CRS would range from about 1,000 for 15 MWe to just over 2,000 for 25 MWe. Preliminary investigations and discussions with DOE second generation heliostat manufacturers seem to indicate that little potential exists for significantly lowering heliostat cost by ordering the larger number. For the purposes of this study, it was determined that no significant price difference would exist.

3.4.3 Approach and Analysis

The analysis approach was to establish a range of acceptable solar contribution levels (15 to 25 MWe as discussed in Subsection 3.4.2) and then, within that range, to assess the economic characteristics of different solar sizes to identify the most cost effective size on a CRS stand-alone basis. In that context, the economic assessment of CRS was conducted for zero, 15 MWe, 20 MWe, and 25 MWe solar contributions. The approach and analysis for that assessment will be discussed in two parts, the first outlining assumed operating strategies and the second detailing the performance and economic evaluation. Following this base line assessment, additional analyses were performed to determine the sensitivity of the size selection to changes in basic assumptions.

3.4.3.1 Operating Strategies. Performance and cost evaluations of CRS operations in the 1986 to 2000 time frame were based on projected dispatch strategies. The Western Power dispatch strategy assumed for this trade study for nonsolar (gas only) operation of CRS for that time period is shown on Figure 3.4-1. The plant will be used primarily as a summer peaking and swing load unit. From 1986 to 2000, the plant will provide an average gas generation of about 20 MWe for the non-summer months in fulfillment of its "swing unit" role.

Proposed CRS operating strategies that incorporate solar are adaptations of the nonsolar operation. Since CRS will be operated as a swing load unit, the net plant output (including contributions from both the solar and fossil steam generators) will meet the dispatch demand at all times. The solar contribution will simply displace gas-fired generation. Figure 3.4-2 illustrates this gas/solar generation concept for a single day under two different dispatch models. The first model shows a constant dispatch demand and serves to illustrate the displacement of gas-fired generation with solar under partially cloudy conditions. The second model shows a more complex dispatch curve, illustrating the net effect of dispatch demand and solar variations on gas-fired generation. As a result of the above factors, the operating strategy with solar shown on Figure 3.4-1, utilized an average gas-fired generation rate such that the total CRS output (solar plus fossil) is approximately equal for each solar size.

3.4.3.2 Performance and Economic Evaluation. Selection of the preferred size of solar contribution was based on an evaluation of the cost effectiveness for three solar sizes: 15, 20, and 25 MWe. The evaluation was conducted in three steps.

(1) Determine the plant performance for each CRS configuration. Annual energy generation and gas usage were computed for the 1986 to 2000 time period.

(2) Estimate capital and operating costs for each solar system size.

(3) Compute the cost of energy for each solar size.

The performance evaluation of CRS for nonsolar operation was based on net plant heat rate curves for the existing CRS.

Based on the operating strategies discussed in Subsection 3.3.4.1, the amount of energy generated from gas, as well as gas consumption for each month and year, were determined; these calculations were based on the net

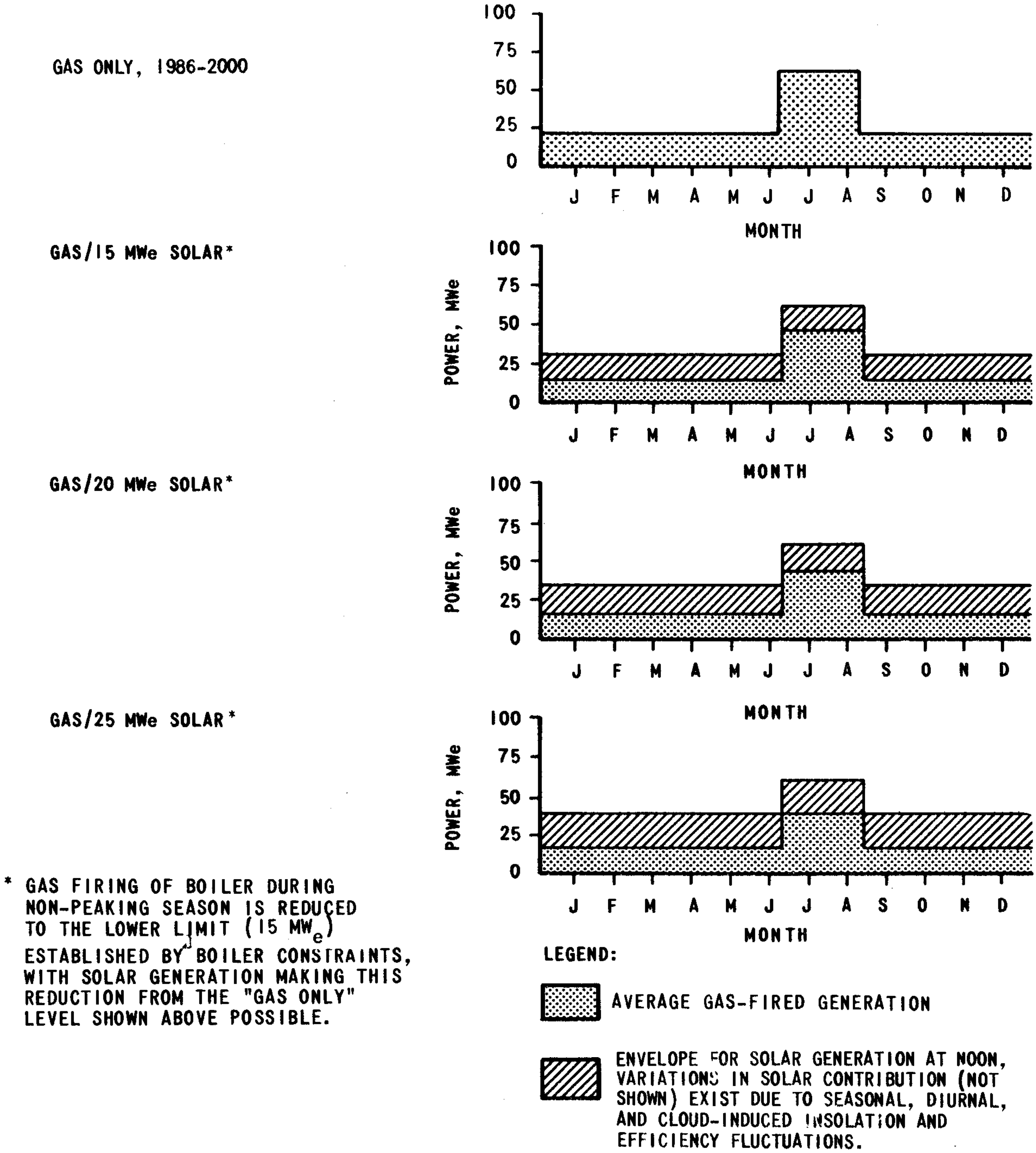


FIGURE 3.4-1. CRS OPERATING STRATEGIES AS MODELED IN SOLAR SIZING STUDY

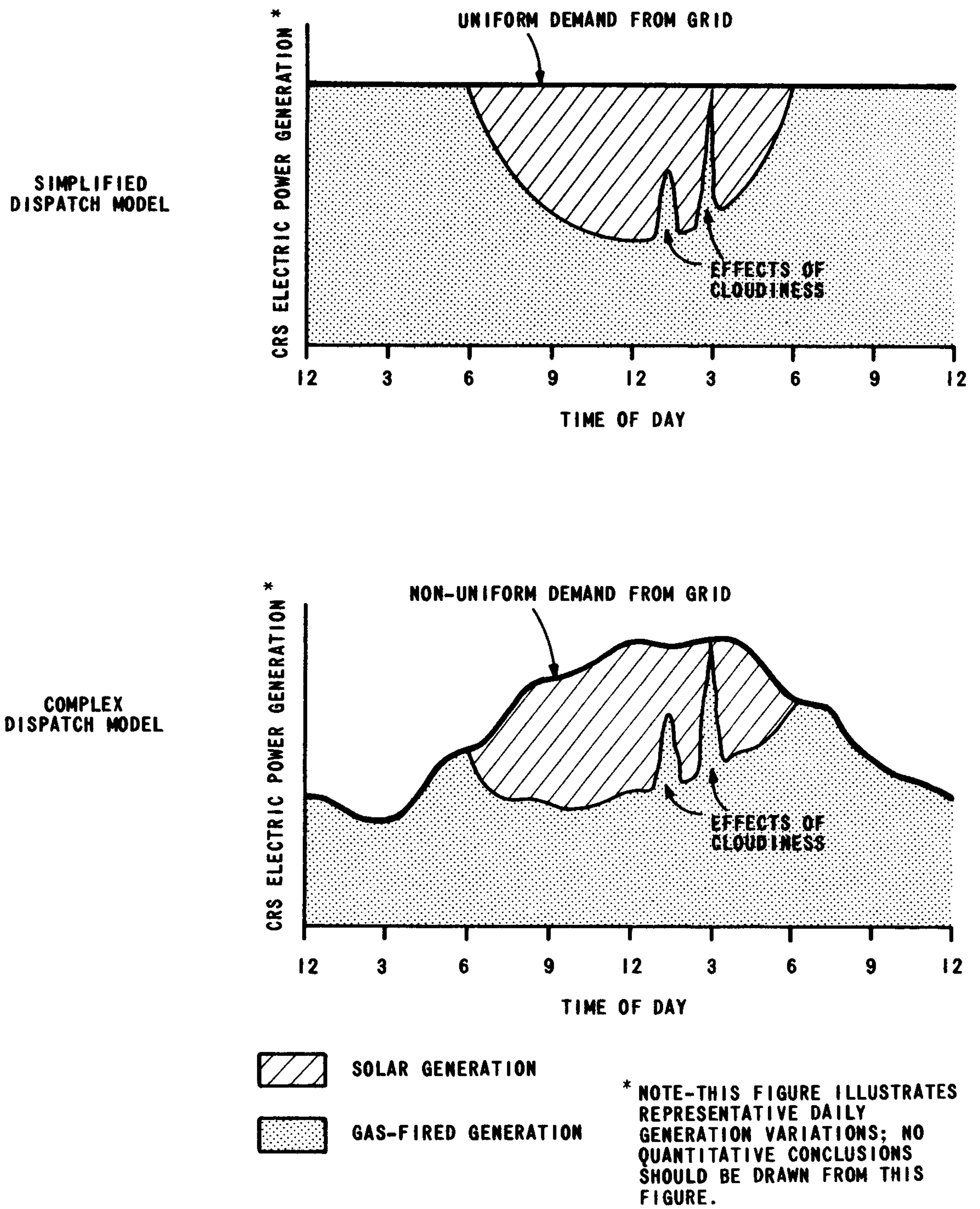


FIGURE 3.4-2. SINGLE DAY GAS/SOLAR CRS OPERATION CONCEPTS

plant heat rate. The solar contribution to energy generation was also computed on a monthly basis, with each year assumed to be identical. Key approaches in the solar performance evaluation are as follows.

(1) Solar insolation was modeled with the ASHRAE Clear Air Model. Monthly performance was modified using per cent sunshine data for Dodge City, Kansas. The resulting effective annual direct normal insolation was 6.1 $kWh/m^2/day$, in good agreement with available insolation isopleth maps.

(2) The receiver thermal output shape was modeled for 12 representative days (one each month) using detailed computer analysis outputs from the Public Service Company of Oklahoma (PSO) Solar Repowering Project.

(3) The solar thermal contribution was converted to solar electrical contribution using the CRS turbine incremental heat rate.

Capital costs for the three solar system sizes were based primarily on scaling of PSO solar repowering systems costs where appropriate and the generation of CRS-specific cost information as necessary. Table 3-3 gives a breakdown of the capital costs on a system level, as well as the basis for those cost estimates. It is important to note that these cost estimates are preliminary; while they can be considered to fairly accurately portray costing trends versus system size, they are not final cost projections for the CRS solar cogeneration project conceptual design. Table 3-3 also gives estimates for solar O&M costs for the three system sizes.

Upon determination of system performance and solar-related costs, the cost of energy for each solar size alternative was computed. Three types of energy costs were developed.

(1) Cost of energy for the solar contribution--This term considers solar capital cost and the resultant power generation. While it is of interest, the cost of energy generated from both gas and solar is a better indicator of cost effectiveness for Western Power.

(2) Cost of energy for CRS generation--This measure takes into account contributions to the plant generation from both gas and solar.

TABLE 3-3. SOLAR SYSTEM COSTS[1]

Item	15 MWe $	20 MWe $	25 MWe $
Site Preparation[2]	0.89	1.18	1.47
Site Facilities[3]	1.86	1.86	1.86
Collector System (at $230/m^2)	14.23	18.94	23.65
Receiver[4]	7.58	9.26	10.82
Tower[3, 5]	1.71	2.17	2.62
Receiver Piping System[2]	2.25	2.32	2.38
Master Control[3]	6.41	6.41	6.41
Fossil Conversion[3]	0.14	0.14	0.14
	35.07	42.28	49.35
Ownership Costs[6]	7.54	9.11	10.65
Total	42.61	51.39	60.00
O&M Costs (10^6\$/y)[3]	0.148	0.197	0.246

[1]Capital costs are in millions of end-of-year 1980 dollars. Costs include contingencies and indirects.

[2]Costs based on estimates from site location trade study.

[3]Costs based on PSO Solar Repowering Project.

[4]Receiver costs as per B&W estimates. Direct costs scale as $P^{0.7}$, where P is receiver output power.

[5]Direct tower costs assumed to scale linearly with power (scale as square of height).

[6]Ownership costs include land, insurance, and property taxes during construction and AFUDC. All capital expenditures were assumed to take place at end-of-year 1983, 2 years before plant operation begins.

The two types of energy cost were determined as a present worth cost of energy generated between 1986 and 2000. Economic data used for the evaluation are provided in Table 5-1 in the System Specification (Appendix A). Costs considered included the following.

(1) Escalated cost of gas.

(2) O&M for both fossil and solar operation, escalated at the general escalation rate.

(3) Solar-fixed costs, with expenditures assumed to take place at end-of-year 1983. Solar capital cost in end-of-year 1980 dollars were escalated to end-of-year 1983 dollars using the general inflation rate.

Fixed costs for the existing CRS were not included in the analysis because those "sunk" costs do not impact the relative costs of energy for the four configurations studied.

Results of the performance and economic evaluation are summarized in Table 3-4; cost-of-energy terms (Entries 8 and 9) are highlighted. Although the solar cost of energy is lowest for the 25 MWe solar system, the CRS cost of energy is lowest for 15 MWe. The small differences among the cost-of-energy values for the three solar system sizes reflects the strong leverage exerted by gas-fired generation.

3.4.3.3 Sensitivity Studies. Four sensitivity studies were conducted to determine the impact of changing certain underlying assumptions for this study. The factors evaluated were as follows.

(1) Capital cost (impact of increased economy of scale).

(2) Cost of heliostats.

(3) Gas escalation rate.

(4) Amount of gas-fired generation.

The capital cost sensitivity study was conducted to determine if inaccuracies in capital cost estimates, resulting in incorrect economy of scale assessments, could give misleading answers for the CRS cost-of-energy trends. The 25 MWe solar system shows economy of scale, as evidenced by the lowest solar cost of energy (Entry 8 on Table 3-4); however, the economy of scale exhibited was not sufficiently large to result in the 25 MWe systems having the lowest CRS energy cost. The approach of this sensitivity study was to determine how much economy of scale is required for the 25 MWe system to break even with the 15 MWe system in terms of CRS cost of energy (Entry 9). The results showed that, for no change of

TABLE 3-4. PERFORMANCE AND ECONOMIC EVALUATION RESULTS

Entry No.	Item	No Solar	15 MWe Solar	20 MWe Solar	25 MWe Solar
1	Energy Generated by CRS[a] (10^6 MWhe)	3.126	3.126	3.155	3.203
2	Energy Generated Via Solar[a] (10^6 MWhe)	--	0.427	0.569	0.710
3	Gas Required[a,c] (10^9 kWht)	13.1	10.6	10.2	9.87
4	Gas Cost[b] (10^6 \$)	77.5	62.8	60.37	58.5
5	O&M[b] (10^6 \$)	3.87	4.56	4.65	5.09
6	Solar Capital Cost[b] (10^6 \$)	--	32.5	39.2	45.7
7	CRS Cost[b] (4+5+6) (10^6 \$)	81.4	99.8	104.2	109.3
8	Solar Cost of Energy (mills/kWhe)	--	78.8	71.6	67.1
9	CRS Cost of Energy (mills/kWhe)	26.0	31.9	33.0	34.1

[a]All energy values are 15-year totals (1986-2000).

[b]All costs are 15-year sums of annual costs, each discounted to 1980 present worth.

[c]Gas consumption for solar options varies because, during the summer months when plant peak output is required, the larger solar sizes displace more gas.

15 MWe capital cost (\$42.6 million, Table 3-3), the 25 MWe capital cost would need to be reduced by 15.5 per cent from \$60.0 million to \$50.7 million. While a 15.5 per cent cost reduction may seem small, it is a substantial amount to be attributed to economy of scale. If, for example, the cost reduction were totally due to the reduced cost of ordering a larger number of heliostats (the most "volume sensitive" element of the facility), the price of heliostats would need to drop from \$230/m^2 for the 15 MWe size to \$156/m^2 for the 25 MWe size. Sandia projections[4], confirmed by independent B&V investigations, of heliostat cost versus cumulative number of heliostats

produced indicate that a drop in heliostat cost of this magnitude would require production of many tens of thousands of heliostats. The necessary economy of scale to make the 25 MWe solar size cost effective in this application cannot, therefore, be attributed to reductions in heliostat costs due to ordering approximately 800 more heliostats than for the 15 MWe solar size. In summary, inaccuracies in cost estimates, in particular as they relate to economy of scale, do not have sufficient leverage to change the trend of CRS energy cost values.

The second sensitivity study considered the impact on relative costs of energy for changing the base line heliostat cost ($\$230/m^2$) to values of $\$170/m^2$ and $\$290/m^2$. Results are recorded in Table 3-5. It can be seen that reduced heliostat costs slightly narrow the differences between costs of energy for the 15 MWe solar and 25 MWe solar sizes; however, for all heliostat costs considered, the cost of energy for the 15 MWe solar size remains lower than for the 25 MWe size.

A third sensitivity study was aimed at determining how much leverage gas escalation rates have on the CRS cost of energy trends. The approach of this study was to determine the necessary uniform gas escalation rate to

TABLE 3-5. RESULTS OF HELIOSTAT COST SENSITIVITY STUDY

	CRS Cost of Energy (mills/kWhe)		
Heliostat Cost $	15 MWe Solar	25 MWe Solar	Difference
$170/m^2$	30.8	32.8	2.0
$230/m^2$*	31.9	34.1	2.2
$290/m^2$	33.0	35.9	2.9

*Assumed heliostat cost for the base line study.

arrive at equal adjusted CRS costs of energy for the 15 MWe and 25 MWe solar sizes; higher escalation rates for gas favor the larger solar system size. It was found that a uniform gas escalation rate of 25 per cent would give equal CRS costs of energy for the two solar sizes. This escalation rate is much higher than those projected by Western Power and by others in industry and government, thereby validating the results of the base line study for reasonable, foreseeable escalation rates.

A fourth sensitivity study explored the impact of reducing the minimum gas-fired generation to 10 MWe. As previously mentioned, the amount of gas-fired generation has strong leverage on the cost of energy for the CRS with solar cogeneration because of the cost of fuel. For no gas-fired generation, the 25 MWe solar system would exhibit the lowest energy cost, due to economy of scale (as Entry 8 on Table 3-4 indicates); however, when fuel costs are considered, the 15 MWe solar size has the lowest energy cost. This implies that some cross-over value of gas generation exists; i.e., that as the underlying gas generation is increased from 0 to 15 MWe, there is some value where the CRS energy costs for 15 MWe and 25 MWe solar are equal. Because of initial uncertainty about the exact lower limit of gas operation within the 10 to 15 MWe range, CRS costs of energy were also computed for the 10 MWe gas generation. For the 10 MWe gas generation, CRS energy costs for 15 MWe and 25 MWe solar contribution were determined to be 35.0 mills/kWhe and 37.0 mills/kWhe respectively, thereby affirming the CRS cost of energy trend established using the 15 MWe gas generation.

3.4.4 Conclusions

As a result of this trade study, the 15 MWe solar size was selected as the basis for the remainder of the conceptual design. Selection of the 15 MWe size was based on its lowest cost of energy of the three solar sizes evaluated: 15 MWe, 20 MWe, and 25 MWe.

The validity of the 15 MWe selection was verified by four sensitivity studies which evaluated the impacts of changing underlying assumptions for the study. The sensitivity analyses addressed economies of scale, heliostat costs, gas escalation rate, and the minimum load allowable for the existing fossil boiler. Substantial changes in the base line assumptions did not alter the trend of cost of energy being lower for the smallar solar size.

3.5 FIELD LAYOUT AND FLUX PATTERNS

The collector system was analyzed to establish the geometry of the heliostat field and the redirect flux patterns it would provide to the solar receiver.

3.5.1 Objectives and Scope

The purpose of this study was to determine the collector field layout that provides the most cost effective means of collecting solar energy at the CRS solar cogeneration facility. The study tailored the field layout for existing site constraints, and coupled collector and receiver performance calculations to identify a heliostat aiming strategy that meets the receiver incident flux requirements for controlability and reliability.

3.5.2 Relevant Factors

The type of receiver system (cavity or external) strongly influences the collector design and the solar facility cost, efficiency, and performance. Although the cavity receiver experiences greater spillage losses than the external receiver, its absorption efficiency is higher due to lower radiation and convection losses. As a result, the cavity receiver has an overall efficiency 3 to 4 per cent higher than the external receiver, corresponding to a $0.5 million savings in heliostats. However, B&W estimates the cost of the cavity receiver would be at least $1 million higher than the external receiver and, because of the larger size, would require a more massive support structure to accommodate the increased weight and high wind loads. Consequently, the external receiver was selected on the basis of its lower overall system cost.

The steam conditions trade study, discussed in Section 3.6, initially identified 520 C (968 F) and 10.82 MPa (1,569 psia) as the most cost effective receiver outlet steam conditions, based on external receiver performance and on receiver and piping costs. At the design point, the CRS facility will generate 15 MWe from solar-produced steam. Based on these steam conditions and power requirements, the receiver thermal power output required at the design point is 37.13 MWt. The corresponding receiver efficiency is 88.3 per cent.

The design point was selected as that time of the year when the collector is most efficient. For small collector systems, as in this case, heliostat fields tend to be highly north-biased, placing heliostats north of the tower where annual cosine losses are lowest. North-biased fields tend to be most efficient at noon near the fall or spring equinox. Hence, March 21 noon was selected as the collector system design time point.

The external receiver has superheater and economizer panels forming a nearly cylindrical shape which allows flexibility in aiming heliostats to meet the receiver flux requirements and minimize the amount of redirected power that misses the receiver. B&W has identified two flux requirements for this receiver system.

(1) The incident flux distribution should be as uniform as possible to minimize the risk of tube-to-tube or flow path temperature unbalances.

(2) Incident flux should not exceed 720 kW/m^2.

The site preparation trade study, discussed in Section 3.3, identified an area north of the CRS turbine building and cooling tower as the most cost effective field location, considering the combined costs of site preparation and receiver piping. Figure 3.5-1 illustrates the Cimarron River site arrangement, showing the approximate dimensions and location of a 37.13 MWt collector/receiver system. Because of the rugged terrain, the collector field will require grading to smooth the local features. But to minimize the amount of earth moved, the final field will have a gently rolling topography with an overall slope to the north that retains the prominent features of the existing site. For the purposes of design and performance calculations in this trade study, the collector field shape is modeled as a flat plane, level from east to west, and sloping to the north at a grade of 3 per cent. The 3 per cent slope is representative of the general slope expected in the final field after site preparation.

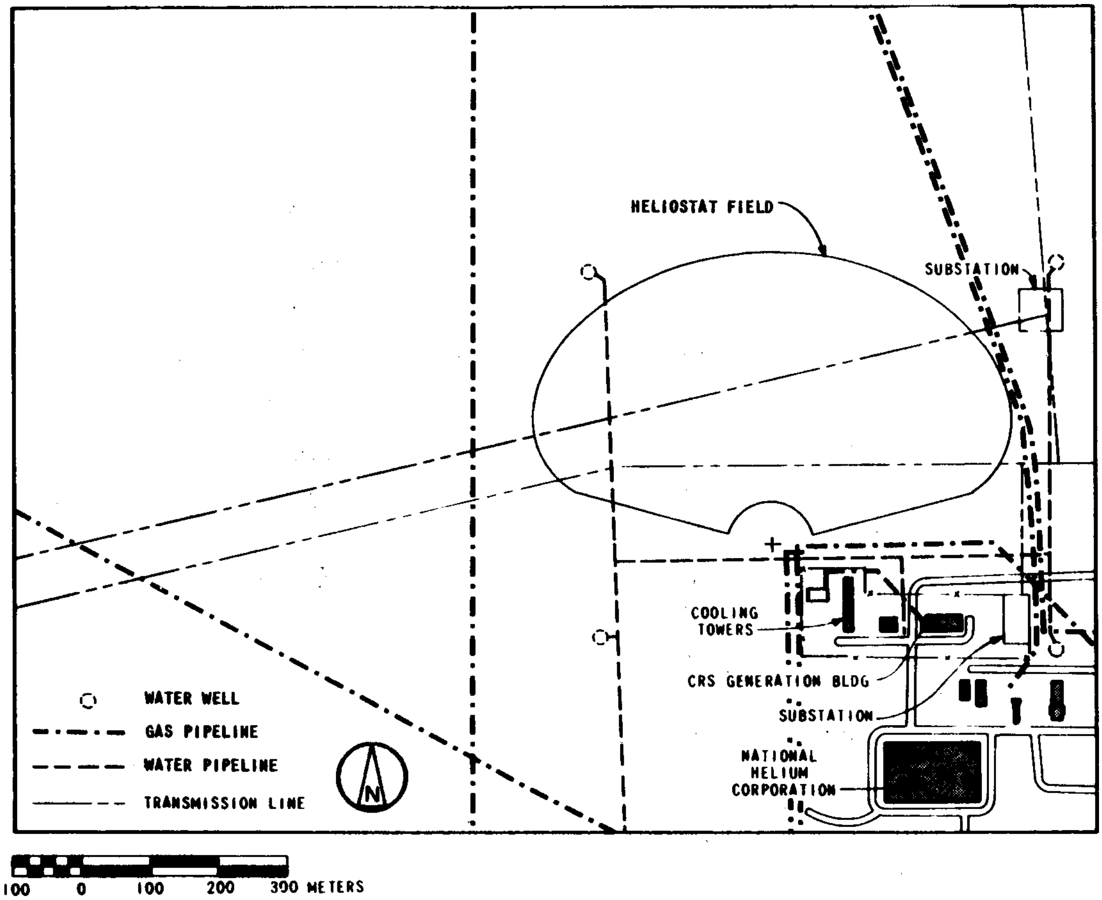


FIGURE 3.5-1. SITE ARRANGEMENT

The procedure used in optimizing the locations of heliostats within the collector field considers the combined effects of insolation, cosine effects, shadowing and blocking, reflectivity, atmospheric attenuation, and flux spillage. For the purposes of this trade study, the heliostat characteristics presented in Table 3-6 are used. These characteristics are nominal values that approximate the general features of all DOE second generation production heliostats. Although the reflectivity of clean mirrors is expected to be 0.92, a value of 0.90 is assumed in these trade studies as an average reflectivity between washings. Insolation is modeled with the ASHRAE*

*American Society of Heating, Refrigerating and Air Conditioning Engineers.

TABLE 3-6. NOMINAL HELIOSTAT CHARACTERISTICS

Heliostat Height	7.44 m (24.25 ft)
Heliostat Width	7.39 m (24.42 ft)
Height of Elevation Axis Center Line	4.04 m (13.25 ft)
Heliostat Area	55.01 m^2 (592.1 ft^2)
Total Reflective Area	52.77 m^2 (568.0 ft^2)
Number of Mirror Modules Per Heliostat	12 (2 Horizontal, 6 Vertical)
Mirror Module Size	1.22 m x 3.66 m (4 ft x 12 ft)
Mirror Reflectivity	0.90 average, 0.92 clean
Standard Deviation of Angular Errors for Pointing	0.75 milliradians each axis
Standard Deviation of Angular Errors in Surface Normal	1.0 milliradians each axis
Mirror Modules Individually Canted	
Array of Mirror Modules Approximates a Spherical Surface with Focal Length Equal to Slant Range	
Heliostats Meet Requirements of Collector Subsystem Requirements Specification A10772, Issue D	

clear air model, with the design point insolation fixed at 0.95 kW/m^2 per contract requirements. Also, the effects of atmospheric attentuation between the heliostat and receiver is modeled according to:

Transmittance = Exp(-slant range/10,000 meters).

Determining the optimum receiver elevation represents a key field design tradeoff. Higher elevations improve the optical performance of the collector by lowering cosine and shadow/block losses, and allow closer packing of heliostats with less land usage. However, the higher elevations require a taller receiver support tower and longer piping runs. Thus, a tradeoff is made by designing collector systems at several receiver elevations, and selecting the elevation resulting in the least total heliostat, tower, piping, land, and site preparation costs.

As illustrated in Figure 3.5-1, several site constraints exist that impact the location of the receiver support tower and the location of heliostats within the collector field. On the east side of the plant site are two underground gas pipelines lying within a 30 meter wide right-of-way. To the east of the pipelines are an electrical substation, an overhead electrical transmission line, an underground water pipeline, and buried control and power cables.

Although Figure 3.5-1 shows the collector system located entirely to the west of the pipelines and transmission mentioned above, economics may favor shifting the field further to the east to reduce receiver piping costs. For this case the field layout would be adjusted to avoid relocation of the pipelines. Regardless of the collector location, site preparation work will require the relocation of water pipelines buried along the western edge of the site and two overhead transmission lines crossing the site from east to west.

3.5.3 Approach and Analyses

The methodology for developing the collector field layout consists of three general steps.

(1) Identify the receiver dimensions and arrangement of heat transfer panels that minimize receiver cost yet conform to incident flux requirements.

(2) Determine the optimum receiver elevation by trading off the better optical performance of higher elevations with higher tower and piping costs.

(3) Make modifications to the field layout and aim strategy to conform to existing site constraints and meet the receiver flux requirements.

The field layout trade study involves a number of separate field designs tailored for specific receiver sizes and elevations. In each design, the number of heliostats required and their locations within the collector field are determined through an optimization procedure aimed at maximizing the annual efficiency of the collector field. The field is sized to meet the 37.13 MWt receiver power requirement at the design point, but heliostats are positioned within the field to maximize the annual energy redirected to the receiver.

By scaling collector and receiver dimensions from a similar solar facility[2] to the 37.13 MWt receiver size, the first estimates of receiver dimensions were 7.3 m (24 ft) diameter, 10.4 m (34 ft) height, and 90 m (295 ft) elevation. The optimum field layout for these receiver dimensions forms a 150 degree sector north of the receiver support tower. Using an aim strategy that alternates the aiming of heliostats between four vertical aim points on the receiver surface, uniform flux distributions were achieved with peak fluxes well below the 720 kW/m^2 peak flux limit. Analysis of both receiver and collector performance data for that system showed that the size of the receiver could be reduced to lower its costs without significantly increasing spillage losses or exceeding the peak flux requirements. As a result, the receiver dimensions were lowered to 6.71 m (22 ft) diameter and 9.45 m (31 ft) height, with superheater panels covering a 180 degree sector on the north side of the receiver. Economizer panels were placed 15 degrees beyond the superheater panels on the east and west sides of the receiver to pick up incident flux spilled from the superheater surfaces.

After receiver dimensions and power requirements were established, a trade study was conducted to determine the optimum receiver elevation, trading off the better optical performance and close heliostat packing associated with higher elevations with the higher tower and piping costs. Separate collector designs were made for several elevations ranging from 65 to 100 m (receiver center line to grade). Each field was sized such that the receiver would deliver 37.13 MWt at the design point, yet the heliostats were positioned to maximize the annual collector efficiency. Cost estimates were then made for each field, including the costs of heliostats, land, site preparation, tower, and piping within the tower. The following cost information was used in the study.

(1) Heliostat costs based on \$230/m^2.

(2) Land cost based on \$1,483/hectare (\$600/acre).

(3) Site preparation costs were based on an average value of \$13,000 per acre of collector field which was estimated in the site preparation trade study.

(4) Steel towers are more economical than concrete for the external receiver in this range of tower heights. Tower costs were modeled with the Sandia/Stearns Roger tower cost model.[5]

(5) Receiver piping costs were based on pipe sizes identified in steam conditions trade study, Section 3.6. Installed costs for piping, including insulation, are $978/m for 0.15 m (6-inch) main steam and $374/m for 0.10 m (4-inch) feedwater pipe.

The results of the receiver elevation trade study are shown graphically on Figure 3.5-2. This figure indicates the total cost is relatively insensitive to receiver elevation, but indicates an optimum center line elevation of 84 m above grade (80 m above the heliostat center lines). The optimized collector field for that system would occupy a 120 degree sector north of the tower, as illustrated on Figure 3.5-3. However, as its design point

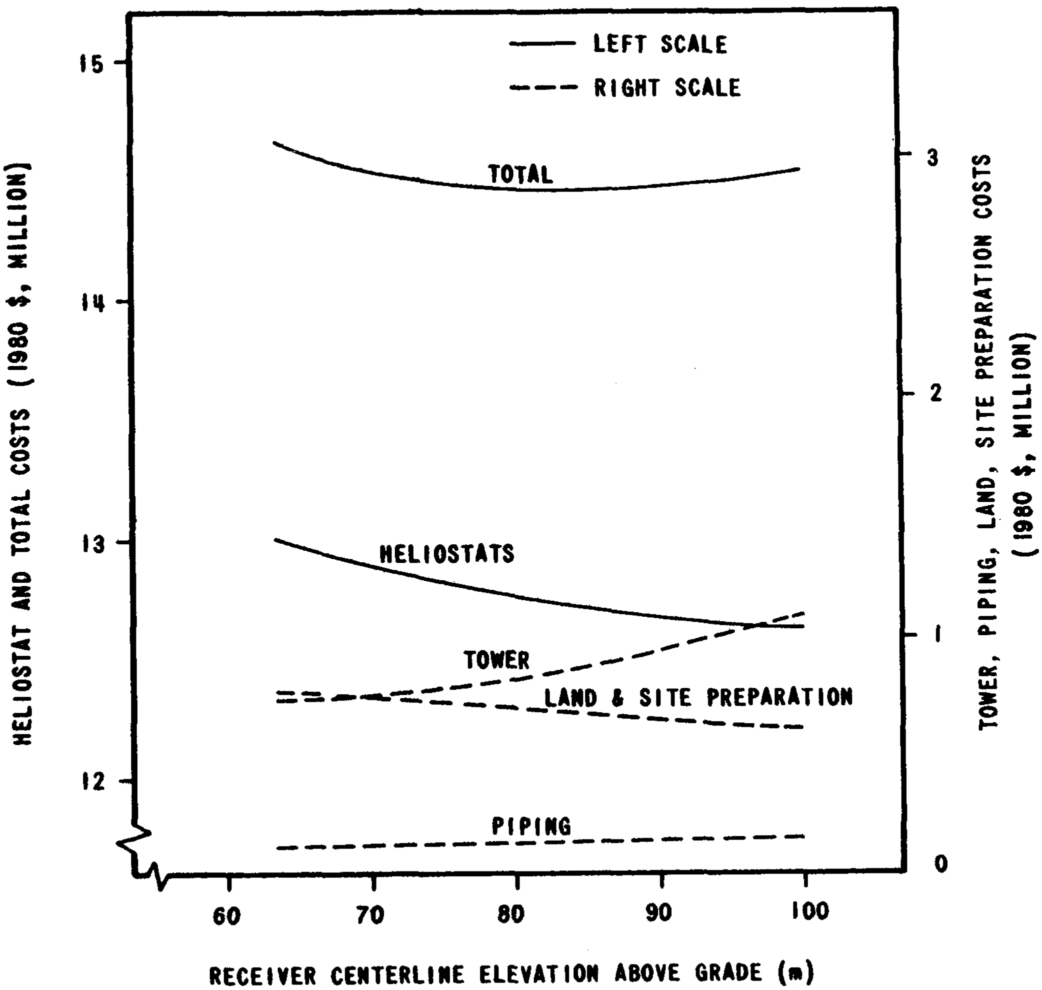
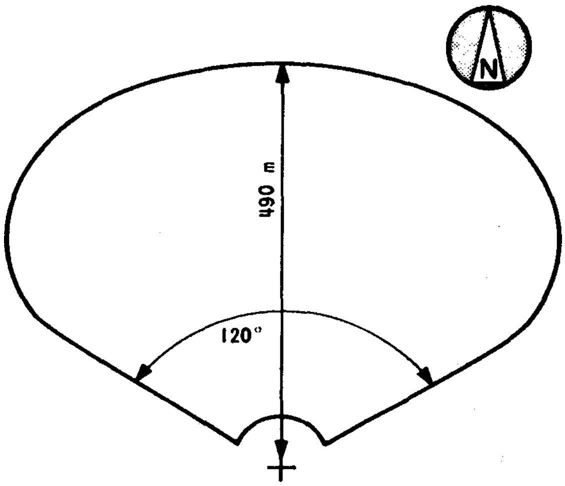
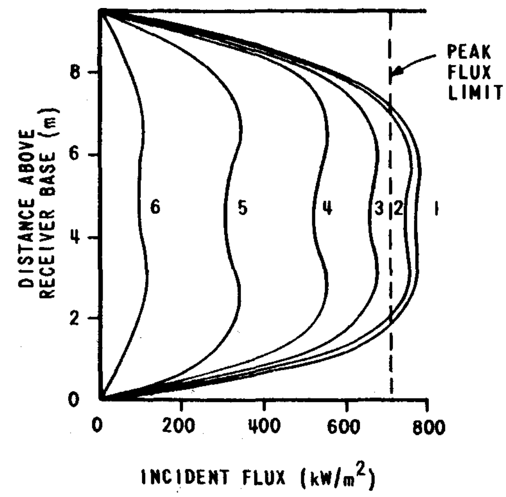


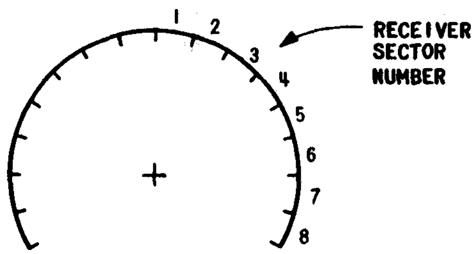
FIGURE 3.5-2. SOLAR FACILITY COSTS AS A FUNCTION OF RECEIVER ELEVATION

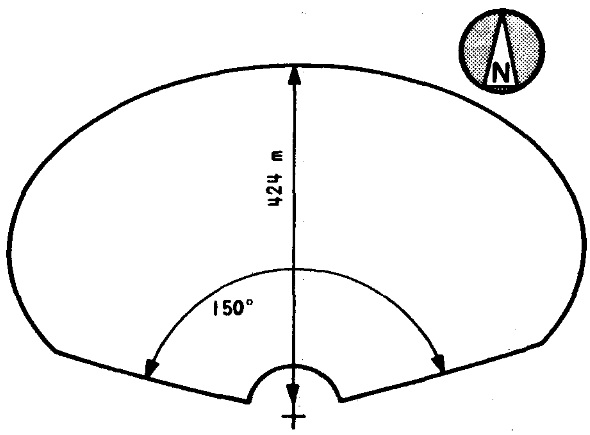


A. OPTIMUM FIELD SHAPE FOR 37.3 MW_t RECEIVER

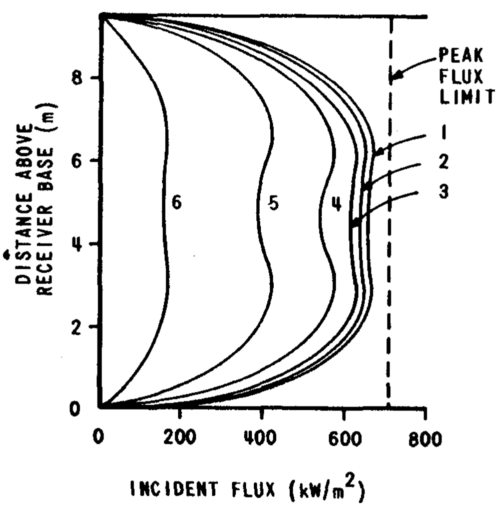


B. DESIGN POINT FLUX DISTRIBUTION FROM 120° FIELD





C. MODIFIED FIELD MEETING PEAK FLUX REQUIREMENTS



D. DESIGN POINT FLUX DISTRIBUTION FROM 150° FIELD

FIGURE 3.5-3. ALTERNATE FIELD DESIGNS

flux distribution on Figure 3.5-3 indicates, the narrow, highly north-biased collector shape produces flux levels on the north side of the receiver in excess of 800 kW/m^2, well above the 720 kW/m^2 peak flux limit. To lower the fluxes on the north side of the receiver, the collector field was modified, shifting heliostats from the northern edge of the field to the east and west sides to form the 150 degree field shape illustrated on Figure 3.5-3. Shifting heliostats in this manner increases collector losses due to cosine effects but reduces the losses due to spillage. As a result, the modifications increased the required mirror area by only 0.2 per cent and reduced the annual energy redirected to the receiver by less than 0.2 per cent. The effects of the field modifications on the receiver flux distribution are illustrated on Figure 3.5-3, showing that all flux levels at the design point are below the 720 kW/m^2 peak flux limit.

The collector field resulting from the field layout trade study, shown on Figure 3.5-3, occupies a 150 degree sector north of the tower with an outer radius of 424 m (1,391 ft) and an inner radius of 68 m (223 ft) from the tower center line. The field contains 1,057 heliostats, occupying a land area of 222,000 m^2 (55 acres). The aim strategy developed for that field, illustrated on Figure 3.5-4, uses four aim points to spread the incident power vertically along the heat transfer surfaces. All heliostats having the same slant range alternate between four aim points whose vertical separation on the receiver surface are a function of slant range. Heliostats farthest from the tower, having the largest images, aim near the center of the receiver to avoid excessive spillage off the top and bottom of the receiver. On the other hand, heliostats nearest the tower, which redirect the smallest images onto the receiver, aim at points near the top and bottom of the receiver to fill in the flux profile in those regions.

3.5.4 Conclusion

This trade study determined that the collector field would occupy a 150 degree sector north of the receiver support tower, with an inner radius of 68 m (223 ft) and an outer radius of 424 m (1,391 ft) from the tower. The field contains 1,057 heliostats which redirect power to a 210 degree sector of a cylindrical, external receiver centered 84 m (276 ft) above grade. A four point aim stragety is employed to spread the incident heat flux as uniformly as possible on the heat transfer surfaces.

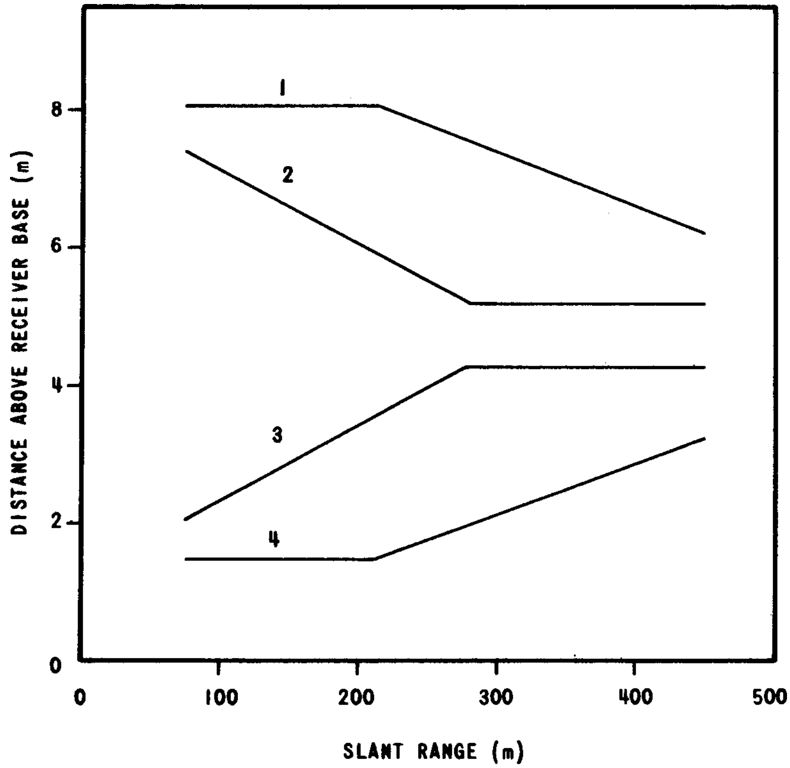


FIGURE 3.5-4. FOUR POINT AIM STRATEGY

3.6 STEAM CONDITIONS

The solar generated steam conditions most favorable to the cogeneration facility were evaluated.

3.6.1 Objectives and Scope

The primary objective of the steam conditions trade study was to determine the preferred temperature and pressure of steam delivered from the solar receiver to the existing turbine at CRS Unit 1. In addition, secondary objectives were to determine the preferred sizes of receiver feedwater and main steam piping. Piping size determination was included as part of the study due to the fundamental impact of piping losses on receiver performance and cost.

Preferred steam conditions and piping sizes were selected based on three primary considerations. The first consideration was the operational requirements and limitations of the existing system. The second consideration was the relative cost and performance impact of alternative steam conditions and pipe sizes.

3.6.2 <u>Relevant Factors</u>

A number of factors are relevant to the selection of preferred steam conditions and pipe sizes. Some of these factors impact the range of steam conditions and pipe sizes initially considered in the study. Other factors impact the final selection of the preferred system.

3.6.2.1 <u>Initial Consideration Factors</u>. Major factors which impact the range of conditions initially considered are discussed in the following.

3.6.2.1.1 <u>Turbine Throttle Pressure</u>. Steam delivered from the solar receiver must match the turbine throttle pressure of steam from the fossil boiler. The maximum turbine throttle pressure, corresponding to the overpressure rating, is 9.58 MPa (1,390 psia). Therefore, as a maximum condition, the solar receiver must be designed to deliver 9.58 MPa (1,390 psia) steam to the turbine throttle valves.

3.6.2.1.2 <u>Turbine Throttle Temperature</u>. The existing turbine at CRS Unit 1 has a throttle temperature limit of 510 C (950 F). Therefore, an upper limit of 510 C (950 F) was set for delivered receiver steam temperature. A lower limit of delivered receiver steam temperature was established at 482 C (900 F). This lower limit was based on consideration of the decrease in cycle efficiency, a potential decrease in turbine life due to temperature cycling, and a demonstration of state of the art receiver design.

3.6.2.1.3 <u>Piping Sizes</u>. Main steam and feedwater piping sizes impact the selection of the preferred system via differential capital and operational costs (operational costs result from enthalpy losses and pumping power to overcome pressure drops). For the purposes of this study, three main steam pipe sizes and three feedwater pipe sizes were considered. Initial pipe sizes were selected based on standard pipe sizing methods for fossil-fueled power plants. Two additional pipe sizes were selected for consideration by choosing the next larger and smaller available pipe sizes.

3.6.2.1.4 Receiver Feedwater Booster Pump. An evaluation of the existing boiler feed pump revealed that it would not be capable of providing feedwater at sufficient head to the solar receiver for all operating conditions. Therefore, it was necessary to add a booster pump. The booster pump would be located in the receiver feedwater piping and would include appropriate control valves to regulate receiver drum water level.

3.6.2.2 Final Selection Factors. Major factors which impact the final selection of the preferred system include the following.

(1) Cycle Heat Rate--The cycle heat rate increases for turbine throttle temperatures lower than 510 C (950 F). Therefore, solar receivers with delivered steam temperatures lower than 510 C (950 F) will require more heat input to the turbine and a correspondingly larger heliostat field.

(2) Receiver Feedwater Booster Pump Cost--It was established that all of the systems considered will require the addition of a booster pump. The size and cost of the booster pump is a function of the design pressure drop in the receiver piping system. Booster pumps will cost more for systems with larger receiver piping system pressure drops (i.e., systems with smaller feedwater and main steam piping).

(3) Receiver Cost--The capital cost of the solar receiver increases with increasing design point outlet temperature. Systems with higher design point delivered receiver steam temperatures will therefore have higher cost receivers.

(4) Receiver Efficiency--The efficiency of the solar receiver is a function of its outlet temperature. As outlet temperature increases, the receiver efficiency decreases. Systems with higher receiver outlet temperatures will, therefore, require larger heliostat fields to deliver the same quantity of thermal power.

(5) Piping Thermal Losses--Thermal losses in the main steam and feedwater piping have two principal effects. First, the thermal losses directly lower the thermal power input to the turbine. Therefore, the receiver and heliostat field must be sized correspondingly larger to meet the same design point power to the

turbine. Secondly, through thermal losses, the temperature of steam delivered to the turbine is lowered. Therefore, to meet the same turbine throttle temperature design value, the receiver outlet temperature must be correspondingly higher.

(6) Piping Pressure Losses--Pressure losses in the main steam and feedwater piping are higher for smaller pipe sizes. These pressure losses have two principal effects. First, auxiliary power requirements for receiver feedwater pumping increase directly with increasing pressure drop. Since the solar system is sized to supply its own auxiliary power, it must be sized larger for larger auxiliary powers. Secondly, main steam piping pressure losses cause a temperature drop due to throttling. Therefore, the receiver outlet temperature must be increased in order to meet the same turbine throttle temperature design value.

3.6.3 Approach and Analysis

3.6.3.1 Initial Analysis. As explained in Subsection 3.6.2, two steam temperatures, three main steam pipe sizes, and three feedwater pipe sizes were selected for initial consideration. All possible combinations of steam temperature and pipe sizes were evaluated, resulting in a total of 18 cases. These 18 cases are identified on Table 3-7.

To evaluate the 18 cases, a Figure of Merit (FOM) was calculated for each. The FOM, defined on Table 3-8, accounts for both capital costs and performance. Therefore, the FOM provides a common basis for comparison of the 18 cases; the case with the lowest FOM has the best cost/performance.

3.6.3.1.1 Details of the Analysis. Details of the calculation of each component in the FOM formula are provided in the following.

(1) Heliostat Field Cost--Heliostat reflector area was determined based on the following.
   (a) Noon, March 21 design point.
   (b) Solar providing 15 MWe net at design point in addition to underlying fossil generation of 20 MWe net.
   (c) Solar auxiliaries of 0.5 MWe.

TABLE 3-7. INITIAL CASES CONSIDERED FOR STEAM CONDITIONS STUDY

Case Number	Delivered Steam Temperature		Nominal Main Steam Pipe Size		Nominal Feedwater Pipe Size	
	C	F	meters	inches	meters	inches
1	482	900	0.15	6	0.076	3
2	482	900	0.15	6	0.10	4
3	482	900	0.15	6	0.13	5
4	482	900	0.20	8	0.076	3
5	482	900	0.20	8	0.10	4
6	482	900	0.20	8	0.13	5
7	482	900	0.25	10	0.076	3
8	482	900	0.25	10	0.10	4
9	482	900	0.25	10	0.13	5
10	510	950	0.15	6	0.076	3
11	510	950	0.15	6	0.10	4
12	510	950	0.15	6	0.13	5
13	510	950	0.20	8	0.076	3
14	510	950	0.20	8	0.10	4
15	510	950	0.20	8	0.13	5
16	510	950	0.25	10	0.076	3
17	510	950	0.25	10	0.10	4
18	510	950	0.25	10	0.13	5

(d) Heat rate data as provided on Figure 3.6-1 for the 510 C (950 F) cases and appropriate heat rate correction factors for the 482 C (900 F) cases.

(e) Piping thermal losses computed for each case.

(f) Receiver efficiency computed for each case.

(g) A symmetric north field.

TABLE 3-8. DEFINITION OF THE FIGURE OF MERIT

$$FOM = \frac{(HFC + SRC + MSPC + FWPC + BPC) \times FCR}{ASEG}$$

Where:

FOM	=	Figure of Merit ($/MWhe)
HFC	=	Heliostat Field Cost ($)
SRC	=	Solar Receiver Cost ($)
MSPC	=	Main Steam Piping Cost ($)
FWPC	=	Feedwater Piping Cost ($)
BPC	=	Booster Pump Cost ($)
FCR	=	Fixed Charge Rate
ASEG	=	Annual Solar Electricity Generation (MWhe)*

*Net generation.

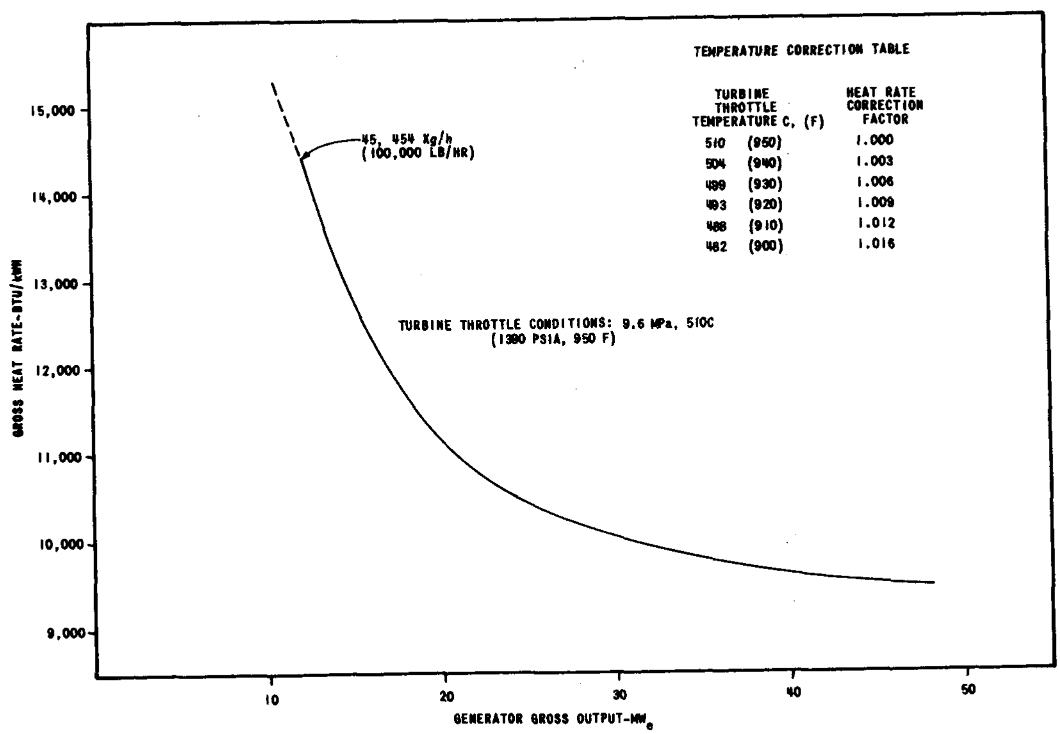


FIGURE 3.6-1. GROSS HEAT RATE VS OUTPUT

Field cost was determined based on the heliostat reflector area and a unit cost of $\$230/m^2$.

(2) Solar Receiver Cost--The cost of the solar receiver was calculated via a cost algorithm provided by B&W.* The algorithm defines receiver cost as a function of receiver outlet temperature for receivers designed to provide 15 MWe net additional power at the design point.

(3) Main Steam Piping Cost--The cost of main steam piping was calculated based on the following.

(a) A vertical piping length of 131 m (431 feet) in the receiver tower, including an expansion loop factor of 1.4.

(b) A horizontal piping length of 418 m (1,372 feet) from the tower base to the CRS Unit I turbine, including an expansion loop factor of 1.4.

(c) Unit cost estimates for each pipe size for horizontal and vertical installation. Costs included insulation, aluminum sheathing, supports, and installation.

(4) Feedwater Piping Costs--The cost of feedwater piping was calculated based on the following.

(a) A vertical piping length of 117 m (383 feet) in the receiver tower, including an expansion loop factor of 1.1.

(b) A horizontal piping length of 329 m (1,078 feet) from the tower base to the CRS Unit I feedwater piping, including an expansion loop factor of 1.1.

(c) Unit cost estimates for each pipe size for horizontal and vertical installation. Costs included insulation, aluminum sheathing, supports, and installation.

(5) Booster Pump Cost--The cost of the booster pump and associated motor for each case was based on the following.

(a) The fluid conditions of the feedwater (i.e., temperature and pressure).

---

*The cost algorithm was:

$$\text{Cost} = \$10^6 \ [6.6 + 0.05 \ (\text{Receiver Outlet Temp-900 F})^{0.573}]$$

(b) The design feedwater flow rate for each case.

(c) The design total developed head for each case.

(6) Fixed Charge Rate--A fixed charge rate of 17.5 per cent was used. This value is based upon the economic evaluation criteria established for the project. (See Appendix A)

(7) Annual Solar Electricity Generation--The annual net electricity generated by CRS Unit I which can be attributed to the solar addition was determined based on the following.

(a) The ASHRAE clear air insolation model for Dodge City, Kansas. Electricity generation was not corrected for available sunshine.

(b) The load model for CRS Unit I: 45 MWe generated from gas during July and August; 20 We generated from gas during the remainder of the year.

(c) Auxiliary power requirements for the solar addition. Auxiliary power algorithms were developed for each case based on feedwater pumping to the receiver and other power requirements.

(d) Expected field and receiver efficiencies and piping thermal losses.

(e) The heat rate as a function of load for CRS Unit I, assuming 23,000 kg/h (50,000 lb/h) of process steam to NHC and sliding pressure operation. For the 482 C (900 F) cases, a heat rate correction factor was used to correct for lower turbine throttle temperatures.

The calculation was performed by the B&V computer code, "STEPPE."

3.6.3.1.2 Results of the Analysis. The results of the initial analysis are reported on Tables 3-9 and 3-10. Reported values include the FOM, heliostat field cost, solar receiver cost, main steam piping cost, feedwater piping cost, booster pump cost, and annual solar electricity generation for each case. The FOM is plotted on Figure 3.6-2 to illustrate the results.

TABLE 3-9. FIGURE OF MERIT SUMMARY: STEAM TEMPERATURE = 482 C (900 F)

	Case 1	Case 2	Case 3	Case 4	Case 5	Case 6	Case 7	Case 8	Case 9
Main Steam Pipe Size m (in.)	0.15 (6)	0.15 (6)	0.15 (6)	0.20 (8)	0.20 (8)	0.20 (8)	0.25 (10)	0.25 (10)	0.25 (10)
Feedwater Pipe Size m (in.)	0.076 (3)	0.10 (4)	0.13 (5)	0.076 (3)	0.10 (4)	0.13 (5)	0.076 (3)	0.10 (4)	0.13 (5)
Capital Costs ($ x 10^3)									
Heliostat field	12,809	12,809	12,809	12,799	12,799	12,799	12,796	12,796	12,796
Solar receiver	6,864	6,864	6,864	6,781	6,781	6,781	6,760	6,760	6,760
Main steam piping	444	444	444	623	623	623	913	913	913
Feedwater piping	98.2	117	141	98.2	117	141	98.2	117	141
Booster pump	64.7	62.6	62.6	62.6	60	60	62.6	60	60
Total	20,279.9	20,296.6	20,320.6	20,363.8	20,380.0	20,404.0	20,629.8	20,646.0	20,670.0
Total x Fixed Charge Rate ($ x 10^3)	3,549.0	3,551.9	3,556.1	3,563.7	3,566.5	3,570.7	3,610.2	3,613.1	3,617.3
Annual Solar Electricity Generation (MWhe)	41,671	41,738	41,741	41,719	41,783	41,785	41,713	41,782	41,783
Figure of Merit ($/MWhe)	85.17	85.10	85.19	85.42	85.36	85.45	86.55	86.47	86.57

TABLE 3-10. FIGURE OF MERIT SUMMARY: STEAM TEMPERATURE 510 C (950 F)

	Case 10	Case 11	Case 11	Case 13	Case 14	Case 15	Case 16	Case 17	Case 18
Main Steam Pipe Size m (in.)	0.15 (6)	0.15 (6)	0.15 (6)	0.20 (8)	0.20 (8)	0.20 (8)	0.25 (10)	0.25 (10)	0.25 (10)
Feedwater Pipe Size m (in.)	0.076 (3)	0.10 (4)	0.13 (5)	0.076 (3)	0.10 (4)	0.13 (5)	0.076 (3)	0.10 (4)	0.13 (5)
Capital Costs ($ × 10^3)									
Heliostat field	12,692	12,692	12,692	12,706	12,706	12,706	12,702	12,702	12,702
Solar receiver	7,159	7,159	7,159	7,123	7,123	7,123	7,115	7,115	7,115
Main steam piping	444	444	444	623	623	623	913	913	913
Feedwater piping	98.2	117	141	98.2	117	141	98.2	117	141
Booster pump	64.7	62.6	61.4	62.6	60	60	61.4	60	60
Total	20,457.9	20,474.6	20,497.4	20,612.8	20,629.0	20,653.0	20,889.6	20,907.0	20,931.0
Total × Fixed Charge Rate ($ × 10^3)	3,580.1	3,583.1	3,587.0	3,607.2	3,610.1	3,614.0	3,655.7	3,658.7	3,662.9
Annual Solar Electricity Generation (MWhe)	41,348	41,452	41,454	41,520	41,573	41,578	41,514	41,567	41,571
Figure of Merit ($/MWhe)	86.48	86.44	86.53	86.88	86.84	86.93	88.06	88.02	88.11

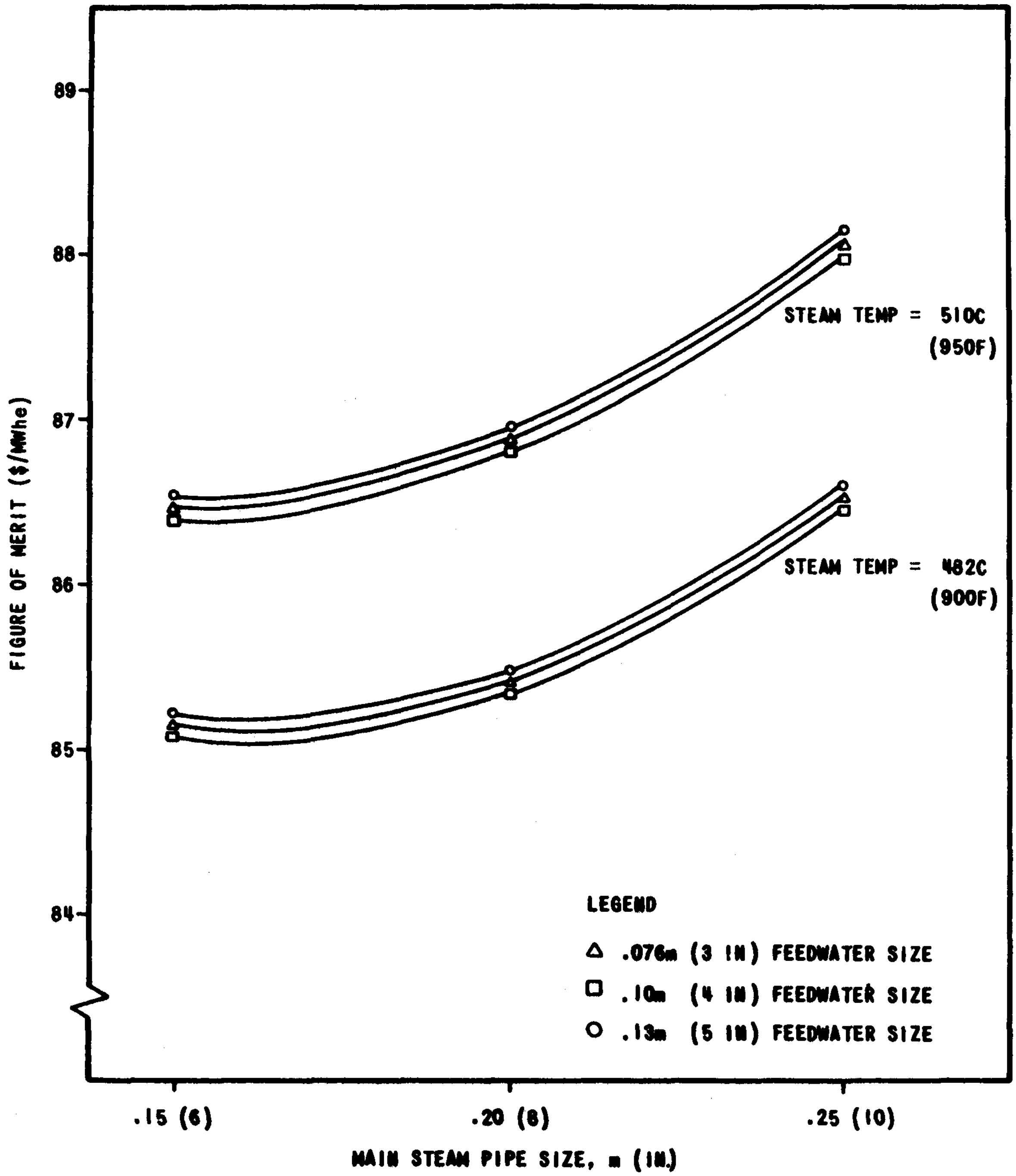


FIGURE 3.6-2. STEAM CONDITIONS STUDY RESULTS

Results of the initial steam conditions analysis show the following.

(1) Case 2 has the lowest FOM: $85.10/MWhe.

(2) The advantage of 482 C (900 F) steam versus 510 C (950 F) steam is slight; Case 2 has a 1.6 per cent lower FOM than the corresponding Case 11.

(3) The 0.10 m (4 inch) feedwater pipe cases consistently have lower FOM's than the 0.076 m (3 inch) or 0.13 m (5 inch) cases.

(4) The 0.15 m (6 inch) main steam pipe cases consistently have lower FOM's than the 0.20 m (8 inch) or 0.25 m (10 inch) cases.

3.6.3.2 Additional Analysis. The initial analysis showed a consistent trend of decreasing FOM as the main steam pipe size decreased from 0.25 m (10 inches) to 0.20 m (8 inches) to 0.15 m (6 inches). Therefore, in order to determine the trend below 0.15 m (6 inches), an additional case was evaluated. The case, termed Case 19, was evaluated for 510 C (950 F) steam, 0.13 m (5 inch) main steam pipe, and 0.10 m (4 inch) feedwater pipe.

Case 19 was evaluated as Cases 1 through 18 were, using the methods described in Subsection 3.6.3.1. Results of the evaluation are summarized on Table 3-11. To illustrate the trend of FOM versus main steam pipe size, the FOM's are plotted on Figure 3.6-3 for 510 C (950 F) steam and 0.10 m (4 inch) feedwater pipe.

Results of this additional analysis show the following.

(1) The lowest FOM is for the 0.15 m (6 inch) main steam pipe case.

(2) For main steam pipe sizes less than 0.15 m (6 inches), the FOM rises sharply.

3.6.3.3 Other Considerations. Two other considerations have an important impact on the selection of the preferred steam conditions and pipe sizes. One of the other considerations is the potentially detrimental effect of turbine temperature mismatches that would occur with a 482 C (900 F) solar system. The temperature mismatches would cause increased turbine cyclic stresses which can potentially result in increased turbine maintenance. A second important consideration is that a 510 C (950 F) receiver would better satisfy the objectives of the Solar Cogeneration Program, since it requires high temperature resistant alloy materials. By demonstrating

TABLE 3-11. FIGURE OF MERIT SUMMARY: CASE 19

Case Number	19
Main Steam Pipe Size, m (inches)	0.13 (5)
Feedwater Pipe Size, m (inches)	0.10 (4)
Capital Costs ($\$ \times 10^3$)	
Heliostat field	12,752
Solar receiver	7,229
Main steam piping	388
Feedwater piping	117
Booster pump	64.7
Total	20,550.7
Total x Fixed Charge Rate ($\$ \times 10^3$)	3,596.4
Annual Solar Electricity Generation (MWhe)	41,411
Figure of Merit ($/MWhe)	86.85

higher temperature receiver technology, the 510 C (950 F) system would do more to advance the state-of-the-art of solar thermal power.

3.6.4 Conclusions

The preferred steam conditions and pipe sizes are identified in the following. Selection rationale is also provided.

(1) Steam Pressure--Due to the operational groundrules established for the solar receiver, the preferred system should deliver steam which matches the turbine throttle inlet pressure for all operating conditions. The maximum turbine throttle pressure, corresponding to overpressure conditions, is 9.58 MPa (1,390 psia).

(2) Steam Temperature--The cost/performance analyses presented in Subsection 3.6.3 indicate that 482 C (900 F) systems have a slight advantage over 510 C (950 F) systems. However, this advantage is very small and within the accuracy of input data used in the analysis. Therefore, other considerations have a strong influence on the selection. These other considerations,

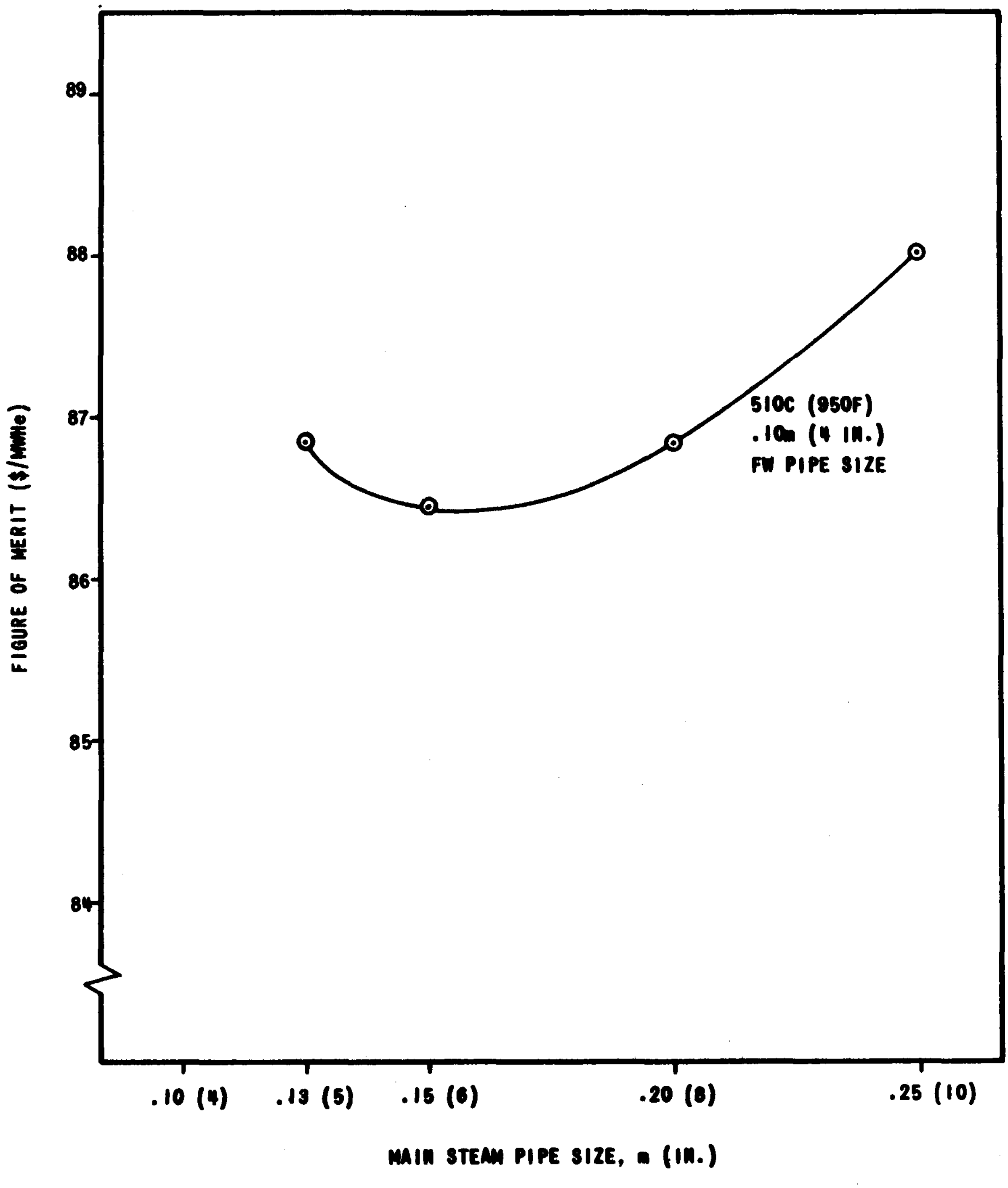


FIGURE 3.6-3. MAIN STEAM PIPE SIZE TRENDS

turbine thermal cycling and demonstration of receiver technology, were the basis for selecting a 510 C (950 F) system.

(3) Pipe Sizes--The results of the cost/performance analyses presented in Subsection 3.6.3 consistently show that 0.15 m (6 in) main steam pipe and 0.10 m (4 in) feedwater pipe are optimum. Therefore, these pipe sizes were selected as the preferred sizes.

4.0 SOLAR FACILITY CONCEPTUAL DESIGN

In the previous section, the results of several trade studies performed on the project were presented. These studies identified key design characteristics of the preferred system which were then used as the baseline upon which the conceptual design was developed. The broad system-level features of that design are discussed in this section. A more detailed treatment of individual systems is contained in Section 5.

This section begins with a description of the overall system, followed by discussions of functional requirements, design and operating characteristics, site requirements, and system performance. Next, capital cost and operating and maintenance costs are summarized. The section is concluded with discussions of safety, environmental impacts, and institutional and regulatory considerations.

4.1 FACILITY DESCRIPTION

The solar cogeneration facility, pictorially shown on Figure 4.1-1, is designed to supply superheated steam to the existing Cimarron River Station (CRS) Unit 1. CRS provides electricity to the Western Power system and process heat and electricity to the adjacent National Helium Corporation's (NHC) natural gas processing plant. The solar facility, which consists of five solar-unique systems, is fully integrated with the existing CRS unit.

The systems which comprise the solar facility are the collector, receiver, receiver piping, solar master control, and solar auxiliary electric systems. Their overall function is to transform solar energy into thermal energy for use by the existing fossil-fueled plant; this plant is characterized by the fossil energy delivery, electric power generation and process heat systems. The key features and principal interfaces of each of these systems are described below; a more rigorous discussion of the solar facility systems is presented in Section 5.

