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SOLAR PILOT PLANT, PHASE 1. PRELIMINARY DESIGN REPORT

Volume 6. Electrical Power Generation; Master Control Subsystems; Balance of Plant. CDRL Item 2

066

May 1, 1977

Work Performed under Contract EY-76-C-03-1109

Energy Resources Center
Honeywell, Incorporated
Minneapolis, Minnesota

U.S. Department of Energy

Solar Energy

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Honeywell

ERDA Contract No. E(04-3)-1109

1 MAY 1977

SOLAR PILOT PLANT
PHASE I

PRELIMINARY DESIGN REPORT

VOLUME VI

ELECTRICAL POWER GENERATION MASTER CONTROL SUBSYSTEMS BALANCE OF PLANT

CDRL Item 2

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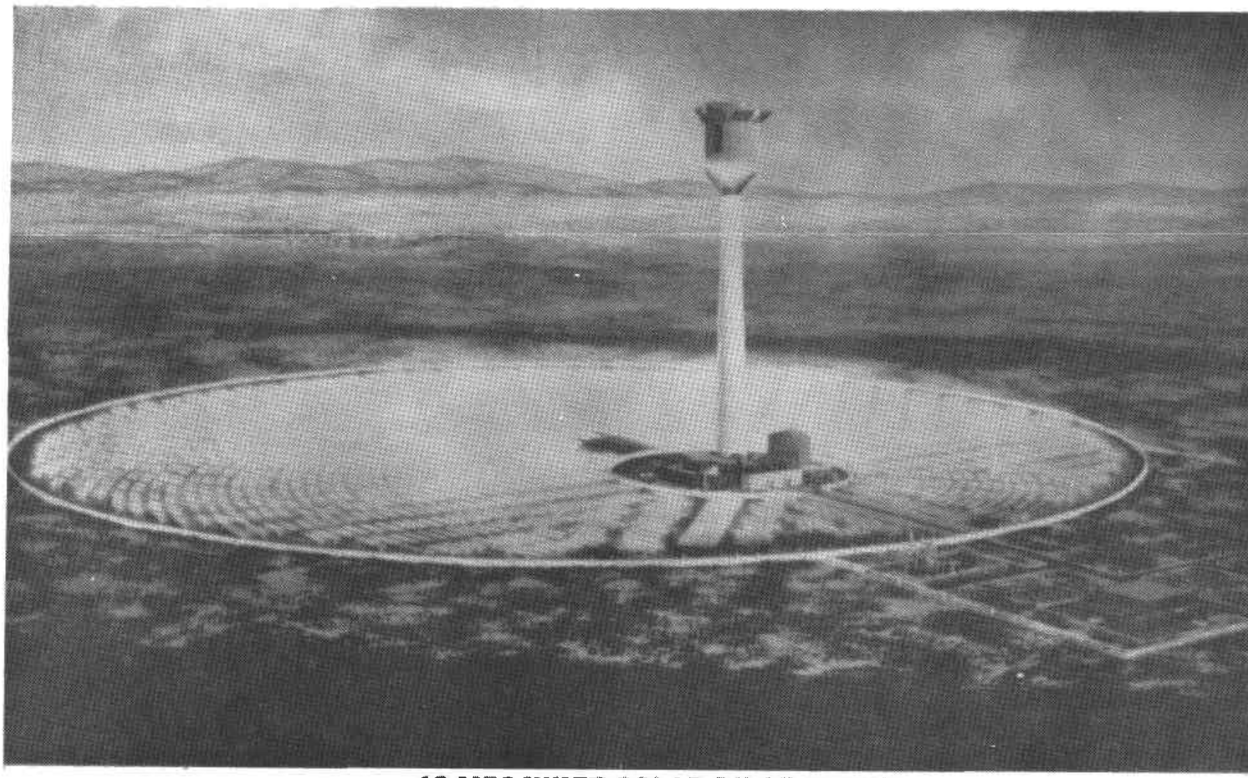
FOREWORD

This is the initial submittal of the Solar Pilot Plant Preliminary Design Report per Contract Data Requirement List Item 2 of ERDA Contract E(04-3)-1109. The report is submitted for review and approval by ERDA. This is Volume VI of seven volumes.



10 MEGAWATT SOLAR PILOT PLANT
ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION

ABSTRACT

ELECTRICAL POWER GENERATION SUBSYSTEM, CONTROLS, AND BALANCE-OF-PLANT

The Honeywell electrical power generation subsystem centers on a General Electric dual admission, triple extraction turbine generator sized to the output requirements of the Pilot Plant. The turbine receives steam from the receiver subsystem and/or the thermal storage subsystem and supplies those subsystems with feedwater. The turbine condensor is wet cooled. The plant control system consists of a coordinated digital master and subsystem digital/analog controls. The remainder of the plant, work spaces, maintenance areas, roads, and reception area are laid out to provide maximum convenience compatible with utility and safety. Most of the activities are housed in a complex around the base of the receiver tower. This volume contains a description of the relationship of the electrical power generation subsystem to the rest of the plant, the design methodology and evolution, the interface integration and control, and the operation and maintenance procedures.

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SECTION 1
INTRODUCTION

BACKGROUND

Supplies of most conventional fuels are being depleted rapidly. Consequently, it is necessary to identify alternate sources of energy and to develop the most promising to ensure availability when needed.

An alternative with great potential is the conversion of sunlight to energy. One aspect of this usage is generating electricity through solar energy. A goal of the national energy program is to demonstrate the technical and economic feasibility of a central receiver solar power plant for generating electricity. Pursuant to that goal, the Energy Research and Development Administration (ERDA), on 1 July 1975, awarded Honeywell Inc. a two-year contract for Phase I of such a program.

The initial program phase, which is the subject of this report, consisted of developing a preliminary design for a 10 MW(e) proof-of-concept solar pilot plant. The second phase will consist of building and operating the pilot plant and projecting the information gained to larger-scale plants. This phase is scheduled to be completed in the early 1980's. The third phase will consist of designing, building, and operating two 50-100 MW(e) demonstration plants. The final phase will consist of building and operating plants in the 100-300 MW(e) range.

PHASE I PROGRAM SCOPE

The Phase I program consisted of developing a pilot plant preliminary design by first developing a preliminary baseline design to meet specified and assumed performance requirements. The baseline was then refined through analysis and experimentation, and evaluated by testing key subsystems, i.e., collector, steam generator, and thermal energy storage.

The complexity of the undertaking dictated a team approach to provide the technical and managerial skills required. The Honeywell team is identified in Figure 1-1.

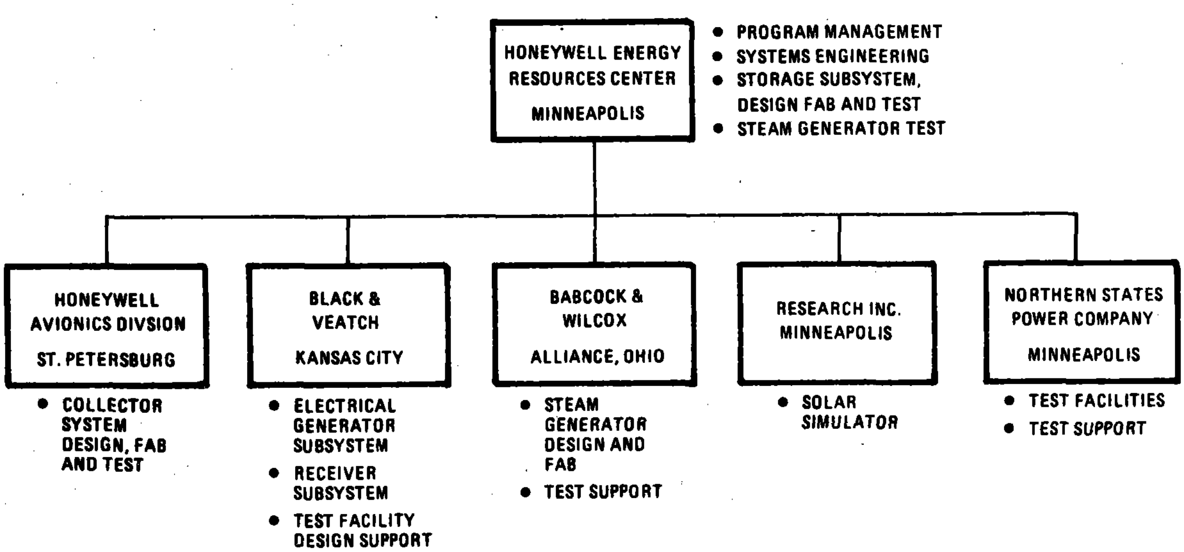


Figure 1-1. Honeywell Team for Phase I Solar Pilot Plant Program.

A unique feature of the test plan was the use of selected facilities of an operating power plant, Northern States Power's Riverside Plant in Minneapolis, Minnesota, to test the steam generator and thermal energy storage subsystems. An ERDA-directed change from latent heat (phase change) storage to sensible heat storage cancelled the storage portion of the test plan. The steam generator was tested using a solar array to simulate the insolation required to generate steam. The collector subsystem hardware, one mobile and three stationary, full-scale, four-mirror units, was field tested for performance and reaction to operating environments at Honeywell's Avionics Division facility in St. Petersburg, Florida.

The information obtained from the subsystems tests was used to complete the pilot plant preliminary design, and to project performance and cost of a 100 MW(e) plant to facilitate long-range planning.

The chronology of the work done in Phase I is summarized in Figure 1-2.

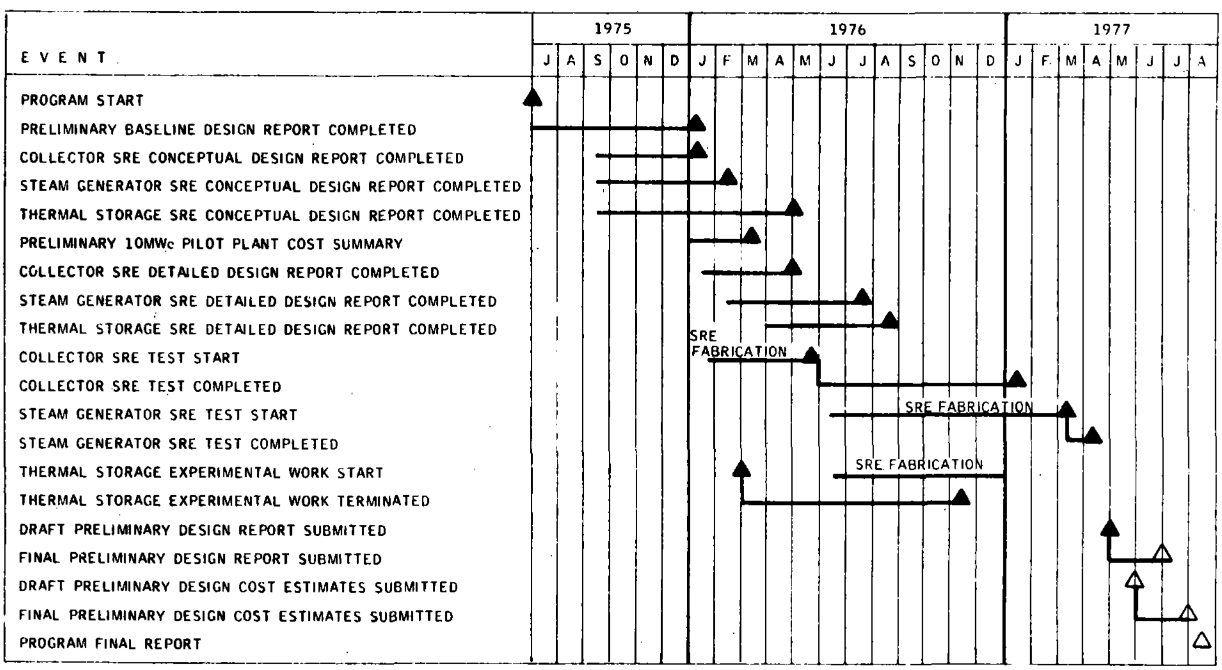


Figure 1-2. Chronology of Phase I Solar Pilot Plant Program

ORGANIZATION OF THE PRELIMINARY DESIGN REPORT

The preliminary design and supportive data resulting from the Phase I work are presented in seven volumes:

- I - Executive Overview
- II - System Description and System Analysis (3 books)*
- III - Collector Subsystem
- IV - Receiver Subsystem
- V - Thermal Storage Subsystem
- VI - Electrical Power Generation/Master Control Subsystems and Balance of Plant
- VII - Pilot Plant Cost/Commercial Plant Cost and Performance

Abstracts of volumes other than the one in hand and Volumes I and VII are on the following pages.

*Book 2 is Central Receiver Optical Model Users Manual
Book 3 is Dynamic Simulation Model and Computer Program Descriptions

ABSTRACTS

Vol. II - SYSTEM ANALYSIS AND SYSTEM DESCRIPTION

Honeywell conducted a parametric analysis of the 10 MW(e) solar pilot plant requirements and expected performance and established an optimum system design. The main analytical simulation tools were the optical (ray trace) and the dynamic simulation models. These are described in detail in Books 2 and 3 of this volume under separate cover. In making design decisions, available performance and cost data were used in provide a design reflecting the overall requirements and economics of a commercial-scale plant. This volume contains a description of this analysis/design process and resultant system/subsystem design and performance.

Vol. III - COLLECTOR SUBSYSTEM

The Honeywell collector subsystem features a low-profile, multifaceted heliostat designed to provide high reflectivity and accurate angular and spatial positioning of the redirected solar energy under all conditions of wind load and mirror attitude within the design operational envelope. The heliostats are arranged in a circular field around a cavity receiver on a tower halfway south of the field center. A calibration array mounted on the receiver tower provides capability to measure individual heliostat beam location and energy periodically. This information and weather data from the collector field are transmitted to a computerized control subsystem that addresses the individual heliostat to correct pointing errors and determine when the mirrors need cleaning. This volume contains a detailed subsystem design description, a presentation of the design process, and the results of the SRE heliostat test program.

Vol. IV - RECEIVER SUBSYSTEM

The Honeywell receiver subsystem design uses well established fossil technology and consists of a cavity receiver housing, a steam generator, a cavity barrier, piping, and a support tower. The steam generator absorbs the redirected solar energy from the collector subsystem and converts it to superheated steam which drives the turbine. The receiver is adequately shielded to protect personnel and equipment. A cavity barrier is lowered at night to conserve heat and expedite startup the following day. This volume contains the subsystem design and methodology and the correlation with the design and performance characteristics of the SRE steam generator which was fabricated and successfully tested during the program.

Vol. V - THERMAL STORAGE SUBSYSTEM

The Honeywell thermal storage subsystem design features a sensible heat storage arrangement using proven equipment and materials. The subsystem consists of a main storage containing oil and rock, two buried superheater tanks containing inorganic salts (Hitec), and the necessary piping, instrumentation, controls, and safety devices. The subsystem can provide 7 MW (e) for three hours after twenty hours of hold. It can be charged in approximately four hours. Storage for the commercial-scale plant consists of the same elements appropriately scaled up. This volume contains a description of the subsystem design methodology and evolution and the subsystem operation and performance.

Section 2

SUMMARY ELECTRICAL POWER GENERATION SUBSYSTEM/BALANCE OF PLANT AND MASTER CONTROL SUBSYSTEM DESCRIPTION

The preliminary design of the Solar Pilot Plant Electrical Power Generation Subsystem (EPGS)/Balance of Plant (BOP) and the Master Control Subsystem is summarized in this section. Subsystem design requirements are reviewed, the design approach is explained, brief descriptions of subsystem design are presented, and consideration is given to the justification of the design. A detailed discussion of the EPGS/BOP and the Master Control Subsystem is provided in Section 3 of this volume.

ELECTRICAL POWER GENERATION SUBSYSTEM/BALANCE OF PLANT SUMMARY DESCRIPTION

The Electrical Power Generation Subsystem (EPGS)/Balance of Plant (BOP) convert thermal energy in the receiver and thermal storage steam supplies into electricity and provide the support facilities for the pilot plant. This summary presents the requirements, design approach, general description and design justification for the EPGS.

Requirements

The EPGS design is based on meeting pilot plant design requirements and interfacing with the other subsystems. The primary performance requirements the EPGS is designed to satisfy are as follows.

(1) Generating 10 MW net busbar electricity at 2 p.m. on a clear day at winter solstice using superheated steam supplied directly from the receiver subsystem.
(2) Generating 7 MW net busbar electricity for a period of three hours using superheated steam supplied directly from the thermal storage subsystem.
(3) Generating 7 MW net busbar electricity using steam from the receiver and thermal storage subsystems simultaneously.
(4) Operating safely and reliably with the maximum steam flow generated by the receiver subsystem.

The EPGS design must have the flexibility to perform efficiently in all the primary operating modes shown in Table 2-1 and to change smoothly from one mode to the other. In Mode A, the turbine generator is driven directly by receiver steam while the thermal storage subsystem is holding. This corresponds to the mode of operation described in the first requirement above. In Mode B, the turbine generator is driven directly by thermal

TABLE 2-1

PILOT PLANT PRIMARY OPERATING MODES

Subsystem	Mode A	Mode B	Mode C	Mode D
Collector	Focused	Defocused	Focused	Focused
Receiver	Generating Steam	Sealed	Generating Steam	Generating Steam
Thermal Storage	Holding	Discharging	Discharging	Charging
EPGS/BOP	Generating Electricity	Generating Electricity	Generating Electricity	Sealed

storage steam while the collector subsystem is defocused and the receiver cavity is sealed by the cavity barrier to minimize heat loss. This corresponds to the mode of operation described in the second requirement above. In Mode C, the turbine generator is driven by steam from the receiver and thermal storage subsystems simultaneously. This corresponds to the mode of operation described in the third requirement above. In Mode D, the receiver is charging the thermal storage subsystem. In this mode of operation, the turbine generator is not producing electricity but the EPGS is pumping the condensed charging steam back to the receiver. The turbine is sealed to prevent corrosion.

The EPGS must also be capable of operation in a number of other plant modes, including:

(1) Receiver driving the turbine and charging thermal storage.
(2) Receiver and thermal storage driving the turbine simultaneously while the receiver is charging thermal storage.
(3) Receiver charging thermal storage while thermal storage is driving the turbine.
(4) Diurnal shutdown of the receiver while thermal storage is providing seal steam to the turbine.

The EPGS must be designed to undergo all possible mode transitions quickly and efficiently.

Design Approach

The EPGS/BOP is the most conventional part of the pilot plant. The design selected, with minor modification, could be used in a power plant which operates on fossil fuel. The EPGS/BOP is designed with the ultimate utility owner in mind. To be practical, the solar power plant must tie into the utility grid and require as few operational or maintenance adjustments as possible.

Proven power plant design practice is the basis for the EPGS/BOP design. From the basic subsystem arrangement to the pipe flow velocities, industry codes and standards, and proven engineering design procedures, were used in the design.

The EPGS/BOP design incorporates standard equipment and state-of-the-art technology. All components in this subsystem are presently commercially available; no experimentation is necessary.

The turbine generator size, 15 MWe nominal generating capacity, is selected to satisfy the primary performance requirements. The turbine generator must generate 12 MWe at 2 p.m. on winter solstice using receiver steam to meet the busbar electrical power requirement and satisfy the auxiliary power demand. The receiver steam flow necessary to generate

12 MWe will be exceeded by a maximum amount of about 23 per cent at noon on the equinoxes, according to clear air model insolation data. The turbine generator output at this peak flow is about 14.6 MWe. Of the standard turbine generator unit sizes available from the General Electric Company (10, 12.5, 15, and 20 MWe) the 15 MWe unit best satisfies the design requirements.

Two concerns of every power plant design are capital investment cost and busbar energy cost. It is desirable to keep both as low as possible without sacrificing reliability, flexibility, and efficiency. Components were selected on the basis of maximizing plant output and minimizing total plant cost, not just component cost.

General Description

The major elements of the EPGS/BOP are:

(1) Turbine Generator
(2) Mechanical Systems
(3) Electrical Systems

A schematic arrangement of the Electrical Power Generation Subsystem is shown in Figure 2-1.

Turbine Generator. The EPGS design centers around the Turbine Generator System. The function of the Turbine Generator System is to convert thermal energy to electrical energy. A nominal 15 MWe General Electric Company automatic admission turbine generator is selected on the basis of meeting the performance requirements and operating in the modes described above. The turbine steam conditions selected are 10,101 kPa (1465 psia), 510 C (950 F) at the turbine throttle (receiver steam) and 3275 kPa (475 psia), 388 C (730 F) at the admission port (thermal storage steam).

The turbine is a 3600 rpm, non-reheat, condensing, bottom exhaust, single-shell, automatic admission type turbine. Three extraction ports for regenerative feedwater heating are located between the automatic admission port and the turbine exhaust. The turbine is directly connected to a rotating field, synchronous, totally enclosed, air-cooled generator.

The major parts of the turbine are the main and admission stop valves and throttle valves, expansion stages, shaft or rotor extractions, exhaust, cooling steam bypass line and high pressure and low pressure packings (HP and LP PKG) or seals.

The turbine generator is designed to operate over a wide range of generator output. Generator output varies in relation to the flow rates of receiver and/or thermal storage steam used to drive the turbine.

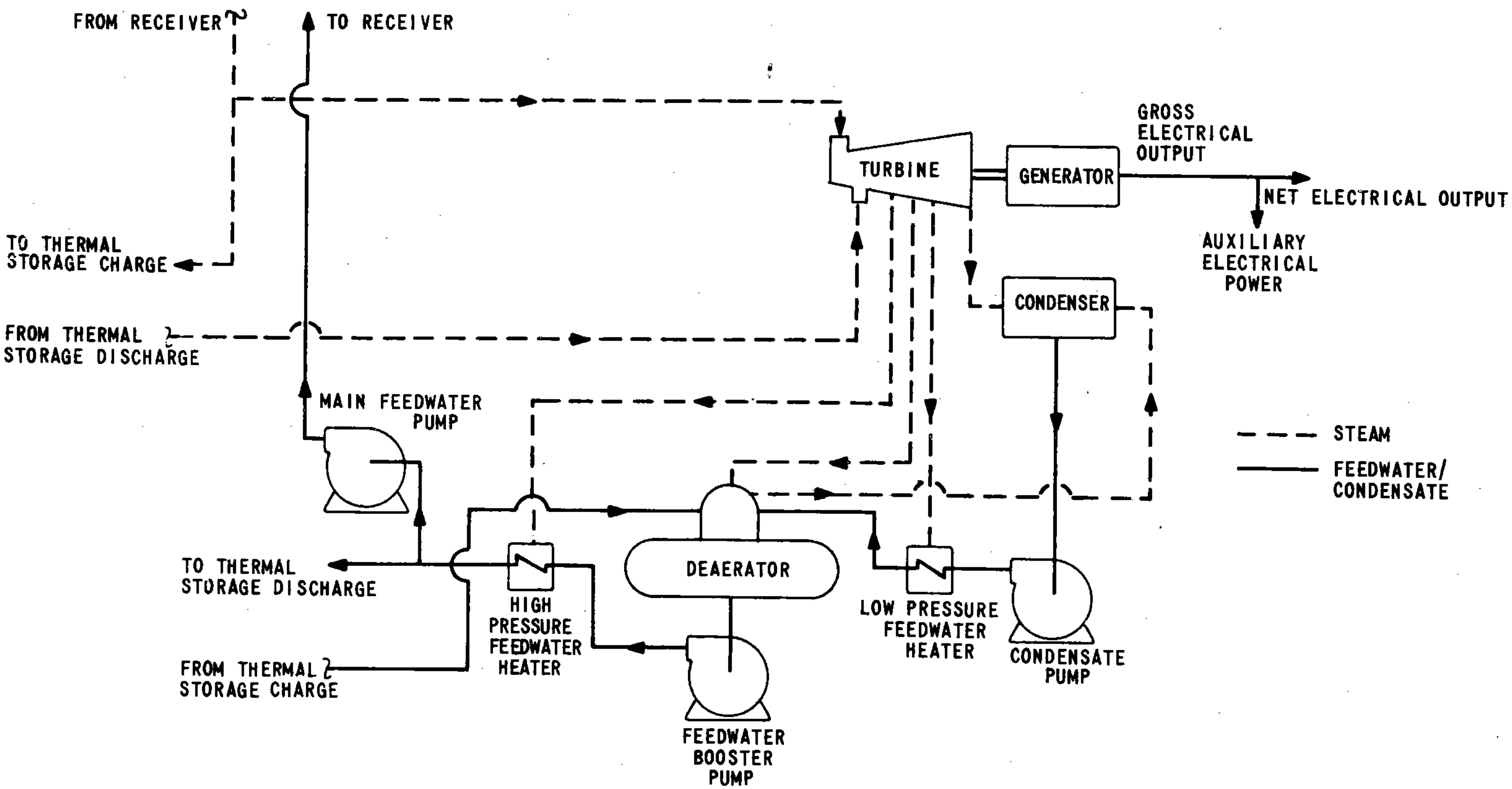


Figure 2-1. Electrical Power Generation Subsystem

Turbine generator performance varies as a function of back pressure. The turbine exhaust pressure, or back pressure, is determined by (1) the exhaust steam flow, (2) the condenser, cooling tower and circulating water system designs, and (3) the ambient air temperature. The design of the last stage turbine blades determines the limits of backpressure within which the turbine can operate efficiently.

Turbine life is significantly reduced at high temperature ramp rates over large temperature changes. For small temperature ramp rates, the turbine life is not affected by the amount of temperature change. Conversely, for small temperature changes, the turbine life is not affected by the temperature ramp rate.

The turbine generator is capable of start-up on receiver and thermal storage steam. The minimum times required for the turbine to be synchronized are 13 minutes when starting from hot stand-by and 34 minutes when starting from cold stand-by, assuming sufficient steam at rated conditions is available at the throttle or admission port. Hot stand-by refers to a condition which the turbine has reached after a shutdown period of up to 12 hours. Cold stand-by, on the other hand, refers to a condition which the turbine has reached after a shutdown period of more than 72 hours.

During diurnal shutdown, the turbine is maintained on its turning gear while steam is supplied to the turbine seals. The turning gear operation prevents shaft deformation and sealing prevents corrosion of turbine internals. The mass flow required for different seal steam pressures and temperatures at the seal steam regulator are:

Pressure kPa (psia)	Temperature C (F)	Mass Flow kg/hr (lb/hr)
10,101 (1465)	510 (950)	454 (1000)
3,275 (475)	388 (730)	454 (1000)
138 (20)	121 (250)	590 (1300)

The turbine is capable of varying load at 4 per cent rated load per minute and 10 per cent rated load instantaneous load change over the range of 20 per cent to 100 per cent load.

The transfer of steam sources from receiver to thermal storage and from thermal storage to receiver can be accomplished with zero steam mixing time, based on rated steam conditions.

The minimum shutdown time from emergency trip to zero speed is twenty to thirty minutes.

The turbine is controlled by an electro-hydraulic controller (EHC). The EHC uses a combination of electric and hydraulic circuits to regulate turbine operation. The turbine governor is used to regulate turbine speed prior to synchronization. After synchronization, the governor may be required to control load, admission steam pressure, or throttle steam pressure depending upon the operating mode of the plant.

Mechanical Systems. Five mechanical systems in the EPGS were designed in conjunction with the turbine system. These systems include:

(1) High Pressure Steam
(2) Extraction Steam and Heater Drain
(3) Feedwater
(4) Condensate
(5) Circulating Water

The High Pressure Steam System supplies steam from the receiver to the turbine high pressure steam stop valve and to the charging side of the thermal storage system. The High Pressure Steam System also supplies steam from the discharge side of the thermal storage system to the turbine admission steam stop valve.

Drip legs, provided for condensate removal from the high pressure steam lines, are located at the low point in the line as close as possible to the turbine.

All piping in the High Pressure Steam System is provided with electrical heating capable of maintaining metal temperature at 371 C (700 F) for the main steam and charging steam piping, and 316 C (600 F) for admission steam.

The Extraction Steam and Heater Drain System performs two functions. Turbine extraction steam is routed to the feedwater heaters, by the extraction steam system, for regenerative feedwater heating. Extraction steam condensed in the feedwater heater shell by the feedwater flowing through the heater tubes is drained from the heaters by the heater drain system.

Three stages of turbine extraction are provided.

(1) High pressure extraction to the high pressure feedwater heater.
(2) Intermediate pressure extraction to the deaerator.
(3) Low pressure extraction to the low pressure feedwater heater.

The Feedwater System functions are (1) to pump feedwater from the deaerator storage tank to the receiver and/or the thermal storage unit, (2) to provide regenerative feedwater heating, and (3) to provide desuperheating water to the receiver superheat desuperheater, and thermal storage charging system desuperheaters.

Feedwater from the deaerator storage tank is pumped by one of two full-capacity, high-speed, centrifugal feedwater booster pumps through the high pressure feedwater heater. At this point feedwater flow is directed as required to thermal storage and/or to one of the two full-capacity, high-speed, centrifugal feedwater pumps which in turn pumps to the receiver.

An auxiliary feedwater pump provides feedwater to thermal storage during diurnal shutdown to generate turbine seal steam. This pump requires minimal operating power compared to the feedwater booster pump for the low flow, low pressure feedwater supply required during diurnal shutdown.

Regenerative feedwater heating is provided for by the high pressure feedwater heater. The heater is of the shell and U-tube design with feedwater flowing through the tubes and turbine extraction steam flowing through the shell.

Desuperheating spray water for the receiver superheat desuperheater and thermal storage charging system desuperheaters is obtained from the discharge of the feedwater pumps.

The Condensate System condenses the turbine exhaust steam and delivers water from the condenser hotwell to the deaerator through the Low Pressure Feedwater Heater. In addition, this system supplies high quality water to the seal steam system and auxiliary cooling water makeup.

The primary function of the cylindrical, two-pass surface condenser is to condense the exhaust steam from the turbine. In addition, the surface condenser serves the following purposes.

(1) Recovers condensed steam as condensate.
(2) Provides a low exhaust pressure for the turbine for better operating efficiency.
(3) Provides a low pressure collection point for condensate drains from several systems in the plant.
(4) Provides deaeration of the collected condensate.
(5) Provides short-term storage of condensate.

The two full-capacity, vertical shaft, can type condensate pumps take suction from the condenser hotwell and supply the condensate through the low pressure feedwater heater to the deaerator.

The low pressure feedwater heater uses extraction steam to heat the condensate. It is a vertical shell and tube heat exchanger with an integral drains cooler.

The direct contact type deaerating heater is provided to remove oxygen and noncondensible gases from the condensate. The unit consists of a vertical-type deaerator located atop a horizontal storage tank.

The Circulating Water System provides cooling water to the condenser for condensing the turbine exhaust steam, and to the Auxiliary Cooling Water System heat exchangers for removing waste heat from plant equipment.

The induced mechanical draft, wood framed, filled, two cell type cooling tower rejects waste heat of the steam cycle and plant auxiliary equipment. The heat is rejected to the atmosphere by cooling the circulating water.

Two half-capacity, vertical wet pit type circulating water pumps supply water from the cooling tower basin to the condenser and auxiliary cooling water heat exchangers for heat rejection.

The remaining mechanical and chemical systems perform support functions for the major turbine cycle systems listed above, for the other subsystems, and for the overall pilot plant.

Electrical Systems

The EPGS Electrical Design systems consist of the following.

(1) Main Electric
(2) Auxiliary Electric
(3) Essential Service Power
(4) Miscellaneous Electrical Systems

The designs of these electrical systems are based on satisfying the busbar electricity requirements and meeting all the auxiliary equipment electrical needs of the EPGS, and other subsystems in the pilot plant.

The function of the Main Electric System is to generate gross electrical power at 13,800 volts, 60 hertz, and deliver the net busbar power to the utility transmission line at 115,000 volts. The Main Electric System has the capability to generate and deliver as much power as the turbine is able to develop under maximum steam flow conditions.

The generator has three stationary windings, called stator windings, and a rotating winding, called rotor or field winding. The excitation system provides direct current (dc) to the rotor winding thereby producing a magnetic field. Electrical power at 13,800 volts, three phase alternating current (ac) is generated at the terminals of the stator windings whenever the rotating magnetic field cuts through the stationary windings of the stator.

The function of the Auxiliary Electric System is to supply electrical power to all plant auxiliary loads. The auxiliary loads are defined as electrical loads required by the various auxiliary devices during shutdown, start-up, and different operating modes of the solar pilot plant. The Auxiliary Electric System has the capability to deliver as much power as will be required under all modes of plant operation.

The auxiliary electric power is tapped from the generator phase bus duct at 13,800 volts. For the most economic distribution, the auxiliary electric power is required at three different voltage levels.

(1) 4160 volts, three phase, for large loads, e.g., motors above 250 horsepower.
(2) 480 volts, three phase, for medium loads, e.g., integral horsepower motors up to 250 horsepower.
(3) 120 volts, single phase, for small loads, e.g., most fractional horsepower motors.

Different voltage levels are obtained by the use of transformers.

The function of the Essential Service Power System is to maintain a reliable, and in some cases an uninterruptible, supply of electrical power to those direct current (dc) and alternating current (ac) loads which are necessary for the protection of major plant equipment and which must remain in service under normal and/or abnormal operating conditions.

Depending on the criticality of the load it serves, the essential service power can be divided into the following three categories.

(1) dc power: supplied to certain dc loads whose operations are critical for the safety of equipment and personnel. Turbine emergency bearing oil pump is an example of critical dc load.
(2) Continuous ac power: supplied to certain critical ac loads, where an interruption of power cannot be tolerated under any normal and/or abnormal operating conditions of the solar pilot plant. This power supply is sometimes called "uninterruptible power supply." Such loads include the plant computers and certain devices having critical monitoring and instrumentation functions.
(3) Reliable ac power: supplied to those loads whose operations are extremely important but not as critical as the continuous ac loads. Turbine turning gear motor drive is an example of reliable power load.

The Miscellaneous Electrical Systems perform support functions for the EPGS, other subsystems, and the overall plant.

Design Justification

An automatic admission type turbine is used, rather than a more conventional single high pressure inlet turbine, in order to more fully accommodate the two steam conditions from the receiver and thermal storage subsystems, and to provide flexibility for meeting the operating requirements of the 10 MWe Solar Pilot Plant.

An automatic admission turbine can be designed without excess capacity to accommodate sufficient thermal storage generated steam to meet the specified generation requirement.

An automatic admission turbine is less expensive and requires a less complicated EPGS design than do two single inlet turbines, one for each steam source.

The turbine steam conditions, pressure and temperature at the throttle and admission, are selected to achieve high efficiency, to keep turbine size and cost as small as possible, and to minimize steam source transfer time while keeping within the limits of materials constraints.

The turbine generator size, or rated electrical capacity, is selected to permit the utility operator/owner to maximize the utilization of solar energy which the collector subsystem redirects into the receiver cavity and to permit testing of other plant subsystems at the limits of their capacities.

Three turbine extractions for regenerative feedwater heating are selected for the pilot plant on the basis of engineering judgment. The more extractions for regenerative feedwater heaters a turbine has, the greater its efficiency. However, the practicality of designing extraction ports in the shell of a nominal 15 MWe turbine limits the number of turbine extractions to about five. Further, the cost of the heat exchangers, piping, valves and controls associated with feedwater heaters typically reduces the number of turbine extractions below the turbine design limit.

Design of the feedwater pumping system requires selection of pump type, pump arrangement, pump capacity, and the potential use of an auxiliary feedwater pump for diurnal operation. The evaluation criteria for making these selections include capital cost, operating power requirements, and reliability.

High speed, single stage centrifugal pumps are selected over multi-stage centrifugal and positive displacement pumps on the basis of capital cost and pump operating power requirements. The concept of using a main feedwater pump and a feedwater booster pump is preferred to a single pump which utilizes throttling when delivering feedwater to thermal storage due to the lower power requirement. Two full-capacity pumps, one in operation, the other in a standby mode, for both main and booster feedwater pumping are less expensive and consume less auxiliary power than three half-capacity pumps, two in operation and one in standby. The use of an auxiliary feedwater pump is justified because of large power savings during diurnal shutdown.

The turbine back pressure which the condenser is designed to provide is selected on the basis of a study of solar power plant cooling systems. The condenser tube material is selected on the basis of cost and material compatibility with the plant chemical design. The condenser tube diameter is selected on the basis of standard industry practice. A condenser tube water velocity is selected to ensure turbulent flow yet prevent erosion and excessive pressure drop. The wet cooling tower approach temperature is based on minimal plant cost and site weather data. The tower is located outside and downwind (during prevailing winds) of the heliostat field to minimize the amount of drift reaching the heliostats.

The condenser tube length selected makes maximum use of the space provided by the turbine foundation while keeping the condenser extension past the turbine foundation to a minimum. The two-pass condenser water flow configuration is selected over a single-pass configuration on the basis of minimal cost.

In short, the design of the major mechanical systems meets all of the design criteria for the use of standard equipment, low plant cost, and reliable, flexible, efficient operation.

MASTER CONTROL SUBSYSTEM SUMMARY DESCRIPTION

The Master Control (Figures 2-2 and 2-3) must meet the primary objective of providing Pilot Plant operation such that solar energy is utilized most efficiently consistent with load demand and plant subsystem capability. It must maintain reliable operation and performance under steady state and transient conditions which include both start-up and shutdown. It also includes transitions between steady states as required by solar output, megawatt demand and changes in operating strategy. When solar conditions vary widely, the operating procedures must be changed to get optimum output. Data must be collected for monitoring and experimental objectives. Plant equipment must be protected from catastrophic failures or severe damage due to component or subsystem malfunction.

All plant subsystems, including Master Control, were designed so that the plant will operate at the same level of reliability as that of conventional generating units. Solar-unique characteristics require a special design approach for plant control. During the day, cloud passage will tend to interrupt or unbalance the collection of solar energy. To maintain operation under such conditions the plant must be capable of transition from receiver steam to storage generated steam in the minimum feasible time. These operating transitions and the requirement for daily start-up or shutdown expose the turbine and other massive high-temperature components to possible rapid exhaustion of fatigue life, and these maneuvers must be accomplished in a manner which minimizes this effect. Complex operating transitions must be accomplished without distracting operating personnel from the normal duties of monitoring plant operation. In addition, operating concepts for a commercial scale plant should be incorporated in the pilot plant control system for increased realism and to verify feasibility.

The present economics of electrical power generation by solar energy are governed by the capital intensive nature of the plant and indicate that the plant be operated to achieve the largest possible electrical energy generation. The control system is therefore designed to follow the variations in solar energy input as well as meeting a megawatt demand requirement of the utility's transmission grid.

The Master Control Subsystem was also designed recognizing that the solar pilot plant is a first-of-a-kind system employing new technology, and that maximum flexibility should be available so that many different operational strategies may be tried and evaluated. The experimental nature of the plant also required that an instrumentation system be developed which would monitor and record all relevant operating parameters. This same approach, i.e., incorporation of new technology, increased operating flexibility, and data collection, was followed in design of the plant control room and specification of plant personnel requirements.