The collector system, which consists of a field of computer-controlled, two-axis tracking heliostats, intercepts, redirects and concentrates direct

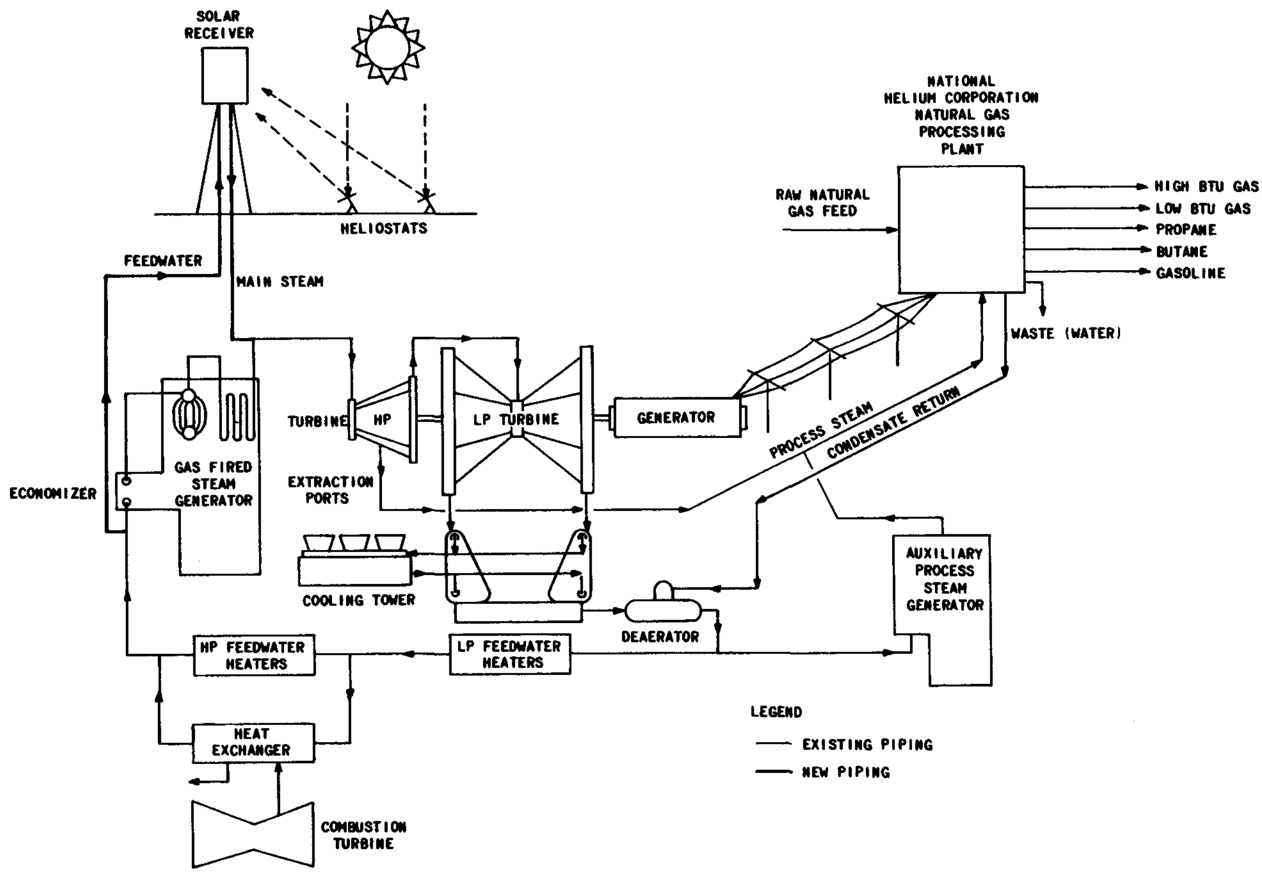


FIGURE 4.1-1 SIMPLIFIED SCHEMATIC OF COGENERATION FACILITY

normal insolation. For this design, a generic DOE second generation heliostat is specified; key features of this heliostat include 52.8 m^2 of reflective surface area, an effective reflectivity of 0.90, and separate motors for azimuthal and elevation steering. The collector field design consists of 1,057 heliostats located north of the receiver. Principal interfaces with other plant systems include the redirected solar flux onto the solar receiver, power for heliostat drive motors from the solar auxiliary electric system, and control signals received from the solar master control system.

The water/steam receiver system absorbs solar energy and converts it into thermal energy. This heat is then transferred to the working fluid, converting feedwater into superheated steam. For this solar cogeneration application, the receiver has symmetric external heat absorbing surfaces which extend 105 degrees either side of north. It employs a pumped circulation system and has three stages of superheating. The solar receiver is located atop a structural steel tower; the tower provides personnel access to the receiver and supports receiver piping and receiver auxiliary equipment. Major interfaces with other systems are the solar flux from the collector system, feedwater from and superheated steam to the receiver piping system, power from the solar auxiliary electric system, and control signals exchanged with the solar master control system.

The function of the receiver piping system is to transport the working fluid between the receiver system and the electric power generating system (EPGS), which consists of the turbine generator and other power conversion cycle components. Key system features consist of insulated feedwater and steam piping, a booster pump to supplement the existing boiler feed pump, a tank at the base of the tower for draining the receiver, and condensate return lines. Primary interfaces include feedwater and steam line connections to the receiver system; feedwater, steam and condensate line connections with the EPGS; auxiliary power from the solar auxiliary electric system; and control signals to and from the solar master control system.

The solar master control system coordinates the operation of the collector, receiver, receiver piping, solar auxiliary electric, fossil energy delivery and EPGS systems by receiving operating data from and sending command signals to these systems. In addition, the system serves as the data acquisition center for the solar facility by collecting, analyzing, and displaying all critical plant parameters. The solar master control system provides the capability for start-up, normal operation, and shutdown (including emergency shutdown) in either a fully automatic or a manual mode. The key elements of the system are a control and data acquisition computer (including peripheral equipment and software), an emergency shutdown system, multiplexed data links, and a control panel. The principal solar master control system interfaces consist of command and operating data signals exchanged with the other plant systems.

The solar auxiliary electric system provides electric power to those systems that are added to the existing CRS plant for the solar cogeneration application. While it normally receives its power from the existing station auxiliary power system, it also provides uninterruptible power to critical control and instrumentation functions and an emergency power source to defocus the collector field in the event of a loss of normal station power. Key elements of the system are an emergency diesel generator, batteries and associated equipment for the noninterruptible power supply, transformers, relays and cabling. It interfaces with all the solar-related systems and with existing electrical distribution equipment in the Electric Power Generating System.

The fossil energy delivery system (FEDS) uses natural gas fuel to generate superheated steam for use in the EPGS to generate electricity and to supply the process steam needs of NHC. Key elements of the system are the steam generator, the fuel gas supply and combustion equipment, and the necessary operating controls. The FEDS interfaces primarily with the EPGS.

The EPGS converts the thermal energy in superheated steam into electricity, provides steam to the process heat system, and returns the steam condensate to the FEDS steam generator and the receiver piping system. The EPGS receives superheated steam from both the solar facility and the FEDS steam generator. The major components in the EPGS include the steam turbine generator, feedwater heaters, condenser, cooling tower, and feedwater pump. Major interfaces include the exchange of feedwater, steam, and condensate with the FEDS and receiver piping system; supply of electricity to the solar auxiliary electric system; and the exchange of control and information signals with the solar master control system.

The process heat system delivers process heat in the form of steam to NHC. It normally receives steam from the EPGS after a portion of the thermal energy has been used by the turbine generator to produce electricity. Key elements of the system are steam supply and condensate return piping, and an auxiliary package boiler for use when the FEDS steam generator is shut down. This system interfaces with the EPGS at the pressure control valves on the main steam line to the turbine, the first two turbine extraction steam lines, and the feedwater line.

The major systems which comprise the solar cogeneration facility are configured to perform their unique functions and are completely integrated into a functional system. The conceptual design of this integrated system is the subject of the remainder of this section.

4.2 FUNCTIONAL REQUIREMENTS

The solar cogeneration facility is designed to intercept and collect incident direct normal insolation. The collected solar energy is used to generate superheated steam from the feedwater flowing through the solar receiver. The superheated steam is subsequently merged with steam generated in a conventional fossil steam generator and delivered to a turbine for the generation of electricity and for providing process steam.

The functional system requirements of the solar cogeneration facility designed for CRS are listed in Table 4-1. These requirements are discussed in the following paragraphs.

4.2.1 Performance Requirements

The solar cogeneration facility is to operate in a hybrid mode; steam generated in the solar receiver is admitted to the turbine simultaneously with steam generated in the existing natural gas-fired steam generator. This arrangement provides great system flexibility and a reliable heat source while eliminating the need for thermal energy storage.

At the design point of noon, March 21, at the reference site of Liberal, Kansas, the solar facility is to collect a net power of 37.13 MW_t with a reference insolation of 950 W/m^2. This represents approximately 25 per cent of the total thermal input to the cycle at the plant rated output.

At the design point, the collected thermal energy heats a 54,331 kg/h (119,800 lb/h) flow of feedwater to produce superheated steam. Feedwater is provided to the solar portion of the plant at a temperature of 218 C (425 F) and a pressure of 11.13 MPa (1,615 psia); superheated steam is returned to the power plant at a temperature of 510 C (950 F) and a pressure of 9.72 MPa (1,410 psia).

4.2.2 Environmental Requirements

The solar cogeneration facility is to operate in winds, including gusts, of speeds of up to 16 m/s (36 mph), as measured at an elevation of 10 meters. The plant is to survive winds of speeds of up to 36 m/s (80 mph) without damage.

TABLE 4-1. SOLAR FACILITY REQUIREMENTS

Performance Requirements	Value
Operating Mode	Hybrid
Design Point Power Level	
Thermal Energy (MW_t)	37.13
Equivalent MW_e (net)	15
Design Insolation (W/m^2)	950
Design Point	Noon, March 21
Reference Site	Liberal, Kansas
Latitude	37° 10'N
Longitude	100° 46'W
Input Feedwater Conditions	
Temperature [C (F)]	218 (425)
Pressure [MPa (psia)]	11.13 (1,615)
Flow rate [kg/h (lb/h)]	54,331 (119,800)
Delivered Steam Conditions	
Temperature [C (F)]	519 (950)
Pressure [MPa (psia)]	9.72 (1,410)
Flow rate [kg/h (lb/h)]	54,331 (119,800)
Design Point Solar Fraction	0.247
Storage Capacity	None
Environmental Requirements	
Maximum Operating Wind* (including gusts) [m/s (mph)]	16 (36)
Maximum Survival Wind* (including gusts) [m/s (mph)]	40 (90)
Seismic Environment	UBC Zone I
Operational Horizontal Acceleration (g)	0.02
Survival Horizontal Acceleration (g)	0.07
Operating Temperature [C (F)]	
Minimum	-26 (-15)
Maximum	43 (109)
Reliability Lifetime Requirements	
Availability (Exclusive of Sunshine)	
Expected	0.95
Required	0.85
Lifetime (years)	
Design	30
Operational	15

*At an elevation of 10 m.

The solar facility shall be able to operate during earthquakes with peak horizontal accelerations of up to 0.02 g; the system shall be able to survive earthquakes with peak horizontal accelerations up to 0.07 g without major damage.

The solar facility shall be able to operate in, and survive without damage, ambient air temperatures ranging from a low of -26 C (-15 F) to a high of 43 C (109 F).

4.2.3 Reliability Requirements

The components employed in the solar portion of the cogeneration facility are to be designed for a 30-year lifetime. This requirement is consistent with current power plant engineering practice, and it is compatible with the solar hardware currently being developed. The solar facility, however, is expected to be operated for a period of 15 years, at which time the existing power plant will meet the end of its useful lifetime.

The solar cogeneration facility should have an availability of at least 85 per cent, exclusive of sunshine, in order for Western Power to significantly use the addition. As a result of component redundancy and design conservation, the solar facility is expected to achieve an availability of at least 95 per cent, exclusive of sunshine.

4.2.4 Control Requirements

The solar facility will be capable of operation by a single plant operator who will simultaneously operate the non-solar portions of the cogeneration facility. The mode of operation will be primarily automatic with manual override capability. All solar equipment required for startup, normal operation and shutdown will be operated from a centralized location in the existing main control room. No operating personnel will be required in the receiver tower or at the heliostat field.

The controls for the solar facility will be divided into five major control systems. Separate, independent control systems shall be provided with the receiver, receiver piping, collector, and the existing fossil plant. Each of these control systems operates the equipment within its respective system. The fifth control system, the Solar Master Control System, coordinates the activities of the other four control systems to provide fully automatic control of the solar cogeneration facility.

4.2.4.1 Fossil Energy Delivery and Electric Power Generating System Controls. This existing control system adjusts the fossil steam generator fuel flow, air flow, feedwater flow, superheat attemperator spray flow, and the turbine throttle valves, in order to automatically regulate the generated power, main steam pressure, boiler drum level, and main steam temperature. This system also includes numerous controls for auxiliary equipment and a unit protection system to safely shut down the non-solar equipment during emergency conditions.

4.2.4.2 Receiver Controls. This control system shall adjust the receiver feedwater flow, superheat spray flow, and superheater panel bias valves to automatically regulate the receiver drum level, receiver outlet steam temperature, and receiver panel temperature, respectively. The system will also contain controls for the receiver vent and drain lines and the receiver steam shutoff valve.

4.2.4.3 Collector Controls. This control system will adjust heliostat orientations to regulate the amount of solar insolation on the receiver and provide for safe operation of the heliostat field.

4.2.4.4 Receiver Piping Controls. This control system shall operate the receiver piping system feedwater and steam isolation valves, the receiver feedwater booster pump recirculation valve, and the steam line drain valves. This system also will operate the pumps and valves in the condensate return line from the receiver to the electric power generating system.

4.2.4.5 Solar Master Control System. This control system shall be designed to provide the coordination of the other four control systems during hybrid operation. This system must provide the capability for an automated start-up and shutdown of the solar equipment. The Master Control System will include an emergency shutdown system to safely shut down the solar equipment during emergency conditions.

4.3 DESIGN AND OPERATING CHARACTERISTICS

The conceptual design of the solar facility at CRS provides approximately 24 per cent solar repowering at the noon, March 21 design point.

The facility design characteristics and the associated operating modes are discussed as follows.

- Existing Facility Characteristics.
- Solar Facility Characteristics.
- Integrated Facility Operating Modes.

4.3.1 Existing Facility Characteristics

The Cimarron River Station cogeneration facility contains three major elements: a natural gas fueled conventional steam power plant (Unit 1), a combustion gas turbine (Unit 2), and a natural gas fueled process steam generator. Major component design characteristics are listed in Table 4-2. The Unit 1 power conversion cycle is shown on the heat balance in Figure 4.3-1 with process steam (0.65 MPa, 95 psia) being provided to National Helium Corporation (NHC). Unit 1 utilizes a 44 MWe General Electric tandem compound, double flow, non-reheat, turbine generator. The turbine generator is normally operated at the overpressure condition for improved cycle efficiency and has a maximum capability of 60 MWe. The Unit 1 steam generator was built by Babcock & Wilcox and is a two drum Stirling, natural circulation, pressurized furnace. The Unit 1 cycle configuration includes five stages of feedwater heating. The steam cycle also employs a horizontal, two pass, surface type condenser and a mechanical draft wet cooling tower. The plant control systems were supplied by the Foxboro Company.

The combustion turbine is rated at 14 MWe. It is provided with an exhaust heat recovery exchanger. When Units 1 and 2 are operating in a combined cycle mode, the Unit 1 high pressure feedwater heaters are bypassed and feedwater heating is provided by the exhaust heat recovery heat exchanger. The combustion turbine normally operates only during summer peaking months in a combined cycle mode with Unit 1.

The process steam generator has a capability of 27,000 kg/h (60,000 lb/h) of steam. It is utilized to provide process steam to NHC when Unit 1 is shut down.

Service water and makeup water for the circulating water system is provided from five wells located onsite. Cooling tower blowdown is directed to an onsite evaporation pond.

TABLE 4-2. EXISTING FACILITY DESIGN CHARACTERISTICS

I. UNIT 1 TURBINE GENERATOR	
Manufacturer	General Electric
Installation Date	1963
Type	Tandem compound, double flow, condensing, nonreheat
Generator	58,800 kVA, 0.85 power factor, three-phase, 60 hertz, 13,800 V
Exciter	Static
Capability	
Rated Steam Conditions	
Throttle Steam Pressure	8.7 MPa (1,265 psia)
Throttle Steam Temperature	510 C (950 F)
Generator Output	44,000 kWe
Turbine Cycle Heat Rate*	9,786 Btu/kWh
Overpressure Steam Conditions	
Throttle Steam Pressure	9.6 MPa (1,390 psia)
Throttle Steam Temperature	510 C (950 F)
Generator Output	61,450 kWe
Turbine Cycle Heat Rate (without process steam extraction)	9,533 Btu/kWh
Net Plant Heat Rate (combined cycle operation with process steam**)	12,620 Btu/kWh
II. UNIT I STEAM GENERATOR	
Manufacturer	Babcock & Wilcox
Type of Unit	Natural circulation, pressurized furnace
Continuous Rating	193,000 kg/h (425,000 lb/h)
Maximum Rating	227,270 kg/h (500,000 lb/h)

*Process steam flow of 22,700 kg/h (50,000 lb/h).

**Net plant output of 56,500 kWe (44 MWe Unit 1 + 12.5 MWe Unit 2) with 22,700 kg/h (50,000 lb/h) process steam flow.

TABLE 4-2 (Continued). EXISTING FACILITY DESIGN CHARACTERISTICS

	Design Pressure	11.5 MPa (1,665 psia)
	Superheater Outlet Pressure	9.1 MPa (1,315 psia)
	Superheater Outlet Temperature	513 C (955 F)
	Efficiency at Rated Flow	79.8 per cent
III.	UNIT 2 COMBUSTION TURBINE	
	Manufacturer	General Electric
	Type	Simple Cycle Gas Turbine
	Generator	17,647 kVA, 0.85 power factor, 13,800 V, 60 hertz, air-cooled
	Unit Rated Output	14,000 kWe
IV.	PROCESS STEAM GENERATOR	
	Manufacturer	Babcock & Wilcox
	Design Pressure	1.83 MPa (265 psia)
	Rated Steam Flow	27,272 kg/h (60,000 lb/h)
	Efficiency at Rated Flow	77.4 per cent

The cogeneration facility provides process electricity to the Western Power system and steam and electrical energy to the adjacent NHC plant. Process steam is taken from the first two extraction ports of the steam turbine through pressure regulating valves to maintain .65 MPa (95 psia) steam for delivery to NHC. This steam is desuperheated to 204 C (400 F). The electric energy supplied to NHC may be provided from either the CRS or the Western Power grid. The NHC plant processes the raw natural gas entering the Panhandle Eastern Pipeline for transportation to the Detroit, Michigan area. A refrigeration process is utilized to remove the propane, butane, and gasoline (pentane and greater fractions) products. At the same time, water and carbon dioxide are removed from the gas stream. The refrigeration process used requires both electric and thermal energy

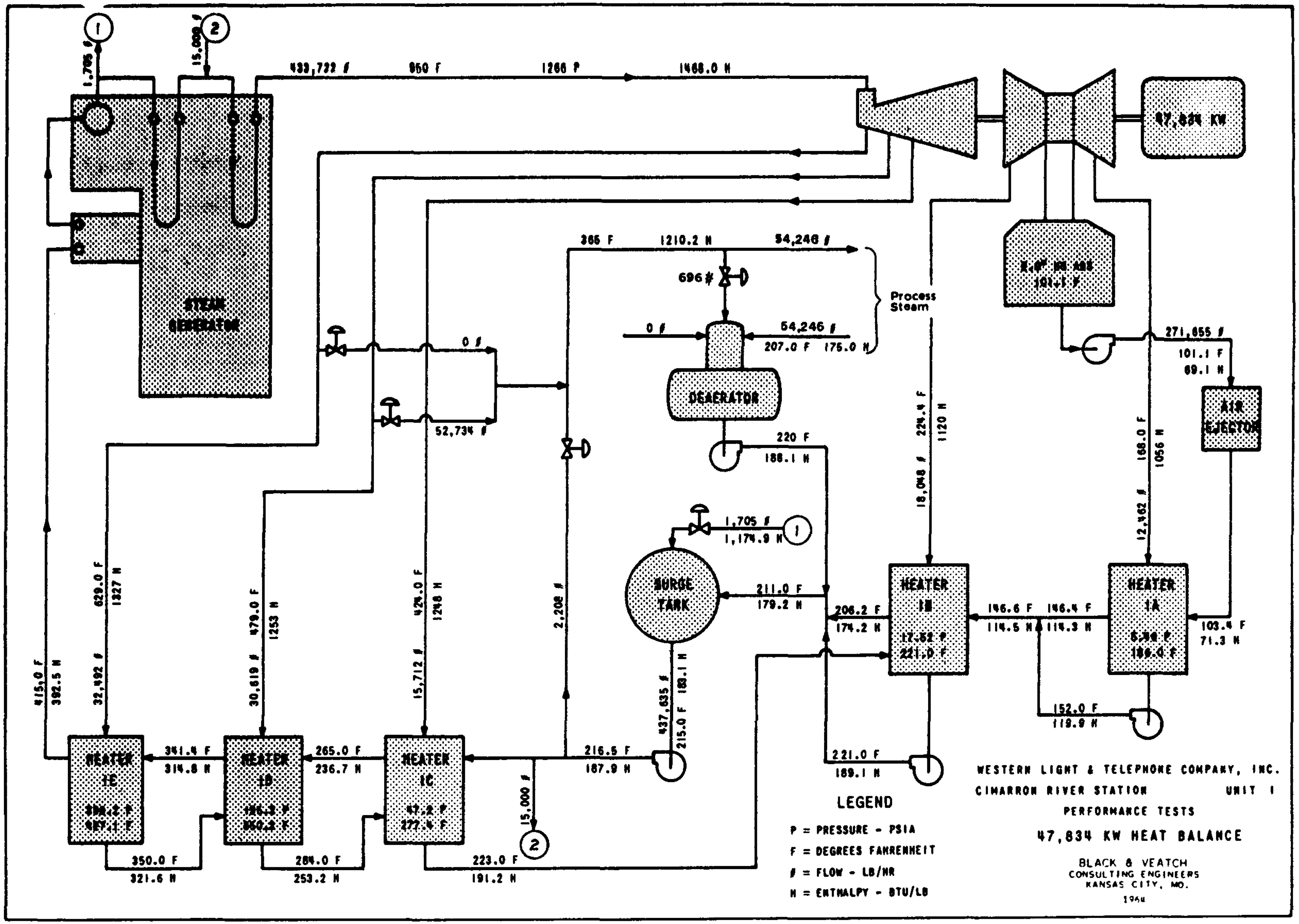


FIGURE 4.3-1. 47,834 KW HEAT BALANCE

in the ratio of approximately 3:1, thermal equivalent. The addition of the solar facility requires no modifications to the NHC plant.

Additional existing facility information is provided in Appendix A.

4.3.2 Solar Facility Characteristics

The solar facility was designed to provide 37.13 MW_t (126.7 MBtu/h) of 510 C (950 F) steam to the turbine inlet at the noon, March 21, design point. Table 4-3 provides a summary of solar facility characteristics for the solar facility systems: the Collector System, the Receiver System, the Receiver Piping System, the Solar Master Control System, and the Solar Auxiliary Electric System, each of which is briefly described below. The various operating modes of the integrated solar facility are discussed in Section 4.3.3.

TABLE 4-3. SOLAR FACILITY DESIGN CHARACTERISTICS

I. COLLECTOR SYSTEM	
Type	
Heliostat Characteristics	
Reflective Area	52.77 m^2 (568 ft^2)
Number of Panels	12
Elevation of Axis	4.04 m (13.3 ft)
Beam Quality (Reflected Beam)	±0.75 milliradians (1s), each axis
Pointing Accuracy (Reflected Beam)	±1.0 milliradians (1s), each axis
Number of Heliostats	1,057
Total Mirror Area	55,780 m^2 (600,400 ft^2)
Land Area Under Heliostats	222,000 m^2 (55 acres)
Maximum Field Width (east-west)	848 m (2,782 ft)
Maximum Field Length (north-south other radius)	424 m (1,390 ft)
II. RECEIVER SYSTEM	
Type	External receiver with closure doors, modular designed steam generator with pumped circulation.

TABLE 4-3 (Continued). SOLAR FACILITY DESIGN CHARACTERISTICS

Receiver Diameter	6.71 m (22 ft)
Receiver Height	9.45 m (31 ft)
Tower Type	Structural Steel
Active Surface (210° sector of cylinder 1.45 m tall and 6.71 m in diameter)	116.1 m^2 (1,250 ft^2)
Elevation of Receiver (ground to receiver midpoint)	84.1 m (276 ft)
Peak Flux	720 kW/m^2
Receiver Power Rating	37.13 MW_t (126.7 MBtu/h)
Receiver Feedwater Conditions	
Feedwater temperature	217 C (423 F)
Feedwater pressure	12.79 MPa (1,855 psia)
Superheater Outlet Conditions	
Rated Steam Flow	54,331 kg/h (119,800 lb/h)
Steam Pressure	11.07 MPa (1,605 psia)
Steam Temperature	520 C (968 F)
Overall Receiver Efficiency	88.4 per cent

III. RECEIVER PIPING SYSTEM

Main Steam Piping	
Pipe size and material	0.15 m (6 in), Schedule 160, ASTM A335 Grade P22 seamless 2-1/4 chrome, 1 per cent moly alloy steel
Total length (includes expansion loops)	481 m (1,580 ft)
Insulation thickness	0.15 m (6 in)
Design point heat loss	0.2 per cent
Design Point Pressure Loss	1.34 MPa (195 psi)
Feedwater Piping	
Pipe size and material	0.10 m (4 in) Schedule 160 ASTM A106 Grade B carbon steel

TABLE 4-3 (Continued). SOLAR FACILITY DESIGN CHARACTERISTICS

	Total Length (includes expansion loops)	443 m (1,455 ft)
	Insulation thickness	0.08 m (3 in)
	Design point heat loss	0.08 per cent
	Design point pressure loss	1.34 MPa (195 psi)
IV.	SOLAR MASTER CONTROL SYSTEM	
	Control Panel	3 m (10 ft) wide, 2 m (7 ft) high, 1.2 m (4 ft) deep standup bench front panel with graphic display subpanel and 5 CRT's
IV.	SOLAR MASTER CONTROL SYSTEM (Continued)	
	Control Computer	16-bit microprocessor with 64K words of high speed random access working memory
	Data Acquisition Computer	24-bit microprocessor with 64K working memory and 13.8 million word large case memory
	Emergency Shutdown System	Hardwired relay cabinet with power supplies.
V.	SOLAR AUXILIARY ELECTRIC SYSTEM	
	Emergency Diesel Generator	45 kW, 0.8 power factor, 4,160 V, three phase, 60 hertz, fast start
	Static Inverters	Two 37.5 kVA, 125 V dc input, 120 V 60 hertz single phase ac output
	Switchgear	Metal enclosed, 4,160 V, 60 BIL, three phase, 60 hertz, 1,200 ampere

The Collector System, consisting of 1,057 heliostats, redirects solar radiation to the solar receiver located atop a structural steel tower at a receiver mid-point elevation of 84.1 m (276 ft). The aim-point strategy for the heliostats provides essentially uniform fluxes on the heat absorbing surface of the receiver. The Receiver System includes a receiver support tower and a recirculating boiler design configured as an external receiver, with boiler tubes providing a screen for both the superheater tubes. The peak flux design limit on the receiver surfaces is 720 kW/m^2. Closure doors are provided to reduce overnight heat loss. The Receiver Piping System provides feedwater to the solar receiver from the existing facility and accepts steam from the receiver for delivery to the Unit 1 steam turbine. The Solar Master Control System provides supervisory control, data acquisition and display, and emergency shutdown of the solar facility. The Solar Auxiliary Electric System provides electric power to the solar facility equipment.

Additional information on the solar facility may be found in Section 5 and in Appendix A.

4.3.3 Integrated Facility Operating Modes

The integrated cogeneration facility will be capable of hybrid (combination solar and fossil) operation and also capable of non-solar (fossil only) operation. The cogeneration facility will be capable of start-ups and shutdowns of the solar equipment while maintaining the desired facility electrical and steam flow outputs. The cogeneration facility will be responsive to all demands from the system load dispatcher in all modes of operation.

4.3.3.1 Non-Solar Operation. The non-solar (fossil) mode of operation will use the fossil steam generator as the only source of steam. The automatic controls of the fossil steam generator and of the turbine will maintain the unit's electrical output and steam output at the desired levels. The electrical output demand will be set either by the load dispatch center or the station operator. The operating range of the unit during non-solar operation is 10 to 60 MW. The turbine will be operated in a variable pressure operation mode during low loads which increases unit efficiency, and permits a lower minimum unit output which is constrained by the capability of the steam generator to maintain rated steam temperature. With variable pressure operation, the steam generator can maintain rated steam temperature at 45,000 kg/h (100,000 lb/h) steam flow which corresponds to a unit electrical output of about 10 MW_e.

During non-solar operation, the heliostats are placed in a stow position and the solar facility steam and feedwater lines are isolated from the electric power generating system (EPGS). If the receiver or steam piping drop below atmospheric pressure (all steam has condensed), the receiver steam sections and steam piping are filled with nitrogen for corrosion protection. Freeze protection during normal solar receiver shutdown periods during extremely cold weather conditions is accomplished by activating the receiver circulation pump to circulate a small amount of warm feedwater from the EPGS through the receiver to maintain the receiver water temperature above 4.4 C (40 F).

4.3.3.2 Normal Solar Operation. The normal (hybrid) mode of solar operation will use the fossil steam generator and the solar receiver as parallel steam sources. Otherwise, this mode of operation is similar to the non-solar mode of operation. As is the case of non-solar operation, automatic controls will maintain the unit's electrical and steam outputs at their desired levels and the turbine will be operated in a variable pressure operation mode during low loads. As the daily variation in the amount of available solar insolation changes the solar receiver steam flow, the fuel firing rate of the fossil steam generator will automatically compensate to maintain the proper turbine steam flow. The operating range of the unit during hybrid operation is 10 MW_e to 60 MW_e, with the lower fossil generation level at any specific time being the 10 MW_e minimum load limit and the upper fossil generation limit being about 45 MW_e during time periods when solar steam is available.

4.3.3.3 Intermittent Cloud Operation. During intermittent cloud passage, the unit will continue to operate normally. The firing rate of the fossil steam generator will automatically be adjusted to compensate for the changes in solar receiver steam flow. The fossil steam generator is capable of changing its steaming rate by 19,300 kg/h (42,500 lb/h) each minute.

Therefore, the fossil steam generator is capable of counteracting even the largest possible interruptions in solar energy within a few minutes. This is compatible with Western Power's agreement with other members of their power pool to recover from imbalances of electrical supply and demand within ten minutes.

4.3.3.4 Solar Startups. The solar facility will have several modes of startup operation depending primarily on the temperature of the solar receiver prior to startup and the amount of solar energy available at the time of startup.

During routine startups of the solar facility after an overnight shutdown, the fossil steam generator will be maintained at, or above, its minimum load, depending upon the system load demand.

Except for unusually cold or high wind conditions, the receiver temperature will be above 116 C (240 F) at sunrise. Just before sunrise, superheated steam from the fossil steam generator will be fed back through the receiver piping system for heating the receiver steam drum to match saturation temperature for the existing steam pressure. Spargers will be used to inject the heating steam into the receiver circulating pump suction. Excess condensate from the heating steam is drained to the EPGS via the receiver blowdown and drain lines. Following heatup of the receiver steam drum to saturation temperature, the system load dispatcher will be notified that the solar facility is to be started. The dispatcher will make any necessary modifications to his unit load demand. The receiver closure doors will be opened just prior to beginning of heliostat focusing. At sunrise, the heliostats will be sequentially focused onto the receiver and the receiver steam shutoff valve opened. Temperature rises in the superheater panels will be limited to 27.8 C (50 F) per minute. As the amount of solar energy directed to the receiver increases, the steam temperature will approach its normal operating value of 510 C (950 F) and solar generated steam is delivered to the EPGS.

An expanded startup operation is required for cold starts (receiver temperature less than 116 C (240 F)) after extended solar facility shutdown periods. Prior to startup of the solar facility, the receiver feedwater booster pump will be used to fill and prewarm the receiver with feedwater from the EPGS. The receiver will be filled at a controlled rate to avoid thermal shock. Receiver drum level will be maintained by draining excess water to the receiver blowdown tank for return to the EPGS. Feedwater flow will be used to prewarm the receiver to above 116 C (240 F). The water flow will be controlled to limit the rate of saturation temperature rise in the receiver to 4.4 C (8 F) per minute. After the receiver has been prewarmed with feedwater, the startup continues according to the routine diurnal startup procedures described above.

Hot restarts after short shutdowns during mid-day will proceed similarly to routine startups. Since the receiver is at a relatively high temperature prior to startup, the time for restart is reduced. The time required for the heliostat focusing sequence is lengthened to prevent possible rapid receiver temperature changes due to high insolation levels.

4.3.3.5 Solar Shutdown. As the solar insolation decreases in the evening, the amount of steam generated in the solar receiver will decrease. As this flow decreases, the controllability of the steam temperature out of the receiver will become more difficult. When this temperature becomes uncontrollable, the operator will initiate an automatic shutdown sequence for the solar equipment. The heliostats will be put in stow position and the receiver steam shutoff valve will be closed to isolate the receiver. The cogeneration facility will then revert to a non-solar operation mode.

4.3.3.6 Emergency Solar Shutdown. Upon detection of any one of several abnormal operating conditions which might compromise the personnel safety or equipment integrity, a rapid automatic shutdown of the solar equipment will be triggered. The main objectives of this emergency shutdown are to immediately remove all solar energy input to the system and prevent any possibility of water induction into the turbine. Some of the conditions that automatically trigger an emergency shutdown are: very high or very low receiver drum water level, a turbine trip, a fossil steam generator trip, or a loss of normal electrical power to the heliostat field. The plant operator may also manually initiate an emergency shutdown.

4.4 SITE REQUIREMENTS

This section discusses site requirements in the context of site development, site improvements and facilities, and site structures.

4.4.1 Site Development

The heliostat field and receiver for the solar facility will be located north and northwest of the existing Cimarron River Station, as shown on Figure 4.4-1. This area is presently covered by native ground vegetation, with rolling hills generally sloping to the north. Site development will include clearing and grading work followed by construction of security fencing and access roads with drainage provisions. Foundations for the receiver support tower and heliostats will be supported on auger cast concrete piles. Site data and site improvements are described in more detail in the following subsections.

4.4.1.1 Site Soil Conditions. The site soils consist of various mixtures of sand, clay, and gravel. There are no subsurface rock formations which will affect site grading or which can be used for foundation support. Approximately the top 1.5 m (5 ft) at the site location is composed of a sandy clay which is suitable for fill material. Below this layer is a 9 to 12 m (30 to 40 ft) thick layer composed primarily of medium-dense to dense sands and gravels. The allowable bearing pressure on this layer is approximately 19,500 kg/m^2 (2 tons/ft^2). Below this layer are additional sandy clay and sand layers. See Subsection 4.9.2.1 for additional information on site geology.

4.4.1.2 Site Grading. The site will be graded to a maximum slope of four per cent. This will keep the amount of earthwork to a minimum, yet prevent shadowing of adjacent heliostats. A four per cent maximum grade will also permit access of maintenance vehicles to the heliostats. Existing berms which direct runoff away from the plant will be modified as necessary to accommodate the heliostat field and access roads. The total volume of material to be moved is estimated to be 150,000 m^3 (200,000 yd^3).

Before site clearing and grading can begin, two 115 kV transmission lines will have to be relocated (Figure 4.4-2). The north line will be relocated to the north of the field, and the south line will be relocated to

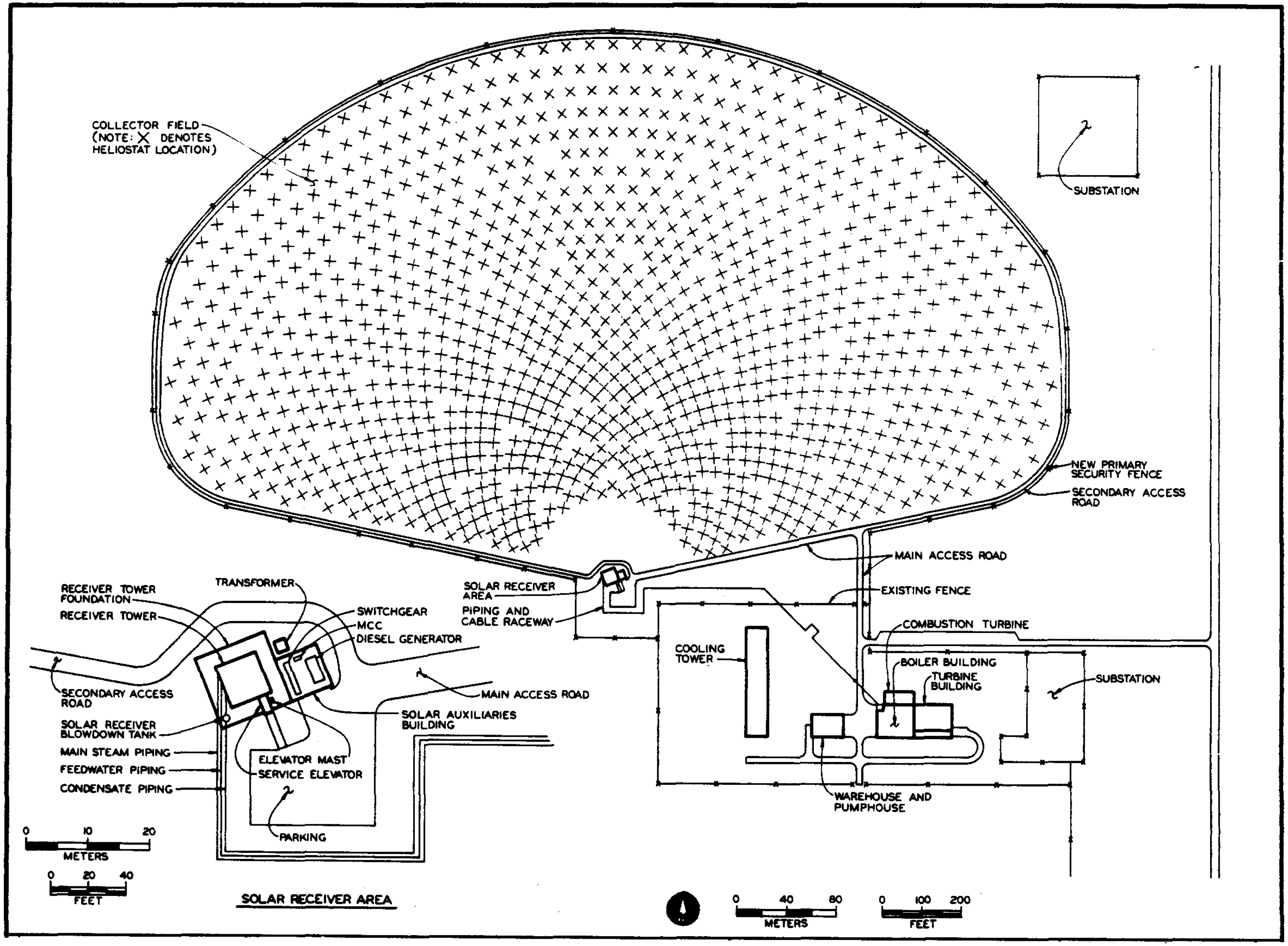


FIGURE 4.4-1. SOLAR COGENERATION FACILITY SITE ARRANGEMENT

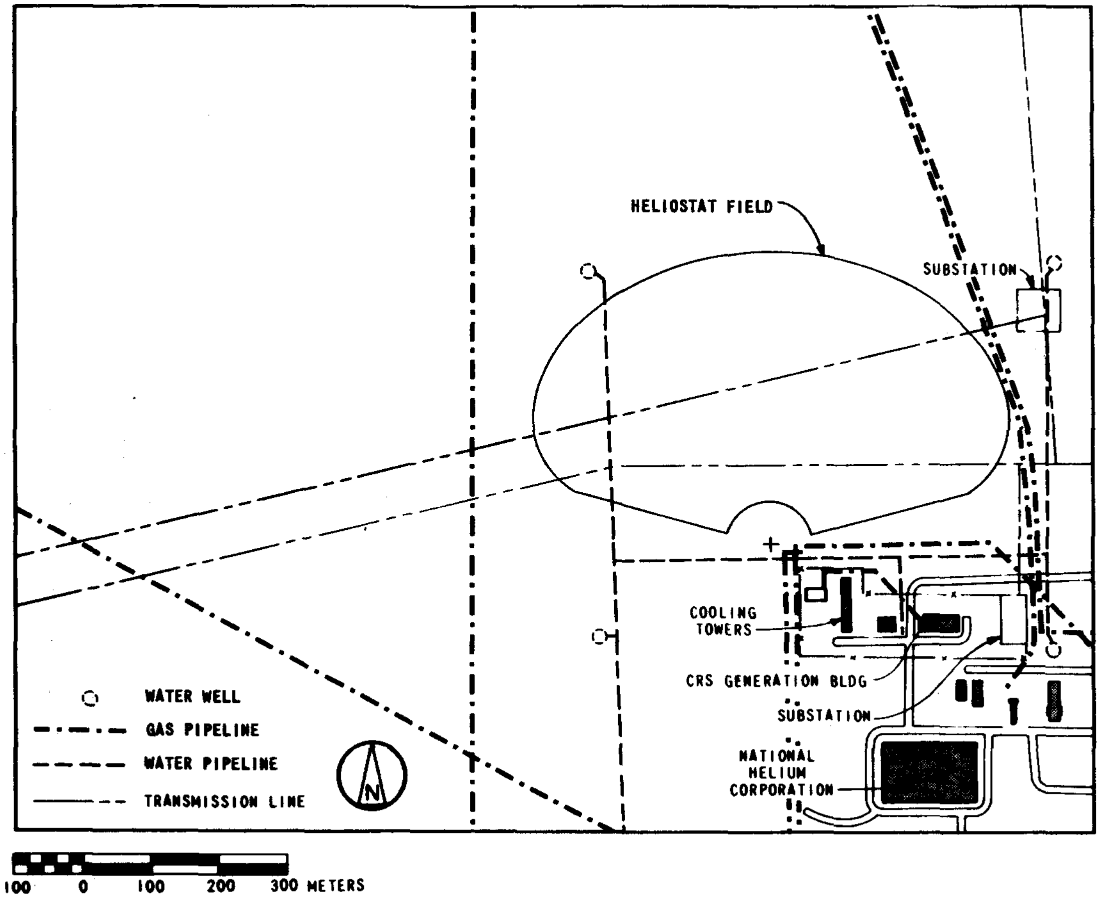


FIGURE 4.4-2 SITE UTILITIES

the south of the field. In addition, a 0.15 m (6 in) transite water line which connects a well northwest of the heliostat field with the plant will be removed during grading. This line will be replaced in its existing location after grading is complete. Cast iron pipe will be used to permit crossing of maintenance vehicles. The interruption of service from this well will not affect CRS operation because the other four wells have sufficient capacity to serve the plant. The natural gas pipelines just to the east of the field will not be disturbed during grading.

4.4.1.3 Site Improvements. Site improvements will consist of drainage provisions, access roads and parking, security fencing, and landscaping. No site lighting will be required except at the receiver tower.

The natural present site drainage will be altered slightly. Drainage ditches will be provided adjacent to the access roads, and culverts will be provided where roads cross natural drainage patterns. It will also be necessary to modify and extend existing berms to protect existing facilities and the solar receiver area from direct runoff.

A paved road will be provided to connect the existing road near the boiler area to the receiver tower, as indicated on Figure 4.4-1. The parking area at the tower will also be paved to reduce dusting of the heliostat field. This main road and the parking area will be permanent-type construction with a crowned 6.1 m (20 ft) wide traffic lane, 1.5 m (5 ft) wide shoulders, and contoured drainage ditches. Surfacing will consist of a 0.08 m (3 in) asphaltic course on a 0.2 m (8 in) crushed rock prepared basecourse. The crushed rock basecourse will be underlain by a prepared subgrade of site materials selected for drainability. Drainage slope will be to the outer shoulder at about 0.021 meter/meter (1/4 in/ft). Shoulders will not be paved, but will be oiled, and will be sloped to the ditches at about 0.042 m/m (1/2 in/ft).

A secondary road will be provided from the receiver tower around the heliostat field. This 3.5 m (12 ft) wide road will not be paved or provided with shoulders. It will be constructed of crushed rock and oiled to minimize dusting of the heliostat field.

The existing primary fencing section will be supplemented with new fencing to surround the solar facility as shown on Figure 4.4-1. The new fencing will be galvanized steel chain link type with a three-strand barbed wire extension mounted at 45 degrees. The chain link height will be 1.8 m (6 ft), and the overall height 2.1 m (7 ft). Two truck gates will be provided: one for access to the receiver area and collector field; the other on the northwest side of the collector field for access to the existing water well.

Temporary revegetation of the area following site preparation will be provided for erosion control. A planting of winter wheat, or similar crop that germinates and grows quickly, will provide this initial cover. After the heliostats are installed, revegetation with native grasses will provide permanent erosion control. These grasses typically have creeping rhizomes or stolons, or a bunch-type growth. Native species that provide these characteristics include the following: buffalo grass, tall fescue, Italian ryegrass, sideoats grama, blue grama, switchgrass, and Western wheatgrass.

4.4.2 Site Facilities

The existing facilities at the Cimarron River Station will be used to supply most of the auxiliary services required by the solar facility addition. The following paragraphs summarize the required services and how they will be provided.

4.4.2.1 Service Water. No site service water continuous requirements have been identified. Demineralized water makeup to the chemical feed equipment in the receiver tower will be by portable containers.

4.4.2.2 Nitrogen. Separate nitrogen storage equipment will be provided for the solar facility. The nitrogen storage equipment will store nitrogen at high pressure for use in corrosion protection of the receiver and receiver piping system during cold shutdowns. The requirements of the nitrogen storage system are listed in the System Specification (Appendix A).

4.4.2.3 Fire Protection. Hand-held and movable cart-mounted dry chemical fire extinguishers will be provided in the receiver tower area. No interconnection with the existing plant fire protection system is planned.

4.4.2.4 Communications. A communications system between the solar receiver tower and the main control room will be provided.

4.4.2.5 Water Treatment. The existing water treatment facilities will be used for water treatment for various solar facility uses. A hose connection downstream of the existing demineralization system will be added to provide a means to fill the heliostat wash vehicle with demineralized water.

4.4.2.6 Personnel Facilities. The existing plant buildings and parking lot will accommodate the additional personnel needed for the solar facility. No modifications to these facilities are planned.

4.4.2.7 Storage and Maintenance. The existing plant warehouse and machine shop facilities will be used. No modifications to these facilities are planned.

4.4.3 Site Structures

Site structures will be added for the solar installation as described below.

The solar receiver support tower structure will be added as described in Section 5.2. The heliostat support structures described in Section 5.1 will also be added.

Miscellaneous structures to be added include the Solar Auxiliaries Building located near the base of the receiver support tower, as shown on Figure 4.4-1. This building will be a 7.32 m x 7.32 m (24 ft x 24 ft) prefabricated metal building supported by a slab on grade. It will house a motor control center, switchgear, and an emergency diesel generator, which are part of the solar auxiliary electric system. The Solar Auxiliaries Building will be uninsulated. However, an electric space heater will be provided for personnel.

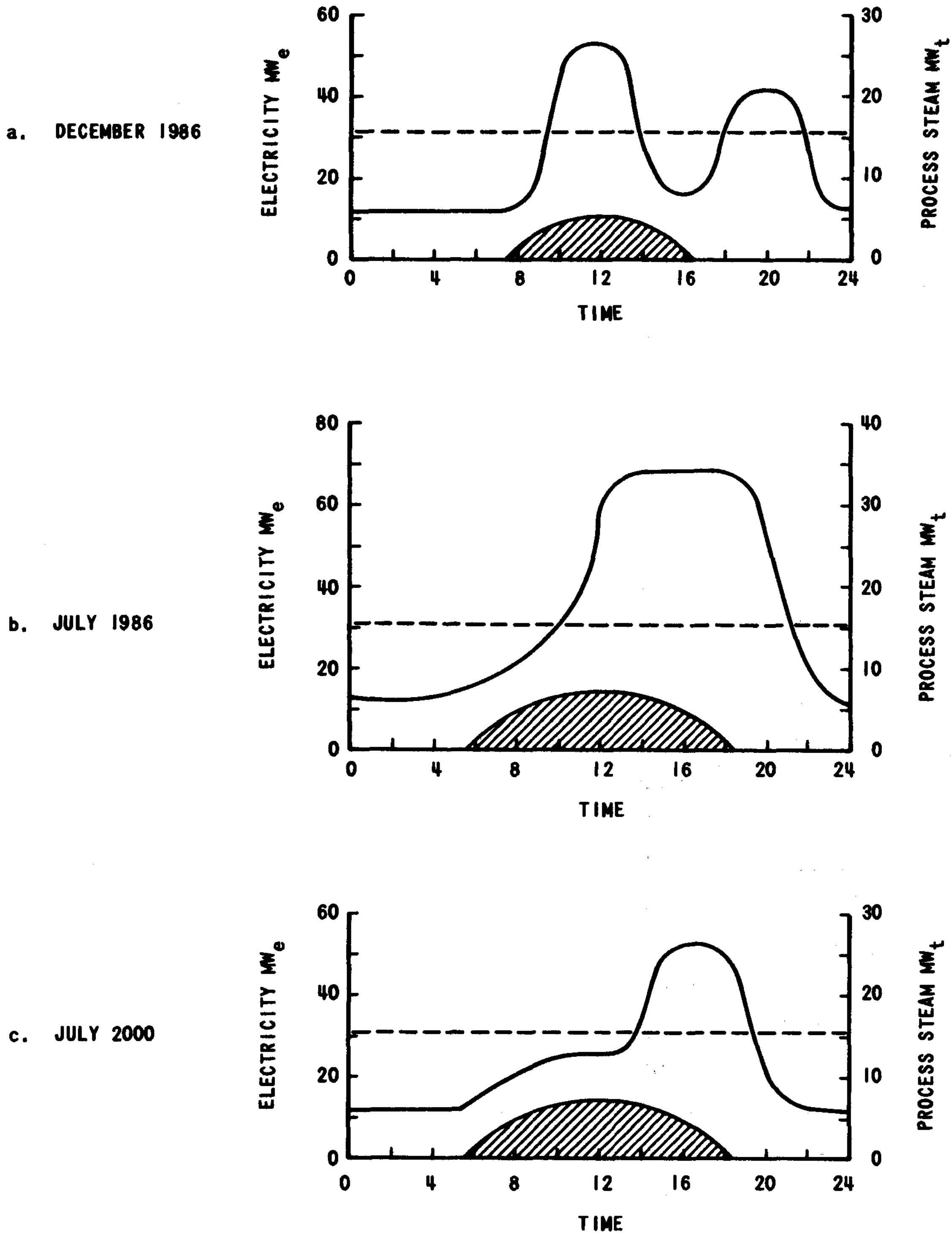
4.5 ENERGY LOAD PROFILE

The expected operation of the solar cogeneration facility closely resembles the same plant role that CRS will play in future years if solar is not added, i.e. it will be a "swing" unit in the Western Power grid. A base gas-fired load of N10 MW_e net will be employed to maintain CRS capability to rapidly respond to swings in the grid demand level and to supply NHC process steam needs. The facility will be economically dispatched at levels above 10 MW_e as required by the Western Power system demand, considering the availability of other units, particularly the coal-fired units. Because the demand on CRS depends on the variable grid demand, as well as on the availability of coal-fired units, no single, specific electrical energy load profile can be stated. Furthermore, CRS load demands will be not only seasonally variable, but will change from year to year due to a growing grid demand, unit retirements, and addition of new generating capacity. These circumstances, which establish how CRS will be operated, will prevail with or without the solar addition.

Despite the normal uncertainities associated with generation planning, it is possible to forecast expected operating patterns for WP in general and

CRS in particular. To that end, economic dispatch projections for CRS have been made as a part of the economic analyses of Section 6. Figure 4.5-1 shows three representative days of interest from those dispatch projections; note that the solar portions of the graphs are simplified for illustration purposes. As such, only electric generation, assuming a clear day, is shown omitting the solar contribution to process steam. Figure 4.5-1a shows a typical December (winter) day loading on CRS. The solar contribution to the plant output changes throughout the day, but all available solar energy is always utilized. Process steam to NHC is essentially constant at 15.1 MW_t. While some seasonal variation in steam flow may exist, it was assumed constant for this study. The December day CRS electrical load has two peaks, reflecting the two peaks in the WP load. The July 1986 CRS electrical load in Figure 4.5-lb shows a single, longer duration peak, which requires that both CRS Units l and 2 operate. Again, all available solar energy is utilized. The longer-term effects of increased coal-fired capacity and the retirement of CRS Unit 2 are shown in Figure 4.5-1c; this July 2000 CRS generation profile illustrates that CRS is called on to generate less power and for a shorter peak duration. The slow rise in electrical generation from 6 a.m. until noon reflects the dispatch of "free" solar power by WP while the more costly, underlying gas-fired generation at CRS is held constant as the more economical coal-fired plants are dispatched. The afternoon peak at CRS is a result of WP having fully dispatched all of their coal-fired capacity earlier in the day and thus, WP must resort to more costly gas-fired generation (e.g. the non-solar portion of CRS) to satisfy system demand levels. In all cases, all of the available solar generation capacity is used at all times since it is "free" power (ignoring sunk costs).

The trend to utilize CRS less in later years is a direct consequence of the generating mix on the WP power system, i.e., the availability of coal-based plants, and not a negative indication of the solar facility's value per se.



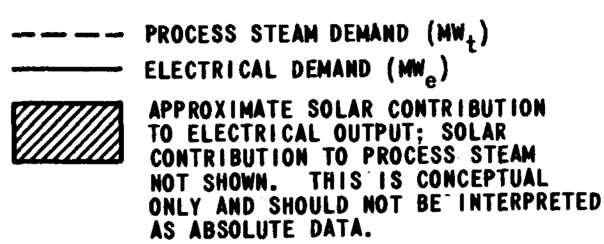


FIGURE 4.5-1 CRS LOAD PROFILES

4.6 FACILITY PERFORMANCE

Design point (noon, March 21) and annual system performance have been predicted using collector field efficiency data computed by the B&V optics codes, receiver efficiency data provided by B&W, and by characterizing the entire plant with the B&V computer code, STEPPE, Solar Thermal Electric Plant Performance Evaluator. The direct normal insolation was simulated using the ASHRAE Clear Air Model (discussed in Subsection 5.5.1 of the System Specification, Appendix A); the insolation was modified with percentage sunshine data so as to include the effects of cloud cover. The annual average daily direct normal insolation resulting from this model was 6.1 $kW/m^2/day$; this value is in reasonable agreement with available insolation isopleth diagrams.[1, 2]

Figure 4.6-1 illustrates the system performance of the design point, noon March 21, for combined cycle operation (Units 1 and 2 operating) and the Unit 1 turbine operating at maximum rating (500,000 lb/h steam flow). Figure 4.6-2 provides the system performance for a more typical March load level (i.e. the expected load assignment to CRS in March will be about 35 MWe due to other considerations within the WP system) with only Unit 1 operating. In both cases, the solar-to-thermal efficiency is 70.0 per cent, resulting in 37.13 MW_t of solar power being delivered to the turbine. Figure 4.6-3 shows the system performance for a clear noon July day, for combined cycle operation and the turbine at rated capability, when a high CRS output is anticipated due to air conditioning power demands. The solar contribution is somewhat less than for March 21 due to decreased insolation and field efficiency. In addition, the electrical conversion efficiency is lower in July due to a high wet bulb temperature.

Figure 4.6-4 illustrates average annual system performance based on the average CRS load determined from the economic dispatch projections (Section 6) for the 15-year load period.

The annual average solar-thermal efficiency (including field, receiver, and piping losses, as well as receiver and piping heat-up requirements) is 56.9 per cent, resulting in 66.0 GWh_t of steam being delivered to the turbine by the solar system. This solar contribution corresponds to an

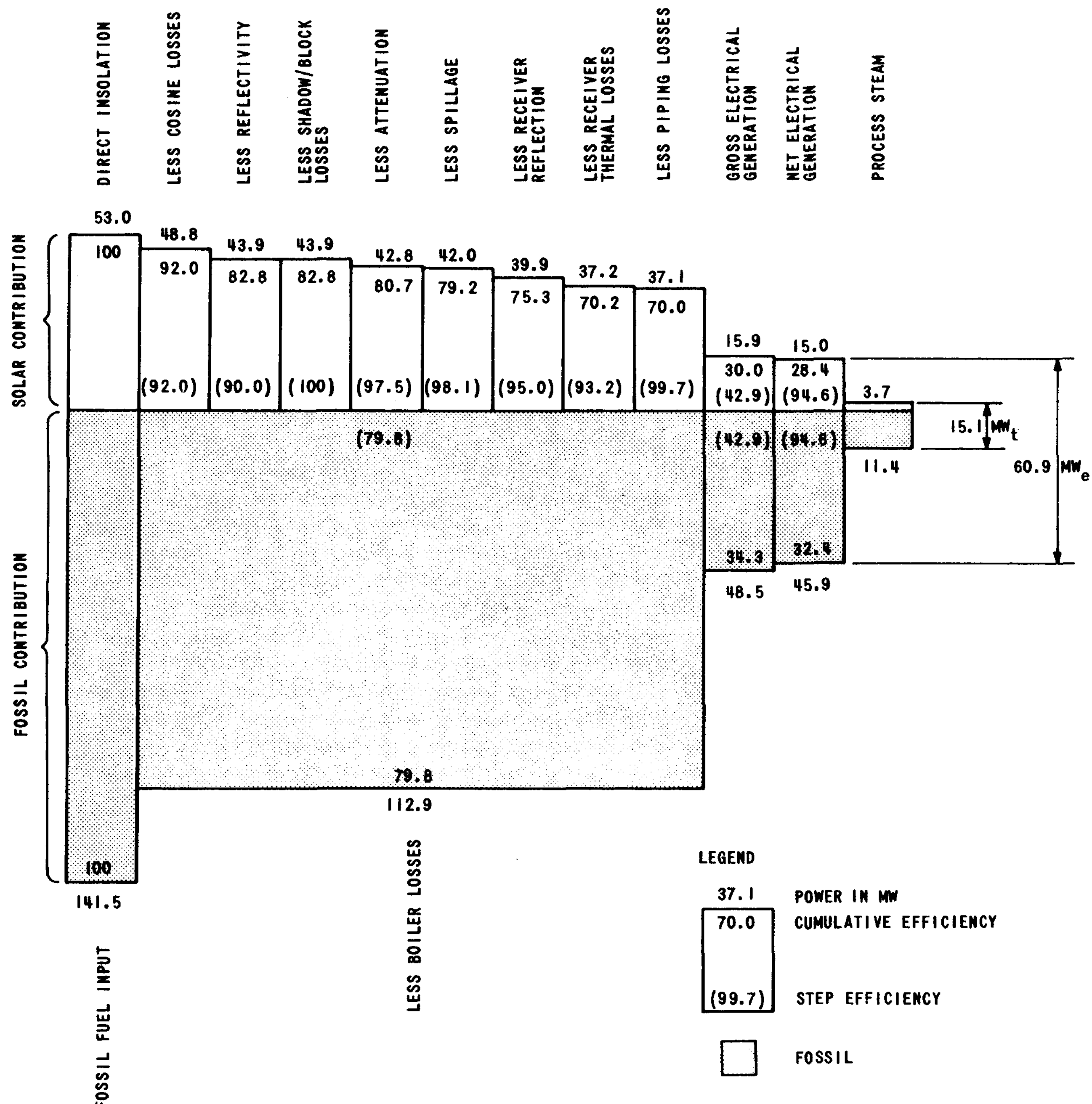


FIGURE 4.6-1 EFFICIENCY STAIRSTEP: NOON MARCH 21, TURBINE AT RATED CAPABILITY, COMBINED CYCLE

annual displacement of natural gas equivalent to 48,100 barrels of oil (based on an average boiler efficiency of 80.8 per cent, and 5.8×10^6 Btu/barrel).

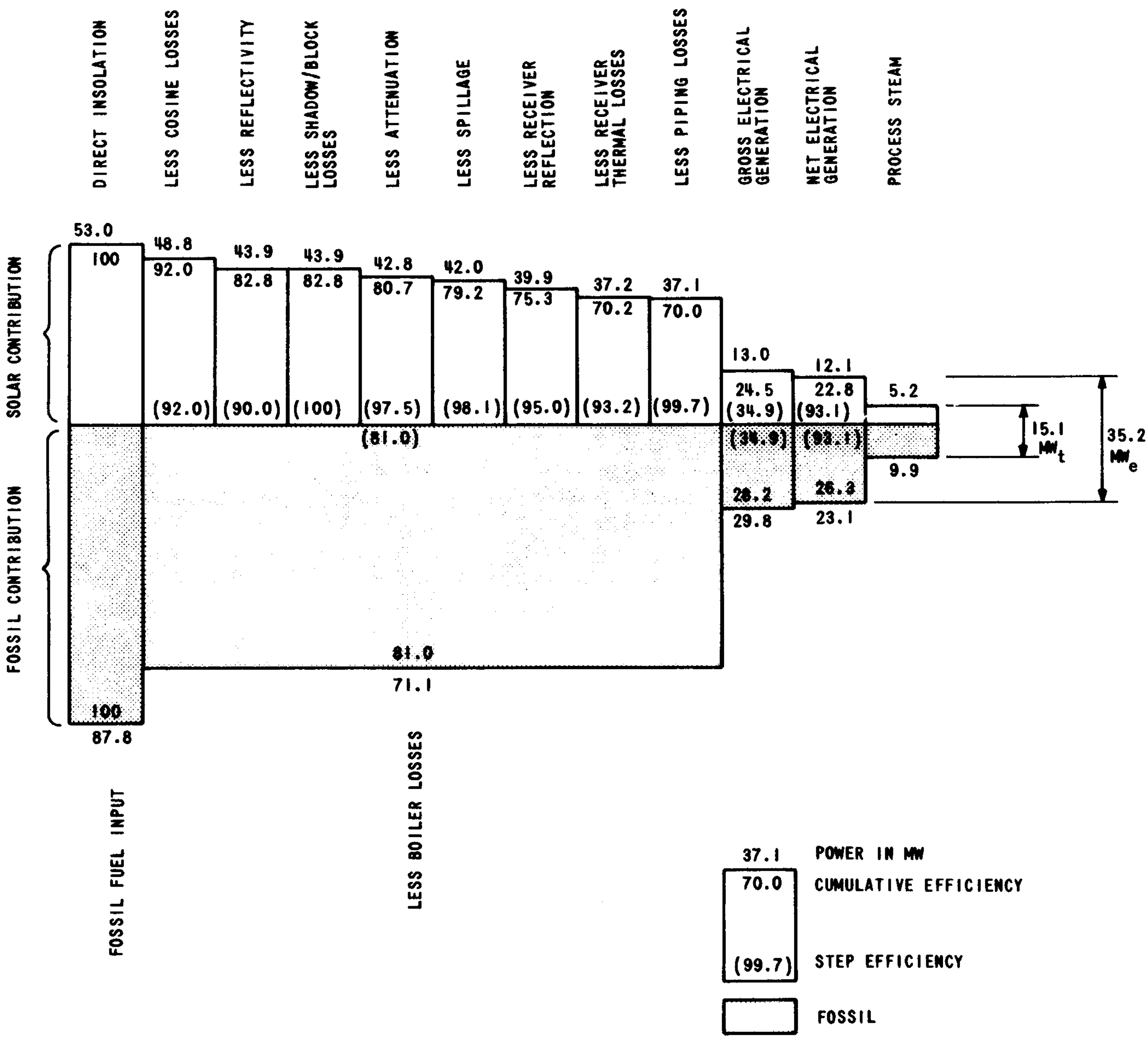


FIGURE 4.6-2 EFFICIENCY STAIRSTEP: NOON MARCH 21, TYPICAL OPERATING POWER LEVEL

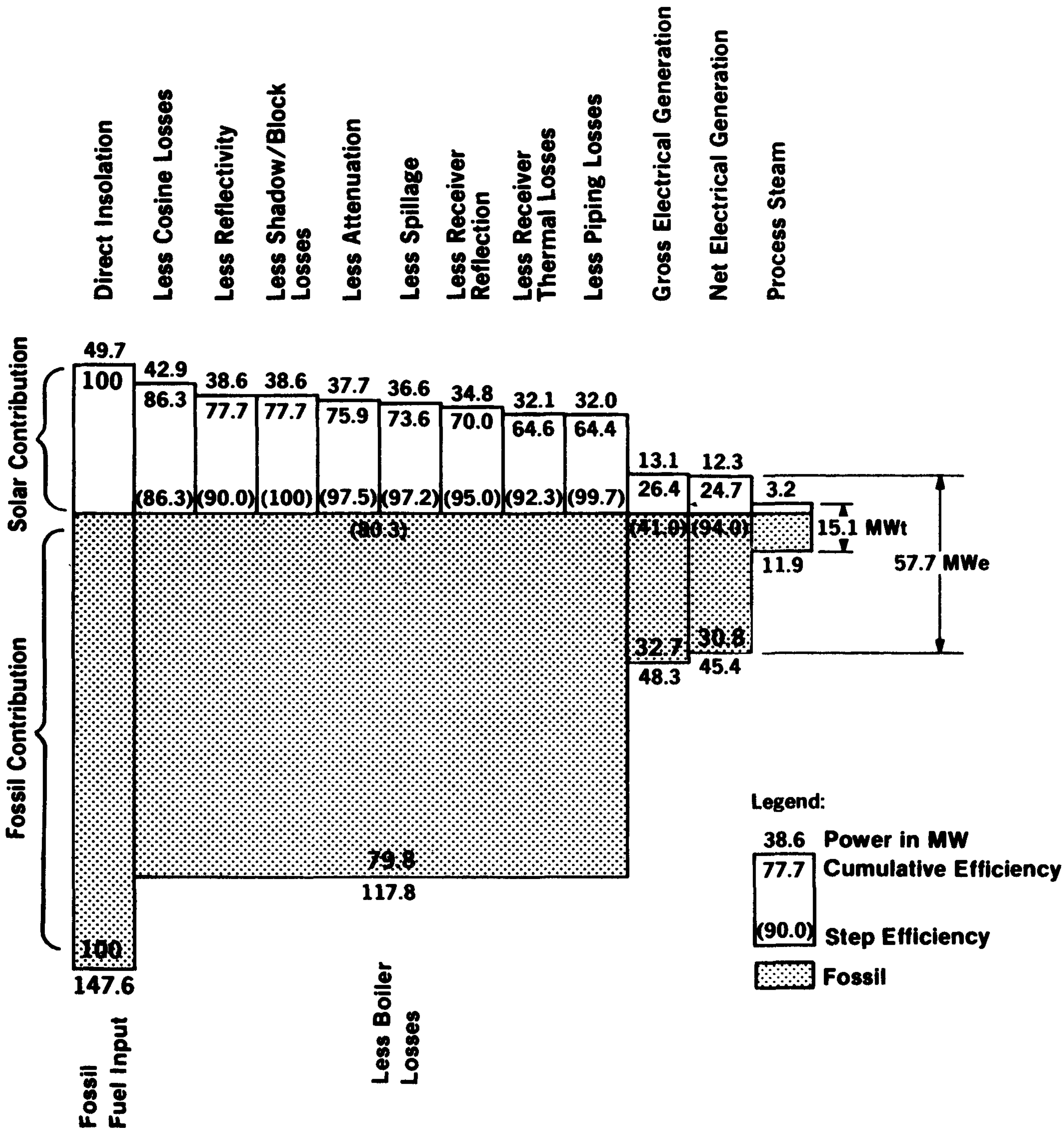


FIGURE 4.6-3 EFFICIENCY STAIRSTEP: CLEAR JULY NOON, TURBINE AT RATED CAPABILITY, COMBINED CYCLE OPERATION

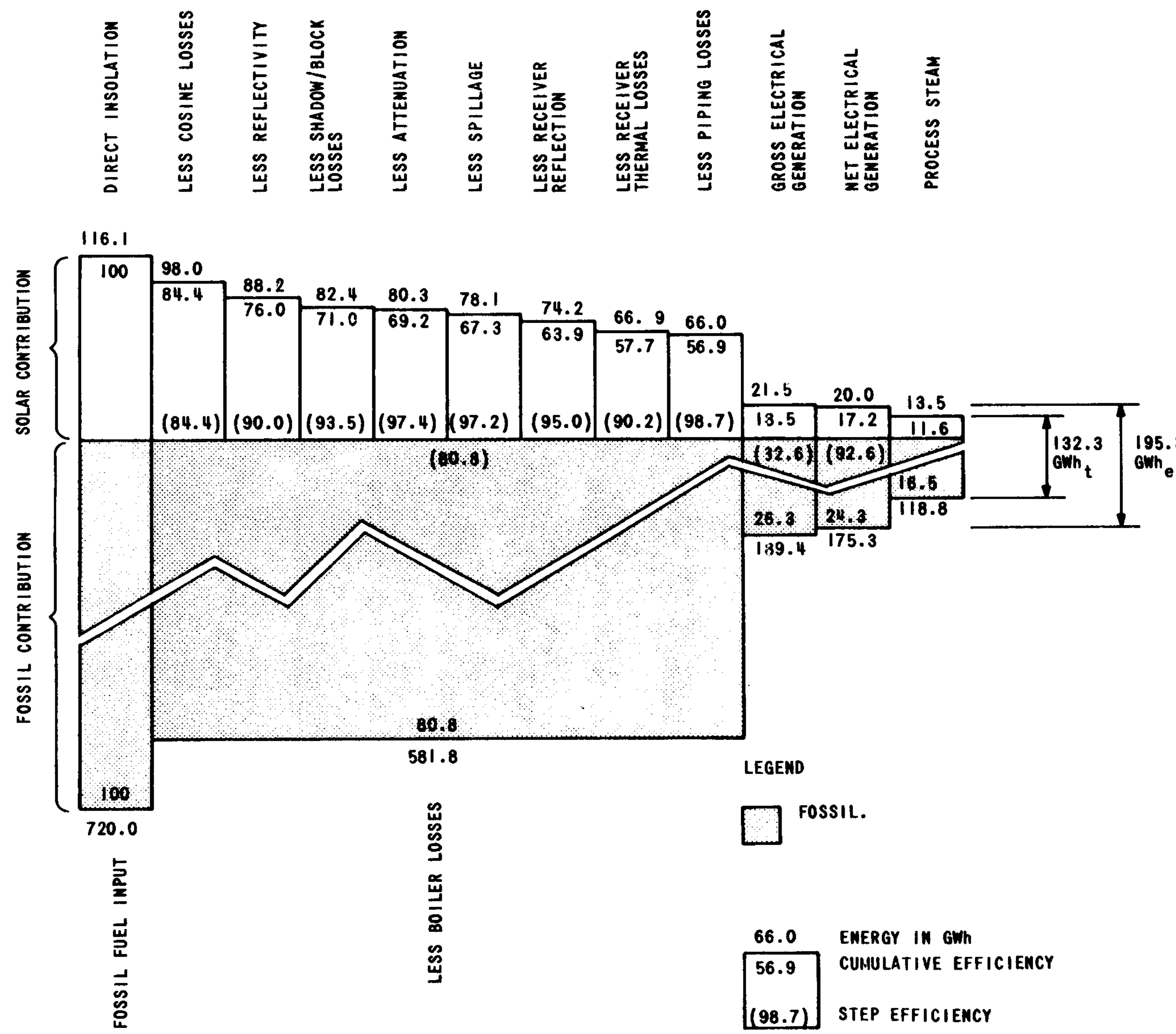


FIGURE 4.6-4 AVERAGE ANNUAL ENERGY STAIRSTEP

The 15-year average cogeneration utilization efficiency* for the system is 41.0 per cent. For the 15-year load period, the average annual solar

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*The Cogeneration Utilization Efficiency (CUE) is defined by:

$$CUE = \frac{MWh_e + MWh_t}{MWh}$$

Where: MWh_e is net electrical energy generated; MWh_t is net thermal energy to NHC; MWh is total energy input to the facility (fuel plus solar energy incident on the receiver) using annual energy in megawatt-hours.

contribution to the CRS energy needs is 10.2 per cent. The overall energy needs and the solar and fossil contributions thereto are illustrated in Figure 4.6-5.

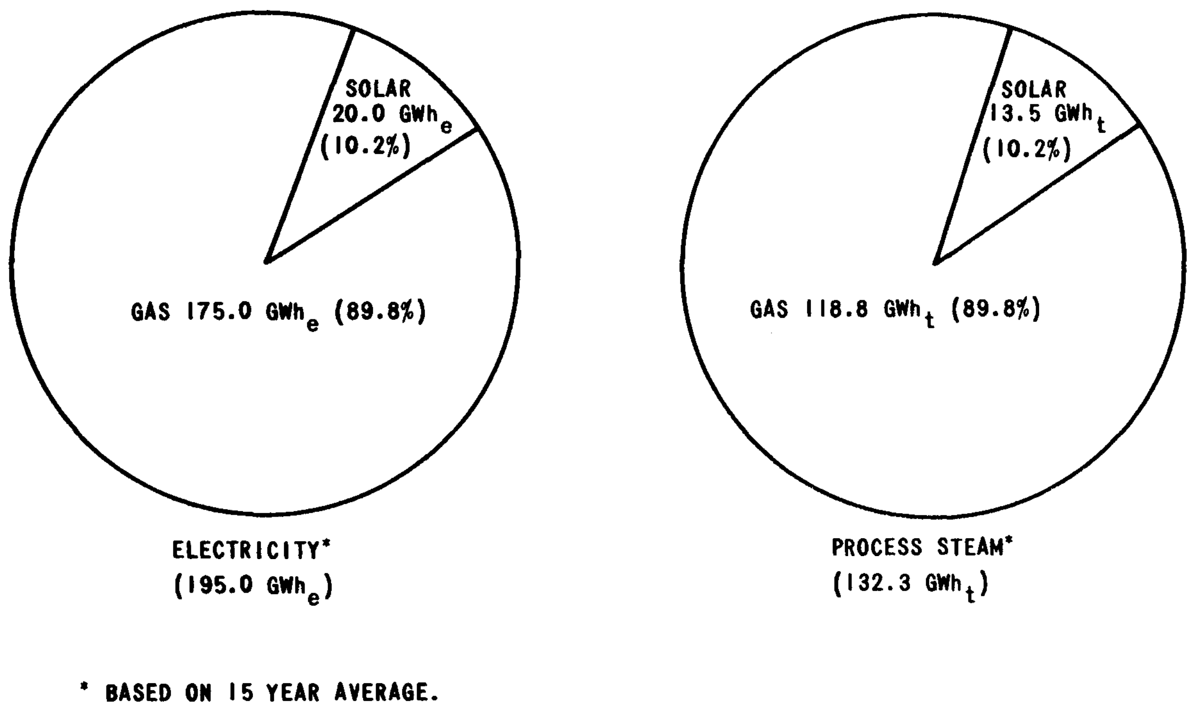


FIGURE 4.6-5 SOLAR AND FOSSIL CONTRIBUTIONS TO AVERAGE ANNUAL ENERGY DEMAND

4.7 PROJECT CAPITAL COST SUMMARY

This section contains the construction and owner's cost estimate for solar cogeneration at the Cimarron River Station. These are summarized in Table 4-4.

4.7.1 Construction Cost Estimate

The boundaries of the cost account categories are shown physically in Figure 4.7-1 and schematically in Figure 4.7-2.

TABLE 4-4. PROJECT CAPITAL COST ESTIMATE SUMMARY (7-1-80 $)

Owner's Cost Estimate	$ 5,609,645
Construction Cost Estimate	$28,226,753
Total	$33,836,398

The construction cost estimate is summarized in Table 4-5 and Figure 4.7-3; the data supporting this estimate are provided in Appendix B.

The construction cost estimate is based on the following assumptions.

(1) The unit will be located near Liberal, Kansas.

(2) All costs in the estimate are expressed in July 1, 1980 dollars.

(3) Land and mobile equipment are not included.