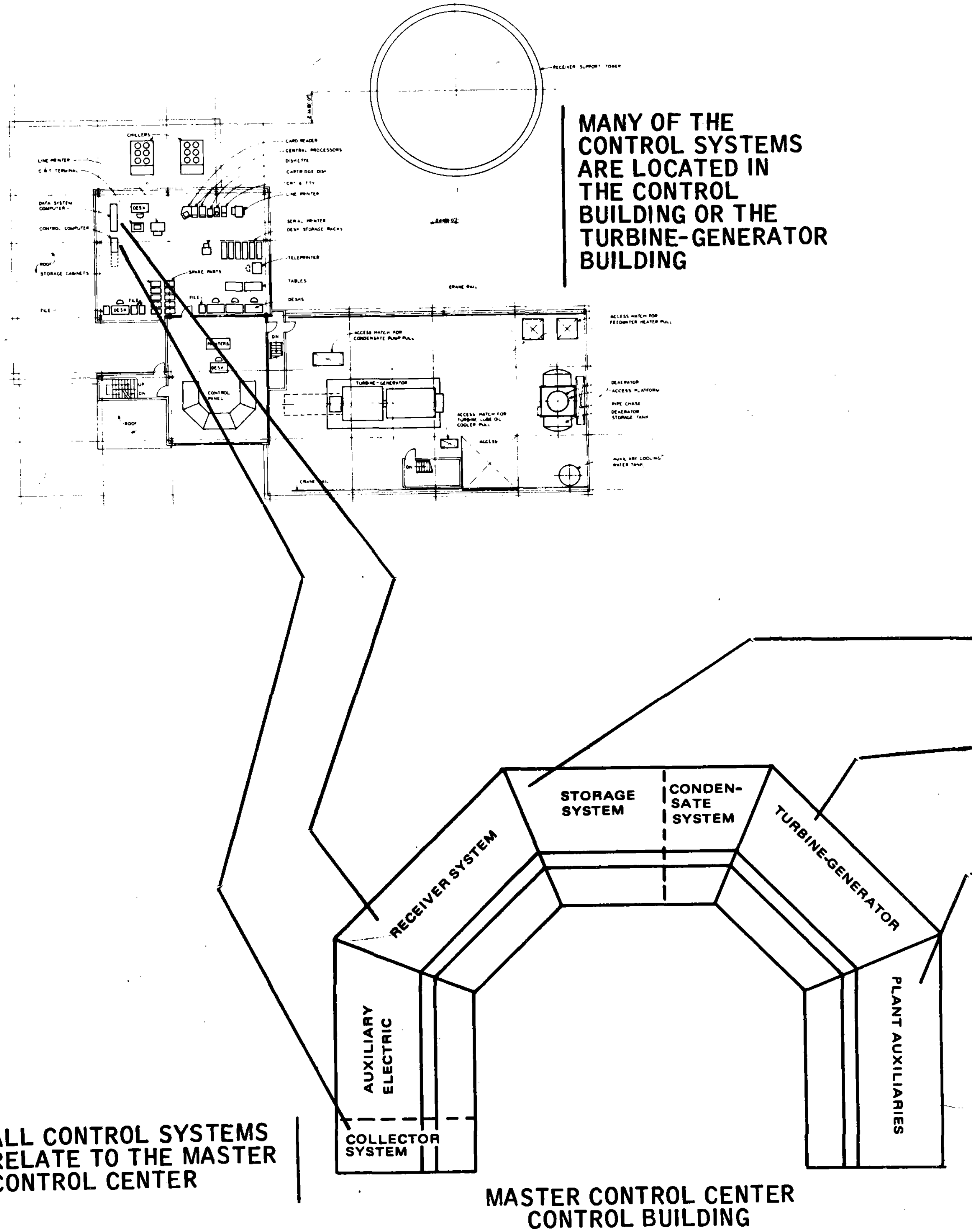
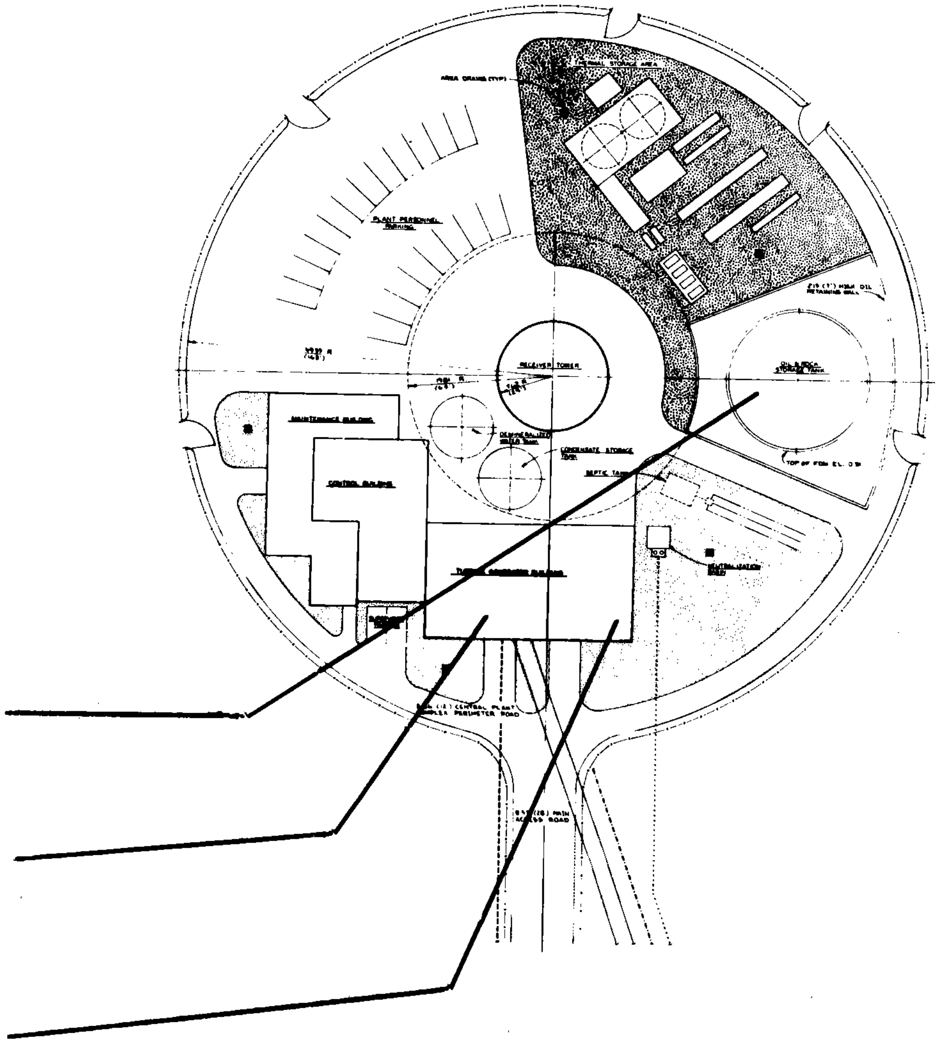


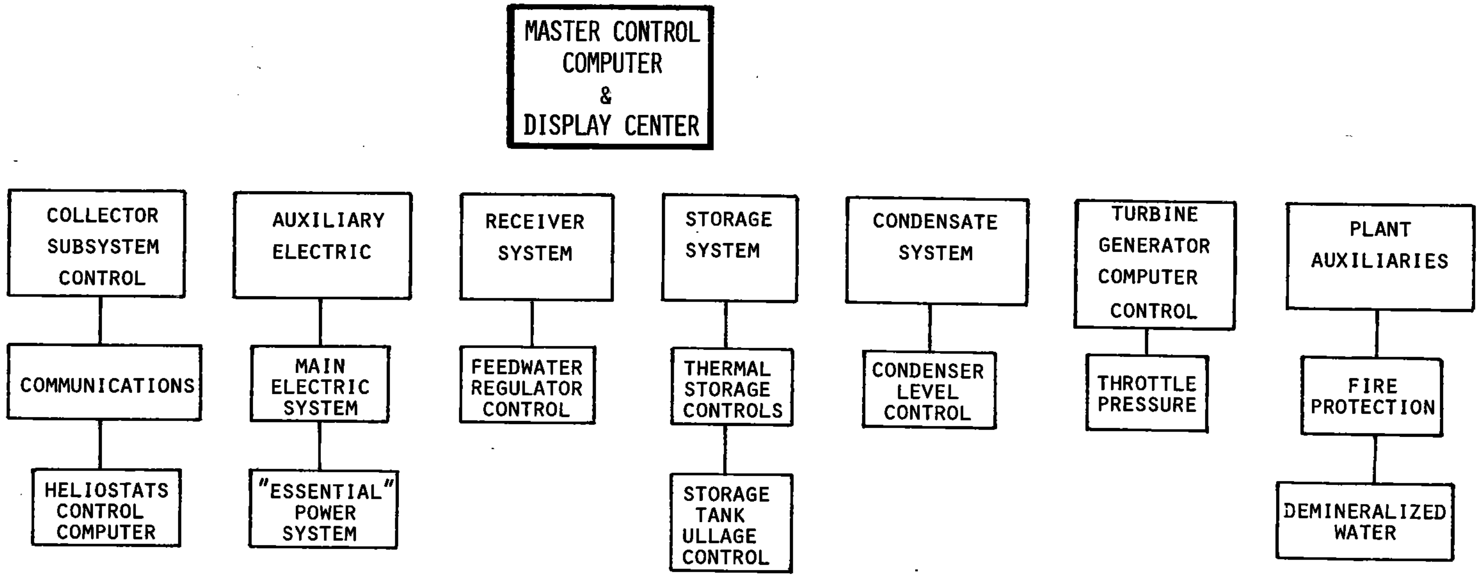
Figure 2-2. Master



STORAGE FUNCTIONS ARE LOCATED IN THE SHADED AREA

OTHER CONTROL FUNCTIONS ARE DISTRIBUTED IN AREAS NEAR THE RECEIVER TOWER

Control System Center Central Building



SERVICES

SERVICE & CONTROL AIR

SPACE CONDITIONING

WASTE TREATMENT

AUXILIARY COOLING WATER

PLANT PROTECTION

PLANT SECURITY MONITORS

HEATING

FUNCTION:
- MAINTAIN RELIABLE PLANT OPERATION & PERFORMANCE
- ALLOW FLEXIBILITY TO MATCH VARYING SOLAR CONDITIONS
- COLLECT & RECORD DATA FOR EXPERIMENTAL USES
- PROTECT PLANT EQUIPMENT FROM CATASTROPHIC FAILURE OR DAMAGE DUE TO MALFUNCTIONS

REFERENCE: VOLUME VI

Figure 2-3. Master Control Center

Considering these requirements and characteristics, the operating plant control system was developed for the solar pilot plant based on the following assumptions.

All available solar energy is utilized, either directly by the turbine or subsequently through use of energy storage capabilities of the plant. The solar generated steam is apportioned as follows.

- First priority of direct solar generated steam is to the turbine for megawatt demand satisfaction.
- Surplus solar generated steam (steam not required for immediate megawatt demand satisfaction) is used to charge the energy storage subsystem.
- Where direct solar generated steam is insufficient to meet current megawatt demand, storage generated steam will be used to supplement the direct solar generated steam.

The control system is to protect major plant equipment from extremes of certain process parameter values and their rates of change.

Subsystem Description

The major elements of plant Master Control are:

(1) Plant Overall Control System
(2) Plant Operation Plan
(3) Plant Instrumentation System

(4) Plant Protection System
(5) Plant Control Room
(6) Plant Personnel

Each of these elements is described briefly in the following paragraphs.

Plant Overall Control System. The system developed for the solar pilot plant incorporates the following control hierarchy.

(1) Coordinated Master Control, incorporating features necessary to recognize overall plant status, energy availability, and load demand, and to establish demand signals to each of the major plant subsystem controls as required to implement the overall plant control philosophy.
(2) Plant EPGS and Thermal Storage Subsystem Controls, incorporating features to receive and respond to demand signals generated by the Coordinated Master Control for:
    (a) Plant Generation Control of the turbine and generator for which the major control element is the turbine governor.
    (b) "Storage-In" Control which regulates and apportions surplus solar generated steam in order to charge the storage subsystem.
    (c) "Storage-Out" Control which supervises the generation of steam by the thermal storage subsystem to augment or replace direct solar generated throttle steam to the turbine.
(3) Controls for plant components which are independent of the coordinating control system. These include:
    (a) Receiver boiler drum level control.
    (b) Receiver boiler steam temperature control.
    (c) Storage charge steam desuperheater control.
    (d) Storage charge condensate control.
    (e) Storage discharge boiler drum level control.
    (f) Storage discharge steam temperature control.
(4) Generation Subsystem Auxiliary Controls (Minor Control Loops), not listed specifically, but which include the numerous tank level, pressure, and temperature control systems having only local involvement with plant equipment, such as heater and deaerator level controls, auxiliary cooling water temperature control, etc.

Plant Operation Plan. The basic diurnal operations of the pilot plant include:

(1) Start-up: to return the plant to a specified level of electrical power generation after an overnight shutdown.
(2) Charging the thermal storage subsystem: to store the excess thermal energy that becomes available.

(3) Discharging the thermal storage subsystem: to continue electrical power generation when adequate solar energy is not available.
(4) Shutdown: to include readying the plant for start-up the following day.

The shutdown operation is more or less typical of any power plant. The first three operations are the most important for a solar plant, and, when considered in terms of the daily variation of the solar energy source, combine to form the operating strategy, or plan.

Solar plants, because they are capital intensive, will generally be operated to maximize electrical generation from the available solar energy. This translates to the requirement for the quickest practical diurnal start-up to full turbine load early in the operating period, and maximum use of stored energy towards the end of the operating day. The diurnal operating strategy considered to be near optimum for the 10 MWe solar pilot plant, when committed primarily to electrical power generation, is described here assuming normal start-up and clear air. (The operational impact of cloud cover is addressed in the detailed description of the Master Control Subsystem.)

Electric generation by use of receiver steam is the most energy effective use of solar energy. Energy that has been collected, stored, and recovered from storage has approximately 85 per cent of the theoretical generating capability of receiver steam, and parasitic losses of the storage system further reduce the energy ultimately recovered. The most effective strategy for operation under load is therefore to utilize fully the capability of the turbine-generator during the day and to store for later use only that energy that cannot be accepted by the turbine.

It must be remembered that any operation involving charging of the storage system must be at design throttle pressure, so variable pressure operation can be used only during the morning start-up, when thermal storage is not being charged. The storage system capacity is sufficient to store a full day's capture of solar energy, and simultaneous charge and discharge operations are feasible, which offers the operator the opportunity to explore other operating strategies as well as the one outlined here.

Based on the above comments, the normal start-up and operation strategy is to start electrical generation at the earliest feasible time, increase electric load and raise receiver pressure simultaneously until both full electric load and full pressure are achieved. During a normal diurnal start-up, the turbine throttle pressure (i.e., steam pressure at the turbine throttle valve) is allowed to vary between approximately 200 psi at synchronization to 1450 psi at full load. Full load operation is reached approximately 3 hours after sunrise. Energy received in excess of electrical generation requirements is stored during the mid portion of the day. When the available energy declines in the afternoon below that required for full turbine load, the storage charge cycle is terminated. As solar energy declines in the late afternoon, the turbine load is allowed to decline, but design steam pressure and temperature are maintained. When gross electrical generation decreases to about 8.4 MWe, the storage discharge cycle is initiated. Dual admission operation is then used until sunset, followed by use of only admission steam until storage is depleted to the minimum acceptable level. Sufficient stored energy must be retained to meet overnight requirements, primarily for the steam seal system.

Plant Instrumentation System. The pilot plant instrumentation includes plant monitoring instrumentation and experimental data acquisition instrumentation.

The plant monitoring instrumentation provides guidance to the plant operators when executing remote manual control functions. Plant monitoring instrumentation is also required for monitoring the performance of the automatic controls and for detection of operation close to equipment capacity limits. Monitoring instruments are, of course, functionally independent of control systems.

Virtually all aspects of the operating pilot plant are to some degree experimental in nature, and operating data are required for evaluation of performance. A computer-based experimental data acquisition system is therefore provided which also provides monitoring of plant operation. The system is to include facilities for test engineers to organize data presentation as required for test programs.

Plant Protection System. A plant protective system is required to provide comprehensive automatic protection of plant equipment and personnel in event of a major disturbance to operation. Typical events for which automatic protective action are required include:

(1) Generator trip.
(2) Turbine trip.
(3) Collector field trip.
(4) Storage-out trip.

Plant auxiliary motors require start-stop control from the control room, and the motor control systems incorporate protective interlocking appropriate to the needs of the motor and the driven equipment.

Plant Control Room. Control of the plant is centered in a control room area to provide control and monitoring of significant plant operating parameters. The major element of the control room is the control room panel which is designed for operation by two operators during the start-up phase and by a single operator during the balance of the day. The panel is designed for operation in a standing position, with all instruments and devices located for convenient viewing and for convenient manual operation. The control panel contains all of the instrumentation, alarms, and manual controls stations required for start-up, shutdown, remote manual operation, and monitoring of automatic operation of the plant.

Operator surveillance of the sky and the heliostat field is desirable, and during operation with broken cloud cover is considered essential. Surveillance may be by direct observation through windows or by use of closed circuit television. Windows providing observation are considered preferable to television systems because of the superior orientation provided, but the plant location and arrangement make direct viewing of the heliostat field less effective than television. It is therefore planned that the heliostat field will be monitored by use of two television cameras mounted on the receiver tower.

Pilot Plant Personnel

The pilot plant staff will be organized on a three shift, 24 hour basis, to address the unique operating and maintenance problems associated with this first-of-a-kind solar electric plant. Staff will fall into one of the following categories.

(1) Administration
(2) Operation
(3) Maintenance
(4) Technical

The technical staff will include professional engineers who are knowledgable about the solar central receiver plant design and equipment. This staff will also have responsibility for heliostat inspection and maintenance, an activity which is given special attention because of the large number of heliostats and the fact that their operation is essential to pilot plant success.

The following tabulation gives a summary of the pilot plant staff requirements.

Administrative		
Plant Superintendent		1
Assistant Plant Superintendent		1
Maintenance Supervisor		1
Plant Engineer		1
	Total	4
Operating		
Lead Plant Operator		3
Control Room Operator		5- 6
Roving Plant Attendant		5- 6
	Total	13-15

Maintenance		
Machinist		1
Instrument Technician		3- 4
Electrician		2
Pipefitter/Welder		1
Repairman		3
Laborer		1
	Total	11-12
Technical		
Mechanical Engineer		1
Analyst/Computer Engineer		1
Heliostat Engineer		1
Instrument Technician		1
Electrician		1
Mechanic		1
Repairman		1
	Total	7
	Total Staff	35-38

This organization and total staff requirement will doubtless change as operating experience is obtained. However, they represent the best estimates that can now be made for a first-of-a-kind solar central receiver system.

Design Justification

The control functions described in the preceding paragraphs may be performed by use of an electronic analog system or by a digital computer based system.

Electronic analog control employs operational amplifiers to perform the control functions. The control system would be located in a cabinet in the computer room, and would receive electrical measurement signals from remotely located transmitter devices. Operator commands also would be transmitted electrically between the control system and devices located on the control room panel. Final control actuator position order would be transmitted through an operator control station in the control room panel to provide the operator opportunity for direct intervention in the control process.

Digital computer based systems, known as direct digital control (DDC), perform the required control functions by converting the analog control signals to digital form and making arithmetic calculations at frequent intervals. DDC is advantageous for applications subject to revision or alteration of control strategy and for applications having multiple identical control loops which can share the calculation routine. Although DDC has had only limited application in power generation control, the experience gained has been favorable. It is considered to be suitable for all of the control functions of the solar pilot plant with the exception of minor independent control loops. The physical arrangement of a DDC system would be similar to that for an analog system.

DDC is selected for the pilot plant because of the diverse conditions of operation anticipated for the plant and the ease with which DDC can accommodate changes in control strategy.

Section 3

DETAILED ELECTRICAL POWER GENERATION SUBSYSTEM/BALANCE OF PLANT AND MASTER CONTROL SUBSYSTEM DESCRIPTION

This section presents a detailed description of the preliminary design of the Electrical Power Generation Subsystem (EPGS)/Balance of Plant (BOP) and the Master Control Subsystem. For elements of the EPGS/BOP, the elements' function, description and operation are considered, and a brief discussion of the control of the element is presented when appropriate. The Master Control Subsystem is described in a similar manner through considering the function and design requirements of the subsystem, the major elements of plant Master Control and the design features of the Master Control elements. The description of the Master Control Subsystem includes a discussion of plant operational sequences and plant personnel requirements.

ELECTRICAL POWER GENERATION SUBSYSTEM/BALANCE OF PLANT

The detailed description of the Electrical Power Generation Subsystem (EPGS)/Balance of Plant (BOP) is presented for the designs of the turbine generator, mechanical systems, and electrical systems.

Turbine Generator Design

Six turbine manufacturers were contacted and asked to provide turbine generator design and performance characteristics consistent with the Pilot Plant design criteria. Brown Boveri, Inc., General Electric Company, and the Siemens Company responded with design information. The General Electric Company design was selected and the turbine generator design and performance parameters described in this section are furnished by General Electric. The following paragraphs detail the turbine generator design in terms of its function, rationale for its selection, design description, performance, and control.

Function. The function of the turbine generator is to convert thermal energy to electrical energy. It is a hybrid system which is part mechanical (turbine) and part electrical (generator). Further, the turbine generator system is the major element of the EPGS, and establishes the requirements for other mechanical and electrical system designs. The Turbine Generator Preliminary System Design Specification is provided in Appendix B.

Selection Rationale. Four primary considerations govern the selection of the turbine. These are the turbine type, steam conditions, size, and number of extractions for regenerative feedwater heating.

Type. An automatic admission type turbine is used, rather than a more conventional single high pressure inlet turbine, in order to more fully accommodate the varied performance and operating requirements of the 10 MWe Solar Pilot Plant. An automatic admission turbine allows receiver generated and thermal storage generated steam to be used separately or simultaneously, and accommodates the transfer of steam sources efficiently and quickly.

The thermal storage subsystem necessarily produces steam at a lower pressure and temperature than the receiver steam that charges it. Further, the specific volume of the thermal storage steam is significantly greater than that of receiver steam. Thus, a single high pressure inlet turbine would have to be overrated in order to meet the 7 MWe net generation requirement when using thermal storage steam due to volume flow limitations, whereas an automatic admission turbine can be designed without this excess capacity.

An automatic admission turbine is less expensive and requires a less complicated EPGS design than do two single inlet turbines designed for each steam source.

Steam Conditions. The turbine steam pressure and temperature at its throttle valve and admission port, are specified to satisfy certain design objectives within the limits of materials constraints.

With reference to the selection of throttle steam pressure, turbine efficiency decreases slightly with increasing throttle pressure. However, the physical size of the turbine decreases with the reduced specific volume at higher throttle pressures resulting in a more economical machine. Also, higher throttle pressures provide a higher saturation temperature driving force for charging thermal storage.

The physical properties of materials typically used in turbine shells limit the throttle pressure to around 10,101 kPa (1465 psia) for single shell designs which are preferred to double shell designs because of lower cost and lower start-up times.

Based on these considerations, the throttle pressure for the pilot plant automatic admission turbine selected is 10,101 kPa (1465 psia).

With reference to throttle steam temperature, turbine efficiency increases with increasing throttle temperature, but an upper limit on throttle temperature is imposed by turbine materials. At 510 C (950 F) and below, carbon moly steels, which have good cyclic thermal cracking properties, can be used in the turbine shell and rotor. Above 510 C (950 F), chrome moly steels are required for creep rupture strength. However, chrome moly steels are not as ductile and are less resistant to cyclic thermal cracking than are carbon moly steels. Because of the cyclic nature of the pilot plant, and these considerations, the turbine throttle temperature selected is 510 C (950 F).

The turbine admission pressure is selected to eliminate oversizing the turbine. The objective is to select an admission pressure for which the admission steam mass flow equals the throttle steam mass flow for the respective storage and receiver electrical output requirements. The thermal storage media thermal properties, however, can constrain this objective. Too high of an admission pressure, and corresponding steam saturation temperature, may effect degradation in the thermal storage media due to the overheating of the media to reach the necessary storage temperature to generate the steam.

The admission pressure selected for the pilot plant turbine is 3275 kPa (475 psia). This pressure requires an admission steam mass flow that is within about one per cent of the throttle steam mass flow for the thermal storage 7 MWe net output requirement and the receiver 10 MWe net output requirement, respectively. Further, it effects minimal degradation of the thermal storage media.

The turbine admission temperature is selected to minimize the time required to transfer the source of steam driving the turbine. The variation of steam pressure and temperature from the throttle steam as it expands through the turbine is determined by the turbine characteristics, the steam flow rate, and the state conditions of the steam at the turbine throttle and exhaust. In an automatic admission turbine, a constant pressure is maintained at the admission port independent of the throttle steam flow.

Hence, the primary design objectives in selecting an admission steam temperature are to match the temperature of the throttle steam at the admission stage as it expands through the turbine while maintaining the admission temperature sufficiently low so that the thermal storage media are not seriously degraded in the process of generating steam at that temperature. The admission temperature selected for the pilot plant turbine is 388 C (730 F). This temperature does not cause serious degradation of thermal storage materials.

Turbine Generator Size. The turbine generator nominal size selected for the pilot plant is 15 MWe or 18,750 kVA. The turbine generator size, or rated electrical capacity, is selected to permit the utility operator/owner to maximize the utilization of solar energy which the collector subsystem redirects into the receiver cavity, and to permit testing of other plant subsystems at the limits of their capacities.

A solar power plant is a capital intensive investment with essentially no annual fuel cost. As such, the utility operator/owner will likely operate the plant at the limit of its capacity, as determined by insolation variation throughout the year. The collector subsystem is sized to generate 10 MWe net plant electrical output at 2 p.m. on winter solstice. On any other clear day of the year, the insolation peak exceeds the design insolation value, with the yearly peak clear day insolation occuring at the vernal and autumnal equinoxes.

The turbine is sized to operate on the peak receiver steam flow generated at these insolation peaks. Thus, at no time during the year are heliostats defocused and energy lost because of turbine generator limitations. The additional capital cost of a turbine generator with this capacity is an insignificant percentage of the total plant cost when compared with a turbine generator with a maximum capacity of 10 MWe net plant electrical output. This is partly due to the fact that the turbine selected is a standard design that is readily available.

Further, the 10 MWe Solar Pilot Plant is to serve as a proof of concept experiment for Rankine cycle central receiver solar power plants. As such, it is desirable to test the solar peculiar subsystems at or near their design limits. The turbine generator size is selected such that it does not limit the testing capabilities of any other subsystem in the plant.

Number of Turbine Extractions. Three turbine extractions for regenerative feedwater heating are selected for the pilot plant on the basis of Black & Veatch experience and engineering judgment.

The efficiency of a turbine increases with the number of extractions for regenerative feedwater heating. Theoretically, an infinite number of regenerative feedwater heaters maximizes the efficiency of a Rankine cycle. The practicality of designing extraction ports in the shell of a nominal 15 MWe turbine limits the number of turbine extractions to about five.

The cost of the heat exchanger, piping, valves, and controls associated with a feedwater heater typically reduces the number of turbine extractions below the turbine design limit and a cost-performance trade-off study is required to select the optimum number of feedwater heaters. Such an analysis was not performed in this design, but is recommended for the detailed design phase of the pilot plant.

Turbine Generator Design Description. The turbine part of the turbine generator set is a 3600 rpm, non-reheat, condensing, bottom exhaust, single-shell automatic admission type turbine. Three extraction ports for regenerative feedwater heating are located between the automatic admission port and the turbine exhaust. The turbine is directly connected to a rotating field, synchronous, totally enclosed, air-cooled generator. A proposition outline drawing of the turbine generator is shown in Figure 3-1.

A schematic of an automatic admission turbine is shown in Figure 3-2. The major features of the turbine are the main and admission stop valves and throttle valves, expansion stages, rotor or shaft, extraction and exhaust ports, cooling steam bypass line, and high pressure and low pressure packings (HP and LP PKG) or seals.

The main stop valve isolates the turbine from the receiver steam source. The main throttle valve regulates receiver steam pressure when the main stop valve is open. The admission stop valve isolates the turbine from the thermal storage steam source. The admission throttle valve maintains constant pressure of the receiver and/or thermal storage steam ahead of the lower pressure turbine stages. The turbine stages, or blades, are attached to the turbine shaft. The turbine shaft, in turn, is attached to the generator shaft. The steam, expanding through the turbine, imparts angular momentum to the shaft through the blades. The extractions divert part of the steam expanding through the turbine to regenerative feedwater heaters to improve cycle efficiency. The exhaust duct directs the fully expanded steam to the condenser. The cooling steam bypass line diverts admission steam to cool the higher pressure turbine stages when the main stop valve is closed and the valve in the cooling steam bypass line is open. The high pressure and low pressure packings minimize the outflow of steam and the inflow of air at the points where the turbine shaft penetrates the turbine shell.

Turbine Generator Performance. The turbine generator performance characteristic of primary significance is the relationship between turbine steam flow and heat rate, efficiency, or electrical output of the generator. Other performance characteristics of the turbine generator include back pressure effects, the effect of different steam temperature ramp rates on turbine life, turbine start-up times, dynamic load variations, emergency shutdown time, turbine cool-down characteristics, and seal steam requirements.

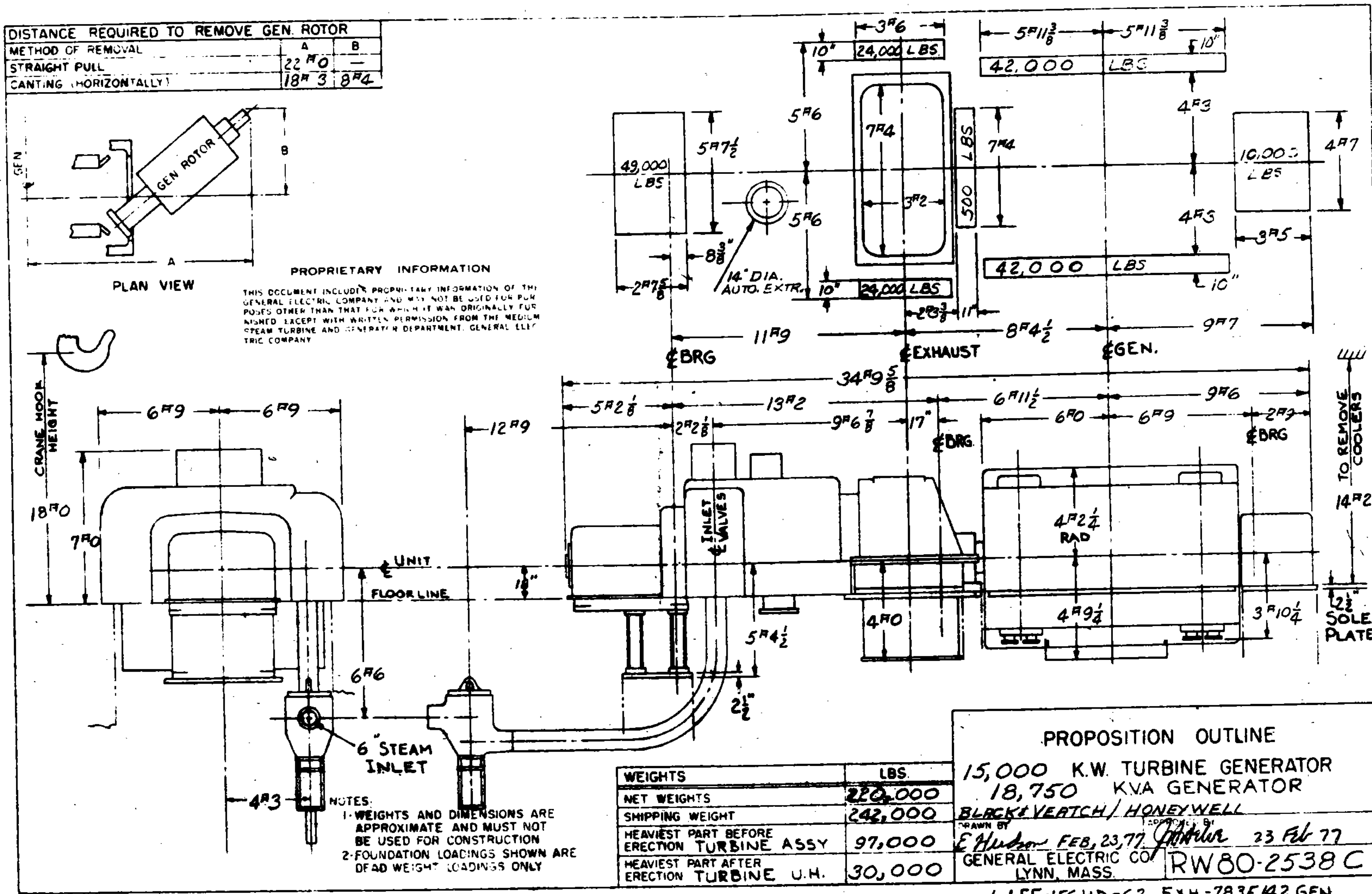


Figure 3-1. Turbine Generator Proposition Outline

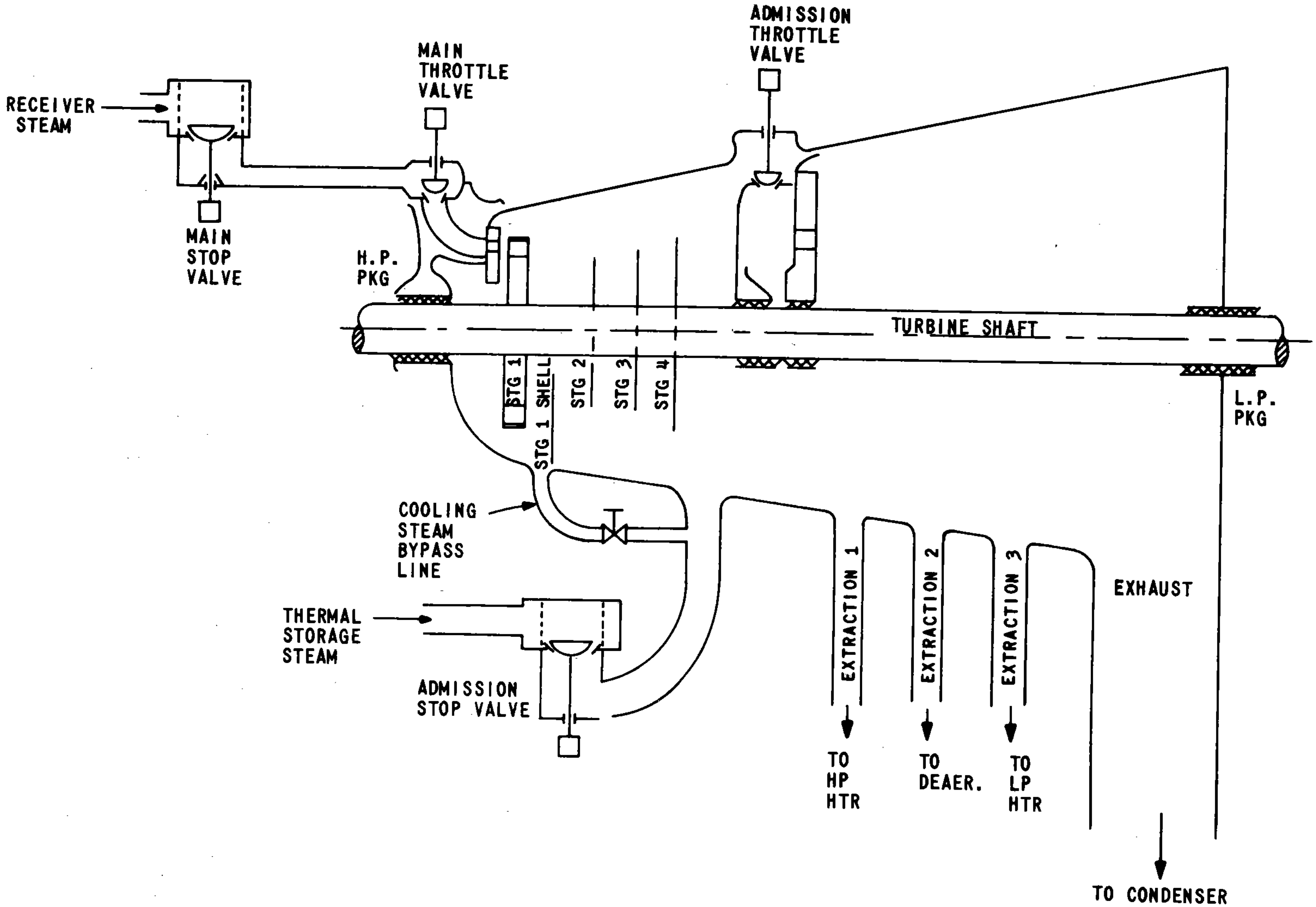


Figure 3-2. Automatic Admission Turbine Schematic

Turbine Steam Flow versus Generator Output. The turbine generator is designed to operate over a wide range of generator output. Its performance varies in relation to the flow rates of receiver and/or thermal storage steam used to drive the turbine.

Figures 3-3 through 3-14 are the turbine heat balances for different combinations of receiver and thermal storage steam flows. The gross turbine heat rates indicated on the heat balances were converted to gross turbine efficiencies and are shown in Figure 3-15. These heat rates and efficiencies are based on 6.67 kPa (2 in. Hg) back pressure.

Figure 3-16 shows the generator output versus steam flow for operation with 6.76 kPa (2.0 in. Hg) back pressure. This curve indicates turbine performance for any combination of throttle and admission flow within the turbine maximum and minimum steam flow limits.

Back Pressure Effects. Turbine generator performance varies as a function of back pressure. The turbine exhaust pressure, or back pressure, is determined by the exhaust steam flow, the condenser and cooling tower designs, and the ambient air temperature. The design of the turbine last stage blades determines the limits of back pressure within which the turbine can operate efficiently.

Figure 3-17 can be used in conjunction with Figure 3-16 to determine the generator output for any combination of receiver and thermal storage steam flows at different back pressures. Over the majority of the back pressure range indicated in Figure 3-17, generator output, hence efficiency, increases as back pressure decreases.

Figure 3-18 shows the lower limit of turbine back pressure as a function of throttle steam flow. At or below back pressures indicated by the line, choking occurs and turbine efficiency drops considerably. The turbine should be operated at back pressures corresponding to the incremental change in output peaks in Figure 3-17 or at slightly higher back pressures.

Turbine Life. Figure 3-19 indicates the reduction in turbine life, expressed as a per cent per cycle or number of cycles, for different temperature ramp rates and total temperature changes. This curve applies primarily to turbine start-up, although it also applies to steam source transfer. Turbine life is significantly reduced at high temperature ramp rates over large temperature changes. For small temperature ramp rates, the turbine life is not affected by the amount of temperature change. Conversely, for small temperature changes, the turbine life is not affected by the temperature ramp rate.

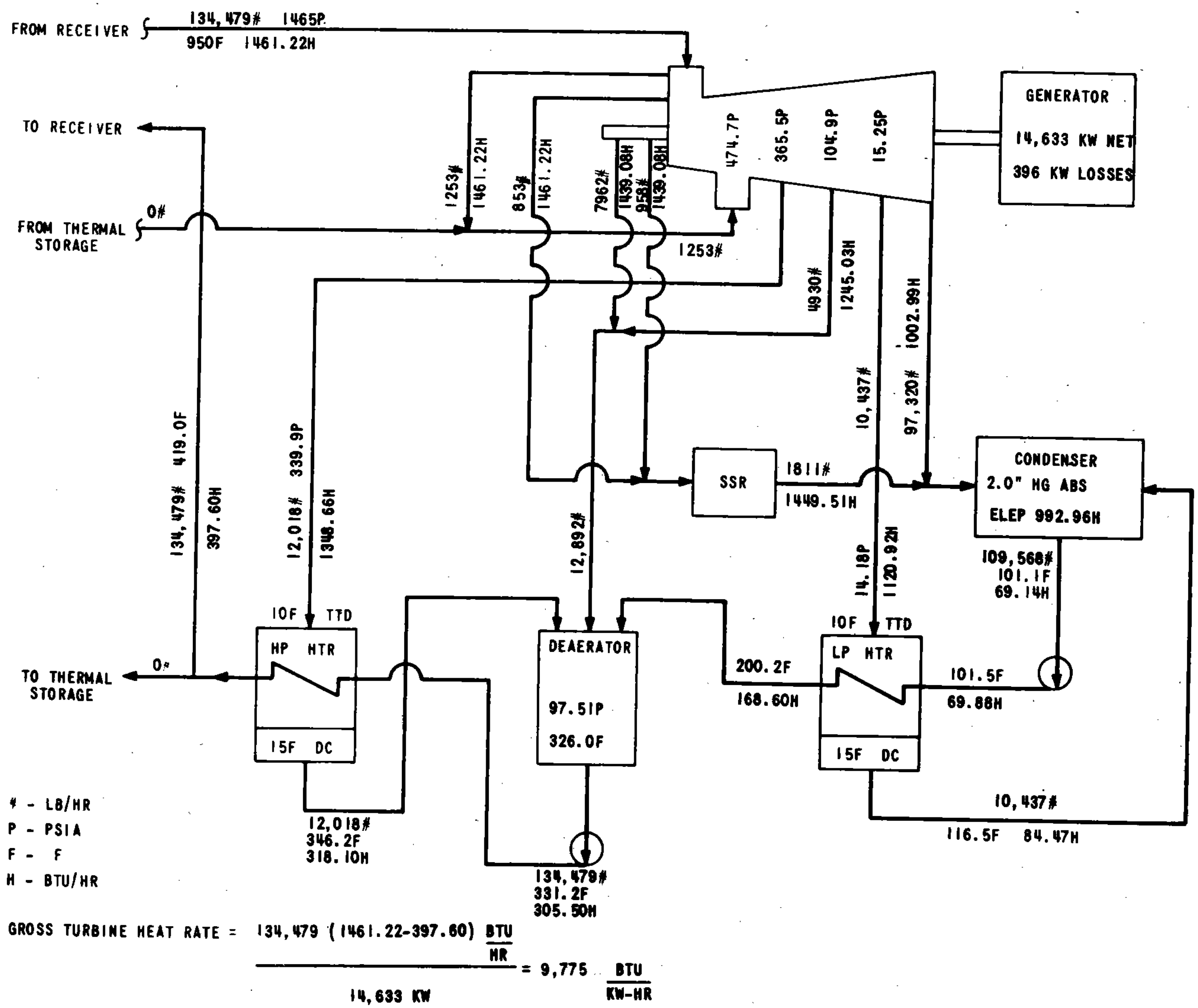
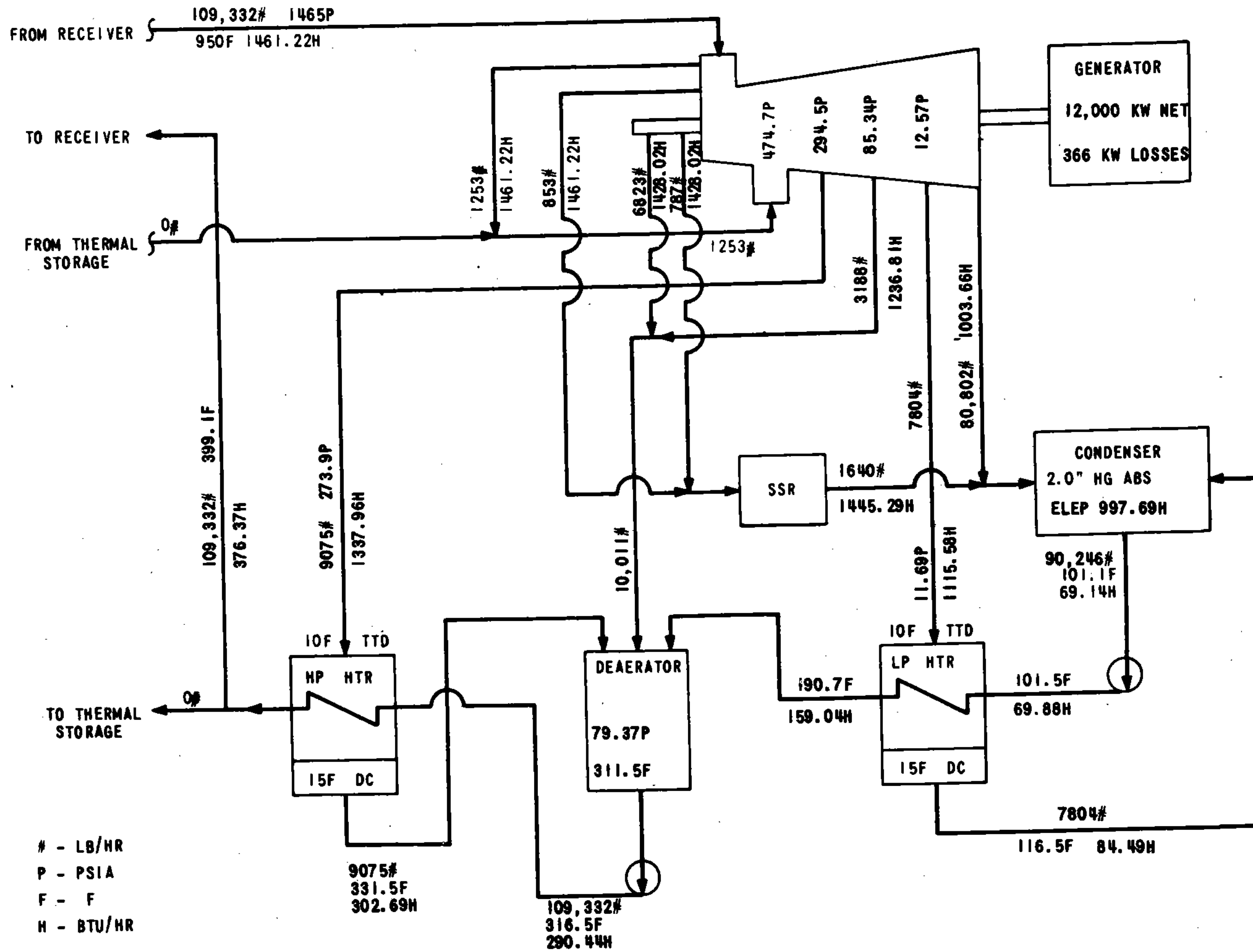
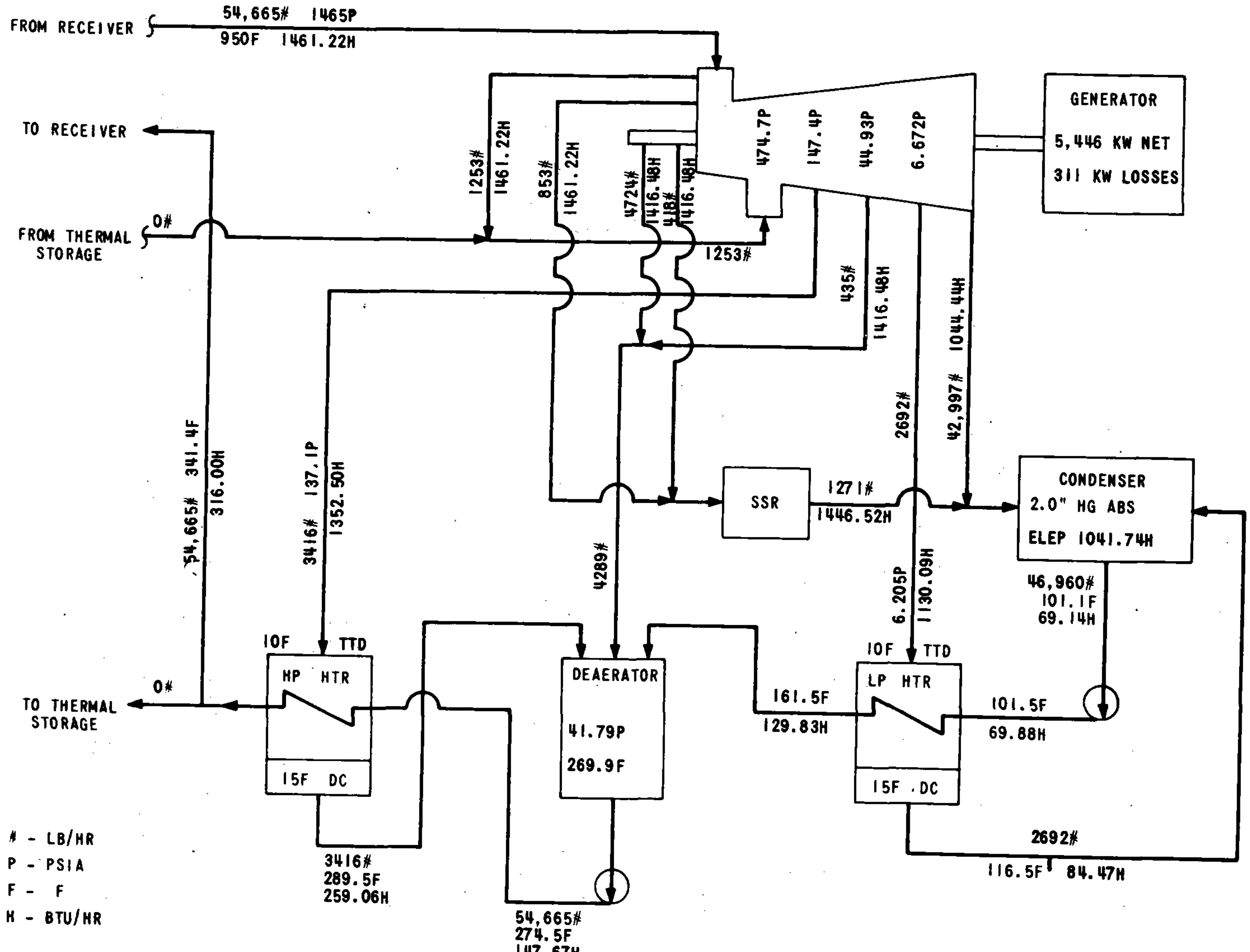


Figure 3-3. Turbine Heat Balance - Receiver Steam Only - 14,633 kW



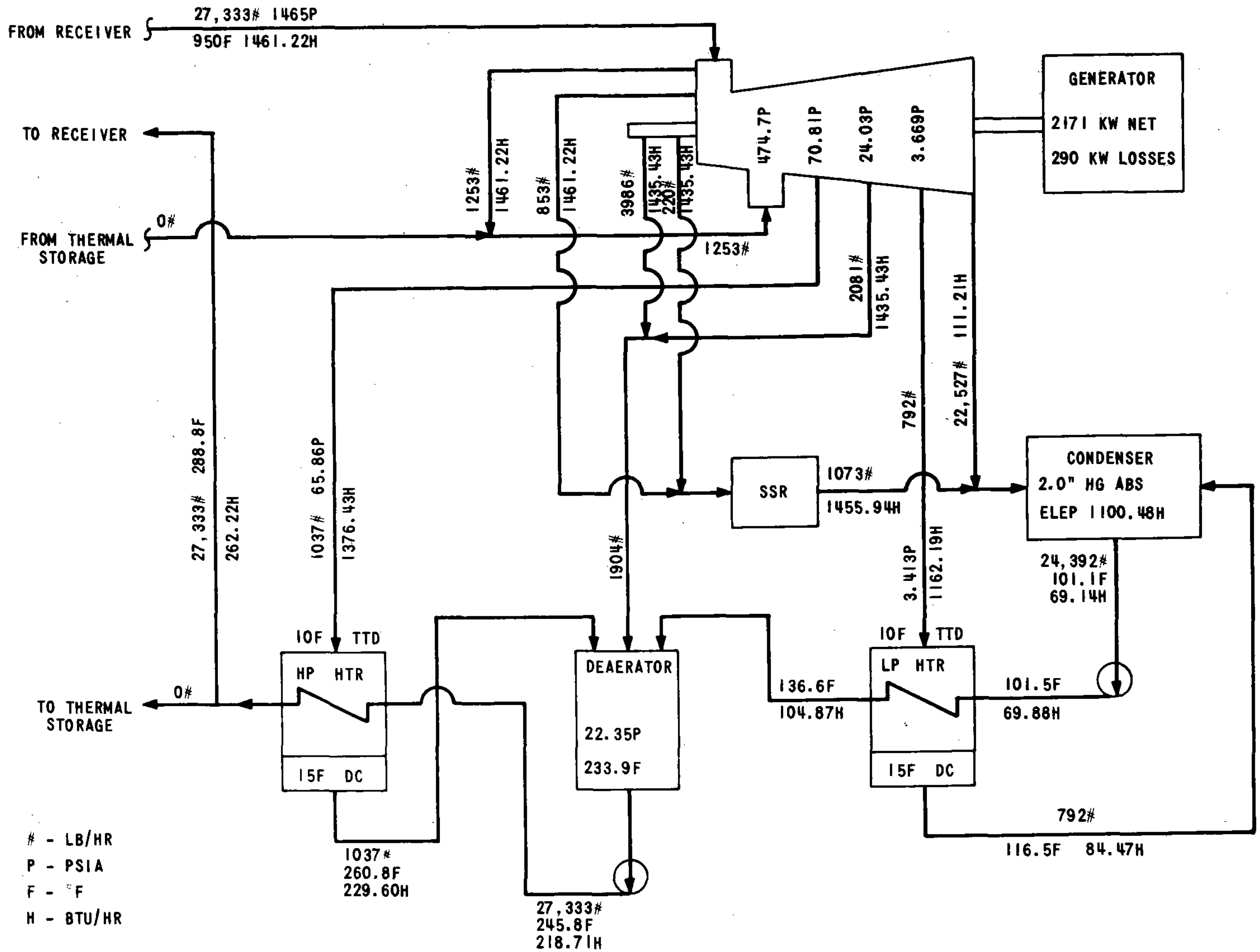
$$\text{GROSS TURBINE HEAT RATE} = \frac{109{,}332\ (1461.22-376.37)\ \frac{\text{BTU}}{\text{HR}}}{12{,}000\ \text{KW}} = 9{,}884\ \frac{\text{BTU}}{\text{KW-HR}}$$

Figure 3-4. Turbine Heat Balance - Receiver Steam Only - 12,000 kW



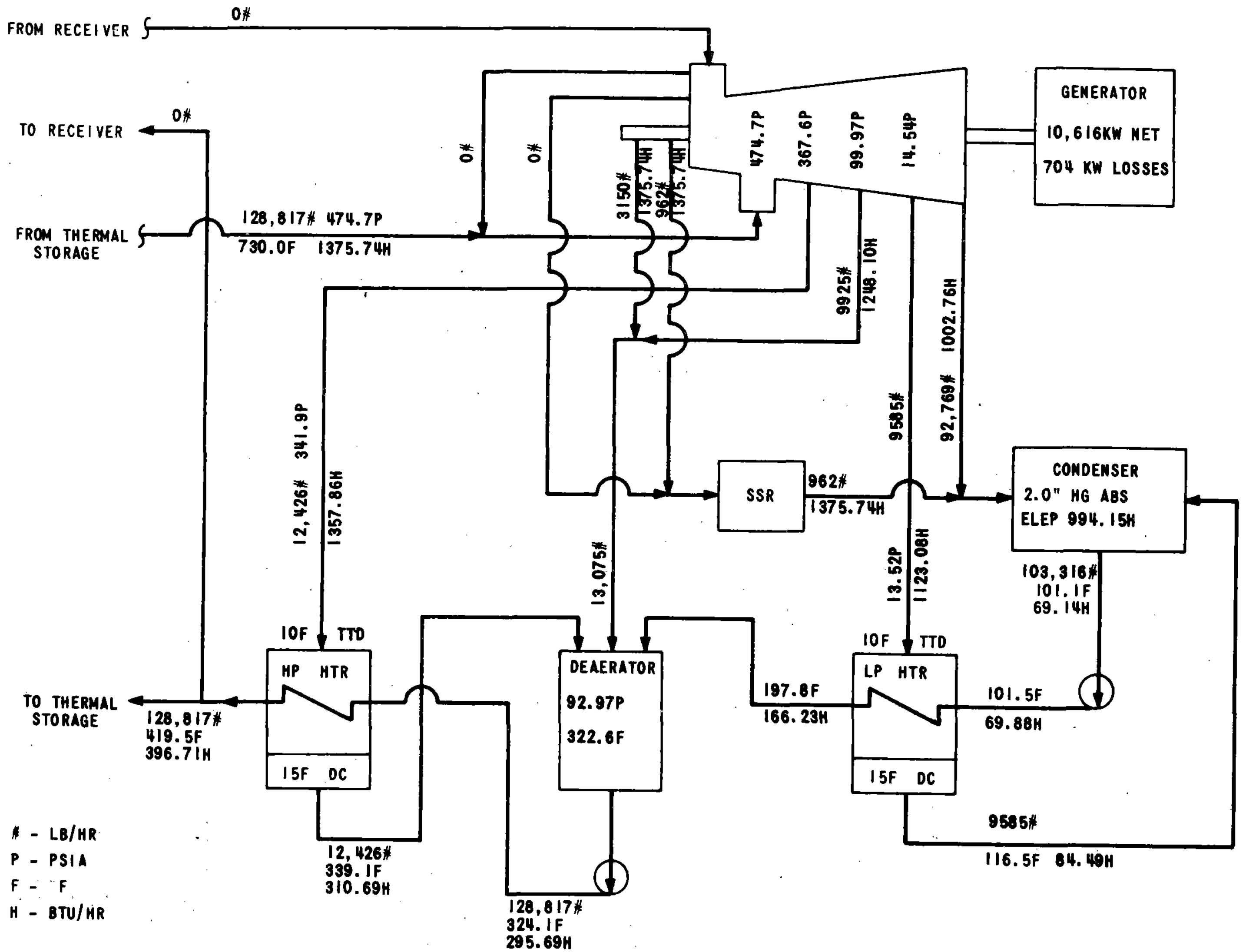
$$\text{GROSS TURBINE HEAT RATE} = \frac{54{,}665\ (1461.22-316.00)\ \frac{\text{BTU}}{\text{HR}}}{5446\ \text{KW}} = 11{,}495\ \frac{\text{BTU}}{\text{KW HR}}$$

Figure 3-5. Turbine Heat Balance - Receiver Steam Only - 5,446



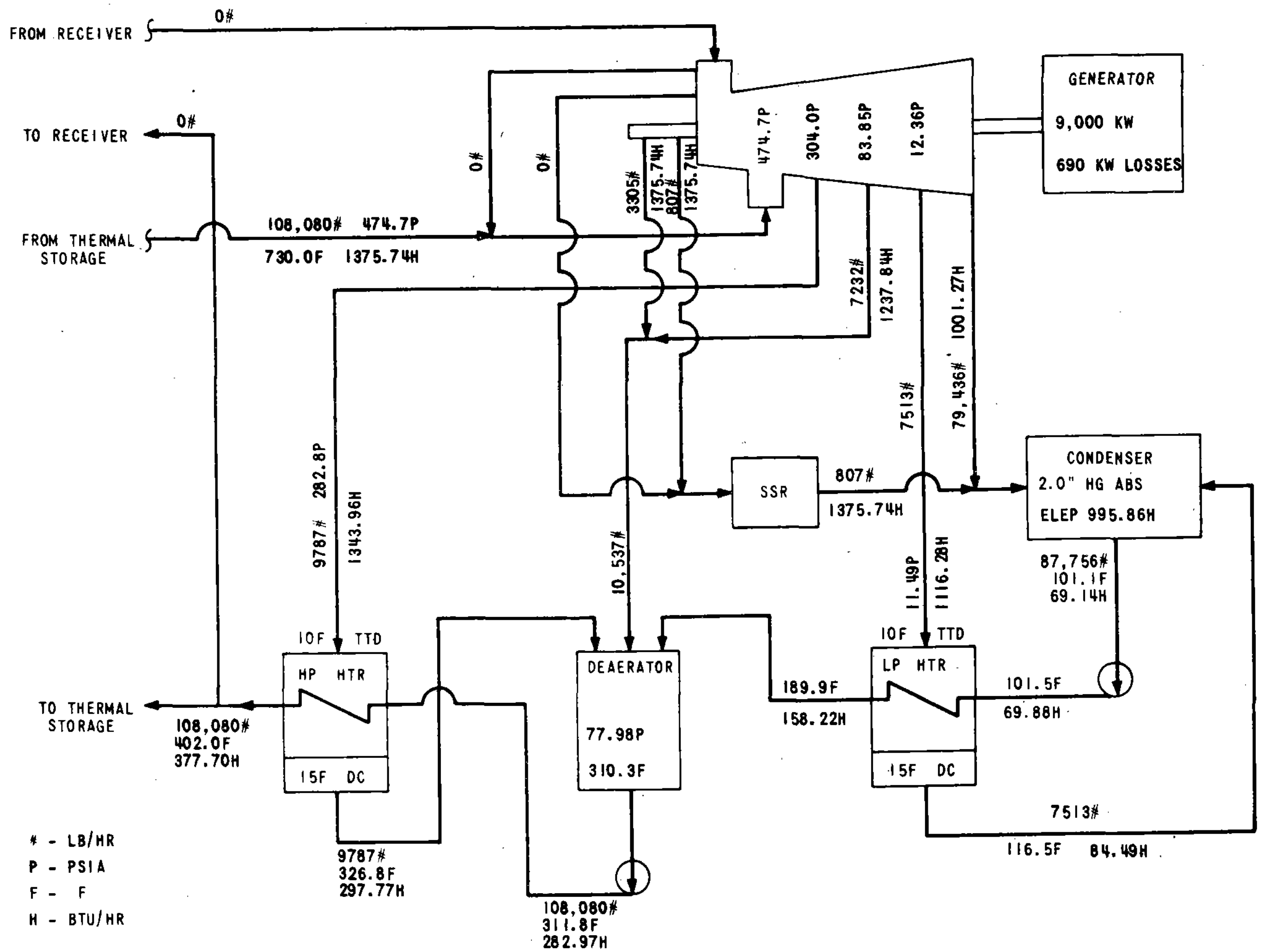
$$\text{GROSS TURBINE HEAT RATE} = \frac{27{,}333\ (1461.22-262.22)\ \frac{\text{BTU}}{\text{HR}}}{2{,}171\ \text{KW}} = 15{,}095\ \frac{\text{BTU}}{\text{KW HR}}$$

Figure 3-6. Turbine Heat Balance - Receiver Steam Only - 2,171 kW



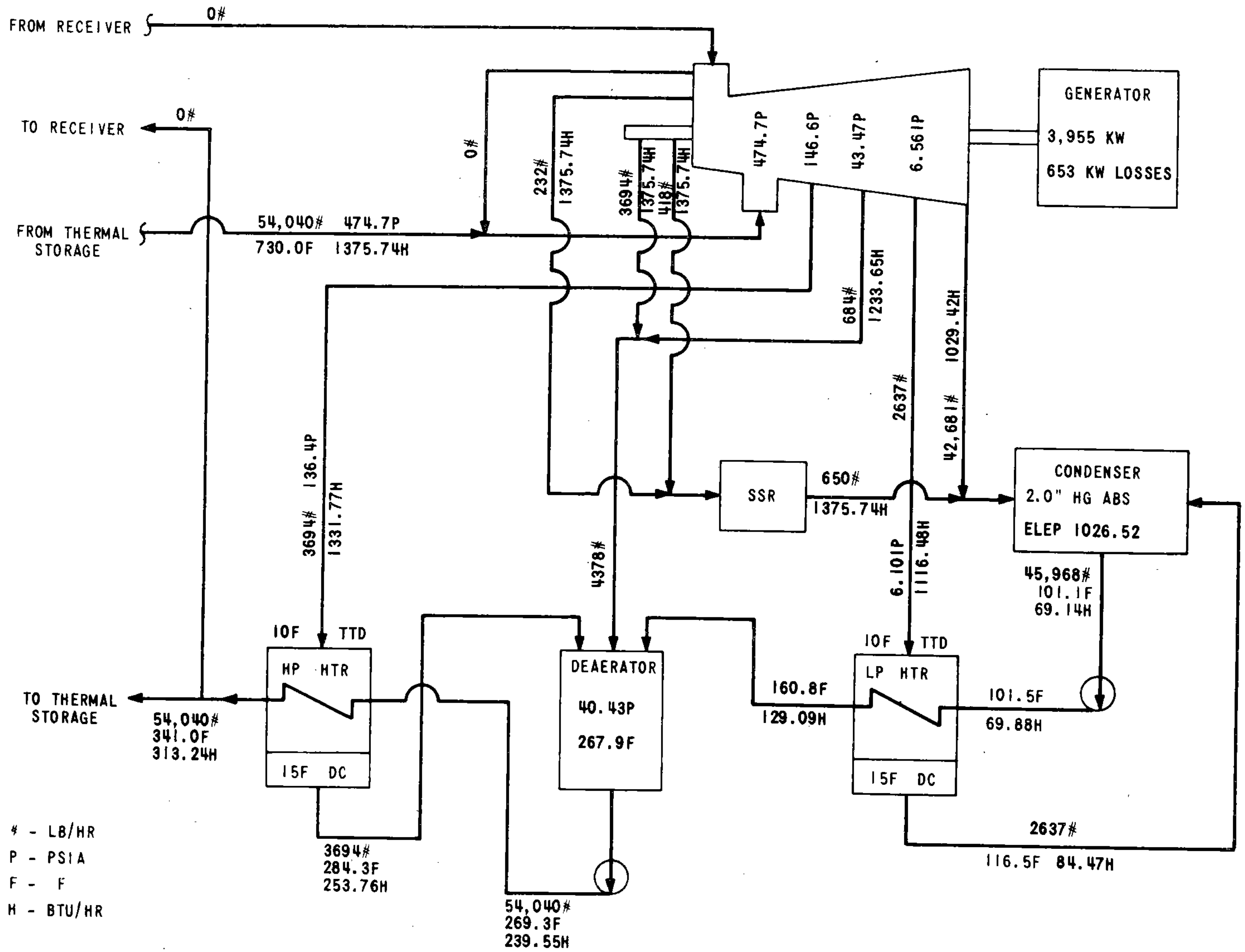
$$\text{GROSS TURBINE HEAT RATE} = \frac{128{,}817\ (1375.74-396.71)\ \frac{\text{BTU}}{\text{HR}}}{10{,}616\ \text{KW}} = 11{,}880\ \frac{\text{BTU}}{\text{KW HR}}$$

Figure 3-7. Turbine Heat Balance - Storage Steam Only - 10,616 kW



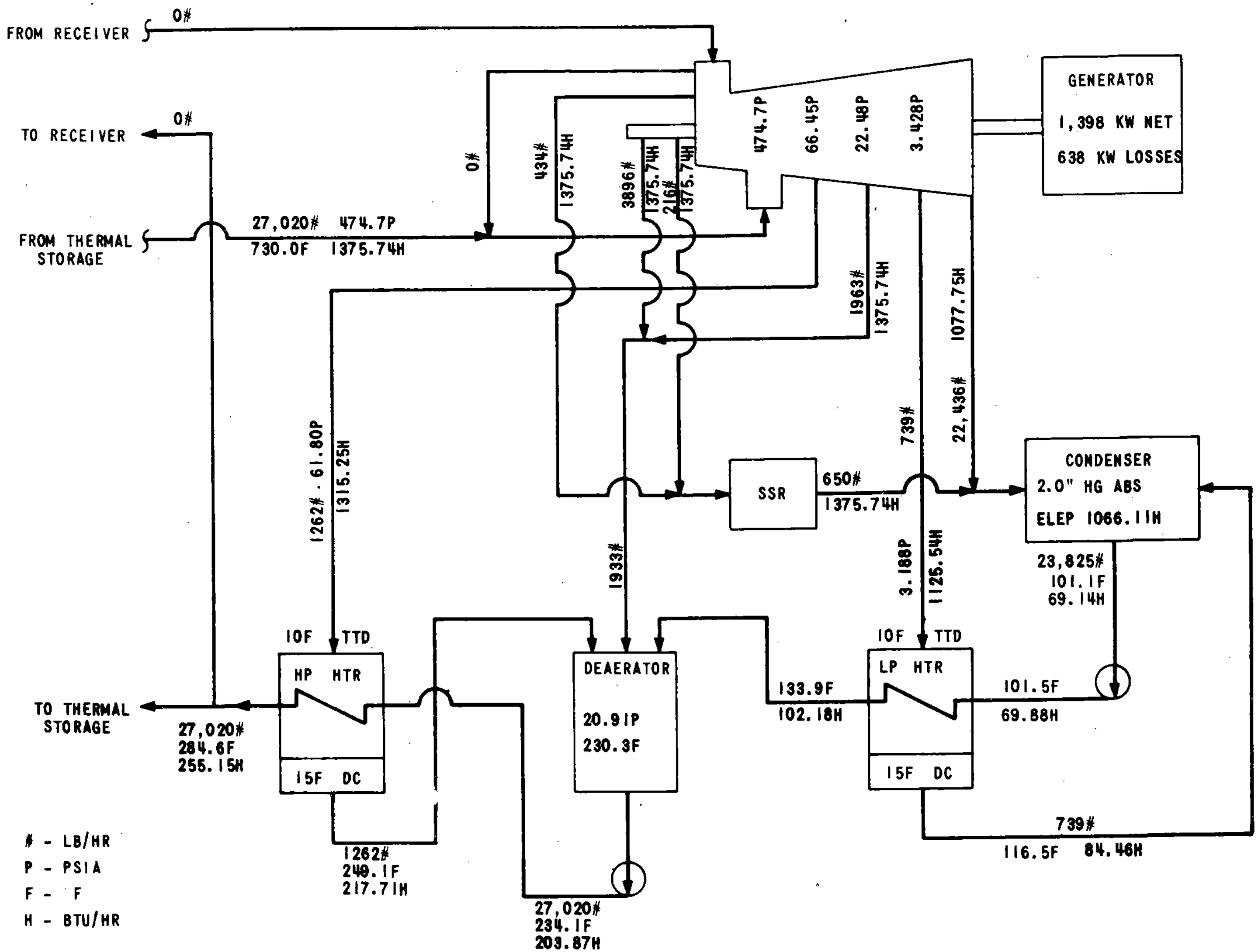
$$\text{GROSS TURBINE HEAT RATE} = \frac{108{,}080\ (1375.74-377.70)\ \frac{\text{BTU}}{\text{HR}}}{9{,}000\ \text{KW}} = 11{,}985\ \frac{\text{BTU}}{\text{KW-HR}}$$

Figure 3-8. Turbine Heat Balance - Storage Steam Only - 9,000 kW



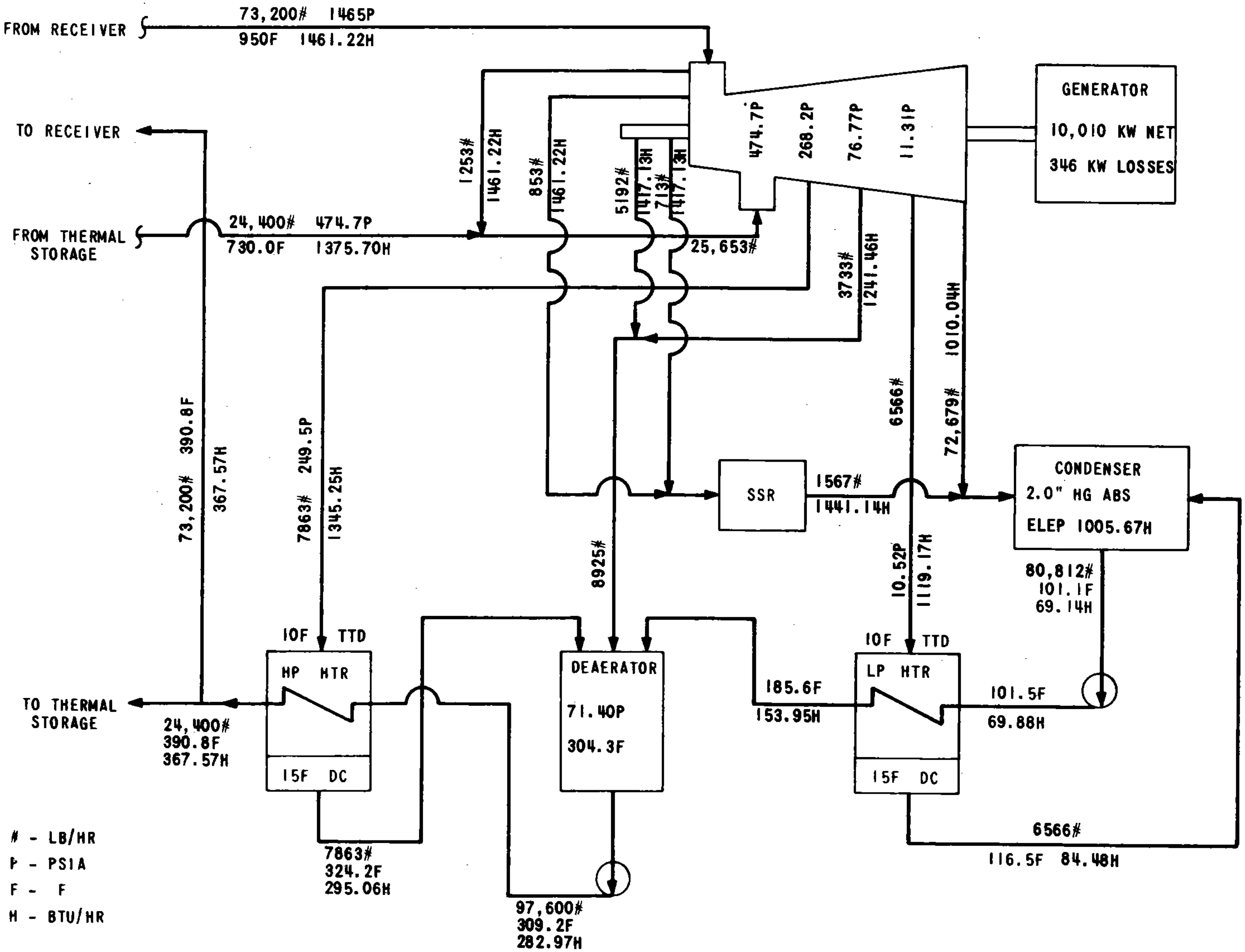
GROSS TURBINE HEAT RATE = $\dfrac{54{,}040\ (1375.74-313.24)\ \frac{BTU}{HR}}{3955\ KW} = 14{,}518\ \dfrac{BTU}{KW\ HR}$

Figure 3-9. Turbine Heat Balance - Storage Steam Only - 3,955 kW



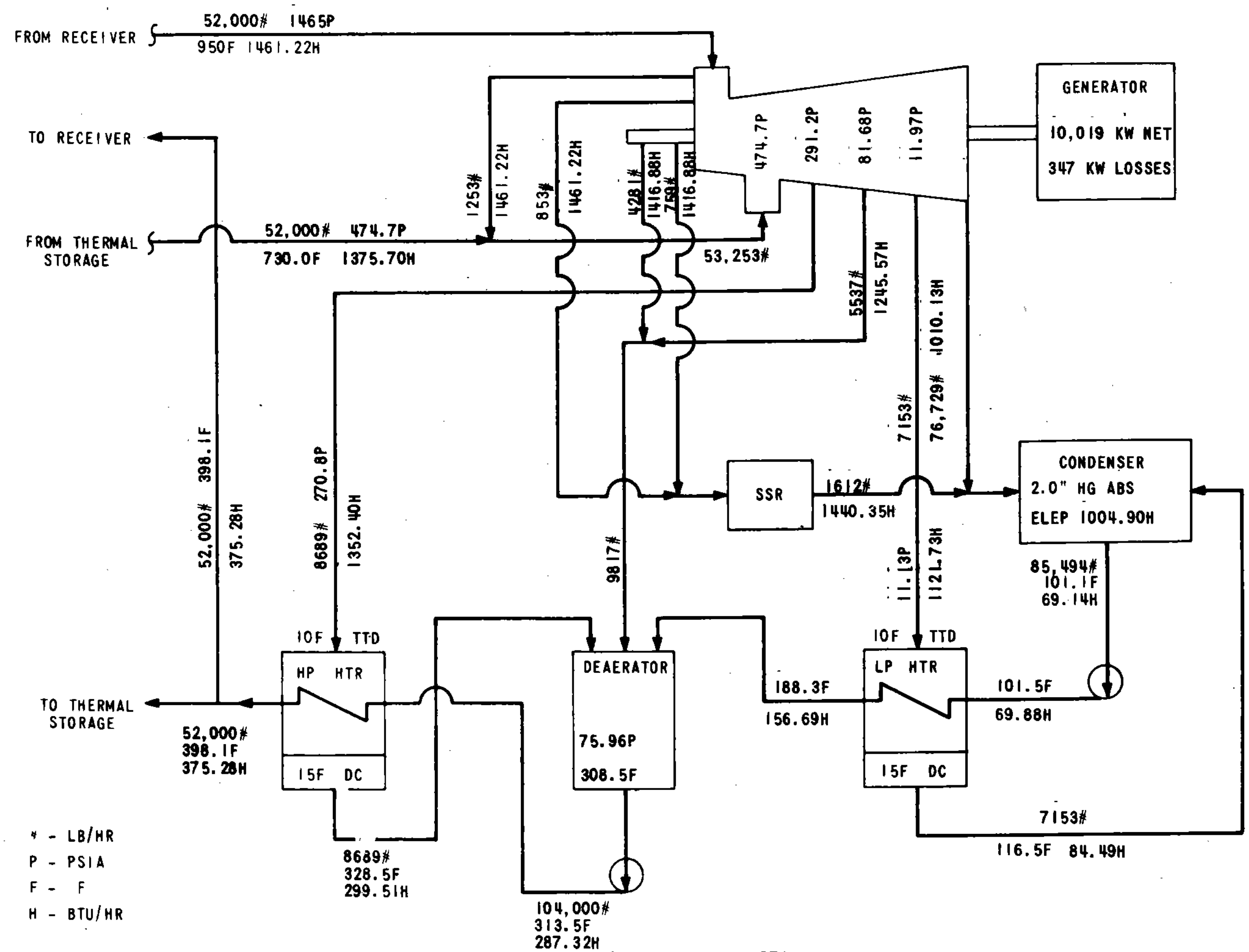
$$\text{GROSS TURBINE HEAT RATE} = \frac{27{,}020\ (1375.74-255.15)\ \frac{\text{BTU}}{\text{HR}}}{1{,}398\ \text{KW}} = 21{,}658\ \frac{\text{BTU}}{\text{KW HR}}$$