(4) The structural steel receiver tower has a concrete foundation set on auger cast piles. Heliostat foundations consist of drilled piers.

(5) Labor costs in lines A-K are determined by man-hours multiplied by the appropriate crew base rate, not including employee fringe benefits. Man-hour estimates are based on B&V experience involving similar tasks. Labor costs in lines L-Q include overhead and profit and line P includes fringe benefits for crafts. Wage rates are based on the Liberal, Kansas area.

(6) A contingency of 10 per cent is applied to total field and office costs.

(7) The collector costs are based on estimates provided by manufacturers of DOE Second Generation Heliostats. The receiver cost was estimated by Babcock & Wilcox. The tower cost is based on quantity takeoff and pricing of conceptual design by Black & Veatch. The cost of the majority of the items included in the master control system were supplied by the Foxboro Company.

Other equipment and structure costs are based on power plant design projects recently completed by B&V.

The methodology used to prepare the construction cost estimate is outlined by the following.

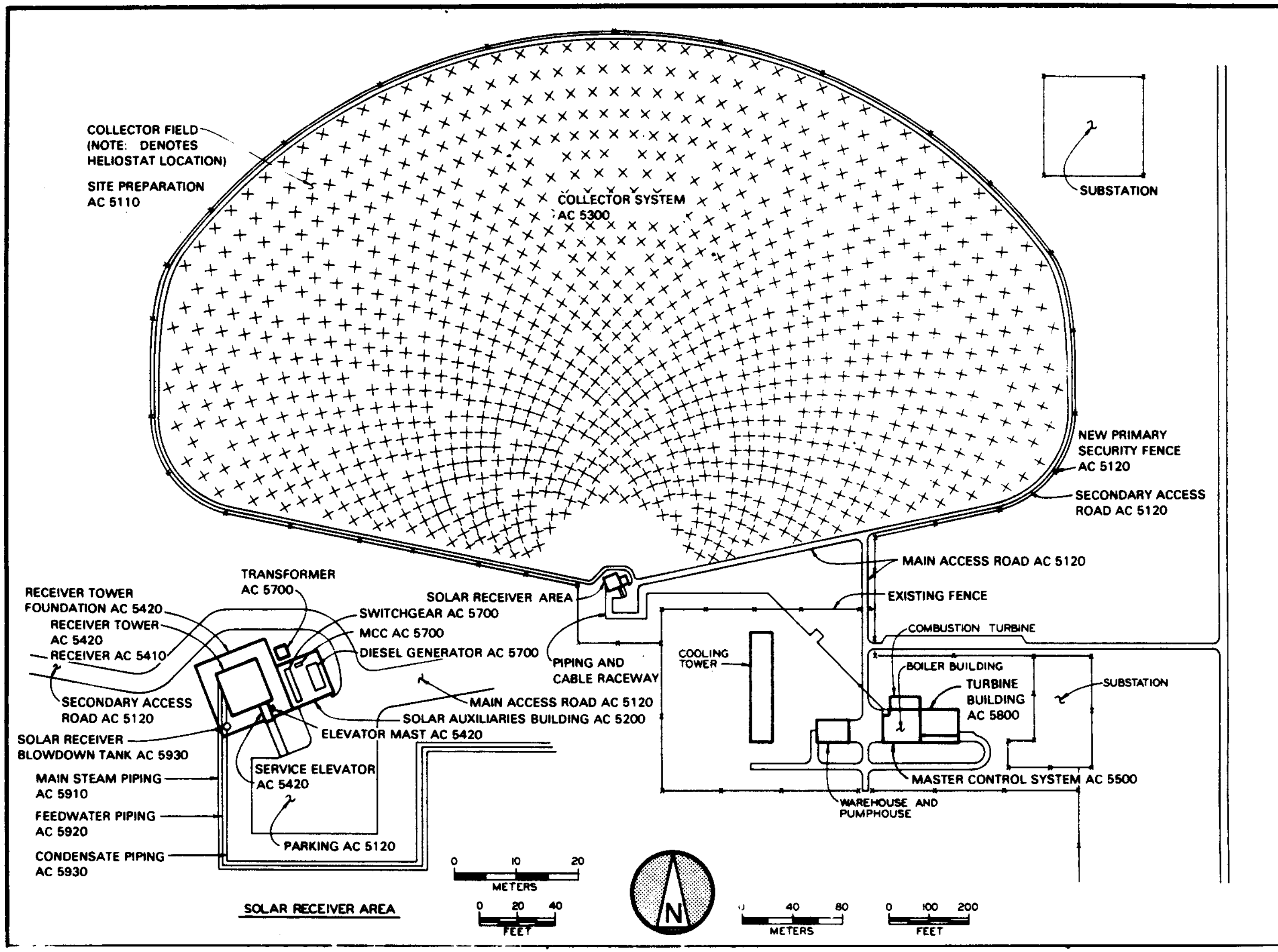


FIGURE 4.7-1. SOLAR COGENERATION FACILITY SITE ARRANGEMENT
SHOWING COST ACCOUNT BOUNDARIES

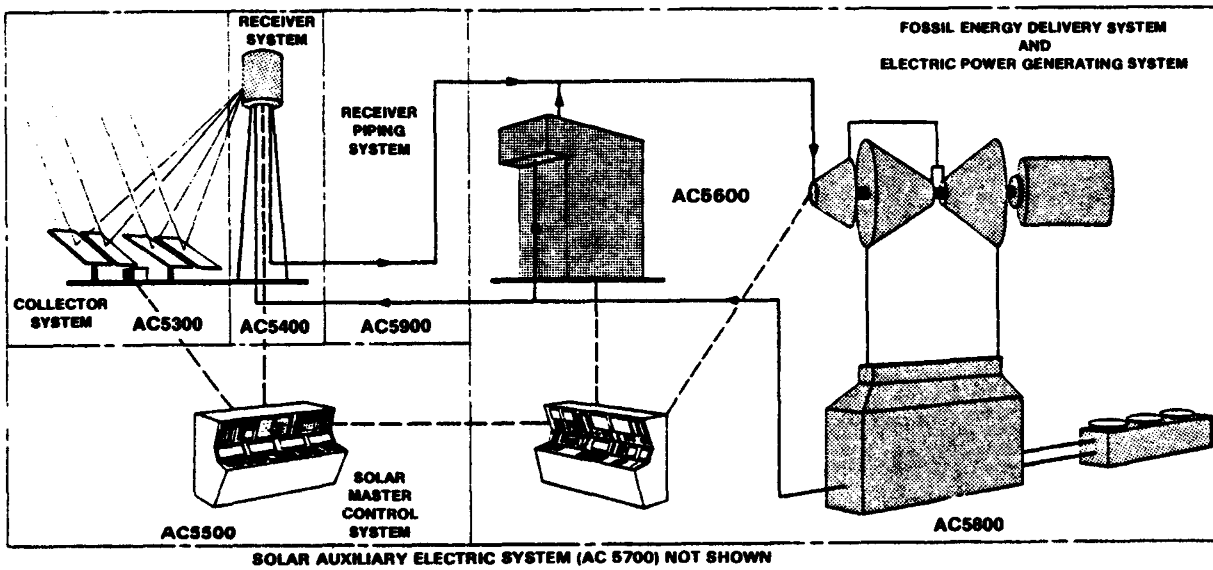


FIGURE 4.7-2 SOLAR COGENERATION FACILITY SCHEMATIC SHOWING COST ACCOUNT BOUNDARIES

(1) Current design data are obtained for all items to be estimated.

(2) Quantity takeoffs of materials and/or a listing of equipment required for plant construction are prepared based upon a review of design drawings, design reports, and Black & Veatch experience.

(3) All cost items listed are priced based upon vendor quotations or recent Black & Veatch contract prices for similar tasks or items.

4.7.2 Owner's Cost Estimate

The owner's cost estimate is summarized on Table 4-6. The following costs were considered owner's costs for the estimate.

(1) Land and Land rights at $1,483/hectare ($600/acre).

(2) Consulting services for site studies including topographic surveying, geotechnical investigations, and construction control testing.

(3) Owner's managerial, engineering, financing, and accounting, procurement, labor relations, general services, estimating, planning and scheduling, coordination, construction management, and other home office services directly associated with the project.

TABLE 4-5. CONSTRUCTION COST ESTIMATE SUMMARY

Account Number	Element Description	Construction Cost* Level 2	Level 1	Level 0
5000	Total Facility**			28,227
5100	Site Improvements		2,019	
5110	Site Preparation	1,657		
5120	Site Facilities and Improvements	362		
5200	Site Building (Excluding Receiver Tower)		21	
5300	Collector System		13,192	
5400	Receiver System		8,179	
5410	Receiver	7,350		
5420	Receiver Tower	829		
5500	Master Control System		2,676	
5600	Fossil Energy Delivery System Modifications		0	
5700	Solar Auxiliary Electrical System		709	
5800	Electrical Power Generating System Modifications		67	
5900	Receiver Piping System		1,366	
5910	Main Steam Piping	769		
5920	Feedwater Piping	421		
5930	Condensate Piping	176		

*Cost expressed in thousands of July, 1980 dollars.

**Total facility cost excludes owner's costs and operations and maintenance costs.

Also includes insurance, consumable supplies and start up costs as well as costs of obtaining all necessary licenses and permits including preparation of environmental information document.

(4) Plant conumable supplies and start-up costs (included as part of the owners indirect costs).

(5) Ad valorem property tax and sales tax.

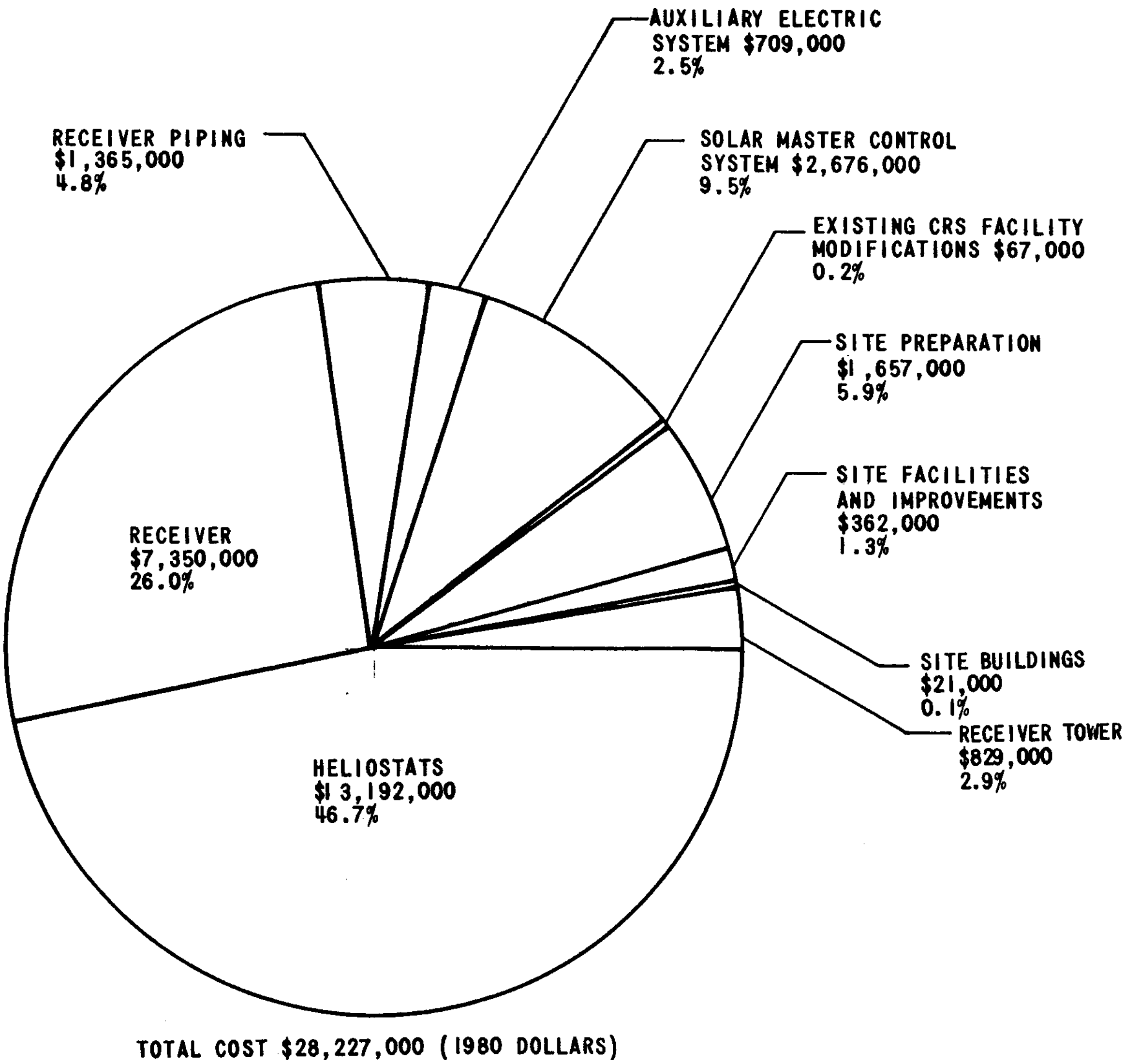


FIGURE 4.7-3 CONSTRUCTION COST ESTIMATE

(6) Cost of money, AFUDC (Allowance for Funds Used During Construction) based upon a rate of 13 per cent compounded semi-annually.

4.8 OPERATING AND MAINTENANCE COSTS AND CONSIDERATIONS

Knowledgeable estimates of operating and maintenance costs (those annual costs related to day-to-day operation of the plant, preventive

TABLE 4-6. OWNER'S COST ESTIMATE SUMMARY (7-1-80 $)

Item	Total Cost $
Land and Land Rights	48,000
Topographic Survey	18,000
Geotechnical Investigation	10,250
Construction Control Testing	40,000
Western Power Indirect Costs*	479,885*
Design Engineering	**
Property Tax	486,735
Sales Tax	17,035
AFDC	4,509,740
Total	5,609,645

*Includes consumable supplies and start up costs, licenses and permits, and insurance.

**Included in construction cost estimate.

maintenance, and corrective maintenance), are essential to the economic analyses of the cogeneration facility. O&M costs contribute to the cost of energy over the lifetime of the plant, and along with fuel costs, play a significant role in economic dispatch decisions once construction costs have been capitalized.

The O&M cost estimates for the solar portion of the Cimamon River Station have been developed on a system-by-system basis. Each system was analyzed to identify key operational and maintenance requirements. Cost estimates for those requirements have been determined on the basis of CTU and B&V experience, as well as by using available literature sources. In some cases, lack of operational experience has required an estimate based on engineering judgement.

The O&M cost estimate is shown on Figure 4.8-1. Table 4-7 gives a listing of the operations costs and of maintenance costs on a system-by-system basis. An expansion of this O&M cost table in Section 5.3 of the

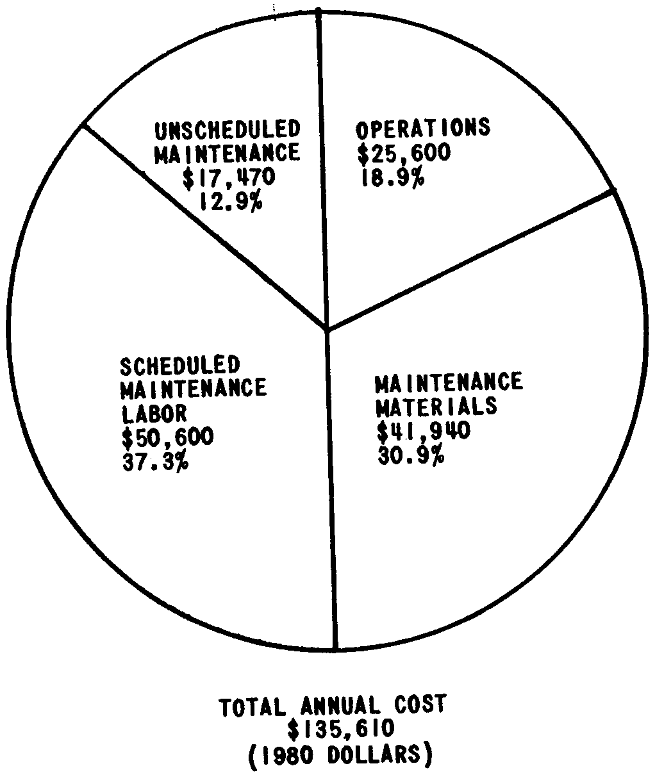


FIGURE 4.8-1 OPERATING AND MAINTENANCE COST ESTIMATE

System Specification (Appendix A) gives a further quantitative breakdown of the O&M items for each system, including estimated man-hours for various maintenance requirements. The following subsections will, therefore, discuss the identified O&M requirements in a primarily qualitative manner. Maintenance requirements will be discussed on a system-by-system basis.

4.8.1 Operations

Operating costs are divided into two categories, personnel requirements and consumables. Because operation of the solar facility will be largely automated and, in addition, will be integrated into the total plant operation, no additional control room staff will be necessary to attend the solar

TABLE 4-7. ANNUAL OPERATIONS AND MAINTENANCE COSTS (1980 Dollars)*

OPERATIONS

Personnel	$21,000
Consumables	$ 4,600
Total	$25,600

MAINTENANCE

System	Maintenance Materials $	Scheduled Labor $	Unscheduled Labor $	System Total $
Site	--	1,620	--	1,620
Site Buildings	--	5,000	--	5,000
Collector	12,790	31,800	11,950	56,540
Receiver	12,600	8,880	4,380	25,860
Solar Master Control	3,300	--	--	3,300
Fossil Energy Delivery (Mods.)	--	--	--	--
Solar Auxiliary Electric	3,000	2,130	440	5,570
EPGS (Mods.)	--	--	--	--
Receiver Piping	100	1,170	700	1,970
General	10,150	--	--	10,150
Total	$41,940	$50,600	$17,470	$110,010

Total O&M Cost:	$135,610

*An expansion of O&M costs is given in Section 5.3 of the System Specification (Appendix A).

facility controls. However, one technician will be employed full time to service and maintain the solar master control system equipment and the instrumentation and controls for the receiver, collector, receiver piping and solar auxiliary electric systems.

Included in operating considerations are those materials consumed in day-to-day plant operation. Three major consumables have been identified.

- Nitrogen, used in blanketing the receiver and receiver piping system to prevent corrosion following cooldown.
- Makeup water for boiler blowdown.
- Water Treatment chemicals.

Of these consumables, nitrogen represents the largest cost.

4.8.2 Maintenance

Maintenance of the solar system will include scheduled maintenance (e.g., heliostat washing and preventive maintenance on pumps and valves) and unscheduled (or corrective) maintenance. The following subsections will discuss these activities for each system.

4.8.2.1 Site. Site maintenance is expected to be minimal. The heliostat field area will be mowed about three times a year to facilitate access of maintenance vehicles to the heliostats and to prevent possible shading of heliostats or fouling of heliostat drive mechanisms.

4.8.2.2 Site Buildings. Most of the site facilities (e.g., control room and maintenance shops) for the solar cogeneration system are the same as for the existing system. As such, only minimal scheduled maintenance activities related solely to the solar system are anticipated.

4.8.2.3 Collector System. The largest portion of scheduled maintenance for the collector system will be heliostat washing. Three methods of washing have been identified: mobile high-pressure spray, mobile spray and brush, and a permanently fixed individual heliostat washing system. The high-pressure spray method has been chosen as the most appropriate for this system. It is assumed that heliostats will be washed 12 times per year. Other scheduled maintenance activities will include a semi-annual inspection of heliostats for any signs of deterioration.

Lack of experience with large, continuously operating heliostat fields makes estimation of unscheduled maintenance for the collector system more uncertain than for other, more conventional systems. Components which can experience failure include electronic modules in the controllers, drive motors, and drive mechanisms. In most cases, repairs will be made by replacing faulty components with spares. The faulty components will be either repaired or new spares purchased in order to maintain a sufficient spare part inventory. More major maintenance tasks such as replacement of mirror facets and mirror support structures are expected to be infrequent. Cost estimates for collector field maintenance tasks have been based on the heliostat component failure rates and costs expected for second generation production heliostats[3]

4.8.2.4 Receiver System. Scheduled maintenance for the receiver system will be similar, in most respects, to that of conventional steam generators. The boiler drum will be opened annually to allow inspection for signs of deterioration. Likewise, the boiler, superheater, and economizer tubes will undergo annual visual inspection; this inspection will be scheduled to coincide with the annual repainting of the heat absorption surfaces so as to reduce the number of times scaffolding must be erected. The extent of repainting which will be necessary with the black Pyromark paint is not known; the cost estimate assumes total repainting each year.

Additional conventional aspects of scheduled receiver maintenance include packing of valves, routine pump maintenance, and recalibration of controls. Because these maintenance tasks can be accomplished from the interior of the receiver, they present no unusual access requirements.

Unscheduled maintenance of the receiver will be minimized by the scheduled maintenance plan. Inevitably, failures in such components as valves and controllers will occur. Because these maintenance tasks are not unusual in a power plant, additional specialized skills and equipment will not be required for the solar addition. Failure of boiler, superheater, and economizer tubes is not expected to occur frequently; the absence of corrosive combustion products interacting with tube surfaces is expected to reduce deterioration levels of these solar receiver components to below those of fossil boilers. However, in the event of tube failure, sections of tubes can be removed and replaced through a proprietary technique developed by B&W. A supply of spare boiler and superheater tubes will be maintained at the plant site.

Because of the long lead time for replacement parts, a spare motor will be purchased for the receiver circulating water pump. The cost ($160,000) is included in the capital cost estimate in accordance with CTU/WP procedures.

4.8.2.5 Solar Master Control System. Scheduled maintenance for the solar master control system will be limited primarily to occasional lubricating and cleaning of the printer. The cathode ray tubes on the control panel will need convergence alignment once every year. The moving head disc will require refurbishing every 5 years. This procedure, involving only a few man-hours of labor, will require replacement of the disc with a spare; the original will then be returned to the manufacturer for refurbishing. Unscheduled maintenance will make up the majority of solar master control system maintenance requirements. A fairly large inventory of spare computer electronic modules will be maintained to allow rapid repair of computer failures. Replaced modules will be shipped to the manufacturer for repairs, or replacement parts will be purchased. Printer and disc failures are expected to constitute a smaller fraction of the unscheduled maintenance requirements.

4.8.2.6 Solar Auxiliary Electrical System. Routine maintenance of the solar auxiliary electrical system will include inspection and servicing of switchgear and inverters, servicing of storage batteries, and periodic startup and checkout of the emergency diesel generator. Unscheduled maintenance will included replacement of fuses, contactors, control transformers and inverter circuit cards.

4.8.2.7 Receiver Piping System. The receiver loop system is expected to have minimal maintenance requirements. The major costs for the receiver loop will include semi-annual inspection of the piping and pipe supports, packing of valves, routine pump maintenance, and recalibration of controls. Unscheduled maintenance will include the repair or replacement of valves and pumps.

4.8.2.8 General. Maintenance material requirements for specialized equipment (e.g., heliostat maintenance vehicle), materials for general repairs (e.g., welding rods), and other maintenance consumables (vehicle fuel) have been included in the "General" category in Table 4-7.

4.9 SUPPORTING ANALYSES

In order for the facility to receive wide acceptance, the design of the solar cogeneration facility must be supplemented by supporting analyses. This section addresses three analyses: system safety, environmental impact, and regulatory issues.

4.9.1 System Safety

Safety is a wide-ranging issue that necessarily deals with diverse concerns, such as noise, misdirected radiation effects, construction considerations, field and tower effects on aircraft, equipment failure, heliostat focussing accuracies and energy losses.

Except for special measures related to the collector field, the CRS Solar Cogeneration Facility requires safety considerations similar to a conventional power plant due to the water/steam receiver design. These conventional plant safety requirements have been established by extensive operating experience and are recorded in a large number of applicable codes, standards, and regulations. They include the Occupational Safety and Health Administration (OSHA) regulations, the American National Standards Institute (ANSI) standards, the National Electrical Manufacturers Association (NEMA) standards, the ASME Boiler and Pressure Vessel Code, the ANSI Power Piping Code, the American Concrete Institute standards, the American Institute of Steel Construction standards, and other applicable standards and regulations. The safety topics addressed by the various codes generally fall into the three categories: construction safety, operational safety for the plant and personnel, and public safety. Each area is discussed for the CRS Solar Cogeneration Facility in the following.

4.9.1.1 Construction Safety. Commonly accepted construction safety practices will be implemented for the CRS Solar Facility erection. For example, these practices would typically include limitation of personnel access to the construction site and regular inspections of construction equipment, such as hoists, cables, and elevators. Clearance areas for falling objects will be provided at the base of the tower during the tower and receiver construction phase.

Personnel engaged in work near the top of the tower will be tethered for additional support. Specific precautions will also be employed to safeguard personnel working on the tower from the hazards of sunlight reflected from heliostats during their installation. Another safety issue involves connecting the Receiver Piping System to the Fossil Energy Delivery System. To eliminate the danger of high pressure, superheated steam from entering the solar facility receiver piping system, the piping connections will be made during the annual outage when the fossil boiler is shut down. The use of appropriate isolation valves in the receiver piping system near the points of interconnection will permit normal operation of the CRS while construction of the solar facility is completed.

4.9.1.2 Operational Safety. Operational safety includes both personnel safety and plant safety. The first aspect, personnel safety, concerns potential safety problems which must be considered to safeguard employees and visitors during normal plant operation. The second aspect, plant safety, assures that the total system will be designed to sustain minimal damage in the event of a system or component failure. These two categories of operational safety will be discussed separately.

Personnel Safety. The design of a solar central receiver power plant must address those safety issues which can potentially impact plant personnel. These issues include redirected solar radiation, noise, and commonly experienced industrial hazards such as high pressure/temperature fluids, hot surfaces, high voltages, fire hazards, and rotating machinery.

(1) Redirected Solar Radiation--Redirected solar radiation is a safety hazard unique to a solar facility. Solar radiation incident on a heliostat is reflected and concentrated by the concave surfaces (mirror facets). Consequently, flux levels are substantially elevated near the focal zone of even a single heliostat. The region of concentrated flux for a single heliostat extends for a

distance of approximately ten per cent of the focal length to either side of the focal zone.[4]

High solar flux levels impact operational safety by creating a potential for skin burns and eye damage to personnel; the potential of this hazard can be understood by considering the effect of "normal" sunlight (Nl kW/m^2). For example, in some cases a first-degree burn may be produced after several minutes exposure to direct sunlight. After several hours of exposure, second-degree burns are produced. Third-degree burns could occur with prolonged exposures of multiple hours. Higher flux levels associated with heliostats produce burns in shorter time periods.

Flux levels from individual heliostats may constitute an operational hazard to personnel. Three separate cases were analyzed for the maximum flux from a single heliostat. These cases are presented as follows.

(a) In a worst-case scenario (on-axis focussing), incident solar rays strike the control heliostat in the front row of the heliostat field, and are reflected to the receiver at the top of the tower. Under these conditions, the flux from a single heliostat may range up to 70 kW/m^2 at noon.

(b) A second illustrative case was considered whereby a control failure allowed the central front-row heliostat to redirect incident solar flux to a spot near the ground. A maximum flux of 20 kW/m^2 was calculated for this case at noon.

(c) At times other than noon, lower flux levels would exist. For example, at 8 a.m. on March 21, with the central heliostat in the front row redirecting solar radiation to the receiver, the maximum flux would be approximately 10 kW/m^2.

Assuming that first-degree skin burns may be produced by exposure to a solar flux of 40 kW/m^2 for 5 seconds, a flux of 10 kW/m^2 could produce a skin burn in 20 seconds. Similarly, fluxes of 20 kW/m^2 and 70 kW/m^2 could cause skin burns in 10 seconds and 3 seconds, respectively.

While the flux levels from a single heliostat are sufficient to pose a personnel safety hazard as previously discussed, even higher flux levels are produced when the redirected rays of many heliostats coincide at a common focal spot. For example, typical flux levels from the full field at the receiver are expected to reach 700 kW/m^2. Therefore, safety measures are warranted.

To prevent personnel exposure to high heat fluxes, safety precautions will be implemented. Among these precautions, heliostat movements will be controlled by means of mechanical limits and stops to contain reflected radiation within a limited potential exposure zone. Start-up and shut-down procedures will be designed for moving and orienting heliostats so as to minimize stray reflected radiation and to limit concentrated radiation to locations having restricted access. Other restricted access regions will be established at the base of the tower and at the receiver. Personnel working in the heliostat field during daytime hours will be shielded by protective clothing, as well as head and eye devices.

Normal physiological responses to misdirected or reflected solar insolation will tend to minimize the radiation hazard. The physiological signs and responses include pain, typically experienced after 1 to 3 seconds[5] exposure to redirected flux at levels of approximately 40 kW/m^2. The pain would produce an avoidance response. Similarly, bright light would induce a blink response in 0.135 second to protect the eyes from corneal or retinal damage.[6] Reflected light from the receiver, while not a hazard, is bright and uncomfortable and produces an afterglow effect.[4] To prevent eye strain, personnel working in the field will wear protective glasses or goggles.

(2) Noise--Noise emissions from several sources are present in solar central receiver power plants. Turbines and electric generators emit noise from their casings. Other sources of noise emissions are fans and water splash, which procude noise in a wet cooling tower, and valves and other power plant components.[7]

However, since all of these noise sources already exist at CRS, the solar facility is not increasing the noise level except by way of the steam flow associated with the solar receiver. In practice, this noise is not likely to be an additional noise, but rather, noise that replaces noise that would have otherwise been produced in the gas-fired steam generator. Therefore, overall noise emissions are not expected to change.

The facility is located far from any population center, at a remote industrial site where noise problems should be minimal. Personnel working at the facility who are in close proximity to noise-producing components and who experience sound levels in excess of the Occupational Safety and Health Act permissible exposures will be provided with personal protective equipment.

(3) Common Industrial Hazards--Common industrial hazards include high pressure/temperature fluids, hot surfaces, high voltages, fire hazards, and rotating machinery. These hazards are commonly experienced with conventional power plants. Consequently, current personnel safety practices will provide adequate protection for these aspects of the solar facility. Additional protection will be afforded by good design and adherence to safety codes and standards. For example, stairwells will be provided as a back-up to elevators, with handrails and toe guards provided on platforms and stairs as appropriate. Instrumentation and sensors will be installed with isolation valves and instrument wells such that personnel can maintain these devices without exposure to steam or the need to shut down the plant. Thermal insulation on piping serves the dual function of reducing thermal losses and reducing temperatures below flash-burn levels. Care will be taken to direct discharges from condensate traps, vents, or drain lines away from possible personnel locations.

Plant Safety. Plant safety is a second aspect of system operational safety. Total system design will compensate for component or system failures such that minimal system damage is sustained. A key consideration in central receiver facility design is failure of the collector or receiver system. The receiver circulating pump provides cooling water to the receiver to protect the receiver from thermal damage in the event of loss of power to the heliostat field and consequent image drift across the receiver. If the circulating pump fails, the heliostats must be defocussed within approximately 30 seconds to prevent receiver damage.[8] To assure this capability, a source of back-up power is provided to the field by means of a diesel generator. With these design features, fail-safe conditions are achieved, and the probability of coincident receiver/field failures becomes very small. Isolation valves on the Receiver Piping System provide the capability to interrupt feedwater or main steam flows if critical problems develop which require isolation of the solar facility from the existing plant.

4.9.1.3 Public Safety. Safety factors which may impact the surrounding community are considered under public safety. These factors include the following.

(1) Radiation redirected by the heliostat field.

(2) Aircraft hazards.

Public safety radiation hazards concern radiation redirected towards off-site pedestrians and vehicular traffic. Dangerous flux levels (greater than 100 kW/m^2) are not expected off-site because high flux levels require two or more heliostats focussing at the same unintended spot, and this is not likely to occur beyond the site boundaries. Furthermore, blockage of reflected radiation at ground level can be caused by other heliostats in the field and by slatted fences. Such fences can be used if necessary to shield off-site persons and traffic from radiation by erection adjacent to the north-south county road which runs alongside the site. The presence of these barriers should reduce glint and glare problems to minimal levels.

Two primary central receiver aircraft safety considerations are glare from the field and obstruction by the tower. The first safety considerations concern glint and glare from the field. Aircraft flying over the field should observe a visual effect similar to sunlight reflecting from the surface of choppy water. This effect arises from rays reflected by a multitude of heliostat facets oriented at different angles. Minimal aircraft glare problems are expected due to the nature of the reflections. Glazed aircraft windows should serve to further reduce glare.

The second aircraft safety hazard is obstruction. The tower height to the receiver centerline is 84.12 m (276 ft), which is below the 152.4 m (500 ft) height at which an object is considered to be an obstruction for aircraft. However, as a precaution for aircraft, the FAA safe altitude regulations specify a 15.24 m (50 ft) minimum distance of closest approach to any structures. In essence this exclusion zone simultaneously protects aircraft from collisions with the tower and from radiation hazards, since the zone of intense reflected radiation is generally localized to the tower.

4.9.2 Environmental Impact Estimate

Although the overall environmental consequences of the proposed solar facility addition are considered to be relatively minor, several aspects of both the natural and man-made environment will be affected to some degree. These effects will occur in two distinct phases and will cause different impacts. During the construction phase, certain aspects of the construction activities will result in temporary adverse impacts which will not continue for the estimated operational life of the project. On the other hand, construction will result in increased employment opportunity in the area. Following the completion of construction, the operation of solar cogeneration facility for an estimated life of 15 years will cause minor continuing or permanent beneficial as well as adverse impacts. The estimates of the project environmental impacts are presented in the following discussion of environmental factors.

4.9.2.1 Geology. The project site is within the High Plains Section of the Great Plains Physiographic Province and lies on the east valley slope of the Cimarron River in east central Seward County, Kansas. The bedrock, at the surface, in the vicinity of the site is the Ogallala formation which consists of sand, gravel, silt, clay, shale, and caliche. The lower strata of the formation consist of sand and gravel; the middle strata are mixed sand, silt, and caliche; and the upper strata are clay or shale and sand. The Ogallala formation is of the Pliocene Age of the Tertiary Period at its lower strata and of the Pleistocene Age of the Quaternary Period at its upper strata. This formation is mostly unconsolidated and yields moderate to abundant supplies of ground water.

Surface soils have been derived from parent materials of the Ogallala formation and are generally sandy loams with some clay content. In the vicinity of the site, attempts at row crop agriculture are not apparent. Most of the area is vegetated with grass/forb/shrub mixtures.

Construction Impacts. Construction activities for the heliostat field and the solar receiver will not result in significant adverse impacts to any geological resources. Only about 243,000 m^2 (60 acres) of land will be significantly modified for the project. The surface topography within the heliostat field will be graded to smooth the natural contour. The soil surface within the heliostat field will be temporarily exposed as a result of the grading activities. The upper soil horizons which have resulted from natural geophysical forces will be disturbed by the surface grading activities. However, the heliostat field is small in relation to the area of similar terrain in the region. No effective mitigation measures are available to offset the temporary physical disturbances to the natural soil horizons.

Operation Impacts. The operation of the Solar Cogeneration Facility at the Cimarron River Station will not have adverse effect on geological resources of the site or the region.

4.9.2.2 Hydrology. Surface water resources in the area consist of the Cimarron River and its tributaries which are generally short, high-gradient, intermittent streams. These streams have active flow only during periods of rainfall and surface runoff. The Cimarron River is subject to wide fluctuations in flow from virtually no flow to flood stage as a result of intense storms on its watershed to the northwest. No significant surface water storage facilities are located near the site.

The major ground water aquifers in the vicinity of the site are the Ogallala and the Laverne Formations. Ground water from these aquifers is hard, but suitable for most uses. The general recharge areas for aquifers beneath the site are located to the north and west, generally along the Cimarron River and its tributaries. Recharge is derived from precipitation percolating downward to reach the aquifer. Significant amounts of ground water recharge are from stream channels.

Construction Impacts. Construction activities will result in temporary effects on the surface water resources of the immediate area. Clearing the construction area of all vegetation will make the area more susceptible to surface erosion and soil losses to water courses. Scheduling the construction activity during dryer portions of the year, revegetation of cleared areas as soon as practical, and the use of special sediment retention facilities such as perimeter berms will serve to mitigate these effects.

No significant adverse impacts of construction activities are anticipated on the ground water resources of the area.

Operation Impacts. The operation of the solar facility for approximately 15 years may result in some minor changes to the hydrological characteristics of the areas immediately under the heliostats. The ground within the solar collector area will be more shaded, it may receive less wind, and additional water will be incidentially applied to the area as a result of heliostat washing. A slight increase in surface runoff could result because of increased soil moisture under the heliostats. Also, additional infiltration of water as a result of the washing operations would result in recharge to ground water. However, the establishment of a new, improved vegetative cover on the surface of the heliostat field will tend to promote increased evapotranspiration which may offset any tendency towards increased recharge.

The actual amount of washing water which will reach the ground under the heliostats will be small. Without accounting for evaporation losses during washing, the total annual average amount of washing water will be less than 0.003 m (0.1 in) per year over the field. The typical fluctuations in annual precipitation amounts are many times greater than this and the added amount is considered to be insignificant.

4.9.2.3 Climate and Meteorology. The regional climate is of the continental, semi-arid type with high daytime summer temperatures. The relative humidity is generally low and moderate winds are present most of the time. Winters are cold and windy with little snow although occasional blizzards threaten livestock. Average temperatures vary from a high of 34 C (93 F) in July to a low of -9 C (18 F) in January. The growing season is approximately 186 days long. Annual precipitation varies from a low of 0.26 m (10.25 in) to a high of 0.82 m (32.4 in) with an average of about 0.48 m (19 in). Approximately 75 per cent of the precipitation occurs during the growing seasons. The strongest winds are from the north followed by more frequent south and south-southeast winds.

Construction Impacts. Construction activities associated with installation of the solar facility will have no effect on the climate of the vicinity.

Operation Impacts. The solar collector and receiver facilities and their operation will not have any major effect on the climate of the site or the immediate vicinity. However, the microclimate at the surface of the soil within the heliostat field will be affected. These impacts include additional shade, slightly increased amounts of moisture, and modifications of the wind patterns and air currents at the soil surface. The increased shade will result in decreased temperatures at ground level which will probably reduce the rate of evapotranspiration, however, the addition of more water to the soil surface will probably promote the growth of more dense vegetation. The net result may be actually an increase of in the total amount of water vaporized to the atmosphere through evapotranspiration. The general effect of the project on the microclimate within the heliostat field will be to make it less arid, and more compatible with plant growth.

4.9.2.4 Air Quality. No air quality problems are known to exist in the vicinity of the site. Seasonal increases in total suspended particulates occur as a result of agricultural practices and seasonally strong winds.

Construction Impacts. The operation of heavy equipment for the site preparation work will result in wind erosion and emission of fugitive dust to the atmosphere. The relocation of approximately 150,000 m^3 (200,000 yd^3) of earth within the collector field will result in the emission of fugitive dust. Following earthwork, most of the area will be barren of stabilizing vegetation until the area can be reseeded. The emission rates for fugitive dust depend on soil types, sizes and speeds of earth moving machines, and the moisture condition of the earth. Construction areas may be sprayed with water to reduce dust about 50 per cent.

Although some fugitive dust will be generated during construction, the amounts will be insignificant compared to that emitted during the cultivation of large agricultural fields in western Kansas. In the case of fallow farming, large fields may be kept barren for more than a year to conserve moisture. Suspended particulate levels near the construction site will be increased at times. However, dust control measures will be used to minimize the increases.

Operation Impacts. The operation of the solar facility at CRS will have no impact on air quality during the life of the project. The solar facility will displace some natural gas which would otherwise be burned in the CRS boiler; however, CRS natural gas consumption has little effect on air quality.

4.9.2.5 Biotic Resources. The biotic resources of the site and immediate area consist primarily of the terrestrial plant and animal communities. No aquatic resources will be impacted by the construction or operation of the solar facilities.

The terrestrial plant communities of the site consist of grasses, forbs, and desert-type scrubs. The animal populations associated with these communities include birds, mammals, reptiles, and invertebrates. The site area is not considered to be a critical habitat for endangered or threatened plant or animal species.

Construction Impacts. Construction activities will repel populations of birds and animals which inhabit the immediate area around the site. All of the animal populations residing on the heliostat field area will be displaced temporarily until revegetation can be accomplished. When construction activities cease, it is probable that birds and mammals will return to habitat areas immediately adjacent to the construction area.

Operation Impacts. Small mammals and ground-dwelling birds will benefit slightly by the microclimate changes which will occur under the heliostats. Most species of reptiles, birds, and mammals will find the environmental conditions under the heliostat somewhat improved over the matural setting.

Vegetative productivity will be higher, temperatures will be lower, and relative humidity will be higher.

Migrating birds whose flight paths bring them into contact with focused rays of the sun near the face of the receiver or in space will be killed by the intense heat. Concentrated solar reflections from the heliostat will not be permitted to strike the ground surface. During the operation of the solar facility, the rays of the heliostat field or groups of heliostats may be concurrently focused on the same imaginary point in space just to one side of the receiver tower. These imaginary points in space will be areas of intense solar flux, but they will be small. Beyond these points, the focused rays will again diverge and their intensity will deteriorate rapidly with distance.

4.9.2.6 Socio-Economic Factors

The Cimarron River Station is in a remote rural area in east central Seward County. Human population is very sparse in the area. The general economy in the region is based on agriculture. Irrigated row crop production, cattle grazing, and wheat production are important activities. The nearest town of any size is Liberal, Kansas, but several smaller communities are located throughout the region.

The project site is presently grassland suitable for livestock grazing, but it is presently not grazed. The nearest farm specializes in hog production.

Transportation facilities in the area consist of a railroad, highways, and a commercial airport at Liberal, Kansas.

The project site is already developed as a gas-fired generating station in connection with the NHC gas processing facility. Because of these previous developments, electricity, natural gas, telephone service, a water supply system, and a waste water disposal system are already in place and operational.

Construction Impacts. Construction of the solar facilities is estimated to require approximately two years. While highly specialized skilled trade workers may not be available within a reasonable commuting distance from the project site, the number of such individuals required will be relatively low and the time duration of the requirement will be short. Therefore, it is unlikely that workers will permanently relocate to communities in the area.

Other skilled workers, semi-skilled workers, and non-skilled workers will be available in adequate numbers in the region for the relatively short durations of the activities. No large immigrations of workers and their families to area communities are anticipated. Therefore, the social and cultural institutions of the area will not be significantly affected.

The presence of the construction work force in the area for approximately two years will result in slight increases in highway traffic, but the construction payroll will probably be partially spent in the nearby communities.

Operation Impacts. Operation of the solar cogeneration facility will require four new operating and maintenance personnel. This small increase will have no discernible effect on local communities.

Minor changes in land use will occur as a result of installing the solar facilities. The 243,000 m^2 (60 acre) area used for the collector field and the receiver location will be preempted from other uses as long as the facility is maintained and operated.

4.9.2.7 Paleontological, Archaeological, and Historical Resources. No historical resources are located near the project site. The site has not been surveyed for paleontological or archaeological resources. An abandoned railroad right-of-way is located within the heliostat field area; this indicates that some portion of the heliostat field has been previously disturbed. The services of a professional archaeologist will be obtained to conduct an inspection of the heliostat field area prior to construction activities. If evidence of archaeological or paleontological resources is found, more detailed investigations will be conducted to determine the nature of the resources. Further, if significant paleontological and archaeological resources are discovered, appropriate measures will be developed for recovery of the material.

4.9.2.8 Aesthetic Resources. The site vicinity does not include high quality visual resources of unique nature. The area can be described as a small industrial complex surrounded by large expanses of open grassland.

Construction Impacts. Construction activities will cause a minor temporary impact on the appearance on the CRS and NHC site in that heavy equipment and earth moving machinery will be present onsite during the construction period. The importance of such an impact is low since it will only be temporary and also since large agricultural equipment is common in western Kansas.

Operation Impacts. The permanent impacts associated with the solar cogeneration facility consist of the appearance changes resulting from the heliostat field and a 84 m (276 ft) tall receiver tower. This tower will be visible from long distances in the gently rolling area.

4.9.3 Institutional, Regulatory and Other Considerations

Just as conventional power generation systems are influenced and/or governed by a range of institutional and regulatory factors, solar thermal receiver plants and other developing energy technologies are also impacted. At the national level, existing and proposed energy and tax legislation can have pronounced effects on the economic feasibility of solar thermal power plants in general and on solar cogeneration of CRS. Energy and tax legislation have historically favored fossil fuel consumption by allowing fuel costs to be deducted as an operating expense, by controlling the price of oil and natural gas, and by providing favorable tax treatment to the oil and gas industry; however, some of these regulations are under review in an effort to encourage the use of alternate energy sources. For example, as the price of natural gas is decontrolled and increases in response to natural market forces, the value of the solar contribution to CRS operations will increase. Other methods to enhance the economic attraction to WP of the solar addition would include granting rapid tax depreciation of the solar equipment, waiving the investment tax credit restrictions (1/7 of 10 per cent) that are normally applied to utilities, and allowing these solar facility additions to qualify for cogeneration tax credits.

The Fuel Use Act (FUA) is another law that could impact CRS solar cogeneration. The Act currently will prohibit the consumption of natural gas for power generation at CRS after 1990 except in peak duty service, unless an exemption is granted. In the absence of assured permission to burn natural gas and thus permit the continuous operation of the solar cogeneration facility throughout its useful life, major capital expenditures at CRS by WP would be subject to risk. However, it is believed that the addition of the solar cogeneration facility will greatly increase the likelihood that an exemption will be granted. In addition, many believe that the restrictive provisions of the FUA will be eliminated.

Another area of concern involves the customers of WP and the Kansas Corporation Commission (KCC). In general, the KCC attempts to represent the interests of WP customers by performing a variety of functions, including regulating the electricity sales price. Because the expected, near-term costs of solar generated electricity and process steam exceed those achievable using conventional technologies (e.g., pulverized coal power plant), it is not likely that the KCC would allow WP to include the "premium" cost of the solar facility in its rate base. In a similar fashion, some commercial WP customers (e.g., rural electric cooperative) might have an opportunity to purchase power from a utility other than WP at a lower price because the other utility would not have the extra cost burden associated with a solar facility. Therefore, education of and acceptance by both customers and the KCC would necessarily be factors in the WP consideration of solar cogeneration expenditures.

In addition to the above consideration that relates to the unique characteristics of the solar facility, several normal permits and approvals will be required. Those requirements are as follows.

(1) Federal Approvals.

   (a) Federal Aviation Administration--Determination of No Hazard to Air Navigation; Notice of Construction Progress to Greatest Height.

(2) State Approvals.

   (a) Kansas Department of Human Resources--Boiler Inspection.

   (b) Kansas Department of Health and Environment--Open Burning Notification (if open burning is conducted during land clearing activities).

(3) Local Approvals.

(a) Fire Department--Open Burning Approval (if open burning is conducted during land clearing activities).

If federal funds are involved, the funding agency may also require the preparation of an Environmental Assessment and, possibly, a complete Environmental Impact Statement before federal funds can be allocated to the project. Given the retrofit nature of this project and the relatively benign nature of a solar facility, it is likely that an Environmental Information Document and an Environmental Assessment will be sufficient. Also, it is likely that the required scope will be a summary of all environmental issues associated with the plant, a description of the measures employed to avoid or lessen the impacts, and limited site investigations addressing only natural and human environmental systems. Extensive, long-term environmental monitoring probably will not be required.

5.0 SYSTEM CHARACTERISTICS

The solar facility, presented in an integral manner in Section 4.0, is described in this section on a system-by-system basis. That is, for the purposes of this section, the plant is divided into collector, receiver, receiver piping, solar master control, and solar auxiliary electric systems. Each of these systems is described in terms of its major components, functional requirements, design, operating characteristics, performance, and cost estimates. Additional information on each system is presented in the System Specification (Appendix A). In addition, this section describes modifications to the existing CRS cogeneration facility which are necessary for the solar facility addition.

5.1 COLLECTOR SYSTEM

The collector system consists of 1,057 heliostats located in a 156 degree sector north of the receiver support tower. The field contains a total reflective area of 55,780 m^2 and covers a land area of 2.2×10^5 m^2 (55 acres). Components of the collector system include the following.

- Reflective modules, including mirrors and structural supports.
- Azimuth and elevation drive assemblies.
- Pedestal and foundation.
- Electrical power distribution wiring.
- Control elements, including heliostat controllers, field controllers, heliostat array controllers, and wiring.

The following sections outline the functional requirements of the collector system, and describe its design and performance characteristics.

5.1.1 Functional Requirements

The design of the collector system is subject to a number of functional requirements, which relate to interfaces with other systems as well as to siting and climate considerations. Included in the functional requirements are the following.

- The power redirected to the receiver must result in 37.13 MWt delivered to the working fluid at the design point, Equinox noon, with a direct normal insolation value of 0.95 kW/m^2.

- Collector design will be based on a cylindrical, external receiver 9.45 m (31 ft) tall, 6.71 m (22 ft) in diameter, and centered 84.13 m (276 ft) above grade.
- Heliostats must redirect sunlight to absorber panels covering a 210 degree segment on the north side of the receiver cylinder.
- Proper flux distributions on the receiver, resulting in material temperatures within design limits, must be maintained.
- Annual energy redirected to the receiver per unit mirror area is maximized within constraints of available land shape and receiver flux distributions.
- Control of heliostats must allow diverse operations including normal tracking, start-up, shutdown, emergency shutdown, standby, and defocusing of select portions of the field.
- Heliostat foundations must provide rigid support for accurate beam direction, and have the capability to withstand extreme winds.

5.1.2 Collector Location

The site preparation trade study, discussed in Section 3.4, identified an area north of the CRS turbine building and cooling tower as the most cost effective field location based on the combined costs of site preparation and receiver system piping. However, the existence of gas and water pipelines in that area constrain the location and shape of the collector field. The site arrangement plan on Figure 5.1-1 shows a pair of underground gas pipelines crossing the east side of the plant site. Further to the east are an electrical substation, an underground water pipeline, and buried control and power cables. All heliostats are located entirely to the west of the buried gas pipelines to permit heavy equipment access for pipeline maintenance.

Figure 5.1-1 shows the baseline collector field design resulting from the field layout/flux pattern trade study (Section 3.5), with the receiver support tower located approximately 100 m north and 215 m west of the CRS generation building. During the field layout effort, a modification to the baseline collector design/location appeared to be justified to reduce receiver

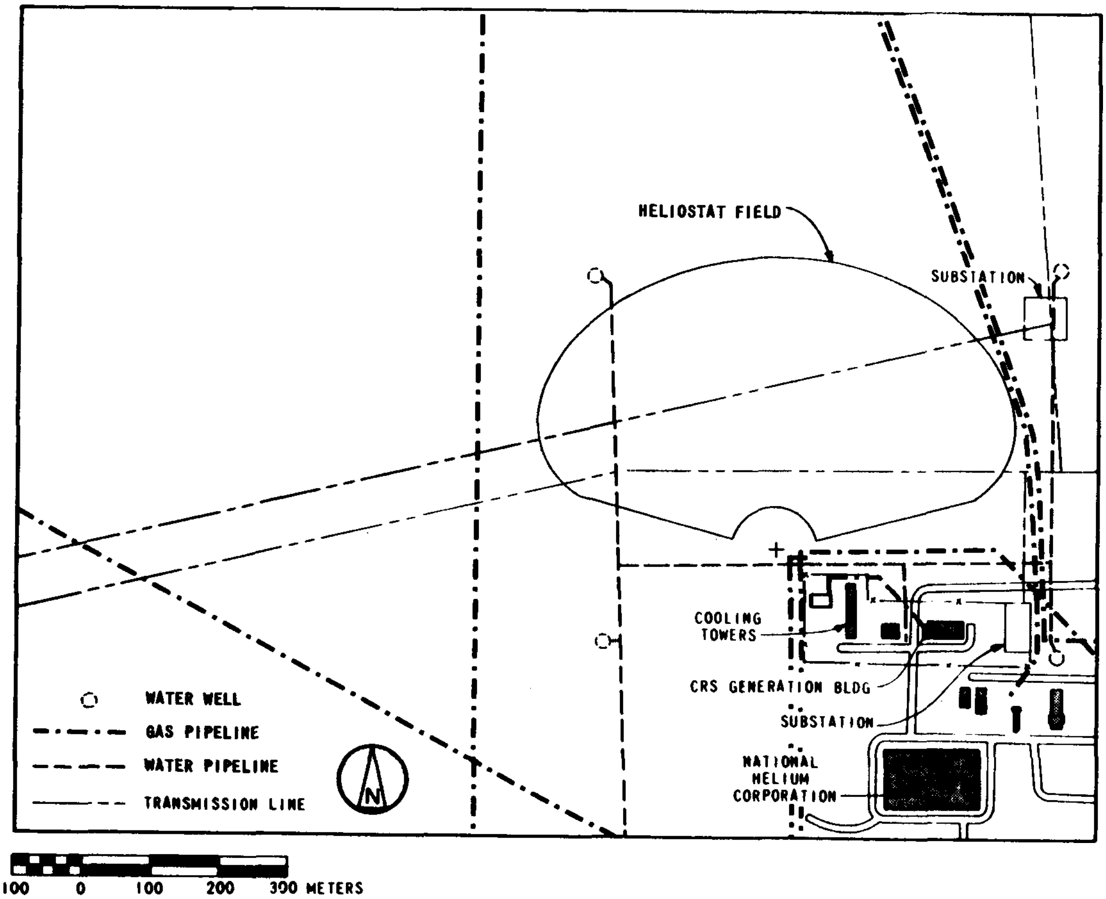


FIGURE 5.1-1 BASELINE COLLECTOR FIELD LOCATION

piping costs by locating the receiver support tower closer to the generation building. Shifting the baseline collector field to the east would reduce the length of main steam and feedwater piping, but as the example in Figure 5.1-2 illustrates, the shift would result in an asymmetric field shape. The eastern edge of the field would be truncated to avoid the gas pipelines on the east side of the plant site, and heliostats would be moved to the southern and western edges of the field. These field modifications have a negative impact on the collector cost and performance since heliostats are forced into less efficient parts of the field. Thus, the field would require more heliostats to generate 37.13 MW_t at the design point and would redirect less annual energy per heliostat to the receiver.

To assess the cost effectiveness of modifying the collector field, a comparison was made of the savings in piping costs versus the increase in

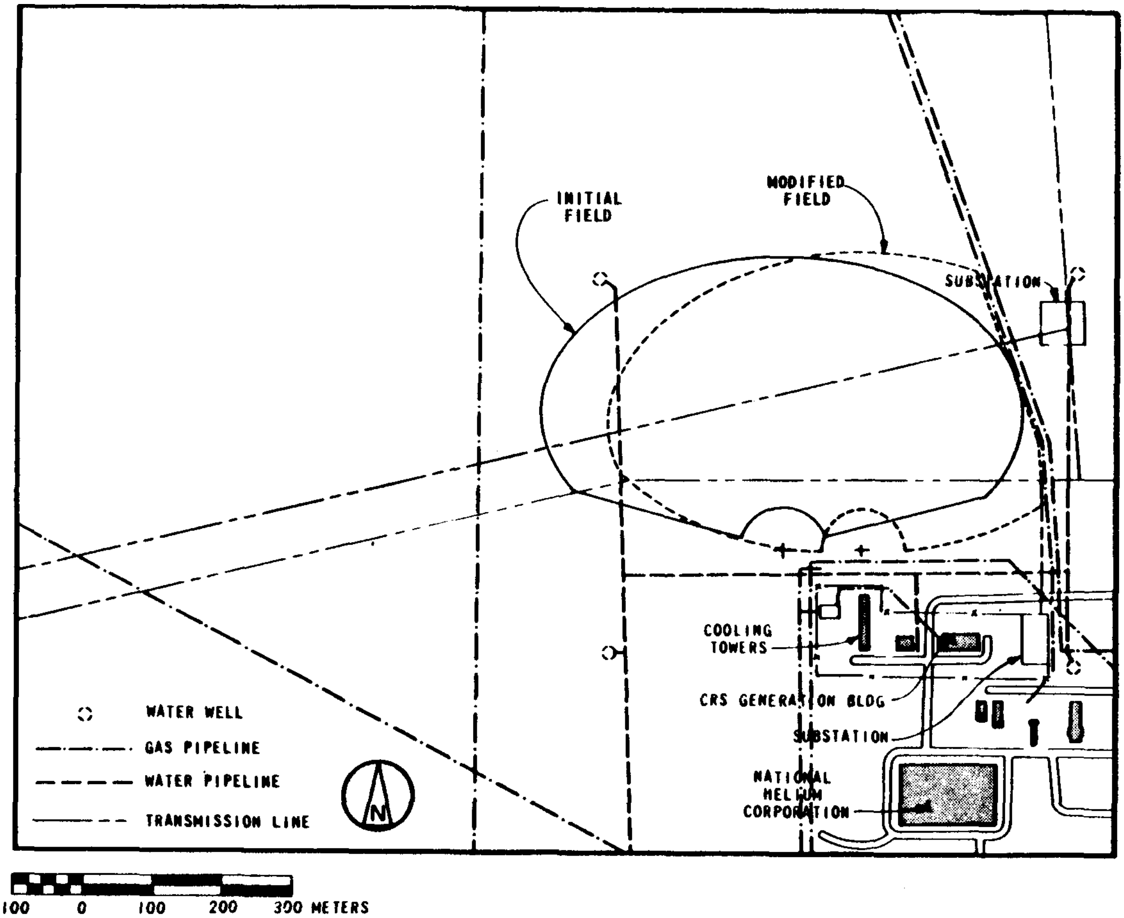


FIGURE 5.1-2 COLLECTOR MODIFICATIONS TO REDUCE RECEIVER PIPING COSTS

heliostat costs. Several collector fields were designed as the receiver support tower was shifted due east from its baseline position, and cost estimates were made for the receiver piping and modified heliostat field.

The results of the comparison indicated that shifting the receiver support tower 100 to 120 m east of its baseline position would result in a savings of $100,000 in a combined heliostat and receiver piping costs. Although field performance estimates showed the asymmetric field would deliver only slightly less annual energy to the receiver than the symmetric field, panel temperature imbalances are expected to be more severe for the asymmetric field during cloud transients. As a result, the cost savings do not appear to be justified in light of the additional receiver design and material costs that might be incurred in avoiding those problems. Consequently, the baseline field location identified in Figure 5.1-1 was selected as the final collector location.

Investigation of the CRS topography reveals that the terrain is quite rough; rolling peaks and valleys with fairly steep slopes and localized elevation differences of 1.5 to 6 m (5 to 20 ft) are common. Because the local terrain exhibits such wide variance, site grading is necessary. The site preparation study, discussed in Section 3.4, indicated that the most cost effective site grading plan has a "rolling" topography; the underlying contour of the site remains, but the terrain is smoother to avoid excessive shadowing and blocking. The soil is compacted where fills are necessary, allowing the use of a standard heliostat foundation/ pedestal design throughout the field.

The "rolling" field topography, shown in the contour map in Figure 5.1-3, has little impact on the total daily solar energy redirected to the receiver. A maximum field slope limit of four per cent was imposed during the development of the site grading plan so that shadowing effects resulting from the gentle contour hills are only experienced during extremely low sun elevations. At these times, insolation is low and of little value for power generation.

5.1.3 Heliostat Description

A total of 1,057 heliostats are required to deliver the 37.13 MW_t design point absorbed power, based on a heliostat reflective area of 52.77 m^2. Any of the second-generation production heliostats could be used in this system without significantly affecting the total land usage or receiver design. However, the number of heliostat units required and their spacings within the field would depend on the actual dimensions and reflective area of the heliostat chosen. The selection of a specific heliostat supplier for this project will be made on the basis of the most proven and cost effective design available during the procurement process to support design and construction of the facility.

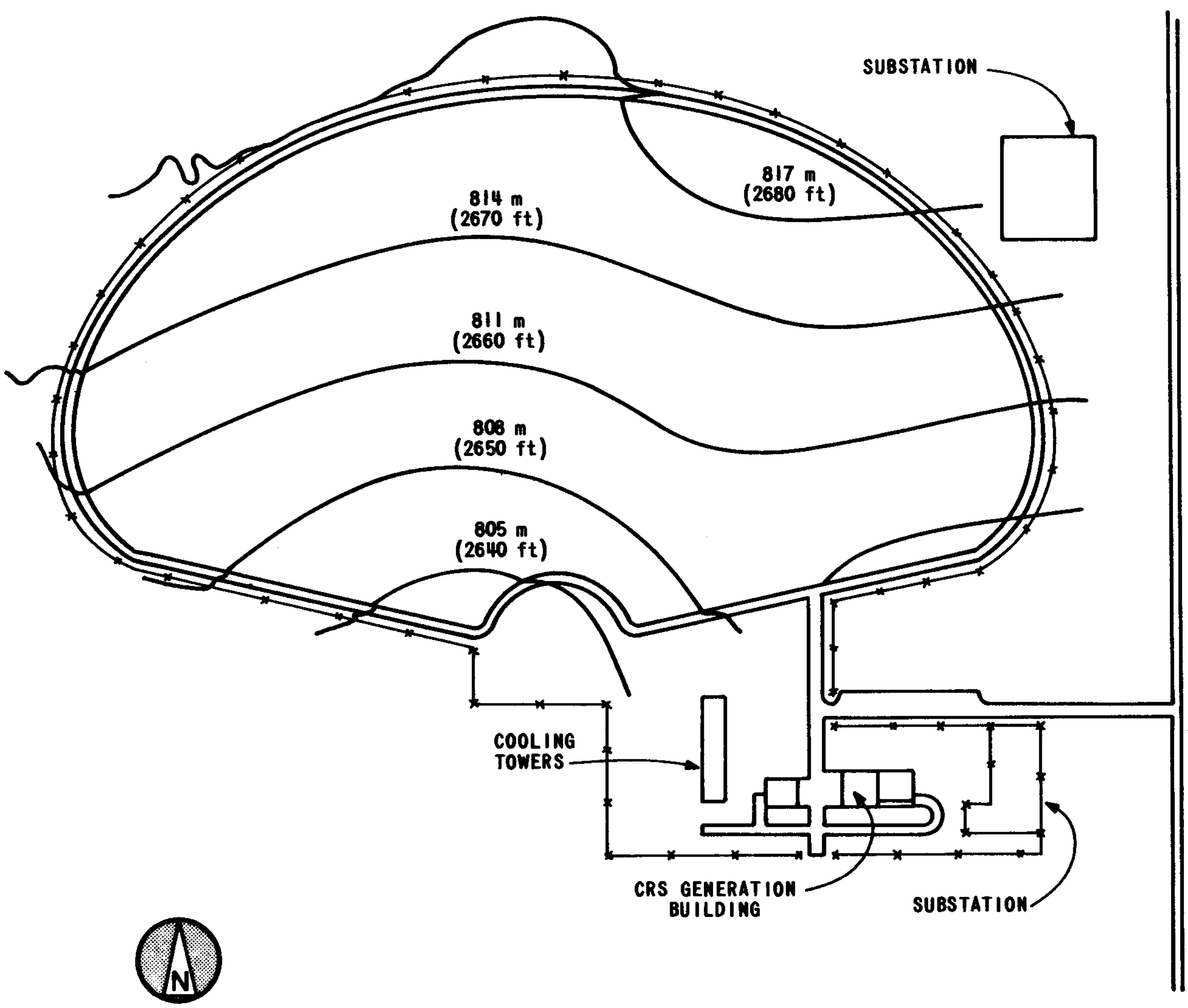


FIGURE 5.1-3 COLLECTOR FIELD SITE GRADING PLAN

For the purposes of this study the heliostat characteristics listed in Table 5-1 were used to generate heliostat locations and field performance data. The heliostat consists of 12 curved mirror panels attached to a single frame, with a total reflective area of 52.77 m^2 (568 ft^2).

TABLE 5-1. NOMINAL HELIOSTAT CHARACTERISTICS

Heliostat Design Characteristics	
• Height	7.44 m
• Width	7.39 m
• Height of Elevation Axis Center line	4.04 m
• Heliostat Area	55.01 m^2
• Total Reflective Area	52.77 m^2
• Number of Mirror Modules	12 (2 Horizontal, 6 Vertical)
• Mirror Reflectivity	0.90 average
Heliostat Performance Parameters	
• Standard Deviation of Angular Errors for Pointing	0.75 milliradians each axis
• Standard Deviation of Angular Errors in Surface Normal	1.0 milliradians each axis
• Mirror Modules individually canted	
• Mirrors have spherical curvature with Focal Length Equal to Slant Range	
• Heliostats meet Requirements of Collector Subsystem Requirements Specification A10772, Issue D	

The panels are adjusted on the frame (canted) to form an overall heliostat curvature which serves to reduce the beam size at the receiver. For the purposes of this study, it was assumed that the focal length of the panels and the focal length formed by on-axis canting were both equal to the heliostat slantrange, the distance from heliostat to target. On-axis refers to the prefect focusing of a heliostat when the sun, target, and heliostat lie on the same line.

Heliostat steering is accomplished by two motors driving the azimuth and elevation positions separately. The heliostat frame and drive motors are supported by a single pedestal attached to a concrete foundation. Below grade, the foundation is constructed as a drilled pier 0.76 m (30 in) in diameter socketed 3.05 m (10 ft) into the ground. Above grade, the pedestal will be constructed as a circular column with a diameter and height compatible with the heliostat chosen for this project. A reinforcing cage extends the full height of the foundation and pedestal. The dimensions and design forces are based on data produced for the second generation heliostat design in the DOE Heliostat Development Program.

5.1.4 Collector System Layout

The final collector field layout was developed through an optimization procedure that determined the number of heliostats required to meet the design point power requirement, and positioned those heliostats to maximize the annual energy collected per unit of mirror area. In other words, the field was optimized for annual rather than design point performance, but it was sized to deliver rated power at the design point.

The collector field layout resulting from the optimization procedure contains a total of 1,057 heliostats, (55,780 m^2 of reflective area) occupying a land area of $2.2 \times 10^5 m^2$ (53 acres), as illustrated in Figure 5.1-4. Heliostats are located in 34 circular arcs surrounding the receiver support tower, with the inner row 66.1 m (217 ft) and the outer row 424 m (1,391 ft) from the tower center line. Heliostats are located in a radial stagger pattern formed by circular arcs and diverging radial lines; the staggering arrangement allows close packing with a minimum of optical interference (blocking) among heliostats.

Because heliostats are located on diverging radial lines, the lateral spacing of heliostats within the rows ($rd\theta$) increase with distance from the tower. When the lateral separation becomes unacceptably large, the angular separation between radial lines is reduced by a factor of 0.75, causing the periodic readjustment in lateral separation shown in Figure 5.1-5. Counting outward from the tower, transitions in angular separation occur in rows 3, 7, 11, 17, 23, and 29. Within those transition rows, heliostats are periodically deleted to avoid mechanical and optical interference.

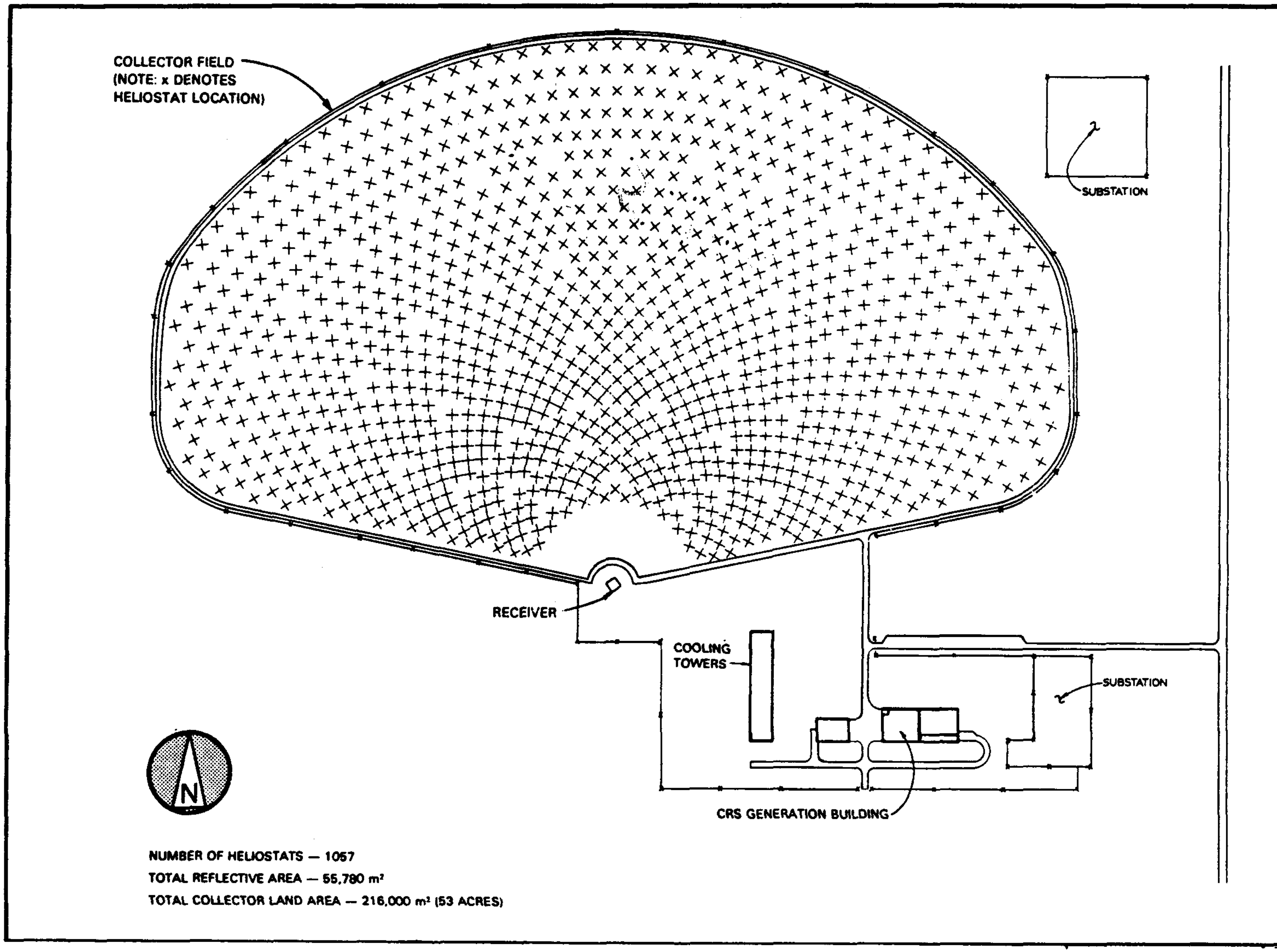


FIGURE 5.1-4. COLLECTOR FIELD LAYOUT

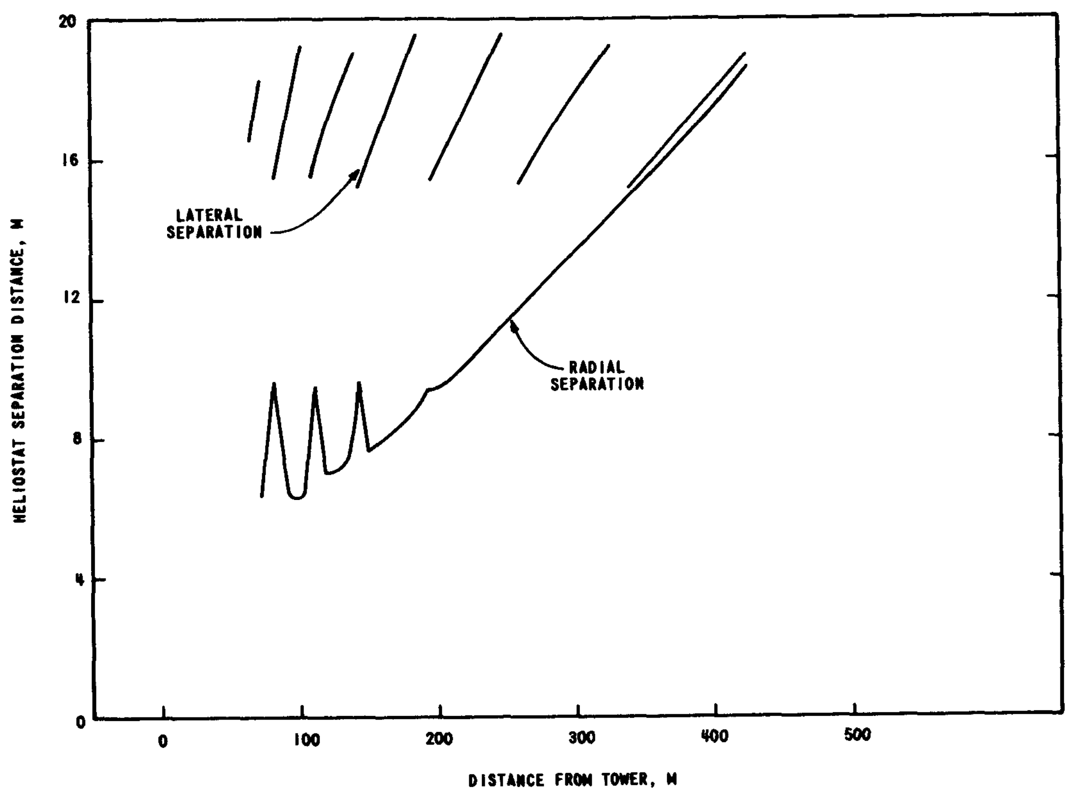


FIGURE 5.1-5 HELIOSTAT SEPARATION VERSUS DISTANCE FROM TOWER

Figure 5.1-5 shows the radial separation between rows also increases with distance from the tower, allowing heliostats to see over the neighboring heliostats in front without blocking. To prevent mechanical interference, the transition rows 3, 7, and 11 were given slightly larger spacings as illustrated by the spikes in the figure.