Figure 3-10. Turbine Heat Balance - Storage Steam Only - 1,398 kW



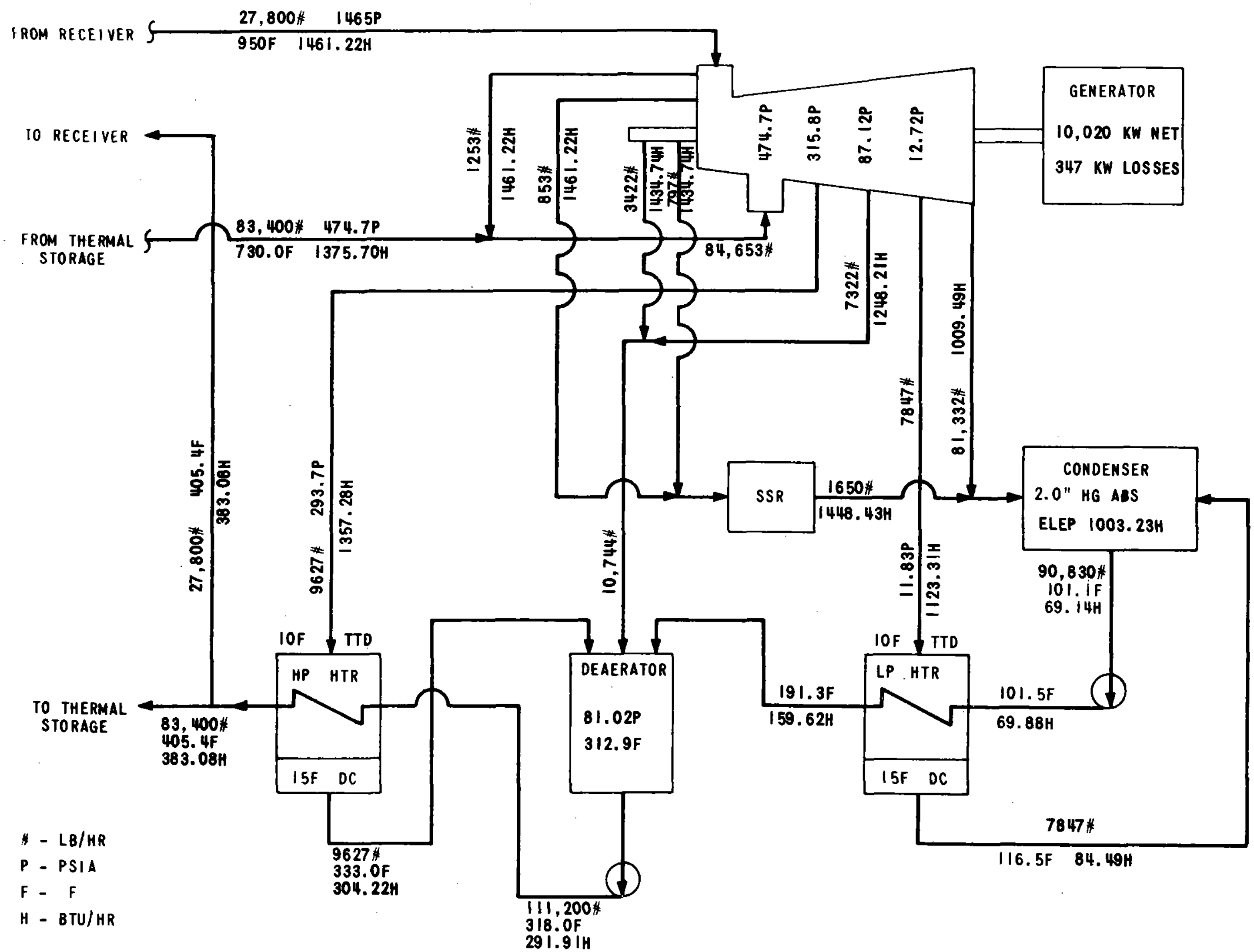
$$\text{GROSS TURBINE HEAT RATE} = \frac{73{,}200\ (1461.22-367.57) + 24{,}400\ (1375.70-367.57)\ \frac{\text{BTU}}{\text{HR}}}{10{,}010\ \text{KW}} = 10{,}455\ \frac{\text{BTU}}{\text{KW HR}}$$

Figure 3-11. Turbine Heat Balance - 75% Receiver/25% Storage - 10,010 kW



$$\text{GROSS TURBINE HEAT RATE} = \frac{52{,}000\ (1461.22-375.28) + 52{,}000\ (1375.70-375.28)\ \frac{\text{BTU}}{\text{HR}}}{10{,}019\ \text{KW}} = 10{,}828\ \frac{\text{BTU}}{\text{KW-HR}}$$

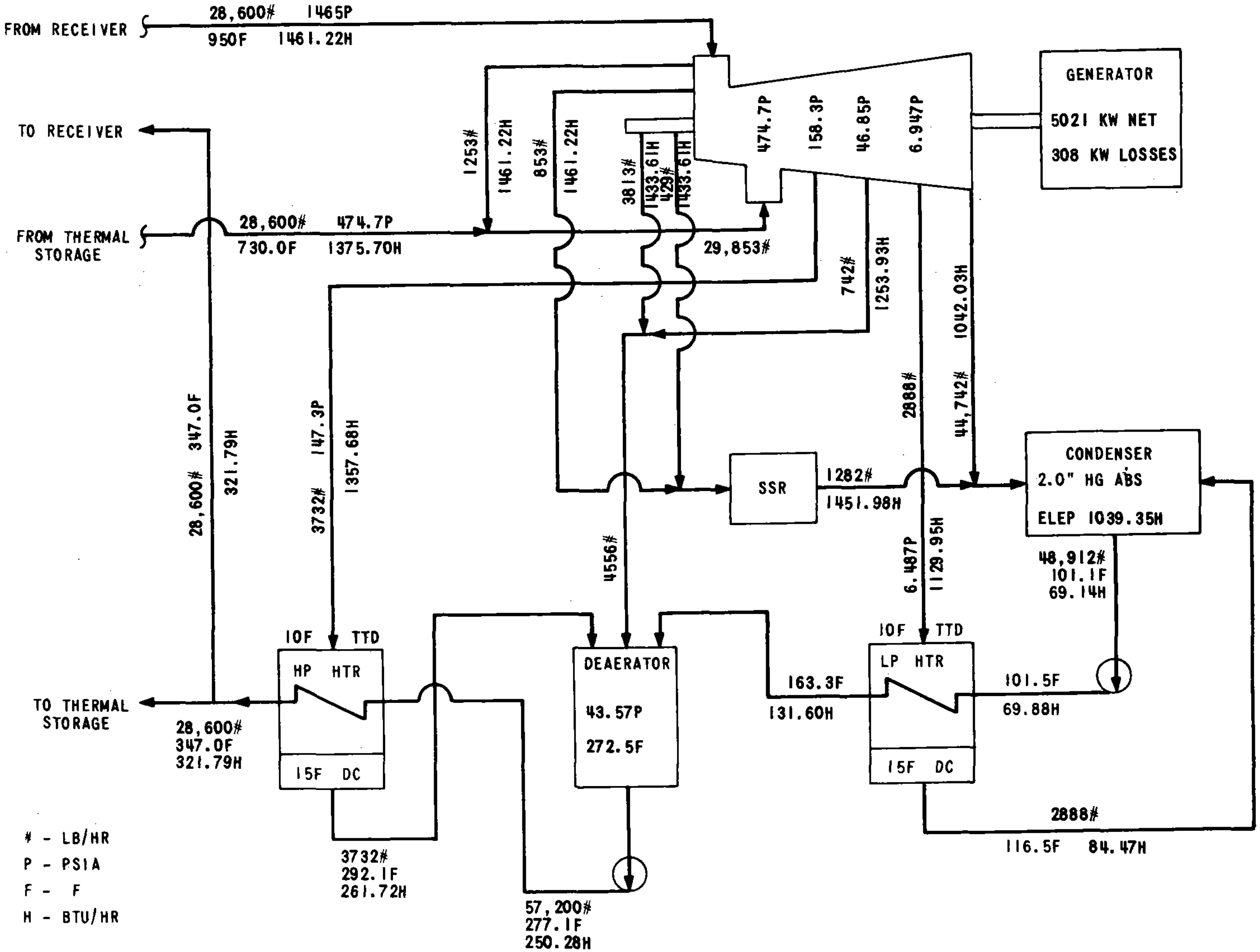
Figure 3-12. Turbine Heat Balance - 50% Receiver/50% Storage - 10,019 kW



GROSS TURBINE HEAT RATE =

$$\frac{27{,}800\ (1461.22-383.08) + 83{,}400\ (1375.70-383.08)\ \frac{\text{BTU}}{\text{HR}}}{10{,}020\ \text{KW}} = 11{,}253\ \frac{\text{BTU}}{\text{KW HR}}$$

Figure 3-13. Turbine Heat Balance - 25% Receiver/75% Storage - 10,020 kW



$$\text{GROSS TURBINE HEAT RATE} = \frac{28{,}600\ (1461.22-321.79) + 28{,}600\ (1375.74-321.79)\ \frac{\text{BTU}}{\text{HR}}}{5{,}021\ \text{KW}} = 12{,}494\ \frac{\text{BTU}}{\text{KW HR}}$$

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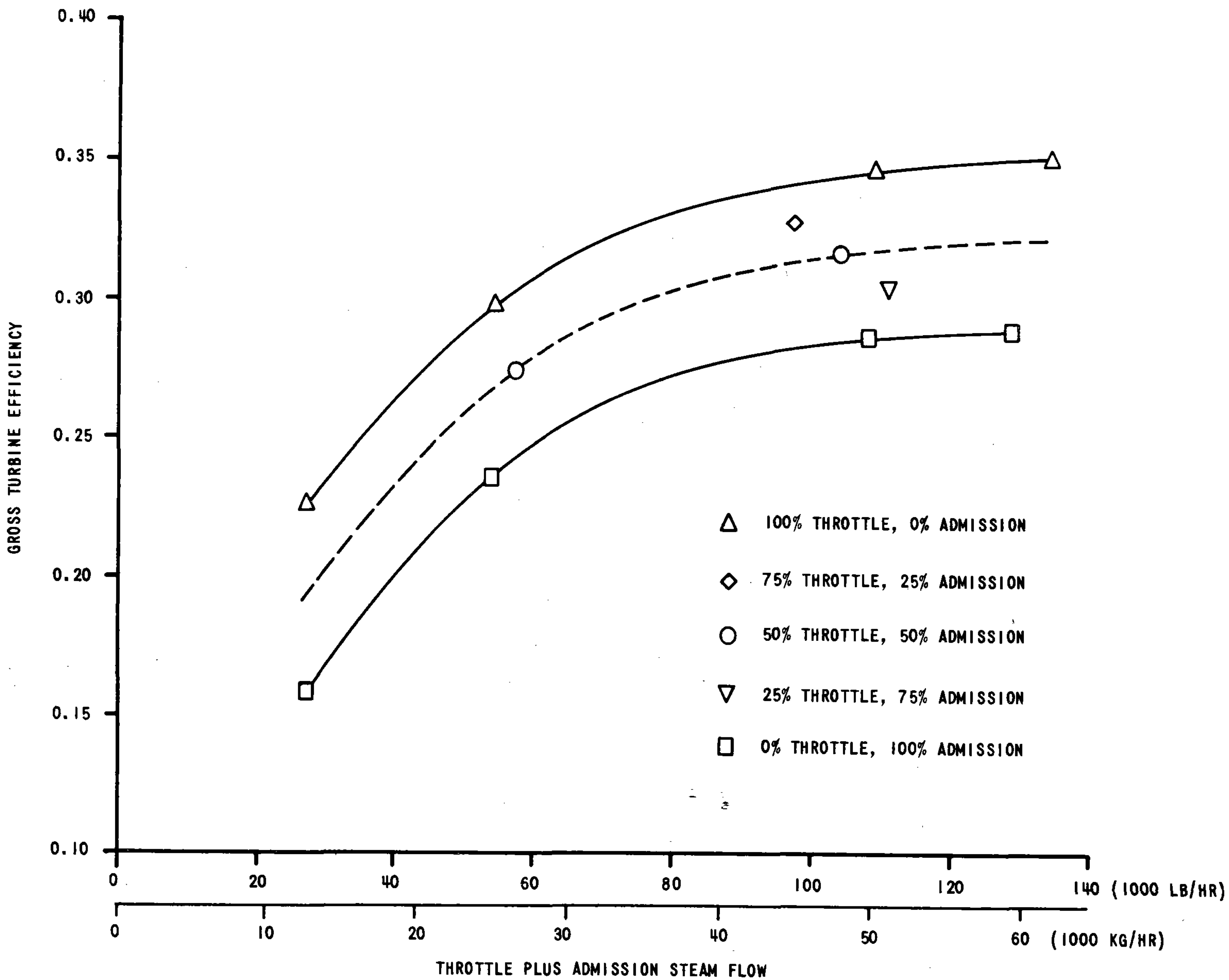

Figure 3-15. Gross Turbine Efficiency vs. Throttle Plus Admission Steam Flow

THROTTLE - 10101 kPa (1465 PSIA), 510°C (950°F)
ADMISSION - 3275 kPa (475 PSIA), 388°C (730°F)
EXHAUST- 6.8 kPa (2 IN HG)

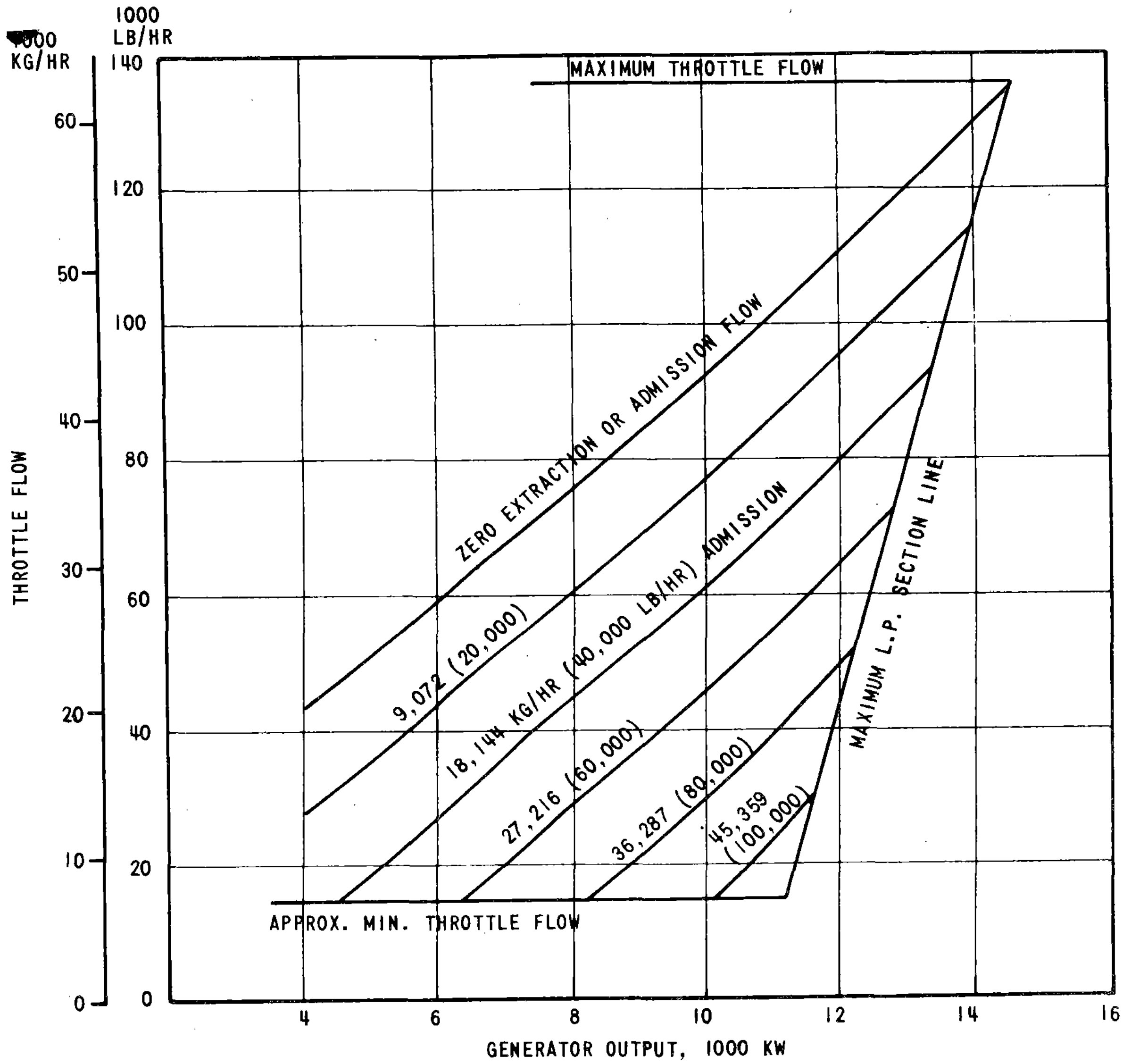

Figure 3-16. Generator Output vs. Steam Mass Flow for Three Stages of Feedwater Heating

NOTE:

1. FIGURES ON CURVES DENOTE VALUES OF APPARENT L.P. SECTION FLOW WHICH IS DEFINED AS THE SUM OF THE THROTTLE FLOW AND SIMULTANEOUS ADMISSION FLOW (IF ANY).

2. THE CORRECT OUTPUT AT VARIANT PRESSURE IS EQUAL TO THE BASE OUTPUT FROM GENERATOR OUTPUT VS. STEAM MASS FLOW CURVE PLUS THE ΔKW FOR VARIANT EXHAUST PRESSURE.

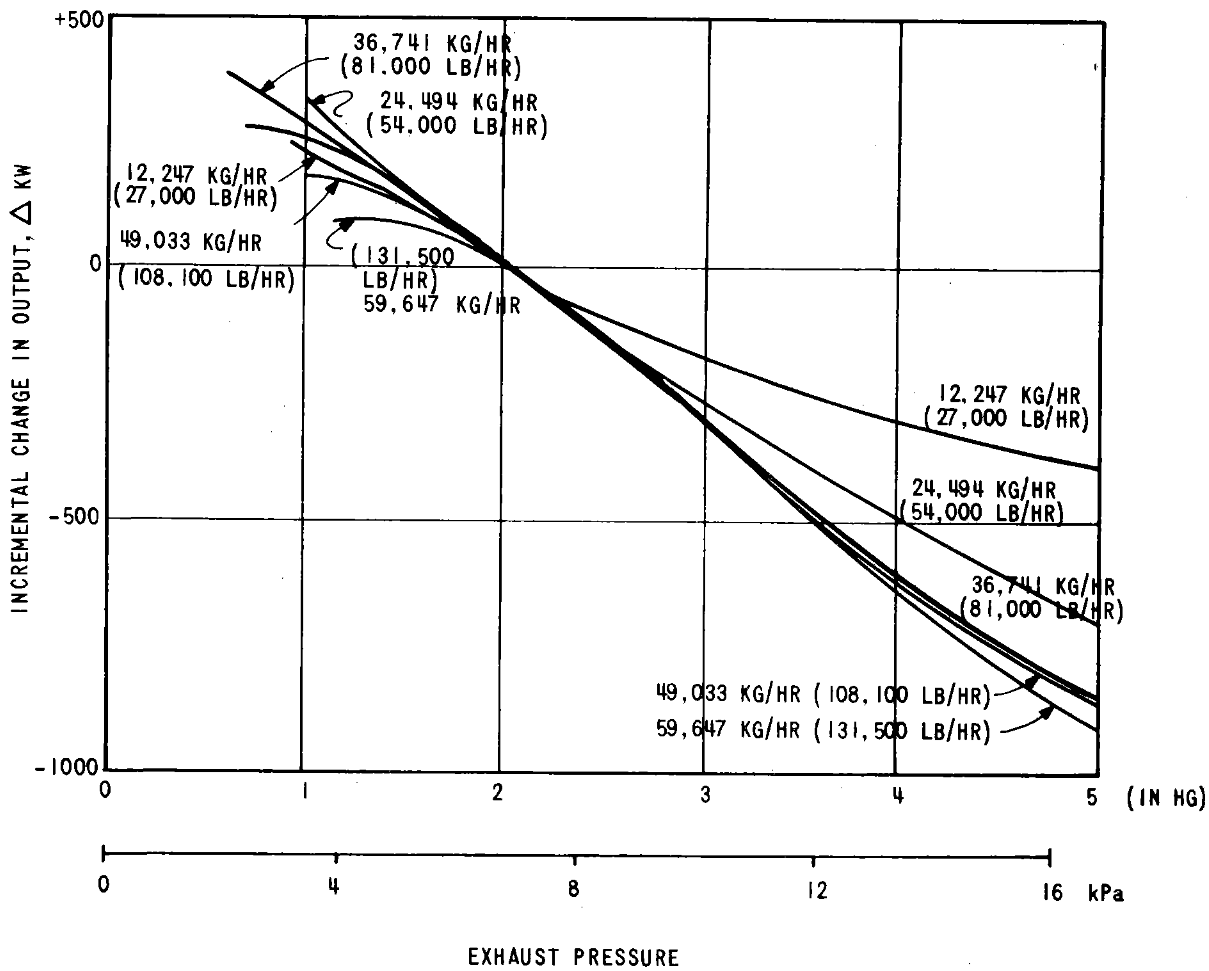

Figure 3-17. Approximate Correction Curve for Variant Exhaust Pressure

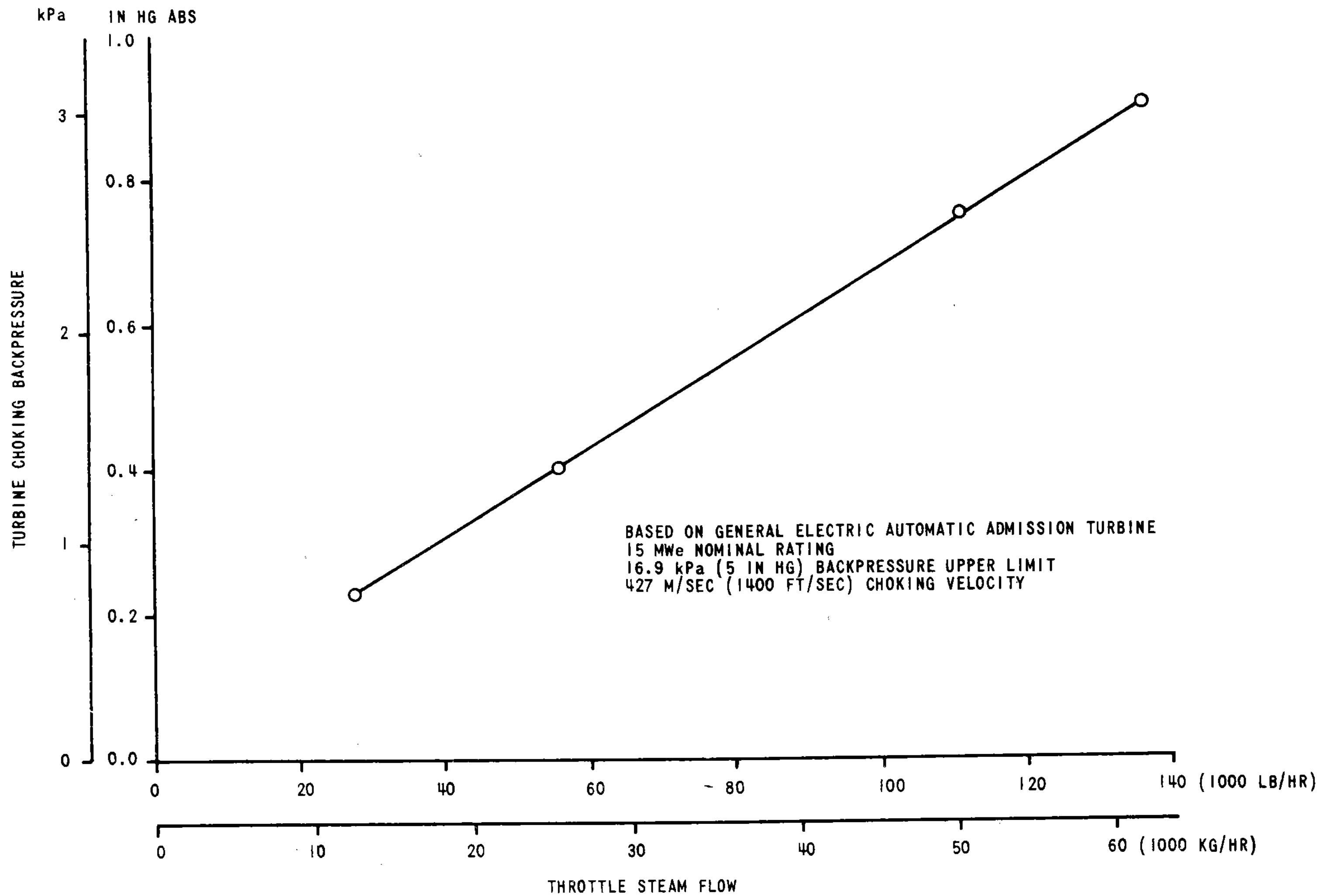

Figure 3-18. Turbine Choking Backpressure vs. Throttle Steam flow

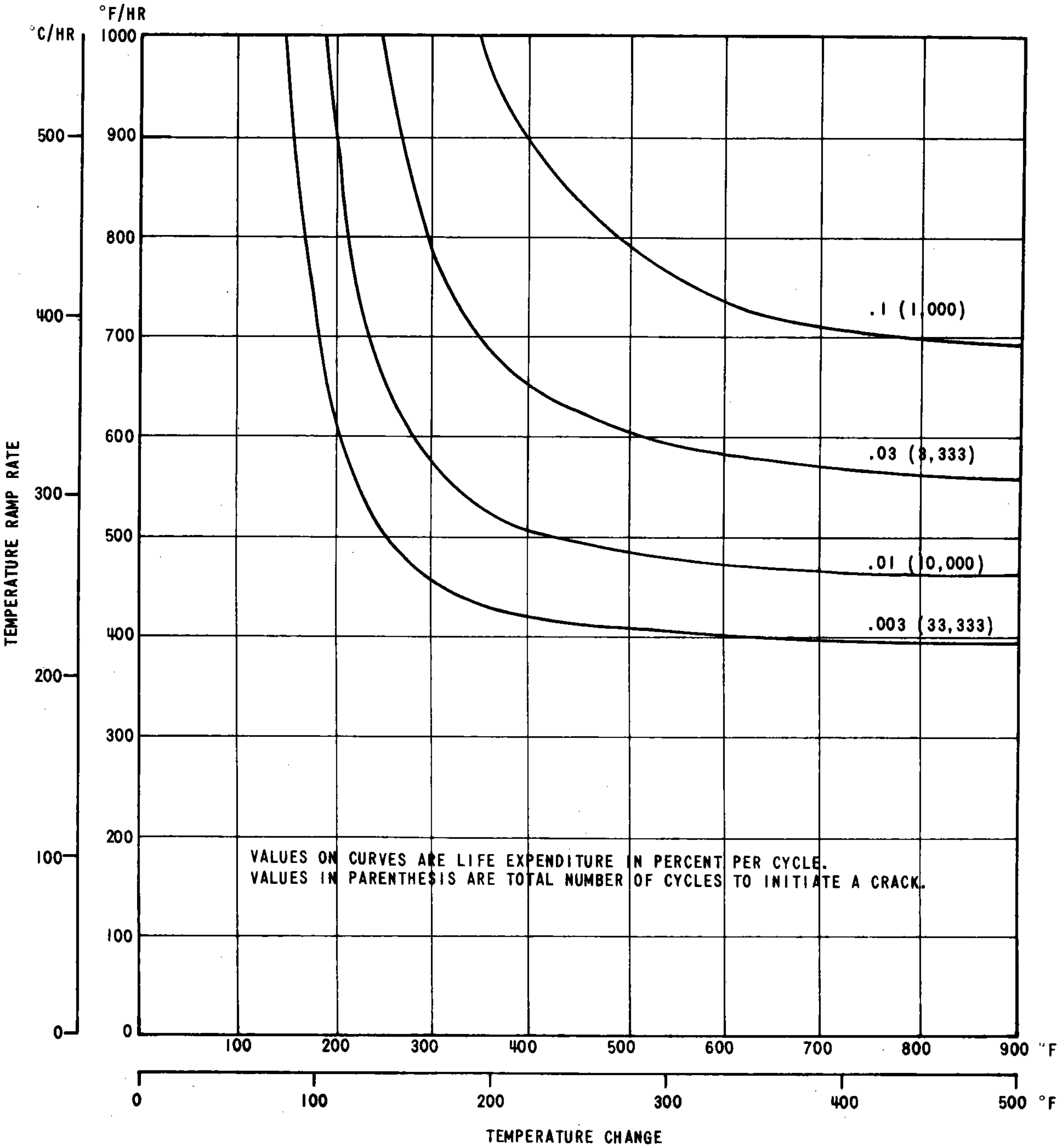

Figure 3-19. Typical Cyclic Life Curves for Turbines with .46 M (18") Diameter Rotors

Figure 3-19 illustrates the objective of expansion line matching for the selection of admission steam temperature. For a temperature mismatch of 56 C (100 F), turbine steam sources can be transferred with no time required for mixing (infinite temperature ramp rate).

Turbine Start-up Times. The turbine generator is capable of start-up on receiver and thermal storage steam. The minimum times required for the turbine to be synchronized are 13 minutes when starting from hot stand-by and 34 minutes when starting from cold stand-by. Hot stand-by refers to the condition which the turbine has reached over a shutdown period of up to 12 hours. The average temperature of the high pressure turbine section shell has not dropped to 371 C (700 F) in that time. Cold stand-by, on the other hand, refers to a condition which the turbine has reached over a shutdown period of more than 72 hours. The average temperature of the high pressure turbine section shell has fallen to 149 C (300 F) or below in that time.

Dynamic Load Variations. The turbine is capable of varying load at the rate of 4 per cent rated load or rated steam flow per minute and 10 per cent instantaneous load change over the range of 20 per cent to 100 per cent load.

Emergency Shutdown Time. The minimum shutdown time from emergency trip to zero speed is 20 to 30 minutes.

Turbine Cool-down. Figure 3-20 illustrates the decline in tne high pressure turbine metal temperature over time following turbine trip. This curve can be used to determine the approximate temperature of the high pressure turbine after diurnal or extended shutdown.

Seal Steam Requirements. The turbine is designed with labyrinth seals at either end of the shaft where it penetrates the shell. These seals minimize the leakage of steam out of the turbine and the leakage of air into the turbine. The loss of steam is minimized to reduce the amount of expensive, high quality makeup water required. The seals minimize the leakage of air into the turbine to reduce the corrosion of heat turbine internals.

During normal power generation operation, when the turbine is driven by receiver and/or thermal storage steam, some of that steam is used to seal the turbine. During diurnal shutdown or in the operating mode where the receiver is charging thermal storage, no steam is being supplied by either the receiver or thermal storage. Table 3-1 shows the mass flow

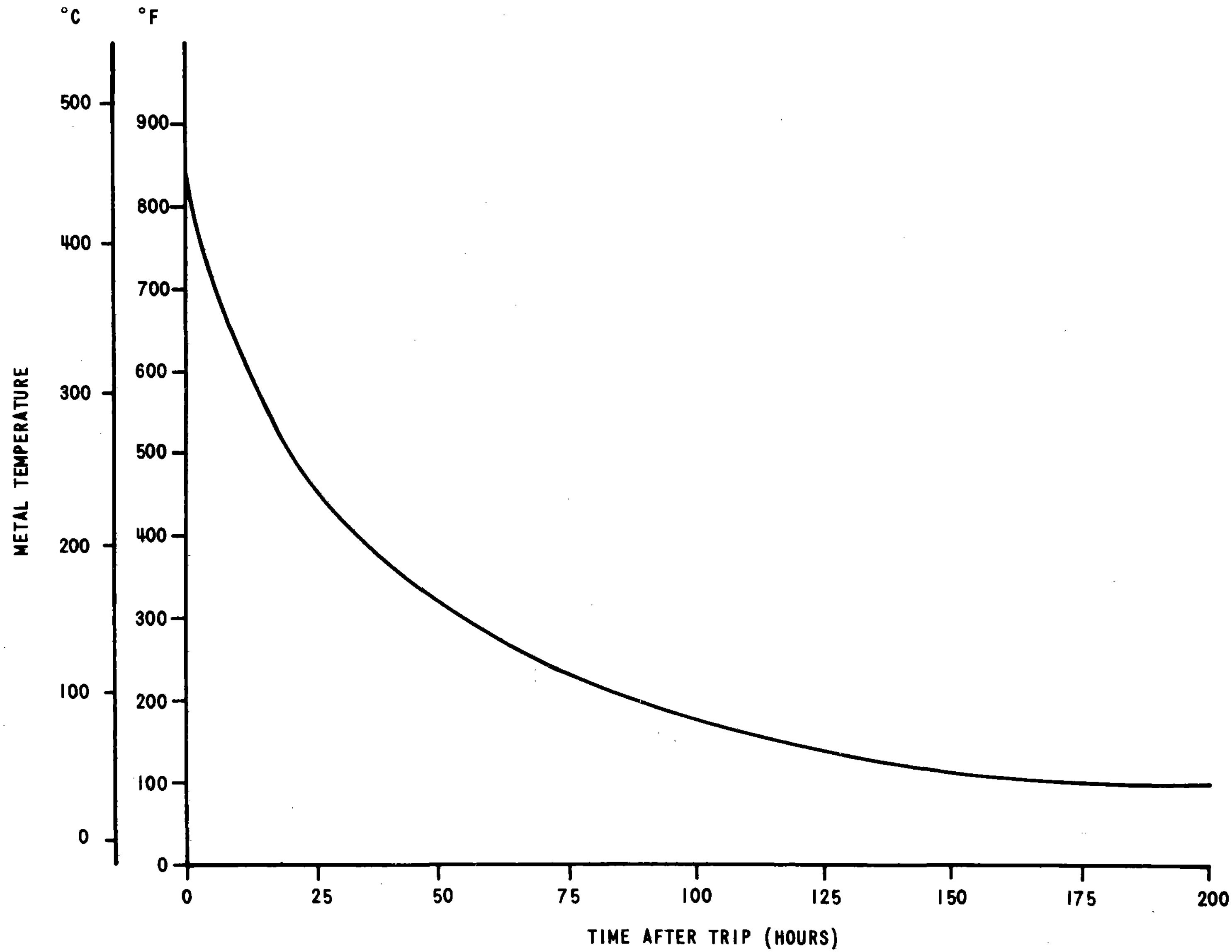

Figure 3-20. Typical Cool Down Curve for Single Shell Turbine

TABLE 3-1

TURBINE SEAL STEAM ALTERNATIVES

Alternative	Pressure kPa (psia)	Temperature C (F)	Mass Flow kg/hr (lb/hr)
1	10,101 (1465)	510 (950)	454 (1000)
2	3,275 (475)	388 (730)	454 (1000)
3	138 (20)	121 (750)	590 (1300)

rates specified by General Electric Company for different combinations of steam pressure and temperature.

Turbine Generator Control. The turbine is controlled by an electric-hydraulic controller (EHC). The EHC uses a combination of electric and hydraulic circuits to regulate turbine operation.

The turbine governor is used to regulate turbine speed prior to synchronization. After synchronization, the governor may be required to control load, admission steam pressure, or throttle steam pressure depending upon the operating mode of the plant.

Mechanical Design

The mechanical design systems in the EPGS include high pressure steam, extraction steam, feedwater, condensate, circulating water, and minor mechanical and chemical systems. These systems are considered in the following sections.

High Pressure Steam System. This subsection defines the High Pressure Steam System function, description, and operation. A more detailed description of the system is given in the Preliminary System Design Specification for the High Pressure Steam System presented in Appendix B.

System Function. The High Pressure Steam System supplies steam from the receiver to the turbine high pressure steam stop valve and to the charging side of the thermal storage system. The High Pressure Steam System also supplies steam from the discharge side of the thermal storage system to the turbine admission steam stop valve.

System Description. The High Pressure Steam System is shown on Piping and Instrument Diagram M1003 given in Appendix E and reproduced in Figure 3-21.

The system is divided into three distinct sections.

(1) Main Steam--steam from the receiver to the turbine main steam stop valve.
(2) Charging Steam--steam from the receiver to the charging side of the thermal storage unit.
(3) Admission Steam--steam from the thermal storage unit to the turbine admission steam stop valve.

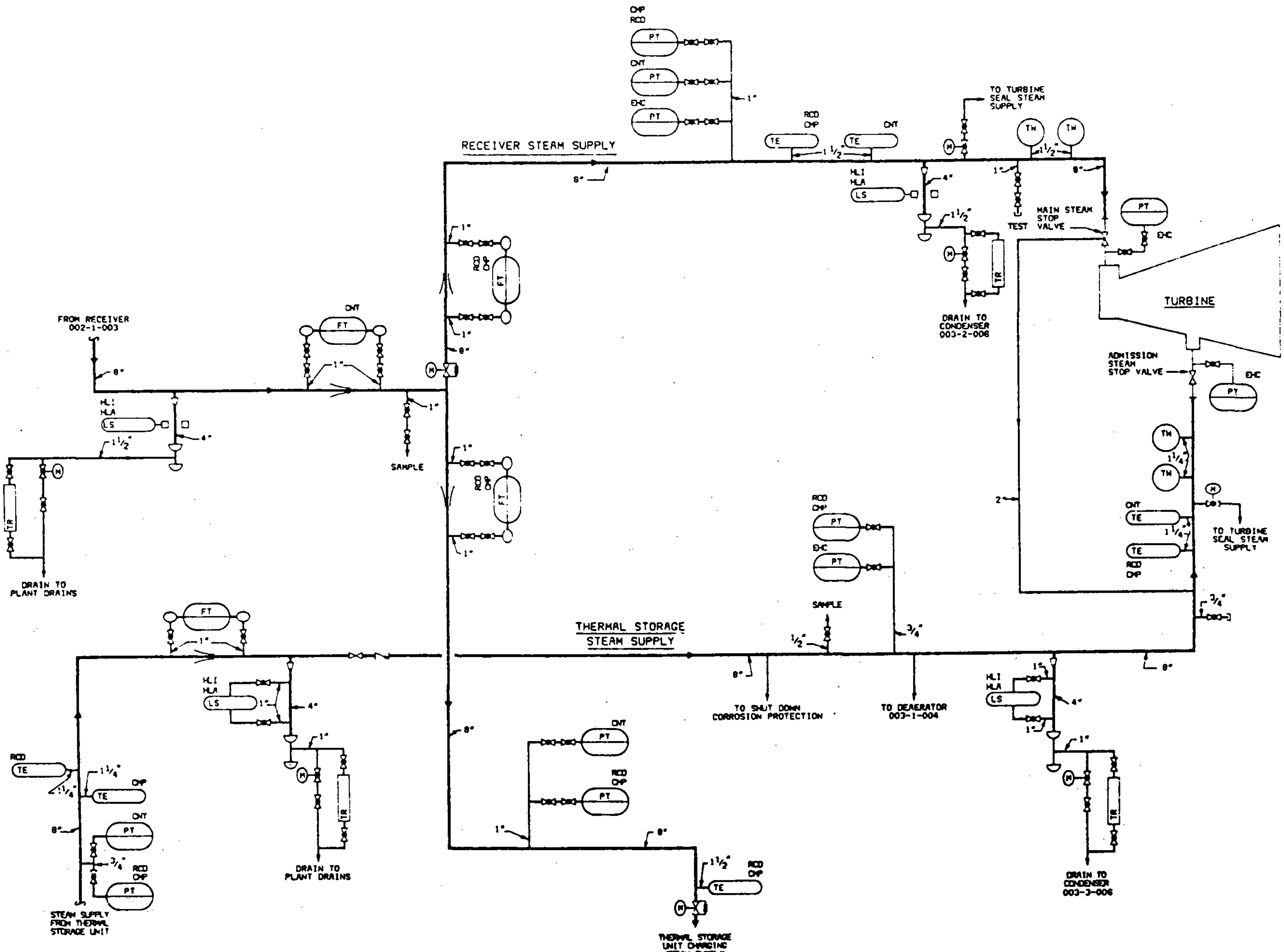

Figure 3-21. Piping and Instrument Diagram - High Pressure Steam

Superheated high pressure steam, generated in the receiver, is used to drive the turbine and to charge the thermal storage subsystem. Superheated steam generated by the thermal storage subsystem is used to drive the turbine and, during diurnal shutdown, to seal the turbine and maintain deaerator pressure at approximately 138 kPa (5 psig).

The steam supply to the turbine can be from the receiver or thermal storage or both simultaneously. Further, the high pressure steam system permits charging the thermal storage subsystem while supplying main steam and/or admission steam to the turbine.

Drip legs are provided for condensate removal from the high pressure steam lines and are located at the low point in the line as close as possible to the turbine.

All piping in the High Pressure Steam System is provided with electrical heating capable of maintaining metal temperature at 371 C (700 F) for the main steam and charging steam piping, and 316 C (600 F) for admission steam.

System Operation. The High Pressure Steam System continuously supplies steam to the turbine during generating system operation. The following normal modes of operation exist.

(1) The receiver supplying main steam to the turbine.
(2) Thermal storage supplying admission steam to the turbine.
(3) The receiver supplying charging steam to thermal storage.
(4) 1 and 2 simultaneously.
(5) 1 and 3 simultaneously.
(6) 2 and 3 simultaneously.
(7) 1, 2, and 3 simultaneously.

Extraction Steam and Heater Drain System. This subsection defines the Extraction Steam and Heater Drain System function, description, and control. A more detailed description is given in the Preliminary System Design Specification for the Extraction Steam and Heater Drain System presented in Appendix B.

System Function. The Extraction Steam and Heater Drain System is divided functionally into an extraction steam system and a heater drain system.

Turbine extraction steam is carried to the feedwater heaters, by the extraction steam system, for regenerative feedwater heating, to increase the cycle efficiency.

Extraction steam condensed in the feedwater heater is drained from the heaters by the heater drain system.

System Description. The Extraction Steam and Heater Drain System is shown on Piping and Instrument Diagram M1004 given in Appendix E and reproduced in Figure 3-22.

Three stages of turbine extraction are provided.

(1) High pressure extraction to the high pressure feedwater heater.
(2) Intermediate pressure extraction to the deaerator.
(3) Low pressure extraction to the low pressure feedwater heater.

The high pressure feedwater heater and the low pressure feedwater heater are vertical shell and tube heat exchangers.

The deaerator is a direct contact open heater which is located above the turbine centerline.

With main steam from the receiver and the unit operating at rated load, the high pressure extraction steam is superheated, the intermediate pressure extraction steam is slightly superheated, and the low pressure extraction steam is wet.

With admission steam from thermal storage and the unit operating at rated load, the high pressure extraction steam is slightly superheated and the intermediate and low pressure extraction steam is wet.

Power assisted extraction check valves and motor operated isolation valves are provided in each extraction line. These valves protect the turbine from water induction and from overspeed due to flashing of saturated water stored in the feedwater heaters.

One extraction check valve and one isolation valve are located in each extraction line to the high pressure feedwater heater and the low pressure feedwater heater.

Because of the large amount of energy stored in the deaerator, two extraction check valves are located in the intermediate pressure extraction line to the deaerator. An isolation valve is also included in this line.

Drip legs are provided at low points in each extraction line to drain water from the lines during start-up, and after a turbine trip, and as required during normal operation. Drip legs are also provided upstream of the extraction check valves for turbine water induction protection.

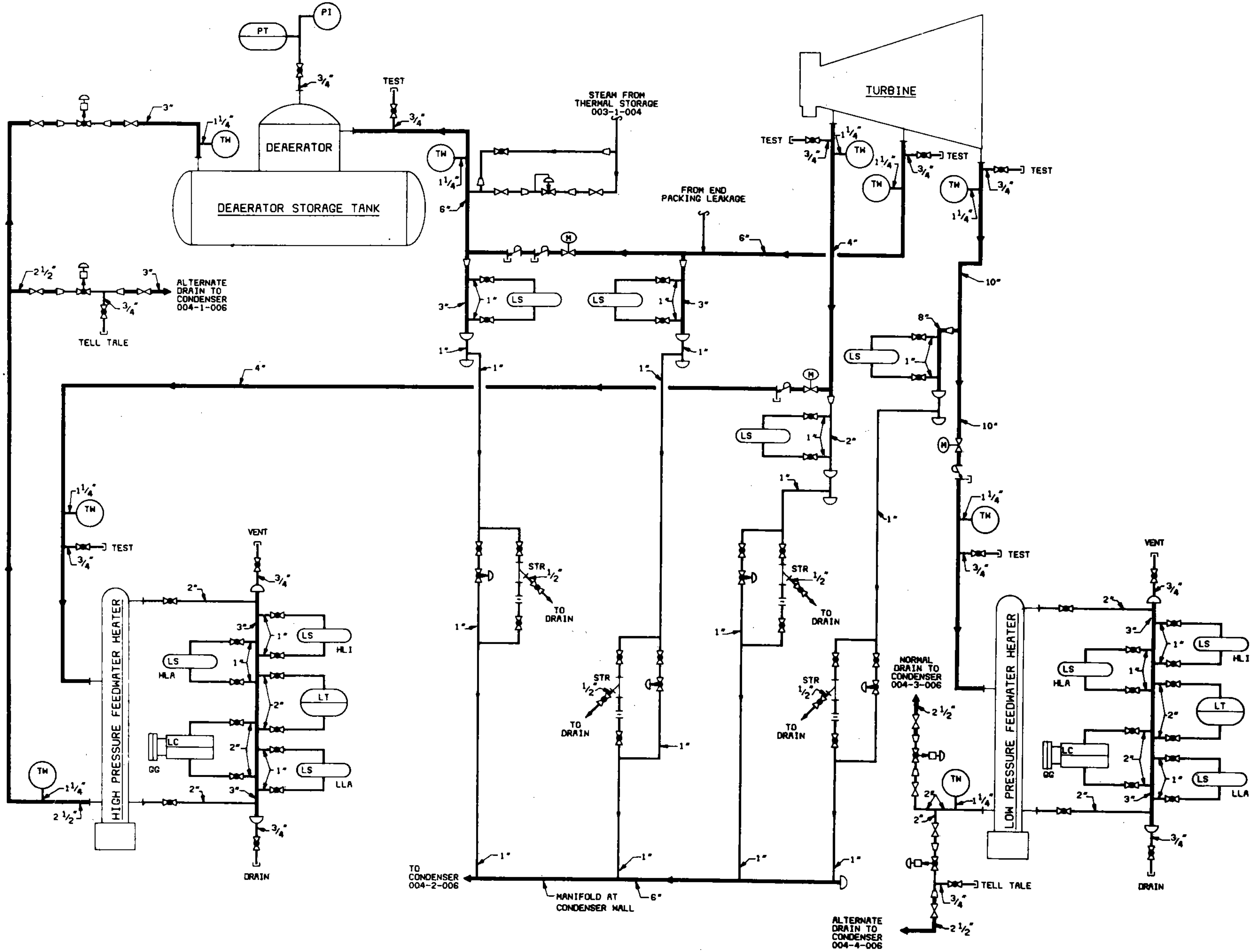

Figure 3-22. Piping and Instrument Diagram - Extraction Steam and Heater Drains

Automatic drain valves in parallel with restricting drain orifices are provided in each drip leg drain line. The valves are controlled by an automatic interlock initiated by a level switch located in the drip leg drain line.

Steam from thermal storage is used to maintain the deaerator pressure at 138 kPa (5 psig) during diurnal shutdown. This is done to (1) protect the deaerator from corrosion during the diurnal shutdown period and (2) maintain the deaerator in a "ready" condition for start-up.

Normal and alternate drains are provided from the high pressure feedwater heater and from the low pressure feedwater heater. High pressure feedwater heater normal drains cascade to the deaerator. Normal drains from the low pressure feedwater heater are routed to the condenser.

System Control. The extraction check valves and isolation valves close on trip signals received from the turbine control system and turbine water injection interlock system.

Individual extraction line motor operated isolation valves and drip leg automatic drain valves are controlled by the turbine water injection interlock system.

Normal and alternate heater drain control is by the level in the respective heater. High pressure feedwater heater normal drain control is also subject to deaerator storage tank level control.

During normal operation, normal heater drain control valves modulate to maintain normal operating level in the associated heater.

On high heater level, the respective alternate heater drain control valve opens to reduce water level.

The normal drains are controlled by pneumatic level controls. Alternate drains are controlled by an electric level control system.

The high pressure feedwater heater normal drain control valve closes at extreme high level in the deaerator storage tank.

<u>Feedwater System</u>. This subsection defines the feedwater system function, system description, individual system component functions and descriptions system operation, and system control. The components of the Feedwater System are as follows.

(1) Main feedwater pumps.
(2) Feedwater booster pumps.
(3) High pressure feedwater heater.
(4) Auxiliary feedwater pump.

A more detailed system and component description is presented in the Preliminary System Design Specification for the Feedwater System in Appendix B. The rationale for the feedwater pumping arrangement, shown in Figure 3-23, is contained in the Feedwater Pumping System report presented in Appendix D.

System Function. The feedwater system functions are (1) to pump feedwater from the deaerator storage tank to the receiver and/or the thermal storage unit, (2) to provide regenerative feedwater heating, and (3) to provide desuperheating water to the receiver attemperator, and thermal storage charging steam desuperheaters.

System Description. The feedwater system is shown on Piping and Instrument Diagram M1005 presented in Appendix E and reproduced in Figure 3-24.

Feedwater from the deaerator storage tank is pumped by one of two full capacity feedwater booster pumps through the high pressure feedwater heater. At this point, feedwater flow is directed as required to thermal storage and/or to one of the two full capacity feedwater pumps which in turn pump the feedwater to the receiver.

An auxiliary feedwater pump is provided to supply feedwater to thermal storage during diurnal shutdown when only a low flow, low pressure feedwater supply is required. This minimizes operating power requirements during diurnal shutdown.

Regenerative feedwater heating is provided by the high pressure feedwater heater. The heater is of the shell and U-tube design with feedwater flowing through the tubes and turbine extraction steam flowing through the shell.

Desuperheating spray water for the receiver superheater attemperator and thermal storage charging system desuperheaters is obtained from the discharge of the feedwater pumps.

The main feedwater pumps take suction from the feedwater booster pumps and add the additional head required to provide the receiver with high pressure feedwater. They are high speed centrifugal pumps driven by an electric motor through a geared speed increaser.

The feedwater booster pumps take suction from the deaerator and pump feedwater through the high pressure heater to thermal storage and/or the main feedwater pumps. They are located on the ground level to maximize the NPSH available. The feedwater booster pumps are high speed centrifugal pumps driven by an electric motor through a speed

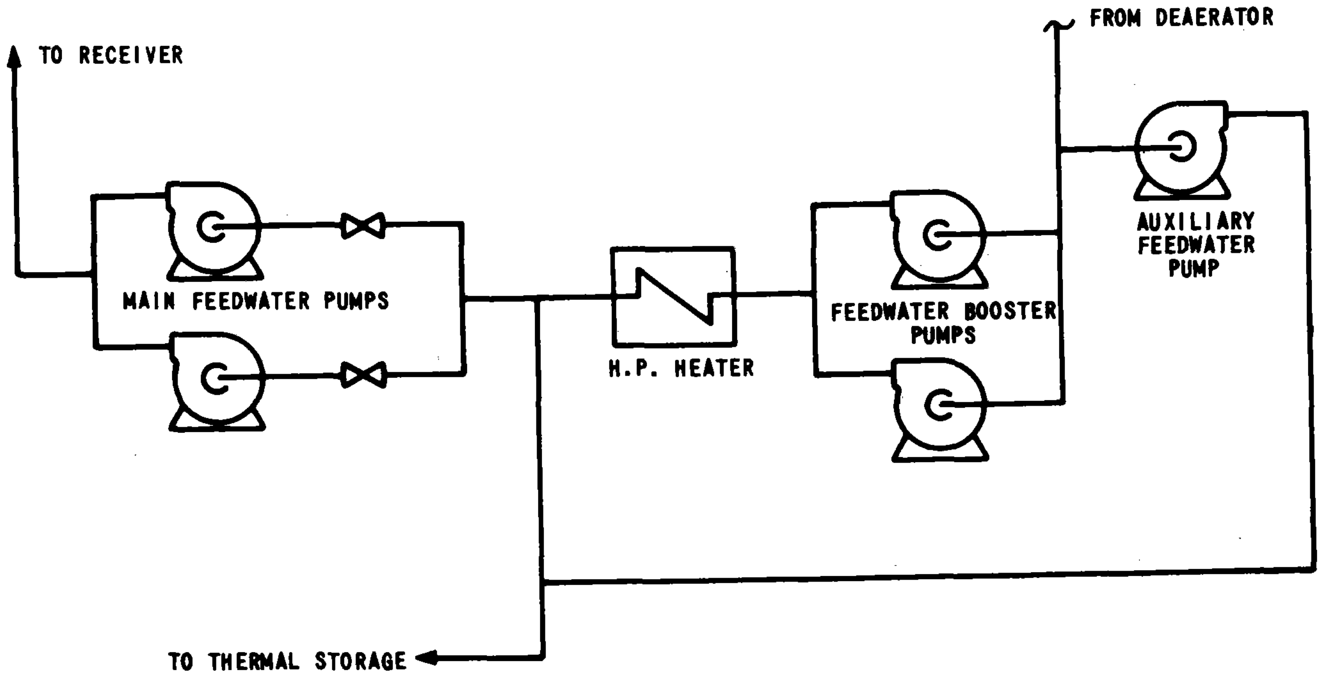

Figure 3-23. Selected Feedwater Pumping Concept

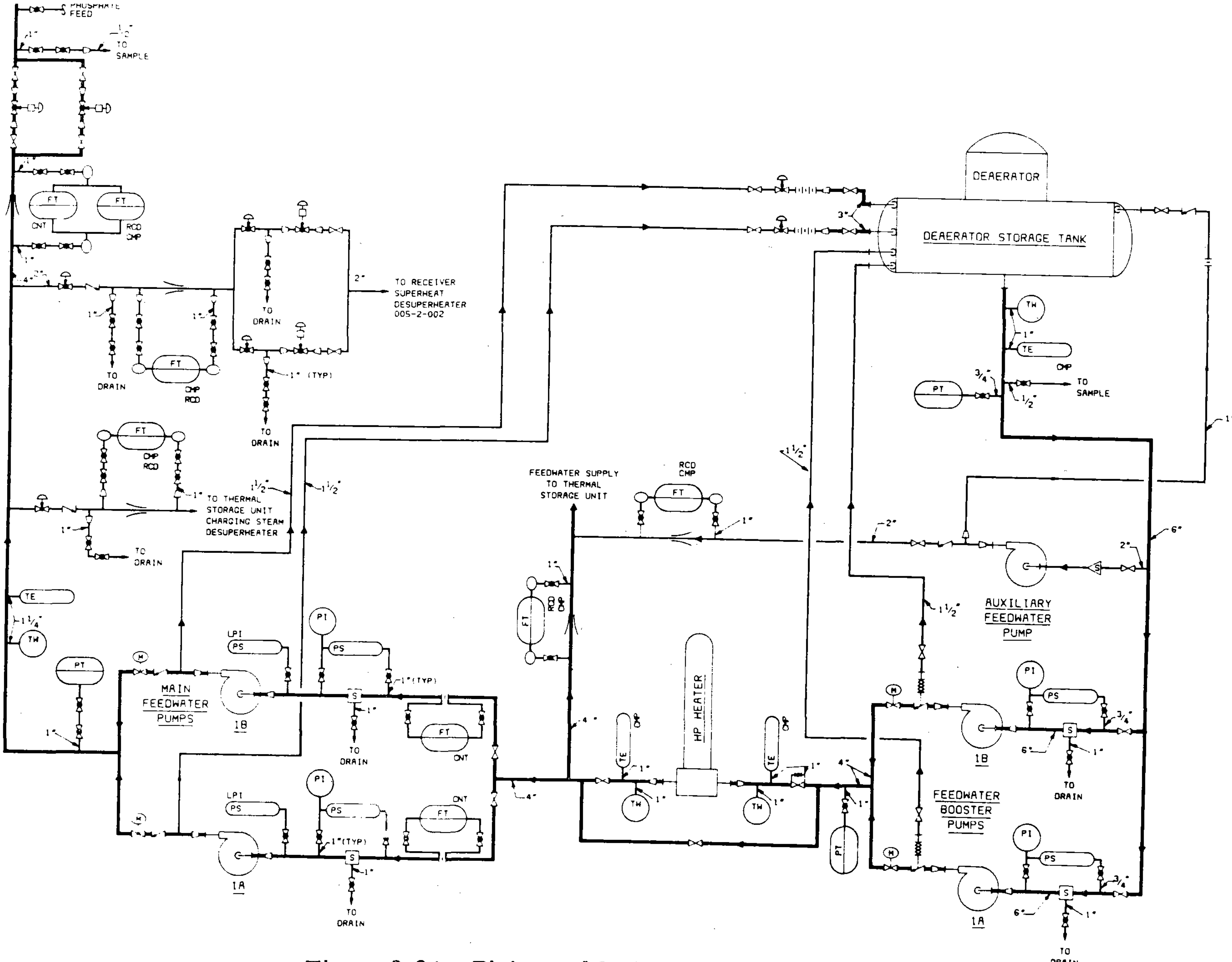

Figure 3-24. Piping and Instrument Diagram - Feedwater

increaser. The feedwater booster pumps are identical to the main feedwater pumps to minimize the number of spare parts required. The speed increasers, however, are different. The feedwater booster pumps are provided with inducers to minimize the NPSH required.

The high pressure feedwater heater uses extraction steam to heat the feedwater. It is located between the discharge of the feedwater booster pumps and the suction of the main feedwater pumps. The high pressure feedwater heater is a vertical shell and tube heat exchanger with integral desuperheater and drain cooler.

The auxiliary feedwater pump takes suction from the deaerator and pumps feedwater to thermal storage during diurnal shutdown. It is a frame mounted end suction pump located on the ground level to maximize the NPSH available.

System Operation. The feedwater system can be operated in any one of the following three normal modes.

(1) Feedwater booster pump running. In this mode of operation feedwater is provided to the thermal storage unit for the purpose of generating admission steam to drive the turbine.
(2) Feedwater booster pump and main feedwater pump running. In this mode of operation feedwater is delivered to the receiver for the purpose of generating steam to drive the turbine and/or to charge thermal storage. Feedwater can also be supplied to thermal storage from the booster pump discharge.
(3) Auxiliary feedwater pump running. This mode of operation is used to minimize power requirements during diurnal operation when only low pressure feedwater is required by thermal storage to produce seal steam and maintain deaerator pressure.

In the first two modes of operation the high pressure feedwater heater is in service to heat the feedwater before entering the receiver and/or thermal storage. During diurnal shutdown steam is required to maintain deaerator pressure and seal the turbine. Feedwater is supplied to the thermal storage steam generating system by the auxiliary feedwater pump. Since this is a low flow requirement, the pump will also be recirculating to the deaerator to provide minimum pump flow requirements. Steam blanketing of the high pressure feedwater heater during diurnal shutdown is required for corrosion protection. The steam supply is from thermal storage.

In addition to the above normal modes of operation, abnormal system operation can occur during start-up and low load operation, transient operation, or when the high pressure feedwater heater is out of service. During start-up and low load operation, the feedwater flow through the feedwater pumps cannot be less than the minimum flow recommended by the pump manufacturer. A recirculation system for each pump recirculates water from the pump discharge to the deaerator storage tank. Each recirculation system is designed for the minimum allowable flow rate as determined by the pump manufacturer.

Transient operating conditions occur during rapid load changes which can be either a load increase or load reduction. There are two general areas of the Feedwater System design which are affected by transient operating conditions.

(1) Control systems.
(2) Design and arrangement of equipment to provide adequate NPSH at the feedwater pumps.

A general requirement for Feedwater System controls is that their response to load changes be as rapid as that of the turbine generator and receiver steam generator. The feedwater booster pump suction system is designed to provide adequate NPSH at the booster pumps during rapid load reduction. This is accomplished mainly by locating the deaerator as required to provide adequate NSPH.

The high pressure feedwater heater may be removed from service for maintenance. A manually operated heater bypass valve, and heater isolation valves, are provided to permit maintenance work during cycle operation.

Figure 3-25 shows the temperature of feedwater pumped to the receiver and thermal storage subsystems as a function of feedwater flow for different modes of operation.

System Control. The feedwater control system automatically controls the feedwater flow entering the receiver and/or thermal storage unit so that it equals the receiver superheater outlet and/or thermal storage superheater outlet flow. In addition, the receiver drum level is monitored and maintained at a constant level.

Feedwater flow is controlled by throttling the discharge flow of the constant speed centrifugal feedwater pumps. Major control elements in the feedwater system are as follows.

(1) Flow nozzles in feedwater piping to
  (a) Receiver.
  (b) Thermal Storage.
  (c) Receiver Desuperheater.
  (d) Thermal Storage Desuperheaters.
(2) Throttling valves in feedwater piping to
  (a) Receiver.
  (b) Receiver Superheat Desuperheaters.

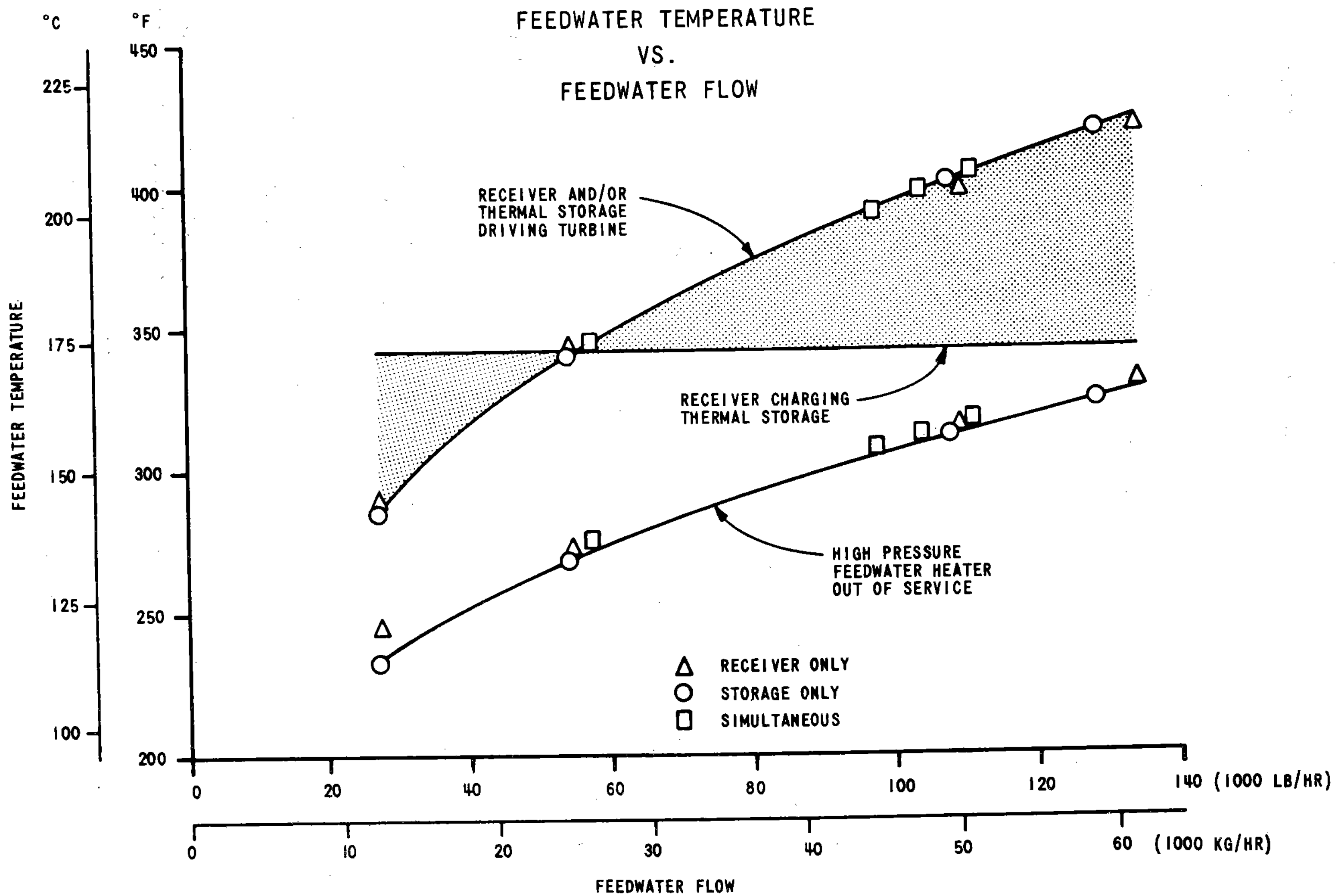

Figure 3-25. Feedwater Temperature vs. Feedwater Flow

(c) Thermal Storage Feedwater supply (located in thermal storage feedwater piping).
(d) Thermal Storage Desuperheater (located in thermal storage desuperheater piping).

(3) Flow orifice in each main feedwater pump suction line.

Each main feedwater pump and feedwater booster pump is provided with a recirculation control system which automatically allows feedwater from the pump discharge to be recirculated to the deaerator storage tank to provide the minimum flow requirements set by the pump manufacturer.

Each feedwater pump is also provided with a suction strainer to protect pump internals against damage caused by foreign objects in the feedwater. The strainers are provided with a control system to detect differential pressure across the strainer. Control room annunciation is provided to alert the operator that strainer difference pressure is high.

Isolation valves are provided at each feedwater pump suction, discharge, and recirculation line to permit maintenance to be performed on the pump. Each feedwater pump is interlocked such that it cannot be started unless its suction valve and recirculation isolation valves are open, thus providing an open flow path through the pump to the deaerator. In addition, the main feedwater pumps are provided with a suction pressure switch interlock. The main feedwater pumps can only be started with sufficient suction pressure, indicating a feedwater booster pump is operating with an open flow path to the main feedwater pumps.

Condensate System. This subsection defines the Condensate System function, system description, individual system component functions and descriptions, system operation, and system control. The components of the Condensate System are as follows.

(1) Condenser.
(2) Condensate pumps.
(3) Low pressure feedwater heater.
(4) Deaerator.

A more detailed description of the system and its components is given in the Preliminary System Design Specification for the Condensate System presented in Appendix B.

The rationale for the condenser design, shown in Figure 3-26 is provided in the Heat Rejection System report given in Appendix D.

System Function. The Condensate System condenses the turbine exhaust steam and delivers water from the condenser hotwell to the deaerator through the

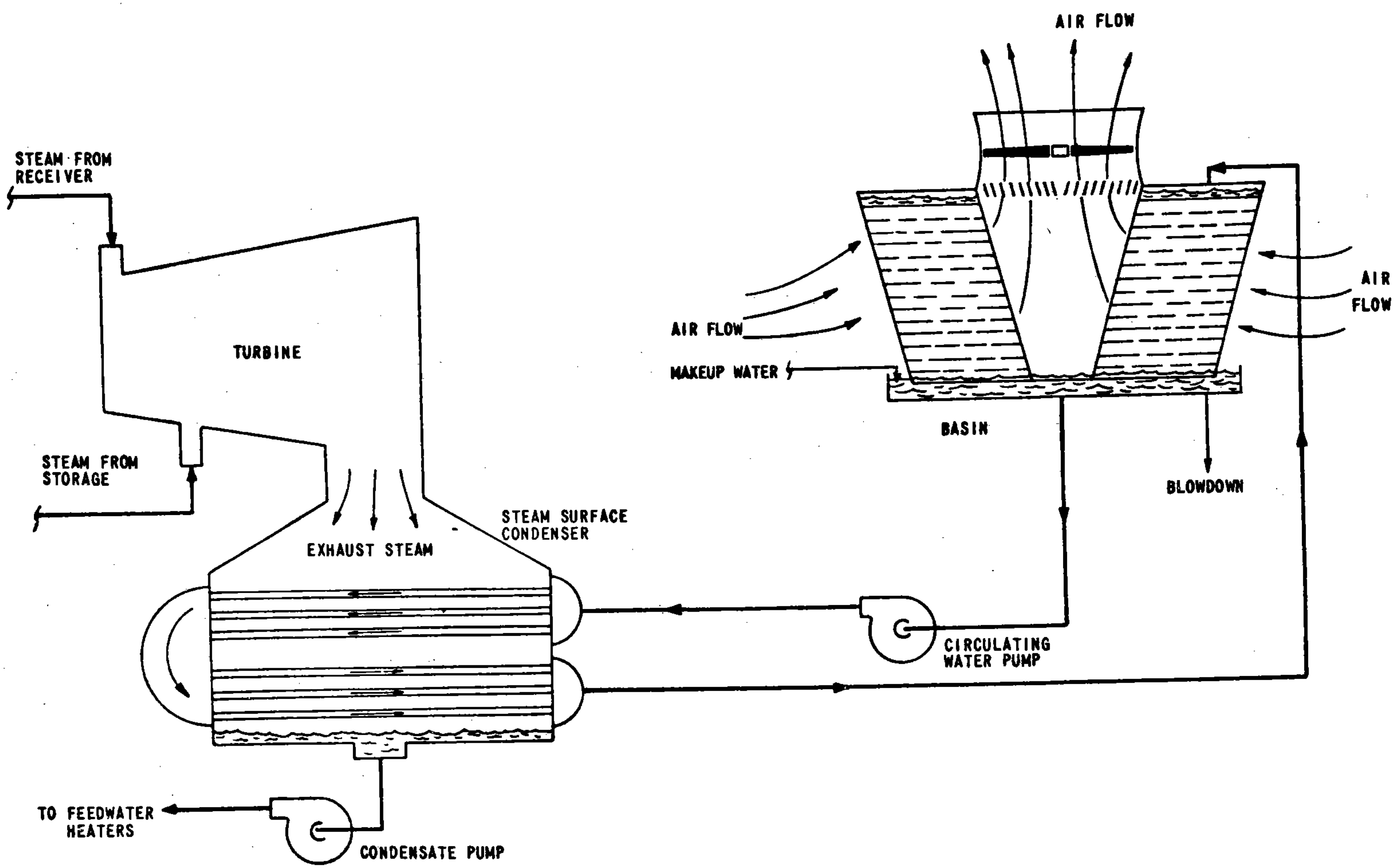

Figure 3-26. Steam Surface Condenser with Wet Cooling Tower

Low Pressure Feedwater Heater. In addition, this system supplies high quality water to the:

(1) seal steam spray chamber
(2) seal steam desuperheater
(3) seal steam spray nozzle
(4) auxiliary cooling water makeup

System Description. The Condensate System is shown on Piping and Instrument Diagram M1006 presented in Appendix E and reproduced in Figure 3-27.

Suction from the condenser hotwell is pumped by one of two full capacity condensate pumps through the low pressure feedwater heater to the deaerator.

Regenerative feedwater heating is provided for by the low pressure feedwater heater. The heater is of the shell and U-tube design with feedwater flowing through the tubes and turbine extraction steam flowing through the shell.

Condensate flow is regulated by two full-capacity control valves. Under normal operating conditions, one of these valves is in service and the other serves as a standby.

The primary function of the surface condenser is to condense the exhaust steam from the main turbine. In addition, the surface condenser serves the following purposes.

(1) Recovers condensed steam as condensate.
(2) Provides a low exhaust pressure for the turbine for better operating efficiency.
(3) Provides a low pressure collection point for condensate drains from several systems in the plant.
(4) Provides deaeration of the collected condensate.
(5) Provides short-term storage of condensate.

The surface condenser is of the cylindrical, two-pass design. The condenser shell is located directly beneath the turbine exhaust with its longitudinal center line perpendicular to the longitudinal center line of the turbine.

The condensate pumps take suction from the condenser hotwell and supply the condensate through the low pressure feedwater heater to the deaerator. Pump shafts are sealed against leakage with seal water taken from the condensate discharge line.

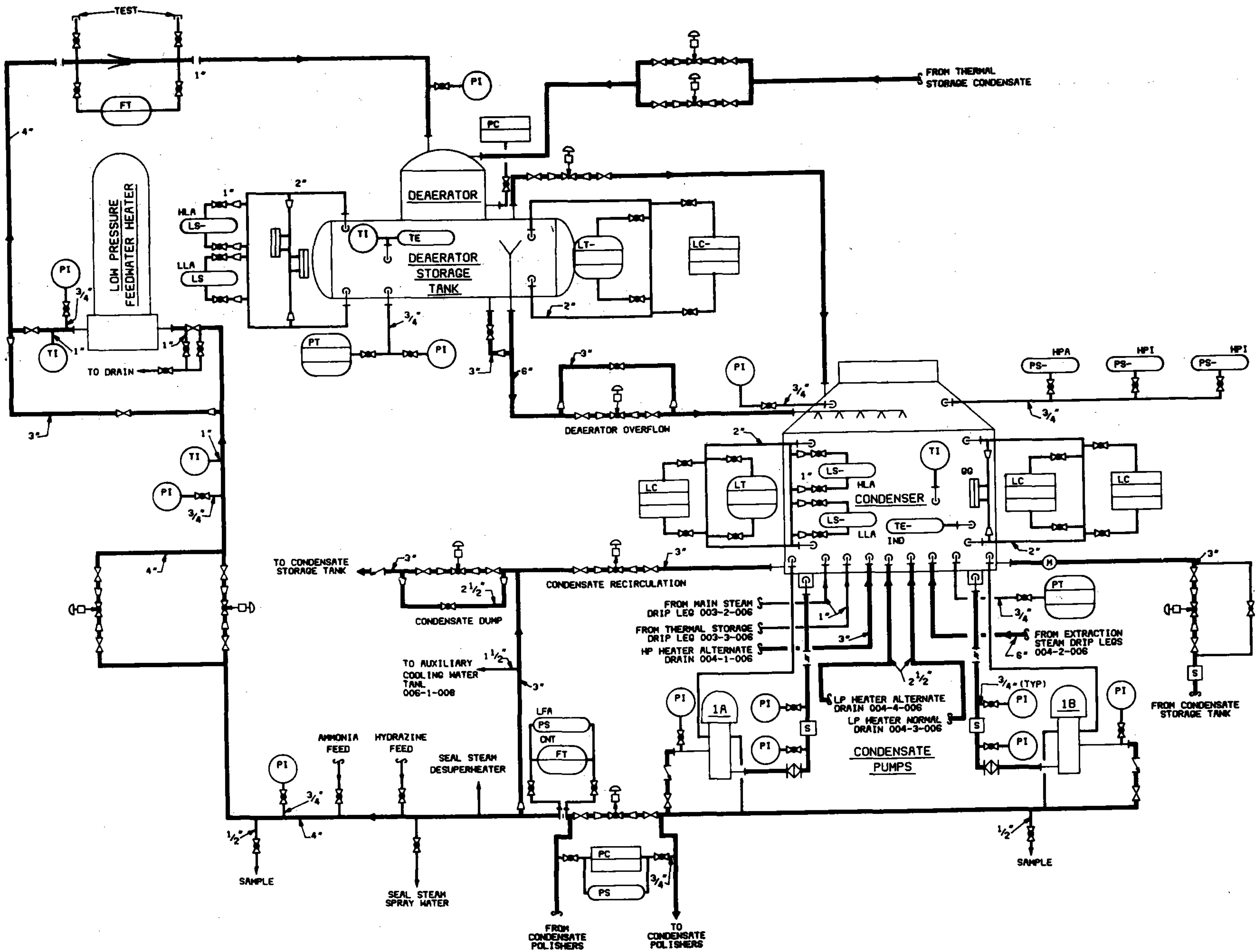

Figure 3-27. Piping and Instrument Diagram - Condensate

The two full-capacity condensate pumps are vertical shaft, submerged suction, can type pumps. They are located on the ground level of the turbine building near the condenser.

The low pressure feedwater heater uses extraction steam to heat the condensate. It is located between the discharge of the condensate pumps and the deaerator. The low pressure feedwater heater is a vertical shell and tube heat exchanger with an integral drains cooler. The direct contact type deaerating heater is provided to remove oxygen and noncondensible gases from the condensate. The unit consists of a vertical-type deaerator located atop a horizontal storage tank. As the condensate enters the deaerator, it is directed across trays which break up the flow into small droplets. Extraction steam is introduced into the deaerator and passes through the condensate cascade, facilitating removal of oxygen and other non-condensible gases. Vent steam and condensate from the high pressure heater drains and thermal storage condensate are also discharged into the deaerator. The air and other gases are exhausted through a vent condenser. The condensate then passes into the deaerator storage tank from which it is removed by the feedwater pumps.

System Operation. The system normal operation is with one condensate pump running and pumping water to the deaerator. In addition to the normal mode of operation, abnormal system operation can occur during start-up and low load operation, transient operation, thermal storage charging, or when the low pressure feedwater heater is out of service.

During start-up and low load operation, the condensate flow through the condensate pumps cannot be less than the minimum flow recommended by the pump manufacturer. A condensate recirculation line is provided to maintain the minimum flow requirement of the condensate pumps during start-up and low load conditions. This line shall be sized for the minimum pump flow as determined by the pump manufacturer.

Transient operation occurs because the water level in the condenser hotwell is not constant, but changes with turbine load, condensate flow from thermal storage, and other variable conditions. On high water level, the excess condensate is dumped to the demineralized water storage tank. When the level is low, the condensate makeup line provides additional water from the condensate makeup storage tank.