The field optimization procedure used in designing the collector field computed the ideal ground cover ratios (heliostat packing density) throughout the field. In general, for external receivers of this type, ground cover ratios are a strong function of distance from the tower, but are only moderately dependent on the azimuthal field position. Consequently, heliostats are placed in circular rows forming ground cover ratios that are independent of azimuthal location. Figure 5.1-6 illustrates the ground

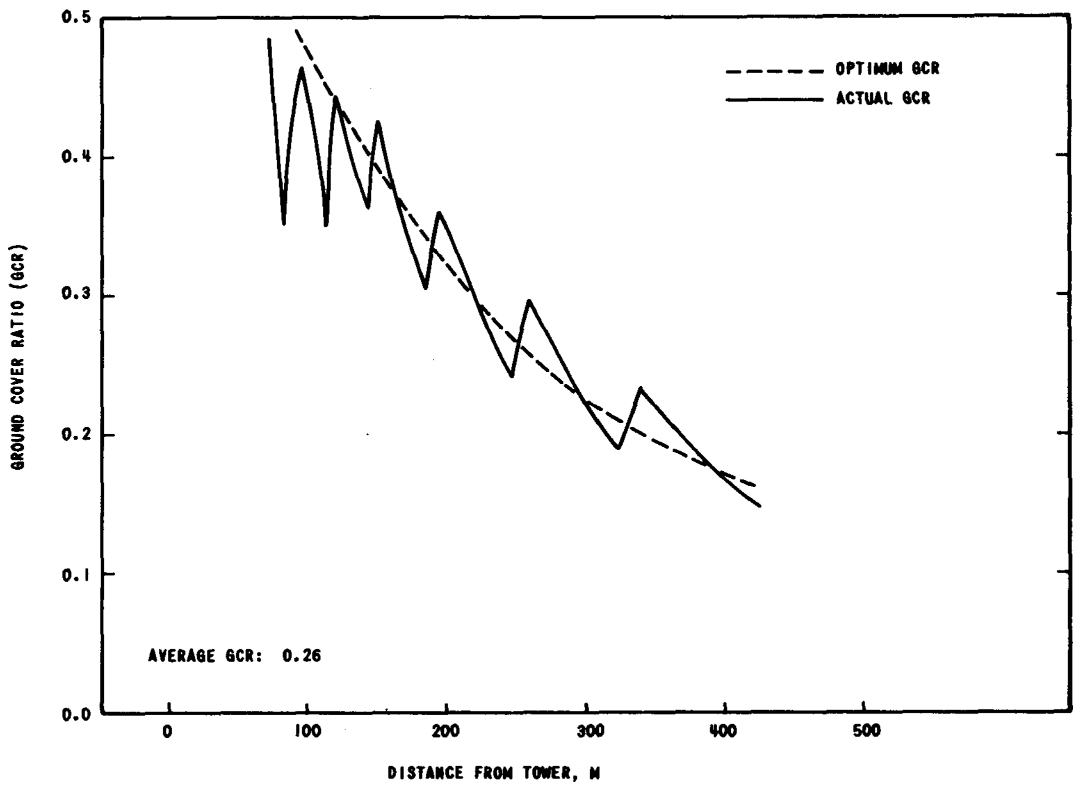


FIGURE 5.1-6 HELIOSTAT GROUND COVER RATIO VERSUS DISTANCE FROM TOWER

cover ratios as a function of field radius predicted by the optimization procedure and compares them to the actual values defined by the final field layout. The curves show that the final field layout approximates the ideal layout, with slight ground cover variations due to the staggered heliostat array pattern.

The actual X, Y and Z locations of all 1,057 heliostats are listed in Table 5-1 of the System Specification (Appendix A). Heliostats are numbered from one to 1,057 and are listed from the inner row to the outer, counting heliostats from the west end of the rows clockwise to the east. The X, Y and Z coordinates are listed in meters with positive X east, positive Y north, and positive Z above the base of the receiver support tower.

5.1.5 Collector System Operation and Control

Heliostat control is accomplished by a digital computer system which interprets operator commands, generates steering instructions for each heliostat individually, and performs monitoring and self-test routines.

Executive control is exercised by the Heliostat Array Controller (HAC), which interfaces with the Solar Master Control System (SMCS) and interprets commands entered by the operator via Cathode Ray Tube (CRT). The HAC performs sun position calculations using the ephemeris tables and time inputs synchronized with Coordinated Universal Time through radio station WWV. The calculations use barometric pressure and temperature to make corrections to the sun position due to the atmospheric refraction.

The HAC interfaces with the heliostat field by sequentially addressing the 34 Heliostat Field Controllers (HFC), and transmitting the sun position data and command information. Through the HFC's, the HAC is capable of addressing individual heliostats and groups of heliostats on the entire field.

Each HFC controls up to 32 heliostats by accepting sun position and command data from the HAC and sequentially transmitting the information to the individual Heliostat Controllers (HC). The HFC also accepts status information from the HC's and transmits it to the HAC.

The HC is a microprocessor controller which receives data from the HFC and calculates the azimuth and elevation gimbal angles of the heliostat based on sun position and on the heliostat location and aim point coordinates stored in the microprocessor memory. The HC also services the ac motor control loop, advancing the motors until the calculated gimbal angles are reached. In addition, the HC has a self-check system which signals the HAC in the event of a failure. If command from the HAC is lost, the HC is capable of directing the heliostat to a stow position. In the case of a loss of normal power, backup power to the heliostat drive motors is provided by an emergency diesel generator.

In the normal operating mode, the control system commands heliostats to track the sun and direct their beams to specific aim points on the receiver surface. An aiming strategy has been developed for the collector system which assigns a unique aim point location to each heliostat in the field. Each heliostat redirects its beam toward the receiver center line (i.e., no azimuthal shift); however, as shown in Figure 5.1-7, the vertical aim point of each heliostat on the receiver surface is one of four points and is a function of the heliostat's slant range (the distance from the heliostat to target). The four point aim strategy is tailored to meet the incident flux requirements of the receiver. By spreading the beams vertically, incident power is evenly distributed without significantly increasing the total spillage loss. Subsection 5.1.2 in the System Specification (Appendix A) presents an algorithm to compute the aim point coordinates for any heliostat in the field based on the heliostat's location in the field and unique identification number.

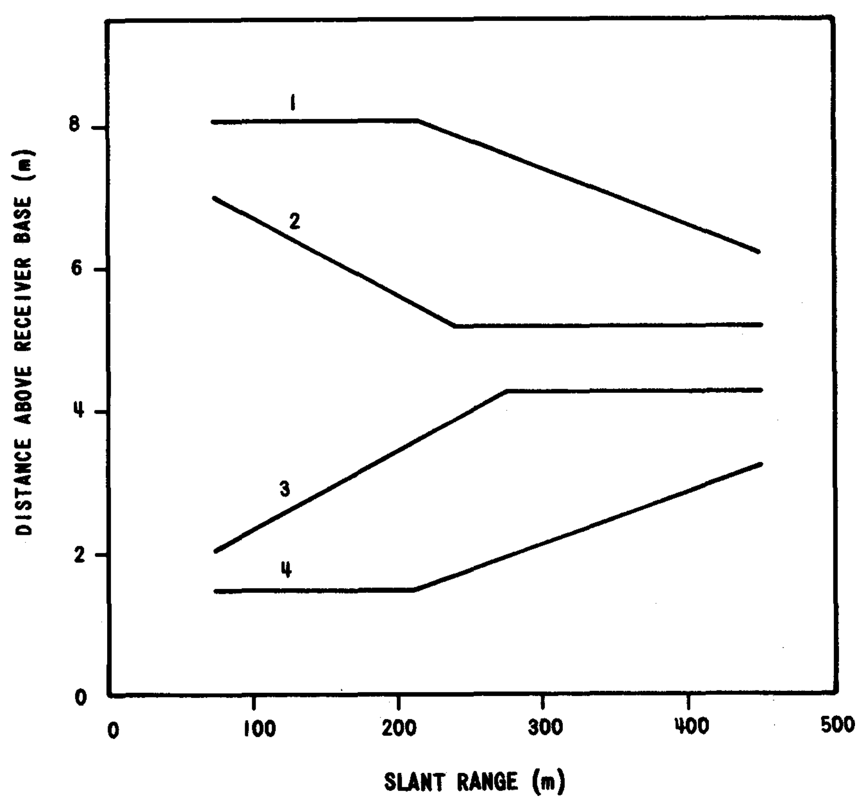


FIGURE 5.1-7 FOUR POINT AIM STRATEGY

In the standby mode, heliostats track the sun, redirecting their beams to a pair of stationary points in space located northeast and northwest of the receiver, but at the receiver elevation. Heliostats in the east half of the collector field will be assigned a standby position northwest of the receiver, allowing all heliostats on that side of the field to be brought from standby to the receiver without tracking across the tower or the normally unirradiated portion of the south side of the receiver. Similarly, heliostats in the west half of the field will be assigned a standby position northeast of the tower. The use of two standby points as described prevents heliostats from tracking across surfaces that are not actively cooled, and ensures that the beams will be directed away from the receiver during standby.

In addition to the normal operation and standby modes, heliostats will assume a predetermined position for cleaning, maintenance, or stowage on command from the Heliostat Array Controller or from local manual command at the Heliostat Controller.

Control software is used to provide time sequenced commands to the heliostats to execute predefined procedures such as start-up, shutdown and emergency defocusing. In normal start-up, groups of heliostats are brought from stow position to standby by moving their beams from ground level up a vertical safety corridor to standby position. Then, upon command, the beams will be moved from standby to the receiver surface as needed. Evening shutdown will follow the reverse sequence, with beams redirected from the target to standby, then down the safety corridor to ground level.

Under emergency conditions requiring the immediate removal of power from the receiver surface, all heliostats are directed to stand by and wait for operator command to return to target or to stow position. Upon loss of command from the Heliostat Array Controller, the Heliostat Controllers initiate a stow sequence, using preprogrammed instructions to bring the beam down safely. Upon loss of electrical power to the drive motors power, the heliostats fail in position.

The collector system delivers 37.13 MWt to the working fluid (42.0 MWt incident) at the design point, based on an 88.3 per cent receiver efficiency and 0.95 kW/m^2 direct normal solar radiation. Similarly, Figure 5.1-8 shows the annual field performance stairstep. Annual energy estimates were based on an annual average-day insolation value of 6.1 kWh/m^2 day. The value was computed from the clear air insolation model described in Subsection 5.5.1 of the System Specification (Appendix A), corrected for observed per cent sunshine data for Dodge City, Kansas.

Figure 5.1-9 presents the overall field efficiency values in graphical and tabular form for various sun azimuths and elevations. Field efficiency is defined as the calculated energy incident on the receiver divided by direct normal insolation times total field mirror area. The values shown include the combined effects of cosine, tower shadow, heliostat shading and blocking, mirror reflectivity, atmospheric attenuation and spillage.

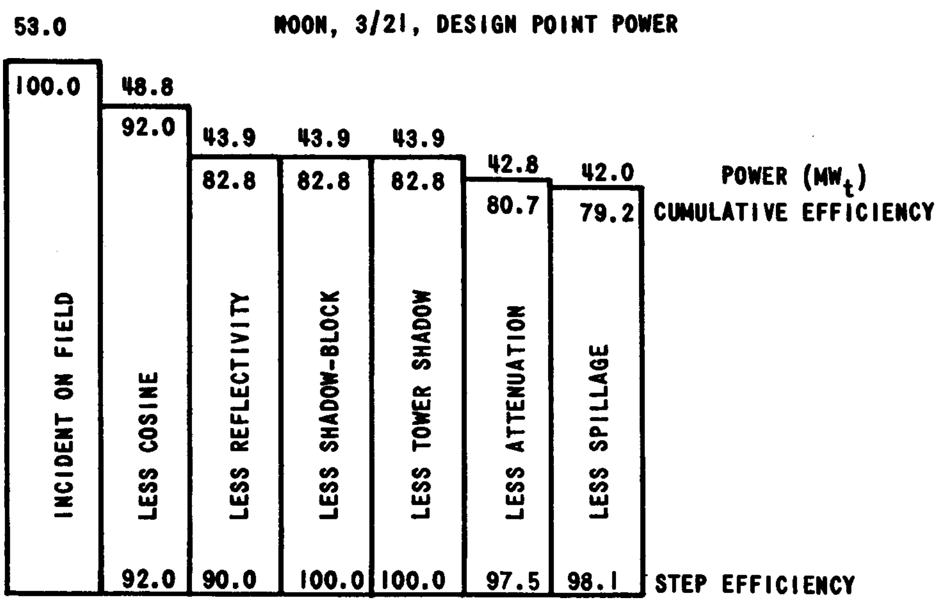
The incident flux distributions on the receiver are presented in Section 5.2, and are discussed in terms of their impact upon receiver performance.

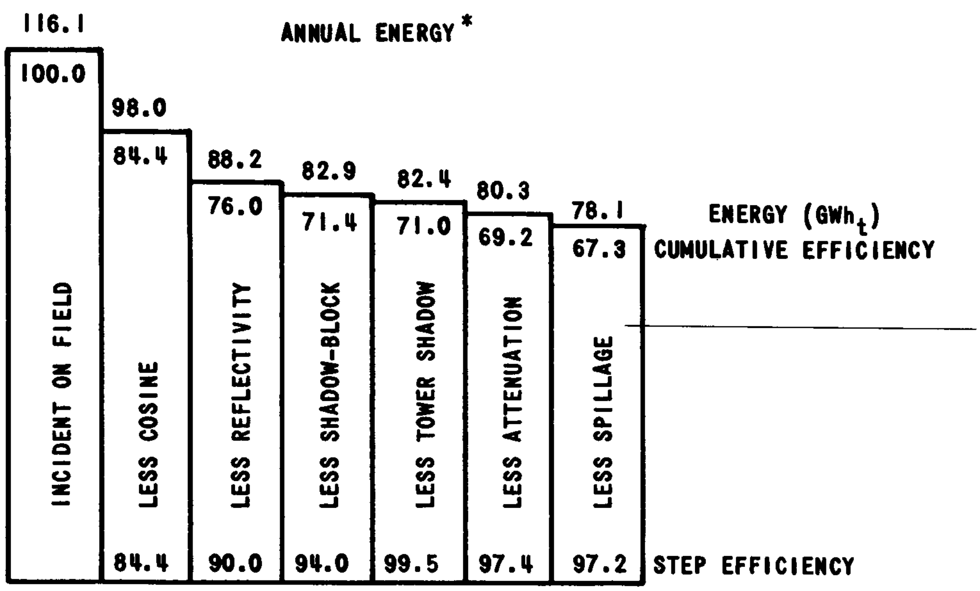
5.1.6 Collector System Cost Estimates

Cost estimates of the collector system have been made which include the erected cost of heliostats, foundations, wiring, and the heliostat control system, and startup and checkout. Based on information supplied by four second generation heliostat vendors (Boeing, Martin Marrietta, McDonnell Douglas, and Northrup), the collector system cost is estimated to be $\$215/m^2$; this is the cost of the heliostat including foundation. A contingency of 10 per cent is added, giving a total cost of $\$236.50/m^2$. This results in a total collector system cost (account number 5300) of $\$13.192 \times 10^6$ in July 1, 1980 dollars.

5.2 RECEIVER SYSTEM

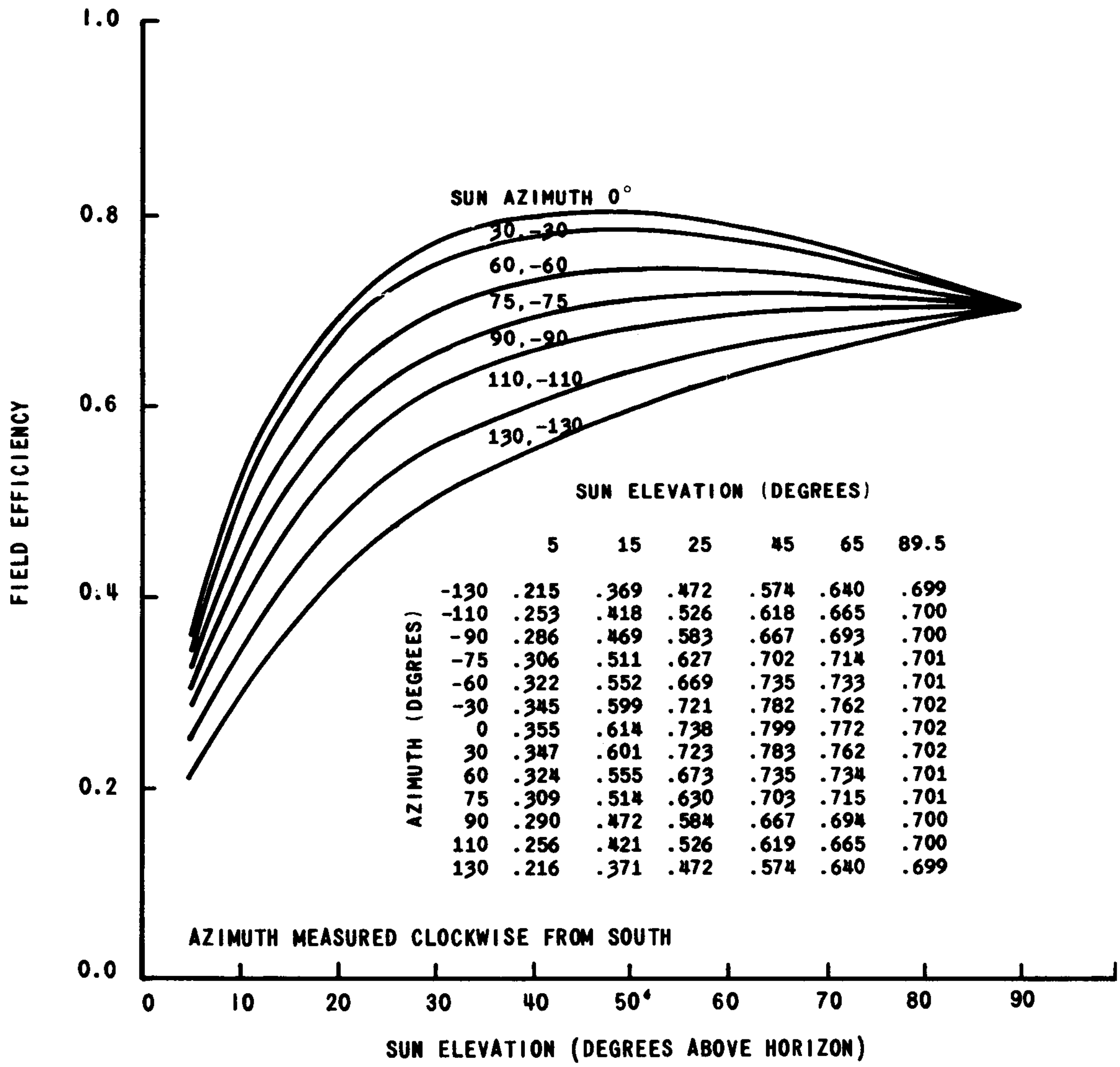
The primary function of the receiver system is to convert sunlight into usable thermal energy. This is accomplished by absorbing insolation (which is redirected onto the receiver surface by the collector system), thus, transforming solar energy into thermal energy and transferring that





* INCLUDES THREE WEEKS SCHEDULED ANNUAL OUTAGE.

FIGURE 5.1-8 COLLECTOR SYSTEM EFFICIENCY STAIR STEPS



SUN ELEVATION (DEGREES)

AZIMUTH (DEGREES)	5	15	25	45	65	89.5
-130	.215	.369	.472	.574	.640	.699
-110	.253	.418	.526	.618	.665	.700
-90	.286	.469	.583	.667	.693	.700
-75	.306	.511	.627	.702	.714	.701
-60	.322	.552	.669	.735	.733	.701
-30	.345	.599	.721	.782	.762	.702
0	.355	.614	.738	.799	.772	.702
30	.347	.601	.723	.783	.762	.702
60	.324	.555	.673	.735	.734	.701
75	.309	.514	.630	.703	.715	.701
90	.290	.472	.584	.667	.694	.700
110	.256	.421	.526	.619	.665	.700
130	.216	.371	.472	.574	.640	.699

FIGURE 5.1-9 COLLECTOR FIELD EFFICIENCY AS A FUNCTION OF SUN POSITION

thermal energy into the working fluid. The thermal energy in the working fluid is then transported to the electric power generating system to be converted into electricity. Since the efficient conversion of solar energy to thermal energy is of prime importance to the cogeneration design, and since that conversion takes place in the solar receiver, the majority of this subsection is devoted to the description of the solar receiver. In addition to the receiver, however, the receiver tower, which supports the receiver above the heliostat field, is described in the latter part of this subsection.

5.2.1 Solar Receiver

The receiver design concept is based on the Babcock & Wilcox advanced water/steam receiver technology which combines high reliability and efficient performance with ease of operation and insensitivity to partial cloud cover.

External and cavity receiver configurations were investigated in the field layout/flux patterns trade study to select the most cost effective concept. As a result, the external receiver was selected on the basis of lower overall cost and simpler design.

For this cogeneration project the basic B&W external receiver arrangement of the advanced design has been optimized to minimize size, weight and cost without compromising the performance. A general view of the receiver is shown on Figures 5.2-1 and 5.2-2.

A solar receiver operates in an environment different from fossil or nuclear steam generators. It is exposed to daily cycling from zero to peak power with a multitude of fast variations in insolation due to cloud transients. The number and rate of metal temperature changes will be much greater than those encountered in any conventional power boiler. Of special concern is selection of superheater tube materials capable of withstanding the upset operating conditions (created by intermittent cloud passage) when the generated steam flow is low but the local heat fluxes are high.

5.2.1.1 Design Requirements. A solar steam generator requires rigorous design criteria to provide the reliability and cost effectiveness desired by electric utilities.

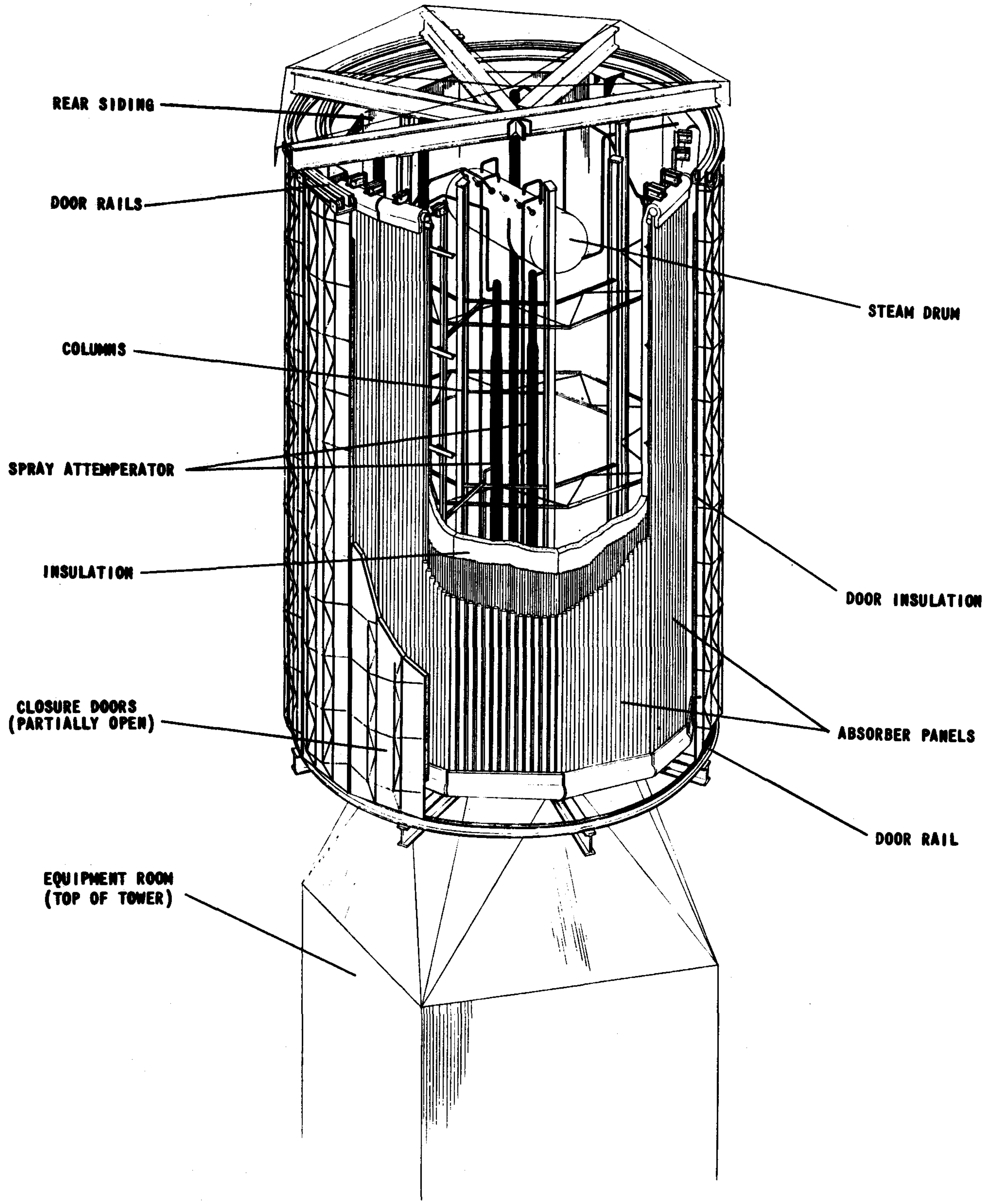


FIGURE 5.2-1 EXTERNAL WATER-STEAM SOLAR RECEIVER

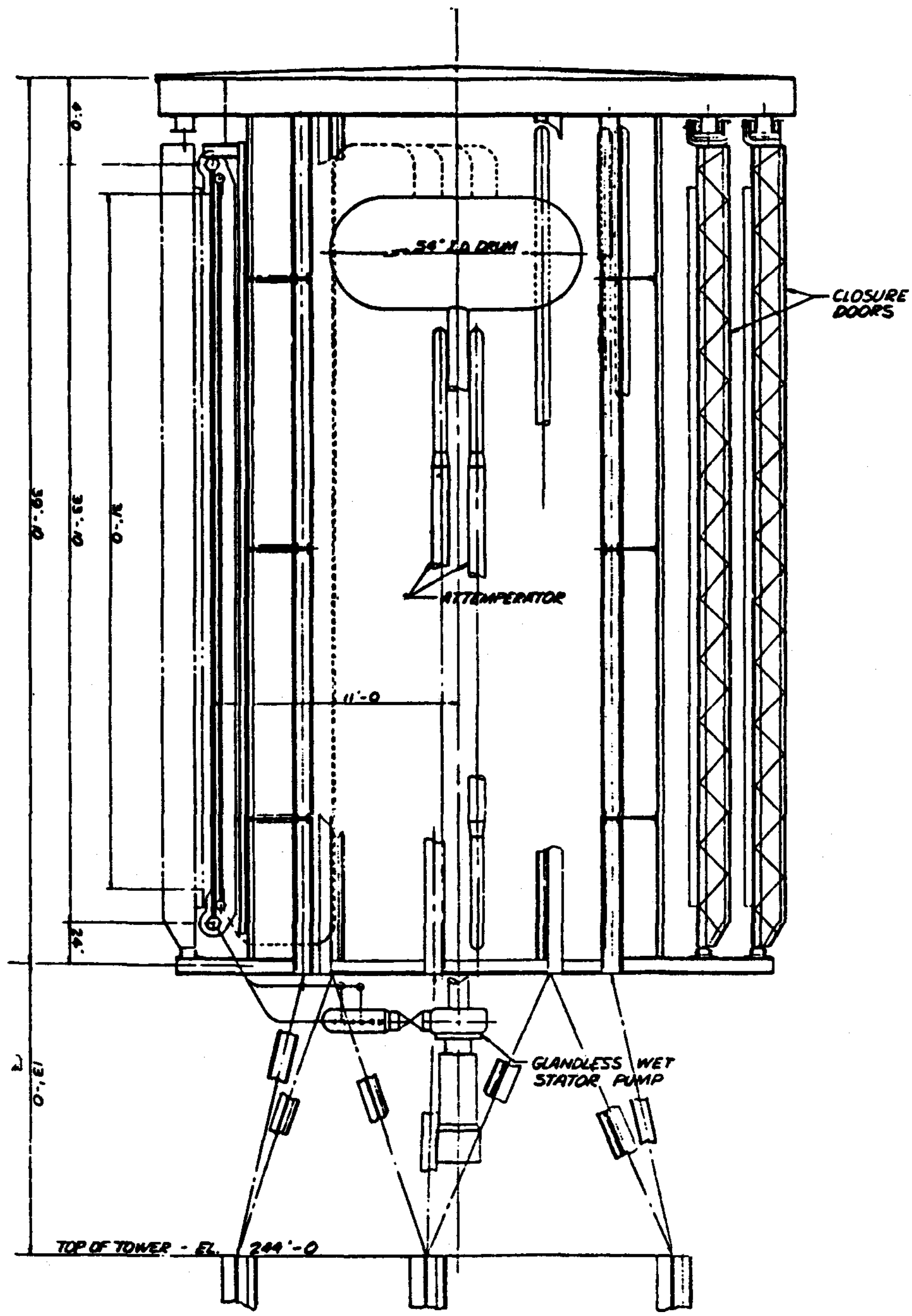


FIGURE 5.2-2 SECTION THROUGH RECEIVER

The solar receiver for cogeneration must satisfy the following requirements.

- High reliability.
- Maximum Utilization of Incident Energy.
- Endurance of Diurnal and Cloud Cucles.
- Tolerance of Extreme Upsets.
- Ease of Operation and Maintenance.
- Fast Start-up.
- Compliance With Applicable Codes and Regulations.
- 30-Year Life.
- Minimum Size, Weight and Cost.

5.2.1.2 Receiver Conceptual Design. The fundamental approach in the design of the B&W solar receiver was to fully utilize the existing boiler technology and manufacturing techniques with special considerations for the unique requirements of solar power. The analyses of the unique characteristics of the heat flux incident on the receiver led to the development of a receiver design concept which can withstand the severe duty imposed by the expected variations of solar insolation. Innovative ideas were used to obtain the desired performance at a low cost. The basic features of the B&W receiver design consist of the following.

- Membrane Wall Superheater and Economizer.
- Screen Tubes.
- Pump Assisted Circulation.
- Ribbed Tubes to Avoid Departure from Nucleate Boiling (DNB).
- Three Over-Surfaced Superheater Passes.
- Dual (East, West) Flow Paths.
- Spray Attemperation.
- Biasing Valves.

Membrane Wall--As in fossil-fueled steam generators, the absorber surface of the receiver consists of membrane wall panels which provide a firm boundary capable of withstanding safely and reliably the thermal stresses and external loads (wind). The membrane panels are light-tight to protect the supporting structure. The superheater panels consist of small diameter Incoloy 800H tubes welded together with 9.5 mm (3/8 in) wide bars about 5 mm (0.19 in) thick of the same material to form a membrane construction. The inlet and outlet headers are also of the same material (Incoloy 800H) to provide uniform thermal expansion. The steam flow in the superheater panels is always upward in order to ensure positive steam flow in all tubes during fast cloud transients, when the heat flux can change from near zero to full value in 10 seconds. The panel is provided with structural steel buckstays to maintain its flat shape and to hold it to the tower structure. The panel is free to expand downward from the support grid and sideward about its centerline.

To minimize the size, weight and thermal losses of the absorber it is necessary to design the receiver for high heat flux. High temperature superheater panels cannot withstand high fluxes nor the extreme variations of solar insolation. Therefore, superheater panels must be located in areas of low heat flux.

Screen Tubes--The B&W design utilizes spaced screen tubes in front of the superheater panels (Figure 5.2-3) to reduce the heat flux incident on superheater tubes to an acceptable level. The screen tubes are cooled by subcooled or boiling water which absorb the major part of the high incident heat flux. One row of screen tubes can reduce the heat flux by 30 to 70 per cent, depending on tube size and spacing. By proper selection of screen tube variable spacing and stand-off distance it is possible to obtain an acceptably low-level, relatively uniform peak heat flux pattern on all superheater panels, as shown in Figure 5.2-4.

Use of screen tubes as the boiler section in front of the superheater panels provides a significant advantage for reliable receiver operation. With this arrangement of heating surface, the superheater panels always absorb the same proportion of incident heat. Therefore, any diurnal, seasonal, and cloud shadowing variations of incident heat flux affect the boiler and the superheater in the same degree. This facilitates the steam temperature control especially during periods of partial cloud coverage.

Another benefit of the screen tubes is increased thermal efficiency of the receiver. This is because the screen tubes are cooled by subcooled or

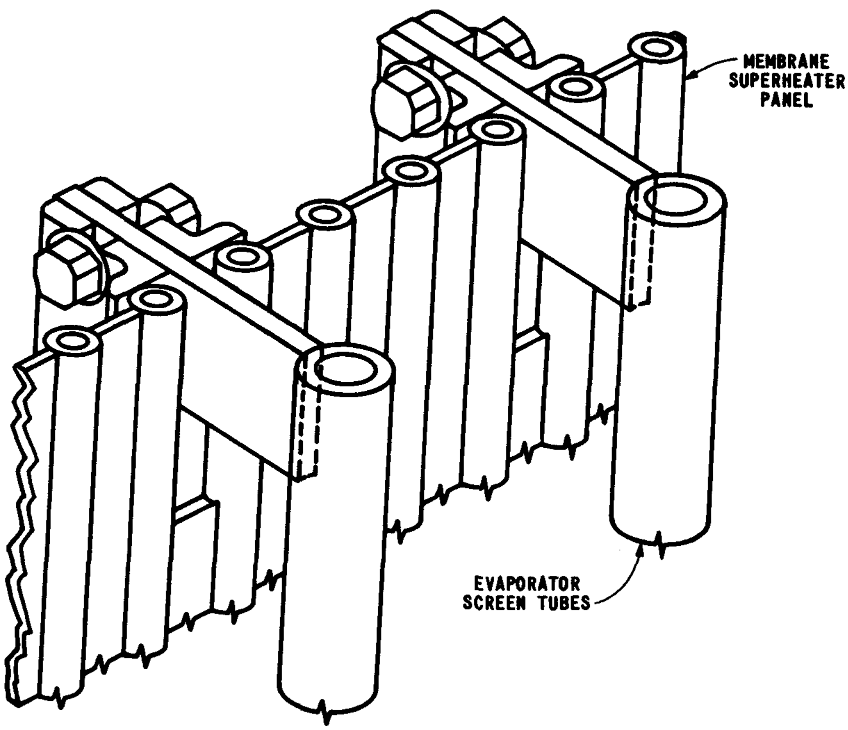


FIGURE 5.2-3 MEMBRANE WALL WITH SCREEN TUBES

boiling water; the metal temperatures are much lower than those of the superheater panels. Thus, the overall mean external metal temperature of the receiver is considerably lower than for a design without screen tubes. The effect is a reduction of the heat losses from the receiver due to emissivity and convection to the surrounding air. Also reradiation losses from the superheater are reduced because a significant portion of the energy reradiated from the superheater is absorbed on the rear of the screen tubes.

Pump Assisted Circulation--This feature was selected to provide maximum freedom for transitions between operating modes. The circulating pump is important to receiver reliability because of its ability to maintain the required mass velocity at all operating conditions. No orifices are

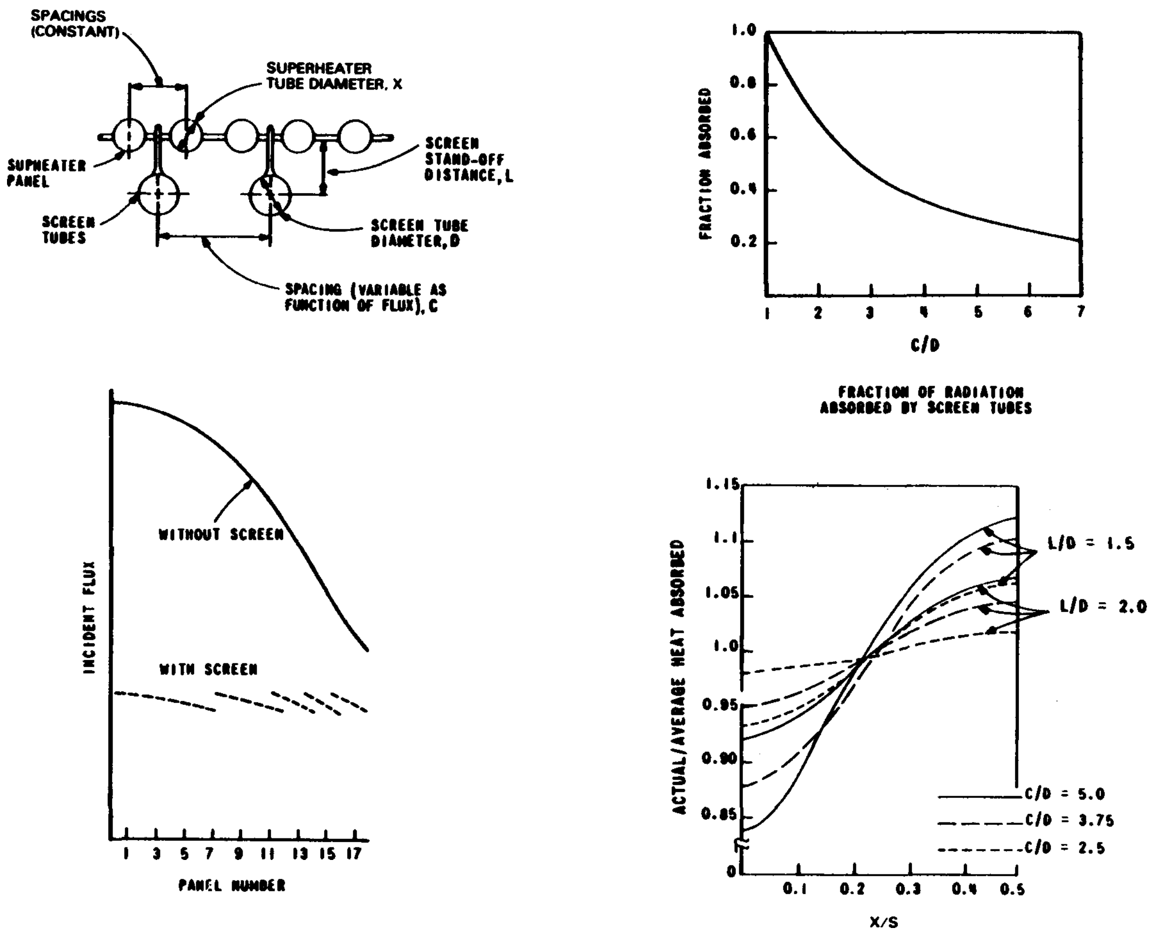


FIGURE 5.2-4 EFFECT OF SCREEN TUBES ON SUPERHEATER TUBES FLUX LEVEL

required in the B&W design. Pump assisted recirculation eliminates possible dynamic flow instabilities during fast insolation transients. With natural circulation, a risk exists that tubes which become stagnant or have reverse flow during cloud cover will not be able to re-establish adequate mass velocities by the time the cloud passes. With pump assisted circulation, the flow in the tubes remains substantially constant independent of load or heat absorption variations.

Ribbed Tubes--Ribbed Tubes with internal spirals are used for the screen tubes to avoid DNB (Figure 5.2-5). The circulating pump maintains the required mass velocity and circulation ratio (steam quality) at all predictable operating conditions, including extremes of insolation distribution. Ribbed screen tubes operating with nucleate boiling can withstand very high heat fluxes without excessive thermal stresses. Accordingly, the

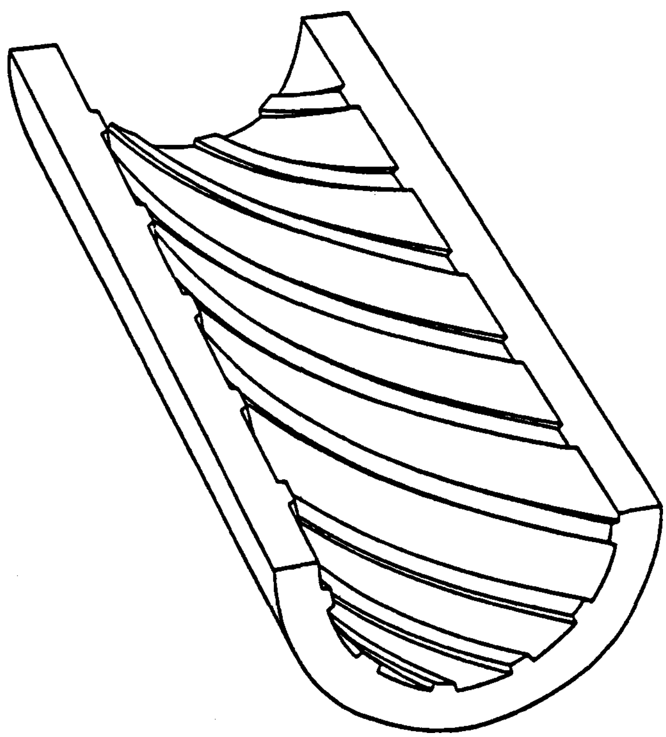


FIGURE 5.2-5 RIBBED TUBE

high water side heat transfer rate of the tubes allows the use of low alloy material (SA-213 T2) for the screen tubes.

Superheater--The superheater is divided into three separate passes with spray attemperation between them. During normal operation, the incident solar energy varies considerably from panel to panel with time of day and with seasons of the year. The fraction of total radiant energy absorbed by each panel varies greatly with partial cloud cover. These variations in absorption of each panel result in different steam temperatures leaving the various panels and often can become excessive. A reduction of heat pickup per pass decreases the temperature differentials. Also after each pass the steam is mixed to equalize the unbalanced temperatures.

The superheater absorbing surface is "over-surfaced" to obtain full rated steam temperature at reduced or unbalanced insolation, especially during partial cloud shading. Under normal conditions, the excess steam temperature obtained by the oversized superheater is "attemperated" by spraying feedwater in through the use of attemperators. This provides very rapid control of the steam temperature without degrading the cycle efficiency.

Dual Flow Path--The superheater is divided into two symmetrical flow paths, east and west, each consisting of three series passes with spray attemperation between the passes. The two flow paths and the spray attemperation are needed to compensate for the large diurnal, seasonal, and cloud-induced variations of incident power on the west and east sides of the receiver. During the morning hours the west side receives more insolation while in the afternoon the east side absorbs more. The separate attemperators in each flow path equalize the steam temperatures.

Biasing Valves--A butterfly control valve is located at the inlet to each superheater panel to provide proper flow distribution to panels during severe cloud transients and during early morning and late afternoon operation. During normal operation the valve is throttled to approximately 70 per cent open position. If, during a transient the panel outlet steam temperature exceeds the allowable value, the control repositions the valve to increase the flow to this panel. If the steam temperature is below a given value, the valve is throttled to divert the flow to the other flow paths. When the valve is fully open and the steam temperature at the exit of the panel is above the allowable value, a signal is provided to the collector field control to redirect a corresponding group of heliostats away from the hot flow path.

5.2.1.3 Description of Receiver Configuration.

In the trade-off studies reported in Section 3, the amount of solar cogeneration was established at 37.13 MW_t output, and the optimum superheater outlet steam conditions at the design point were determined to be 10.82 MPa (1,569 psia) at 520 C (968 F). The receiver outlet steam pressure was further refined during the conceptual design to 11.07 MPa (1,605 psia). The field layout trade-off studies resulted in selection of a 156 degree collector field north of an 84 m (276 ft) high receiver tower (to mid height of absorber) redirecting the solar energy to a 210 degree sector of a cylindrical external receiver of 6.71 m (22 ft) diameter and 9.45 m (31 ft) height. Because of the small size of the receiver and to reduce its cost, the number of panels was kept low.

Absorber Panel Arrangement--The panel arrangement is shown schematically on Figure 5.2-6. The external receiver consists of eight panels arranged symmetrically about the north-south axis; six are superheaters and two are economizers. The superheater panels are composed of steam cooled membrane wall tubes with water cooled screen tubes in front of the membrane wall. The panels are numbered in sequence from one to four starting from north. Two sizes of panels are used. The primary (No. 1) and secondary (No. 2) superheater panels are 1.74 m (5.72 ft) wide, the intermediate superheater (No. 3) and the economizer (No. 4) panels are 1.30 m (4.26 ft) wide. The active surface covers 210 degrees of the receiver circumference; the remaining 150 degrees is closed with nonabsorbing steel surface. Two closure doors, each of 105 degree angular width, are stored on the south side of the receiver during normal solar operation.

Panel Design--A sectional view of the basic panel design is shown on Figure 5.2-7. The superheater panels consist of small diameter Incoloy 800H tubes, with screen tubes arranged in front of the panel to shield the panel

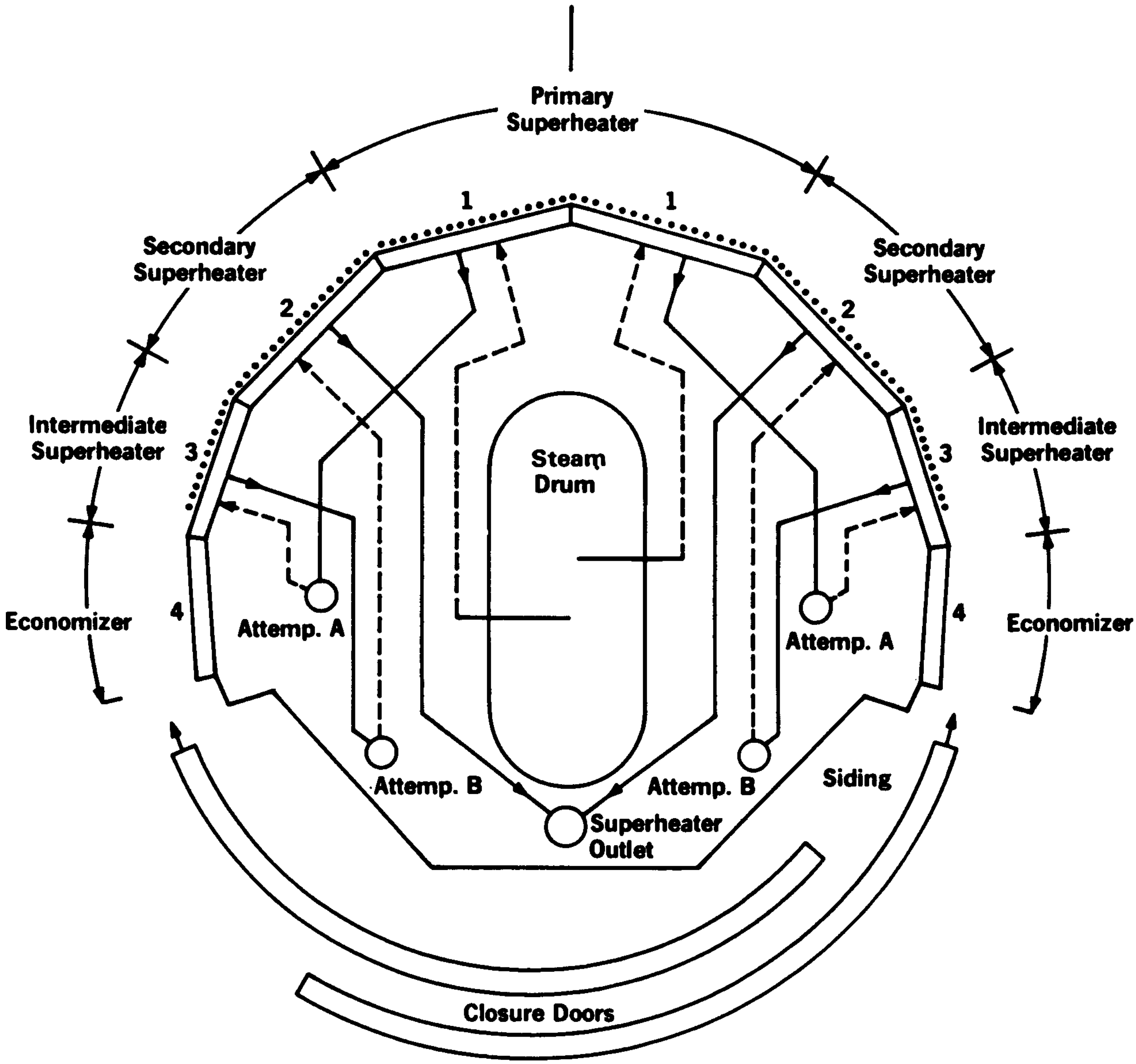


FIGURE 5.2-6 EXTERNAL RECEIVER SCHEMATIC

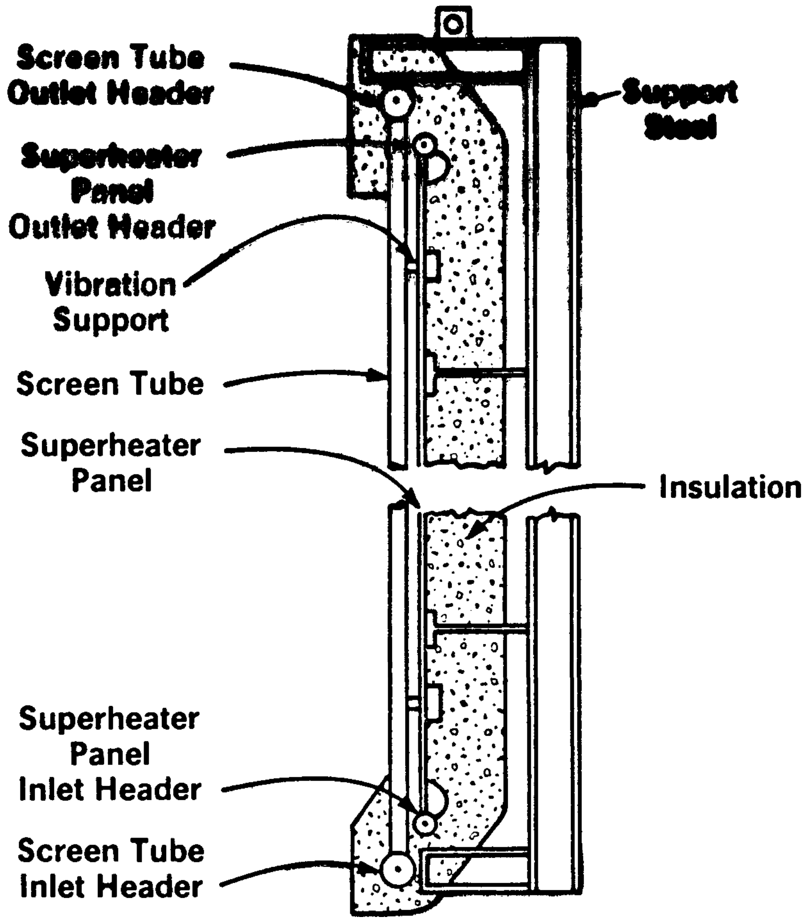


FIGURE 5.2-7 RECEIVER PANEL DESIGN

from excessive heat flux levels. Tables 5-2 and 5-3 show the tube sizes, spacing and other general design data for the panels. The screen tubes are always located in line with the membrane so that the vibration support bar can penetrate directly through the slot in the membrane panel. The spacing of the screen tube is, therefore, always a multiple of the membrane wall tube spacing. As can be seen from the tables, the screen tube spacing of the secondary (No. 2) superheater panel is the same across the panel width 0.101 m (4 in) but the screen tube diameter varies. The first eight tubes from the north end are 0.051 m (2 in) diameter while the remainder (9) of screen tubes are 0.049 m (1.938 in). The variation was necessary to reduce the steam temperature differences between tubes of the panel.

TABLE 5-2. EXTERNAL RECEIVER PANEL DATA

		Screen Tubes (Boiler)			Membrane Tube			
Panel No.	Width M (ft)	No.	Spacing M (In)	OD M (In)	Type	No.	Spacing M (In)	OD M (In)
I	1.74			.048			.0254	.016
	(5.72)	17	.101 (4)	(1.875)	SH1	68	(1)	(.625)
2	1.74	8	.101 (4)	.051 (2)			.0254	.016
	(5.72)	9	.101 (4)	.049	SH3	68	(I)	(.625)
				(1.938)				
3	1.30	6	.0762 (3)	.041				
	(4.32)			(1.625)	SH2	34	.0254	.016
		5	.0762 (3)	.038			(1)	(.625)
				(1.50)				
		0				I5	.0286	.019
							(1.125)	(.750)
4	1.30	0			ECON	34	.0381	.025
	(4.32)						(1.50)	(1.0)

NOTES: SHI - Primary Superheater; SH2 - Intermediate Superheater; SH3 - Secondary Superheater; ECON - Economizer.

The intermediate superheater panel (No. 3) is located on the receiver in an area where there exists a severe heat flux gradient. To minimize steam temperature differences between the various tubes of the panel it was necessary to subdivide the panel in three sections with different tube sizes. The sections are separated by diaphrams located inside the inlet header. The first and second sections have membrane tubes of the same diameter and spacing but are shielded with screen tubes of different diameter and the same spacing. The third section of the panel has larger tubes in the membrane with greater distance but it is not shielded by screen tubes.

TABLE 5-3. GENERAL DESIGN DATA FOR SOLAR RECEIVER PANELS
External Type, Diameter 6.71 m (22 ft),
Active Height 9.45 m (31 ft)

Membrane (Superheater)	
Tube and Membrane Material	800H
Tube Wall Thickness	2.54 mm (0.100 in)
Active Tube Length	9.45 m (31 ft)
Total Tube Length	9.9 m (32.5 ft)
Membrane Thickness	4.76 mm (0.187 in)
Inlet Header OD	0.114 m (4.5 in)
Outlet Header OD	0.114 m (4.5 in)
Header Material	800H
Design Pressure	13.8 MPa (2,000 psia)
Screen Tubes (Multi-Lead Internal Ribs)	
Tube Material	SA-213-T2
Tube Wall Thickness	3.76 mm (0.148 in)
Active Tube Length	9.45 m (31 ft)
Total Tube Length	10.2 m (33.4 ft)
Inlet Header OD	0.168 m (6.625 in)
Outlet Header OD	0.168 m (6.625 in)
Header Material	SA-210C
Membrane (Economizer)	
Tubes and Membrane Material	SA-210-A1
Tube Wall Thickness	3.43 mm (0.135 in)
Active Tube Length	9.45 m (31 ft)
Total Tube Length	9.9 m (32.5)
Membrane Thickness	6.35 mm (0.250 in)
Inlet Header OD	0.168 m (6.625 in)
Outlet Header OD	0.168 m (6.625 in)
Header Material	SA-106-C
Design Pressure	14.1 MPa (2,050 psia)

The screen tubes originate at an inlet header on the bottom and terminate at outlet headers at the top. Water/steam flows upward through the tubes. The inlet header is supplied from the circulating pump discharge manifold. The outlet header collects the steam and water mixture of low steam mass fraction (quality) and discharges it to the steam separating vessel.

The screen tubes are attached to the superheater panels at a distance depending on tube size. Attachments maintain the appropriate spacing and avoid vibration. The attachment device provides a sliding fit support to compensate for differential thermal growth of the screen tubes and membrane panel. The design of this vibration support, shown on Figure 5.2-8

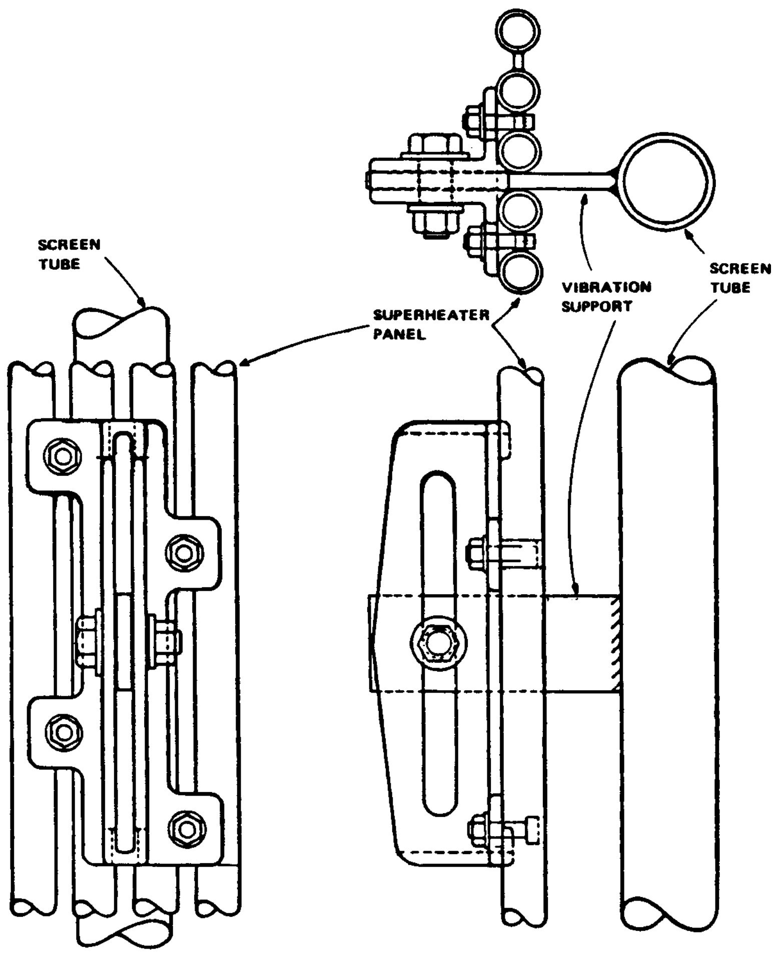


FIGURE 5.2-8 SCREEN TUBE VIBRATION SUPPORT

is an investment casting made of Type 304 stainless steel and is bolted to the rear of the membrane; thus, it is not exposed to the incident heat flux. A slot in the membrane permits the penetration of the screen support bar which is welded to the screen tube. The support bar is guided through a round pin in a pair of vertical slots provided in the casting. This construction provides freedom of relative movement in the vertical direction only.

The design of the vibration support was analyzed for a variety of possible flow instabilities such as galloping, whirling, vertex shedding, turbulent buffering and wake-induced oscillations. Whirling and vertex shedding proved to be the most dangerous instabilities. The spacing of the supports was selected to avoid critical vibration frequencies under any possible wind conditions at the receiver.

The construction of this vibration support is the best possible design to meet all the requirements of its application for an external receiver. However, the cost per unit is more than $100 installed, which will amount to more than $100,000 for this receiver. Vibration and alignment supports on fossil-fired steam generators are of much simpler construction, and their spacing is considerably wider, but the requirements are also considerably less stringent, especially in regard to perfect alignment and amount of expansion movement.

The screen tubes are assembled together with the membrane wall in the shop to form a single shipping unit. All headers and buckstays are shop-assembled. Insulation, applied at the plant site before the panel assembly is lifted into its position on the tower, is applied in two layers to a thickness of 0.2 m (8 in) with staggered joints. Calcium silicate blocks are placed next to the membrane with medium temperature blocks of mineral fiber over it. The insulation is held in place by heat resistant studs welded to the back of the membrane bars. Aluminum sheathing is applied over the insulation.

A tee-shaped member clipped to the membrane panel permits unrestrained lateral growth in both directions from the center, where the tee is fastened to the membrane. Brackets welded to the tee member slide along two I-beams, which represent the buckstay, to permit unrestricted longitudinal expansion and contraction. The I-beams are outside of the insulation and always remain cold, while the tee-shaped member is below the insulation and is hot during boiler operation. The panel is supported from the upper headers that are attached to a horizontal member, which is welded to the upper ends of the buckstays. Two lifting lugs on the horizontal member are used to place the panel on the receiver support grid. The buckstays are attached at several elevations to the horizontal trusses of the main support structure. The surface of the tubes that are exposed to solar radiation is coated with Pyromark black paint, which has a high absorptivity coefficient.

Flow Sequence Through the Receiver--The flow sequence through the receiver is illustrated on Figures 5.2-9 and 5.2-10. Feedwater is introduced

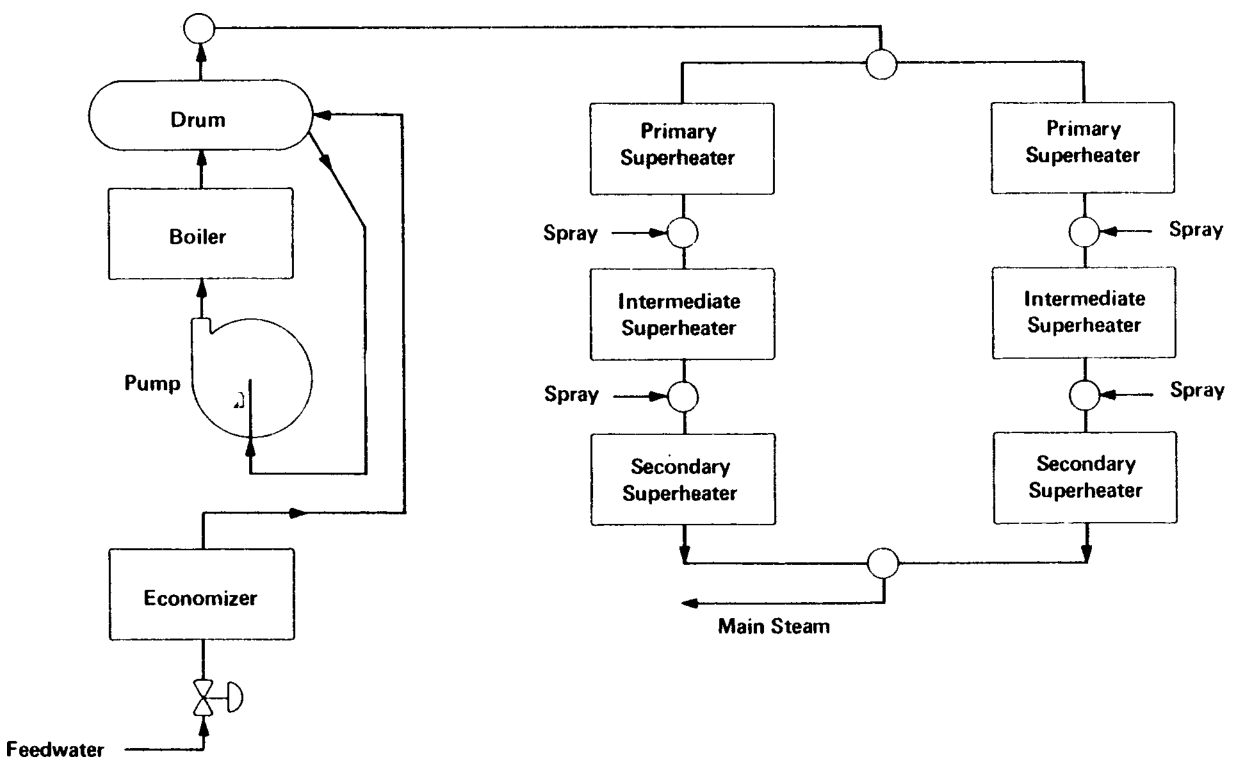


FIGURE 5.2-9 RECEIVER FLOW DIAGRAM

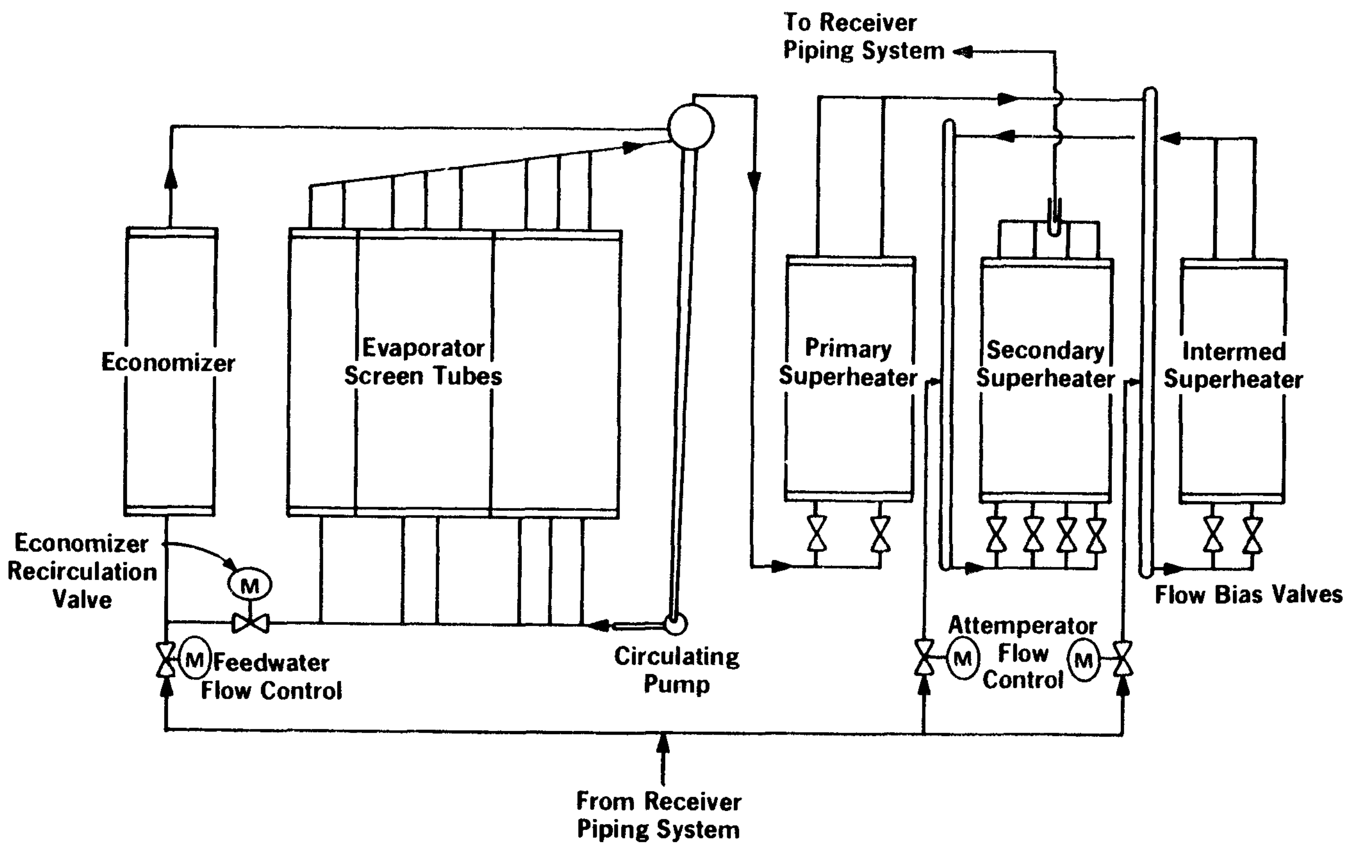


FIGURE 5.2-10 SCHEMATIC FLOW DIAGRAM OF RECEIVER SYSTEM

into the two economizer panels. The flow of the feedwater is controlled by a conventional three-element feedwater regulator, which uses a signal from drum level and from steam flow to regulate the feedwater flow to the receiver. The water is preheated in the economizer panels and is injected into the drum, where it is mixed with the saturated water discharged from the cyclone separators. Slightly subcooled water [318 C, (604 F)] flows from the drum, through an external downcomer, and is pumped through supply pipes into the lower headers of the screen tubes comprising the boiler section. The water is distributed to the screen tubes where steam generation takes place. The resultant steam/water mixture (of average steam fraction less than 0.20) passes through riser pipes into the steam drum, where the water and steam are separated by cyclone separators and steam scrubbers. The separated saturated water is mixed with feedwater from the preheater (economizer) and flows through the downcomer to the glandless, wet motor, circulating pump to be recirculated. A single pump with no shut-off valves is used.

The superheater is divided into two symmetrical flow paths, east and west, each consisting of three series passes. There is one panel per pass in each flow path, with spray attemperation between the passes; thus, four attemperators are provided. The two flow paths and the spray attemperation are needed to compensate for the large diurnal, seasonal, and cloud-induced variations of incident power on the west and east sides of the receiver. Butterfly control valves are located at the inlet to each superheater panel to provide for flow distribution to panels during severe cloud transients and during early morning and late afternoon operation. The biasing of the butterfly valves is needed only at extreme transients when superheater temperatures become excessive.

Moisture-free steam from the drum flows through saturated connections and a single steam downcomer to the primary superheater, where it is heated to about 416 C (782 F). The steam leaving the primary superheater is lead through two steam downcomers, one in each flow path, to the intermediate superheater. A spray attemperator, which consists of an atomizing nozzle and a venturi sleeve, is located in each steam downcomer pipe. Additional feedwater is injected into the steam as required to control the final steam temperature. At the design point, about 10.3 per cent spray is used and the steam temperature entering the intermediate superheater is reduced to 363 C (686 F).

The steam leaving the intermediate superheater, at an average temperature of about 405 C (762 F), passes through a second stage attemperator located in each steam downcomer. At design conditions, no spray is needed at this stage. From the attemperator, the steam enters the secondary superheater, where it is heated to the final steam temperature of 520 C (968 F) at the required pressure of 11.07 MPa (1,605 psia).

Support Structure-- The main support steel for the external solar receiver consists of the structural components required to carry the receiver weight, closure door, ice load, wind load, and seismic effects. The receiver components and the support structure are designed to withstand UBC Zone I earthquake conditions and winds with a maximum speed of 38 m/s (85 mph) gusts at ground level (exponentially increased for height). The design was performed only on a level required to obtain a cost estimate.

The receiver is suspended from a steel grid made up of large beams attached to eight vertical columns. The columns are equally spaced on a 4.27 m (14 ft) diameter circle and are attached by means of a transition section to a square steel tower. Circular (octagonal) trusses brace the columns at several elevations. Every other bay between the columns is diagonally braced for stability and to transfer the loads to the tower. A schematic arrangement of the column and bracing is shown on Figure 5.2-11 which also shows a typical horizontal truss.

The steam drum is suspended at the center of the receiver from the top girders by U-shaped support rods. This is a standard B&W construction used on fossil boilers. The panels are supported directly from the main structural support.

Platforms, stairs, and railing are provided around the drum, pump, headers, and valves to facilitate inspection and maintenance.

Closure Doors--The advantages of the external receiver are enhanced by the use of closure doors. These insulating doors reduce the cooldown rate of the pressure parts when there is no solar input.

Several door designs were briefly investigated. The most viable design consists of two curved, insulated, tambour type, sliding doors moving on trolleys over the absorber surface of the receiver. In closed position, one door covers the east half of the receiver tubes, and the other covers the west half. The two doors move on rails attached to the receiver support structure. The door consists of panels about 11.0 m (36 ft) long, each made of standard steel joists and cross-braced for stiffness. Four panels are hinged together to form the east door, and four panels make up the west door. A trolley drive, operated by a 4.5 kW

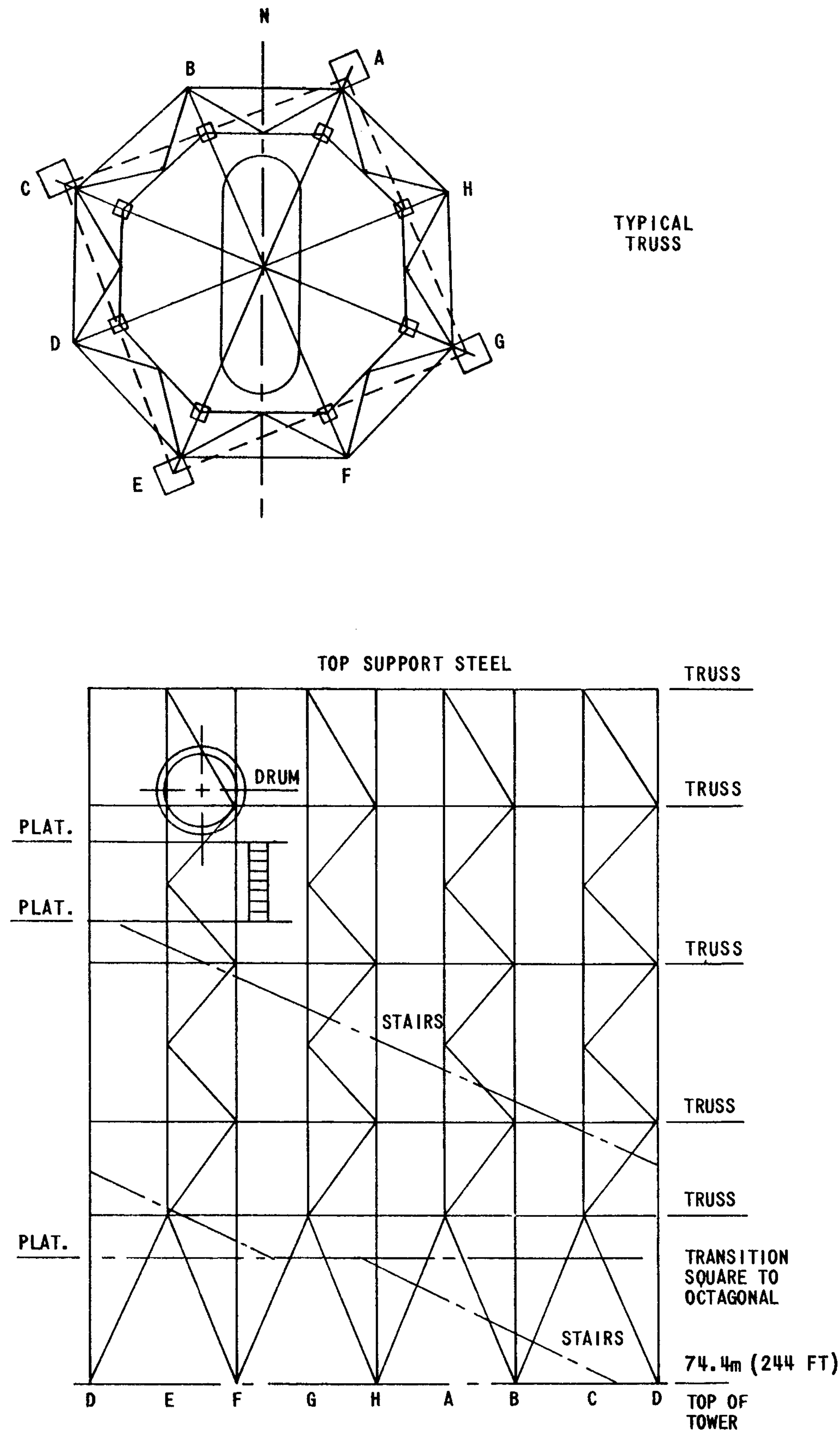


FIGURE 5.2-11 ARRANGEMENT OF SUPPORT STEEL

(6.0 hp) electric motor, will move the door into open or closed position. The door hangs on the upper rails and is guided in the bottom rails.

For structural reasons, the doors are designed to be very stiff, in order not to deflect, warp, or wobble excessively under gusty winds which could cause them to hit and damage the receiver tubes. The weight of the two doors with 0.13 m (5 in) insulation is about 25,000 kg (55,000 lb).

5.2.1.4 Thermo-hydraulic Analyses. The thermo-hydraulic analysis was performed using a number of B&W computer programs. The basic input are heat flux maps, steam conditions, ambient data, and assumed panel arrangement and dimensions.

The heat flux distribution has the largest effect on receiver design. The heat flux map for the solar receiver at the design point of equinox noon, as shown in Table 5-4, was obtained using proprietary Black & Veatch computer software. The heliostat aim strategy selected for the receiver is to provide a nearly uniform vertical heat flux distribution with a slight decrease in the upper half. The vertical heat flux for the four panels is presented in Figure 5.2-12. The peak heat flux on the receiver is 672 kW/m^2. The vertical heat flux profile on the secondary superheater panel at various times of equinox day is shown in Figure 5.2-13. The power distribution to the receiver panels is shown in Figure 5.2-14. This figure illustrates the power level and the amount actually absorbed by each panel.

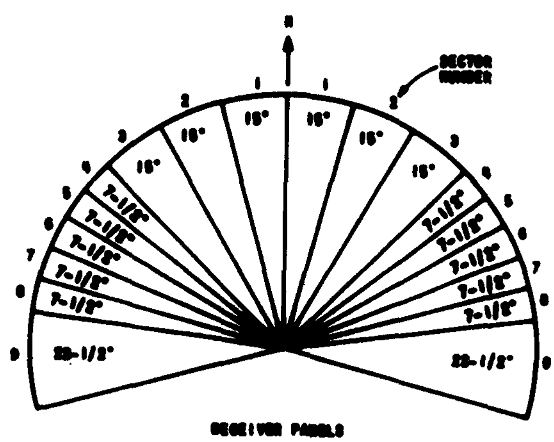
Thermal losses from the receiver include the losses due to reflection from absorber surface, convection to the surrounding air, infra-red radiation of the hot receiver surface and conduction through the insulation and supports.

The convection loss is the most difficult one to predict because of complex geometry. The natural convection part is estimated according to Kreith's correlation. The forced convection part is calculated based on a reasonable extension of Achenbach's experimental data. The method of loss calculation of the receiver is presented in the Sandia Report SAND 79-8177, Solar Advanced Steam/Water Receiver, Appendix C. Ambient temperature and wind speed have a significant effect on thermal losses and, therefore, on receiver efficiency.