When receiver steam is being used to charge thermal storage, the thermal storage condensate is returned to the deaerator. This condensate is flashed when the pressure is broken down by the pressure breakdown control valve just prior to the deaerator. The flashed steam thus produced, in excess of that required to maintain deaerator pressure, is bled to the condenser. One condensate pump is operating to return the condensate to the deaerator.

The low pressure feedwater heater may be removed from service for maintenance without interrupting plant operation. Manually operated inlet and outlet isolation valves and a manually operated bypass valve are provided for remote isolation of the heater.

System Control. The condensate control valves are regulated by a three-element controller which receives inputs from condensate flow, feedwater flow, and deaerator level. Condensate flow is adjusted as required to provide the necessary feedwater flow while maintaining the water level in the deaerator storage tank.

Interlocks are provided to prevent starting the condensate pump unless both suction and discharge valves are completely open and the hotwell level is sufficiently high.

The recirculation control valve is regulated by a flow transmitter located in the condensate pump discharge piping. A flow switch provides alarm of low flow conditions.

A condensate dump and makeup control system discharges condensate to the demineralized water storage tank if the hotwell level is high, and supplies water from the storage tank to the hotwell when the level is low.

The deaerator overflow control valve is positioned by a level switch on the deaerator storage tank. The deaerator is provided with a storage tank level indicator which signals the operator when high and low levels occur.

Condensate flow to the deaerator is measured with a removable calibrated flow measuring nozzle conforming to the requirements of the ASME Performance Test Code for Steam Turbines (PTC-6). Performance testing is done by connection of test manometers to the orifice. A flow transmitter is connected to a second set of connections on the orifice for use in normal plant operation.

An interlock system is provided on the deaerator to protect the turbine from water damage and to protect the boiler feed pumps from cavitation damage caused by low suction pressure.

A pressure controller located on the deaerator is used to operate the flash steam control valve dump to the condenser.

Circulating Water System. This subsection defines the Circulating Water System function, system description, individual system component functions and descriptions, and system control. The components of the Circulating Water System are as follows.

(1) Cooling tower.
(2) Circulating water pumps.

A more detailed system and component description is given in the Preliminary System Design Specification for the Circulating Water System presented in Appendix B.

The rationale for the design of the Circulating Water System is given in the Heat Rejection System report presented in Appendix D.

System Function. The Circulating Water System provides cooling water to the condenser for condensing the turbine exhaust steam, and to the Auxiliary Cooling Water System heat exchangers.

System Description. The Circulating Water System is shown on Piping and Instrument Diagram M1007 presented in Appendix E and reproduced in Figure 3-28.

Water is pumped through the condenser tubes and auxiliary cooling water heat exchangers by the circulating water pumps. The water, heated by the condenser and auxiliary cooling water heat exchangers, is returned to, and cooled by, the cooling towers.

The cooling tower rejects waste heat of the steam cycle and plant auxiliary equipment. The heat is rejected to the atmosphere by cooling the circulating water. The cooling tower is of the induced mechanical draft, wood framed, filled, two cell type. It is supplied with drift eliminators to minimize water loss.

The circulating water pumps supply water from the cooling tower basin to the condenser and auxiliary cooling water heat exchangers for heat rejection. Two half-capacity circulating water pumps of the vertical wet pit type are provided.

System Control. The circulating water system controls the turbine backpressure by either varying the circulating water flow rate or by varying the fan speed in the cooling tower. The control of the circulating water flow rate and fan speed is by operator action. This control becomes especially important for low steam flows and/or low ambient wet bulb temperatures since it prevents the turbine backpressure from dropping below the point at which choking occurs in the turbine. Further, it can be used to reduce the auxiliary power requirements. Figure 3-29 shows

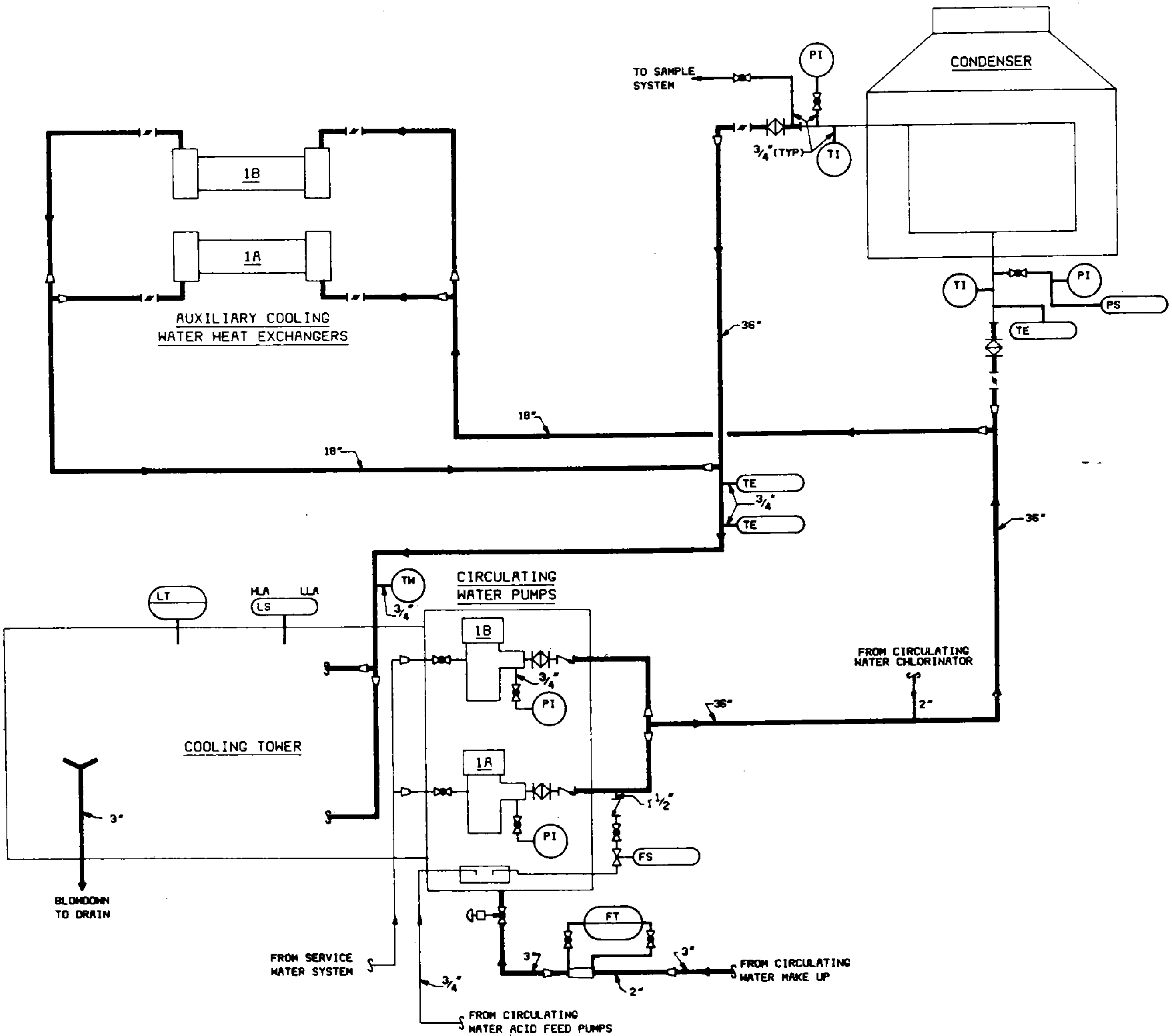

Figure 3-28. Piping and Instrument Diagram - Circulating Water

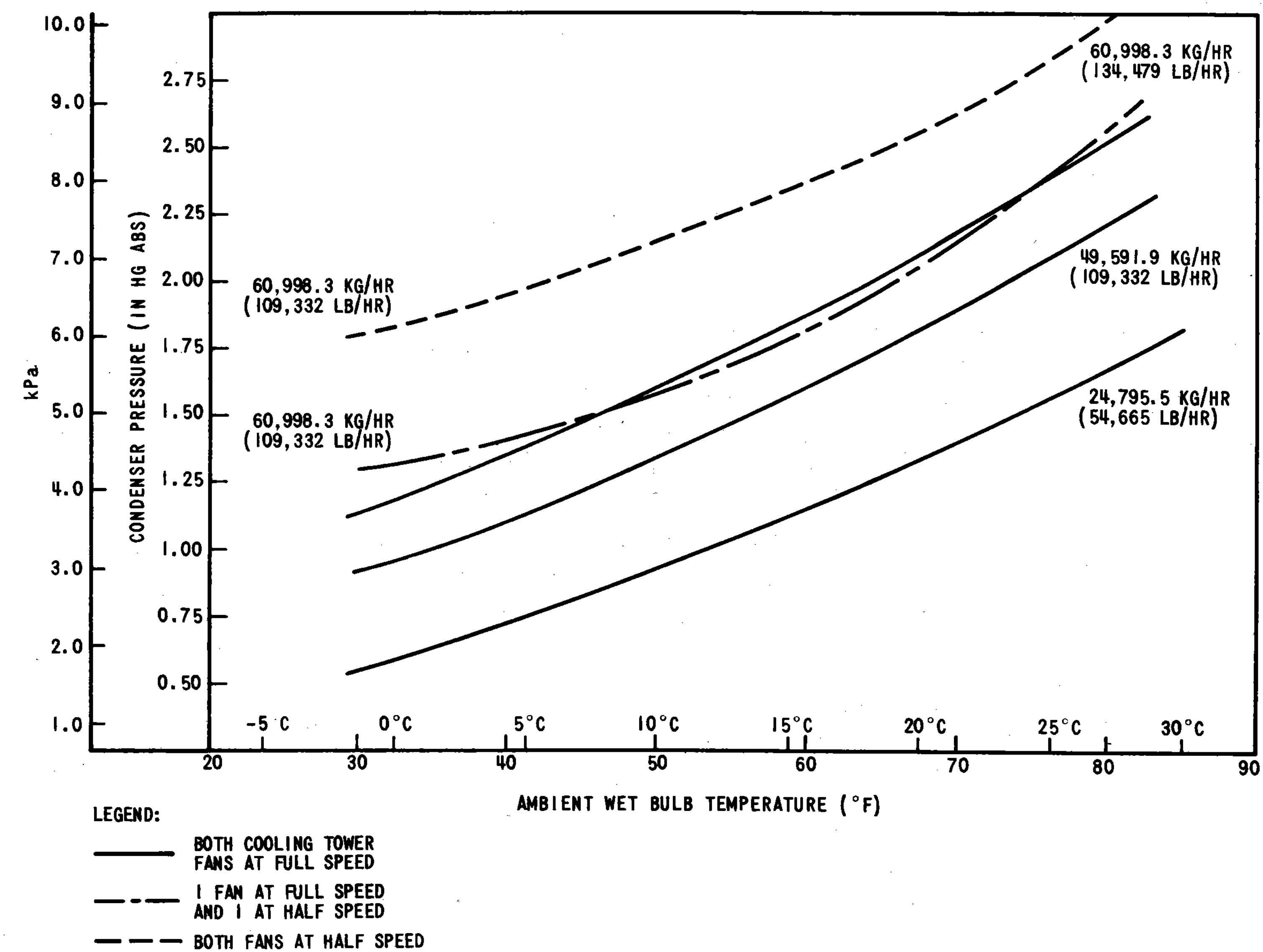

Figure 3-29. Condenser Pressure vs. Wet Bulb Temperature at Various Throttle Steam Flows

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the effects of ambient wet bulb temperature, steam flow to the turbine, and cooling tower fan speed on condenser backpressure.

Minor Mechanical and Chemical Systems. The minor mechanical and chemical support systems of the EPGS are listed in Table 3-2. A system description for each system listed in the table is presented in Appendix C. Brief descriptions of the function of these systems are presented in the following paragraphs.

Auxiliary Cooling Water System. The Auxiliary Cooling Water System supplies condensate quality cooling water for removing waste heat from plant auxiliaries. The system includes two full-capacity auxiliary cooling water pumps, heat exchangers, booster pumps, an auxiliary cooling water head tank, and a chemical pot feeder. The control system maintains cooling water temperature at approximately 35 C (95 F).

Turbine Lubricating Oil System. The Turbine Lubricating Oil System provides continuous purification of the oil stored in the turbine lubricating oil reservoir. This is accomplished by circulating the oil through a conditioning unit which filters the oil and removes any accumulated water. The system includes the lubricating oil reservoir (supplied with the turbine), conditioner, drain tank, and transfer pump. Approximately 20 per cent of the lubricating oil reservoir capacity is circulated through the conditioning unit each hour.

Service and Control Air System. The Service and Control Air System supplies compressed air to equipment and instruments. The system includes two packaged, reciprocating air compressor units, and two heatless desiccant air dryers. The air dryers are used to provide dry air for control and instrumentation applications; general service plant air is not dried. The air compressors cycle as required to maintain air supply pressure within acceptable limits.

Fire Protection System. The Fire Protection System provides fire protection for the electrical generation building, the thermal storage area, the receiver tower, and several yard structures. The system includes a diesel engine-driven fire pump to provide water for fire protection, a halon system to protect the computer room and control room, and hand-held chemical fire extinguishers located throughout the plant. Fire protection water is normally supplied by the service water system. In the event additional water is required, the diesel engine-driven fire pump will start automatically. The halon system is automatically actuated by smoke detectors.

TABLE 3-2

MINOR MECHANICAL AND CHEMICAL SYSTEMS

Auxiliary Cooling Water	Heater Vents and Drains
Chemical Cleaning	Miscellaneous Vents and Drains
Chemical Feed	Service Air and Compressed Air
Circulating Water Makeup and Blowdown	Service Water
Condensate Polishing	Shutdown Corrosion Protection
Condensate Storage	Space Conditioning
Condenser Air Removal	Turbine Lubricating Oil
Demineralized Water Storage	Turbine Seal Steam and Drains
Demineralized Water Supply	Waste Treatment
Fire Protection	Water Quality Control

Service Water System. The service water system provides water for general plant usage. The system includes two full-capacity pumps and an elevated storage tank. A hypochlorinator is also provided for potable water chlorination. The service water pumps cycle as required to maintain the level in the elevated service water tank above the minimum set point.

Condenser Air Removal System. The Condenser Air Removal System removes noncondensible gases from the condenser shell. The system includes two full-capacity, two stage, mechanical exhausters. Hogging operation is accomplished using the first stage vacuum pump. The holding operation automatically begins when the volume of gas discharged from the first stage equals the second stage inlet capacity.

Miscellaneous Vents and Drains System. The Miscellaneous Vents and Drains System includes roof drains, plant drains, and equipment vents and drains not included in other systems. The drains are piped to the plant drains header which drains under gravity to the neutralization basin. On high level, the contents of the neutralization basin are pumped to the evaporation pond.

Circulating Water Makeup and Blowdown System. The Circulating Water Makeup and Blowdown System provides makeup to and blowdown from the Circulating Water System. Makeup flow is regulated as required to limit the solids' concentration of the circulating water and to maintain a minimum water level in the cooling tower basin. Blowdown is by an overflow drain on the cooling tower basin.

Condensate Storage System. The Condensate Storage System provides storage for condensate makeup and dump. The system includes the condensate storage tank. Makeup and dump are regulated by control valves which receive input from level switches located on the condenser hot well.

Turbine Seal Steam and Drains System. The Turbine Seal Steam and Drains System regulates the seal steam supply pressure and provides a low pressure chamber for the seal steam drains. The system includes pressure regulating valves, spray chamber, seal steam exhauster, and gland steam desuperheaters. The pressure regulating valves maintain system pressure at approximately 136 kPa (19.7 psia). Seal steam leakage is condensed in the spray chamber where the air is exhausted to atmosphere and drains are led to the condenser.

Demineralized Water Storage System. The Demineralized Water Storage System provides high purity water for condensate makeup and for feed chemical dilution. The system includes a storage tank and a booster pump. The demineralized water supply system maintains the storage tank level which in turn maintains the water level of the condensate storage tank.

Shutdown Corrosion Protection System. The Shutdown Corrosion Protection System protects the heaters, deaerator, and receiver from corrosion when the equipment is not in use. Nitrogen is used for long-term protection while steam is used for short-term protection. The system includes nitrogen storage facilities, and nitrogen and steam pressure regulators.

Condensate Polishing System. The Condensate Polishing System maintains high purity water in the steam cycle. Removal of dissolved and suspended solids is by ion exchange and filtering, respectively. The system includes two full-capacity, filter-demineralizers complete with recoating facilities. Recoating is initiated by the operator in the event of either a high cation conductivity or high differential pressure alarm.

Water Quality Control System. The Water Quality Control System continuously monitors the feedwater, circulating water system, and thermal storage systems. The system includes the water quality panel. The system provides signals for automatic chemical feed and annunciation in the event of significant variation from the operational limits.

Chemical Feed System. The Chemical Feed System supplies water conditioning chemicals to the feedwater and the circulating water system. The system includes chemical solution tanks, chemical metering pumps, chlorine storage cylinder, chlorinator, and injector. All feed rates are automatically controlled, except the sodium phosphate and chlorine which are manually adjusted.

Demineralized Water Supply System. The Demineralized Water Supply System supplies high purity water for chemical cleaning, hydrostatic testing, cycle fill and makeup, and closed cooling system fill. The system includes a polishing filter, three ion exchange vessels, a forced draft degasifier, regenerator facilities, and control panel. The system is started and stopped in response to level controls mounted on the demineralized water storage tanks.

Chemical Cleaning System. The Chemical Cleaning System provides for chemica cleaning of the condensate-feedwater equipment from the condenser to the receiver drum. This is referred to as the prereceiver cycle. It consists of a temporary chemical cleaning pump, temporary heat exchanger, and temporary piping. The cleaning is performed on the following order.

(1) Condensate and Feedwater System Flush.
(2) Feedwater Heater Shells Hot Water Soak.
(3) Prereceiver System Alkaline Cleaning.
(4) Prereceiver System Acid Cleaning.
(5) Receiver Alkaline Cleaning.
(6) Receiver Acid Cleaning.

Heater Vents and Drains System. The Heater Vents and Drains System includes the operating, start-up, and safety relief vents of the feedwater heaters and deaerator, and drains for the shell and tube side of the heaters. For system start-up, the heater normal operating and start-up vents are opened. The start-up vents are closed after the shell has been vented. At shutdown, air operated vent valves are closed to facilitate corrosion protection.

Waste Treatment System. The Waste Treatment System collects and treats all liquid waste streams emanating from the plant. The system includes a visitors center septic tank, plant septic tank, neutralization basin and mixer, waste water transfer pumps, and evaporation pond. Cooling tower blowdown flows directly to the evaporation pond; sanitary waste flows to the septic tanks; the remainder flows to the neutralization basin for neutralization, and later transfer to the evaporation pond.

Space Conditioning System. The space conditioning system provides heating and ventilating for the enclosed areas of the plant and support structures, and air conditioning for the turbine building control area. The major components include electric unit heaters, fans and ventilators, air handling units, water chillers, chilled water pumps, and electric resistance coils. The control area space conditioning is automatically controlled. Other areas requiring space conditioning have automatically controlled unit heaters and manually controlled fans and ventilators.

Electrical Design

The design of the EPGS electrical systems is based on meeting the pilot plant busbar power requirements of:

(1) 10 MWe at 2 p.m. on a clear day at winter solstice using superheated steam supplied directly from the receiver subsystem,
(2) 7 MWe for a period of three hours using superheated steam supplied directly from the thermal storage subsystem, and
(3) 7 MWe using steam from the receiver and thermal storage subsystems simultaneously.

In addition, the electrical systems are designed to operate when the turbine is driven by the maximum receiver steam flow.

Besides satisfying these requirements, the electrical systems, specifically the generator, must be capable of producing sufficient power to operate plant auxiliary equipment in the different plant operating modes.

Auxiliary power requirements can be referred to as the power required by a piece of equipment (e.g., a pump), usually stated as brake horsepower, or as the power required at the generator terminals or from the grid at the busbar. The latter approach includes the efficiency for a motor (or other intermediate equipment like a transformer) and electrical line losses. The auxiliary power requirements stated in accordance with the first definition are specified for EPGS components in Table 3-3. The auxiliary power requirements stated in accordance with the second definition are presented for the subsystems, and the plant as a whole, listed in Table 3-4.

The following sections describe the electrical design of the EPGS main electric system, auxiliary electric system, essential service power system, and miscellaneous electrical systems.

Main Electric System. The function of the Main Electric System, its operating conditions, and major components are discussed here. A more detailed description of the system is presented in the Main Electric System Preliminary System Design Specification in Appendix B.

Function. The function of the Main Electric System is to generate gross electrical power at 13,800 volts, 60 hertz, and deliver the net busbar power to the utility transmission line at 115,000 volts. The difference between the gross generation and the net busbar power is the auxiliary power required to maintain the operation of the solar pilot plant. The Main Electric System has the capability to generate and deliver as much power as the turbine is able to develop under maximum steam flow conditions.

Operating Conditions. Figure 3-30 shows the one line diagram of the Main Electric System. The generator has three stationary windings called stator windings and a rotating winding called rotor or field winding. The Main Electric System operates with the generator rotor directly coupled to the steam turbine. The turbine is driven by steam from the solar receiver, from the thermal storage subsystem, or from both simultaneously. The turbine drives the generator rotor at 3600 revolutions per minute. The excitation system provides direct current (dc) to the rotor winding producing magnetic field. Electrical power at 13,800 volts, three phase alternating current (ac) is generated at the terminals of the stator windings whenever the rotating magnetic field cuts through the stationary windings of the stator. The generated power

TABLE 3-3. AUXILIARY POWER REQUIREMENTS* FOR ELECTRICAL POWER GENERATION SUBSYSTEM/BALANCE OF PLANT AND MASTER CONTROL SUBSYSTEM, 10 MWe PILOT PLANT

COMPONENT	RECEIVER DESIGN POINT	STORAGE DESIGN POINT	RECEIVER AND STORAGE DRIVING TURBINE	CHARGING STORAGE AND SEALING TURBINE	SEALING TURBINE
Circ. Water Pumps	336	336	336	336	197
Main Feedwater Pump	409	--	155	409	--
Booster FW Pump	148	148	148	148	--
Cooling Tower Fans	112	112	112	112	--
Condensate Pumps	20	20	20	20	7
HVAC**	184	184	184	184	184
Lighting	113	113	113	113	145
Aux. Cooling Pump	24	24	24	24	24
Condenser Exhauster	25	25	25	25	25
Aux. Clg Boost Pump	14	--	14	14	--
Air Compressor	37	37	37	37	37
Service Water Pump	20	20	20	20	20
Bearing Oil Pump	5.6	5.6	5.6	5.6	5.6
EPGS Control	5	5	5	5	5
Turbine Control	5	5	5	5	5
Water Pretreatment	--	--	--	--	--
Waste Treatment	12.2	12.2	12.2	12.2	12.2
Hyd. Fluid Pump	11.2	11.2	11.2	11.2	11.2
Demineralizer	8.7	8.7	8.7	8.7	8.7
Water Qual. Contr.	8.5	8.5	8.5	8.5	8.5
Hyd. Fluid Heater	1.6	1.6	1.6	1.6	1.6
Chemical Feed	1.5	1.5	1.5	1.5	1.5
Lube Oil Cond.	2.5	2.5	2.5	2.5	2.5
Cond. Polishing	2.2	2.2	2.2	2.2	2.2
Vapor Extractor	0.6	0.6	0.6	0.6	0.6
Turbine Turning Gear	--	--	--	5	5
Emer. Bear. Oil Pump+	--	--	--	--	--
Aux. Feedwater Pump	--	--	--	--	0.6
Miscellaneous	60	60	60	60	60
TOTAL	1567	1144	1313	1572	769

*All axuliary power requirements are given in kW for component input or motor output.

**430 kW for ambient air temperature below 13 C (55 F).

+5 kW dc emergency.

TABLE 3-4

AUXILIARY POWER REQUIREMENTS

10 MWe PILOT PLANT

EPGS TURBINE \ THERMAL STORAGE	CHARGE	SIMULTANEOUS CHARGE AND DISCHARGE	DISCHARGE	HOLD
THROTTLE	C 78 R 124 S 337 E 1741 T 2280			RDP C 78 R 124 S 44 E 1741 T 1987
ADMISSION		C 78 R 124 S 401 E 1271 T 1874	SDP C 0 R 0 S 207 E 1271 T 1478	
SIMULTANEOUS THROTTLE AND ADMISSION+		C 78 R 124 S 401 E 1459 T 2062	R/S DP C 78 R 124 S 207 E 1459 T 1868	
SEAL		C 78 R 124 S 370 E 1747 T 2319	C 0 R 0 S 98 E 854 T 952	

*Assumes storage oil maintenance unit consumes 48 kW at an efficiency of 0.90. If new value, X, is obtained, entry in each block should be changed as follows:

$$S' = S - \frac{48}{0.9} + \frac{X}{0.9} = S - 53.3 + \frac{X}{0.9}$$

+Based on 50% from receiver and 50% from thermal storage.

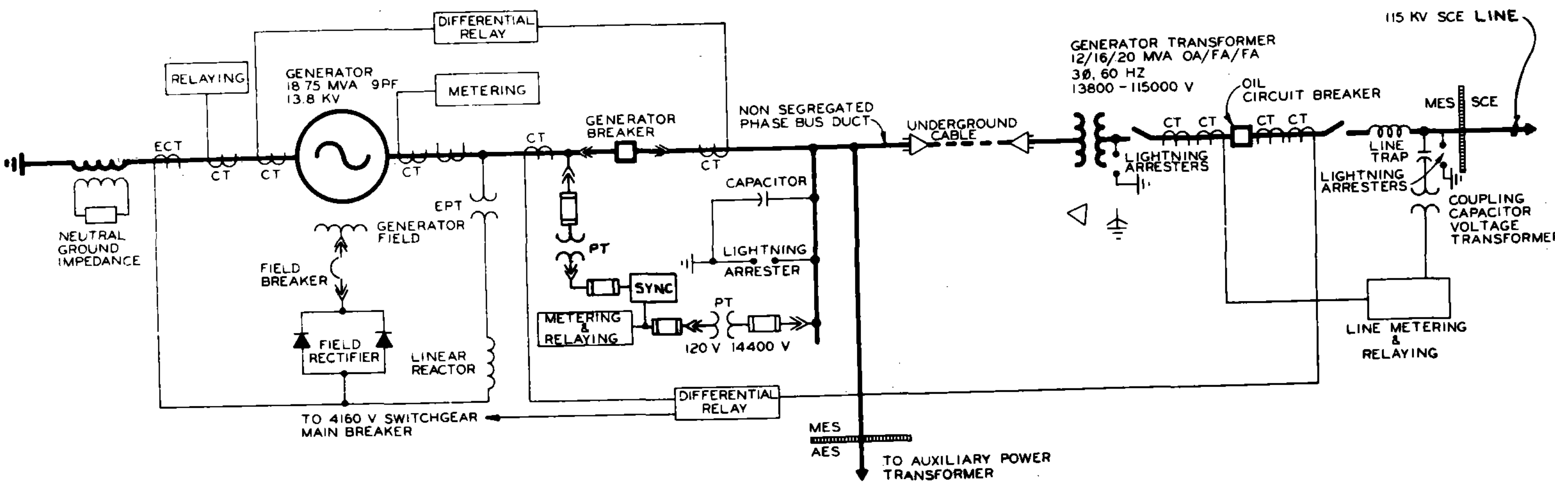


Figure 3-30. Main Electric System
One Line Diagram

less the auxiliary power is delivered to a transformer where the voltage is stepped up to 115,000 volts for tying to the utility transmission line.

Major Components. The major components of the Main Electric System are the generator, the phase bus duct, the neutral grounding equipment, the potential transformers, the surge protection equipment, the generator breaker, the generator transformer, and the miscellaneous switchyard equipment.

Generator. The generator is an alternating current generating unit with manufacturer's standard basic features and accessories for a unit of this size. It is designed with a completely self-contained, air-cooled ventilation system which prevents dirt and moisture from getting into the unit and protects the insulation and other critical internal parts of the unit. Since this is a high speed machine (3600 rpm), the rotor has non-salient poles. Water-to-air cooling is provided by four coolers mounted vertically at the four corners of the generator.

The generator terminal accessories include bushings, bushing current transformers, and neutral enclosure.

The excitation system typically employs a static excitation with solid state voltage control and regulation equipment.

Protective relays are provided to protect the generator under abnormal operating conditions. The relaying performs both alarm functions and trip functions. For faults which are likely to cause damage to equipment if allowed to persist, e.g., loss of field current with the unit on line or short circuited windings, the relays operate to shut the unit down. For less severe conditions, e.g., load unbalance or ground fault, the audible alarm cautions the operator of any abnormal or unsatisfactory operating conditions.

Phase Bus Duct and High Voltage Power Cable. The phase bus duct and the high voltage power cable are provided to transmit the generated power from the plant to the switchyard. The phase bus duct also provides bus taps for auxiliary electric power.

The main phase bus runs from the generator bushings to the generator breaker and from the generator breaker to an indoor terminal enclosure at the south end of the turbine building. An underground high voltage power cable rated at 15,000 volts connects the main bus duct at this enclosure and with the low voltage terminals of the generator transformer in the switchyard.

Neutral Grounding Equipment. The function of the neutral grounding equipment is to provide a high impedance ground path for the generator neutral current. The high impedance neutral ground reduces any ground fault current flowing through the generator winding to a very small value. Thus the generator is able to withstand a ground fault for an extended period of time without causing major damage to the equipment.

Potential Transformers. The potential transformers (PT's) are provided to transform the generator potential down to a low value (120 volts) which is acceptable to standard meters, relays, and voltage regulating devices used with the unit.

Surge Protection Equipment. The surge protection equipment is used to protect the generator winding from high surge voltage waves that may travel to the unit from an outside source.

Generator Breaker. The generator breaker is provided to isolate the generator from the utility system and to synchronize the unit to the utility system.

The generator breaker is a stored-energy type breaker located in metal-clad switchgear. The breaker is capable of being operated remotely from the plant control room.

Generator Transformer. The generator transformer is provided to step the generator output voltage up to the transmission voltage of the utility grid, so that the pilot plant main electric system can be tied to the utility system.

The generator transformer is located in the switchyard and is of outdoor construction. The transformer has one, three phase high voltage winding rated at 115,000 volts and one, three phase low voltage winding rated at 13,800 volts. The high voltage winding is connected to the switchyard equipment and is protected by three lightning arrestors mounted near three high voltage bushings. The low voltage winding is connected to the underground cable rated at 15,000 volts. The transformer is provided with cooling fans. By running these cooling fans the capacity of the transformer can be increased by 66 per cent over its natural convection cooling.

Other standard accessories provided with the transformer include a liquid level indicator, a liquid temperature detector, three winding temperature detectors, and a pressure relief device. The above devices are equipped with contacts which close to annunciate unsatisfactory operating conditions. Thermal relays are provided to automatically start the cooling fans when the winding temperature reaches a preset point. Also provided is a fault pressure relay which actuates a contact to trip the unit whenever the pressure inside the transformer tank reaches a dangerously high level due to an internal electrical arcing fault in the unit. The arc burns the transformer oil which results in releasing combustible gases and increasing the pressure inside the transformer tank. To detect a low level fault, a combustible gas detector is provided since no appreciable pressure rise will occur in the beginning.

In addition to the protective features built into the unit, relaying is provided to protect the transformer against phase and ground faults.

Miscellaneous Switchyard Equipment. The switchyard equipment is provided to allow high voltage electrical power to be transmitted from the plant into the utility system when the generator is producing power. The switchyard also allows the power from the utility system to be delivered to the pilot plant to run the auxiliaries when the generator is shut down.

For aesthetic considerations a low profile appearance has been included in the design of the switchyard.

Figure 3-31 shows the one line diagram and the equipment arrangement in the switchyard. Figure 3-32 is a sectional view of the switchyard equipment. The low profile arrangement of the equipment gives a neat and pleasing appearance to the switchyard.

<u>Auxiliary Electric System</u>. The function of the Auxiliary Electric System, its operating conditions and major components are discussed in this section. A more detailed description of the system is presented in the Auxiliary Electric System Preliminary System Design Specifications in Appendix B.

Function. The function of the Auxiliary Electric System is to supply electrical power to all plant auxiliary loads. The auxiliary loads are defined as electrical loads required by the various auxiliary devices during shutdown, start-up and different operating modes of the solar pilot plant. The Auxiliary Electric System has the capability to deliver as much power as will be required under all modes of plant operation.

Operating Conditions. Figure 3-33 shows the one line diagram of the Auxiliary Electric System. The auxiliary electric power is tapped from the generator phase bus duct at 13,800 volts. For the most economic distribution, the auxiliary electric power is required at three different voltage levels.

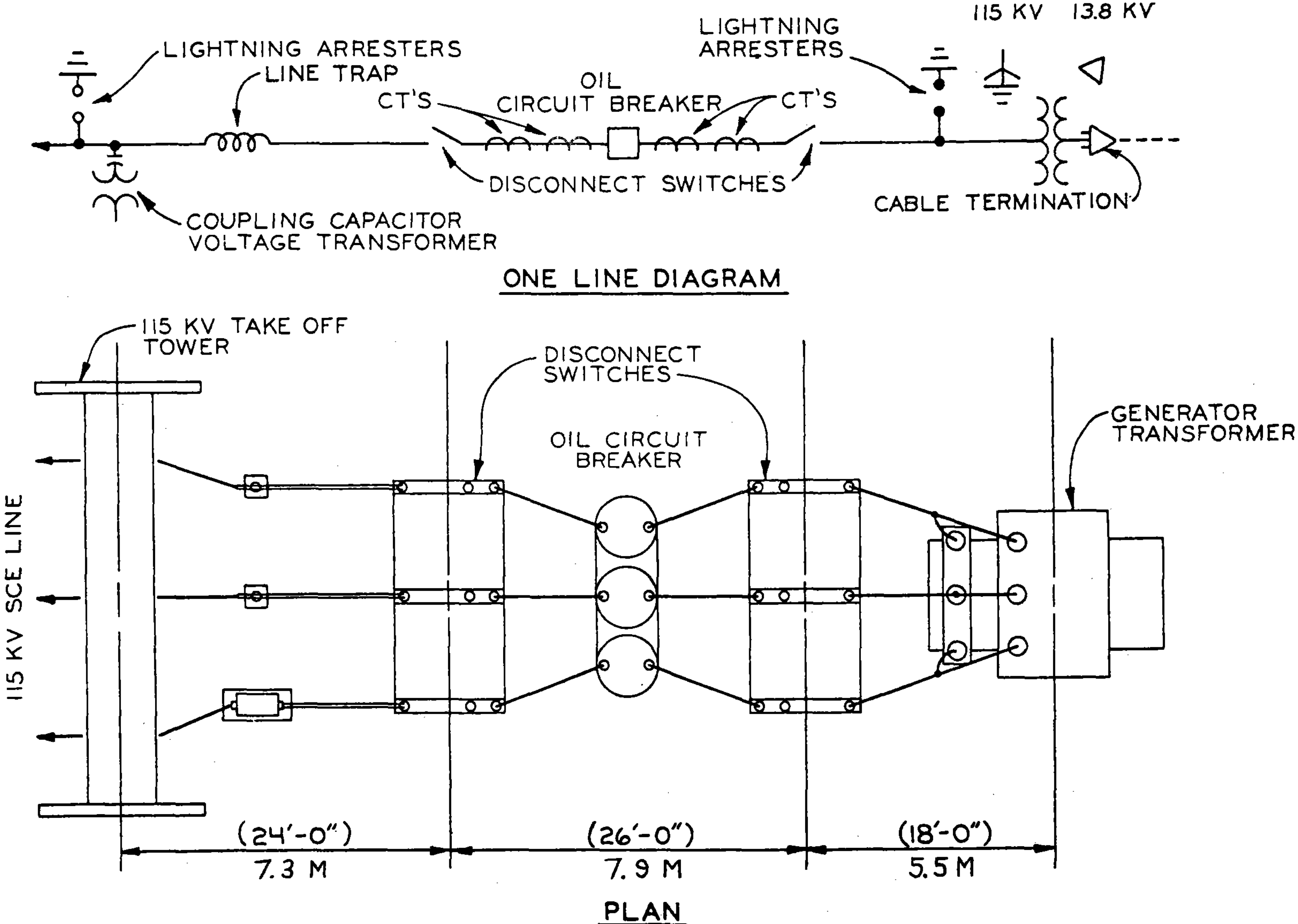


Figure 3-31. Switchyard One Line Diagram and Plan

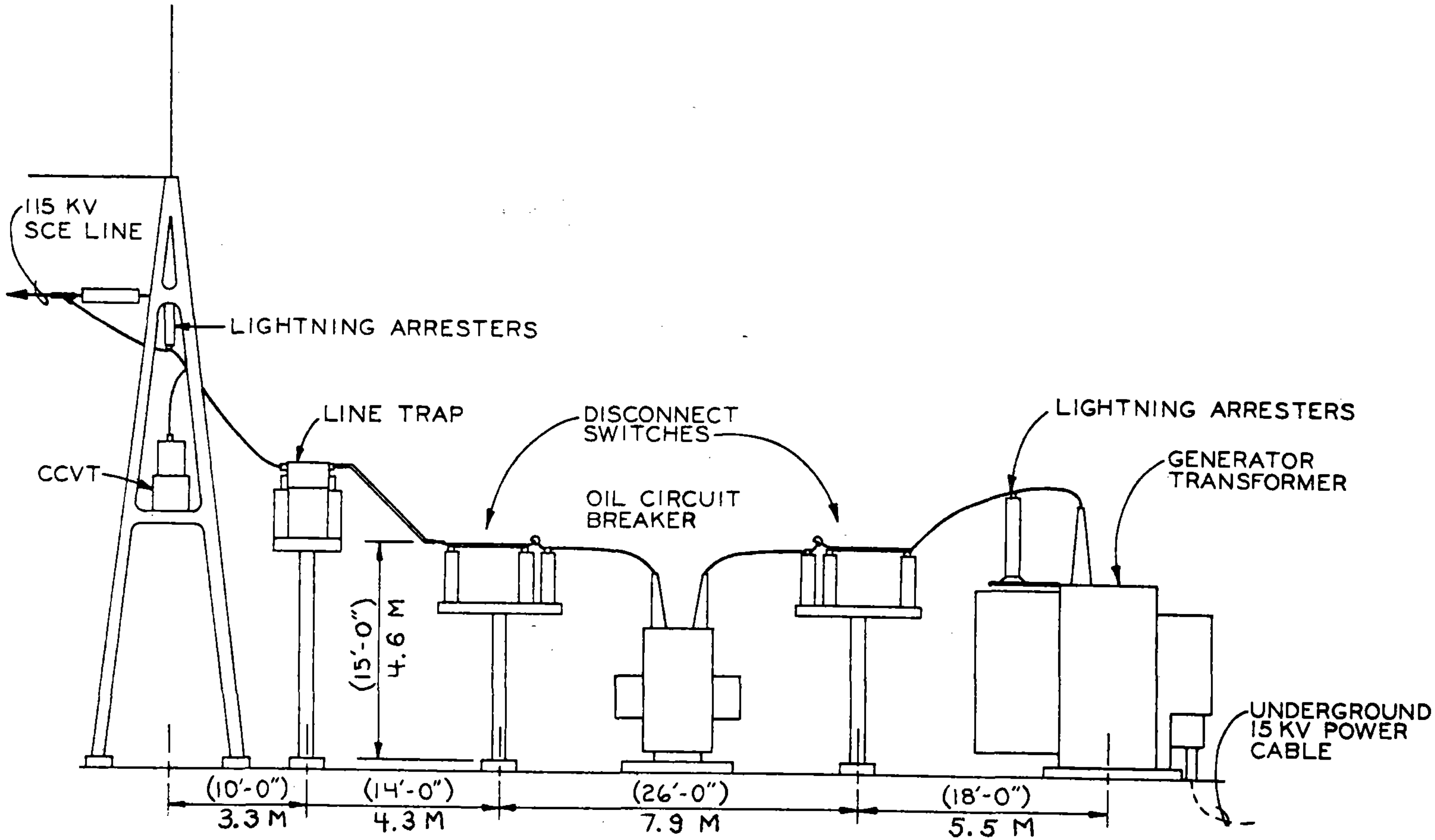


Figure 3-32. Switchyard Elevation

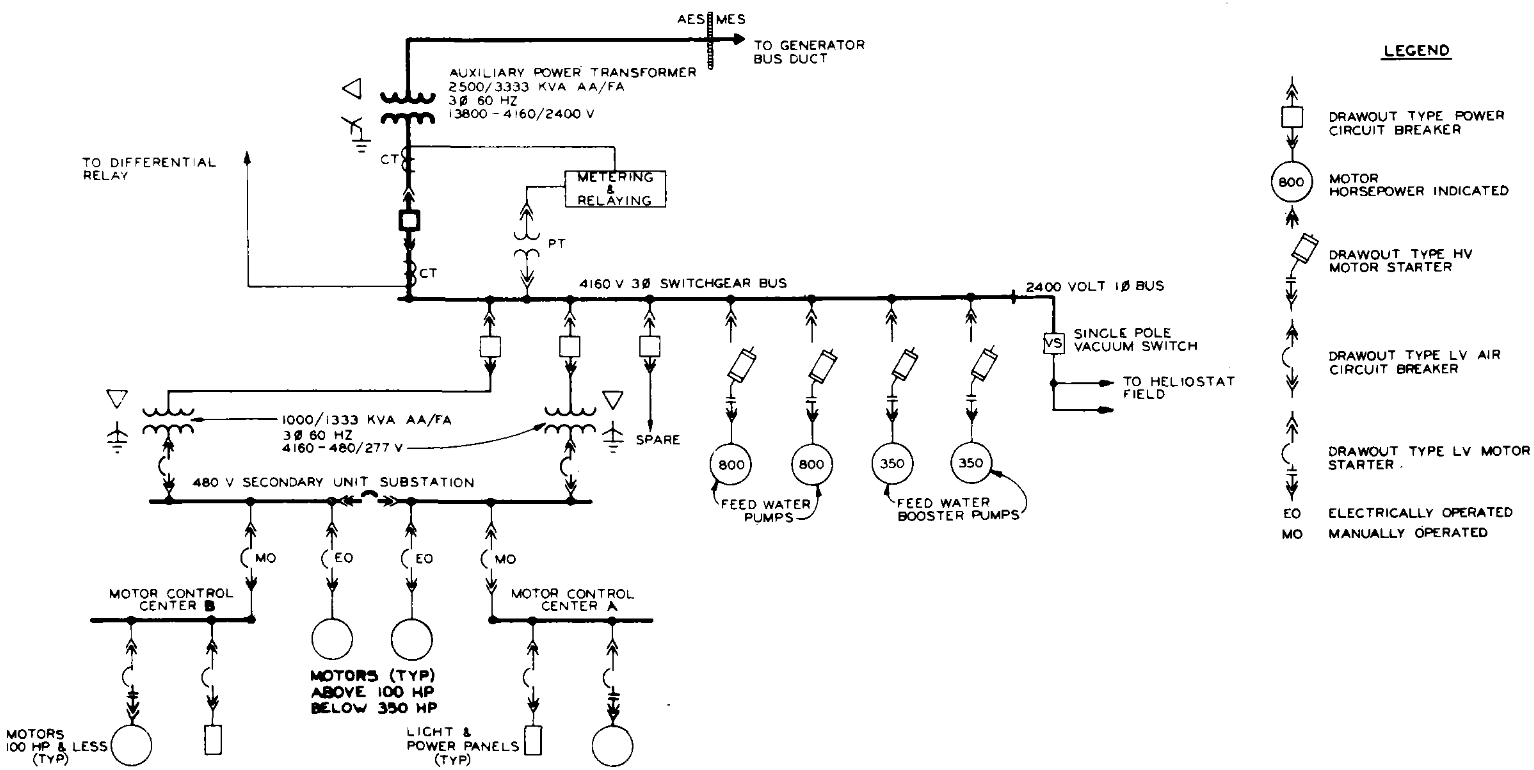


Figure 3-33. Auxiliary Electric System One Line Diagram

(1) 4160 volts, three phase, for large loads, e.g., motors above 250 horsepower.
(2) 480 volts, three phase, for medium loads, e.g., integral horsepower motors up to 250 horsepower.
(3) 120 volts, single phase, for small loads, e.g., most fractional horsepower motors.