TABLE 5-4. DESIGN POINT RECEIVER FLUX MAP

Meters Above Base of Cylinder	SECTOR NUMBER 9	8	7	6	5	4	3	2	1	1	2	3	4	5	6	7	8	9
9.71	9	50	90	94	115	150	123	124	124	124	124	123	150	115	94	90	50	9
8.74	28	94	223	262	265	263	299	315	281	281	315	299	263	255	262	223	94	78
8.27	54	132	255	393	387	468	408	475	463	463	475	468	469	367	393	255	132	54
7.80	42	206	275	382	474	471	510	519	547	547	519	510	471	470	382	275	206	42
7.32	33	153	296	480	379	559	487	505	518	519	535	487	560	379	480	[illegible]	153	33
6.85	56	223	333	417	521	504	550	601	507	507	601	550	504	521	417	333	[illegible]	56
6.38	62	230	336	421	514	[illegible]	[illegible]	673	634	634	673	[illegible]	[illegible]	514	[illegible]	[illegible]	230	62
5.51	61	252	327	392	484	[illegible]	641	564	[illegible]	[illegible]	564	641	[illegible]	484	[illegible]	327	[illegible]	61
5.43	93	212	327	491	473	540	644	561	[illegible]	[illegible]	561	644	540	473	[illegible]	327	212	[illegible]
4.96	71	223	333	444	495	513	630	629	529	529	629	630	519	[illegible]	[illegible]	[illegible]	[illegible]	71
4.49	86	213	340	430	493	552	612	657	672	572	657	612	552	493	430	340	213	[illegible]
4.02	67	183	314	393	535	559	523	613	682	682	613	523	560	[illegible]	393	316	183	67
3.54	81	202	300	441	519	471	617	636	[illegible]	[illegible]	636	617	471	519	441	[illegible]	[illegible]	81
3.07	64	236	375	400	511	561	575	633	642	642	633	675	561	511	[illegible]	375	[illegible]	64
2.60	62	227	290	524	540	507	[illegible]	675	670	670	675	[illegible]	507	540	524	[illegible]	227	[illegible]
2.13	53	223	279	[illegible]	507	540	640	643	647	647	643	640	540	507	[illegible]	279	[illegible]	53
1.65	40	220	355	405	492	562	531	[illegible]	636	636	585	531	562	492	[illegible]	[illegible]	[illegible]	40
1.18	32	141	250	370	384	483	470	504	542	542	504	470	483	384	370	250	141	32
0.71	27	108	187	231	265	282	286	330	281	281	339	286	282	286	231	187	108	27
0.24	11	52	84	123	91	160	157	123	129	129	123	157	160	51	123	84	52	11

NOTE: The time point under test is: Day = 80, Hour = 12; Total power was 43.749 megawatts; 41.935 MW hit the cylinder; .014 MW missed the cylinder; Insolation = 0.95 kW/SQM; Map of the Incident Flux (kW/SQ Meter)



The total thermal loss and the thermal efficiency versus wind speed with ambient air temperature as a parameter are plotted in Figures 5.2-15 and 5.2-16. The solid lines represent the loss, and the dash lines correspond to the thermal efficiency. It is seen that the thermal loss increases either when the wind speed increases or the air temperature decreases. The reversed trends occur for the thermal efficiency. These figures indicate that the wind speed has the predominant effect on the convection loss as compared to ambient air temperature.

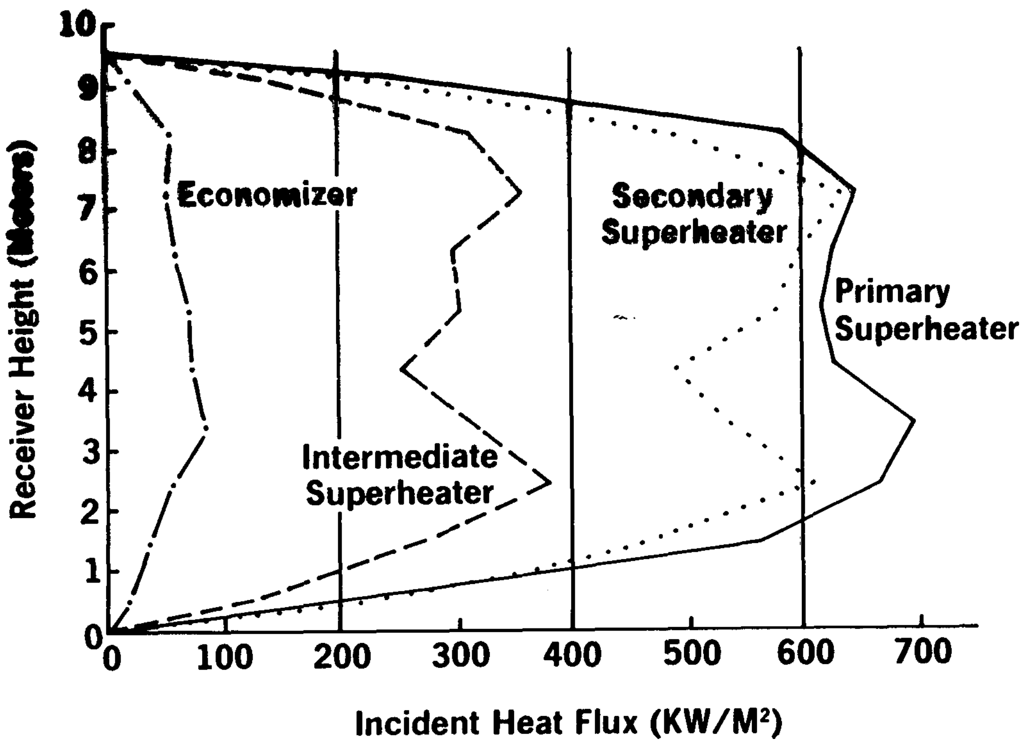


FIGURE 5.2-12 VERTICAL INCIDENT HEAT FLUX DISTRIBUTION ON VARIOUS PANELS (NOON, EQUINOX DAY)

Overall Performance--Solar receiver performance during an equinox day is shown on Figure 5.2-17, which contains information about thermal efficiency, steam flow, and spray quantity during the morning hours of the day. The afternoon performance is a mirror image of the morning graphs. The summary results at the design point of equinox noon are tabulated in Table 5-5.

The fluid and tube wall temperature profiles along the heated length of the economizer, the boiler, and the superheater tubes are depicted on Figure 5.2-18. The same graph also shows the highest possible unbalanced steam temperatures and upset metal temperatures caused by extreme heat

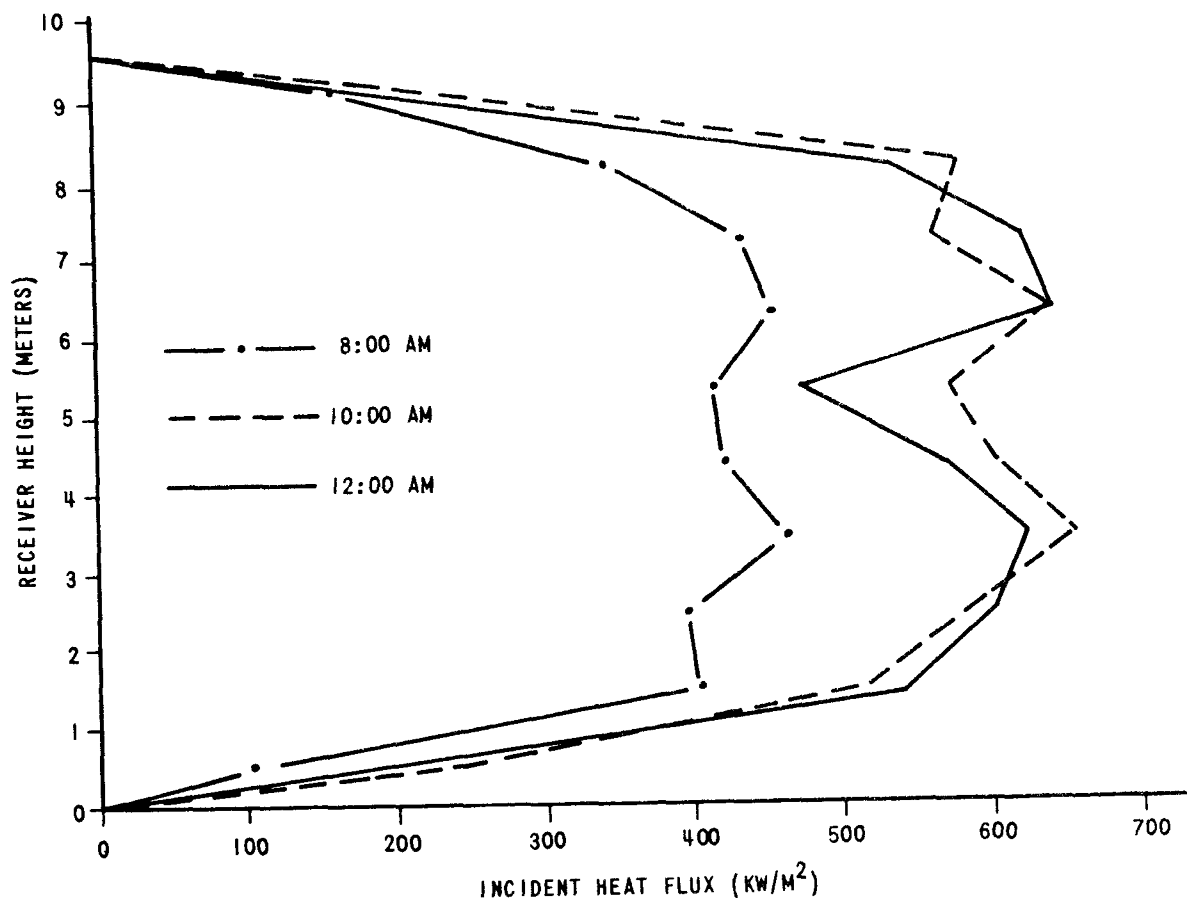


FIGURE 5.2-13 VERTICAL INCIDENT HEAT FLUX ON SECONDARY SUPERHEATER PANEL AT VARIOUS TIMES OF DAY (EQUINOX DAY)

flux and flow imbalance due to a combination of the following reasons: tube manufacturing tolerances, header flow maldistribution, screen tube deflection, panel flux gradients and heat flux peaks due to unusually high irradiation from the sun or heliostat misalignments. The maximum estimated heat flux upset factor for the primary superheater panel amounted to 1.33 with a steam flow unbalance of 0.95. For the intermediate superheater the largest calculated heat flux factor was 1.88 with a flow unbalance of 0.78. The secondary superheater has a 1.69 heat unbalance factor and 0.93 flow unbalance factor.

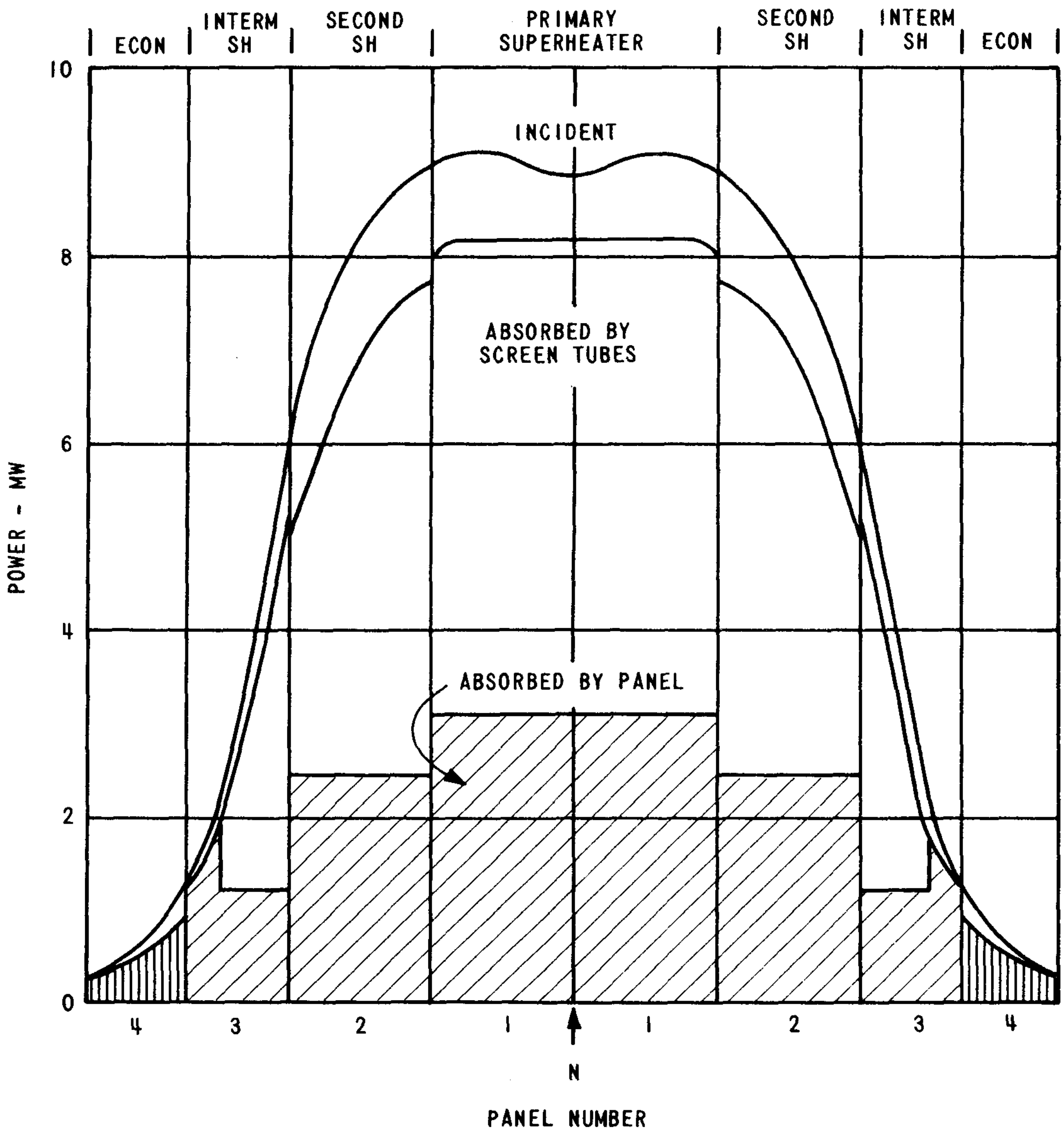


FIGURE 5.2-14 POWER DISTRIBUTION TO RECEIVER PANELS (NOON, EQUINOX DAY)

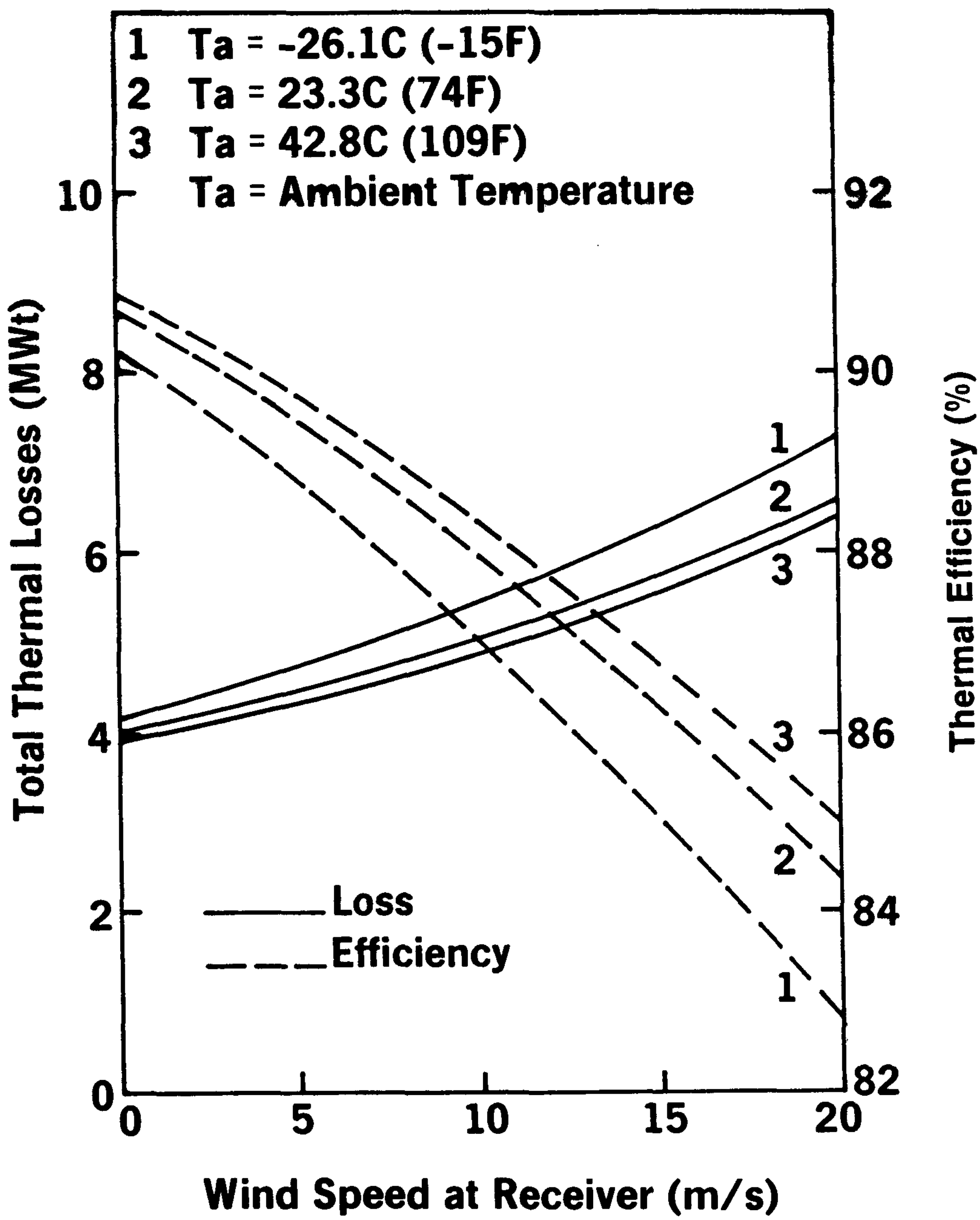


FIGURE 5.2-15 THERMAL EFFICIENCY AND LOSSES AT VARIOUS WIND SPEED AND AMBIENT TEMPERATURE

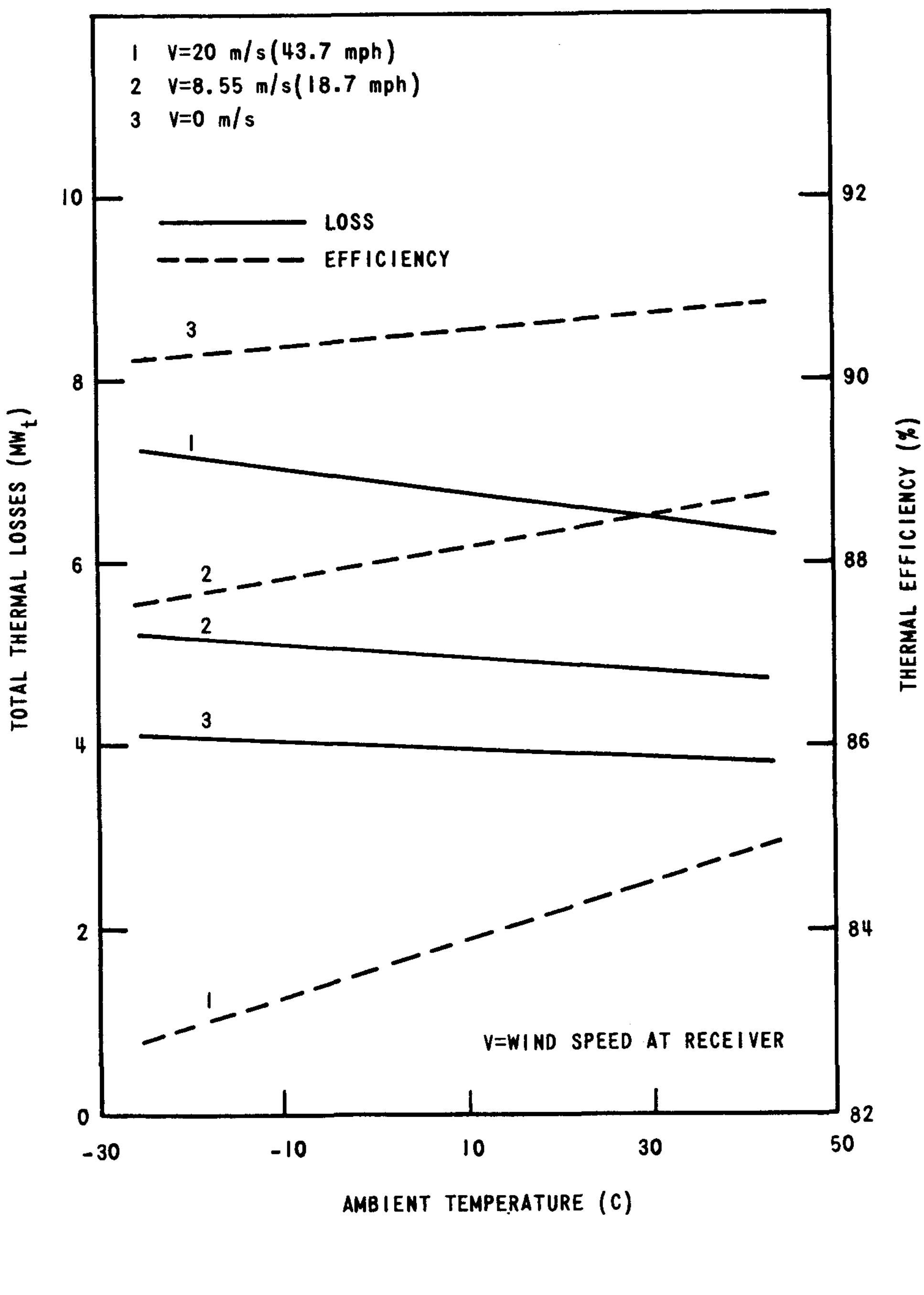


FIGURE 5.2-16 THERMAL EFFICIENCY AND LOSSES AT VARIOUS WIND SPEED AND AMBIENT TEMPERATURE

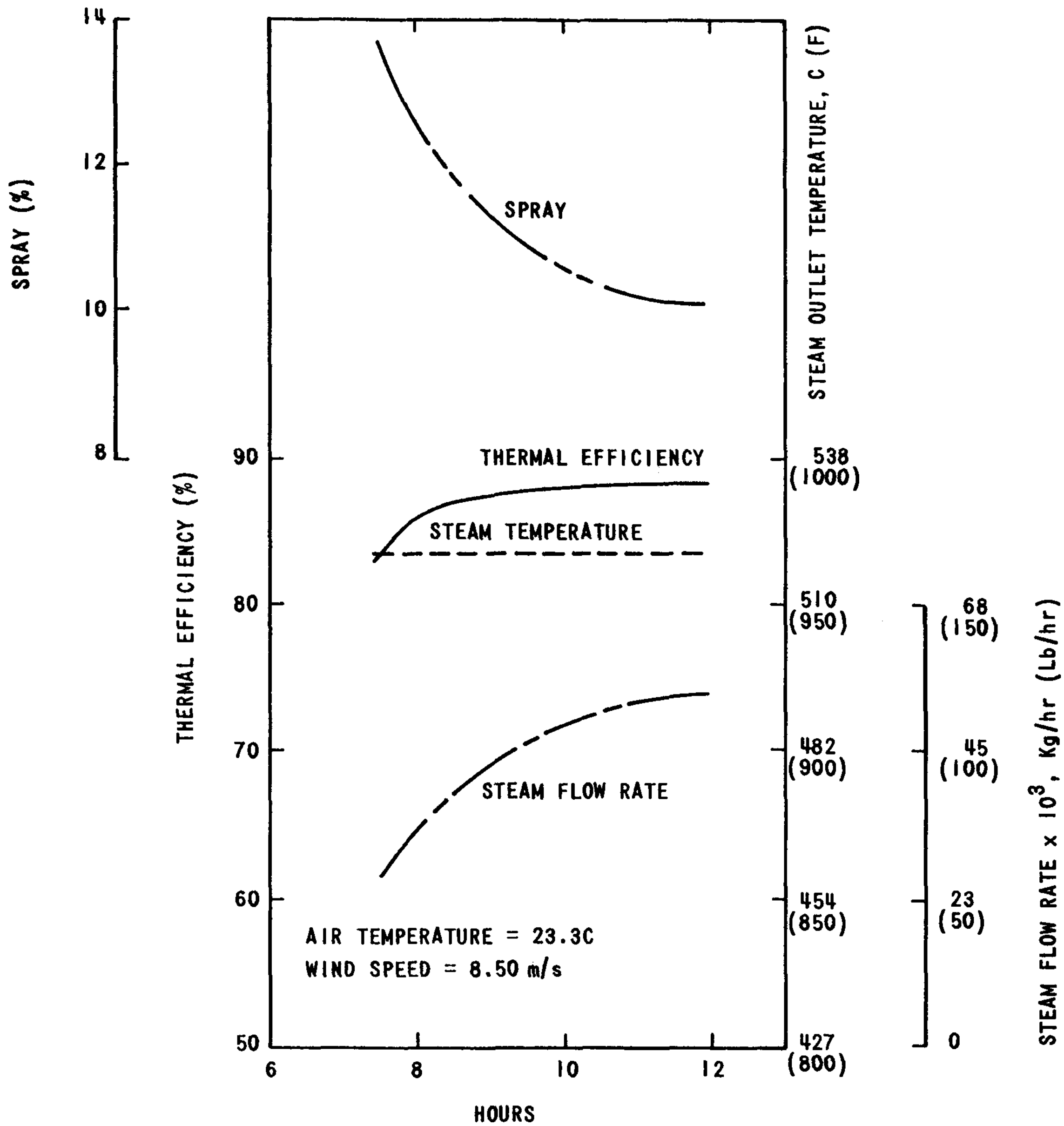


FIGURE 5.2-17 THERMAL PERFORMANCE OF SOLAR RECEIVER DURING EQUINOX DAY

TABLE 5-5. PERFORMANCE OF SOLAR RECEIVER AT DESIGN POINT

Superheater Outlet			
Pressure	MPa (psia)	11.07	(1,605)
Temperature	C (F)	520	(968)
Pressure Drop Through Superheater	MPa (psia)	1.59	(231)
Drum Pressure	MPa (psia)	12.66	(1,836)
Pressure Drop Through Economizer	MPa (psia)	0.13	(19)
Flow Rate	kg/h (lb/hr)	54,331	(119,800)
Primary Superheater (or Preheater)		48,296	(106,251)
Spray Attemperator 1		5,500	(12,210)
Intermediate Superheater		54,331	(119,800)
Spray Attemperator 2		0	
Secondary Superheater		54,331	(110,900)
% Spray		10.31	
Circulation Flow		227,200	(500,500)
Circulation Ratio		4.2	
Circulation Pump Power	kW	24.8	
Feedwater Temperature	C (F)	218.3	(425)
Incident Power	MWt (MBtu/hr)	42.05	(143.57)
Radiation Loss	MWt (MBtu/hr)	0.93	(3.18)
Convection Loss	MWt (MBtu/hr)	1.58	(5.39)
Conduction Loss	MWt (MBtu/hr)	0.25	(.85)
Reflection Loss	MWt (MBtu/hr)	2.15	(7.40)
Absorbed Power	MWt (MBtu/hr)	37.13	(126.75)
Efficiency	Per Cent	88.3	
Power Absorbed by Components			
Preheater	MW (MBtu/hr)	1.05	(3.596)
Evaporator	MW (MBtu/hr)	22.41	(76.589)
Primary Superheater	MW (MBtu/hr)	5.96	(20.342)
Intermediate Superheater	MW (MBtu/hr)	2.77	(9.464)
Secondary Superheater	MW (MBtu/hr)	4.94	(16.755)

TABLE 5-5 (Continued). PERFORMANCE OF SOLAR RECEIVER AT DESIGN POINT

Peak Flux at Equinox Noon	kW/m^2 ($kBtu/hr\text{-}ft^2$)	690	(218.7)
Average Flux at Equinox Noon	kW/m^2 ($kBtu/hr\text{-}ft^2$)	361	(114.7)
Peak Superheater Tube OD Temperature	C (F)	570	(1,058)
Peak Screen Tube OD Temperature	C (F)	374	(705)
Maximum Steam Temperature Leaving Tube	C (F)	567	(1,051)
Maximum Upset Tube OD Temperature	C (F)	618	(1,144)

The total heat flux upset factor (F_Q) varies in both vertical and horizontal directions along the receiver. However, the flow unbalanced factor (F_U) only changes from panel to panel and remains constant along the tube. The above values of the flow unbalance factor were obtained without biasing the butterfly valves but with sectioning of the inlet headers of the secondary and intermediate superheaters through installation of diaphragms.

The highest upset metal temperatures are in the secondary superheater (Figure 5.2-18). It is seen that the fluid temperature in the economizer and superheater tubes continuously increases. However, the tube metal temperature first increases, reaches a peak and then decreases along the receiver height. This is due to the fact that the incident flux becomes small near the top of the receiver. With actuation of the biasing valves, the upset temperatures can be significantly reduced. These biasing valves are needed only for transients, caused by cloud passage.

Circulation System--Pump assisted circulation is used to assure adequate and stable flow in every screen tube at all operating conditions, with sufficient margin of reserve for transient upsets. In the recirculating boiler design, the subcooled or boiling water in the boiling circuits (screen

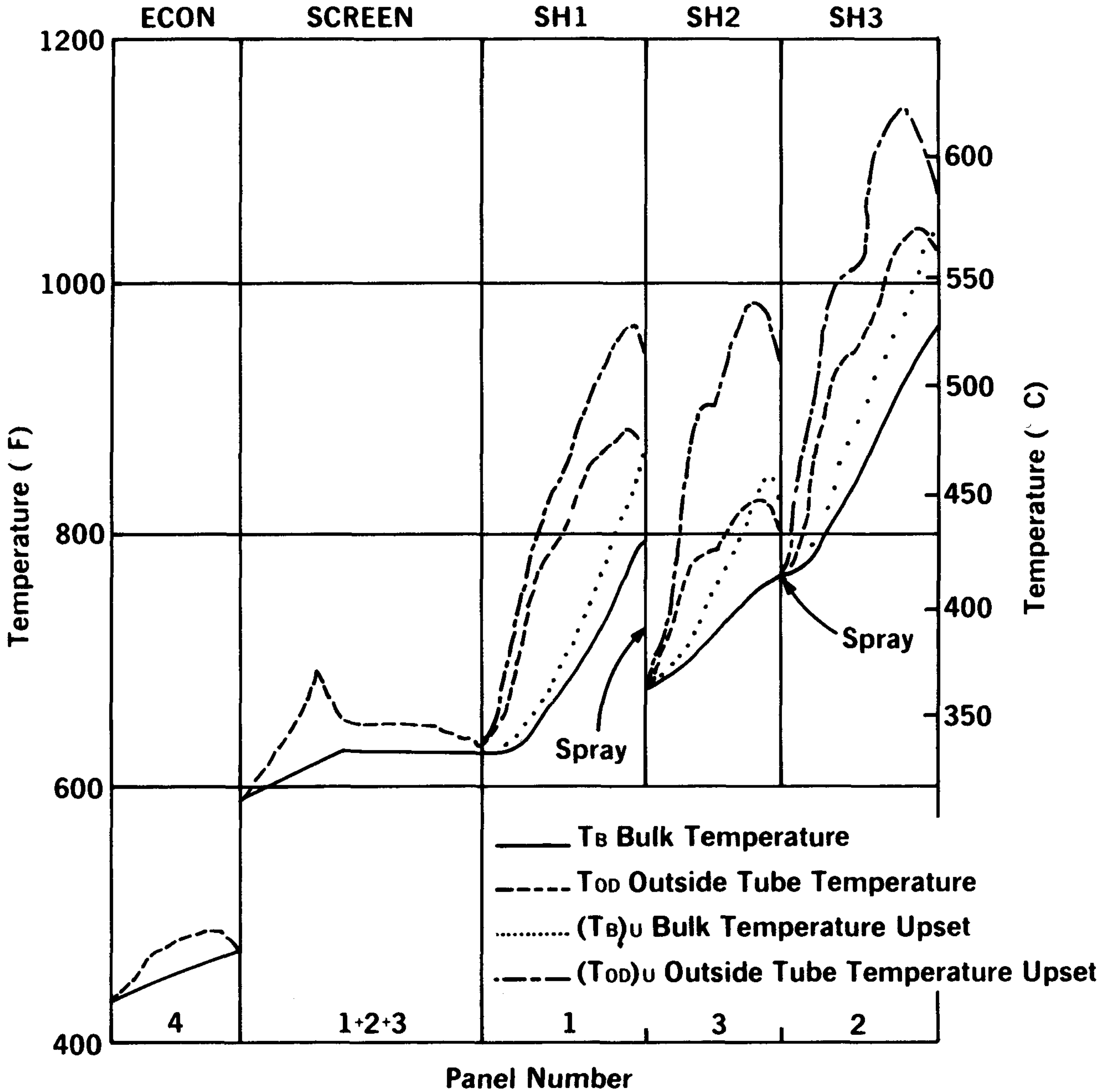


FIGURE 5.2-18 FLUID AND METAL TEMPERATURE PROFILE OF RECEIVER

tubes) is recirculated at a mass flow rate several times higher than the required steam flow. Low quality steam (i.e., low per cent by weight of steam) is allowed to form by nucleate boiling. The steam is separated by cyclone separators in the drum and is routed to the superheater circuits (membrane tube panels). The remaining water is mixed with the feedwater in the drum and routed back to the boiling circuits to pick up more heat and produce steam. The circulation system is shown on Figure 5.2-19. Due to symmetrical arrangement of the panels only one half is shown.

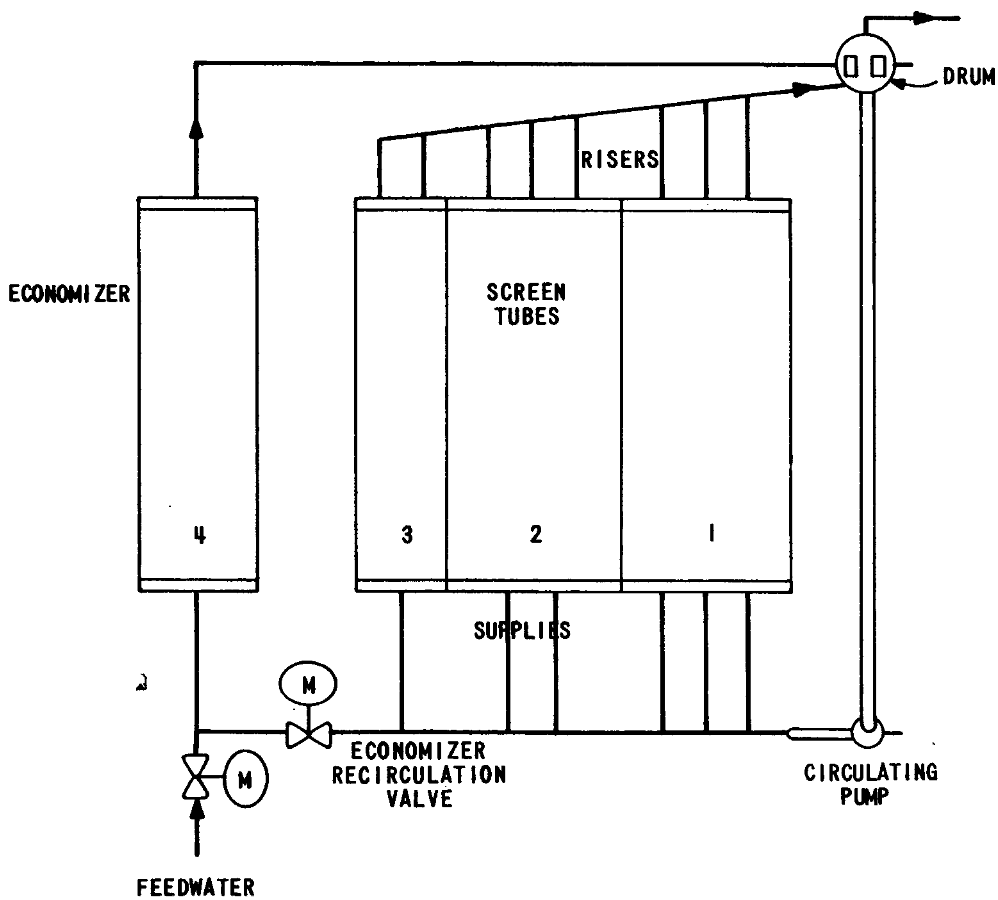


FIGURE 5.2-19 RECEIVER CIRCULATION SYSTEM

The circulation system for the receiver consists of a circulating pump with discharge manifold, supply tubes, screen tubes, risers, drum, and downcomer. A glandless boiler circulating pump is used for the receiver. The glandless wet-stator design is now considered standard for boiler water circulation. It eliminates any leakage problems associated with mechanical seals or packing glands. Both the impeller and the motor are enclosed in a pressure-tight casing. The motor windings are insulated by a waterproof material and immersed in pressurized water which is cooled in an external heat exchanger. The hot water in the pump is separated from the cool water in the motor by a narrow cylindrical annulus in the neck between pump and motor. The radial and truss bearings use self-aligning pivoted shoes which are designed specifically for water lubrication. The pumps must be located well below the drum to ensure the required net positive suction head (NPSH). The power requirement of the pump at normal operation is less than 25 kW with about 36 kW at cold start-up.

The total circulation flow rate is about 2.27×10^5 kg/h (5.0×10^5 lb/h) which corresponds to a circulation ratio of 4.2, based on rated steam generation. The circulation water flow in the screen tubes remains substantially constant and independent from load or heat flux distribution.

The steam drum is a 1.37 m (54 in) internal diameter standard B&W drum 0.10 m (4.0 in) thick, made of SA-515 material. It has about 2.3 m (7.5 ft) cylindrical length and two hemispherical heads. The drum serves to separate steam from water to provide steam-free water to the downcomer and separates water droplets from the steam to provide dry saturated steam to the superheater. The drum serves also as a surge tank to accept shrink and swell of the boiler water content during transients.

The drum internals are shown on Figure 5.2-20. The steam and water mixture enters the drum through risers into the annular space between the drum shell and the internal circumferential baffle which extends through nearly the full length of the shell. The mixture passes through the cyclone separators which are attached to the baffle. Steam leaving the top of the separator passes through the primary scrubbers, consisting of corrugated plates which serve to remove any entrained water droplets. The steam at low velocities passes through the secondary scrubber which serves to dry the steam from the remaining moisture.

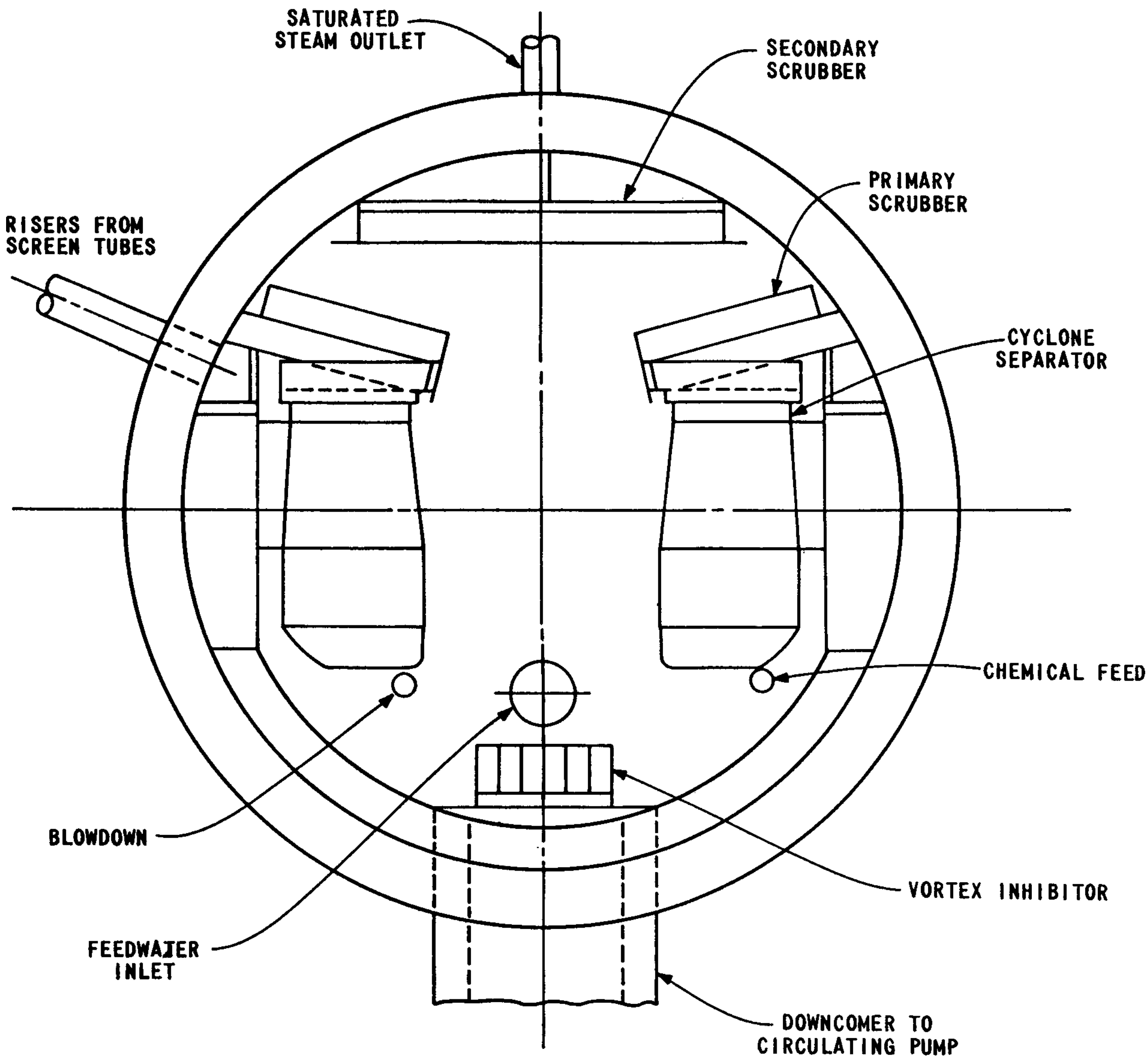


FIGURE 5.2-20 STEAM DRUM INTERNALS

The drum also contains a feedwater discharge pipe to mix the preheated feedwater with the water leaving the bottom of the cyclone separators. Two other pipes are located in the drum: a blowdown line used to remove solids from the boiler water when the concentration is too high, and a chemical feed pipe to add chemicals to control the pH and boiler water chemistry.

A vortex inhibitor is installed at the entrance to the downcomer to provide water level stability. The drum also has connections for the usual water level gages, regulators, safety valves, etc.

Ribbed tubes with internal spirals are used in the screen to avoid DNB. In this design, there is no film boiling and associated critical heat flux temperature oscillation. Pump-assisted circulation is employed to maintain the required mass velocity and circulation ratio (steam quality) at all operating conditions, including extremes of insolation distribution. Ribbed screen tubes operating with nucleate boiling can withstand very high heat fluxes without excessive thermal stresses. Accordingly, the high water side heat transfer rate of the tubes allows the use of alloy material (SA-213-T2) for the screen tubes.

All calculations are performed by using a proprietary B&W circulation balancing computer program. The input consists of all circuits geometry and heat absorption distribution with selected sizes of downcomer, supply tubes, discharge riser, pump and cyclone separators. The output shows flow rates, mass velocities, steam quality, DNB ratio, stability, etc. The output must meet the established standard acceptance criteria and limits. The results indicate that the circulating system needs one downcomer, 14 supplies and 16 risers. The number and sizes are listed in Table 5-6. The calculation was further extended to the worst condition when circulating pumps stop working. In the event of pump failure, the circulation system will still work by natural circulation. However, for a solar receiver with unpredictable heat flux variation from cloud transients, it is difficult to assure adequate flow behavior in all natural circulation circuits. There exists a risk that tubes which become stagnant are having reverse flow from cloud cover and will not be able to reestablish adequate mass velocities

TABLE 5-6. RECEIVER CIRCULATING SYSTEM DATA

Panel No.	Screen Tube (Boiler) No.	Supplies			Risers			Downcomer		
		No.	OD m (in)	Thickness m (in)	No.	OD m (in)	Thickness m (in)	No.	OD m (in)	Thickness m (in)
1	17	3	0.076 (3)	0.0046 (0.18)	3	0.076 (3)	0.0046 (0.18)	0	--	--
2	17	3	0.076 (3)	0.0046 (0.18)	3	0.076 (3)	0.0046 (0.18)	1	0.2731 (10.75)	0.0214 (0.843)
3	11	1	0.076 (3)	0.0046 (0.18)	2	0.076 (3)	0.0046 (0.18)	0	--	--

NOTES:

1. Due to symmetrical arrangement, only half of the receiver is listed here.
2. The dimensions of the screen tubes are shown on Table 5-2.
3. Only one downcomer is needed for entire receiver.
4. The steam drum is 1.37 m (54 in) ID, 0.10 m (4.0 in) thick, 2.3 m (7.5 ft) long with hemispherical heads, material SA-515.

by the time the cloud passes. In the event of an electric power supply disruption to the recirculation pump and controls, the receiver will not be endangered if removal of incident power begins within 15 seconds and the incident heat flux on the receiver is gradually (linearly) and uniformly reduced to below 70 kW/m^2 within 90 seconds of the disruption. The water storage capacity in the drum, even at the low water level, is adequate to maintain circulation and to supply steam to sufficiently cool the superheater to prevent tube failures.

Effect of Cloud Transients on Receiver Performance--A solar receiver system differs from a conventional steam generator in that it does not have control over its input. Atmospheric conditions and time of year and day have a predominant effect on the available energy. Static rarefied clouds restrict the heat flux uniformily. Partial, moving clouds can obscure the collector field in a multitude of random patterns, resulting in nonuniform changes to the receiver heat flux distribution.

The diurnal and seasonal variations in thermal heat input are predictable and the designer must take them into account. Variations of heat flux distributions induced by partial cloud cover are not predictable, but the receiver and each individual panel must be designed to operate with some degree of cloud shadowing.

Thin clouds or smog, which form uniformly over the entire collector field, uniformly reduce the solar flux, but have no adverse effect on the operation of the receiver. The steam generator is capable of generating steam at constant steam temperature because the boiler control system adjusts the amount of water flowing through the receiver to maintain the steam outlet temperature.

Uniform flux reduction does not affect the energy distribution between boiler and superheater; therefore, it does not create steam temperature control problems. All the available solar energy can be accepted by the receiver and used to generate steam at conditions suitable for the turbine. The steam generating rate of the solar boiler varies with fluctuations in the incident solar energy. Similarly, with a steady load on the fossil boiler, the turbine load varies with incident solar energy.

One of the unique design problems associated with the solar receiver is that of rapid transients due to small moving clouds. These clouds, depending on their size and/or location over the heliostat field, have the potential to force the shutdown of the receiver. In a conventional fossil boiler a reduction in total heat input results in a predictable, proportional reduction of absorption among all the heat absorbing components. With the solar receiver it is possible for panels on one side of the receiver to receive little power while panels on the other sides are exposed to full heat flux as shown by the examples in Figures 5.2-21 through 5.2-24.

In the event of large flux pattern imbalances, flow biasing butterfly valves located at the inlet of each superheater panel can be used to redistribute the steam flow to the superheater panels. The flow through the screen tubes, however, remains constant. Without biasing valves an uneven heat distribution would normally result in higher steam flows going to panels with the least heat; this is just the opposite of the desired flow pattern. The biasing valve allows the control system to force flow to the panels and tubes receiving the most heat by throttling the valves in the tubes receiving the least heat. If the heat unbalance is severe, the bias valves on the hottest panel may be full open and be unable to maintain the panel exit steam temperature within the allowable temperature limit. In that event, a signal is provided to the solar master control system to redirect power from groups of heliostats off the receiver, away from the hot flow path. It should be pointed out that the total steam flow within the same pass of superheater remains constant under these unbalanced flow conditions.

To assess the effects of cloud shadows on receiver performance, a number of flux map and receiver performance calculations were made under various cloud shadow conditions. A total of eight case were investigated, resulting in the flux patterns shown in Figures 5.2-21 through 5.2-24. It was found that if the cloud shadowing results in a flux pattern symmetric with respect to the north-south axis (Figure 5.2-24 is an example), the receiver is capable of operating with cloud coverage of up to 75 per cent of the heliostats. The receiver is less tolerant of cloud coverage when it

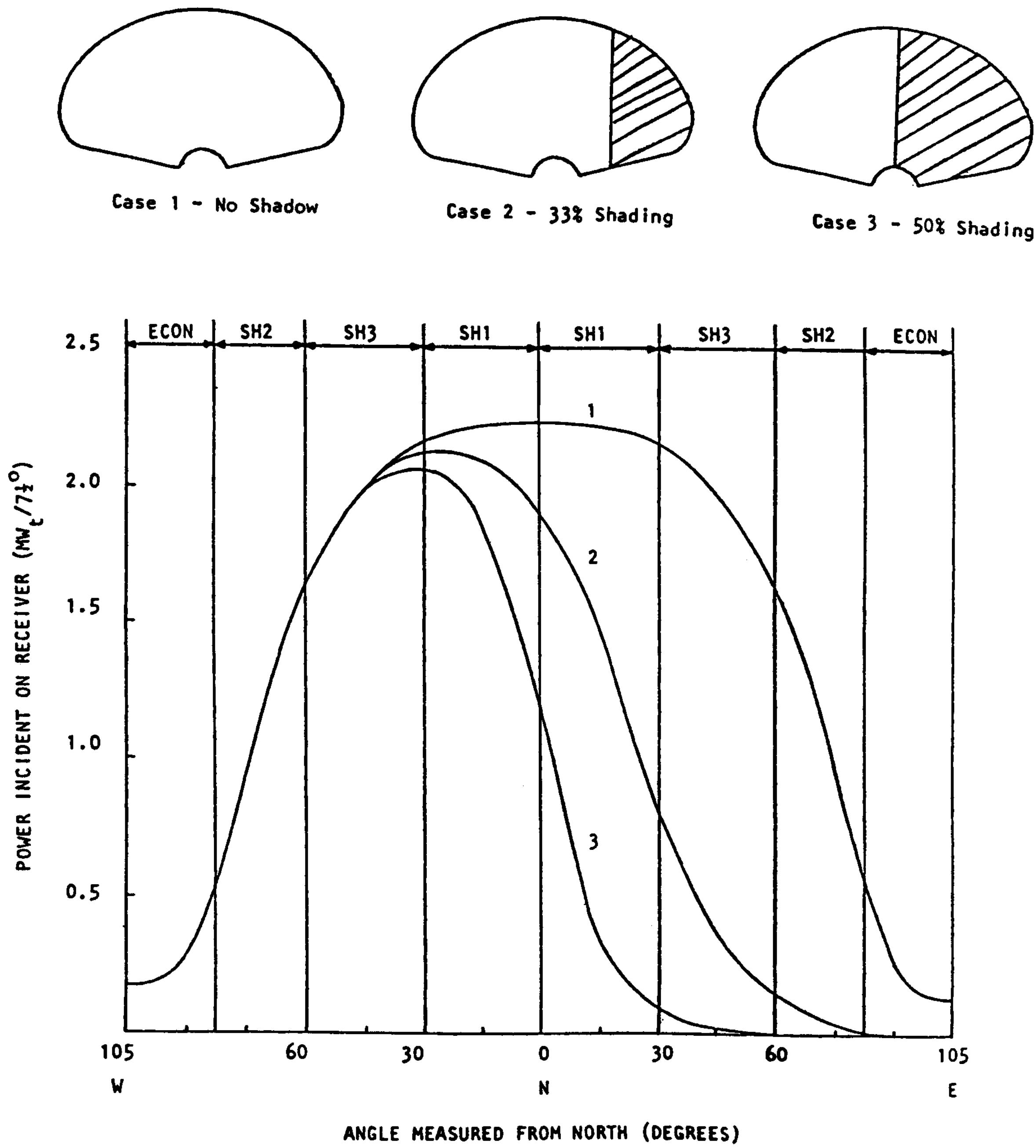
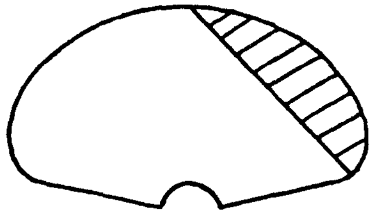
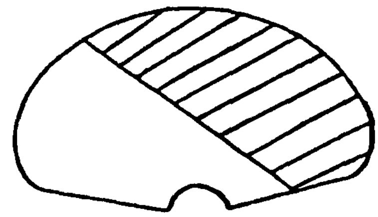


FIGURE 5.2-21 FLUX DISTRIBUTION ON RECEIVER PANELS FOR CLOUD MOVING FROM EAST



Case 4 - 33% Shading



Case 5 - 50% Shading

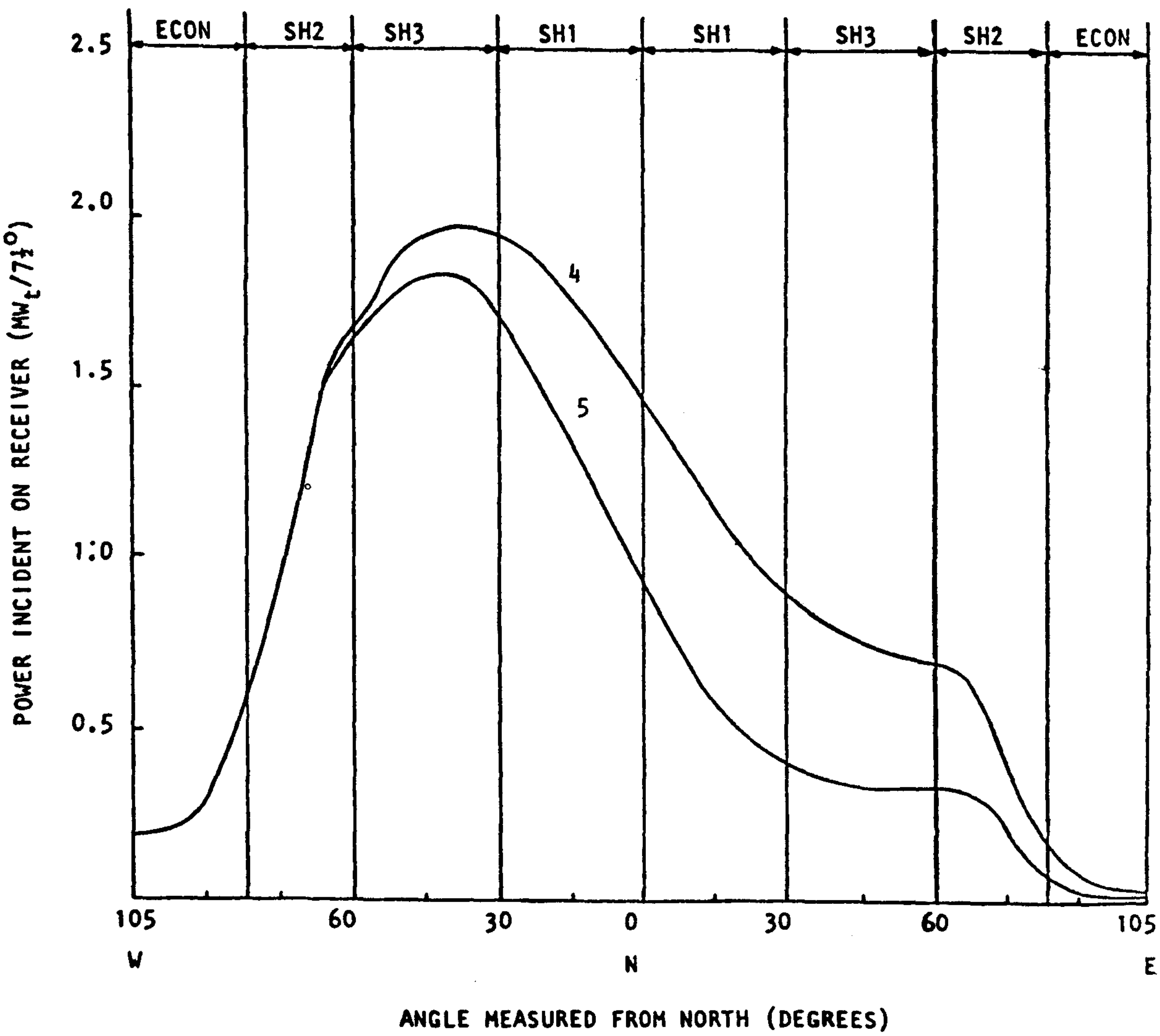


FIGURE 5.2-22 FLUX DISTRIBUTION ON RECEIVER PANELS FOR CLOUD MOVING FROM NORTHWEST

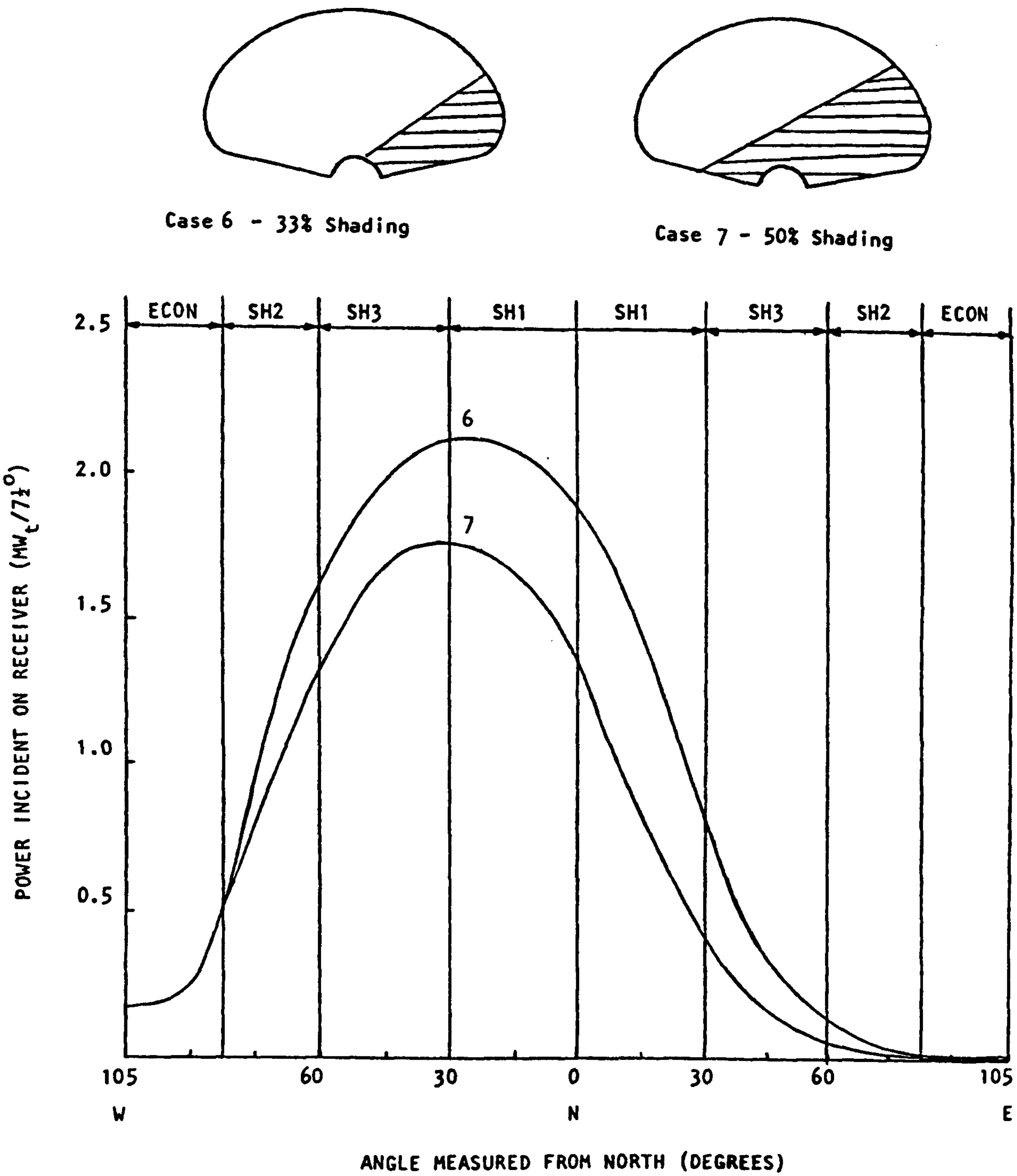


FIGURE 5.2-23 FLUX DISTRIBUTION ON RECEIVER PANELS FOR CLOUD MOVING FROM SOUTHEAST

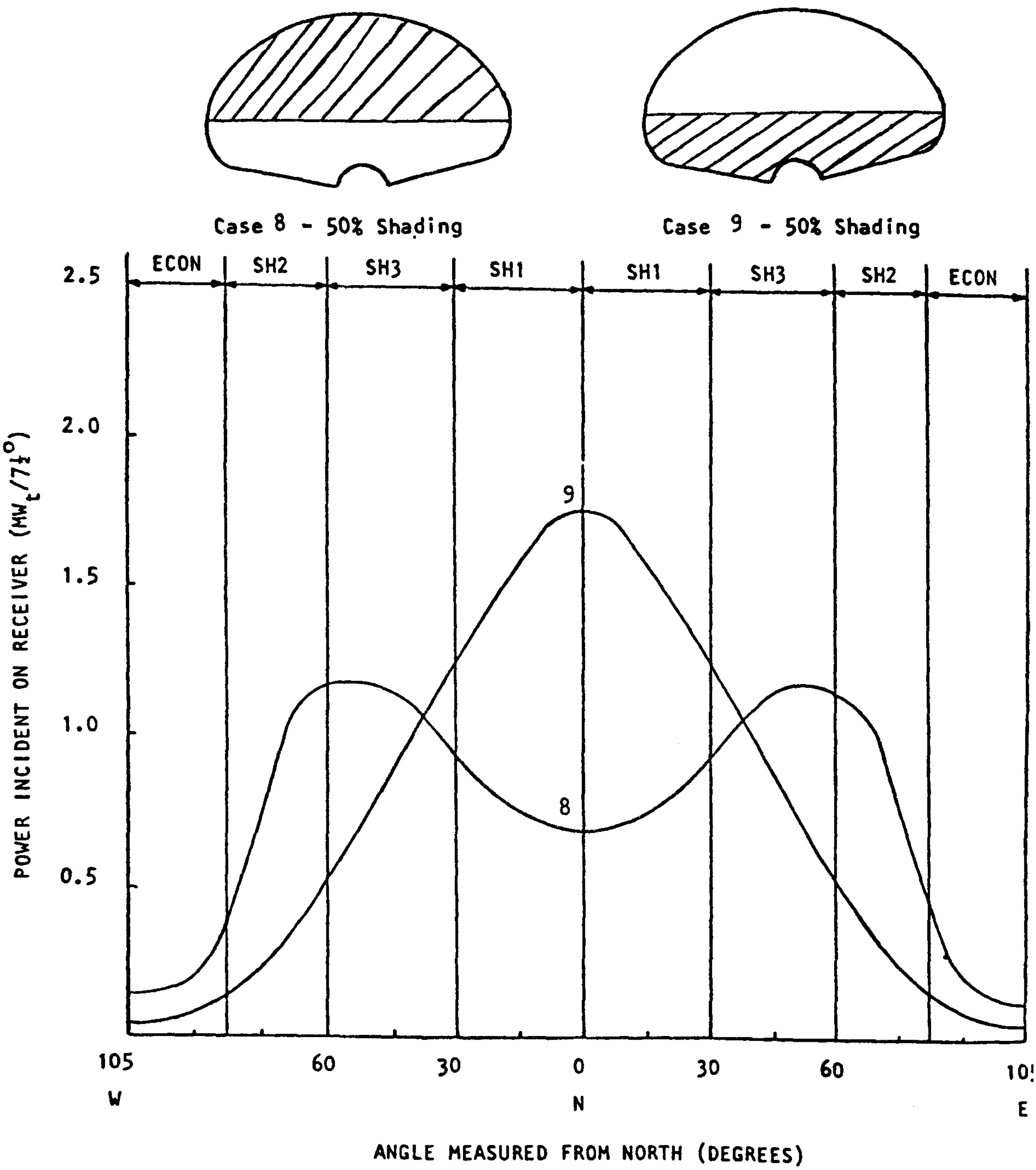


FIGURE 5.2-24 FLUX DISTRIBUTION ON RECEIVER PANELS FOR CLOUD MOVING FROM NORTH AND SOUTH

results in a large imbalance in incident flux between the east and west half of the receiver. However, the use of flow biasing valves to redistribute steam flow to superheater panels will permit receiver operation under most conditions.

Among all cases under study with unbalanced incident power between east and west panels (cases 2 to 7), it is found that case 3 with 50 per cent shading on the east side of receiver is the worst one and case 4 is the best one. The reason is that the incident power ratios between west and east half of the receiver are 10.5 and 2 for case 3 and case 4 respectively. The results of this study indicate that the receiver can withstand a west-to-east incident power ratio of up to 3.0 without the need to defocus the collector. In order to ensure safe receiver operation, selective defocusing of portions of the collector will be required when the west-to-east incident power ratio is greater than 3.

In summary, the use of flow biasing valves to redistribute steam flow to superheater panels permits the receiver to operate without collector defocusing when clouds occlude 33 per cent to 60 per cent of heliostats, depending on cloud shade pattern on the collector field. With preferential defocusing of heliostats it will be possible to operate the receiver with a variety of cloud patterns that randomly obscure up to 70 per cent of the heliostats. This flexibility of operation is the major advantage of the screen tube design.

5.2.1.5 Receiver Controls. The controls for the receiver system modulate feedwater flow, economizer recirculation, secondary superheater outlet temperature, and the flow of each superheater panel. The receiver pressure is a function of the electric power generating system main steam pressure.

Feedwater Flow Control--The feedwater flow is controlled to maintain the proper water level in the drum. During normal operation, the drum level is controlled to a common operator set point by a three-element feedwater control. Measured steam flow is used to establish the feedwater flow demand. Measured drum level is compared to the set point, and the resulting error is applied to a proportional plus integral controller, which is used to correct the feedwater flow demand. The corrected demand is compared with measured flow and applied to a proportional plus integral controller to position the feedwater flow control valve.

During start-up and shutdown, when there is little or no steam flow from the receiver, a single-element feedwater flow control, based on only drum level, is used. Also, a high level dump valve on the drum is used to assist in controlling drum level swell during start-up. If drum level exceeds a high level set point, a proportional controller is used to position the dump valve to limit the drum level rise.

Economizer Recirculation Valve Control--The economizer recirculation valve shown on Figure 5.2-10 is automatically closed when feedwater is flowing to the receiver and the steam flow from the receiver is greater than 15 per cent of the design flow rate [8,000 kg/h (17,600 lb/h)], or when the recirculating pump is not in service. The valve is automatically opened when no feedwater is flowing or steam flow is less than 15 per cent of the design flow rate, and a recirculating pump is in service. Feedwater flowing requires that the receiver feedwater booster pump (see Subsection 5.3.1) be running and feedwater valves are open.

Steam Temperature Control--The secondary superheater outlet temperature of each of the flow paths is independently controlled to a common set point by use of water attemperation at the outlets of the primary and intermediate superheater panels.

The secondary superheater outlet temperature for each flow path is compared with the set point. The resulting error signals, in conjunction with a feedforward function from the steam flow in each flow path, generate the total attemperator flow demand for each flow path. A maximum attemperator flow demand is developed, based on the steam flow through the flow path and the primary superheater outlet temperature, to prevent the first stage of attemperation from spraying when the outlet of the attemperator contains moisture. The maximum attemperator flow limit is based on not allowing the attemperator outlet temperature to go below a predetermined limit.

Initially, the total attemperator flow is through the first-stage attemperator. Once the first-stage attemperator flow demand is at the maximum allowed, any additional attemperator flow demand is applied to the second-stage attemperator. A degree of overlap in the operation of the two attemperators is provided to prevent loss of temperature control when bringing in or removing the second stage of attemperation. During a transient, both attemperators may move in parallel to minimize the temperature swing associated with the transient. The spray demand for each attemperator is compared to its measured flow, to develop the demand for each attemperator flow control valve. A block valve associated with each attemperator control valve is interlocked to close whenever its control valve is demanded closed.

Panel Bias Valve Control--Each of the six superheater panels has a bias valve(s) at its inlet controlled by a deadbanded proportional controller. These valves, under normal temperature conditions, are throttled to approximately 70 per cent open. If, during a transient, the outlet temperature exceeds the deadband, the valve is repositioned to divert flow away from a cold panel or increase flow in a hot panel. If the demand for panel bias valve opening exceeds a predetermined amount, a proportional demand signal is provided to the solar control system to redirect power from some heliostat groups away from the hot flow path.

5.2.1.6 Start-up and Shutdown Procedures. Several start-up and shutdown modes must be considered due to the unpredictable nature of insolation. For each scenario identified, a step-wise procedure is described.

Morning Start-up (Receiver Cold)--The primary consideration for start-up in the morning following a prolonged shutdown (greater than overnight) is to prewarm the receiver with feedwater and steam from the turbine cycle or from the fossil boiler, to allow full power from the collector at sunrise. The initial conditions of the receiver are near ambient temperature with a nitrogen blanket at slightly above atmospheric pressure and doors closed. The warm-up procedure brings the receiver to main steam line pressure and saturation temperature by sunrise.

The expected trends during cold start-up of steam consumption (energy required, receiver pressurization, and temperature) are shown on Figure 5.2-25. For a cold start-up from 21 C (70 F), it takes about 45 minutes to reach 5.62 MPa (815 psia) pressure, and 53 minutes to reach 9.59 MPa (1,390 psia); the energy consumption is about 4.54 MWh or 5.60 MWh, respectively. This energy consumption represents the heat required to warm up the receiver metal and fluid and to overcome losses to the surroundings.

During cold start-up the boiler circulation system is heated from ambient to 100 C (212 F) saturation temperature with the circulation pump running. At 100 C, the superheater is heated by admitting steam from the fossil boiler through vent valves and removing condensate through drain traps. The circulation system and superheater are warmed up together to desired pressure. This accomplishes a cost savings in energy by reducing radiation and convection losses to the surroundings with doors closed.

Additional start-up equipment required for the solar receiver are a steam sparger inductor to warm up the boiler water and a circulation system (drum level dump valve, superheater condensate traps, and a warmup valve) to control the rate of pressurization.

The sequence for cold start-up is shown in Table 5-7.

Diurnal Start-up (Receiver Warm)--The valves used in the warm start-up procedure are shown on Figure 5.2-26. A complete listing and description of the receiver valves are given in Table 5-8. The receiver thermal energy is banked overnight by using the closure doors to reduce losses. As shown on Figure 5.2-27, the initial conditions for morning start-up may vary from 0.172 MPa (25 psia) and 115.6 C (240 F) to 3.10 MPa (450 psia) and 235 C (455 F), depending on ambient conditions. The energy required for receiver warmup depends on initial receiver temperature and steam pressure as shown in Figure 5.2-28.

The fossil steam generator supplies about 3.5 to 5.0 MW_t (12 to 17 MBtu) of energy, depending on receiver temperature, using main steam to warm up the solar receiver to saturation temperature, and pressurize it corresponding to steam line pressure existing at sunrise. The closure door is

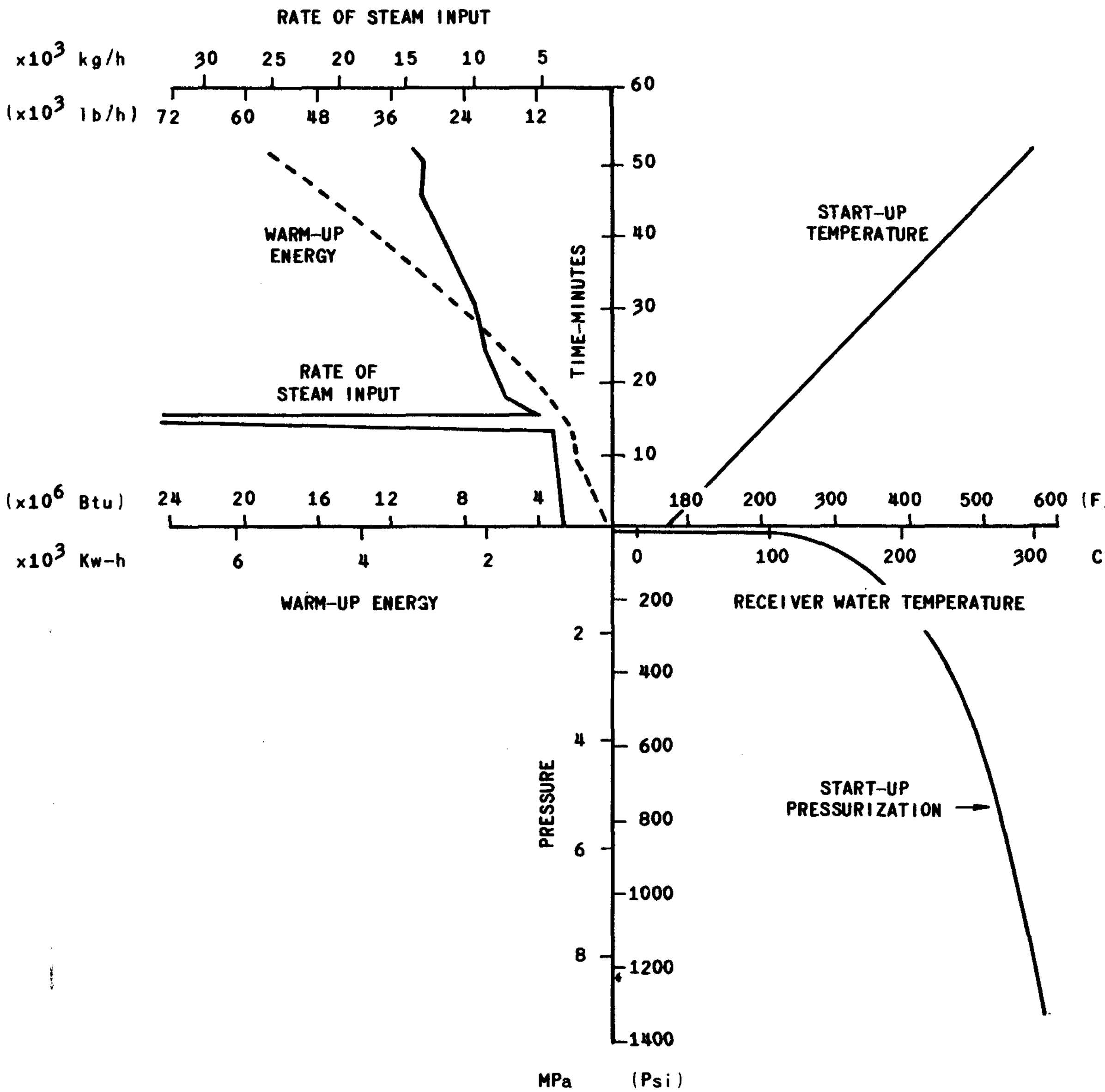


FIGURE 5.2-25 RECEIVER WARM-UP DATA DURING START-UP

TABLE 5-7. START-UP SEQUENCE--RECEIVER COLD (For Reference to Valve Letters, See Figure 5.2-26).

(1) Vent and fill to slightly above normal water level with feedwater (mix as required to match within 65 C (150 F) of bottom lower drum metal temperatures).

(2) Open economizer circulation valve E, superheater drains, and trap system H. Superheater steam vent valve F remains closed until drum is warmed to saturation 100 C (212 F). Figure 5.2-26.

(3) Start boiler circulating pumps.

(4) Close nitrogen blanketing valves, open turbine end main steam stop valve, open warm-up valve B, and control prewarm-up of economizer and screen at prescribed rate. Note: This valve controls pressure and, thus, saturation temperature rate of change 5.6-3.3 C/min (10-6 F/min).

(5) Steam sparger inductor valve D is used to warm up the drum; screen tubes, economizer panels, and all associated connection piping. Open valve F when the drum water reaches saturation temperature 100 C (212 F). Steam is admitted through valve F into the SH, and condensation is returned through traps at H. If SH vent to atmosphere is open, close at 0.172 MPa (25 psia).

(6) As volume of water in drum swells on warm-up, excess is dumped through G to maintain level slightly higher than normal set point (single-element controller). Note: Time to warm-up to 9.59 MPa (1,390 psia), 327 C (620 F) is about 53 minutes after start of step 4, depending on ambient conditions, etc.

(7) At sunrise, open closure doors and focus heliostats on receiver.

(8) Steam evaporation begins at first insolation at a rate corresponding to net power input to screen tubes and economizer. Open receiver steam valve A. Close steam sparger inductor valve D. Close superheater vent valves F. Superheat spray attemperators must be available for use.

TABLE 5-7 (Continued). START-UP SEQUENCE--RECEIVER COLD

(9) Drum level dump valve G should be closed (automatically) as steam flow occurs. The feedwater flow is started when drum level drops below normal. Economizer circulation valve E is closed as this occurs. Drum level control is automatic.

(10) The warm-up valve B and superheater drains H are closed.

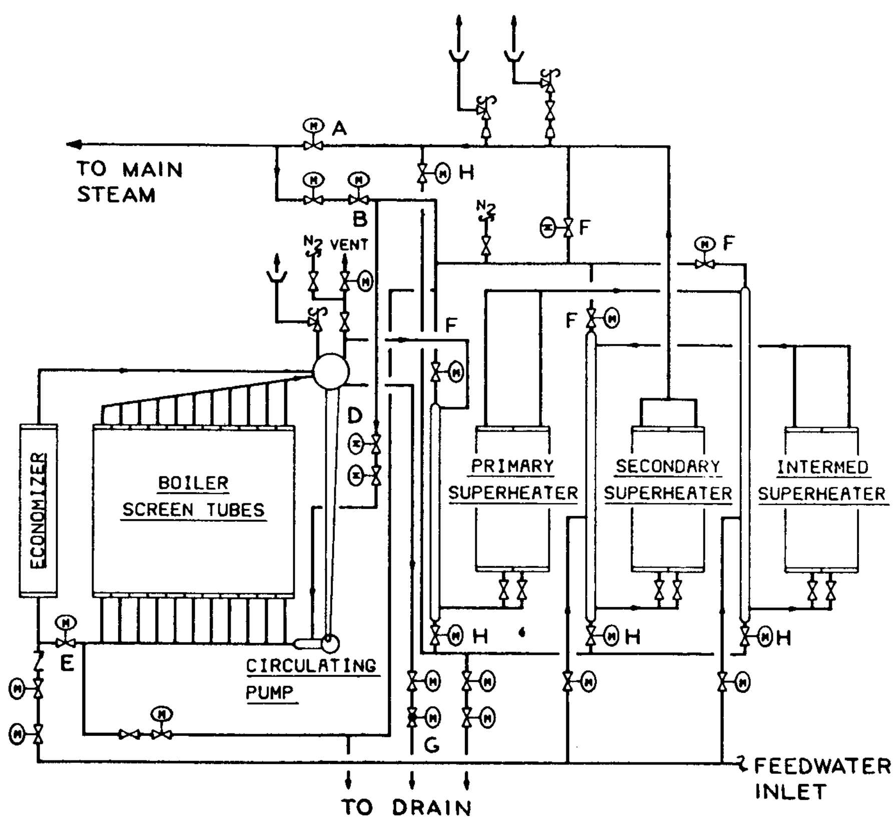


FIGURE 5.2-26 SCHEMATIC LOCATION OF KEY RECEIVER VALVES

TABLE 5-8. LIST OF RECEIVER VALVES

Service	Type	Operator*	Size, m (in)	Quantity
Economizer Drain	Globe	Motor	0.025 (1)	1
Economizer Pressure Test	Globe		0.025 (1)	2
Economizer Vent	Globe		0.025 (1)	2
Drum Atmospheric Vent	Globe	Motor	0.025 (1)	2
Drum Safety Valve	Safety	Spring	0.076 (3)	1
Drum Pressure Test	Globe		0.025 (1)	2
Drum Pressure	Globe		0.025 (1)	2
Drum Nitrogen	Globe	Motor	0.025 (1)	1
Steam Sampling	Globe		0.025 (1)	2
Continuous Blowdown	Globe	Motor	0.025 (1)	2
Chemical Feed	Globe		0.025 (1)	2
Water Sampling	Globe		0.025 (1)	2
Remote Level Transmitter	Globe		0.013 (1/2)	4
Water Gage Glass	Globe		0.013 (1/2)	2
Water Gage Drain	Globe		0.013 (1/2)	2
Drum Level Dump Shut-Off	Gate	Motor	0.051 (2)	1
Drum Level Dump	Globe	Control	0.051 (2)	1
Pump Auxiliary	Globe		0.025 (1)	20
Sparger Check	Nonreturn	Motor	0.038 (1-1/2)	3
Sparger	Globe	Control	0.038 (1-1/2)	1
Receiver Blowdown	Globe	Motor	0.025 (1)	3
Economizer Circulation	Nonreturn	Motor	0.025 (1)	1
Attemperator Block	Gate	Motor	0.025 (1)	1
Attemperator Spray	Globe	Control	0.025 (1)	4
Attemperator Check	Nonreturn		0.025 (1)	4
PSH Panel	Butterfly	Control	0.064 (2-1/2)	4
ISH Panel	Butterfly	Control	0.064 (2-1/2)	6
SSH Panel	Butterfly	Control	0.064 (2-1/2)	6
SH Vents	Globe	Motor	0.025 (1)	6
SH Vent Shut-Off	Globe	Motor	0.051 (2)	1

TABLE 5-8 (Continued). LIST OF RECEIVER VALVES

Service	Type	Operator*	Size, m (in)	Quantity
SH Nitrogen	Globe	Motor	0.025 (1)	2
SH Drain	Globe	Motor	0.025 (1)	6
SH Drain Shut-Off	Globe	Motor	0.038 (1-1/2)	1
SH Trap	Trap		0.025 (1)	6
MS Pressure Test	Globe		0.025 (1)	2
MS Safety Valve	Safety	Spring	0.064 (2-1/2)	1
MS Electromagnetic Shut-Off	Gate	Motor	0.064 (2-1/2)	1
MS Electromatic	Relief	Electric	0.064 (2-1/2)	1
Receiver Steam Shutoff Valve	Gate	Motor	0.153 (6)	1
Warm-Up, Shut-Off Valve	Gate	Motor	0.064 (2-1/2)	1
Warm-Up Valve	Globe	Control	0.064 (2-1/2)	1

*Manual if not otherwise denoted.

PSH--Primary Superheater, ISH--Intermediate Superheater, SSH--Secondary Superheater, SH--Superheater, MS--Main Steam.

opened just prior to the time the receiver conditions are suitable to accept solar insolation.

The sequence for warm start-up (with the closure doors) is listed in Table 5-9.

Mid-Day Start-Up--For start-up after sunrise, selective heliostat focusing is required to duplicate the morning solar power input to the receiver. Other procedures are the same as either the cold or warm morning start-up procedures.

Variable Pressure Start-Up--Variable throttle pressure control is utilized with the receiver warm-up end point to match the main steam line pressure at the turbine. This shortens the start-up time with lower

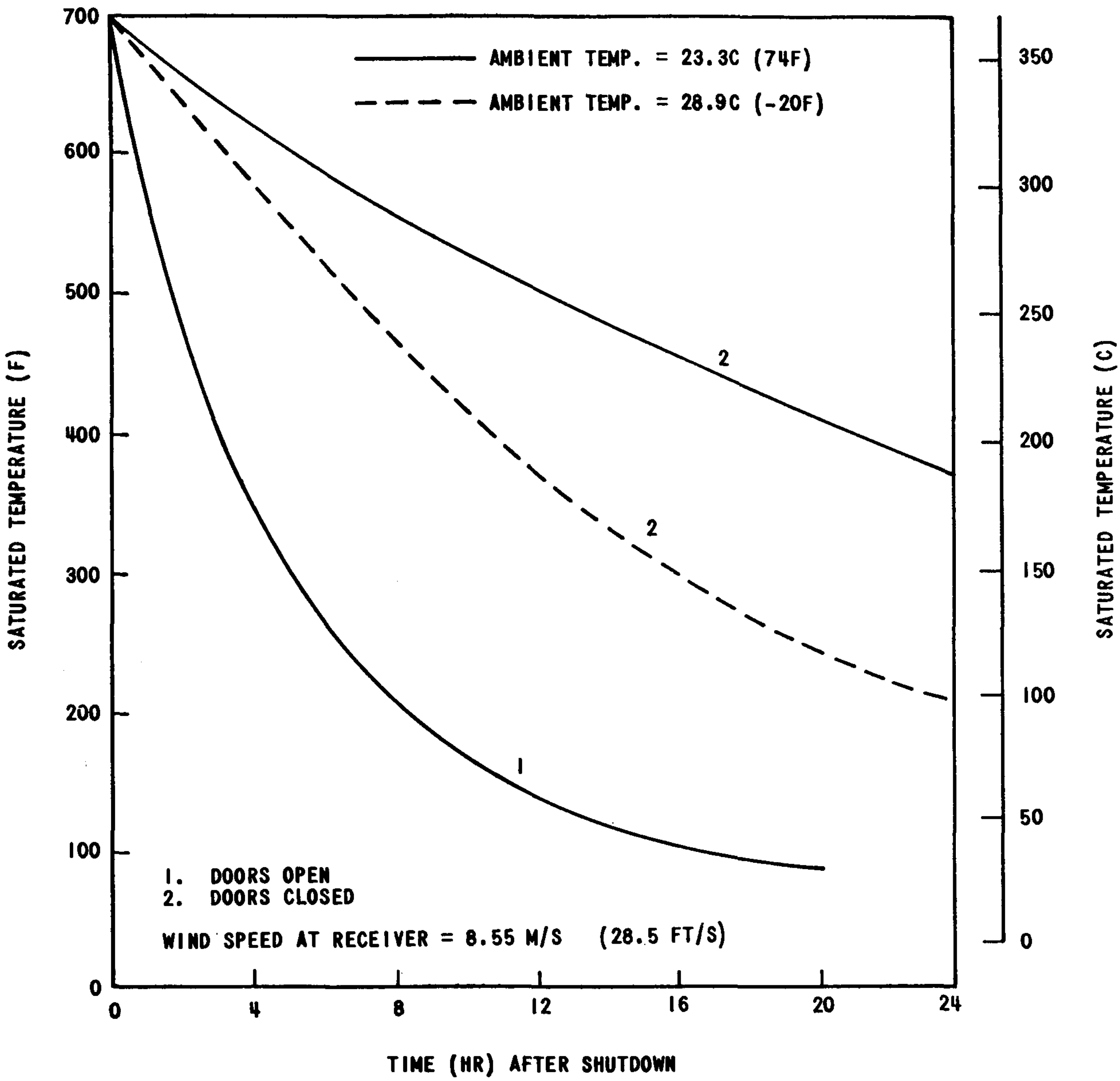


FIGURE 5.2-27 RECEIVER COOL DOWN RATE

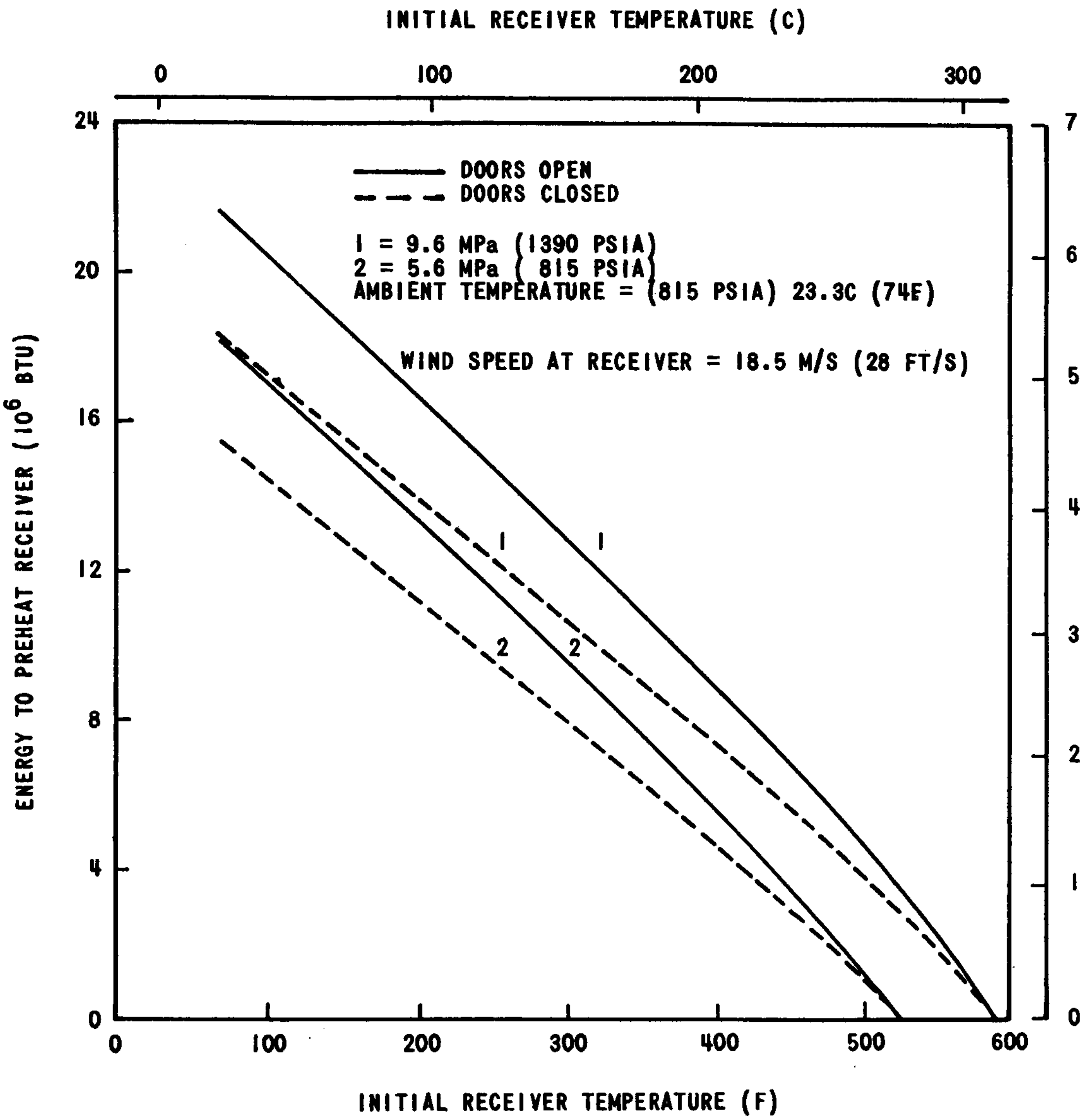


FIGURE 5.2-28 ENERGY REQUIRED FOR RECEIVER WARM-UP

TABLE 5-9. START-UP SEQUENCE--RECEIVER WARM (For Reference to Valve Letters, See Figure 5.2-26)

(1) Establish circulation with boiler circulating pump. Make sure economizer circulation valve E, superheater drains, and trap system H are open.

(2) Open superheater vent valve F. Open warm-up valve B and sparger inductor valve D. Pressurization and saturation temperature are controlled at a prescribed rate of change.

(3) As volume of water in drum swells on warm-up, excess is dumped through G to maintain level slightly higher than normal set point (single-element controller).

(4) The closure doors are opened just prior to sunrise, when the receiver attains steam line pressure and is ready to accept solar energy.

(5) At sunrise, open the receiver steam shutoff valve A, close steam sparger inductor valve D. Close superheater vent valve F. Superheat spray attemperators must be available for use.

(6) Drum level dump valve G should be closed (automatically) as steam flow occurs. The feedwater flow is started when drum level drops below normal. Economizer circulation valve E is closed as this occurs. Drum level control switched to the three-element control for normal operation.

(7) The warm-up valve B and superheater drain H are closed.

requirements for fossil-supplied energy. In addition, solar energy is used earlier to overcome the heat capacity effects and to increase steam conditions along with the throttle pressure ramp.

Shutdown Procedures--The receiver is shut down by reducing the incident solar radiation due to either sunset or selective defocusing of portions of the collector. As solar steam generation and pressure is reduced, the load on the fossil boiler increases to maintain the turbine load.

At the point of minimum solar energy input, the receiver steam shut-off valve 'A' (as shown in Figure 5.2-26) can be shut and the closure doors shut. As the receiver cools and the drum water level shrinks, feedwater will be required to maintain a desired drum level.

The receiver is usually either banked to conserve energy or cooled and drained to prevent freezing. When the receiver pressure drops below 0.14 MPa (20 psia) or when the unit is to be put in storage, wet or dry, a nitrogen blanket will be admitted to the superheater and drum through vent lines to protect those surfaces from corrosion. Normal idle boiler lay-up techniques should be followed.

Draining Criteria--The surface temperature of the receiver can dramatically decrease during the night, especially in the cold and windy winter time. It is possible that, without circulating turbine cycle feedwater through the receiver, the surface temperature and the water in the receiver will reach, or even drop below, the freezing temperature of water. Advanced planning with knowledge of the criteria for draining is required to avoid freezing. The steady-state limiting curve for draining the receiver in terms of wind speed and ambient air is shown in Figure 5.2-29; the advantage of the closure doors is also shown in the figure. The region under the curves is defined as the draining region.

5.2.1.7 Operating Modes. The solar receiver has five modes of operation: normal operation with variable pressure, routine start-up and shutdown, hot restart operation, cold start operation and emergency shutdown.

Normal Operation--Normal operation utilizes variable pressure. During sunlight hours, the solar steam generator augments the power input to the turbine generator by producing steam consistent with the throttle pressure/valve opening characteristic.

The receiver design permits operation with considerable random cloud coverage and sporadic small cloud movement without the need for defocusing the collector. However, when the collector field is shaded so that the ratio of power delivered to the two (east and west) flow paths of the receiver is excessive it is necessary to automatically, preferentially defocus corresponding heliostat groups and place them at standby position. This

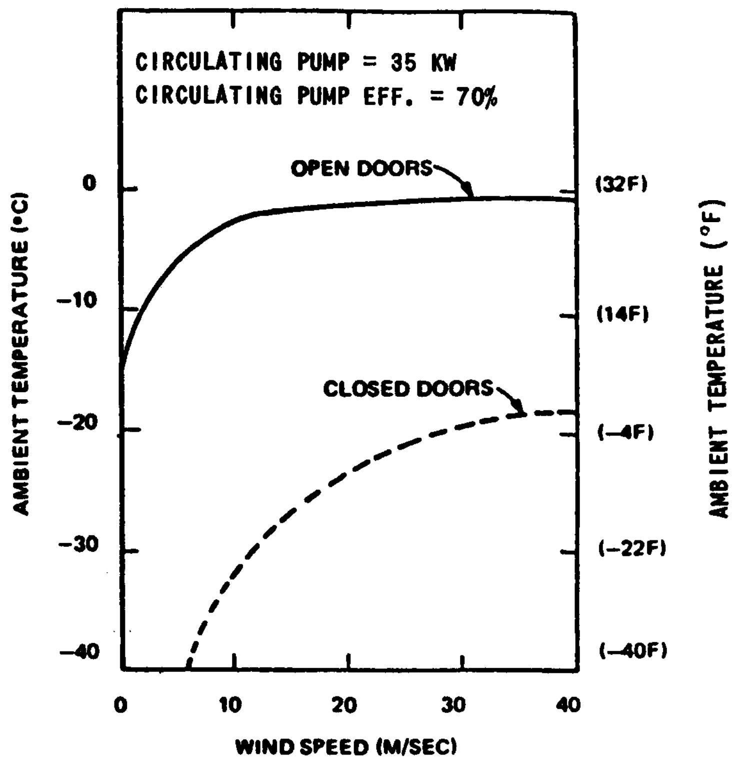


FIGURE 5.2-29 RECEIVER DRAINING REQUIREMENTS VERSUS AMBIENT CONDITIONS

can be accomplished by controls within about 4 seconds, as proven at the Central Receiver Test Facility. When the frequency of cloud passage is such that the variations of steam outlet temperature become excessive it might also be necessary to drop the steam outlet temperature set point.

Routine Shutdown and Start-Up Operation--Except for unusually cold or high wind conditions, the receiver temperature will be above 121 C (250 F) overnight and at sunrise. Just before sunrise, superheated steam from the fossil steam generator is fed back through the receiver piping system steam piping for heating the receiver steam drum to match saturation temperature at the existing turbine throttle pressure. Spargers are used to inject the steam into the receiver circulating pump suction line. The condensate resulting from the preheating steam is drained to the receiver piping system blowdown tank for return to the EPGS. The receiver closure doors are opened just prior to beginning of heliostat focusing to accept solar insolation at sunrise. Prewarming energy requirements will be greatly reduced due to the receiver closure doors.

Hot Restart--A hot restart occurs after the solar receiver has been secured from steaming and heliostats defocused for some reason during mid-day. Selective heliostat focusing is required to generate solar receiver steam conditions suitable for the turbine generator with the expected rate of rising steam pressure and load approximating that of a typical morning start-up.

Cold Start Operation--Fill--Prior to start-up of the receiver system, the booster feed pump fills the receiver with warm feedwater at a controlled rate to avoid thermal shock. Makeup to the fossil energy system will be through the condenser from the deionized water storage tank.

Freeze Protection--For freeze protection, when necessary during shutdown operation, feedwater is circulated to the receiver and then returned to surge tank No. I, (see Subsection 5.3.1) so that the receiver temperature is maintained above 3.3 C (38 F). If required, prior to sunrise, feedwater flow is increased to warm up the receiver water to about 116 C (240 F). The water flow is controlled to limit the rate of saturation temperature rise in the receiver to 6.7 C (12 F) per minute.

Start-Up--After the receiver is filled and prewarmed, start-up is similar to diurnal start-ups described previously. When start-up is not at sunrise, it is necessary to selectively sequence the heliostats to approximate the rate of heating and load production of a typical morning start-up. The objective is to allow for warmup of the main steam transport pipe and to limit the rate of saturation time of the receiver to 4.4 C (8 F) per minute.

Emergency Shutdown--Emergency shutdown may be necessary when there is a failure of the boiler circulating pump, loss of feedwater flow due to booster or feed pump failures, large tube leaks, etc. In such cases when power is available to the collector field, heliostats are slewed to remove the heat flux from the receiver. In case of power failure, the emergency diesel generator is available to provide the necessary power to defocus the collector.

5.2.1.8 Receiver Cost and Weight Estimate. An estimate of the weight and cost of the various components of the external receiver with closure doors is listed in Table 5-10. The estimate was performed using the Babcock & Wilcox Company's experience in the design and manufacture of steam generating equipment.

TABLE 5-10. COST AND WEIGHT ESTIMATE (January 1980 Dollars)

	Shipping Weight		Cost		
	1,000 Kg	(Kips)	Material and Fabrication $1,000	Erection $1,000	Total $1,000
Economizer	4.1	9	40	10	50
Evaporator System	56.7	125	437	248	685
Circulating Pump System	4.1	9	237	33	270
Superheater	49.0	108	1,378	175	1,553
Instrumentation and Controls	13.6	30	575	60	635
Insulation and Lagging (Mat'l)	22.7	50	157	376	533
Solar Doors	24.9	55	295	51	346
Support Structure and Grating	70.3	155	128	89	217
Painting, Loading and Shipping	--	--	81	--	81
Service and Supervision	--	--	100	159	259
Engineering	--	--	975	--	975
Total	245.4	541	4,403	1,201	5,604

Estimates of material for the receiver, structural steel, and other associated equipment are based on January 1980 material costs. Labor for shop fabrication is based on consolidated data for shop fabrication of similar type equipment. Labor costs reflect January 1980 wage rates at Babcock & Wilcox Company manufacturing facilities.

Cost estimates for pumps, valves, controls, and other accessory items are based on vendor quotations, catalog prices, and historical data for cost of similar equipment.

Transportation costs are based on January 1980 freight rates for delivery of equipment to Liberal, Kansas. Cost of field construction of the receiver support structure and installation of the absorber pressure parts with associated equipment was done using the Babcock & Wilcox Company's expertise in construction and installation of steam generating and other various types of equipment. Estimates were based primarily on historical data for construction and installation of steam generating and other similar equipment in the Kansas area.

5.2.2 Receiver Tower

The receiver tower, as shown in Figure 5.2-30, supports the receiver, receiver piping, control equipment, and other elements of the receiver system. The tower has the following general characteristics.

(1) Tower height.
    (a) 74.37 m (244 ft) to receiver support level.
    (b) 90.53 m (297 ft) to top of receiver.
(2) Structural type--Structural Steel.
(3) Top dimensions--4.27 m x 4.27 m (14 ft x 14 ft).
(4) Base dimensions--7.32 m x 7.32 m (24 ft x 24 ft).
(5) Foundation--12.19 m x 10.19 m x 1.52 m (40 ft x 40 ft x 5 ft) reinforced concrete mat supported by 64 auger cast concrete piles.
(6) Material--ASTM A572 Grade 50 structural steel for columns. ASTM A36 structural steel for bracing.

The receiver tower has four support legs and X-bracing is provided to resist lateral loads. Based on economics, bolted structural steel construction is used. The tower is designed to resist all applicable loads, including

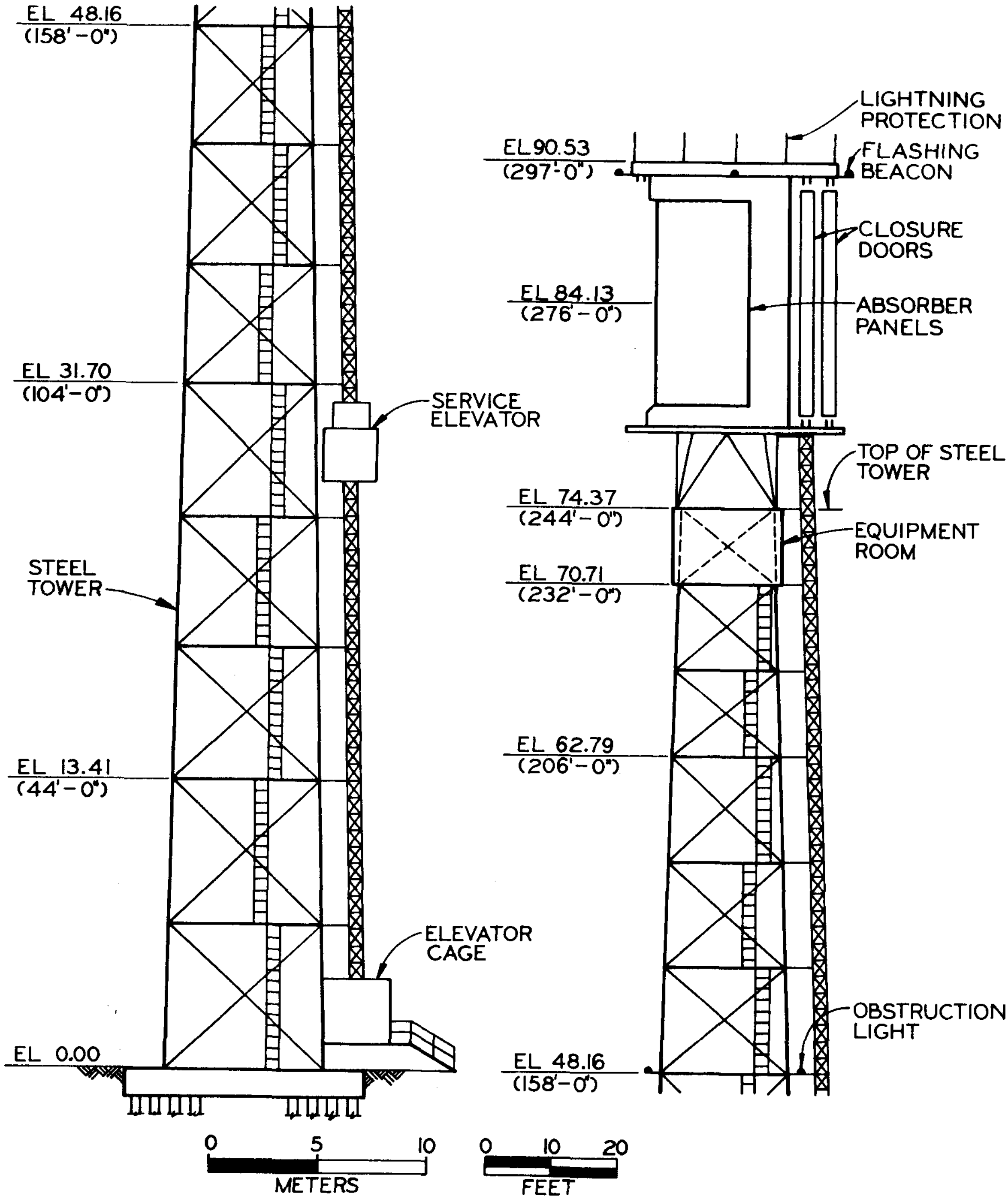


FIGURE 5.2-30 RECEIVER TOWER

gravity loads of the tower and receiver system, the effect of the design basis wind, and the effect of a UBC Seismic Zone I earthquake. Wind analysis is in accordance with the latest edition of ANSI A58.I. Seismic analysis is in accordance with the latest edition of the Uniform Building Code.

An Equipment Room is located in the top section of the tower. It is enclosed with insulated metal wall panels and a prefabricated metal floor deck. This room houses control panels, chemical feed, and other required equipment. A space heater and window unit air conditioner is provided for temperature control. A plan view of the Equipment Room is provided in Figure 5.2-31.

A 1,000 Kg (2,200 lb) capacity service elevator runs the full height outside the tower to provide access to the Equipment Room floor and roof. The elevator has two 0.76 m (30 in) wide doors. The inside door is used at the Equipment Roof floor and roof levels. Safety devices are provided to prevent operation of the elevator while doors are open, and to prevent opening of the outside door except when the elevator is stopped at the base of the tower. The elevator is used to transport personnel and small equipment and maintenance items. During construction, a temporary crane is used to lift major structural and equipment components to the top of the tower. As a backup to the elevator, a caged personnel ladder from grade to the Equipment Room floor will be provided. A personnel ladder also is provided from the Equipment Roof floor to the Equipment Room roof.

Piping is supported from the receiver tower structural steel (See Section 5.3.1). The main steam requires several expansion loops. Feedwater and drain pipes will not require as many loops.

Four flashing, high-intensity obstruction lights are provided near the top of the receiver. In addition, four constant burning obstruction lights are provided near mid-height of the tower. Conventional lighting is provided adjacent to the caged ladder and within the Equipment Room and elevator.

Tower lightning protection is provided and consists of air terminals spaced approximately 2.4 m (8 ft) apart on top of the receiver, two inter-

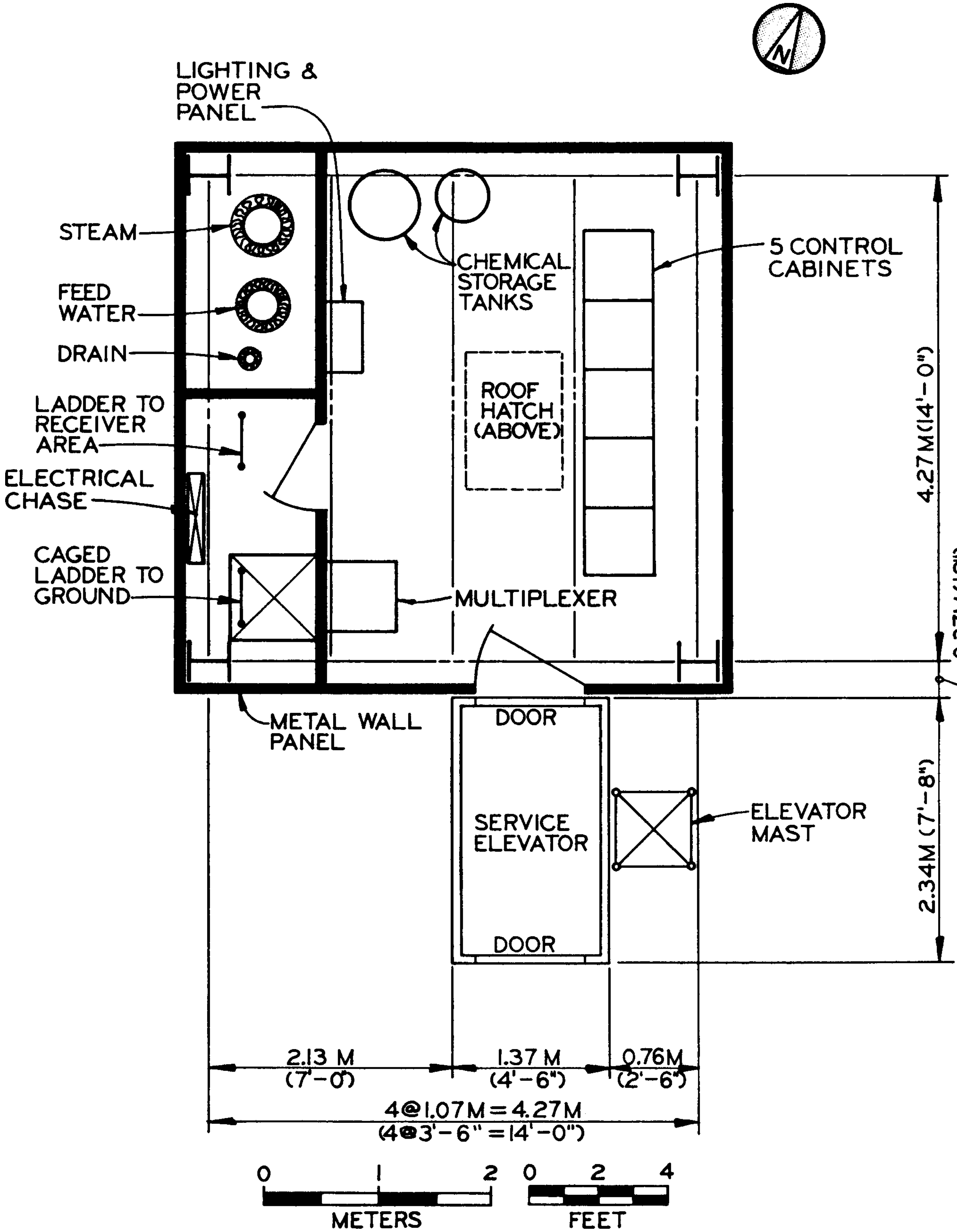


FIGURE 5.2-31 RECEIVER TOWER EQUIPMENT ROOM FLOOR PLAN

connected down connectors, and a below grade ground loop around the base of the tower.

5.2.3 Receiver System Cost Estimate

The total Receiver System cost (account number 5400), including the receiver and tower, is estimated to be $\$8.179 \times 10^6$ in July 1, 1980 dollars.

5.3 RECEIVER PIPING SYSTEM

The Receiver Piping System (RPS) provides the piping interface between the existing Electric Power Generating System (EPGS) and the Receiver System installed with the solar facility. The following sections describe the system, its major components, as well as the key design and operating characteristics.

5.3.1 General Description and Function

The RPS, shown schematically on Figure 5.3-1, satisfies the following four functional requirements.

(1) Transports feedwater from the EPGS to the solar receiver.

(2) Transports steam produced in the solar receiver to the EPGS.

(3) Recovers the condensate drains associated with warmup of the receiver main steam line and transports these back to the EPGS.

(4) Provides the capability to drain the solar receiver and to dispose of receiver blowdown required for water chemistry control.

The RPS delivers feedwater from the last high pressure feedwater heater in the EPGS to the solar receiver. To do this, the receiver feedwater booster pump is required to achieve the higher pressure associated with the solar receiver and RPS as compared to the existing steam generator; this higher pressure is due to the longer piping lengths, the elevation of the receiver, and the pressure drop through the receiver. The RPS feedwater piping interfaces with the EPGS feedwater system downstream of the final high pressure feedwater heater. The RPS feedwater piping interfaces with the Receiver System at the receiver economizer inlet connection and the attemperating spray connection. An interface exists with the EPGS condensate system at the condensate pump discharge piping which

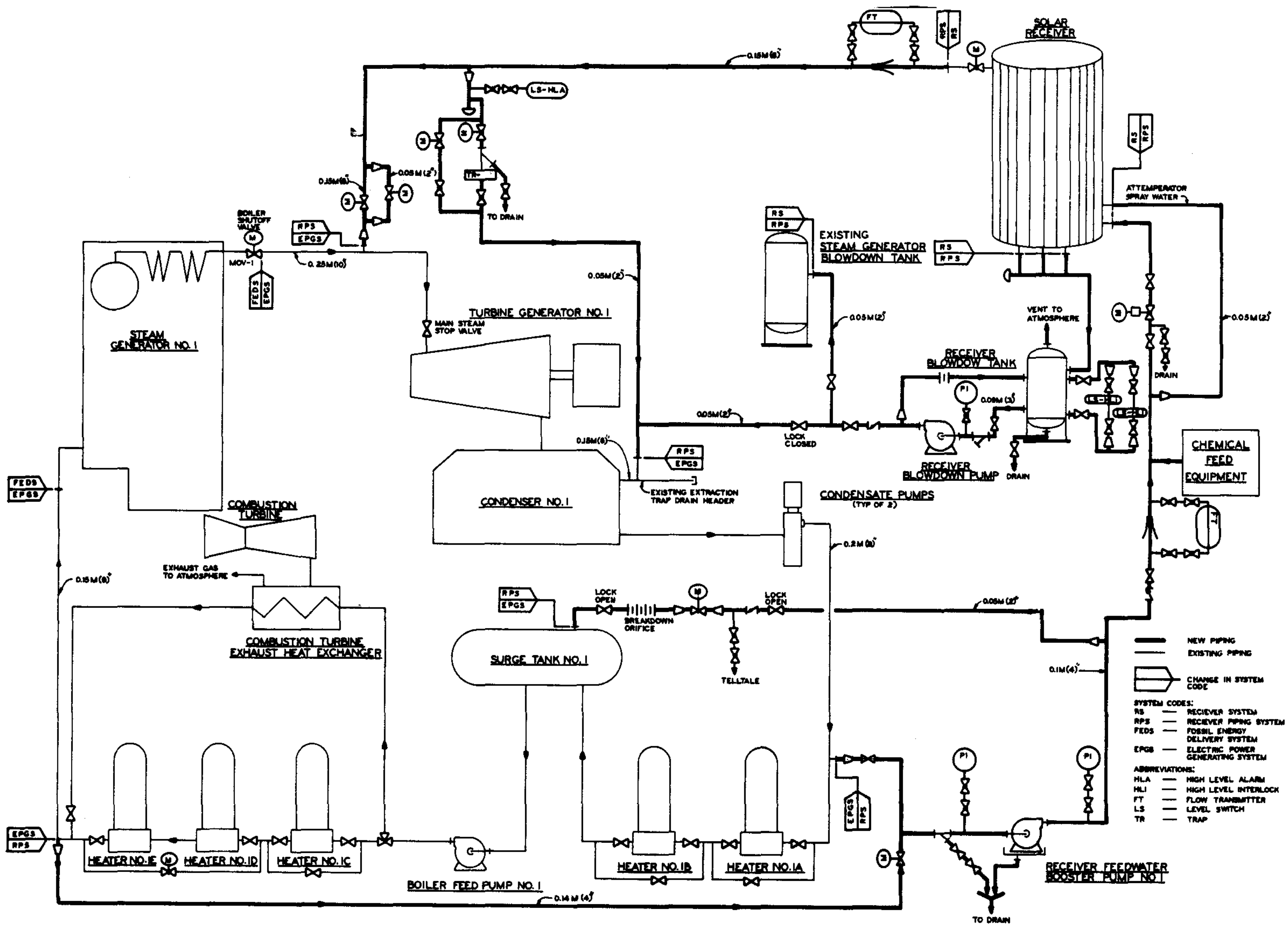


FIGURE 5.3-1. RECEIVER PIPING SYSTEM SCHEMATIC

provides a method of initially filling the receiver. A recirculation line to provide the minimum flow requirements for the receiver feedwater booster pump interfaces with the EPGS surge tank. The RPS also includes chemical feed additive equipment for chemical treatment of the solar receiver water.

The RPS transports high-pressure superheated steam produced in the solar receiver to the EPGS for delivery to the turbine. The RPS steam piping interfaces with the Receiver System at the receiver superheater outlet, after the receiver steam shutoff valve. The RPS steam piping interfaces with the EPGS at the connection to the existing main steam piping near the fossil steam generator.

In order to prohibit the potentially damaging introduction of water into the turbine, the RPS incorporates features to assure the draining of all collected condensate from main steam piping, prior to opening of the solar main steam stop valve. Provisions are in accordance with the turbine generator manufacturer's instructions, with consideration given to the significant lengths of piping involved. Water induction results from the accumulation of water in the steam piping that is inadvertently delivered to the turbine. The water accumulation may be due to condensate in steam piping, or water carry-over from attemperating sprays in the superheater caused by abnormal valve operation. Features incorporated to prevent the induction of water to the turbine include a steam piping isolation valve located near the EPGS interface and a steam pipe drain line located at the low point in the piping system where condensate would collect.

Any water in the steam line is drained to the existing fossil energy system through a trap located at the low point in the piping system. A motor operated valve in the bypass around each trap will open upon detection of water in the associated drip leg. This serves as a backup for removing excessive condensate from the steam line. The RPS drain lines interface with the EPGS at the extraction trap and drain header.

Blowdown for receiver water chemistry control is collected in the blowdown tank provided at the base of the receiver tower. The receiver blowdown tank is pumped to the EPGS blowdown tank for disposal. The receiver drains are also routed to the blowdown tank. During receiver warming operations, a method of recovering this water is provided by pumping from the receiver blowdown tank through a valve, which is normally locked closed, to the main condenser. The RPS drain piping interfaces with the Receiver System at the receiver drain connections.

5.3.2 <u>Major Equipment Description</u>

The major equipment associated with the Receiver Piping System includes the receiver feedwater booster pump, the receiver blowdown tank, the receiver blowdown pump, and the chemical feed equipment.

The receiver feedwater booster pump is a two-stage, motor-driven, direct-drive, vertical in-line pump with shaft seals capable of withstanding the high suction pressure. It has a capacity of 54,000 kg/h (119,000 lb/h). The normal operating water temperature is approximately 218 C (425 F).

The receiver blowdown tank is of all-welded carbon steel construction with an internal stainless steel wear plate at the blowdown connection. The tank is constructed in accordance with the requirements of Section VIII of the ASME Boiler and Pressure Vessel Code. The tank is vented to atmosphere and is drained by the receiver blowdown pump. The tank is 1.22 m (4 ft) in diameter and 1.83 m (6 ft) tall. The tank is sized for an adequate storage capacity in order to limit cycling of the receiver blowdown pump.

The receiver blowdown pump is a motor-driven, direct-drive pump. It is designed to pump saturated liquid at 100 C (212 F). The pump is sized at .095 m^3/min (25 gpm) with a head of 9.1 m (30 ft). With the blowdown tank level switches set at a 1.22 m (4 ft) spacing, the pump will drain the tank in approximately 15 minutes.

Chemical feed equipment will be required for the addition of chemicals to the receiver feedwater makeup to control receiver water chemistry. The equipment will include a chemical solution tank suitable for batch mixing, a chemical solution tank mixer, and a chemical feed pump. The chemical feed pump will be a diaphragm type pump rated to deliver approximately .0038 m^3/h (1 gph) at 15.1 MPa (2,190 psi) from the solution tank to the feedwater piping.

5.3.3 Piping and Valve Design Characteristics

The Receiver Piping System and valves will be designed in accordance with the ANSI Power Piping Code, B31.1. Main steam and feedwater pipe sizes were optimized as described in the steam conditions trade study. The insulation thickness was also optimized by considering the installed cost of the insulation and the heat loss cost.

The RPS main steam piping design conditions are based on the maximum expected sustained pressure at the piping inlet, plus a suitable margin as follows.

Design pressure	11.24 MPa (1,630 psia)
Design temperature	529 C (985 F)

The main steam pipe selected is as follows.

Material	ASTM A335 Grade P22 seamless 2-1/4 chrome, 1 per cent moly alloy steel
Size	0.15 m (6 in) piping Schedule 160
Insulation	0.15 m (6 in) thickness with bright metal jacketing
Length	481 m (1,580 ft)

The RPS feedwater piping design conditions are based on the maximum system pressure at feedwater receiver booster pump discharge plus a suitable margin as follows.

Design pressure	14.89 MPa (2,160 psia)
Design temperature	246 C (475 F)

The feedwater piping selected is as follows.

Material	ASTM A106 Grade B carbon steel
Size	0.10 m (4 in) piping Schedule 160
Insulation	0.08 m (3 in) thickness with bright metal jacketing
Length	443 m (1,455 ft)

The RPS condensate drain piping design is based on the maximum expected return water conditions as follows.

Design pressure	1.48 MPa (215 psia)
Design temperature	199 C (390 F)

The condensate piping size is selected from standard piping sizes with nominal wall thickness. The condensate piping selected is as follows.

Material	ASTM A106 Grade B carbon steel
Size	0.05 m (2 in) piping Schedule 80
Insulation	0.06 m (2-1/2 in) thickness with bright metal jacketing
Length	437 m (1,435 ft)

The length of the main steam, feedwater, and condensate piping includes expansion loops. These loops are required to accommodate the thermal growth resulting from warming of the pipes from ambient temperature to operating temperature conditions.

The valves included with the RPS meet the following code requirements. Valves for main steam service will be ANSI B16.34 Class 2500 with the body constructed of materials equivalent to ASTM A217 Grade WC9 (2-1/4 chrome, 1 per cent moly alloy steel). Valves for feedwater service will be ANSI B16.34 Class 1500 valves, with the body constructed of materials equivalent to ASTM A216 Grade WCB (carbon steel). Valves for condensate service will be ANSI B16.34 Class 150 for 0.06 m (2-1/2 in) and larger valves, and Class 600 for 0.05 m (2 in) and smaller valves; valve body materials will be equivalent to ASTM A216 Grade WCB (Carbon steel). All valves of size 0.06 m (2-1/2 in) and larger will have butt-welding ends, and all valves of size 0.05 m (2 in) and smaller will have socket welding ends.

5.3.4 Operating Characteristics

The RPS operation is based on the solar receiver operating mode. Under normal operation, feedwater is supplied to the solar receiver to maintain the proper drum level, and solar generated main steam is supplied from the solar receiver superheater outlet to the EPGS main steam piping. At normal operating pressure and temperature conditions, the accumulation of condensate at drain points in the RPS is not expected. The main steam piping drains will be closed under normal operation, except for emergency conditions. Receiver blowdown is initiated only when necessary to control receiver water chemistry. The receiver blowdown pump is started and stopped by level switches located on the blowdown tank instrument header.

The steam conditions at rated solar output (with turbine throttle pressure of 9.58 MPa (1,390 psia)) at the solar receiver superheater outlet and at the interface with the existing main steam piping are as required to match the existing turbine throttle steam conditions as follows. The heat loss and pressure drop through the RPS feedwater and steam lines are shown in Figure 5.3-2.

	Receiver System Interface	EPGS Interface
Flow Rate	54,331 kg/h (119,800 lb/h)	54,331 kg/h (119,800 lb/h)
Pressure	11.17 MPa (1,620 psia)	9.72 MPa (1,410 psia)
Temperature	520 C (968 F)	510 C (950 F)

The feedwater conditions at rated solar output at the solar receiver inlet and at the EPGS interface are as follows.

	EPGS Interface	Receiver System Interface
Feedwater Flow	54,331 kg/h (119,800 lb/h)	54,331 kg/h (119,800 lb/h)
Pressure	11.13 MPa (1,615 psia)	12.96 MPa (1,880 psia)
Temperature	247 C (477.2 F)	246 C (475.2 F)

The RPS provides feedwater to the receiver, and returns condensate from the receiver, for receiver warming before startup and for freeze protection during shutdown operation in winter months. After completion of pre-warming by feedwater recirculation, the main steam piping provides steam from the EPGS for final warming as required by the receiver manufacturer.

During shutdown and start-up operation, condensate collected in the receiver superheater is drained to the receiver blowdown tank. The receiver blowdown tank is drained by the receiver blowdown pump. Pump

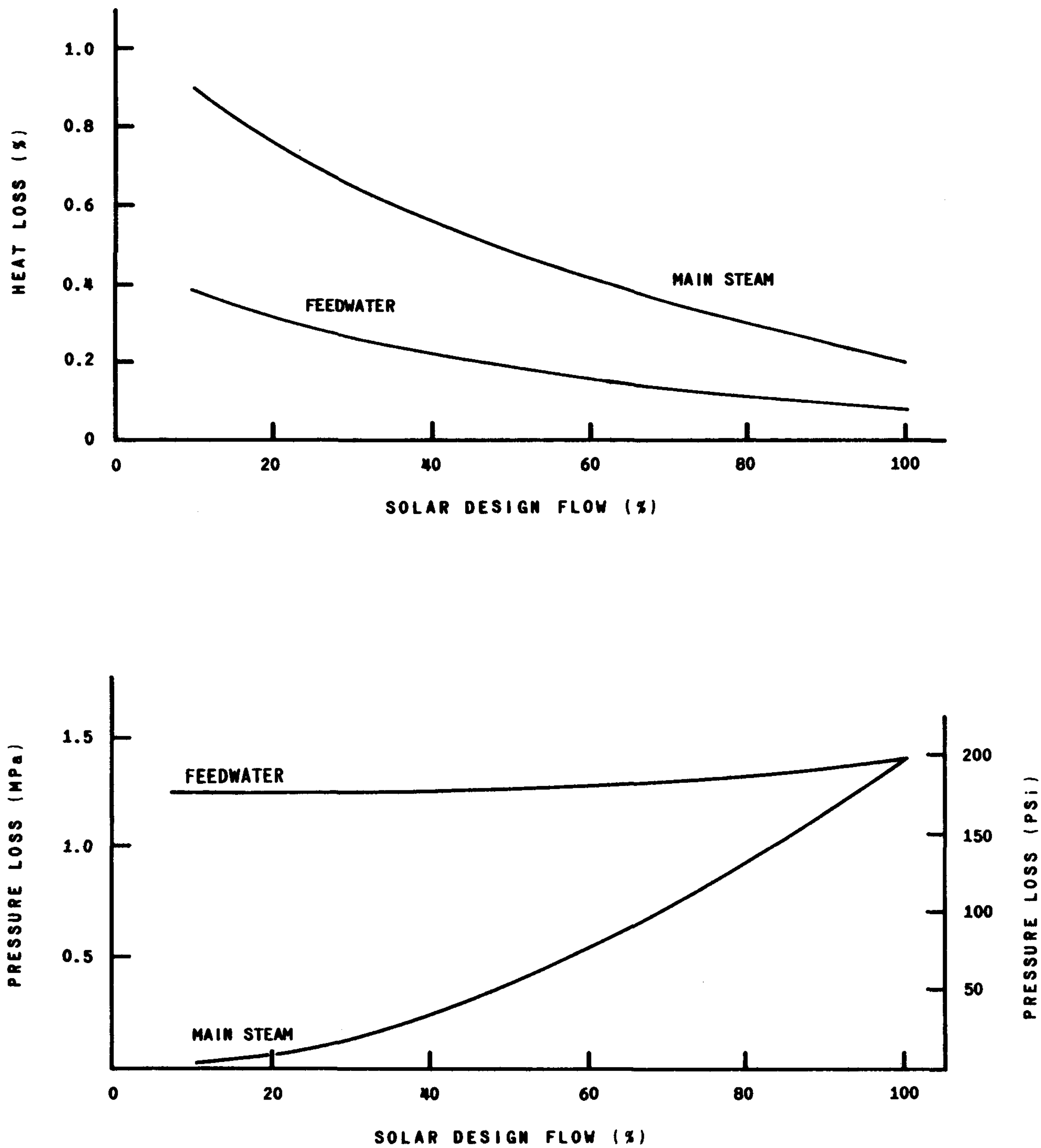


FIGURE 5.3-2 RECEIVER PIPING SYSTEM PRESSURE DROP AND HEAT LOSSES

operation is initiated by level switches located on the receiver blowdown tank. Condensate collected in the main steam piping is drained through a trap to the condenser.

5.3.5 Receiver Piping System Cost Estimate

The total Receiver Piping System cost (account number 5900) is estimated to be $\$1.366 \times 10^6$ in July 1, 1980 dollars.

5.4 SOLAR MASTER CONTROL SYSTEM

The Solar Master Control System (SMCS) coordinates the operations of the collector, receiver, receiver piping and solar auxiliary power systems to ensure safe and proper operation of the entire integrated cogeneration plant. The SMCS also receives appropriate status and data input information from the existing plant control systems. The SMCS operates at the highest level in the control hierarchy as shown on Figure 5.4-1. The SMCS issues commands to the control systems at the lower level of this hierarchy and receives feedback status information from these control systems. The SMCS provides the capability for automatic start-up, normal operation, and shutdown of the collector, receiver, and receiver piping systems. The SMCS also issues emergency shutdown commands.

This system also serves as a centralized data acquisition system which monitors, analyzes, and displays all critical solar system and subsystem parameters.

5.4.1 Major Components

The Solar Master Control System consists of a control computer, a data acquisition computer, computer peripheral equipment, control and display consoles, interface equipment to the other process systems, and all software required for a fully operational system.

The hardware configuration of the SMCS is shown in Figure 5.4-2. The key elements of the SMCS are a control computer, a data acquisition computer, and a control panel. The computers are supported by a complete set of peripherals for program loading and editing, for display of operating parameters to the operator, and for storage of data for offsite analysis. The computers are located in an area adjacent to the main control room.

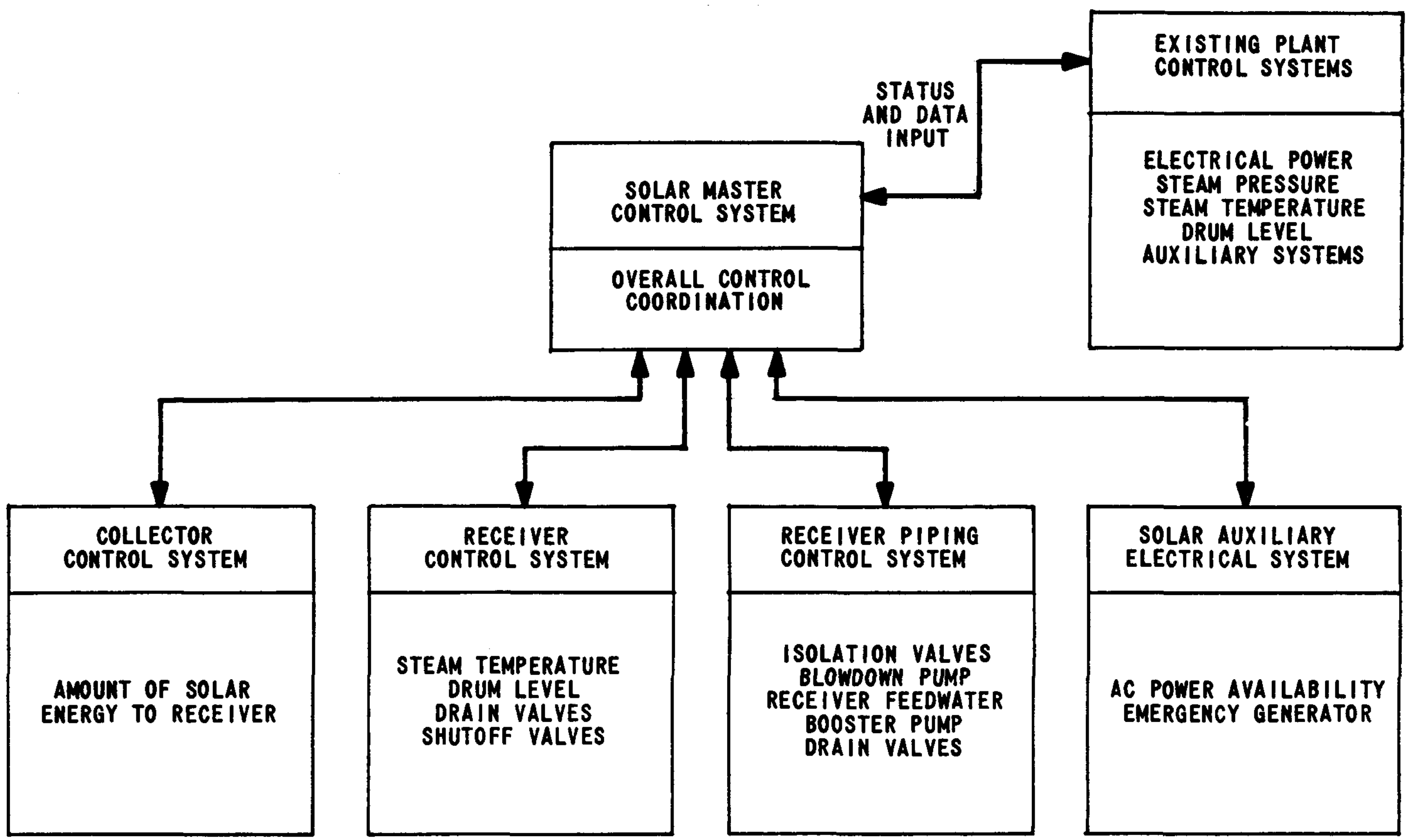


FIGURE 5.4-1. CONTROL SYSTEM HIERARCHY

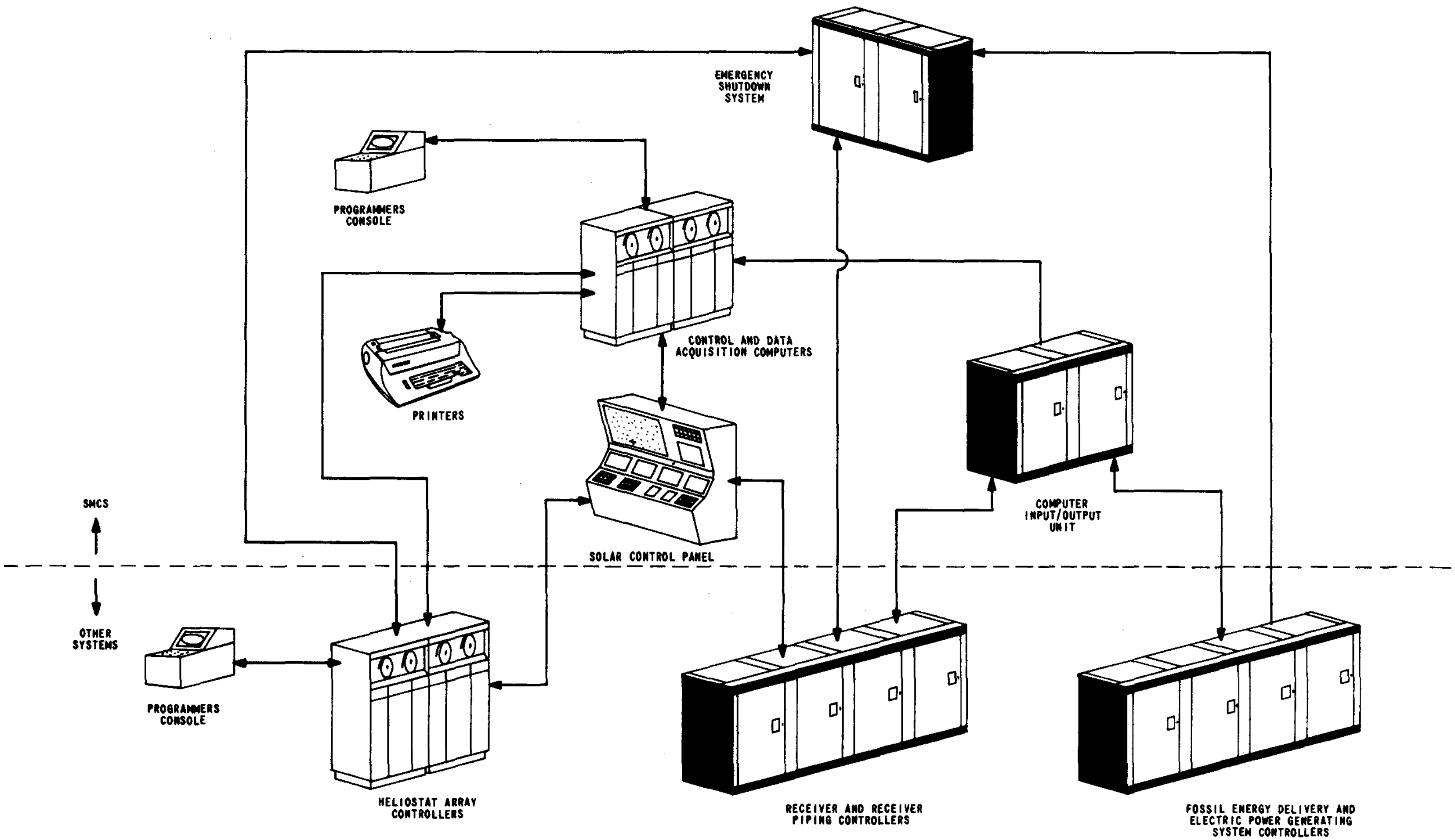


FIGURE 5.4-2. SOLAR MASTER CONTROL SYSTEM

Remote multiplexing equipment is located in the receiver tower to interface with the receiver transmitting and control devices. The SMCS control panel, located in the main control room, contains all displays and manual controls needed to operate the solar equipment. This panel is shown in Figure 5.4-3 as it would appear in the Cimarron River Station control room.

The SMCS is comprised of the following major hardware components.

5.4.1.1 Solar Control Panel. The control panel is a standup bench front panel which contains all solar equipment information displays and controls. The panel includes a 0.9 m by 1.5 m (3 ft by 5 ft) graphic display subpanel which indicates, at a glance, the operational status of each heliostat. This panel is estimated to be 3 m (10 ft) wide, 2 m (7 ft) high, and 1.2 m (4 ft) deep.

5.4.1.2 Control Computer. The control computer utilizes a microprogrammed 16-bit microprocessor with 64 K words of high speed random access working memory. This computer is programmed by using a high level process control language.

5.4.1.3 Data Acquisition Computer. The data acquisition computer is microprocessor based and has 24 bit word capacity. It has a main memory capacity of 64 K words and an auxiliary memory capacity of up to 13.8 million words of large core memory and moving head disc storage.

5.4.1.4 Emergency Shutdown System. The emergency shutdown system is a hardwired relay cabinet with power supplies.

5.4.1.5 Computer Input/Output System. The input/output system uses remote multiplexing stations in the receiver tower and a high speed (l million bits per second) digital data highway for communication between the control and data acquisition computers and the receiver and receiver piping systems. Asynchronous serial binary (EIA* RS-232C) ports are provided with the control and data acquisition computers and the heliostat array controllers for communications with the collector system.

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*Electronic Industries Association.

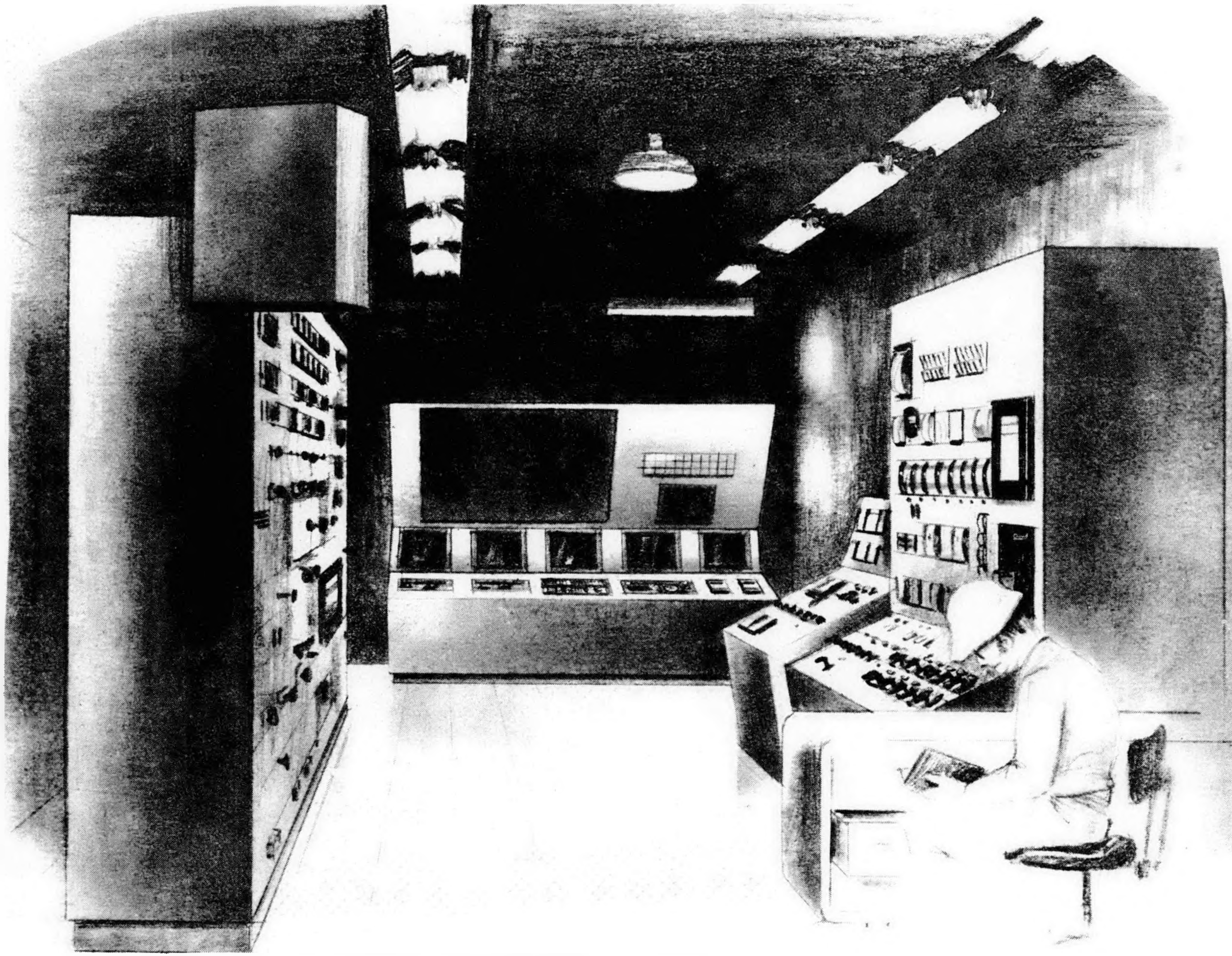

FIGURE 5.4-3. CONTROL ROOM ARTIST RENDERING

5.4.1.6 Programming Consoles. Consoles with a cathode ray tube (CRT) and keyboard are provided for interrogating and modifying the computer software.

5.4.1.7 Magnetic Tape Unit. An IBM compatible nine-track tape unit is provided for program entry and long-term data storage for offsite analysis.

5.4.1.8 Cathode Ray Tubes and Keyboards. Color CRT terminals with alphanumeric and graphic characters are provided on the control panel for operational data displays. The CRT's use a EIA RS-232-C compatible interface at serial rates up to 9600 BAUD*. Each CRT is accompanied by an alphanumeric keyboard and function push buttons for interactive display selection and modification.

5.4.1.9 Printers. Printers with 120 characters per second printing speed and 136-column print are provided for hardcopy documentation. Each printer is complete with pedestal and enclosure.

5.4.2 Functional Control Requirements

The SMCS coordinates the independent controls of the other systems as shown on Figure 5.4-1 to maximize the amount of electrical output produced from the solar energy while operating within the limitations of the operating equipment. The major control functions of the SMCS are as follows.

- Automated start-up of the solar facility.
- Coordination of the collector and receiver during solar operation.
- Automated shutdown of the solar facility.
- Automated emergency shutdown of the solar facility.

5.4.2.1 Automated Start-up. Because of the relatively large number of control actions necessary during the start-up of the solar facility, and because the facility is to be operated by a single operator who will also have additional non-solar responsibilities, it is necessary to automate the solar facility start-up and minimize the required operator actions.

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*Contraction for Baudot. Normally used to describe transmission speed in bits per minute.

The automated start-up program controls all solar equipment. This program is quite comprehensive in order to safely start the equipment during a large variation in available solar insolation conditions. The complexity is equivalent to automatic turbine start-up programs which are routinely used in many new power plants. The start-up program for a normal diurnal start-up consists of several phases as follows.

- Prestart Phase. All solar equipment and systems controls are checked to determine that they are in the proper configuration for start-up (all steam lines drained of condensate, all controls on automatic, all heliostats respond to standby commands, etc.).
- Receiver Warm-up Phase. The receiver drum water temperature is slowly increased at a rate not to exceed 4.4 C (8 F) per minute up to 327 C (620 F). The water warm-up is begun by circulating heated feedwater or steam from the Electric Power Generating System (EPGS) through the receiver. When the temperature rises above 116 C (240 F) the warm-up is then provided by the injection of EPGS steam into the receiver water.
- Steam Generation Phase. The receiver closure doors are opened. The mirrors are rapidly focused on the receiver in a predetermined sequence. As the receiver warms, the steam pressure and temperature rise. When the pressure equals the existing EPGS pressure, the receiver shutoff valve is opened and solar generated steam is delivered to the EPGS.

A mid-day start-up sequence is slightly more complicated since a significantly greater amount of solar energy is available. During the Steam Generation Phase, mirrors are sequenced on target more slowly to prevent excessive receiver heatup.

This start-up sequence is automated to the extent that the required operator participation is limited to push-button initiation of each of these phases. The SMCS keeps the operator appraised of the status of the start-up through CRT messages on the control panel. The operator is able to interrupt the automated sequence at any point and complete the start-up manually.

5.4.2.2 Coordination of Collector and Receiver Systems. The main coordination objective is the prevention of excessive temperature conditions in the receiver panels while maintaining the largest possible number of heliostats on target.

The coordination requirements of the SMCS are minimal during solar operation. This is due to the receiver design and the incorporation of receiver steam temperatures controls in the receiver system which will maintain the proper temperatures during all normal operation conditions. The SMCS operates to focus all available heliostats on the receiver to maximize the solar insolation. Should an abnormal condition arise in which the receiver controls are unable to maintain temperatures below critical limits in the receiver panels, the SMCS automatically defocuses heliostats, according to a predetermined sequence, to reduce the solar insolation to a point that the receiver controls are again able to control temperatures. When the abnormal condition has passed, the SMCS automatically refocuses all heliostats.

5.4.2.3 Automated Shutdown. An automated shutdown is required for the same reasons that an automated start-up is required. The shutdown program safely shuts down the solar equipment and places all equipment into an overnight storage condition. The shutdown program for a normal shutdown consists of the following phases.

- Shutdown Phase. All heliostats are placed in the standby position. When the steam flow from the solar receiver drops to zero, the receiver shutoff is closed, the receiver feedwater booster pump is stopped, and the receiver piping system isolation valves are closed. The receiver closure doors are closed.
- Storage Phase. All heliostats are commanded to their stow positions. All receiver panel bias valves are closed to minimize heat loss from the receiver during shutdown.

As in the automated start-up program, the operator participation is limited to the push-button initiation of each phase. Manual intervention at any point in the shutdown sequence is possible.

5.4.2.4 Automated Emergency Shutdown. The SMCS monitors critical solar equipment parameters and operating conditions of all critical plant equipment. Upon detection of any abnormal condition which would compromise the safety of personnel or integrity of equipment, the SMCS triggers an emergency shutdown of the solar facility. The shutdown consists of the following actions done in parallel.

- Command all heliostats to the stow position.
- Close the receiver shutoff valve.
- Open all receiver superheater and steamline drain valves.
- Close the receiver piping system steam isolation valve.
- Start-up of the emergency diesel generator (loss of heliostat power only).

The main objectives of this emergency shutdown are to immediately remove all input energy from the system and prevent any possibility of water induction into the turbine.

This emergency shutdown system functions independently of all other elements in the SMCS to ensure a safe shutdown.

The conditions that automatically trigger an emergency shutdown are as follows.

- High receiver drum water level.
- Low receiver drum water level.
- Turbine trip.
- Fossil boiler trip.
- Loss of normal electrical power to heliostat drive motors.
- Loss of one of the two redundant sources of uninterruptible control power.

The plant operators may also trigger an emergency shutdown from the main control room or the receiver tower.

5.4.2.5 Control Logic. The functional control requirements of the SMCS described in the preceding articles, require control logic which is predominantly discrete (boolean) in nature. This control logic, with the exception of the emergency shutdown logic which is hardwired, is programmed in software in the control computer. An example of the type of logic that is used is shown in Figure 5.4-4. The example in this figure is an excerpt from the automatic start-up program in the SMCS. All control logic will be documented in this format. The control computer is directly programmed from these diagrams by using a specialized high-level computer control language.

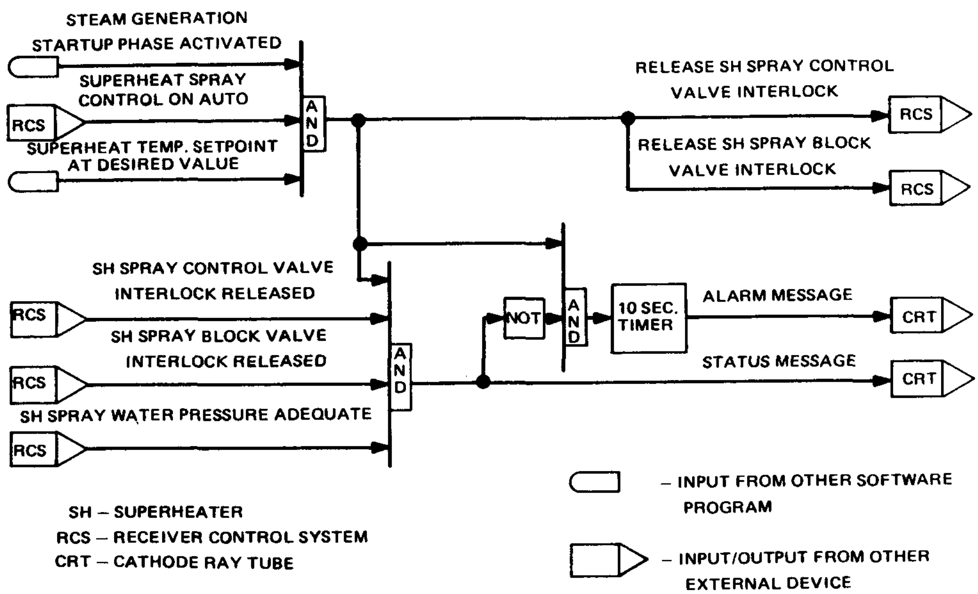

FIGURE 5.4-4 AUTOMATIC START-UP LOGIC DIAGRAM

5.4.3 Functional Data Acquisition Requirements

The SMCS includes the facility to acquire plant data, analyze this data, display performance data to the operator, and store data for future detailed analysis.