Different voltage levels are obtained by the use of transformers. The auxiliary power transformer steps the generator voltage down to 4160 volts. The medium voltage switchgear makes an efficient distribution of 4160 volt power to four large motors and two secondary unit substation transformers. The switchgear also supplies electrical power to eight heliostat field transformers and four security lighting transformers at 2400 volts single phase. The secondary unit substation transformers step 4160 volts down to 480 volts. The secondary unit substation buses supply electrical power to all medium sized motors above 100 horsepower and to two motor control centers for further distribution of 480 volt power to smaller loads. Power of 120 volts is obtained by stepping 480 volts down to 120 volts by conveniently located, dry type, low voltage, distribution transformers.

Major Components. The major components of the Auxiliary Electric System are the auxiliary power transformer, the medium voltage switchgear, the heliostat field primary distribution equipment, the secondary unit substation and the motor control centers.

Auxiliary Power Transformer. The auxiliary power transformer is provided to step the generator output voltage down to 4160 volts. The transformer is located on the ground floor of the turbine building and is of indoor construction. The transformer has one high voltage winding rated at 13,800 volts and one low voltage winding rated at 4160 volts. The transformer is a nonexplosive, fire resistant, air insulated, dry type unit, cooled by the natural circulation of air though its windings. In addition to its basic self-cooled rating, the unit has a supplementary fan-cooled rating. The transformer is equipped with standard accessories including a thermal relay to automatically start the cooling fans whenever the winding hot spot temperature reaches a preset point. The transformer is protected by a differential relay against any electrical fault.

Medium Voltage Switchgear. The medium voltage switchgear is provided to distribute electrical power at 4160 volts. The switchgear is of metal-clad construction. It is an assembly of four breaker housings, four motor starter housings, and an auxiliary housing. All housings are bolted together to form a rigid assembly. All medium voltage circuit breakers are horizontal drawout type. Breakers are operated by a 125 volt dc operated, motor-charged, spring type, stored energy mechanism. Circuit breakers are interchangeable. The medium voltage motor starters employ current limiting power fuses and magnetic air break contactors. Each starter is completely self-contained, prewired and easily removable. All circuit breakers and motor starters are remotely operated from the plant control room. Relaying is provided to protect the switchgear against any electrical fault on the switchgear or on the feeders. These relays are coordinated with any downstream relaying to avoid unnecessary interruption of power. The auxiliary compartment of the medium voltage switchgear lineup houses the power supply equipment for the heliostat field transformers and the security lighting transformers. One of three phases extends into this unit providing a 2400 volt single phase power source. A single phase vacuum switch is provided to switch this power source to the field transformers. The vacuum switch can be electrically operated remotely by the plant operator.

Heliostat Field Primary Distribution Equipment. The heliostat field primary distribution equipment is provided to supply electrical power to all field heliostats and security lighting systems.

Figure 3-34 shows a layout of primary distribution equipment in the heliostat field area. Two 2400 volt single phase feeder circuits from the auxiliary unit of the medium voltage switchgear distribute power to all heliostat field transformers and security lighting transformers. Eight low silhouette, padmounted transformers are used to serve the heliostat field load. Four lighting transformers serve the security lighting loads.

The heliostat field transformers are single phase units rated 2400 volt primary and 120/240 volt secondary. Each unit has two loadbreak primary bushing wells constructed for primary system feed-through and the units are dead front design such that all exposed primary is at ground potential. An accessory mounting bracket is provided at each transformer for mounting an elbow parking bushing. Primary protection of each transformer is provided with an internal weak link or bayonet fuse and secondary protection is provided with a hookstick operated secondary low voltage circuit breaker. The lighting transformers are units similar to the heliostat transformers except that the secondary voltage is 240/480 volts with the center bushing grounded. Power cable serving the heliostat field primary distribution system is solid dielectric, concentric neutral cable buried directly in the earth at a depth of approximately 3 feet. The cable, 15 kV concentric neutral cable, is standard underground residential distribution cable.

A reasonable level of reliability is desirable for the primary distribution system serving the heliostats. The system is designed such that a faulted line section, distribution transformer, or other faulted

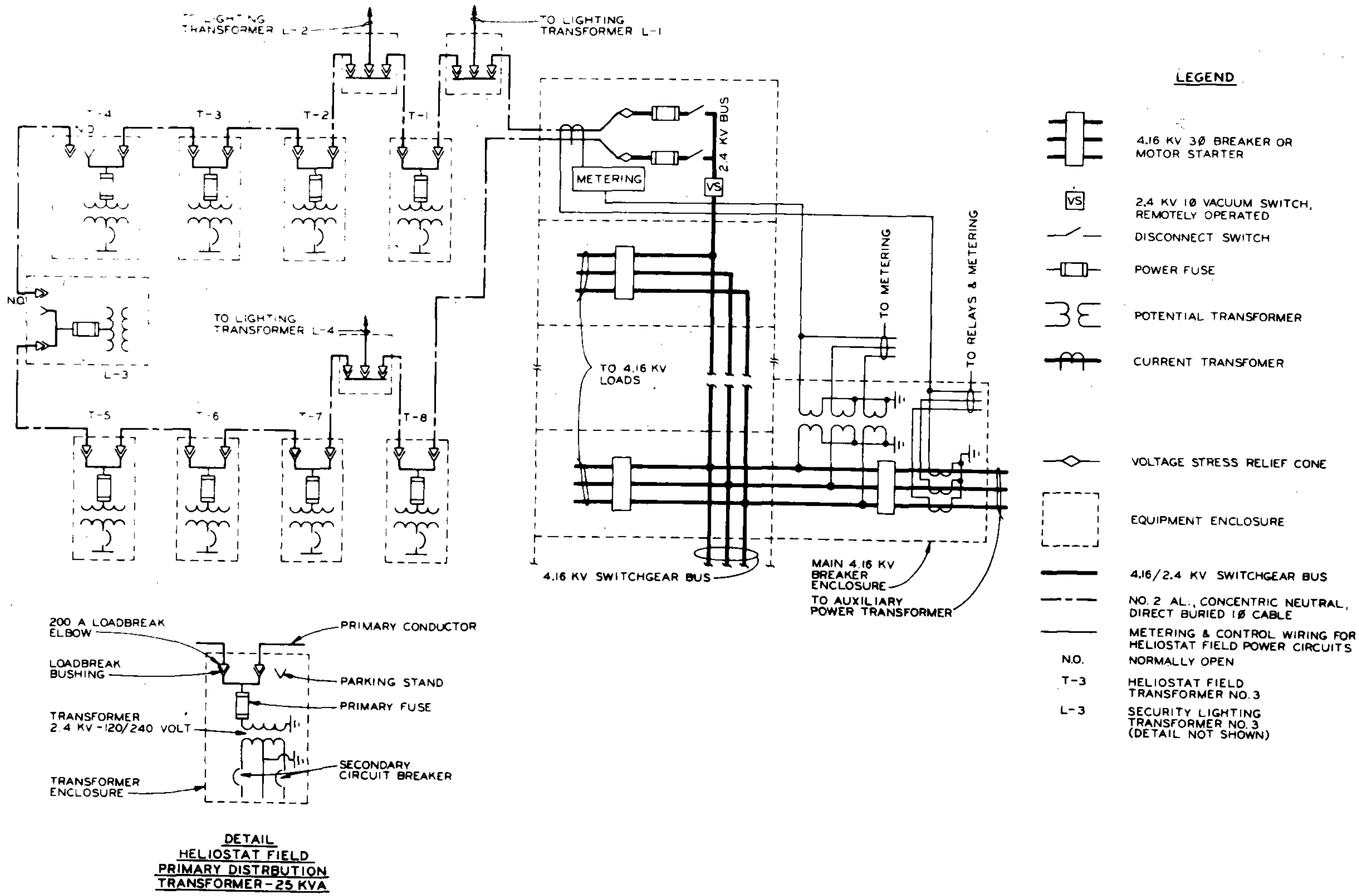


Figure 3-34. Heliostat Field Primary Distribution System Electrical Arrangement

distribution equipment does not cause a long-time outage for a large portion of the heliostats. This requirement is met by using two underground, single phase circuits which serve feed-through padmounted distribution transformers and which tie together through normally open switching to form an open loop system. Distribution switching is provided at each padmounted transformer with 200 ampere load break elbows. Any cable section which is faulted may be opened at the transformers on both sides of the fault and the normally open elbows closed. Service can be restored to all heliostats while the faulted cable section is being repaired.

The metering of heliostat power is provided at the auxiliary compartment of the medium voltage switchgear.

Secondary Unit Substation. The secondary unit substation is provided to serve as a 480 volt distribution center for medium sized motors (above 100 horsepower but below 350 horsepower) and to smaller distribution centers such as the motor control centers.

The secondary unit substation is located on the ground floor of the turbine building and is of indoor construction. It has two 480 volt buses and two transformers at the ends. Due to this construction it is called a double ended secondary unit substation. Normally each bus is fed by one transformer. A normally open tie breaker is provided between the buses. Upon loss of power source on either end the tie breaker automatically closes and thus maintains power to both buses from the other end. By this method some redundancy in 480 volt power supply is obtained in a simple and inexpensive way.

The secondary unit substation transformer has one high voltage winding rated at 4160 volts and one low voltage winding rated at 480 volts. The transformer is of dry ventilated type construction with a self-cooled rating and a supplementary fan-cooled rating. The transformer is equipped with standard accessories.

The switchgear is a metal enclosed assembly consisting of welded steel breaker compartments, auxiliary compartments, three phase bus work and supports. The main and tie breakers are rated 2000 amperes and the feeder breakers are rated 800 amperes. The main, tie, and feeder breakers used as motor controllers are electrically operated and the ones feeding the motor control centers are manually operated. Solid state trip devices are provided with each breaker to protect against any electrical fault on the switchgear bus or on any of the feeders. The relays are coordinated with downstream trip devices to avoid unnecessary interruption of power.

Motor Control Centers. The motor control centers are provided to serve as distribution centers for motors with capacity up to 100 horsepower, lighting and power panels, essential service panels, battery chargers, and small transformers.

Each of the two motor control centers has several vertical sections joined together to form a complete enclosed assembly. The main bus is rated at 600 amperes and feeder buses are 300 amperes. The control centers utilize plug-in type circuit breaker combination starters for motor control and molded case feeder circuit breakers for power feed to panels and transformers. Each motor starter is full voltage, equipped with its own control transformer, manually resettable thermal overload heaters, fuses, and terminals for external cable connections. The circuit breaker is equipped with a magnetic-only trip device to provide protection against short circuit in the feeder cable or the motor. Each feeder circuit breaker is provided with a thermal-magnetic trip device to provide long-time as well as instantaneous overload or fault protection.

Essential Service Power System. The function of the Essential Service Power System, its operating conditions, and major components are discussed in this section. A more detailed description of the system is presented in the Essential Service Power System Preliminary System Design Specification in Appendix B.

Function. The function of the Essential Service Power System is to maintain a reliable, and in some cases an uninterruptible, supply of electrical power to those direct current (dc) and alternating current (ac) loads which are necessary for the protection of major plant equipment and which must remain in service under normal and/or abnormal operating conditions.

Operating Conditions. Figure 3-35 shows the electrical one line diagram of the Essential Service Power System.

Depending on the criticality of the load it serves, the essential service power can be divided into three categories.

(1) dc power
(2) Continuous ac power
(3) Reliable ac power

The dc power supplies electrical power to certain dc loads whose operations are critical for the safety of equipment and personnel. Turbine emergency bearing oil pump in an example of critical dc load. The dc

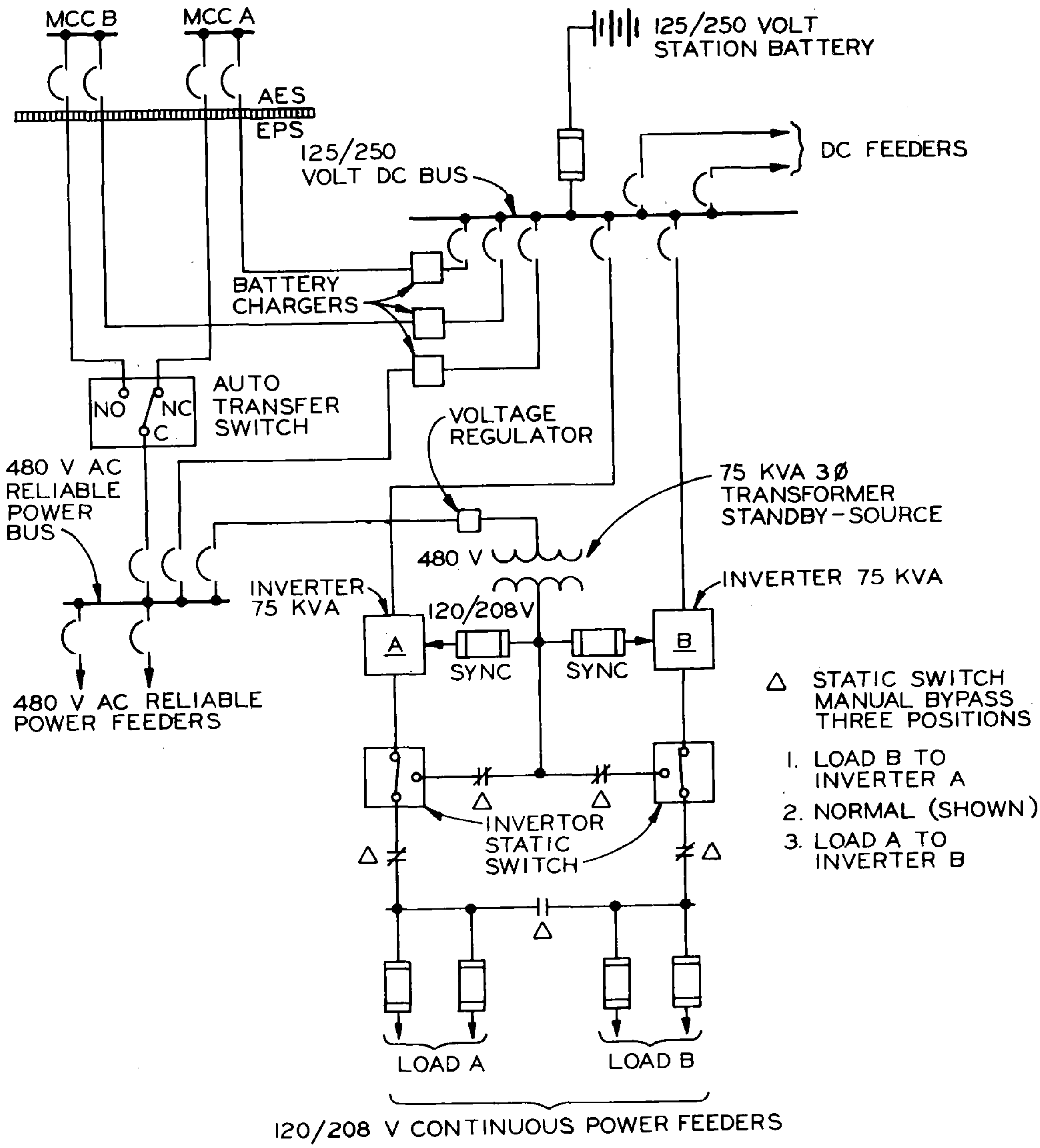


Figure 3-35. Essential Service Power System One Line Diagram

power is also used for input to static inverters, the control of switchgear breakers, and the emergency lighting system. The dc power system includes a 125/250 volt station type battery, three battery chargers, and dc distribution panels. Normally two battery chargers serve the battery and its associated loads with the third charger being available as a backup source of power. Under normal operating conditions, the battery receives only a small amount of charging current, called "float charge" or "trickle charge." After a heavy discharge, the battery needs to build up its charge at a faster rate. This is accomplished by putting the chargers on "quick charge" or "equalizing charge" mode and delivering more charging current to the battery than normally provided under float charge.

The continuous ac power supplies electrical power to certain critical ac loads, where an interruption of power cannot be tolerated under any normal and/or abnormal operating conditions of the solar pilot plant. This power supply is sometimes called "uninterruptible power supply." Such loads include the plant computers and certain devices having critical monitoring and instrumentation functions. Two full-capacity static inverters supply continuous ac power to all critical ac loads. Under normal operating conditions each inverter output is connected to a continuous ac load bus which carries about half of the total critical load. In the event of inverter component failure, a static switch transfers the inverter load to a regulated plant ac supply with almost zero time delay. When the inverter supply is restored, the static switch automatically transfers the load back to normal status. A manual bypass switch is provided to isolate the static switch from its load and alternate power supply and to take it out of service for maintenance purposes without power interruption to the load. In so doing, the manual bypass switch connects both the continuous ac load buses to a single inverter.

The reliable ac power supplies electrical power to those loads whose operations are extremely important but not as critical as the continuous ac loads. Turbine turning gear motor drive is an example of reliable power load. The reliable ac power is also used for the battery chargers, the standby source for continuous ac loads, and a backup source for control room lighting. The reliable power supply bus is fed from one motor control center through the normally closed contact of an automatic transfer switch. If this source is lost, the transfer switch senses the loss of the normal supply and automatically transfers the power supply to the second motor control center after a short time delay. The time delay ensures that no transfer occurs due to a transient voltage dip caused by a system disturbance. When the normal source is reestablished, the switch returns the power supply to its normal status.

Major Components. The major components of the Essential Service Power System are the battery, the battery chargers, and the inverters.

Battery. The battery is designed to supply dc power for one hour when the chargers fail to serve the dc loads.

The battery has a nominal 125/250 volts dc at the output terminals. It consists of 120 heavy-duty lead-acid type cells. The container of each cell is a sealed, heat resistant, clear, shock absorbing plastic.

The battery is furnished with structural steel battery racks for its support, complete with lead coated interrack connectors. Standard accessories provided with the battery include one vent plug thermometer, one vent plug hydrometer, and one cell lifter.

Battery Chargers. The battery chargers are provided to convert plant ac to dc which is then fed into the dc power system to supply all dc loads and keep the battery fully charged. Each charger is a self-regulating, solid-state, silicon-controlled, full-wave, rectifier type, designed for single and parallel operation with the battery. Each charger has 480 volts three phase ac input and 250 volts, 200 amperes dc output. The battery chargers maintain output voltage within plus or minus 1/2 per cent from zero load to full load. Each charger is supplied with input and output voltmeters, ammeters, circuit breakers, indication light, manually resettable equalizing charge timer, voltage adjusters, charge failure alarm, and ground detection circuitry.

Inverters. The inverters are provided to supply a continuous source of ac power to certain critical ac loads. The inverters have completely solid-state devices to convert 250 volt dc to 120/208 volt three phase ac. The output voltage is automatically regulated to not more than plus or minus 0.5 per cent from zero load to full load. The ac wave form does not have harmonic distortion of more than 5 per cent under any loading. The inverter has solid state oscillator devices designed to automatically maintain its output in synchronism with the plant ac standby supply. A static switch is provided to transfer the load to this standby supply within 1/4 of a cycle in the event of inverter failure. The inverter is protected against overloads, short circuits, and 100 per cent loss of load. A manual bypass switch is provided with each inverter to transfer the load from one inverter to the other for maintenance purposes. The inverter is supplied with indicating lights, transfer test push buttons, and auxiliary contacts to annunciate static switch transfer and other abnormal conditions.

<u>Miscellaneous Electrical Systems</u>. The Miscellaneous Electrical Systems include several systems which are considered minor but still have important functions in the overall electrical design of the solar pilot plant. The systems included are as follows.

(1) Lighting System
(2) Grounding System
(3) Cathodic Protection System
(4) Communication System
(5) Electrical Raceway System
(6) Electrical Conductor System
(7) Construction Power System

The function of each of the above systems is briefly discussed in this section. A more detailed description of each system is presented in the Miscellaneous Electrical Systems Preliminary System Design Specification in Appendix B.

Lighting System. The Lighting System is designed to provide general lighting in the plant, aviation obstruction lighting on the receiver tower, roadway lighting, and security lighting in outdoor areas.

Grounding System. The functions of the Grounding System are the following.

(1) To direct lightning and other system surges safely to ground and thus protect electrical equipment.
(2) To provide a fixed ground potential which stabilizes circuit potential when the circuit neutral is connected to ground and which aids relaying.
(3) To protect personnel from shock hazard.

Cathodic Protection System. The Cathodic Protection System is designed to protect underground steel pipes and the bottoms of above-ground steel tanks against rapid corrosion and early failure.

Communication System. The Communication System is designed to provide efficient communication between personnel who operate and maintain the solar pilot plant.

Electrical Raceway System. The Electrical Raceway System is designed to support and protect the electrical cable.

Electrical Conductor System. The Electrical Conductor System is designed to carry electrical power, control, and signal to various electrical equipment.

Construction Power System. The Construction Power System is designed to provide electrical power during the construction of the solar pilot plant.

MASTER CONTROL

The coordinated master control (Figure 3-36) is the highest level in the control hierarchy. Its function is to develop demand signals to "storage in", "storage out" and turbine governor controls based on the demand and any unbalance between steam generation and use. In operation, the system senses a deviation of generated megawatts from megawatt demand and commands the turbine governor to increase or decrease the load as required. If solar steam is generated at rates in excess of turbine requirements, an increase in turbine load demand uses the generated steam that would normally go into storage. If turbine load demand exceeds the solar steam generation rate, the system stops flow to storage and "holds down" the turbine until the resulting megawatt error causes the "storage out" to make up the difference from storage.

Imbalances between solar steam generation and use for turbine load and charging storage are sensed by throttle pressure variations. The sum of throttle steam to the turbine and storage is maintained equal to the solar steam generation rate. At the same time the apportionment of steam between the turbine and storage is varied according to turbine load demands.

Master control uses the storage system data, turbine generator inputs and outputs, boiler, preheater, receiver drum level, throttle pressure and other parameters to control storage input and output. If thermal storage becomes fully charged during plant operation and the surplus energy can't be used for additional electrical power generation, the operator would then selectively defocus heliostats to match the existing generation requirements.

All data that relates to daily operation is collected and can be transferred to disc storage or printer. Displays include the status and alarms for all the subsystems in solar generation control. Direct digital control for all of the storage subsystem and for the turbine controls are also integrated in this center.

Turbine Generator Control

Master control recognizes the load demand, the megawatt output and establishes the throttle pressure set point and desired generator output. Throttle pressure necessary to generate the required power is determined by the set point which results in an error signal that is modified by the proportional and integral gain. Limiters are shown in Figure 3-37 where needed for proper functioning of the controls. Actually most control elements exhibit saturation effects that imply high and low signal limits for most elements.

The turbine governor is the major control element for control of turbine and generator. The control is used to regulate turbine speed prior to synchronization. After synchronization, the governor may be required to control load, admission steam pressure, or throttle steam pressure depending upon the

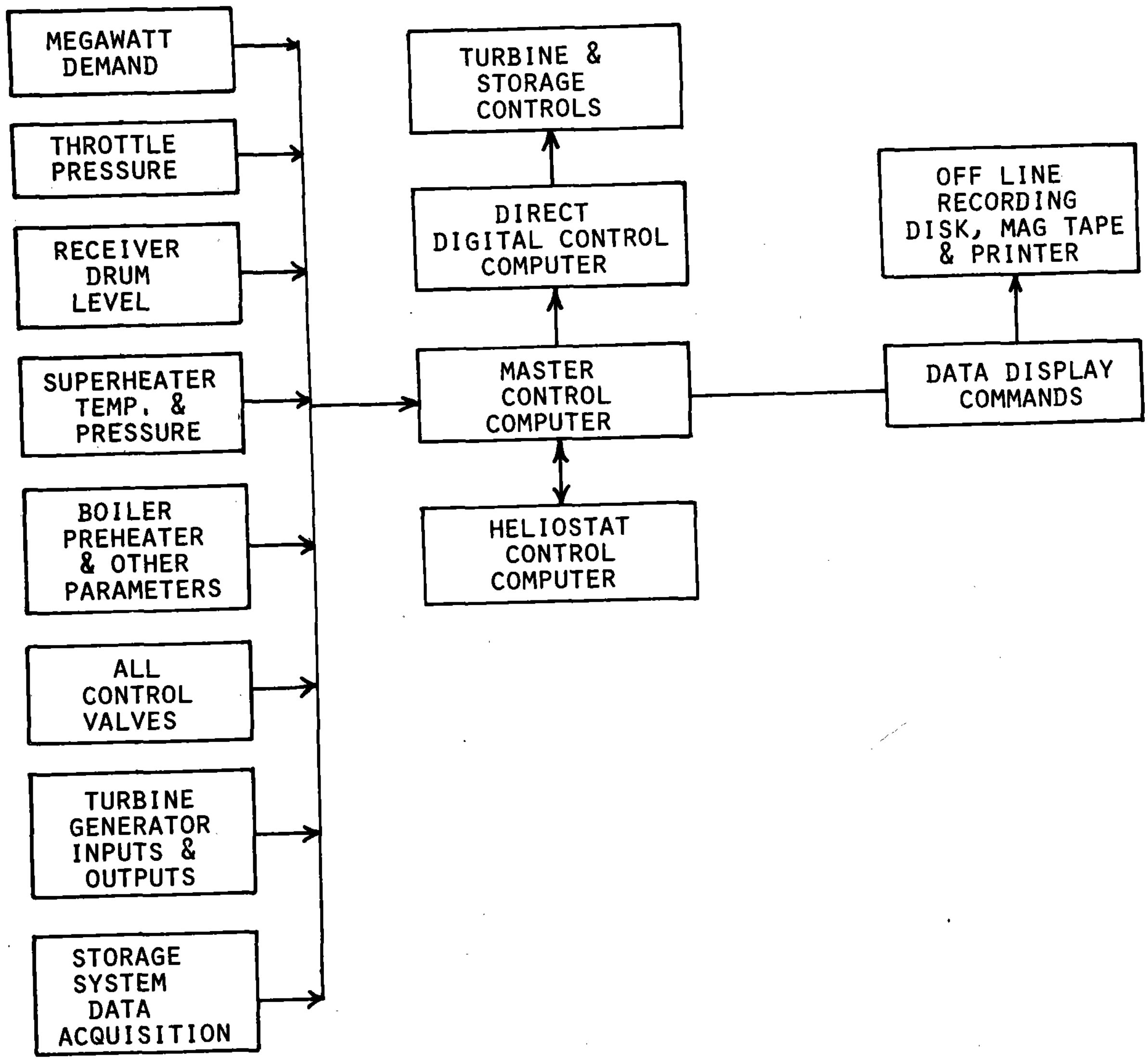
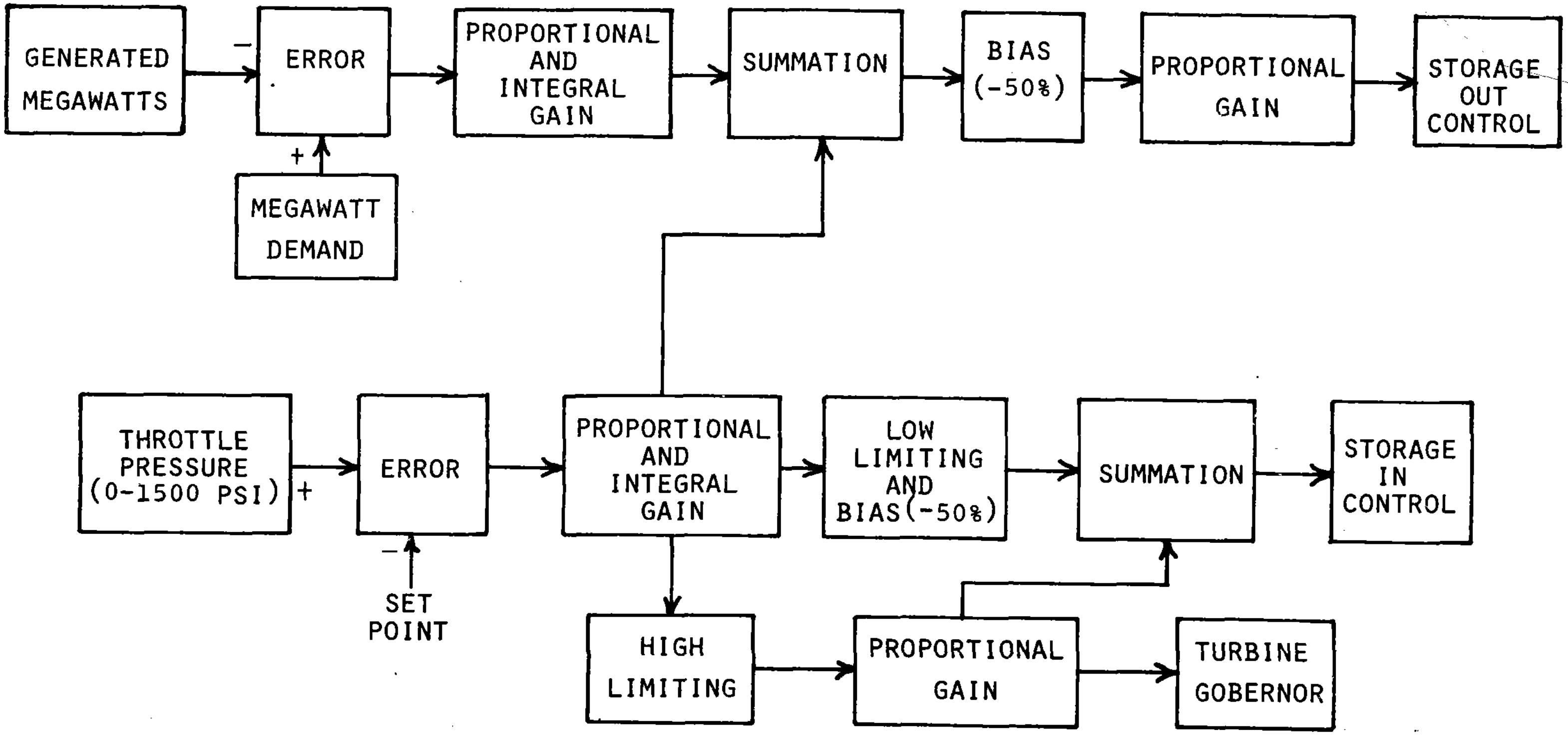


Figure 3-36. Master Control System



FUNCTION: DEVELOP COORDINATED DEMAND SIGNALS TO "STORAGE IN" AND "STORAGE OUT"
PROVIDE TURBINE GOVERNOR CONTROL BASED ON MEGAWATT DEMAND

LOCATION: MASTER CONTROL CENTER

REFERENCE: VOLUME VI PAGE 3-77 TO 3-79

Figure 3-37. Turbine Generator Control

operating mode of the plant.

"Storage in" control regulates and apportions surplus solar-generated steam in order to charge the storage systems when demand is satisfied. Throttle pressure through a proportional and integral gain is used to control the governor. Throttle pressure in combination with the turbine governor signal controls the "storage in" function.

"Storage out" control modulates the generation of steam by the thermal storage subsystem to augment or replace direct solar generated steam to the turbine, depending on the demand. Generated megawatts are compared to the megawatt demand and then modified by the proportional and integral gain. This input is summed with a throttle pressure error signal to modulate the storage out control. Where direct solar-generated steam is insufficient to drive the turbine, even with no flow to charging storage, the megawatt error signal integrates through a 50 percent bias that causes a "storage out" demand signal. Steam flow from storage flows to the low pressure turbine inlet. Steam flow from storage is then increased until the demand load is maintained with maximum direct solar steam and minimum storage steam flow. If thermal storage is insufficient, the demand signal integrates through to its upper limit and an alarm is signalled at master control. Units such as the superheaters may be controlled individually from master control and any combination of units can be switched in the system.

<u>Collector Subsystem</u> (Figure 3-38)

Using National Bureau of Standards time signals as a timing reference, the computer calculates time-dependent sun position at 1-second intervals. From this, it computes gimbal tracking angles for all heliostats. Gimbal angle commands are transmitted to the heliostats via buried twisted shielded lines. Gimbal updates can be in 1- or 15-step increments. One-step commands are for fine tracking while 15-step commands are for controlled speed slewing. In the tracking mode, the computer commands the redirected beam to track the receiver aperture or a secondary target, which can be the calibration array or simply a point in space.

Operation of a solar power plant requires knowledge of weather and solar radiation in the collector field at a given time. A number of remote weather stations are located in the field. They transmit data to the computer, which uses it in deciding when to alter operation to accomodate cloud cover or to stow heliostats against foul weather.

Eight calibration arrays are fixed on top of the receiver tower and measure the redirected solar beam periodically moving the beam from the aperture to the receiver to the array, the computer detects differences between predicted and measured position and makes appropriate corrections. Information is accumulated to identify such long-term influences as foundation drift. More immediately, energy measurements show when mirror cleaning is required.