- Data Acquisition. The SMCS scans plant input data at individual point scan rates of from once a second to once every 30 seconds. The SMCS stores the most current value of each input for further analysis and/or display. The estimated input counts are as follows.

Measurement	Quantity
Temperatures	150
Pressures	20
Flow rates	10
Valve positions	50
Water levels	5
Control valve positions	15
Miscellaneous discrete status inputs (level siwtches, breaker positions)	50
Heliostat status	1,057

- Data Analysis. The SMCS performs real-time data processing on all inputs. This processing consists of conversion to engineering units, detection of bad or unreasonable data, data averaging, and other required processing. The SMCS also performs periodic performance calculations to determine unit and equipment performance.
- Data Display. The SMCS displays operational data to the plant operator. The displays are updated at least once every 2 seconds.
- Data Storage. The SMCS includes long-term data storage capabilities. Both raw input data and computation results are stored on magnetic media for offsite analysis.

5.4.4 Design Considerations

The design considerations presented below include the criteria which guided the design process, interfaces with other plant systems, and the use of redundancy to ensure high availability and plant safety.

5.4.4.1 Design Criteria. The SMCS equipment must meet the following design criteria.

- Reliability. The SMCS must have an availability of over 99.5 per cent. The availability is achieved through the use of simple designs, proven highly reliable components, and redundant elements whenever it is cost effective.

- Flexibility. The SMCS shall have the capabilities to modify control strategies easily at the plant site without extensive hardware or wiring changes.
- Cost Effectiveness. The SMCS will use commercially available equipment throughout. All equipment will be generically similar throughout the SMCS. The equipment configuration will minimize cabling costs by using remote multiplexing techniques.
- Ease of Maintenance. All equipment will be easily maintainable by normal power plant personnel. The equipment configuration will consist of generically similar equipment, wherever practical, for ease of maintenance.
- Ease of Operation. All control panel displays must be readable from a distance of 3 m (10 ft). All manual controls will be arranged to allow all operations by a single plant operator.
- Operating Environment. All equipment shall be capable of continuous operation over an ambient temperature range of 4 C to 32 C (40 F to 90 F) and a relative humidity of 5 per cent to 95 per cent. Electrical power for the SMCS is from the solar auxiliary electric system uninterruptible power supply.
- Expandibility. The computer system will have the capability of adding at least 25 per cent additional memory for future expansion. The central processing units will allow for a 25 per cent spare duty cycle under worst case loading conditions and 40 per cent spare duty cycle under normal loading conditions to accommodate future expansion.

5.4.4.2 Interface Requirements. The SMCS communicates with all other solar facility systems. These communications take the form of control commands from the SMCS to the other systems and status information from the other systems to the SMCS.

The interface between the SMCS and the collector system consists of digital data transmission links between the SMCS computers and the heliostat array controllers. Typical communication signals between the two systems are shown on Figure 5.4-5. The heliostat array controllers will have a pair of CRT's on the SMCS control panel. These CRT's can be used to collect information and issue manual commands to the collector system in the event of a SMCS computer failure.

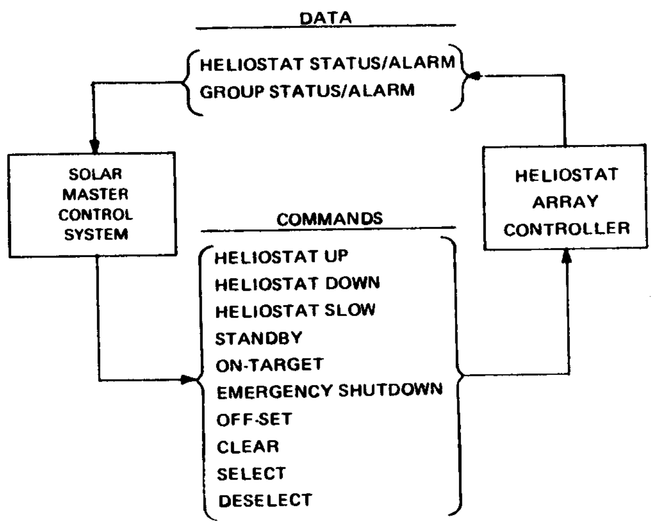

FIGURE 5.4-5 SMCS/COLLECTOR CONTROL COMMUNICATIONS

The interface between the SMCS and the receiver system and between the SMCS and the receiver piping system consists of signal cables between the SMCS computers and the control cabinets located in the equipment room of the receiver tower. Typical communications signals between the systems are shown on Figures 5.4-6 and 5.4-7. The Receiver control system will have a pair of CRT's on the SMCS control panel. These CRT's provide manual control capability for the receiver and receiver piping systems in the event of a SMCS computer failure.

The interface between the SMCS and the existing plant control systems consists of signal cables between the SMCS data acquisition computer and the turbine and fossil boiler control systems. Typical communication signals between these systems are shown in Figure 5.4-8.

The interface between the SMCS and the solar auxiliary electric system consists of signal cables to the emergency shutdown system for

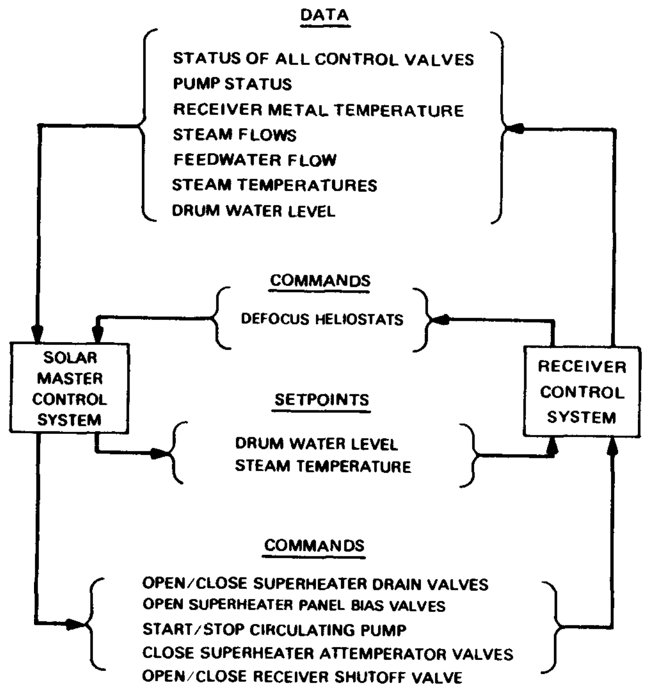

FIGURE 5.4-6 SMCS/RECEIVER CONTROL COMMUNICATIONS

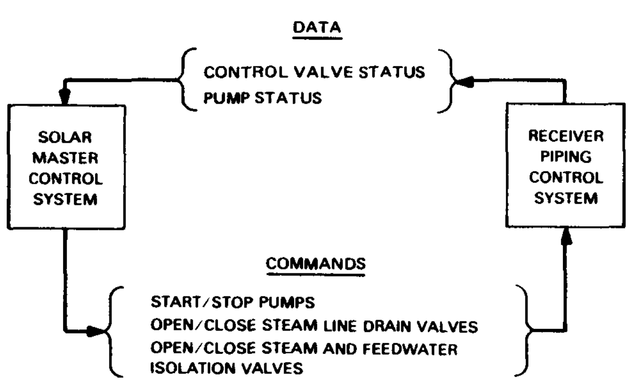

FIGURE 5.4-7 SMCS/RECEIVER PIPING CONTROL COMMUNICATIONS

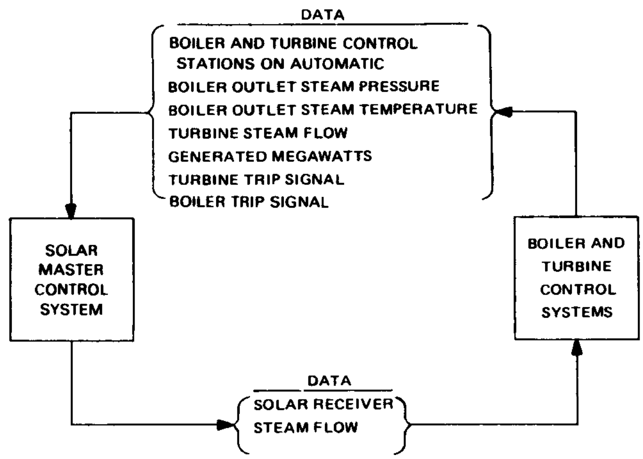

FIGURE 5.4-8 SMCS/EXISTING PLANT CONTROL COMMUNICATIONS

sensing a loss of power and signal cables between the SMCS computers and the emergency diesel generator controls. Typical communication signals between these systems are shown in Figure 5.4-9.

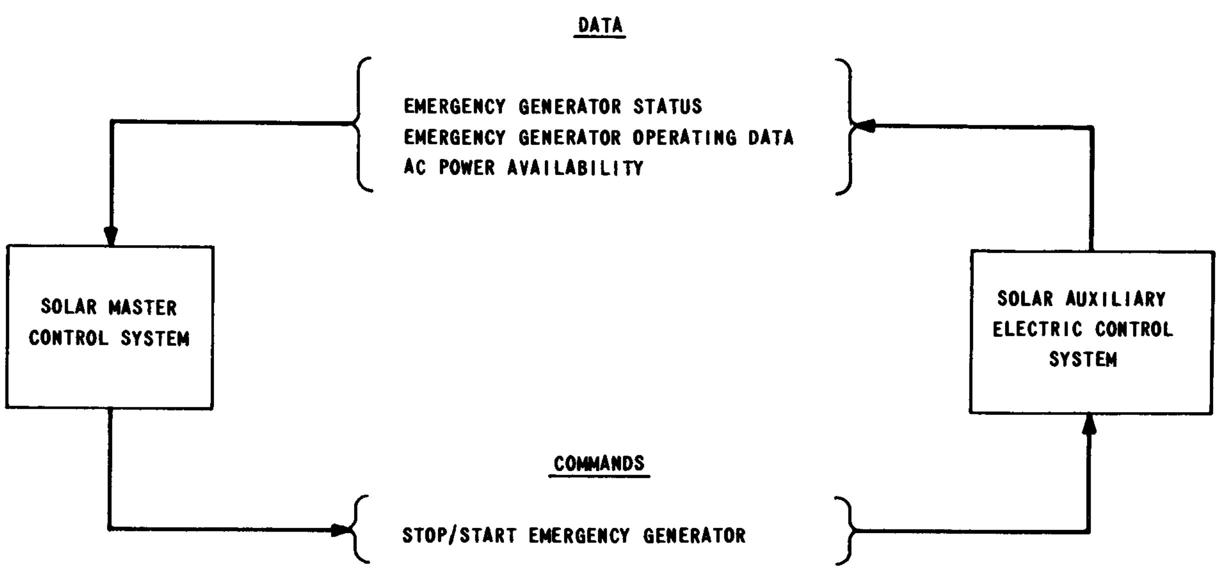

FIGURE 5.4-9 SMCS/SOLAR AUXILIARY ELECTRIC CONTROL COMMUNICATIONS

5.4.4.3 Equipment Redundancy. Equipment redundancy is used where cost effective to achieve high control system availability and to insure that a safe shutdown will occur during emergency conditions.

Equipment Availability--The computer control equipment used in the SMCS has a very high availability. As reported in the IEEE Power Plant Computer Reliability Survey of 1978, equipment of this type has availability of over 99.5 per cent. Because of this high availability, the expense of providing redundant equipment, and the fact that the other systems can be operated manually during a SMCS failure, no redundancy is planned for the SMCS computers. The multiplexed data communication links to the receiver and collector systems however, are redundant because of the vulnerability of these links and the low cost of this redundancy.

Emergency Shutdown System--Because of the need to insure a safe equipment shutdown during emergency conditions, a separate independent Emergency Shutdown System is incorporated into the SMCS. This system is generically different from the control computer in order to reduce the probability of common mode failures. The Emergency Shutdown System incorporates redundancy in the form of multiple sensing elements and logic circuits.

5.4.5 Solar Master Control System Cost Estimate

The total solar master control system cost (account number 5500) is estimated to be $\$2.676 \times 10^6$ in July 1, 1980 dollars.

5.5 SOLAR AUXILIARY ELECTRIC SYSTEM

The Solar Auxiliary Electric System provides electrical power to all solar plant auxiliary loads. The auxiliary loads are defined as electrical loads required by the various equipment during shutdown, start-up, and the operating modes of the solar plant.

Two categories of electrical power are required: normal plant ac power and uninterruptible ac power. Normal ac power is used to supply power to collector, receiver and receiver piping system electrical loads, as well as miscellaneous electrical loads such as lighting, heating, ventilation and air conditioning. Uninterruptible ac power is used to supply power to the solar master control system computers and other critical control and intrumentation, where an interruption of power for even a few cycles cannot be tolerated.

5.5.1 Solar Plant Normal AC Power

As shown in Figure 5.5-1, the source of the normal plant ac will be from the existing medium voltage (4,160 volt, 3 phase) auxiliary power bus 1A of Unit 1. The existing auxiliary bus IA has two sources of power. The normal source is the 13,800 volt generator bus stepped down to 4,160 volt by the Main Auxiliary Transformer. The second source of power is the reserve source which is fed from a 13,800 volt switchgear which in turn receives power from the Western Power system grid. A Reserve Auxiliary Transformer transforms 13,800 volt to 4,160 volt reserve power. These redundant sources and selectivity on the 13,800 volt and 4,160 volt switchgear buses provide a high degree of service reliability.

The power from existing switchgear bus 1A will be distributed by a 5 kV solid di-electric cable to the 4.16 kV solar switchgear located in the Solar Auxiliaries Building near the base of the receiver tower. From the solar switchgear, 4,160 volt power is distributed and transformed to lower voltages, as required for the most economic distribution.

Since the heliostats cover a wide area, primary power distribution in the heliostat field is made by feeder circuits at 4,160 volts to reduce line loses. Several low-profile, pad-mounted transformers are sited in the collector field as close to the center of loads as possible. Secondary ditribution of power to each heliostat is made at either 120 or 208 volts, as required by the specific heliostat.

In the event of a total blackout of the plant ac, an emergency power supply is required to slew heliostats away from the receiver as quickly as possible to prevent damage to the receiver. This emergency power is completely independent of the plant auxiliary power sources and will be supplied by a fast-start diesel generator unit to be located in the Solar Auxiliaries Building.

Low voltage power at 480 volts is distributed by two motor control centers. Motor control center S-1 is located in the existing plant and receives power from the existing load center unit substation, bus 1A. Motor control center S-2 is located in the Solar Auxiliaries Building and receives its power from a pad-mounted transformer to be located outside

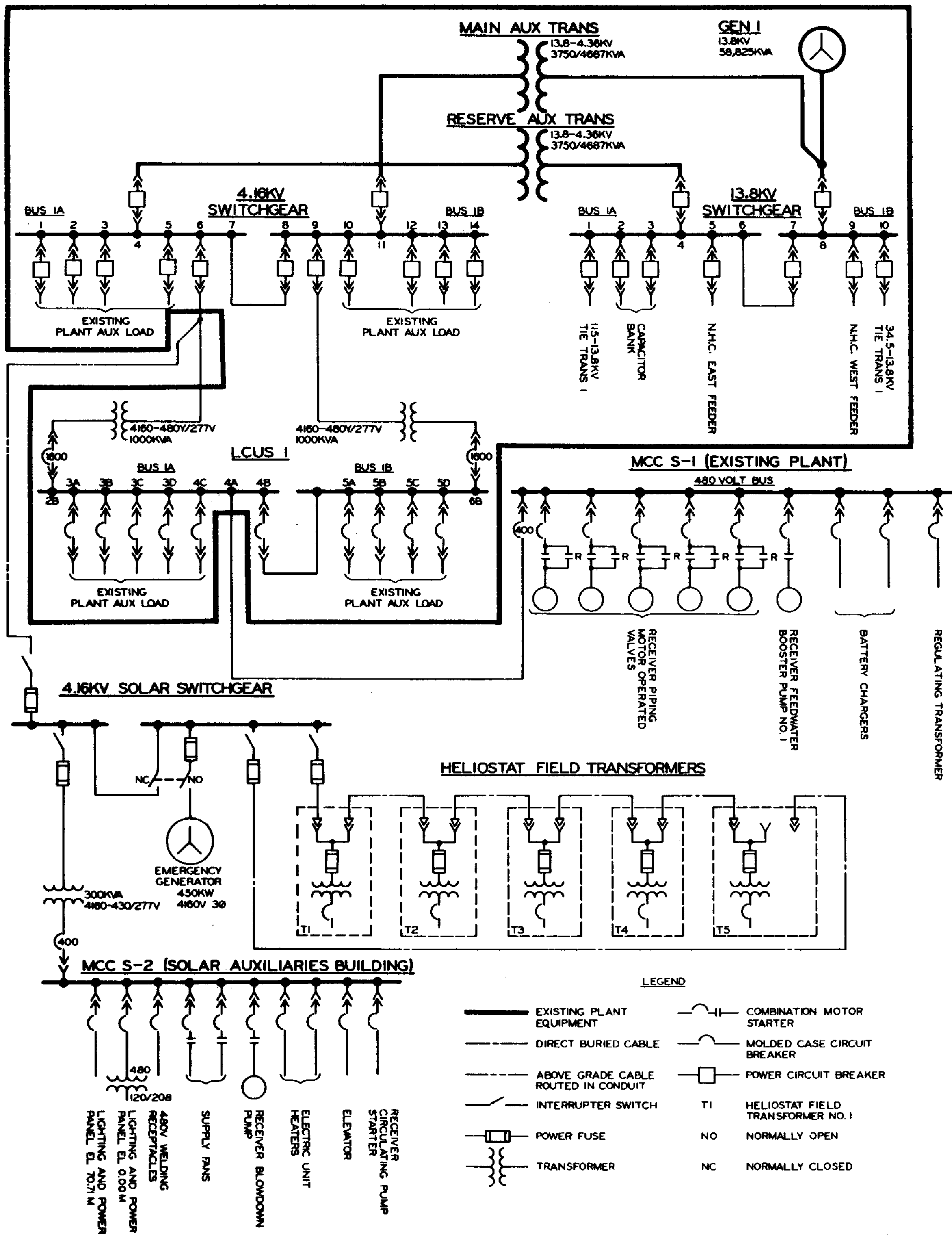

FIGURE 5.5-1 SOLAR FACILITY NORMAL AC POWER SUPPLY ONE LINE DIAGRAM

the Solar Auxiliaries Building. The primary of this transformer is connected by a feeder circuit to the 4,160 volt solar switchgear. Normally all motors 200 horsepower and below and all motor-operated valves are supplied with 480 volt power.

A 480/277 volt lighting and power panel are located in the equipment room of the receiver tower to distribute small 480 volt, three phase loads and 277 volt, single phase lighting loads in the receiver tower.

All lighting, receptacle, and other small loads requiring 120 volt, single-phase power are supplied by an indoor dry type transformer and a 120/208 volt lighting and power distribution panel.

5.5.2 Solar Plant Uninterruptible AC Power

The source of uninterruptible ac power supply comes from two full-capacity, redundant static inverters, as shown in Figure 5.5-2. Under normal operating conditions, each inverter is supplying about half of the

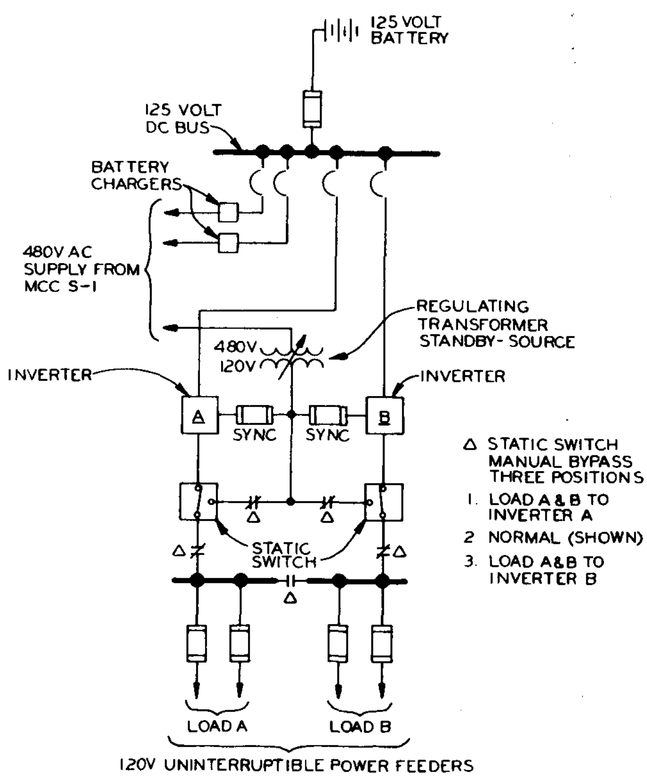

FIGURE 5.5-2 SOLAR FACILITY UNINTERRUPTIBLE AC POWER SUPPLY

total uninterruptible ac power at 120 volts. In the event of an inverter component failure, a static switch transfers the inverter load within 1/4 of a cycle to the regulated standby ac supply from motor control center S-1. When the inverter supply is restored, the static switch automatically transfers the load back to normal status. A manual bypass switch is provided to transfer the load of one inverter to the other inverter. Thus, any one inverter can be taken out of service for maintenance purposes without power interruption to the load.

A dc input to the inverters is provided by a 125 volt battery and two full-capacity, redundant battery chargers. The battery chargers are powered from motor control center S-1. Normally the dc output of the battery chargers provides power for the inverters and the battery is floating. In the event of a loss of ac power to the chargers, the battery is able to supply power to the inverters for at least one hour without reducing the inverter load.

The uninterruptible ac power system equipment is located in the existing power plant.

5.5.3 Solar Auxiliary Electrical System Cost Estimate

The total solar auxiliary electrical system cost (account number 5700) is estimated to be $\$7.09 \times 10^5$ in July 1, 1980 dollars.

5.6 EXISTING FACILITY MODIFICATIONS

Minor modifications to the existing facility are needed to accommodate the new solar equipment. These modifications fall into the following two categories.

(1) Modifications to existing control systems.

(2) Modifications to existing power plant systems.

5.6.1 Modifications to Existing Control Systems

The modifications to the existing control systems are required to permit a variable steam pressure operating strategy which is necessary to maintain boiler outlet steam at rated temperature during low load operation. These modifications are for the existing turbine control system and boiler control system. The required control logic additions are shown on Figure 5.6-1. This drawing shows that the electrical load demand for the unit is set either from the automatic load dispatch system or from a unit master control station at the plant. A variable throttle steam pressure setpoint is calculated as a function of the load demand. This pressure setpoint is sent to the existing boiler control system. The boiler control system adjusts the boiler, firing rate to maintain this desired steam pressure. The operator is able to select either full pressure or variable pressure operation. Provisions are included for automatic load control during full pressure operation by automatic adjustment of the turbine valve. These control system changes provide the capability for automatic operation at the desired turbine inlet steam pressure over the entire unit load range. The modifications allow operation of the boiler down to steam flows as low as 45,000 kg/h (100,000 lb/h).

5.6.2 Modifications to Existing Power Plant Systems

Slight modifications to the existing power plant systems are required in order to integrate the solar facility with the existing station. A connection to the existing service water system is made to provide seal water cooling for the receiver feedwater booster pump. Other modifications include Receiver Piping System connections to the existing feedwater and main steam lines, to the surge tank for receiver feedwater booster pump recirculation flow, and to the miscellaneous equipment drains system. A hose connection is added to the existing demineralized water system to provide a means to fill the heliostat washing vehicle.

5.6.3 Existing Facility Modifications Cost Estimate

The total cost of modifications to existing facilities (account number 5800) is estimated to be $67,000 in July 1, 1980 dollars.

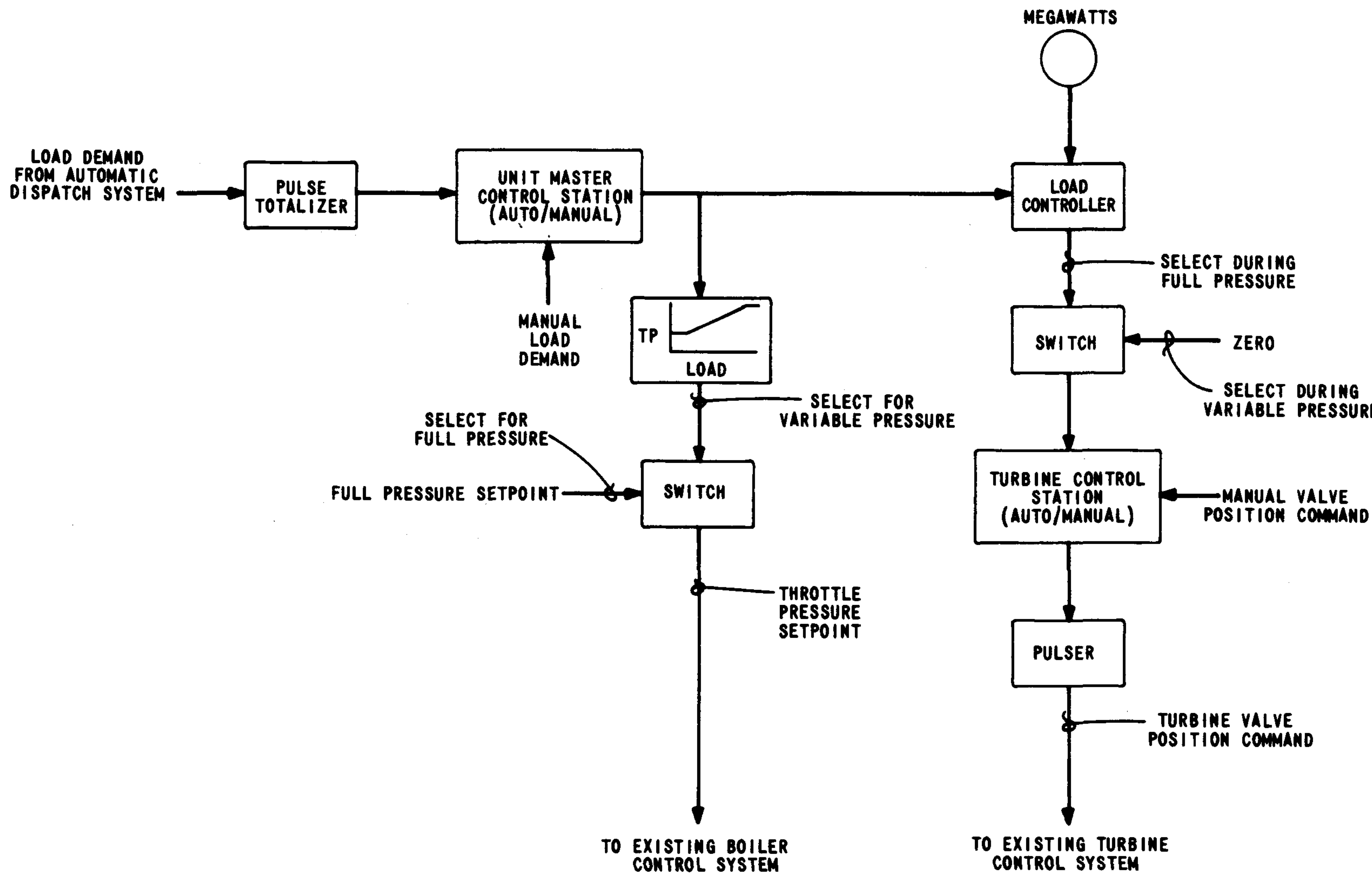

FIGURE 5.6-1. CONTROL SYSTEM MODIFICATION LOGIC DIAGRAM

6.0 ECONOMIC ANALYSIS

A primary consideration in the economic evaluation of the solar repowering of CRS is the determination of the value it could provide to Western Power. The value was determined in the context of the Western Power operating system, including the effect of deferring capacity to meet the system spinning reserve requirement because of the extension of the useful life for CRS. Computer simulations of the Western Power System were used to develop valid estimates of the value.

The system characteristics, performance, and costs, described in the previous section, are the basis for the economic analysis described herein. This section begins with a discussion of the methods and assumptions used in the economic analysis. This is followed by a discussion of the simulation models used to evaluate the performance of the solar addition to CRS. The section ends with a discussion of the value to Western Power of the CRS solar addition.

6.1 METHODOLOGY

The methodology used to determine the value to Western Power of the solar facility addition was based on estimating the impact that the facility would have on system revenue requirements. The economic analysis was performed by analyzing two system operation and expansion schedules. The base schedule was the no-solar plan and included the retirement of CRS in January of 1994. The second plan included the solar facility addition to CRS and an extension of the CRS lifetime to the year 2000, with CRS Unit 1 modified in 1994 to allow for cyclic operation.

The long-term operation of National Helium Corporation (NHC) is dependent on gas industry economics and the future availability of natural gas feedstocks. Since there is considerable uncertainty with regard to both factors, the solar and no-solar plans were evaluated under the following two cases: (1) CRS operating as a cogeneration facility, with CRS supplying process steam and electricity to NHC; (2) CRS operating solely as an electric generating facility, without CRS supplying process steam and electricity to NHC.

The economic evaluation methodology is illustrated in Figure 6.1-1. The various steps in the process are briefly discussed in the succeeding paragraphs of this section.

6.1.1 Solar Plant Evaluation Methodology

The performance of the solar facility was determined using the Black & Veatch computer code, Solar Thermal Electric Plant Performance Evaluator (STEPPE). STEPPE simulates the solar repowered plant by modeling the performance of each system (collector, receiver, receiver piping, fossil energy delivery, and electric power generation systems) described in the conceptual design of Section 5; program inputs include insolation data and system loads. The program includes the capability to model such features as hybrid systems, reheat cycles, thermal deficits due to diurnal and cloud-caused shutdowns, and grid demand. STEPPE was used to provide daily performance characteristics which were subsequently used to evaluate the solar plant's annual performance. Details of the performance simulation are given in Subsection 6.3.1.

6.1.2 Western Power System Evaluation Methodology

The value of repowering CRS was calculated based on the differential revenue requirements for the Western Power system with and without the solar facility addition.

Elements of the methodology are described below.

- System Expansion Plans. Two reference expansion schedules were used. The first was a base Western Power schedule which assumes CRS I, with its 60 MWe of capacity, would be retired in January 1994. The second was the same schedule, but assumes that the solar repowering would extend the economic life of CRS I until the year 2000. The expansion plans were developed from the 1985 system capacity mix shown in Table 6-1. The two expansion plans are shown in Tables 6-2 and 6-3, respectively.

  The expansion plans were modified under the No-NHC case by reducing purchases after 1993 to reflect the loss of NHC electrical load in the Western Power system.

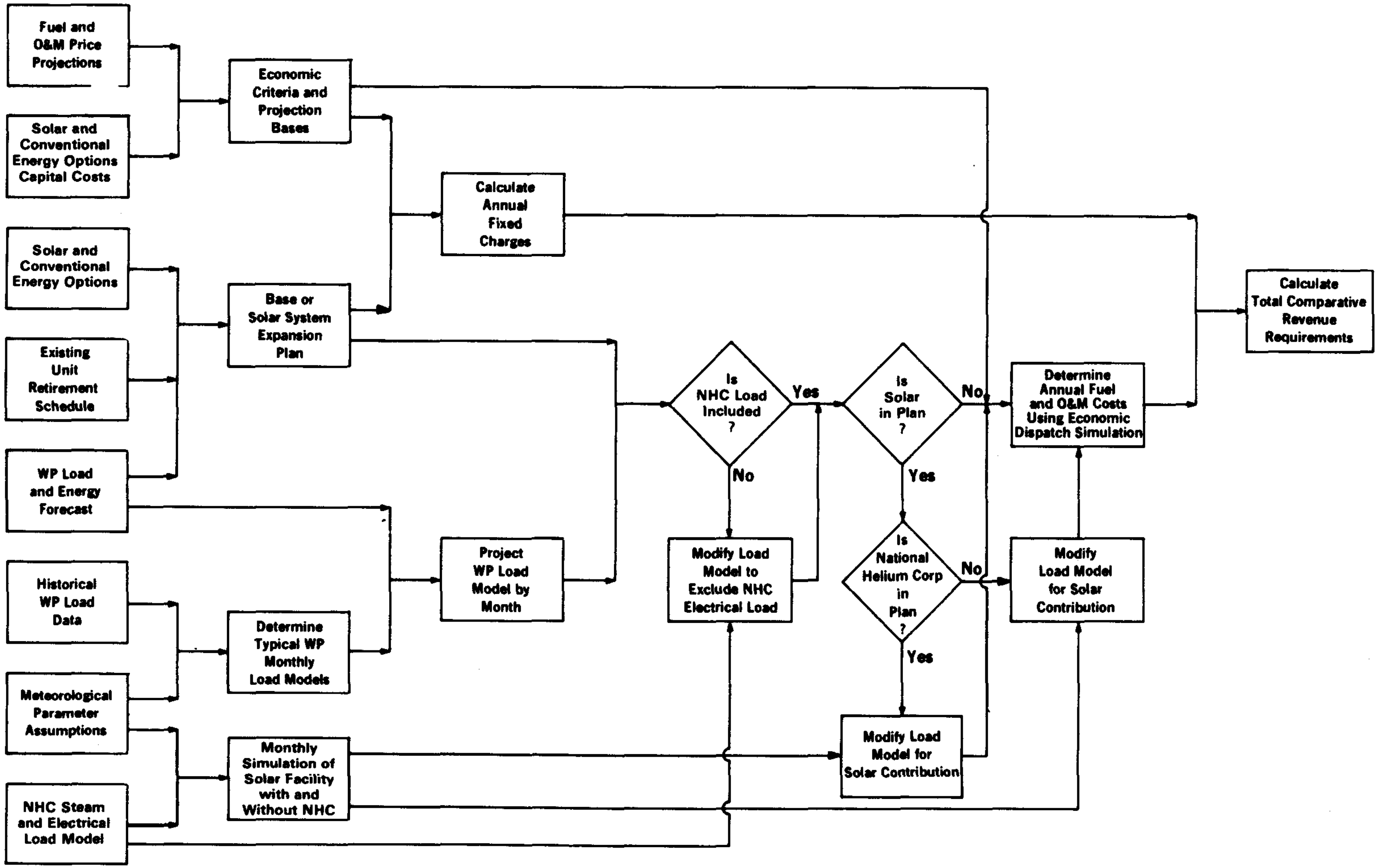

FIGURE 6.1-1. ECONOMIC ANALYSIS METHODOLOGY

TABLE 6-1. SUMMARY OF WESTERN POWER SYSTEM INSTALLED CAPACITY IN 1985

Station	Unit	Capacity* (MW)	Primary Fuel
Arthur Mullergren	2	18	Gas
	3	93	Gas
Cimarron River	1	60	Gas
	2	14	Gas
Clifton	1	70	No. 2 Fuel Oil
	2	3	No. 2 Fuel Oil
Jeffrey Energy Center	1	54	Coal
	2	54	Coal
	3	54	Coal
	4	54	Coal
Judson Large	3	18	Gas
	4	143	Gas
Total		635	

*Capacity is summer season net unit capacity.

TABLE 6-2. WESTERN POWER SYSTEM BASE EXPANSION PLAN: NO SOLAR FACILITY ADDITION AT CIMARRON RIVER STATION

Year	System Peak (MW)	System Responsibility (MW)	Retirements (MW)	Additions (MW)	Installed Capacity (MW)	Capacity Purchases* (MW)	System Capacity Total (MW)	System Capacity Coal Share (%)
1986	445	512	18 (AM-2)		617	130	747	46
1987	463	532			617	130	747	46
1988	482	554	18 (JL-3)		599	130	729	47
1989	502	577			599	130	729	47
1990	522	600			599	130	729	47
1991	541	622			599	130	729	47
1992	561	645			599	130	729	47
1993	581	668		115 (Share-1)	714	0	714	46
1994	602	692	167 (CR-1,2;AM-3)	60 (CT-1,2)	607	85	692	60
1995	624	718			607	111	718	62
1996	646	743		175 (Share-2)	782	0	782	65
1997	669	769			782	0	782	65
1998	693	797			782	15	797	65
1999	717	825	70 (CL-l)		712	113	825	75
2000	742	853			712	141	853	76

*Capacity purchases are for coal fueled capacity; the 130 MW purchase, 1986 through 1992, is currently contracted.

KEY: AM = Arthur Mullergren Station
CL = Clifton Station
CR = Cimarron River Station
JL = Judson Large Station
Share = Share of a new coal fueled unit
CT = Combustion Gas Turbine

TABLE 6-3. WESTERN POWER SYSTEM SOLAR EXPANSION PLAN: SOLAR FACILITY ADDITION AT CIMARRON RIVER STATION

Year	System Peak (MW)	System Responsibility (MW)	Retirements (MW)	Additions (MW)	Installed Capacity (MW)	Capacity Purchases* (MW)	System Capacity Total (MW)	System Capacity Coal Share (%)
1986	445	512	18 (AM-2)	Solar Facility**	617	130	747	46
1987	463	532			617	130	747	46
1988	482	554	18 (JL-3)		599	130	729	47
1989	502	577			599	130	729	47
1990	522	600			599	130	729	47
1991	541	622			599	130	729	47
1992	561	645			599	130	729	47
1993	581	668		115 (Share-1)	714	0	714	46
1994	602	692	107 (CR-2;AM-3)	CRS Cycling Modifications**	607	85	692	60
1995	624	718			607	111	718	62
1996	646	743		175 (Share-2)	782	0	782	65
1997	669	769			782	0	782	65
1998	693	797			782	15	797	65
1999	717	825	70 (CL-I)		712	113	825	75
2000	742	853			712	141	853	76

*Capacity purchases are for coal fueled capacity; the 130 MW purchase, 1986 through 1992, is currently contracted.

**No increase in system installed capacity associated with solar facility addition.

KEY:
- AM = Arthur Mullergren Station
- CL = Clifton Station
- CR = Cimarron River Station
- JL = Judson Large Station
- Share = Share of a new coal fueled unit

- Capital Cost Calculation. Appropriate capital costs were calculated for the unit additions under both expansion plans. The projected costs of capital plant expansion are shown in Table 6-4.
- Western Power System Production Costs Determination. Annual power production costs were calculated for the Western Power system by the use of Black & Veatch's economic dispatch, system simulation program. Table 6-4 summarizes the fuel price projections used in the dispatch program. The program is discussed further in Section 6.3.2.
- Comparative Revenue Requirements. Comparative revenue requirements consist of the sum of the annual production costs and the annual fixed charges on new plant additions, including return on capital investment. Annual return on investment includes proper accounting for tax effects (the tax deductible nature of interest as well as the allowed investment tax credit) and depreciation. For each year of each plan, the total annual revenue requirements and the discounted annual revenue requirements are calculated. The comparison of the cumulative discounted revenue requirements for the two plans indicates the economic value of one plan compared to another plan over the planning period.

  The fixed charges and discount rates as well as other key economic parameters used to calculate the comparative reveune requirements are summarized in Table 6-4. The several fixed charged rates used in this analysis reflect the various economic lifetimes of the different capital investments.
- Value Determination. The value of the solar facility to Western Power is defined as the cost that can be incurred in addition to the system fuel and O&M costs without increasing the 15-year cumulative revenue requirements, as determined by the base (no solar) plan. This can be calculated by adding (1) the cumulative discounted savings from capital investments under the solar

TABLE 6-4. ECONOMIC EVALUATION PARAMETERS

CAPITAL COST PROJECTIONS

Capital Plant Addition	Millions of Dollars
Solar Facility Addition to CRS (1/1/86 In-Service)	47.4
115 MW Share of New 670 MW Coal Unit (1/1/93 In-Service)	204.6
Two 30 MW Combustion Gas Turbines (1/1/94 In-Service)	48.3
CRS Cycling Modifications (1/1/94 In-Service)	1.6
175 MW Share of New 670 MW Coal Unit (1/1/96 In-Service)	381.5

FUEL COST PROJECTIONS

Fuel	1980 Cost ($/MBtu)	Escalation Rate (Per Cent)
Natural Gas	1.86	----
1981	----	14.5
1982	----	13.4
1983-1990	----	12.0
1991-2000	----	11.0
Coal	1.10	----
1981	----	12.2
1982	----	10.7
1983	----	10.1
1984-1985	----	10.0
1986-1990	----	9.0
1991-1995	----	8.0
1996-2000	----	7.0

TABLE 6-4 (Continued). ECONOMIC EVALUATION PARAMETERS

FINANCIAL PARAMETERS

Factor	Per Cent
Discount Rate	13.45
Investment Tax Credit	11.0
AFUDC Rate	13.0
Property Tax Rate	1.45
Insurance Rate	0.22
General Inflation Rate	
1981	10.2
1982	8.7
1983-1990	8.0
1991-2000	7.0
Combined Federal and State	
Income Tax Rate	49.645
Fixed Charge Rate	
Solar	17.50
Combustion Turbine	16.27
Pulverized Coal	15.43
CRS Cycling Modifications	24.60

plan minus the solar facility investment cost*, and (2) the system's cumulative discounted fuel and O&M cost savings under the solar expansion plan. This total savings is the 15-year cumulative discounted annual cost that could be incurred by Western Power for the solar facility and, when divided by the cumulative discounted investment cost of the solar facility, provides a measure of the share of the solar facility cost that Western Power could incur.

- Sensitivity Analyses. The sensitivity of the results to economic factors was evaluated. Specifically, the sensitivity of the value--expressed as a share of total installation cost--was tested for system fuel costs and economic life of the solar facility.
- Incentives Analysis. An extension of the sensitivity analysis methodology allowed for development of a measure of the impact on value to Western Power from lowering the cost of the solar facility by reductions in the cost of key solar components. These reductions could come about by any of several possible incentives, such as, tax credits to manufacturers or government funded R&D.

6.2 ASSUMPTIONS

The development of the economic analysis was based on a number of assumptions. Assumptions necessary for the solar plant performance model and those necessary for the system economic evaluation are given in the next subsections.

6.2.1 Solar Model Assumptions

Several assumptions and approximations were made in modeling the repowered system with the B&V computer code, STEPPE. The major assumptions and approximations, along with assessment of their associated impacts, are listed below.

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*Investment costs include required return on investment, taxes and insurance in addition to construction and owner's costs.

- Insolation data input was based on the ASHRAE Clear Air Model, modified by monthly percentage sunshine data so as to include the effects of cloud cover. The resultant average daily direct normal insolation (6.1 kWh/m^2 day) is in close agreement with available insolation data.
- "Annual" performance was extrapolated from predictions for 12 representative days (one each month). Experience with STEPPE has shown that this approach gives results which are identical (typically to three significant figures) to those for 365-day modeling with STEPPE when the clear air insolation model is being used.
- As a result of using the clear air model, no mid-day receiver start-ups were modeled. This assumption causes a slight over-estimation of annual energy production.
- No solar system shutdowns due to extreme weather conditions (e.g., high winds or extremely low temperatures) were modeled, on the assumption that they were sufficiently infrequent to be unimportant.

6.2.2 Economic Evaluation Assumptions

The assumptions for economic evaluation include financial and economic parameters, fuel costs, and capital costs. Table 6-4 shows these assumed bases.

6.3 SIMULATION MODELS

Two simulation models were used. One simulated the characteristics of the solar repowered unit; the other modeled the dispatch and the operating costs of the Western Power system.

6.3.1 Solar Plant and System Simulation Model.

Performance modeling of the solar repowered plant was conducted using the Black & Veatch computer code STEPPE. STEPPE predicts plant performance by integrating power traces computed at discrete time points to provide a daily or annual energy trace through the plant.

The logic flow for STEPPE is shown in Figure 6.3-1. At each time point (each 15 minutes in the study reported here), the power flow is traced through the plant (e.g., power to the receiver, power from the receiver, and power to the turbine). At the end of each day, and following the last day of the run, the power trace is integrated to give the aggregate energy traces over the modeled period. Modeling capabilities include the following.

- Weather data from an appropriate tape or an artificial model. In this project, an artificial model was used for dry bulb temperature, based on 30-year normal daily minimum, average, and maximum temperatures for Dodge City, Kansas.*
- Insolation data from a weather tape, or the ASHRAE Clear Air Model. In the repowering project, the ASHRAE model was used, and results were modified to include the effects of cloudy days using per cent sunshine data for Dodge City.*
- Heliostat field efficiency as a function of sun aximuth and elevation. Data used were computed by the Black & Veatch central receiver system optical codes.
- Receiver efficient/loss data as a function of input power and dry bulb temperature. Data were provided by B&W based on their solar receiver design.
- Receiver start-up energy, including fossil steam preheating, with heat capacities, losses, and temperature ramp rates.
- Solar main steam piping losses and heat-up requirements. Data based on the receiver loop system conceptual design were used.
- Fossil energy system characteristics (e.g., turbine heat rate versus power generated, fossil steam generator efficiency).
- Existing plant auxiliary power requirements modified to include solar auxiliary power.

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*Normals based on the 1941-1970 period, "Local Climatological Data, 1978, Dodge City, Kansas," National Climatic Center, Ashville, NC.

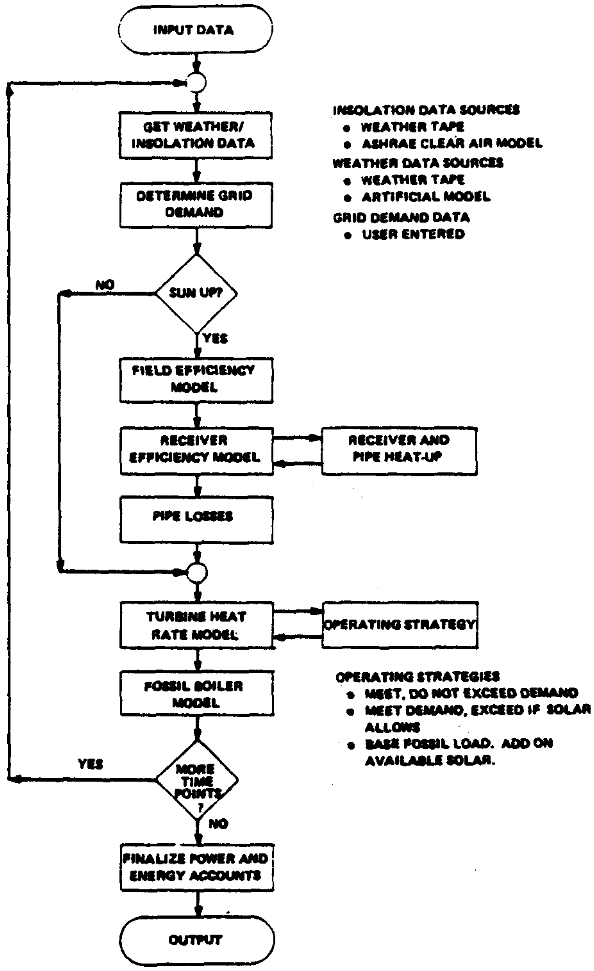

FIGURE 6.3-1. STEPPE PROGRAM LOGIC FOR FOSSIL HYBRID SYSTEM

STEPPE also has the capability to model thermal storage and a solar reheater, neither of which were utilized in this project.

The ASHRAE insolation model and artificial weather model were utilized in the absence of a weather tape (SOLMET or Typical Meteorological Year) giving direct normal insolation for the Dodge City area. For annual data, STEPPE was run for 12 representative days (rather than 365 days) based on previous experience which indicates a highly comparable accuracy (less than 1 per cent difference) when the ASHRAE insolation model and artificial weather model are used.

Five types of plant operating strategies, not all of which are appropriate to CRS, can be modeled using STEPPE. These are described briefly below.

- Load dispatch demand, with a hybrid fossil system. Meet, but do not exceed the user-entered net electrical demand while utilizing as much solar energy as is possible. Defocus any solar energy greater than the user level specified.
- Sunfollowing with a hybrid fossil system. Meet the user-entered minimum net electrical demand with a combination of solar and fossil energy; if excess solar energy is available, exceed the user-entered electrical demand.
- Sunfollowing, with a base fossil load. Use all solar energy available. The total output is the sum of the fossil and the solar contributions.
- Sunfollowing, with thermal storage. Generate as much electricity as possible, using solar and/or storage, at each time point.
- Load dispatch demand, with thermal storage. Meet, but do not exceed the user-entered net electrical demand if solar and/or storage can provide the necessary power.

The user-entered demands in the above strategies are specified on an hourly basis, giving the capability to model a wide range of load profiles.

Plant Operation Strategies modeled for the solar cogeneration utilized STEPPE Strategies I and 3 listed above.

6.3.2 Western Power System Simulation

Annual production costs were estimated through the use of a computerized mathematical model that simulates Western Power system operation. The production costs include fuel costs, operating and maintenance (O&M) costs, and power purchase costs. The Black & Veatch economic dispatch, system simulation computer program is the basic tool used by Black & Veatch for planning studies and fuel budgeting.

The production cost computer program utilizes as its basis the principle of economic dispatch. A detailed description of this principle is beyond the scope of this document; the subject is discussed in a number of references. (See, for example, Leon K. Kirchmayer, Economic Operation of Power Systems, John Wiley & Sons, Inc., 1958.) The essence of optimum allocation of load among a number of generating units is achieved by dispatching each unit so that all units operate at the point of equal incremental costs. This principle is routinely applied in actual power system operating practice as well as in planning investigations.

The economic dispatch incremental cost principle, as expressed in mathematical terms, is translated into a computer code algorithm. Constraints are applied to this optimization algorithm in order to reflect normal utility system operation. The opportunities for mathematically true, least cost dispatch are modified because of planned and unscheduled unit outages, reliability considerations, unit start-up limitations, system stability requirements, and similar factors. The program can, thus, be characterized as a constrained (optimum) economic dispatch.

The program requires three principal inputs in order to perform the optimization.

- Load Models. Monthly load models were specified for each year. The monthly load models were developed from historical system load data and were selected based on weather parameter assumptions used in the STEPPE simulations.
- Generating Unit Operating and Cost Parameters. For each unit which is available during the planning period, unit heat rate data, minimum and maximum loadings, forced outage rates, maintenance schedules, fuel and O&M base year costs, and annual escalation rates are required.
- Specific Load and Energy Data. For each month, the projected peak load and load factor are computed. The total peak load generation required includes loads to satisfy system losses and any external purchase or sales requirements. Units are dispatched against this generation curve for each month in a probabilistic manner.

The determination of Western Power system production costs with solar incorporates the same methods and computer code used for more typical investigations. However, the unique technical and economic characteristics of the solar facility require special modeling, so that the heat rate and output power of the hybrid unit are properly adjusted to reflect the solar input. When a solar unit is to be simulated, the load model must reflect both the time variation in system load and also the time variation in the output of the solar unit.

To represent this time-varying capacity in the computer code, the projected real time load models for each month were adjusted hourly to account for the CRS solar facility output, which was corrected for per cent sunshine. This adjustment assumes that whenever sunlight is available, the solar facility will be dispatched. The resulting real time load model was then used as input to the economic dispatch program. Figures 6.3-2 and 6.3-3 illustrate the effect of adjusting the peak day load model for a peak month and an off-peak month to account for the solar facility output. It should be noted with respect to the dispatch illustrations, Figures 6.3-2 and 6.3-3, that beginning in 1994 the minimum CRS load level becomes zero due to the assumed modifications to allow cyclic operation. Under the base plan, CRS is retired in 1994.

6.4 RESULTS AND CONCLUSIONS

The results of the economic analysis, and the conclusions reached about the economic value of the repowered unit to Western Power are contained in Sections 6.4.1, 6.4.2, and 6.4.3, respectively.

6.4.1 Economic Factors

The results of the economic analysis are presented in terms of fixed charges and production costs, comparative revenue requirements, and the value of the solar facility to Western Power.

6.4.1.1 Annual Production Costs. Two plans were established and evaluated to calculate the annual change in production costs both with and without the NHC steam and electrical loads. These two cases bracket the possibilities with regard to the long term plans for operation of the NHC facility. The two cases are delineated as follows.

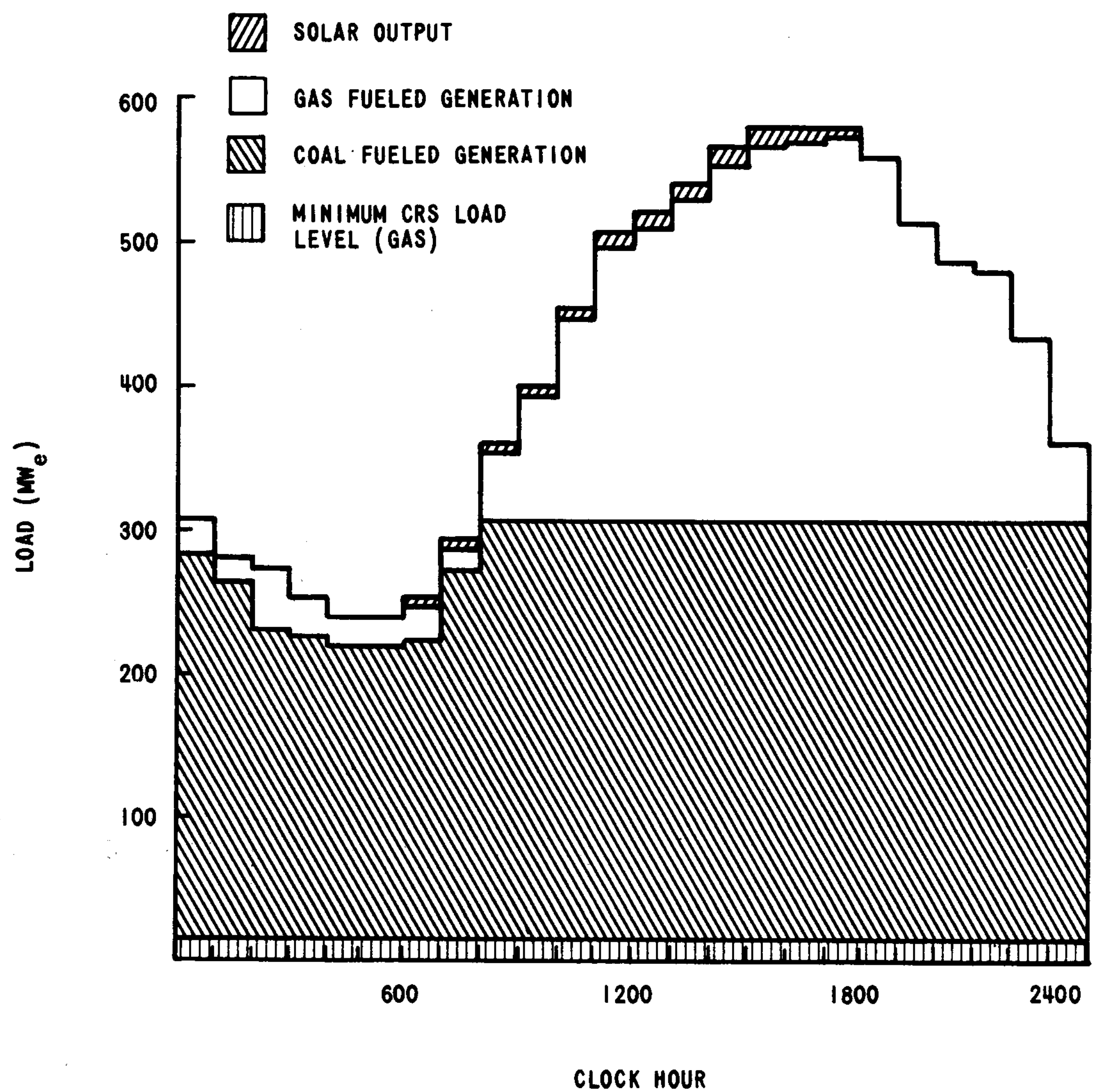

FIGURE 6.3-2. PROJECTED WESTERN POWER SYSTEM LOAD MODEL AND DISPATCH JULY 13, 1993

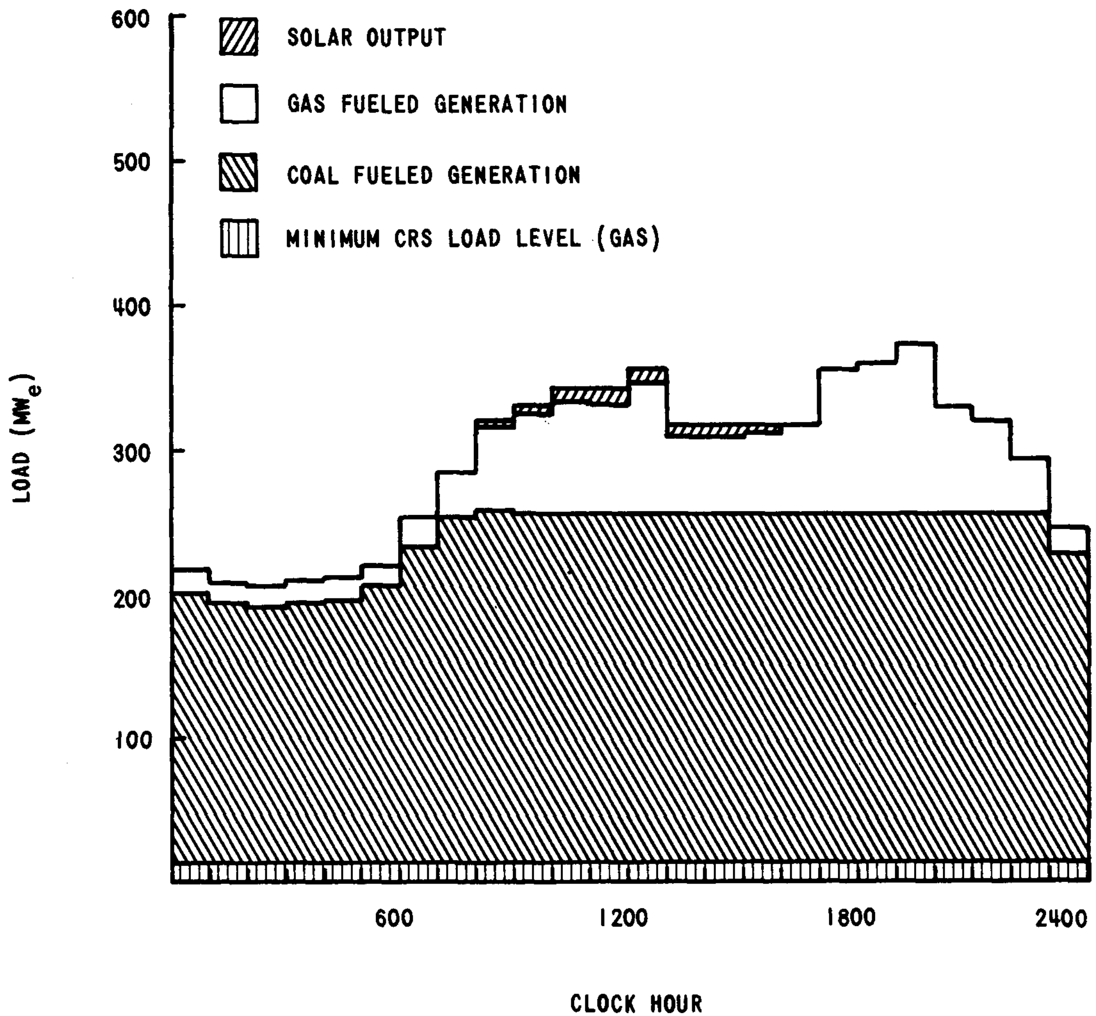

FIGURE 6.3-3. PROJECTED WESTERN POWER SYSTEM LOAD MODEL AND DISPATCH DECEMBER 20, 1993

- NHC Case

  --Base Plan: No solar repowering; Western Power expansion plan including 115 MW of coal capacity in 1993, 60 MW of combustion gas turbine in 1994 when CRS is retired, and 175 MW of coal capacity in 1996.

  --Solar Plan: Solar repowering of CRS in 1986; expansion plan includes 115 MW of coal capacity in 1993 and 175 MW of coal capacity in 1996. CRS Unit 1 modified for cyclic operation in 1994.

- No-NHC Case

  --Base Plan: Same as NHC Case Base Plan except capacity purchases after 1993 reduced to account for loss of 18.9 MW NHC electrical load and CRS heat rates modified to account for loss of NHC process steam load.

  --Solar Plan: Same as NHC Case Solar Plan except capacity purchases after 1993 reduced to account for loss of 18.9 MWe NHC electrical load, CRS heat rates modified to account for loss of NHC process steam load, and impact on effective solar unit performance of change in unit heat rate accounted for in solar output credit. CRS Unit 1 modified for cyclic operation in 1994.

The production cost data for the cases are given in Table 6-5 which shows the annual system operation cost for each plan. Also shown is the savings in annual production costs due to the solar addition for each case.

6.4.1.2 Fixed Charges on Capital Investment. Table 6-6 shows the investment schedules for each plan under either the NHC or the No-NHC case. Also shown are the annual fixed charges associated with the investment schedules for the 15-year evaluation period.

6.4.1.3 Comparative Revenue Requirements. Comparative annual revenue requirements were determined for each plan. Comparative revenue requirements for the 15-year evaluation period are given in Table 6-7. The comparative revenue requirements, as presented, include only fuel and O&M costs and the annual fixed charges. Typically, the comparative revenue

TABLE 6-5. ANNUAL SYSTEM OPERATING COSTS: FUEL AND O&M

	NHC CASE			No-NHC CASE		
Year	Base Plan ($\$ \times 10^6$)	Solar Plan ($\$ \times 10^6$)	Savings* ($\$ \times 10^6$)	Base Plan ($\$ \times 10^6$)	Solar Plan ($\$ \times 10^6$)	Savings* ($\$ \times 10^6$)
1986	50.3	48.2	2.1	44.9	42.6	2.3
1987	57.2	54.6	2.6	51.1	48.5	2.6
1988	64.8	62.1	2.7	57.9	55.7	2.2
1989	73.9	70.7	3.2	66.2	63.2	3.0
1990	83.5	80.0	3.5	75.1	72.5	2.6
1991	93.8	90.3	3.5	85.2	81.3	3.9
1992	103.7	101.5	2.2	94.1	92.1	2.0
1993	124.3	119.8	4.5	112.3	108.1	4.2
1994	121.8	126.4	(4.6)	108.8	111.6	(2.8)
1995	135.6	141.9	(6.3)	121.4	127.5	(6.1)
1996	155.9	161.4	(5.5)	139.2	145.1	(5.9)
1997	174.9	181.2	(6.3)	156.3	162.6	(6.3)
1998	196.9	199.3	(2.4)	178.3	179.6	(1.3)
1999	212.8	222.6	(9.8)	192.7	202.6	(9.9)
2000	236.6	248.0	(11.4)	214.7	225.6	(10.9)
Cumulative Present Worth**	702.7	698.4	4.3	631.8	627.4	4.4

*Savings equals Base Plan value minus Solar Plan value.

**Annual values discounted to 1986 using 13.45 per cent per year discount rate.

TABLE 6-6. ANNUAL FIXED CHARGES ON GENERATING UNIT ADDITIONS: NHC AND NO-NHC CASES

	BASE PLAN			SOLAR PLAN			
Year	Addition	Capital Cost ($\$x10^6$)	Annual Fixed Charges ($\$x10^6$)	Addition	Capital Cost ($\$x10^6$)	Annual Fixed Charges ($\$x10^6$)	Annual Savings* ($\$x10^6$)
1986		--	--	CRS Solar Repowering	47.4	8.3	(8.3)
1987		--	--		--	8.3	(8.3)
1988		--	--		--	8.3	(8.3)
1989		--	--		--	8.3	(8.3)
1990		--	--		--	8.3	(8.3)
1991		--	--		--	8.3	(8.3)
1992		--	--		--	8.3	(8.3)
1993	115 MW (Coal)	204.6	31.6	115 MW (Coal)	204.6	39.9	(8.3)
1994	60 MW (Gas Turbine)	48.3	39.4	CRS Cycling Modification	1.6	40.3	(0.9)
1995		--	39.4		--	40.3	(0.9)
1996	175 MW (Coal)	381.5	98.3	175 MW (Coal)	381.5	99.1	(0.8)
1997		--	98.3		--	99.1	(0.8)
1998		--	98.3		--	99.1	(0.8)
1999		--	98.3		--	99.1	(0.8)
2000		--	98.3		--	99.1	(0.8)
Cumulative Present Worth**							
Including Solar Facility			149.9			195.9	(46.0)
Excluding Solar Facility			149.9			136.4	13.5

*Savings equals Base Plan value minus Solar Plan value.

**Annual values discounted to 1986 using 13.45 per cent discount rate.

TABLE 6-7. COMPARATIVE REVENUE REQUIREMENTS

Year	NHC CASE Base Plan ($\$ \times 10^6$)	NHC CASE Solar Plan ($\$ \times 10^6$)	NHC CASE Savings* ($\$ \times 10^6$)	No-NHC CASE Base Plan ($\$ \times 10^6$)	No-NHC CASE Solar Plan ($\$ \times 10^6$)	No-NHC CASE Savings* ($\$ \times 10^6$)
1986	50.3	56.5	(6.2)	44.9	50.9	(6.0)
1987	57.2	62.9	(5.7)	51.1	56.8	(5.7)
1988	64.8	70.4	(5.6)	57.9	64.0	(6.1)
1989	73.9	79.0	(5.1)	66.2	71.5	(5.3)
1990	83.5	88.3	(4.8)	75.1	80.8	(5.7)
1991	93.8	98.6	(4.8)	85.2	89.6	(4.4)
1992	103.7	109.8	(6.1)	94.1	100.4	(6.3)
1993	155.9	159.7	(3.8)	143.9	148.0	(4.1)
1994	161.2	166.7	(5.5)	148.2	151.9	(3.7)
1995	175.0	182.2	(7.2)	160.8	167.8	(7.0)
1996	254.2	260.5	(6.3)	237.5	244.2	(6.7)
1997	273.2	280.3	(7.1)	254.6	261.7	(7.1)
1998	295.2	298.4	(3.2)	276.6	278.7	(2.1)
1999	311.1	321.7	(10.6)	291.0	301.7	(10.7)
2000	334.9	347.1	(12.2)	313.0	324.7	(11.7)
Cumulative Present Worth**						
Including Solar Facility	852.6	894.3	(41.7)	781.7	823.3	(41.6)
Excluding Solar Facility	852.6	834.8	17.8	781.7	763.8	17.9

*Savings equals Base Plan value minus Solar Plan value.

**Annual values discounted to 1986 using 13.45 per cent per year discount rate.

requirements would also include purchased capacity costs, but, since both the base and solar plans had the same purchase capacity schedules, the purchase capacity costs would net out of any savings computation.

6.4.1.4 Value of Solar Facility. As previously discussed in Subsection 6.1.2, the value of the CRS solar facility to Western Power is the capital investment cost that can be incurred under the solar expansion plan without increasing Western Power's 15-year revenue requirements as determined by the base (no solar) expansion plan. Table 6-8 summarizes the computation of the value of the solar facility. The solar facility savings is the summation of the system investment cost savings, expressed as the cumulative discounted fixed charges savings net of the solar facility related fixed charges of $8.3 million per year, and the cumulative discounted fuel and O&M cost savings. The share value is determined by dividing the solar facility savings by the solar facility cost, both in 1986 discounted dollars; this per cent value is the share of the total costs that Western Power could incur without the 15-year revenue requirements of the solar plan exceeding those of the base plan. As shown in Table 6-8, the value to Western Power of the CRS solar facility is approximately 30 per cent of the estimated cost.

TABLE 6-8. VALUE TO WESTERN POWER OF CRS SOLAR FACILITY

	NHC CASE	No-NHC CASE
Total Solar Facility Savings*	17.76	17.86
Solar Facility Cost**	59.46	59.46
Value of Solar Facility	29.9%	30.0%

*Cumulative present worth of solar plan savings excluding solar facility, from Table 6-7.

**Cumulative present worth of solar facility fixed charges: $8.3 million per year discounted at 13.45 per cent.

6.4.1.5 Sensitivity Analyses. The sensitivity of the NHC Case to key economic parameters was assessed. The sensitivity of the value to Western Power of the solar facility for various fuel price increases is shown in Figure 6.4-1. The sensitivity of solar facility lifetime is illustrated in Figure 6.4-2. In both sensitivity analyses, the value of CRS solar repowering would not vary significantly from the calculated value of about 30 per cent.

An additional analysis was performed to evaluate the sensitivity of the results should Western Power decide not to cycle CRS Unit I with appropriate modifications. If CRS Unit I is not converted to cycling operation in 1999, the value of the solar facility to Western Power would decline from 29.9 per cent to 24.8 per cent under the NHC case and from 30.0 per cent to 17.3 per cent under the No-NHC case. This significant decrease in value of the solar facility, when CRS Unit I is not assumed to cycle beginning in 1994, results from the much higher natural gas consumption under the solar plan beginning in 1994.

6.4.1.6 Solar Incentives Analysis. A separate analysis was performed to determine the impact of key solar facility component costs on the value of the solar facility under the NHC Case. The motivation for this analysis was that various incentives, either directly for Western Power or for solar component manufacturers or indirectly through government supported R&D, might reduce the installed cost of the heliostats or the receiver. The results of this analysis are shown in Figure 6.4-3 with breakeven curves for share values from 35 to 70 per cent.

6.4.2 Conclusions

Based on the detailed analyses presented in the preceding subsections, the following conclusions can be drawn with respect to the solar facility addition to the Cimarron River Station within the Western Power system.

- The value to Western Power of the solar facility is less than the total investment cost for the solar facility and related CRS modifications.
- The value to Western Power of the solar facility is not very sensitive either to the fossil fuel cost projections or to the solar facility lifetime assumption.

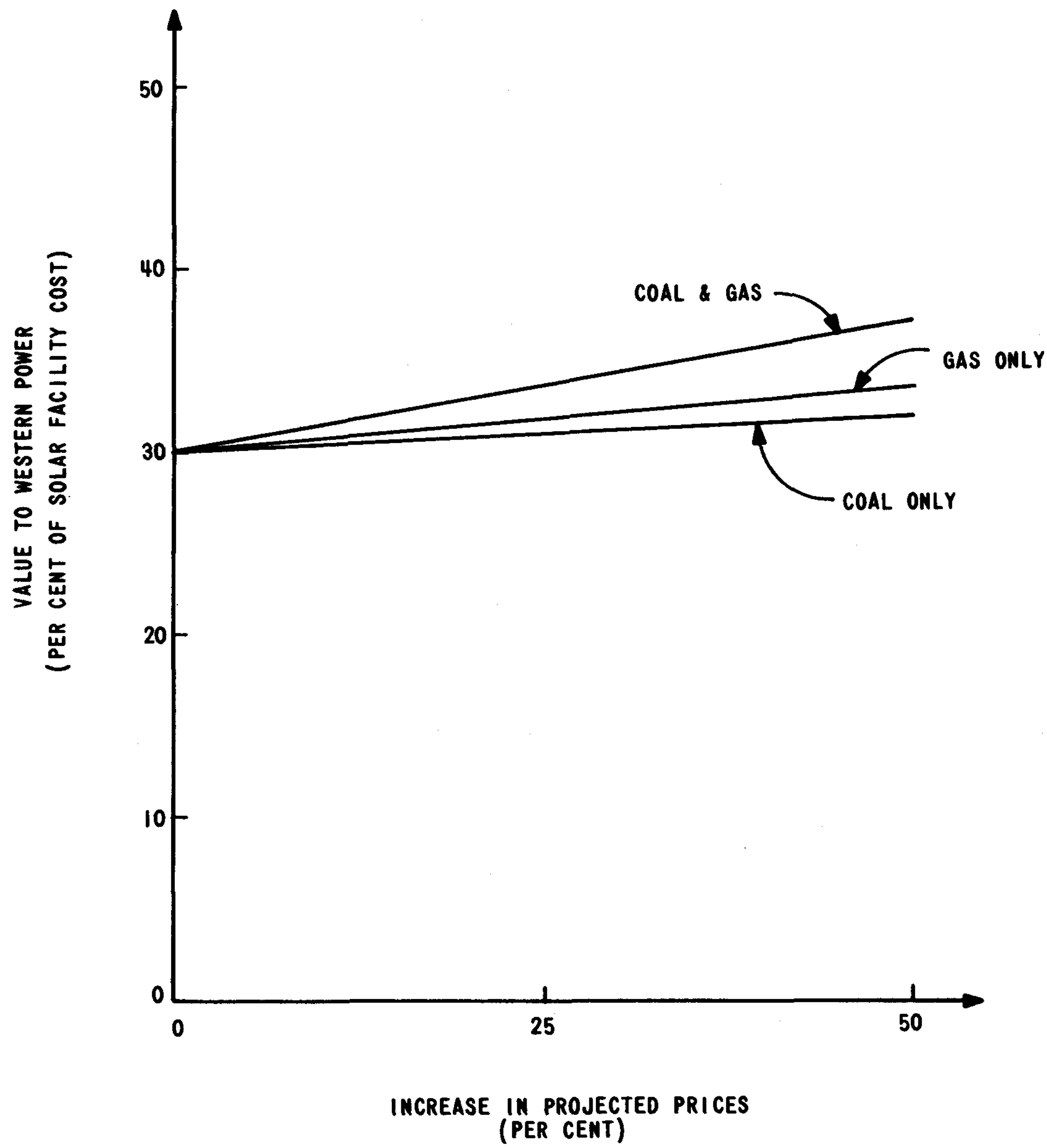

FIGURE 6.4-1. SENSITIVITY ANALYSIS--EFFECT OF FUEL PRICES ON VALUE TO WESTERN POWER OF CRS SOLAR FACILITY

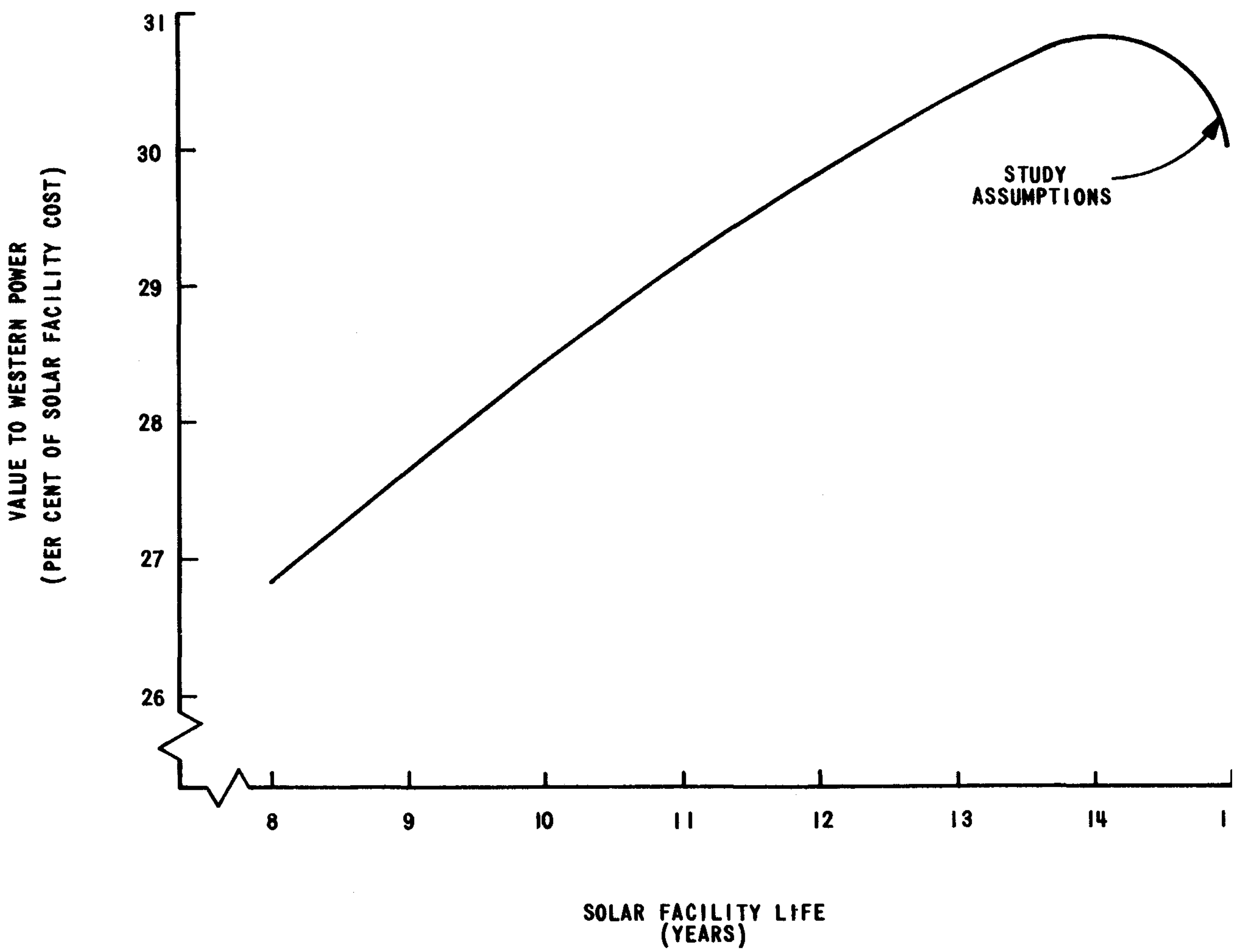

FIGURE 6.4-2. SENSITIVITY ANALYSIS--EFFECT OF SOLAR FACILITY LIFE ON VALUE TO WESTERN POWER OF CRS SOLAR FACILITY

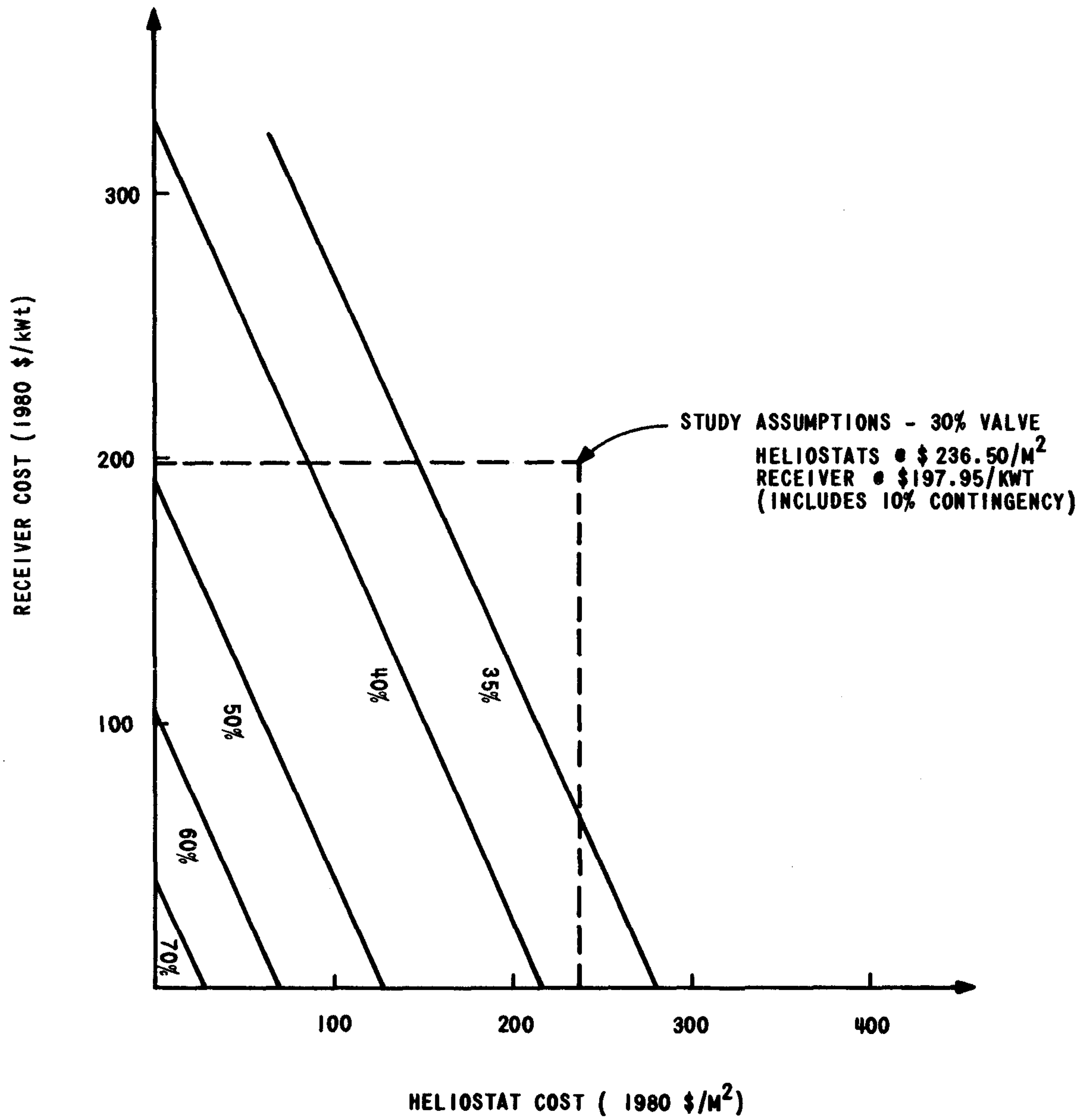

FIGURE 6.4-3. SOLAR INCENTIVE ANALYSIS--EFFECT OF KEY SOLAR COMPONENT COSTS ON VALUE TO WESTERN POWER OF CRS SOLAR FACILITY

- The value to Western Power of the solar facility is very sensitive to the assumption that it will be technically feasible to modify CRS Unit I for cyclic operation beginning in 1994.
- The value to Western Power of the solar facility would increase given direct or indirect incentives for key solar components, though such incentives alone could not result in a 100 per cent share value for Western Power.

7.0 DEVELOPMENT PLAN

The conceptual design, performance evaluation, and economic analyses presented in the previous sections provide the basis for the development plan. The plan addresses the major activities, financial requirements and organizational issues which will lead from conceptual design to commercial operation. One of the objectives of the project is for the solar facility to be in operation by 1986; this objective has guided the preparation of the development plan.

As shown in Figure 7.0-1, the major activities of the development plan consist of licensing, test program, detailed design, procurement, construction, checkout, and performance validation. The cash flow plan identifies the annual financial requirements of the solar facility between conceptual design and initial operation; the plan takes into consideration both the cost of various components/activities and the periods in which those costs will be incurred. The organizational issues focus on the roles of the major participants in the development effort. A more thorough discussion of the development plan follows.

7.1 LICENSING

Based on the discussion in Section 4.9, the following approvals must be obtained.

(1) Federal Aviation Administration
  (a) Determination of No Hazard to Air Navigation.
  (b) Notice of Construction Progress to Greatest Height.

(2) Kansas Department of Human Resources
  (a) Boiler Inspection.

(3) Kansas Department of Health and Environment
  (a) Open Burning Notification.

(4) Local Fire Department
  (a) Open Burning Approval.

The licensing activities will begin immediately following contract award. The primary licensing activities start with the identification of detailed

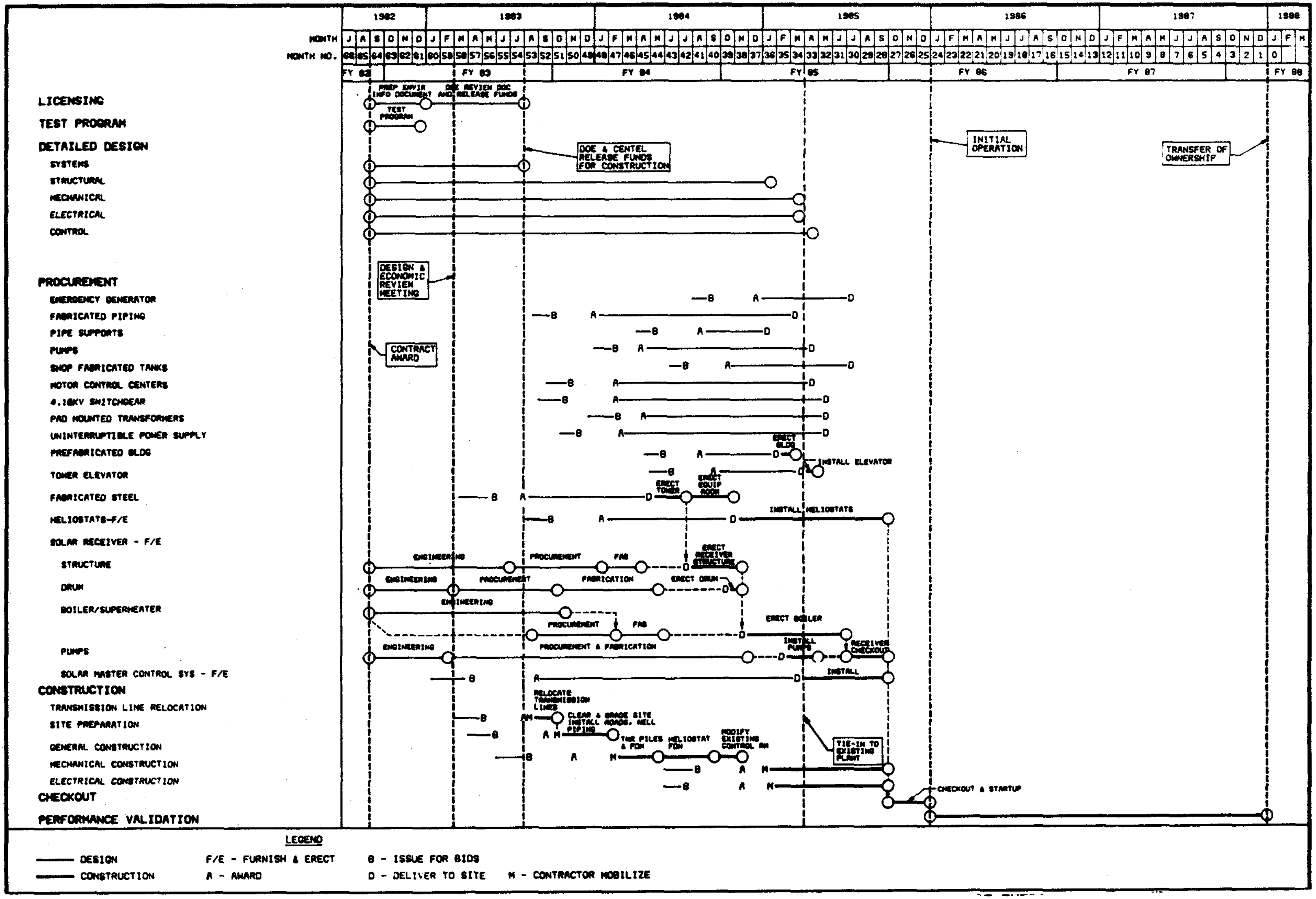

FIGURE 7.0-1. DEVELOPMENT PLAN SCHEDULE

licensing requirements. At about the same time, ecological and archaeological surveys will be conducted at the site. Next, the various approval applications will be prepared and submitted to the appropriate federal, state and local agencies.

Since the development plan assumes cost sharing by the Federal Government, it is likely that an Environmental Information Document (EID) will be required. If, based on the EID, the government determines that the addition of the solar facility does not adversely impact the local environment, a FONSI* statement will be issued and the development effort will proceed. If, on the other hand, the government suspects a significant adverse impact, a complete Environmental Impact Statement (EIS) will be required. Based on available information for the site, the requirement for an EIS appears to be remote. However, should an EIS be necessary, an additional 8 to 15 months may be required before federal funds could be obligated; such a delay would eliminate the possibility of the solar facility being operational by January 1, 1986.

7.2 TEST PROGRAM

In order to more precisely determine the modifications to the existing facilities, a test program will be conducted on the gas-fired boiler and the boiler feedwater pump. Results of these tests will be used in the development of the detailed design.

The boiler will be tested to determine the modifications needed for variable pressure operation. During the conceptual design project, Babcock & Wilcox estimated the turndown capability, or minimum firing rate, of the boiler; although this estimate was judged to be sufficiently accurate for a conceptual study, testing will be required before proceeding with detailed design. In conjunction with the turndown capability tests, adjustment of burner controls will be investigated. Further, tests will be conducted to determine if steam outlet conditions can be modified by adjusting the air/fuel mixture and by bringing different burners into service. Finally,

*Finding Of No Significant Impact.

the boiler will be tested to determine its transient response times; these transients will be representative of hybrid solar/fossil operation.

The boiler feedwater pump will undergo a series of tests aimed at determining its operation at reduced pressure and flow. As with the boiler, the pump will be tested to identify its transient response time.

7.3 DETAILED DESIGN

Detailed design will include conducting system analyses, developing system design specifications, preparing drawings, providing engineering lists, and completing system descriptions. Each of these activities is discussed in the following.

System Analyses will be conducted to refine the conceptual design of major systems. The studies identified for detailed design cover the following topics.

(1) Site Grading Plan.

(2) Heliostat Aim Strategy.

(3) Heliostat Mirror Washing.

(4) Collector Field Layout.

Each analysis will include a statement of the objective, the fixed requirements, and the proposed alternatives to be analyzed. Each study will include appropriate consideration of capital costs, operating and maintenance costs, reliability, maintainability, defined and anticipated regulatory requirements, and other considerations affecting conclusions.

A System Design Specification will be prepared for each solar facility system and modifications to existing facility systems, as well as site and facilities construction. The System Specification (Appendix A) will be used to develop the System Design Specifications. The System Design Specification is a design control document that specifies the requirements for design of the system and major equipment. The System Design Specifications will include the following elements for each system, as appropriate.

(1) System and equipment functions and descriptions.

(2) System performance requirements.

(3) Design parameters and criteria.

(4) Definition of system boundaries and significant interfacing requirements.
(5) The required process control.
(6) The controlling codes and standards and regulatory requirements.
(7) Important materials selections.
(8) Definition of the required quality level for fabrication and construction.
(9) A process flow diagram for functional fluid systems.
(10) A simplified arrangement drawing for building systems.
(11) A schematic arrangement for electrical systems.
(12) A functional block diagram for control systems.
(13) Testing requirements.
(14) Layout and arrangement criteria.

Engineering drawings consist of design control drawings and construction drawings. These drawings will be prepared to guide and coordinate the detailed design activities and to allow timely construction of the project. A representative list of drawings which will be prepared is given below.

(1) Site arrangement.
(2) Equipment arrangements.
(3) Construction facilities.
(4) Roads and walkways.
(5) Grading and fencing.
(6) Drainage.
(7) Foundations.
(8) Structural steel, platform and stairs.
(9) Piping.
(10) Raceway.
(11) One-line electrical diagrams.
(12) Freeze protection.
(13) Yard piping and utilities.
(14) Lighting.
(15) Power and control wiring.
(16) Electrical schematic and interconnection diagrams.
(17) Control panel arrangements.

Engineering lists will be prepared to define component design parameters, procurement information, and installation information. The following are representative of the engineering lists which will be provided.

(1) Equipment List.
(2) Electrical Load List.
(3) Electrical Assembly List.
(4) Electrical Device List.
(5) Instrumentation and Control Device List.
(6) Valve List.
(7) Mechanical Device List.
(8) Annunciator List.
(9) Circuit and Raceway List.
(10) Pipe Hanger List.

System Descriptions will be prepared to document the final detailed design for all plant systems. A complete System Description will include, as a minimum, the following.

(1) General description of system functions and operation.
(2) Process flow diagrams.
(3) Instrument and control diagrams.
(4) Control logic diagrams.
(5) Description of major equipment purchased.
(6) Essential equipment performance curves.
(7) Preoperational testing requirements.
(8) Water chemistry quality control limits.
(9) References such as related drawings and manuals.

7.4 PROCUREMENT

Procurement activities include the preparation of equipment and construction procurement specifications, preparation of qualified bidders lists, analysis of vendor and contractor bids, preparation and execution of contract documents, contract administration, and expediting. With the exception of the solar receiver, equipment and construction contracts will be awarded on the basis of competitive fixed-price, lump sum bids for a defined scope of work. Since the design, fabrication and erection of the solar receiver is on the critical path of the development plan schedule, it will be procured on a sole-source basis from Babcock & Wilcox.

Equipment specifications will define the performance and quality requirements for the components being procured. Construction specifications will include detailed erection drawings and installation requirements which will define the scope, quality, and configuration of the work.

The equipment and construction procurement packages for the solar cogeneration facility are listed in Table 7-1. The equipment procured on a "furnish only" basis will be delivered to the site by the supplier and installed by a construction contractor. Those items which are procured on a "furnish and erect" basis will be delivered to the site and installed by the supplier. For the construction packages, the contractor will furnish his own construction tools and equipment, office and office supplies, consumables, and other equipment and materials not procured separately.

7.5 CONSTRUCTION

The construction activities will begin with the establishment of the construction management organization at the site. The primary responsibilities of construction management will include scheduling, monitoring and reporting construction progress; coordinating construction activities; and administering the quality assurance and site safety programs.

The first onsite construction work will consist of relocating existing transmission lines which cross the proposed heliostat field location. Following this effort, the site preparation construction contractor will clear and grade the site, install new roads, and relocate piping from existing water wells which cross the heliostat field. The general construction contractor's responsibilities will include installing the foundations for the receiver support tower and the heliostats, erecting the structural steel receiver support tower and solar auxiliaries building, providing security at the site, and providing construction housekeeping. The mechanical construction contractor will install all mechanical equipment, such as tanks, piping, pumps, and valves. Finally, the electrical construction contractor will

TABLE 7-1. PROCUREMENT PACKAGES

Equipment-Furnish Only

- Pumps
- Fabricated Steel
- Fabricated Piping
- Pipe Supports
- Receiver Tower Elevator
- Emergency Generator
- Motor Control Centers
- 4.16 kV Switchgear
- Pad Mounted Transformers
- Uninterruptible Power Supply
- Shop Fabricated Tanks
- Prefabricated Building

Equipment-Furnish and Erect

- Heliostats
- Solar Receiver
- Solar Master Control System

Construction

- Transmission Line Relocation
- Site Preparation
- General Construction
- Mechanical Construction
- Electrical Construction

install the solar facility switchgear, motor control centers, raceway, and power and control cables.

7.6 CHECKOUT

The objective of the checkout activities is to verify the operational readiness of the facility and to place it into initial operation. As such, the status of the facility must be confirmed component by component, progressing to the point where entire systems have been prepared for operation, and finally, testing the integrated facility under all anticipated operating modes and mode transitions. A key aspect of this process will be determining that individual components not only operate properly by themselves, but also that the various component interactions function properly, as in the case of a sensor, a controller, a valve, and a pump. This orderly, step-by-step process is a normal part of the start-up procedure for any power plant.

Component checkout will actually begin prior to construction in the form of reviewing manufacturer's drawings; the objective of this review will be to assure compliance with the procurement specification. For some components, tests will be performed at the supplier's factory in order to verify equipment performance. The final step in component checkout will consist of inspecting equipment as it is received at the site to determine if it has been damaged in transit.

The checkout process will continue with the testing of functional systems. Completion checks, which will be made to ensure that system components have been properly installed,, connected and lubricated, will include the following.

(1) System flushing.
(2) Hydrostatic tests.
(3) Alignment checks.
(4) Pneumatic tests.
(5) Motor rotation checks.
(6) Lubrication checks.
(7) Thermal expansion checks.

Preoperational tests will be performed to verify that each system is functionally correct. Equipment run-in procedures and preoperational checkout requirements will be established as the basis for these tests. Examples of preoperational testing activities include control logic functional checkout, instrument calibration and loop checks. The final phase of functional system checkout will occur when individual systems are subjected to expected operating conditions. In some cases, it will not be possible to fully test a single system under operating conditions; here, additional systems will be brought into operation until expected operating conditions are achieved for the system under investigation.

Acceptance testing of the integrated facility will comprise the final segment of checkout activities. After the checkout of each functional system has been completed, individual systems will be sequentially brought into operation until the integrated facility is operational. Initially, this will occur slowly and at conditions below those expected for normal operation. When normal operating conditions are achieved, the performance of the facility will be closely monitored. The integrated facility will also undergo startup and shutdown procedures and the facility's ability to respond to transients will be carefully checked. If facility operation meets the performance requirements, initial operation and the performance validation phase will begin. If the integrated facility fails to meet the performance requirements, sufficient additional testing will be performed to isolate the problem and permit corrective action to be taken.

7.7 PERFORMANCE VALIDATION

In order for Western Power to identify the true value of the solar facility, a two-year performance validation program will be conducted. In this phase, the longer-range operating characteristics and maintenance requirements of the facility will be assessed. Key information regarding system operation which will be obtained includes the following.

(1) Heliostat field efficiency and optical characteristics.

(2) Heliostat aim strategies and receiver flux distributions.

(3) Receiver efficiency and loss mechanisms.

(4) System power capability.

(5) Steam conditions at receiver outlet and at fossil system interface point.

(6) System upsets during cloud transients.

(7) System stability and load sensitivity.

(8) Startup, shutdown, and control techniques.

(9) Receiver cooldown characteristics.

(10) System and component response times.

To ensure that these issues are properly addressed and that performance data will be available in a form that various interactive phenomena can be individually evaluated, specific test conditions and methods will be prescribed in a Test Plan. This plan will also include expected results for the test conditions, thus, providing a point of initial data comparison.

This project phase will result in the demonstrated operation of the integrated solar cogeneration facility at Cimarron River Station. Not only will test data be acquired for analytical evaluation, but plant operators will acquire hands-on experience and a degree of confidence in the system, thus, encouraging their support of the continued use of the solar hybrid system.

During the performance validation testing, ownership of the solar facility will reside in both Western Power and DOE. Western Power will operate the facility during this period and compile data on fuel displaced, system performance, operating and maintenance costs, equipment failures, and downtime due to scheduled and unscheduled maintenance.

At the end of this phase, the facility's performance and future value to Western Power will be evaluated. It is anticipated that the result of this evaluation will provide for transfer of full ownership of the facility to Western Power.

7.8 SCHEDULE AND MILESTONE CHART

The successful completion of a project on time and within planned costs depends upon carrying out the various project activities in accordance with a predetermined schedule. The Major Milestones Schedule, shown in Figure 7.8-1, presents the major project milestones and identifies the

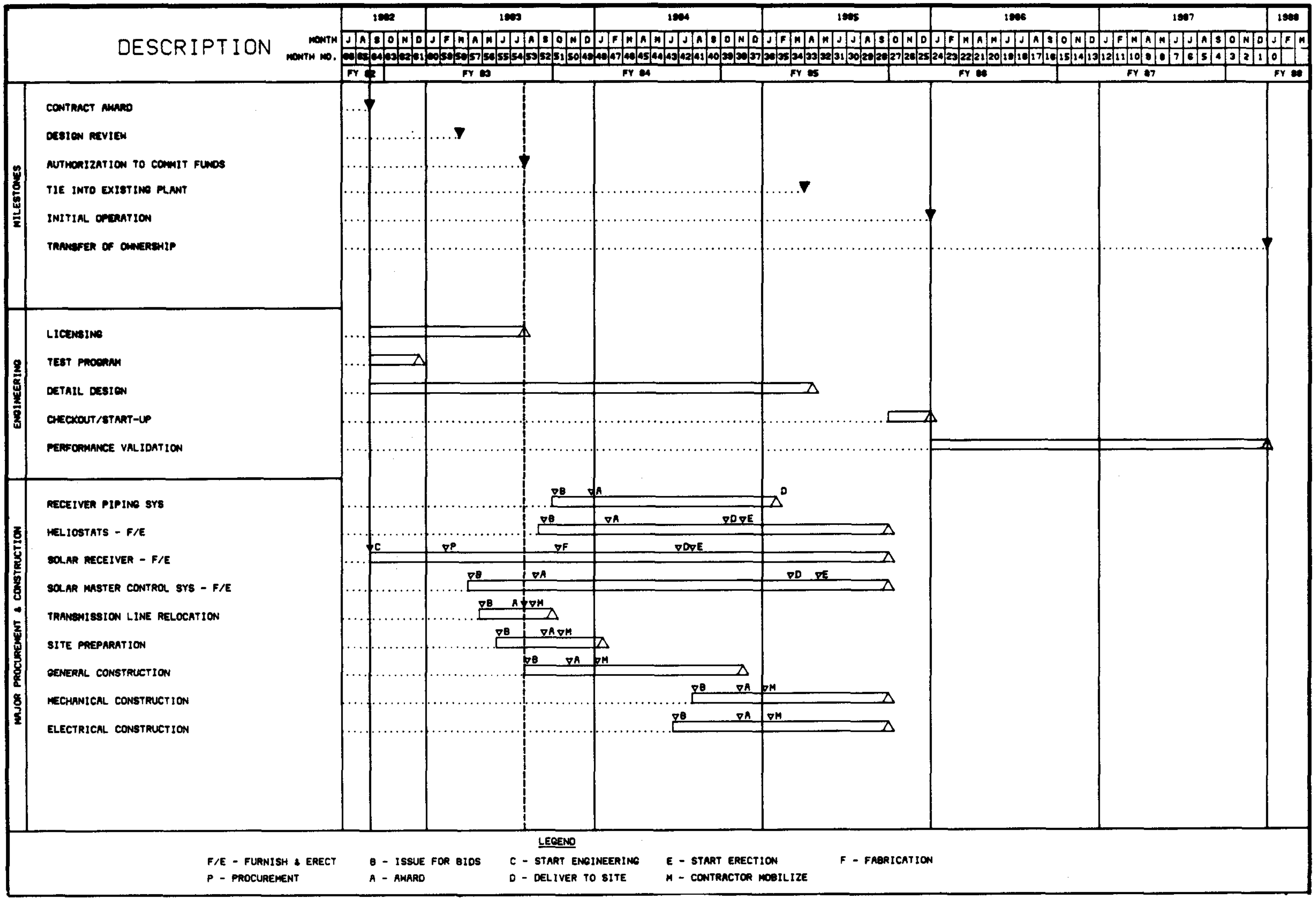

FIGURE 7.8-1. MAJOR MILESTONES SCHEDULE

durations and relationships of the major activities. This schedule was prepared by applying detailed Critical Path Method procedures to over 200 activities.

The cash flow plan, illustrated in Table 7-2, integrates the cost estimate and the development plan schedule. The schedule identifies the periods in which the major activities take place. The material, labor, and indirect costs associated with each activity are then distributed over those periods. From this schedule of cash outlays, the costs of Allowance for

TABLE 7-2. CASH FLOW*

	1982	1983	1984	1985	1986
Calendar Year	643,018	3,839,862	9,194,017	19,564,271	--
Fiscal Year	444,397	3,078,517	7,855,479	16,971,707	4,891,068

Total Construction and Owner's Cost--$33,241,168

*7/1/80 Dollars.

Funds Used During Construction are computed and added to the cash outlays in the appropriate periods, yielding the total cash flow requirements.

7.9 ROLES OF SITE OWNER, GOVERNMENT, AND INDUSTRY

The assumed roles of key participants in the development plan activities will be a combination of traditional power industry working relationships and a unique arrangement necessitated by the experimental nature of the solar cogeneration facility. The working relationships among Western Power, Black & Veatch, Babcock & Wilcox and other equipment suppliers and contractors will essentially follow conventional power industry practice. That is, Western Power will serve as owner and operator of the solar facility. Black & Veatch will provide project management and design services to Western Power; these services will include engineering, procurement, and construction management. Babcock & Wilcox will supply the solar receiver and make any needed modifications to the existing fossil boiler. Other equipment suppliers and construction contractors will fill their traditional roles.

The involvement of DOE in the development plan will require a few adjustments to the conventional working relationships. The proposed roles of Western Power and DOE are analogous to a venture capital situation where DOE has the role of the venture investor and Western Power maintains its role as a secured investor with an assured return. Since both organizations are assuming risk, the decision-making responsibilities will be shared between DOE and Western Power; in this unique working agreement, Western Power will be the prime contractor to DOE.

In addition to its typical role, Black & Veatch will serve as a subcontractor to Western Power and provide project management services for the Western Power contract with DOE. Among the project management responsibilities will be the preparation of several control documents: program plan, project instructions, project design manual, project procurement manual, project schedules, and project cost estimate. The program plan will be developed in accordance with standard DOE reporting requirements; as such, it will consist of a management plan, milestone schedule and status plan, cost plan, and manpower plan. Project Instructions will be prepared to establish the procedures, instructions, and project file system necessary to control the administrative interfaces among DOE, Western Power, Black & Veatch, Babcock & Wilcox, and other parties. A Project Design Manual will be developed to describe the design objectives of the solar cogeneration facility and to provide the basis for detailed design. The completeness of this manual will increase as the design progresses, as the various systems are better defined, and as equipment selection is made. A Project Procurement Manual will be prepared to consolidate and publish information related to project procurement, including instructions, lists of equipment and construction procurement specifications, and procurement scope descriptions. On the basis of general schedule milestones established by DOE, Western Power and Black & Veatch, an integrated project schedule will be developed and periodically updated; this schedule will consist of three principal elements: Project Milestone Schedule, Management Control Schedule, and Construction Control Schedule. The project cost estimate will be developed as the project evolves. A definitive estimate will be developed after the completion of the System Analyses and be presented at the design and economic review meeting. After major equipment contracts have been awarded, the detailed estimate will be developed and periodically updated to reflect estimated costs of known changes in engineering.

In order to meet the 1986 operational date, the solar receiver will be furnished on a sole-source basis by Babcock & Wilcox. Other equipment and construction contracts will be procured on a fixed price, competitive bid basis to minimize cost.

A possible cost sharing plan is for the government to fund the majority of the engineering, procurement, construction and performance validation. Initially, Western Power would contribute those items associated with Owner's cost (see Section 4.7). Assuming the facility operates successfully during the performance validation testing, Western Power would purchase the government's interest based on the demonstrated value of the solar facility, giving consideration to funds previously expended by Western Power. In the event of unsuccessful operation, the government would be responsible for removal of the solar equipment and restoration of the Cimarron River Station site.

8.0 SITE TEST PROGRAM

8.1 INTRODUCTION

The economic viability of the solar cogeneration facility is highly dependent on the performance of the collector system; that performance is determined primarily by the insolation resource available and by the reflectivity of the heliostat mirrors. A test program has been established at the proposed site to measure the direct normal insolation (DNI) and to quantify the decrease in heliostat reflectivity due to mirror surface soiling.

Several features of the proposed site may impact collector system performance. As shown on Figure 8.1-1, the proposed collector field is located north of the Cimarron River Station (CRS). A major portion of the field is directly to the north of the wet cooling towers which serve both the Cimarron River Station and the National Helium Corporation. The

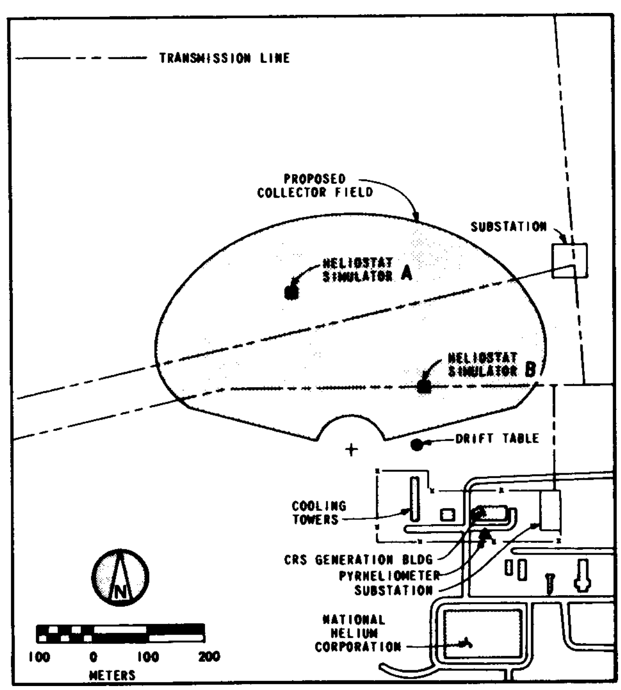

FIGURE 8.1-1. LOCATION OF PROPOSED COLLECTION FIELD AND LOCATION OF TEST EQUIPMENT

proximity of these cooling towers to the collector field is of concern for two reasons. First, water droplets which are entrained in the plume from the cooling towers drop out of the plume when air velocities are not great enough to keep the droplets in suspension. These droplets, known as cooling tower drift, may settle onto heliostat mirrors. Cooling tower drift contains significant levels of dissolved solids which remain on the mirror surfaces after the water has evaporated, thus reducing mirror reflectivity. The second reason for concern is that during cold weather, the plume from the cooling towers condenses, forming an opaque cloud. Winds may carry the opaque plume so that it shadows a portion of the collector field, thus reducing system performance. As can be seen from the wind rose shown on Figure 8.1-2, the wind will carry any cooling tower drift or plume towards the collector field for a significant portion of the year.*

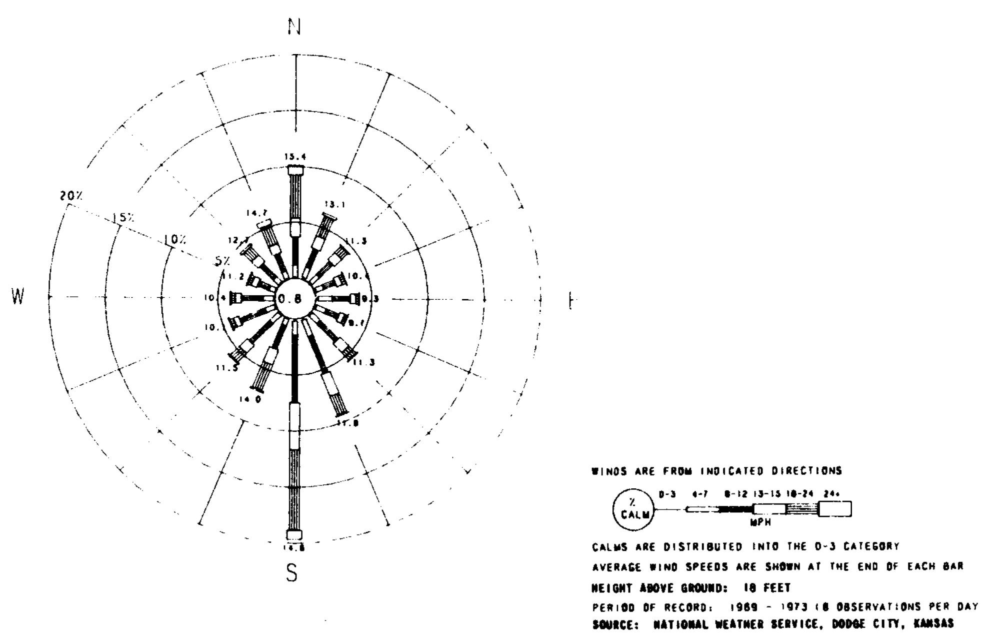

FIGURE 8.1-2. ANNUAL WIND ROSE FOR DODGE CITY, KANSAS

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*The wind rose shown in Figure 8.1-2 is for Dodge City, Kansas, which is about 113 km (70 miles) to the northeast of the proposed site.

In addition, the land in the vicinity of the proposed collector field is characterized as sandy with a light ground cover of grasses; this constitutes an additional source of mirror surface contamination in the form of dust and pollens.

Cooling tower drift, dust, and pollens affect the performance of the collector system directly by reducing heliostat specular reflectivity. Collector system performance is indirectly impacted to a significant degree by the direct normal insolation resource: the greater the resource, the fewer heliostats needed to collect a set amount of energy, and thus the greater the performance of the collector system.

The test program was designed to quantify the impacts on the proposed collector system that the factors discussed above may exert. The test program consists of two separate subprograms: the insolation monitoring program and the heliostat mirror soiling test program. These test subprograms, the methodology employed, and the equipment utilized are described below.

8.2 INSOLATION MONITORING PROGRAM

Prior to this program, the insolation monitoring station closest to the proposed site was located in Dodge City, Kansas, about 113 km (70 miles) to the northeast. The Dodge City station, however, only monitors total horizontal insolation; direct normal insolation, which is the resource of interest, is not measured. Therefore, a station was established to monitor direct normal insolation at the proposed solar cogeneration facility to provide additional site characterization.

8.2.1 Equipment

The equipment for the insolation monitoring station consists of an Eppley normal incidence pyrheliometer, a solar tracker, and an electronic integrator with printer. The pyrheliometer and solar tracker, installed at the CRS, are pictured on Figure 8.2-1. The pyrheliometer is positioned at the site immediately to the south of the CRS turbine building, as indicated on Figure 8.1-1. In this position, the pyrheliometer has an unobstructed view of the southern sky.

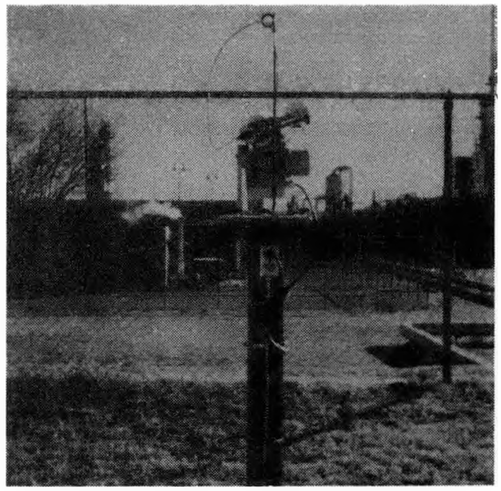

FIGURE 8.2-1. NORMAL INCIDENCE PYRHELIOMETER AND SOLAR TRACKER INSTALLED AT CRS

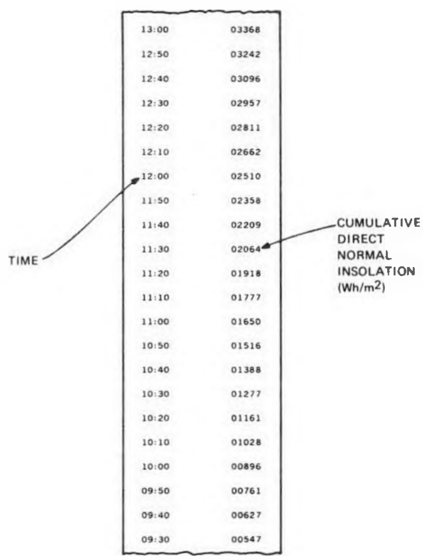

FIGURE 8.2-2. EXAMPLE OF PAPER DATA TAPE OUTPUT

The normal incidence pyrheliometer, which is kept pointed at the sun by the solar tracker, outputs a signal which is proportional to the magnitude of the direct normal insolation. This signal is monitored by the electronic integrator, which, as the name implies, integrates the signal (insolation) to yield the cumulative direct normal insolation intercepted, (energy per unit area). The integrated signal is converted to units of watt-hours per square meter and shown on a display. A printer attached to the integrator prints out the displayed value of intercepted energy along with the local time on a paper tape at set time intervals. For the test program, the printer was set to print out the intercepted energy every 10 minutes. A small segment of the data tape is shown for example in Figure 8.2-2.

The normal incidence pyrheliometer, solar tracker, and electronic integrator with printer were installed and became operational at the site on January 13, 1981. The first full day's worth of insolation data was recorded the following day, January 14.

8.2.2 Results

From the output insolation data tapes, plots of daily insolation profiles can be constructed. These profiles are actually the plots of the average direct normal insolation occurring over 10 minute intervals throughout the day. Still, such plots are useful descriptors of the insolation activity and provide a qualitative indication of the transcient response requirements of the solar cogeneration facility. Two such insolation profiles are shown in Figure 8.2-3. The top profile is for a clear day and approximates the classic clear-day insolation profile, the lower profile is for a partially-cloudy day.

The insolation data tapes identify the daily totals of direct normal insolation (energy per unit area). These daily totals themselves are indicators of the type of day with respect to solar energy collection. As seen in Figure 8.2-3, the clear day had a daily total of direct normal insolation of 10.44 kWh/m^2, while the partially-cloudy day had a daily total of but 2.60 kWh/m^2. Histograms of the daily totals of direct normal insolation are shown in Figure 8.2-4 corresponding to the months of January through June, 1981.

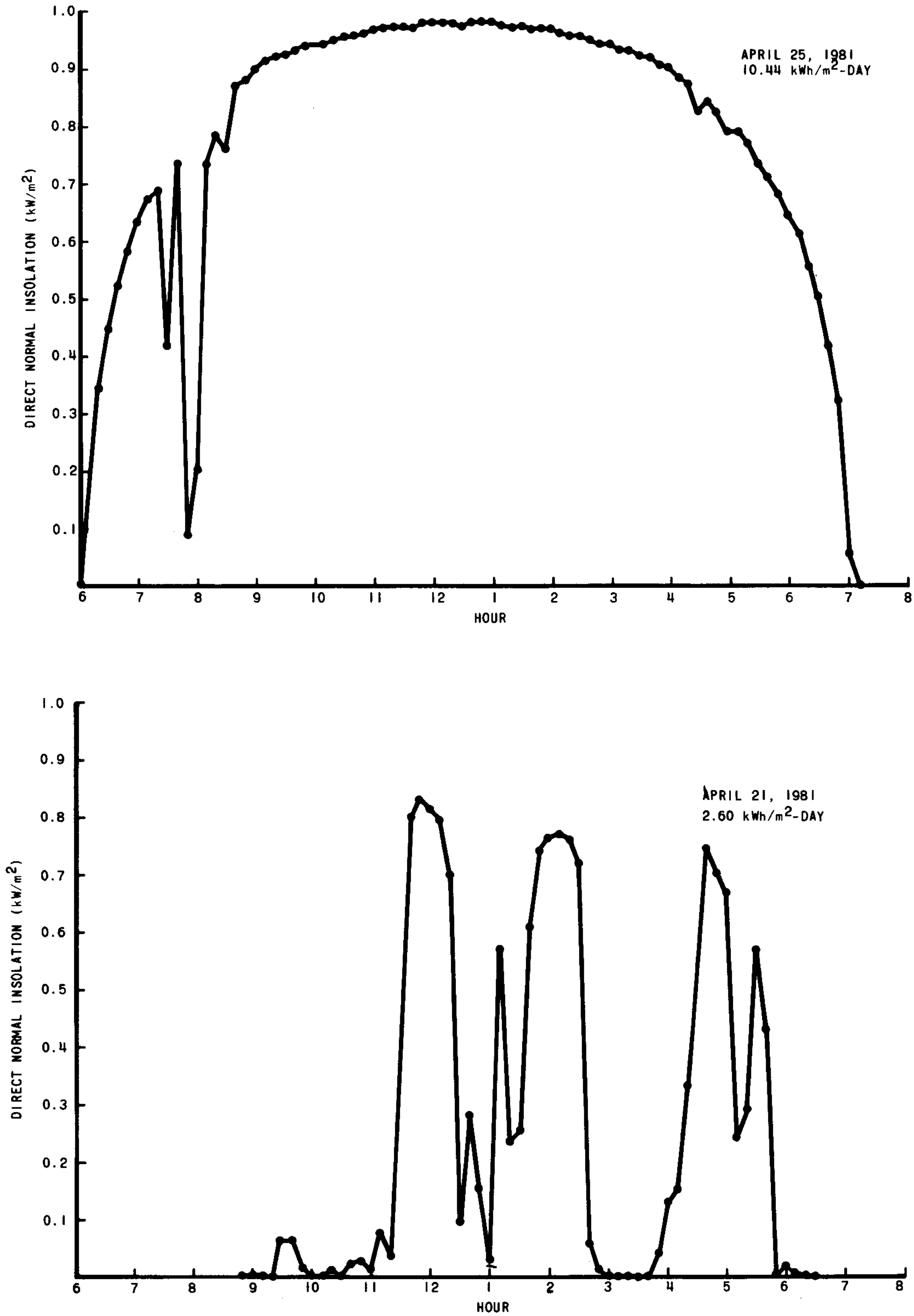

FIGURE 8.2-3. EXAMPLES OF DIRECT NORMAL INSOLATION PROFILES

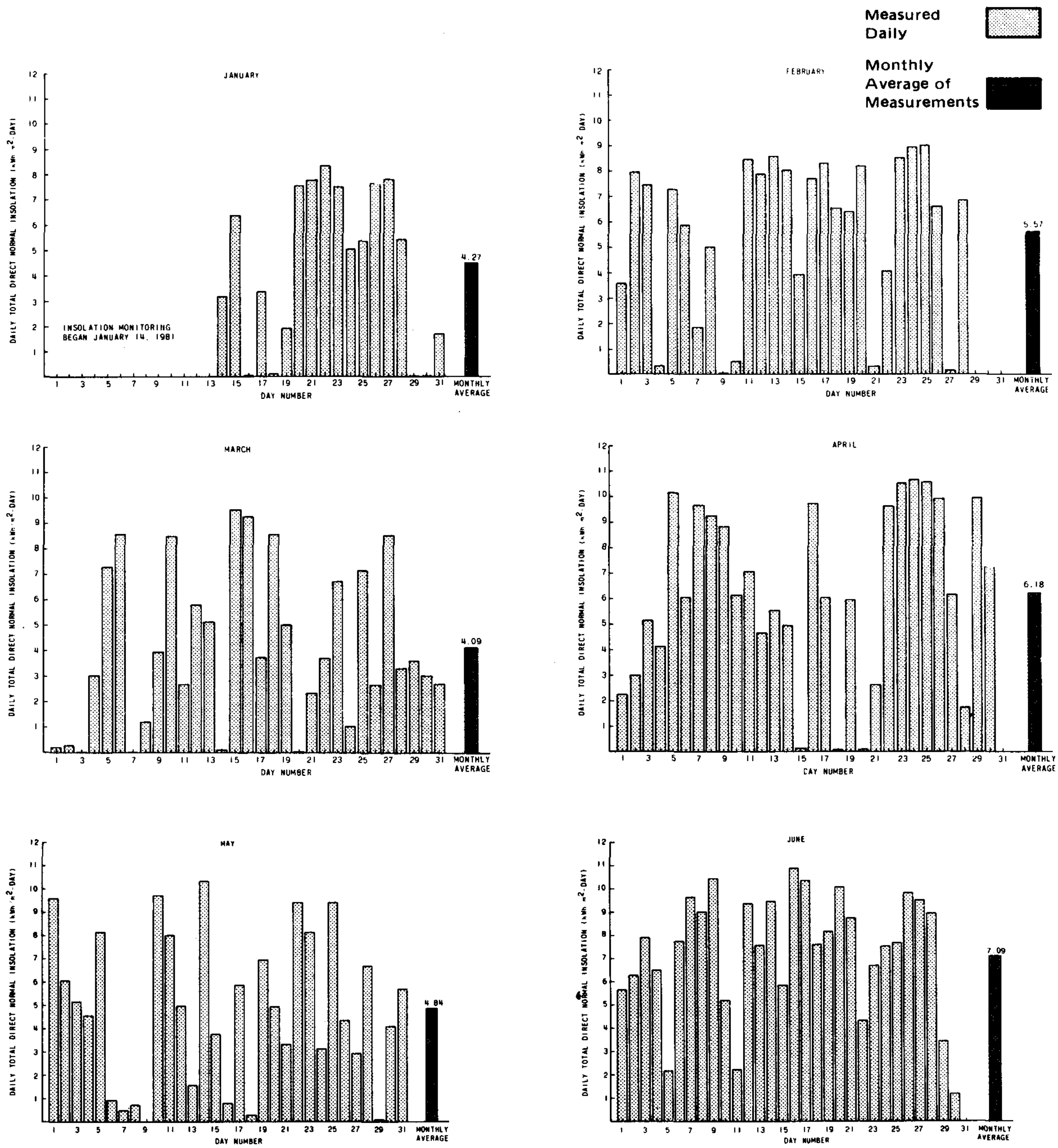

FIGURE 8.2-4. MONTHLY HISTOGRAMS OF DAILY TOTAL DIRECT NORMAL INSOLATION

The monthly averages of the daily totals of direct normal insolation are also given in Figure 8.2-4. These values are of interest in that they may be compared to tabulated "historical" data and other estimates of direct normal insolation. Such a comparison is shown in Figure 8.2-5.

The "historical" data shown in Figure 8.2-5 is for Dodge City, Kansas, about 113 km (70 miles) from the proposed site. However, the "historical" data is not true direct normal insolation data but rather, as previously mentioned, is inferred data from the Dodge City total horizontal insolation measurements and other meteorological factors via empirical equations. Also shown are the products of the historical values of per cent sunshine for Dodge City and the ASHRAE clear air model values of direct normal insolation corresponding to the latitude of Dodge City. This method of estimation is often employed when actual data is not available. As can be seen, the two "historical" estimates differ on a monthly basis, but are in good agreement on an annual basis.

Plotted in the figure are the actual monthly values for 1981 (January through June) measured at Liberal, Kansas. Along with these actual data are shown estimates derived using 1981 measured per cent sunshine for Dodge City and the ASHRAE model. A comparison between these two estimates shows significant differences on a monthly basis; however, the annual trend cannot yet be discerned. A comparison between the historical and 1981 estimates of direct normal insolation based on per cent sunshine shows some considerable monthly differences. This indicates that 1981, to date, contains some atypical months.

With additional measured DNI data, the data can be correlated with other meteorological data (such as per cent sunshine and total horizontal insolation) for the same time period. With these correlations, historical meteorological data can be examined to give an accurate estimation of the direct normal insolation resource at the proposed site.

8.3 MIRROR SOILING TEST PROGRAM

The objective of this test subprogram is to quantify the impact of surface soiling on heliostat mirror reflectivity at the proposed site. The

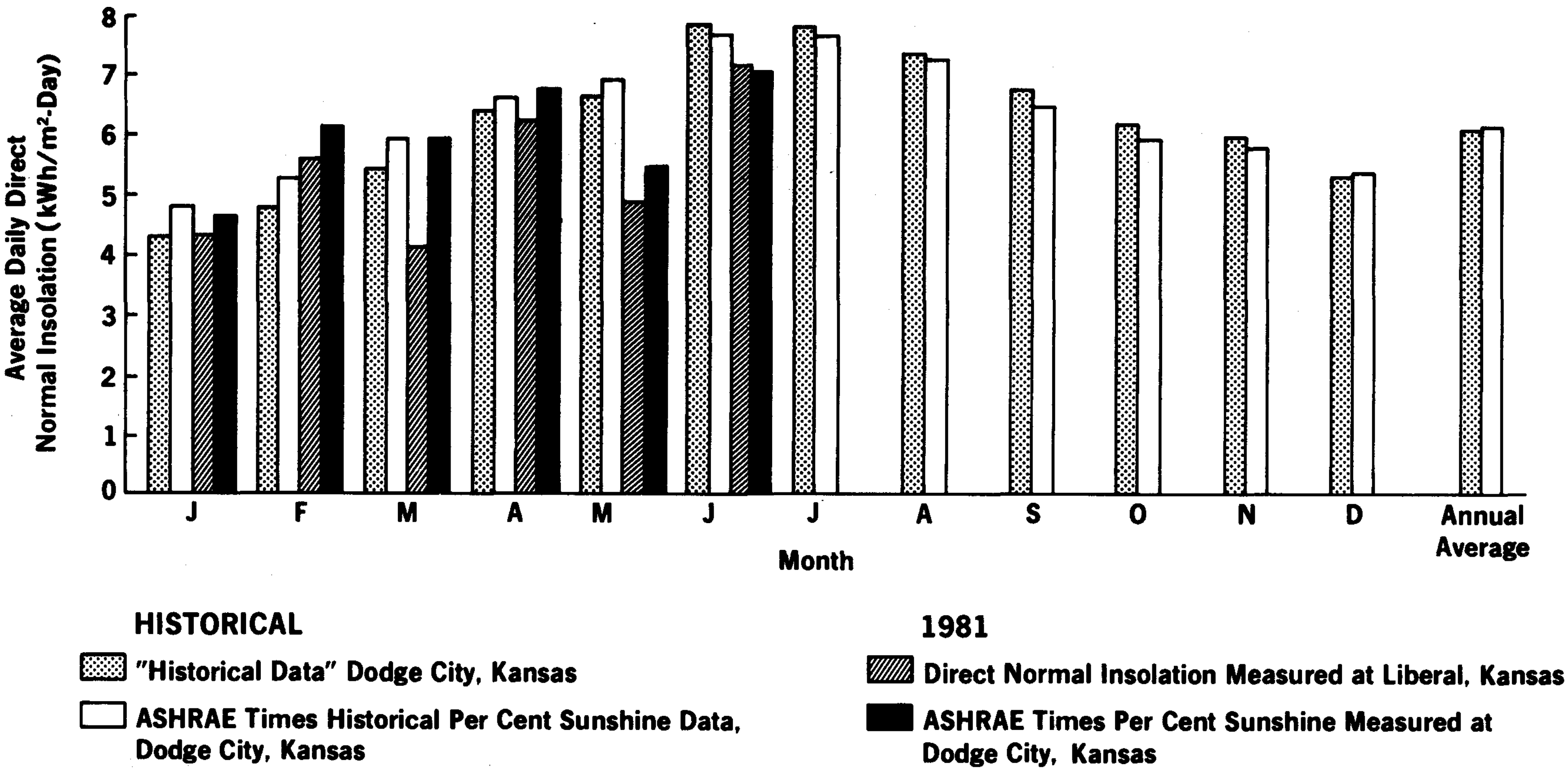

FIGURE 8.2-5. AVERAGE DAILY DIRECT NORMAL INSOLATION BY MONTH

data resulting from this test program will indicate the magnitude of the mirror contamination and provide estimates of the average degradation of reflectivity due to mirror surface soil. These data will also help establish operating and maintenance costs by providing an indication of the required frequency of heliostat mirror washings.

8.3.1 Equipment

The equipment being utilized in the mirror surface soiling test program consists of two heliostat simulators and a cooling tower drift exposure table, devices specially designed and constructed for this type of testing. A heliostat simulator, pictured on Figure 8.3-1, consists of a 0.6 m by 0.6 m (2 ft by 2 ft) metal array table and associated apparatus necessary to rotate the table in a manner so as to mimic the motion of a heliostat. The metal array table supports an array of .05 m by .05 m (2 in by 2 in) mirror coupons, which represent a heliostat mirror facet.

The simulator's metal array table is rotated by an electric actuator which is controlled by a solid-state programmable timer and powered by two automotive-type batteries. The timer is programmed to command the array table to assume four angular positions. At 6:00 a.m., approximately sunrise, the array table is rotated to its first position--face-up, tilted to the south and east, as depicted on Figure 8.3-1. At 10:00 a.m., the array table is rotated to its second position--face-up, tilted to the south. At 2:00 p.m., the table proceeds to the third position--face-up, tilted to the south and west. At 6:00 p.m., approximately sunset, the array table is rotated to the fourth position, the stow position--face-down. The cycle is repeated each day, thus approximating the motions of an actual heliostat. In this manner, soiling of the mirror coupons should be representative of that expected of an actual heliostat.

Each week, one test mirror coupon is removed from each simulator. Upon removal, the coupons are placed in a holder which is then encased in a plastic bag to exclude extraneous dust. The removed coupon is replaced with a "dummy" coupon, thus preserving the aerodynamic characteristics of the test array. When 14 test coupons have been collected in a holder,

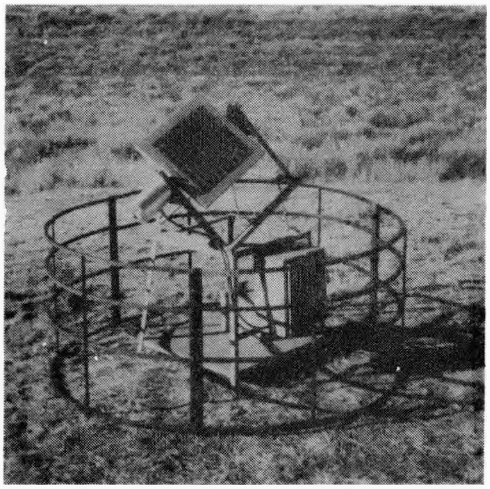

FIGURE 8.3-1. ONE OF TWO HELIOSTAT SIMULATORS INSTALLED AT THE CRS

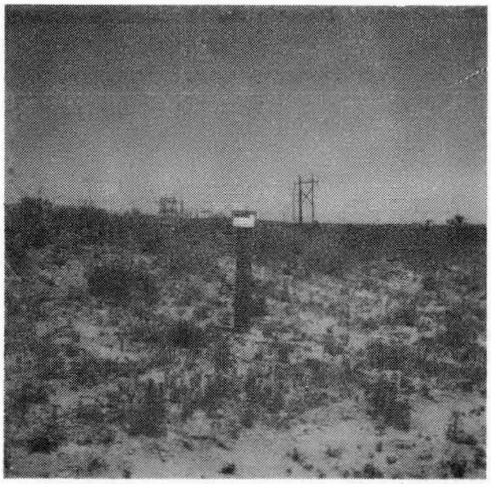

FIGURE 8.3-2. THE COOLING TOWER DRIFT EXPOSURE TABLE

the coupons are mailed to the Battelle Pacific Northwest Laboratories (PNL) for optical measurements.

As shown on Figure 8.1-1, two heliostat simulators were deployed. One simulator (B) is located about 150 m (500 ft) to the north of the cooling towers to represent heliostats most likely to be affected by cooling tower drift. The other simulator (A) is located in a remote portion of the proposed heliostat field to provide a "reference" value of mirror contamination. This simulator should only be exposed to "background" dust and pollens and be essentially unaffected by cooling tower drift, since drift effects decrease with distance from the cooling towers.

In addition to the two heliostat simulators, an experiment was established to provide an indication of the potential severity of mirror fouling due to cooling tower drift. For this experiment, a small, fixed-position table, pictured on Figure 8.3-2, was erected about 30 m (100 ft) to the north of the cooling towers, as shown on Figure 8.1-1. Mirror coupons, identical to those used on the simulators, were placed on the table; one coupon is removed every two weeks for shipment to PNL for optical measurements. These coupons will indicate the severity of surface contamination of heliostat mirrors due to cooling tower drift that is to be expected under the most adverse conditions--i.e. the amount of tower drift should decrease with distance, with the drift table being closer to the cooling tower than any of the heliostats in the proposed field location.

The two heliostat simulators were placed in the proposed collector field and started operation on January 15, 1981. The first coupons were collected from the simulators on Friday, January 23; collections have proceeded weekly since. The cooling tower drift exposure table was placed in the field on February 3, 1981; the first mirror coupon was removed on February 13. Coupon collection from the drift exposure table has proceeded since at approximately two-week intervals.

8.3.2 Results

Results through April are presented in Figure 8.3-3. Note that, as indicated by the solid/hollow data points, at various times throughout the test period one of the heliostat simulators was not tracking. During these times, the malfunctioning simulator was in a face-up fixed position, in

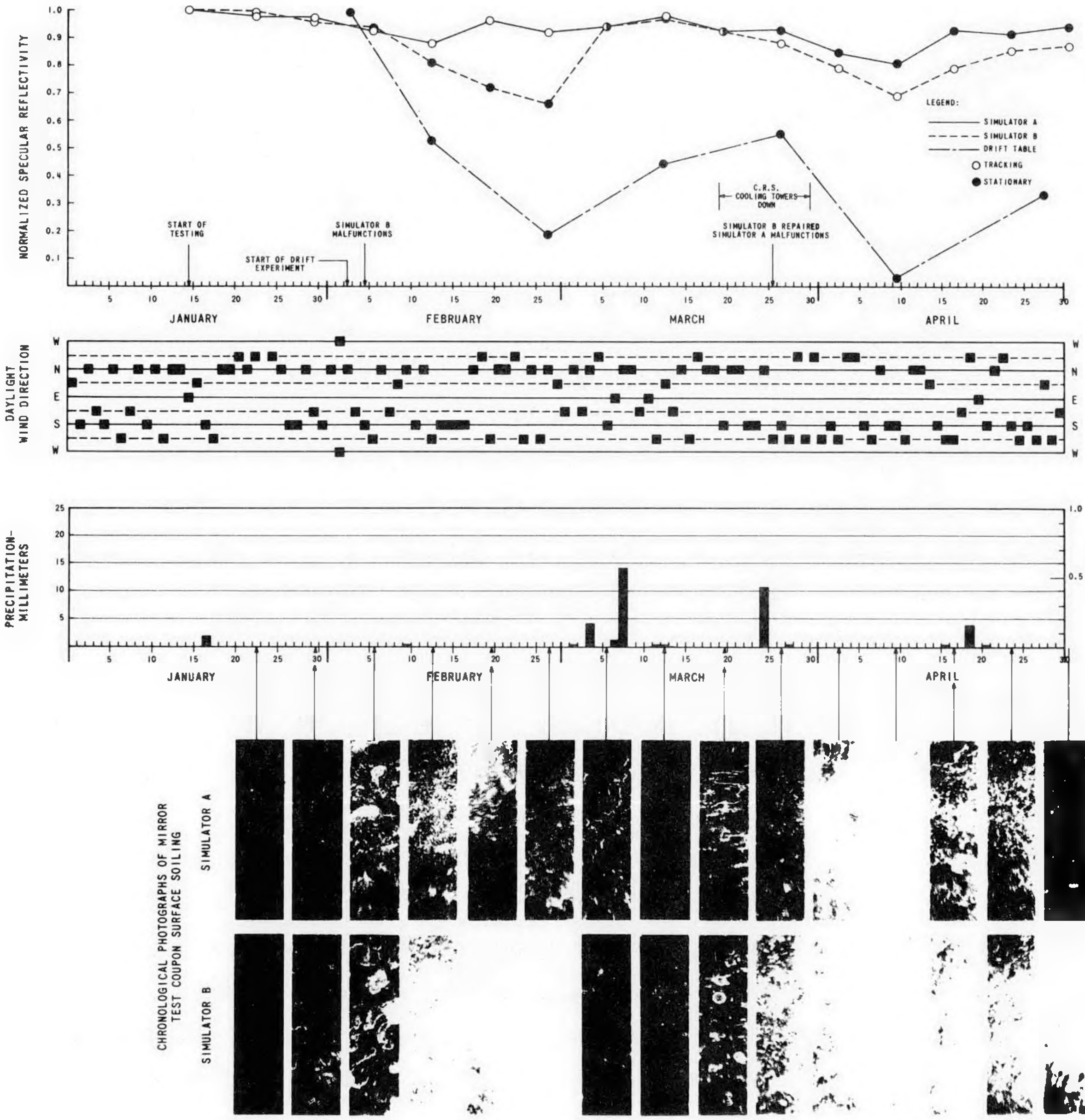

FIGURE 8.3-3. RESULTS OF THE HELIOSTAT MIRROR SURFACE SOILING EXPERIMENT

that position the mirrors would be more exposed to the elements than normal due to the lack of a stow position during non-daylight hours. The bottom portion of Figure 8.3-3 shows segments of photographs of the mirror test coupons taken from the two heliostat simulators, arranged in chronological order. The top row of coupons were taken from Heliostat Simulator A, the simulator located farthest from the cooling towers. The bottom row of coupons were taken from Heliostat Simulator B, the simulator to the north (down wind) of the cooling towers. In these photographs, darkness indicates relative cleanliness--the darker the photograph, the cleaner the mirror coupon.

The photographs on the left of Figure 8.3-3 show coupons that have been exposed continuously to the local environment for approximately one week following their placement on the heliostat simulators on January 15. The pictured coupons increase in exposure time in week-long increments moving from left to right. The coupons pictured at the right of the figure have been continuously exposed to the local environment for approximately 15 weeks following their placement on the heliostat simulators.

The photographs in Figure 8.3-3 visually indicate a buildup of surface soil on the mirror coupons (dark areas becoming lighter moving from left to right). Occurances of dramatic reversal where precipitation has cleansed the mirrors are also apparent (light areas suddently becoming dark moving left to right). The collection dates of the test coupons in the photographs are indicated by the arrows above the rows of photographs pointing to the time scale.

The history of precipitation during the test period is plotted as a histogram along this same time scale. As can be seen, the transition from light to dark observed in the photographs directly corresponds with the occurence of precipitation. Precipitation is shown in units of equivalent liquid: frozen precipitation is first melted before being measured.

The history of the wind direction occurring during the daylight hours is plotted above the precipitation history also for the same time scale. Wind direction is given as the predominant direction occurring during daylight hours; the wind may have been from directions at times during the day other than that shown. Wind direction has been quantized into eight directions.

The photographs in Figure 8.3-3 provide only a qualitative impression of the degree of surface soiling experienced at two places in the proposed location of the collector field. Quantitative results are provided by the measurements performed at the Battelle Pacific Northwest Laboratories (PNL).

At PNL, the total hemispherical reflectance and the diffuse reflectance of each mirror test coupon are measured. The difference between unity and total hemispherical reflectance is the absorptivity of the coupon. Absorptivity is the percentage of incident light (solar energy) that is not reflected by the mirror; rather it is absorbed and converted to thermal energy. The difference between the total hemispherical reflectance and the diffuse reflectance is the specular reflectance of the coupon (the specular reflectance is the parameter of primary interest). Specular reflectance is the percentage of incident light that is "cleanly" reflected (angle of incidence equals angle of reflection). Diffuse reflectivity is the percentage of incident light that, although reflected, it is not "cleanly" reflected but rather reflected in random directions (scattered). The sum of the absorptivity, specular reflectivity, and diffuse reflectivity must be equal to unity (100 per cent).

From the data measured at PNL, it was found that mirror absorptivity remained nearly constant and that a decrease in specular reflectivity was accompanied by a corresponding increase in diffuse reflectivity (the surface soil did not absorb light, but rather was itself diffusely reflective). Thus, surface soil degrades mirror specular reflectivity by scattering the intercepted insolation in lieu of absorbing it.

Shown in the top half of Figure 8.3-3 are the chronological plots of normalized specular reflectivities of the coupons taken from the two heliostat simulators and from the cooling tower drift exposure table. Normalized specular reflectivity is the measured specular reflectivity divided by the clean mirror specular reflectivity. As such, the plot indicates the degree of heliostat specular reflectivity reduction that could be expected given a second surface silvered glass of the type used for these tests and the specific conditions of the CRS site.

Examination of the plots of normalized specular reflectivity show that the soiling of the two simulators were practically identical for the first 4 weeks. After 4 weeks, which corresponded with the malfunctioning of Simulator B, Simulator B began to soil much more rapidly than Simulator A. In a fixed face-up position, soiling might be expected to occur at nominally two to three times the rate as in a tracking mode. However, it is seen that it occurs at rates greater than that. Examination of the wind direction histogram shows that during this period, winds were predominantly from the south and southwest, which would carry cooling tower drift towards Simulator B. This suggests that cooling tower drift is contributing to the soiling of the mirror coupons on Simulator B. This observation is reinforced by the repeat of specular reflectivities divergence beginning in late March. Again, Simulator B's reflectivity decreased faster than Simulator A's during a period when the wind was predominantly from the south and southwest. It is significant that during this period, it was Simulator A that was in a fixed face-up position and not Simulator B.

The occurrence of precipitation in early March is seen to have nearly restored both simulators' normalized specular reflectivities to their clean-mirror values. This cleaning phenomenon is seen again in mid-April. However, the April rainfalls were not of sufficient magnitude to restore fully the normalized specular reflectivities of the two simulators, especially that of Simulator B.

Similar, although more pronounced, trends are present in the drift table coupons which indicate the influence of the cooling towers in the immediately surrounding area. The initial drop in reflectivity again occurs when the wind is predominantly southerly. Precipitation does restore reflectivity to some degree, although the extent of the restoration is masked by the relatively long, two week coupon collection interval.

The plot of normalized specular reflectivities of the coupons taken from the two heliostat simulators suggests that it will be necessary to wash most of the heliostats on the order of once per month if they are to be maintained at an average specular reflectivity equal to 95 per cent of their clean-mirror reflectivity. This estimate assumes that washing will fully restore the heliostats to their clean-mirror value. The more rapid soiling of the drift table coupons suggests that heliostats very close [30-60 m (100-200 ft)] to the cooling towers may require more frequent washing.

Althouth natural washing of the test coupons appears to have been reasonably effective, other test programs have reported the occurrence of an irreversible soiling of glass mirrors. This phenomenon reportedly occurs when silica-based dust accumulates on the surface of the glass and then the glass becomes wetted for extended periods of time (on the order of months). The water leaches salts from the glass substrate. These salts then bond the dust particles to the glass, acting as a "glue." The dust becomes an integral part of the glass substrate and cannot be readily removed via washing. Thus, the specular reflectivity of the mirror is permanently degraded.

To evaluate the effectiveness of heliostat washing and to test to see if the above phenomenon is present at the proposed site, four coupons taken from each of the two heliostat simulators and two coupons taken from the cooling tower drift exposure table were washed in a manner simulating heliostat washing. These coupons were then remeasured to see if their specular reflectivities had been restored to their initial clean-mirror value.

Heliostat washing was simulated by spraying the coupons with a high-pressure jet of a detergent-water solution followed by a thorough rinsing with water. No mechanical cleaning (wiping/scrubbing) was employed. In order to assess the cleaning contribution of the detergent, one of the two mirror test coupons from the cooling tower drift exposure table was washed using only a high-pressure water jet; no detergent was employed.

Following the washing of the coupons and the subsequent measurement of their reflectivities, the coupons were washed a second time. The second washing consisted of "scrubbing" the mirror coupons with a soft cloth and a mild soap and water solution, followed by a thorough rinse. After the second washing, the coupons' reflectivities were again measured.

The results of the washing tests are shown in Table 8-1. As can be seen, the reflectivities of most of the coupons removed from the two heliostat simulators were significantly improved by the high-pressure washing, at least up through the coupons exposed for a 12-week period. However, the

TABLE 8-1. HELIOSTAT WASHING SIMULATION TEST RESULTS

Mirror Coupon	Collection Date	Normalized Specular Reflectivity[a] Before Wash	After Wash[b]	After Scrub[c]
A-4	2/13	0.870	0.976	0.987
A-8	3/13	0.978	0.991	0.995
A-12	4/10	0.802	0.928	0.990
A-16[d]	5/8	0.967	0.977	1.000
A-20[d]	6/5	0.934	0.955	1.000
B-4	2/13	0.807	0.966	0.991
B-8	3/13	0.969	0.971	0.995
B-12	4/10	0.687	0.906	0.982
B-16[d]	5/8	0.886	0.884	0.973
B-20[d]	6/5	0.878	0.895	0.995
CT-7[d]	5/8	0.420	0.423	0.480
CT-8[d]	5/8	0.440	0.445	--
CT-11[d]	6/19	0.107	0.313	0.407

A ≡ Heliostat Simulator A.

B ≡ Heliostat Simulator B.

CT ≡ Drift table by cooling tower.

[a]Shown normalized specularities are accurate to within ±0.005 reflectance units.

[b]All coupons were washed with a high-pressure spray of a water-detergent solution followed by a water rinse except for CT-8; no detergent was used on CT-8.

[c]All coupons were "scrubbed" using a soft cloth and a mild soap-water solution followed by a water rinse.

[d]These coupons do not appear on Figure 8.3-3.

high-pressure wash was not effective on the coupons exposed for a 16-week period on Simulator B for a period longer than 16 weeks. Within the accuracy of the measurements, Coupon B-16's reflectivity did not change as a result of the high-pressure washing. The high-pressure wash, with or without detergent, had no effect on the reflectivities of the coupons taken from the cooling tower drift table after a 14-week exposure; some improvement is seen for the Coupon CT-11, which had been exposed for 20 weeks.

The second washing, using a soft cloth to scrub the mirrors, is seen to virtually fully restore the reflectivities of the coupons taken from Simulator A. A significant improvement is seen in the corresponding reflectivities of the coupons taken from Simulator B. However, there is a slight decreasing trend in the "restored" reflectivities of the coupons taken from Simulator B. Scrubbing was largely ineffective in restoring the specular reflectivity of the coupon taken from the cooling tower drift exposure table. Thus, there is an irreversible soiling of the mirror surface occurring at the cooling tower drift exposure table, and, to a much lesser extent, some irreversible soiling may be occurring at Heliostat Simulator B.

Simulator B, due to its proximity and orientation, should be exposed to more cooling tower drift than Simulator A. Likewise, the cooling tower drift exposure table should be subjected to more drift than Simulator B. Given the increasing soiling with reduced distance to the cooling tower, there are indications that the irreversible soiling is due to exposure to cooling tower drift. However, it should be noted that both the test duration and the number of test coupons are limited and may not properly reflect long term events.

8.4 SUMMARY AND CONCLUSIONS

An insolation station was established at the proposed site in order to evaluate the solar energy resource. To date, direct normal insolation data collected exhibits some differences on a month-to-month basis from published data derived from historical total horizontal insolation data. This may be because either 1981 to date is atypical or because the published data is in error, or a combination of the two. Measured data also differs on a month-to-month basis with estimates computed from other meteorological data collected during the test period. Further data will provide a better comparison and facilitate an accurate estimation of the actual insolation resource.

An experiment was established to quantify the impact of the environment on heliostat reflectivity. It was found that for most of the proposed collector field, cooling tower drift is not a major concern, although it may exert some influence at distances of 150 m (500 ft) and less from the cooling towers. To control this potential problem, heliostats in proximity to the cooling towers could be washed frequently, as discussed in Subsection 3.3.3, or, if necessary, the collector field could be slightly relocated. It was found that high-pressure spray washing of the mirrors not subjected to cooling tower drift nearly fully restored mirror specular reflectivity to the clean-mirror value. Based on data collected to date, it appears that the heliostat field will require washing approximately once per month (this is the basis of O&M costs reported in Section 4.8) in order to maintain the heliostats' specular reflectivity at an average value equal to 95 per cent of the clean-mirror value. Further test data will better define required washing frequency and the long-term impact of cooling tower drift. Establishing the special requirements, if any, of those heliostats close to the cooling tower will be required.

Both the monitoring of direct normal insolation and the measurement of heliostat mirror soiling at the proposed site will be continued through the remainder of 1981.

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9.1 REFERENCES FOR SECTION 1

None

9.2 REFERENCES FOR SECTION 2

None

9.3 REFERENCES FOR SECTION 3

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9.5 REFERENCES FOR SECTION 5

None

9.6 REFERENCES FOR SECTION 6

None

9.7 REFERENCES FOR SECTION 7

None

9.8 REFERENCES FOR SECTION 8

None

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