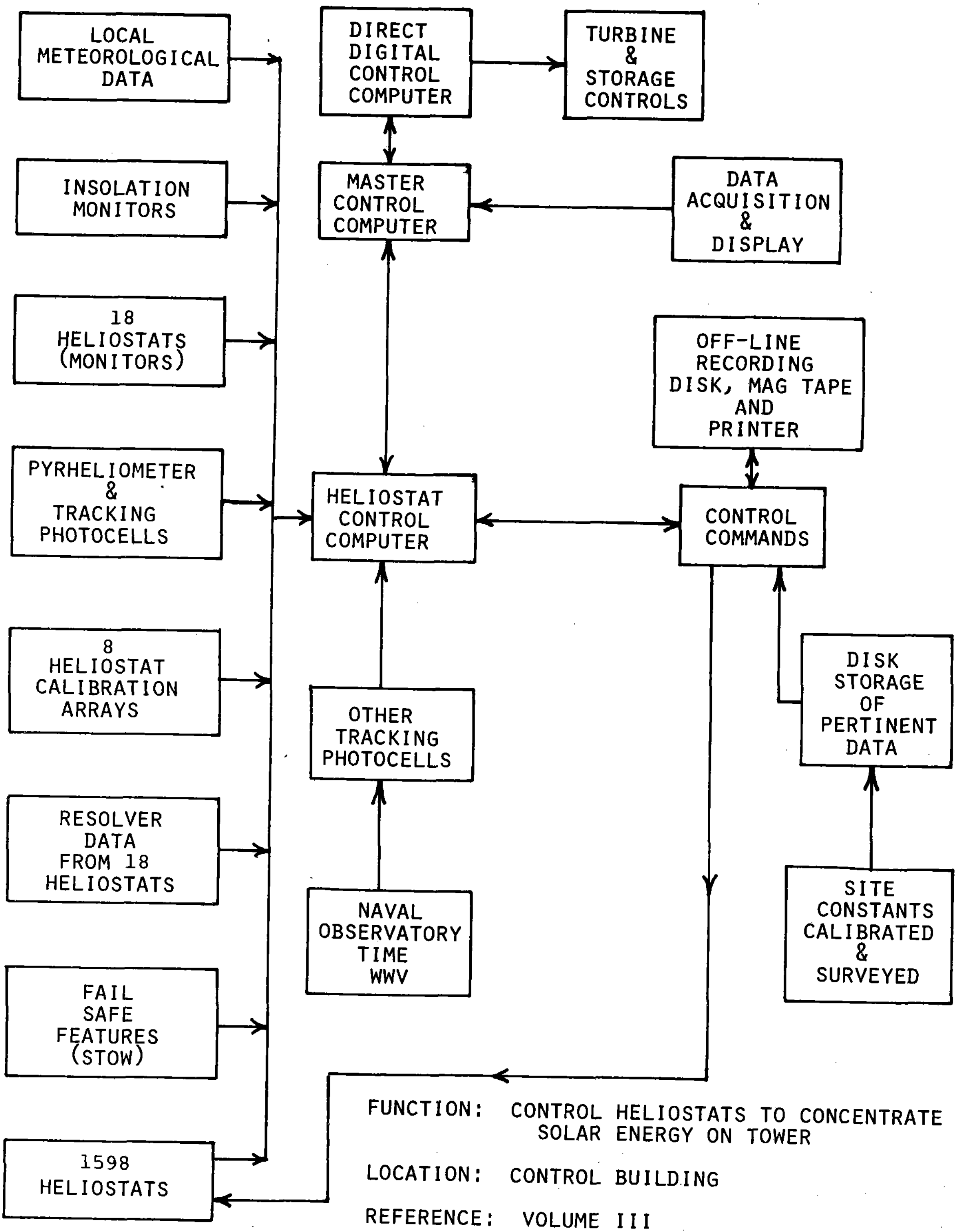


Figure 3-38. Collector Subsystem

The computerized control subsystem has the capability to address all of the heliostats simultaneously while performing calculations of sun position and pointing direction and compensating for known fixed errors. The Honeywell Level 6/45 computer permits cross-checking of input data, including weather conditions in the collector field, thereby enhancing reliability and safety in the collector subsystem.

An important feature from a control standpoint are the collectors that surround the tower and are located halfway south of center. It may be noted that there is also non-uniform spacing between rows of heliostats with a higher density near the tower. These features permit greater control over the generation of steam by allowing an averaging of the "hot spots" since the collectors surround the tower. The tower situated in the south half of the field takes advantage of the more efficient north field without losing steam generation through the averaging effect of the near south collectors.

Superheaters and attemperators in the receiver system can be individually controlled so that the near solar field can be used for averaging solar input. The ability of defocusing a far north field is less than using the near south field and the improved control of individual superheaters should not be overlooked.

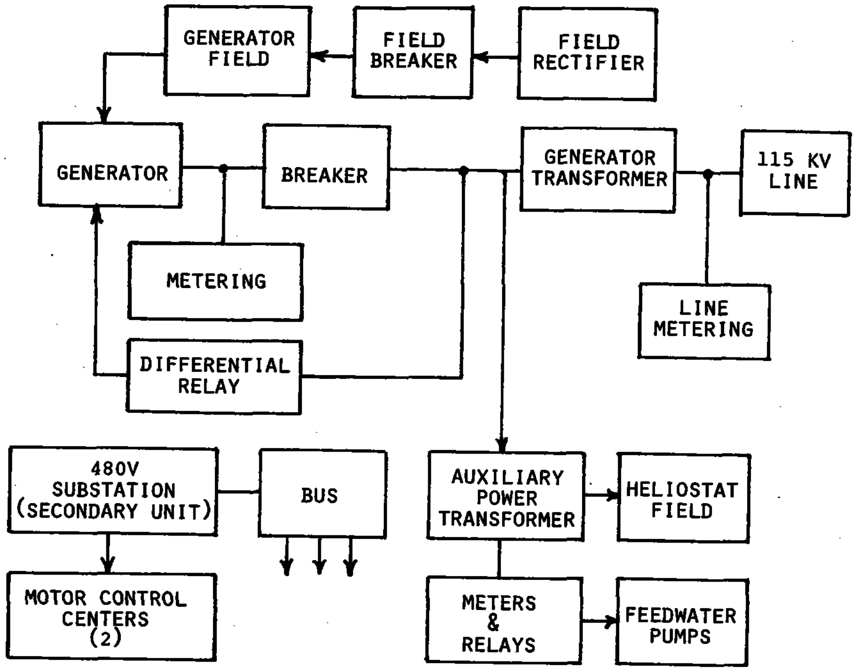
MAIN ELECTRIC SYSTEM

The function of the system (Figure 3-39) is to generate gross electrical power at 13,800 volts, 60 hertz and deliver the power to the utility at 115,000 volts. The auxiliary power is the difference between gross generation and the net busbar power and is used to maintain operation of the solar pilot plant.

A d-c excitation is obtained through the field rectifiers and breakers for the generator rotor windings. The output of the generator is controlled through the breaker and generator transformer to provide the necessary 115,000 volts for the utility line. A lower voltage is provided by the auxiliary power transformer for use in the operation of the solar plant. This includes the heliostats, meters, feedwater pumps, and other units in normal operation.

The "essential" power system (Figure 3-40) maintains a reliable, uninterruptible supply of direct current and alternating current for the necessary protection of the major plant equipment which must remain in service. These systems that are critical for the safety of equipment and personnel are the plant computers, turbine turning gear motor and emergency bearing oil pump.

The d-c power system includes a 125/250 volt station-type battery connected to a supply bus and distribution panel. In the standby mode, two battery chargers provide a trickle charge to keep the battery in a ready state. In operation, the switching gear will start the inverters and supply the a-c bus.



FUNCTION: DELIVER POWER TO UTILITY LINE & FOR USE IN THE SYSTEMS

LOCATION: TURBINE GENERATOR BLDG.

REFERENCE: VOLUME VI PAGE 3-55 TO 3-65

Figure 3-39. Main, Auxiliary and Essential Power

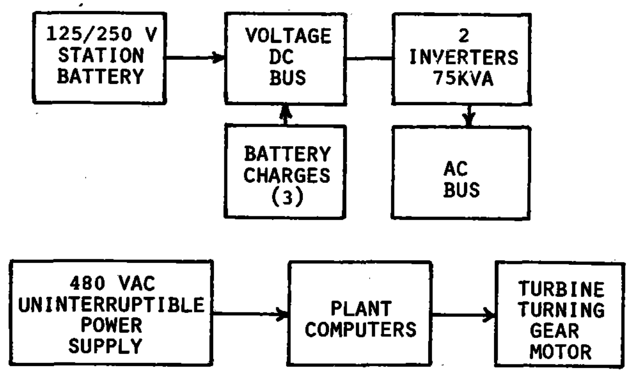
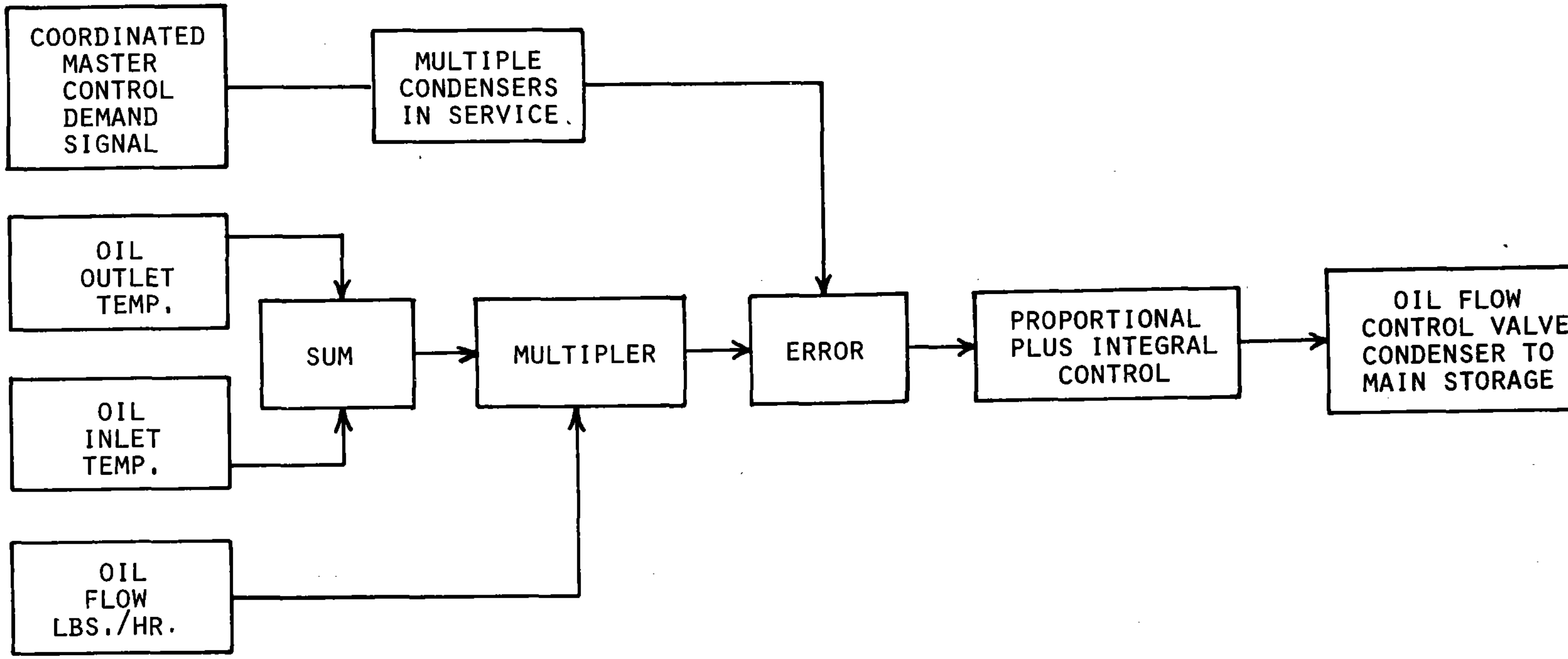


Figure 3-40. "Essential" Power System



FUNCTION: CONTROL OIL FLOW TO MAIN STORAGE TANK

LOCATION: NEAR CONDENSER

REFERENCE: VOL VI PAGE 3-82 & 3-83
VOL V PAGE 5-69

Figure 3-41. "Storage In" Control

A reliable a-c power supplies the electrical power to those loads whose operations are very important but not as critical as the continuous loads. If this source is lost, the transfer switch senses the loss of normal supply and transfers the power supply to a second source after a short time delay. The solid-state inverters are designed to stay in synchronism with the plant a-c supply so as to make a smooth transfer.

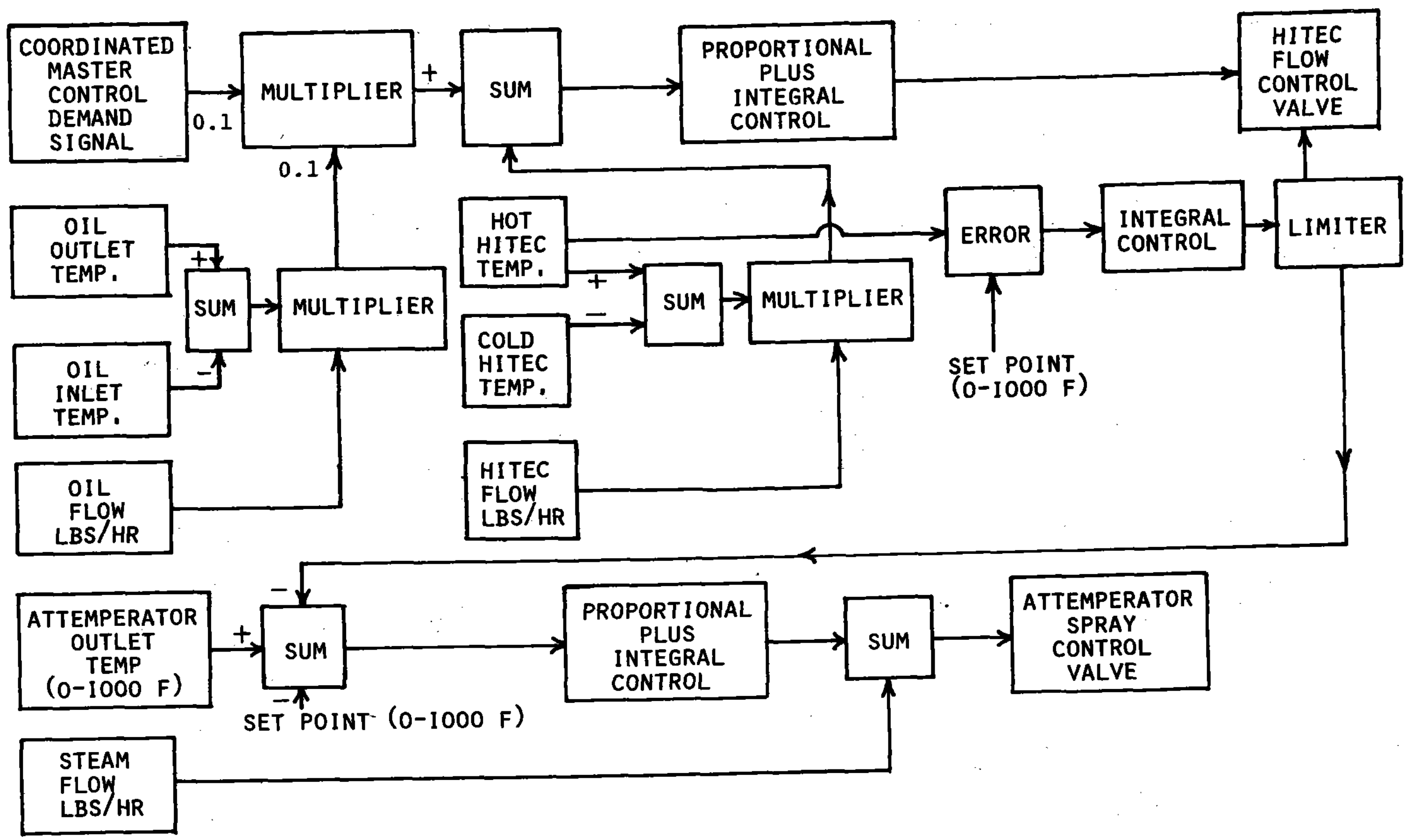
"Storage In" Oil Control (Figure 3-41)

Master control determines the megawatt demand and compares this to the receiver output to determine if any excess can be stored. The oil inlet and oil outlet temperatures are compared to extablish the quantity of heat transferred to the oil. This "error" signal is compared to the quantity of oil flowing in the charge line and is used to regulate the flow to storage. In the event not enough heat is being transferred to the oil, a "manually" operated by-pass valve can be used to recirculate the oil through the condenser without going through the storage tank. The by-pass valve is electrically operated from the master control and is normally outside of the nominal modulating range of the oil flow control valve ACV-7.

HITEC FLOW TO STORAGE

A computer study showed that the heat storage should allot 84 percent to the oil (main) storage and 16 percent to the Hitec storage. Other considerations are the maximum and minimum temperatures allowable for the Hitec to ensure proper flow and avoid decomposition (Figure 3-42).

Master control monitors the megawatt demand and compares it to the receiver output to determine the heat available for storage. The 84 - 16 percent ratio is used to determine the heat to be stored in the Hitec storage and the oil storage tanks. This demand signal is compared with the oil inlet and outlet temperature and the oil flow rate to determine the proportion of heat that should go to Hitec storage. This demand signal is also compared to the Hitec inlet and outlet temperature and flow rate to modulate the Hitec flow. The desired Hitec temperature is used as the set point and through the integral control keeps the Hitec at the maximum permissible value. At the same time this integrated temperature error modifies the spray flow to attemperator number One to increase the spray flow. The attemperator is used to modify the steam flow temperature to within the upper limits of the Hitec. If this temperature is too high, the Hitec begins to break down. Attemperator number One is just before the desuperheater where the first transfer of heat to the Hitec takes place.



FUNCTION: CONTROL HITEC FLOW TO STORAGE
CONTROL SPRAY CONTROL VALVE

LOCATION: NEAR HITEC TANK

REFERENCE: VOLUME VI PAGE 3-82 & 3-83

Figure 3-42. "Storage In" Control (HITEC)

"STORAGE OUT" CONTROL

On the "storage out" control, 83 percent should come from the main oil storage tank and 17 percent from the Hitec storage system. Master control is aware of the megawatt demand and satisfies this demand from the receiver or from storage. The desired steam temperature out of the superheater is the set point which is compared to the actual superheater outlet temperature. The amount of heat that is transferred from the oil storage to the boiler and the oil flow rate are monitored. These signals are summed and passed through a multiplier to form part of the Hitec flow control signal. This same combination is used to control the flow of oil through the boiler. Master control provides the megawatt demand intelligence and also helps maintain the proper ratio of "storage out" between Hitec and oil heat transfer. Proportional plus integral gains provides the necessary proportional modulation and also speeds up the opening of the valved to avoid undue lags (See Figure 3-43).

BY-PASS CONTROL VALVES

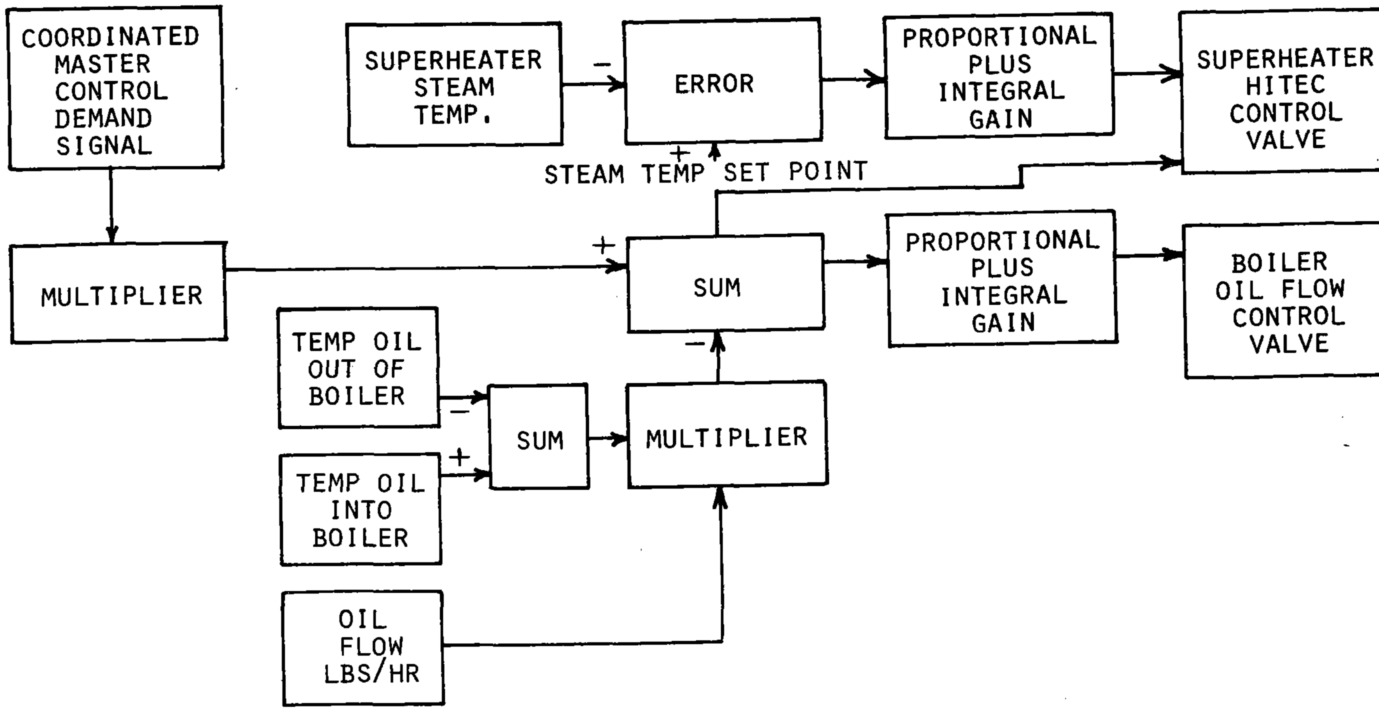
The desired temperature of the Hitec and oil as it goes into the storage tanks (Figure 3-44) is selected by master control. If the transfer of heat to the Hitec and oil is not high enough, the temperatures as it enters the storage tanks will be low. The by-pass control valves are opened from the master control station to allow the Hitec and oil to recirculate through the desuperheater and condenser respectively in order to transfer more heat. Since the by-pass valves are not the same size as the normal modulating valves only a portion of the flow is recirculated through the heat transfer units. The use of by-pass valves reduce the need for larger modulating valves and permit better regulation of the combined flows. There is also a considerable energy saving since the by-pass circuit is much shorter than the lines to the storage tanks.

OIL CONTROL VALVE

As the temperatures tend to break down the composition of the oil, the oil must be replenished or refined (Figure 3-45). Vapors that may mix with the inert nitrogen atmosphere in the ullage space are controlled by the oil maintenance unit. Here the "low boilers" are condensed and then reprocessed to remove all impurities.

TRACING STEAM

It is necessary to provide auxiliary tracing heat to the Hitec lines, tanks and pumps in the event long down times are necessary (Figure 3-45). Steam from the receiver or from the sealing and tracing system can be used

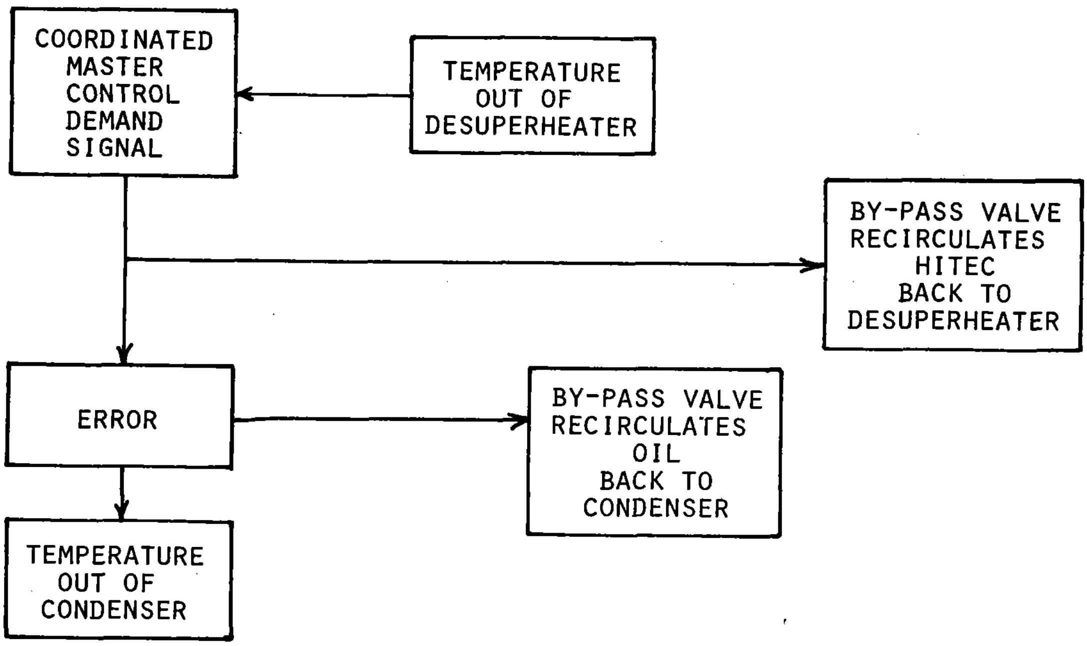


FUNCTION: CONTROL HOT OIL FLOW TO BOILER
CONTROL HOT HITEC FLOW TO SUPERHEATER

LOCATION: NEAR BOILER & SUPERHEATER

REFERENCE: VOLUME VI PAGE 3-80 & 3-81
3-83 & 3-84

Figure 3-43. "Storage-Out" Control

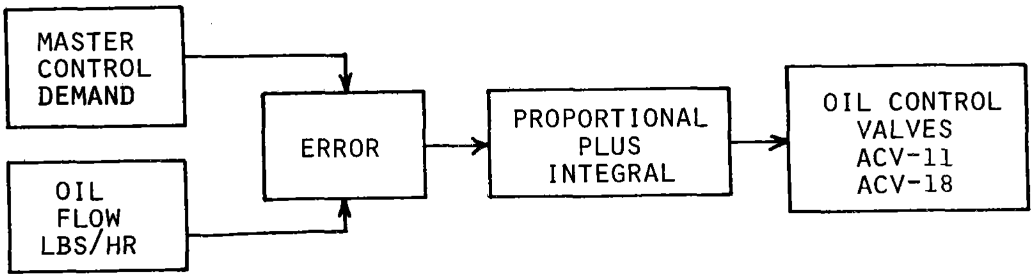


FUNCTION: RECIRCULATE OIL AND HITEC TO DESUPERHEATER AND CONDENSER FOR MORE HEAT TRANSFER

LOCATION: NEAR DESUPERHEATER & CONDENSER

REFERENCE: VOLUME V PAGE 5-68 AND 5-69

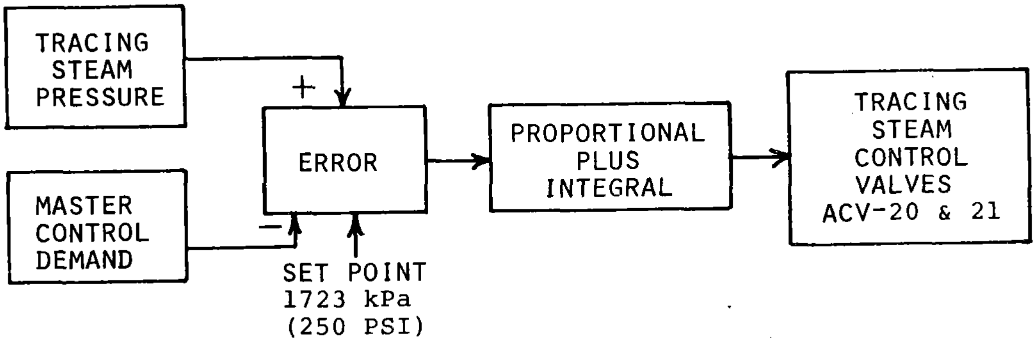
Figure 3-44. Storage Control System



FUNCTION: PROVIDE OIL TO REPLENISH LOSS

LOCATION: ADJACENT TO OIL TANK

REFERENCE: VOLUME V PAGE 5-76



FUNCTION: PROVIDE TRACING STEAM TO STORAGE LINES

LOCATION: NEAR HITEC STORAGE TANK

REFERENCE: VOLUME V PAGE 5-77

Figure 3-45. Storage Control

to heat these units. This control reduces the pressure to a safe 1723 KPa (250 PSI) before intoducing it to the various units. Two valves ACV-20 and ACV-21 are necessary since there are two sources for the steam.

"STORAGE OUT" BY-PASS CONTROL VALVES

The oil inlet temperature and boiler oil flow rates are an indication of the heat discharged into the preheater and boiler (Figure 3-46). The temperature of the oil is monitored as it enters the boiler and again when it leaves the preheater. If the difference is small, it indicates that not enough heat is being absorbed. Master control opens the bypass valve and recirculates the oil through the preheater and boiler. The normal modulating control valve in the return line to the tank is used to modulate the flow. The by-pass valve reduces the energy loss in recirculating the oil back to the tank since the bypass line is very short.

The Hitec flow through the superheater operates in similar fashion. Since 83 percent of the heat on the charge side was received by the oil a similar ratio will be used on the discharge side. More heat will be removed from the oil than from the Hitec and the bypass valves will help maintain this ratio.

ULLAGE PRESSURE CONTROL

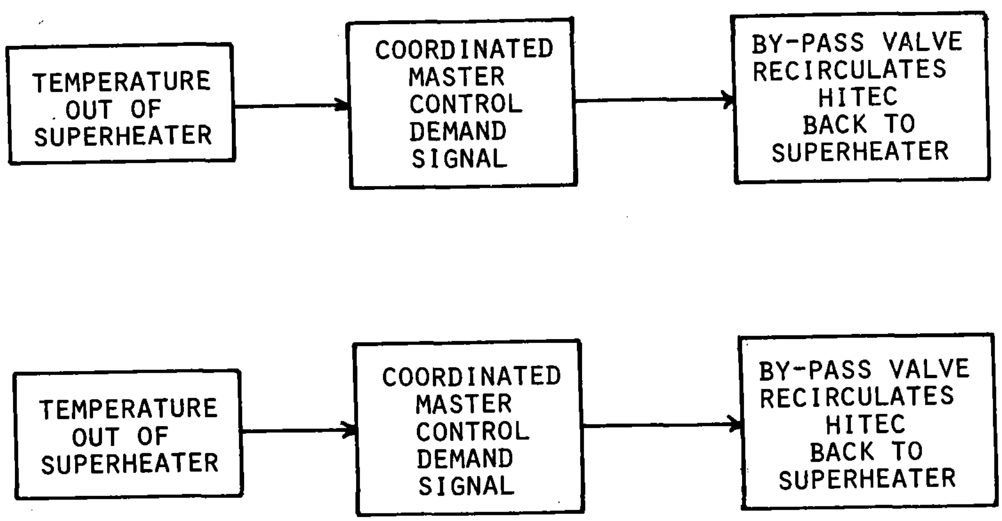
The space above the Hitec in the Hitec storage tank and the oil in the main storage tank is pressurized with nitrogen to avoid flash over in the accumulation of gases (Figure 3-47). At a lower limit 3.44 KPa (0.5 PSI) the nitrogen is vented to the tank to fill the ullage space. At pressures over 8.96 KPa (1.3 PSI) the excess pressure is vented to a condensate chamber where the gases can be converted to a solid state. Master control can override any of the set pressures.

RECEIVER FEEDWATER REGULATOR VALVE

The level in the receiver drum has been selected by master control and is the set point for the receiver drum level. Receiver steam flow and receiver feedwater flow are summed with the drum level error signal to command a feedwater regulator valve position. All three signals are summed in the proper ratio to maintain drum level (Figure 3-48).

DESUPERHEATER SPRAY CONTROL VALVE

Spray control uses a measurement of the superheater outlet and inlet temperature to control the feedwater flow (Figure 3-48). Master control selects the control temperature which is compared with the outlet temperature

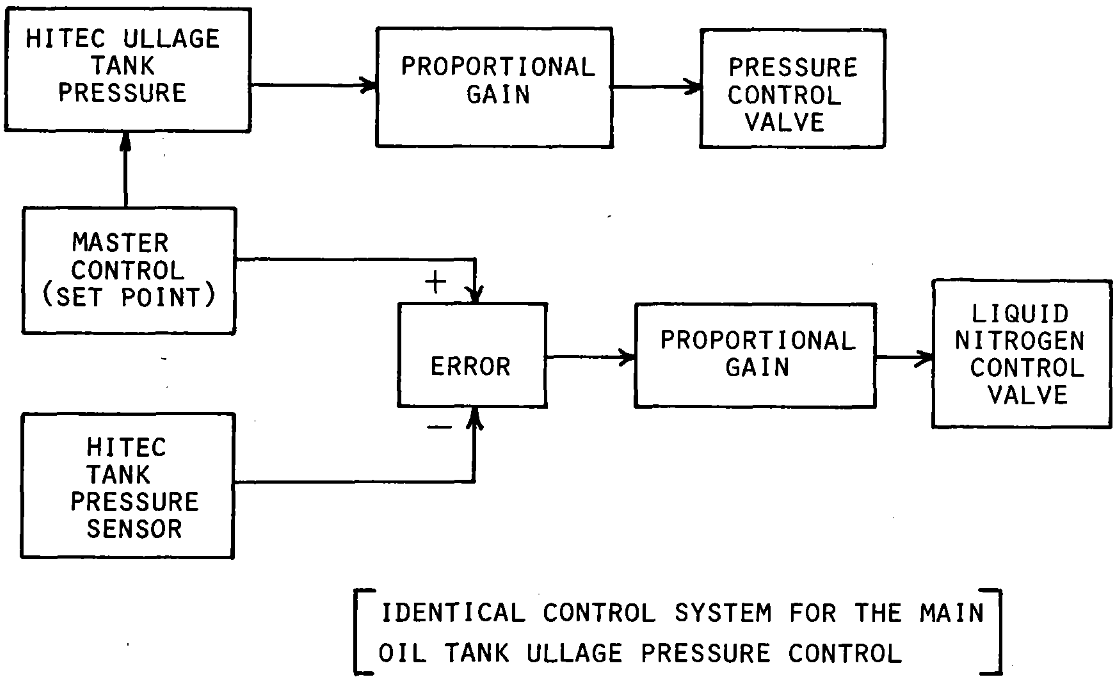


FUNCTION: RECIRCULATES HITEC AND OIL BACK TO SUPERHEATER AND BOILER FOR MORE HEAT TRANSFER

LOCATION: NEAR SUPERHEATER AND BOILER

REFERENCE: VOLUME V PAGE 5-73 & 5-74

Figure 3-46. Storage Control Systems

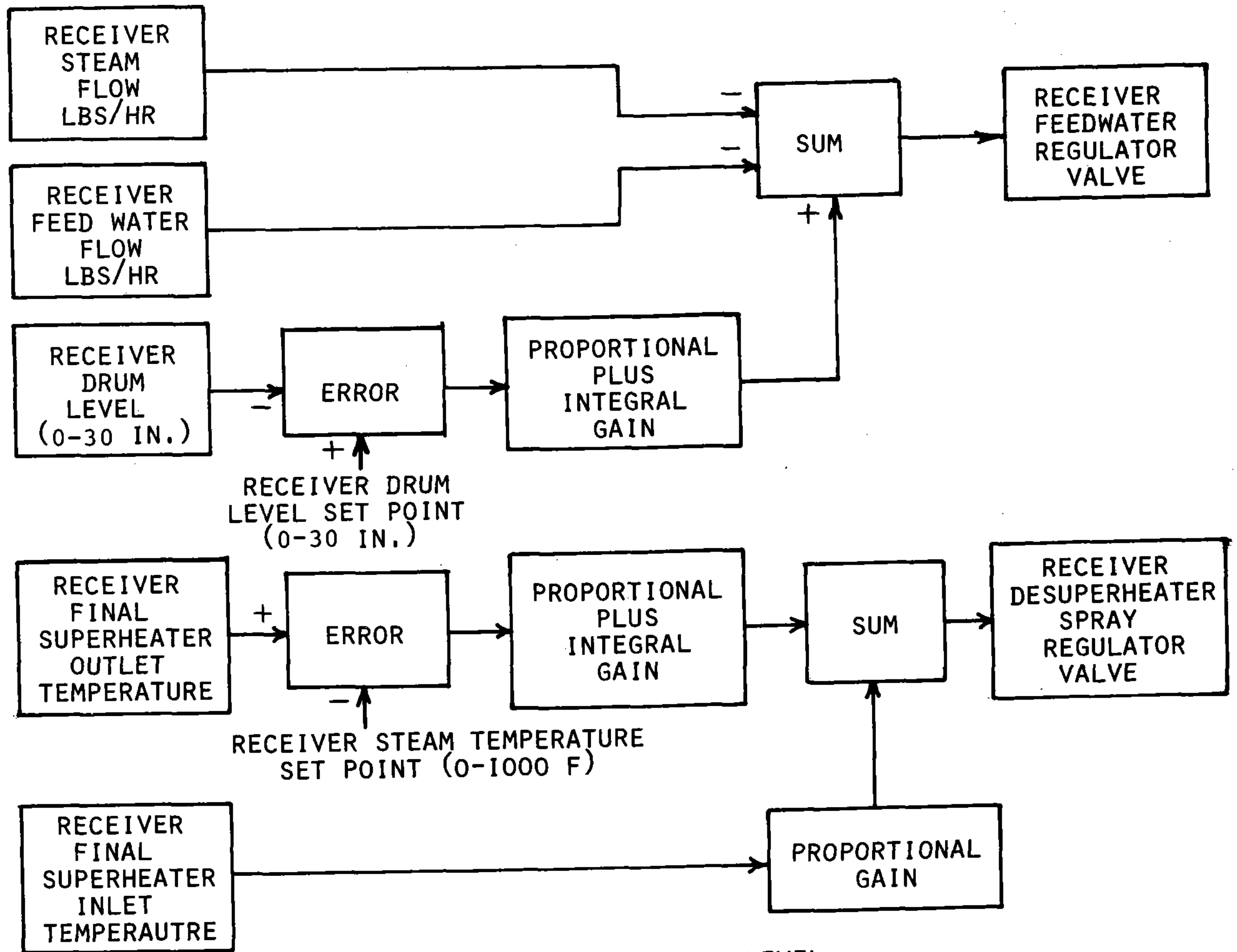


FUNCTION: TO CONTROL ULLAGE PRESSURES ABOVE THE HITEC & OIL STORAGE ULLAGE

LOCATION: NEAR HITEC & OIL TANKS

REFERENCE: VOLUME V PAGE 5-71 AND 5-72

Figure 3-47. Ullage Pressure Storage Control



FUNCTION: CONTROL DRUM LEVEL
CONTROL SPRAY CONTROL VALVE

LOCATION: ADJACENT TO BOILER

REFERENCE: VOLUME VI PAGE 3-85 to 3-87

Figure 3-48. Miscellaneous Controls -- Control Drum Level and is the error signal. The integrated error signal is added to the superheater inlet temperature to achieve more rapid response to upset conditions such as steam flow or temperature unbalances due to cloud passage. When the spray flow reaches its maximum value or goes to zero, the steam temperature goes out of control. The control system generates signals to heliostat control to defocus some heliostats so that spray flow is again within the modulation range.

CONDENSER LEVEL CONTROL

A modulating range or zero to 30 inches is available for condenser level control (Figure 3-49). The exact level is determined by master control and is the reference set point. A proportional plus integral gain provides the necessary signal shaping for the condensate regulator valve.

DRUM LEVEL CONTROL

A three element type control (Figure 3-49) is used for drum level feedwater control. Steam flow, feedwater flow and actual drum level in the boiler are used to generate the error signal. Master control selects the desired level in the boiler and the error difference is used to control the feedwater into the boiler.

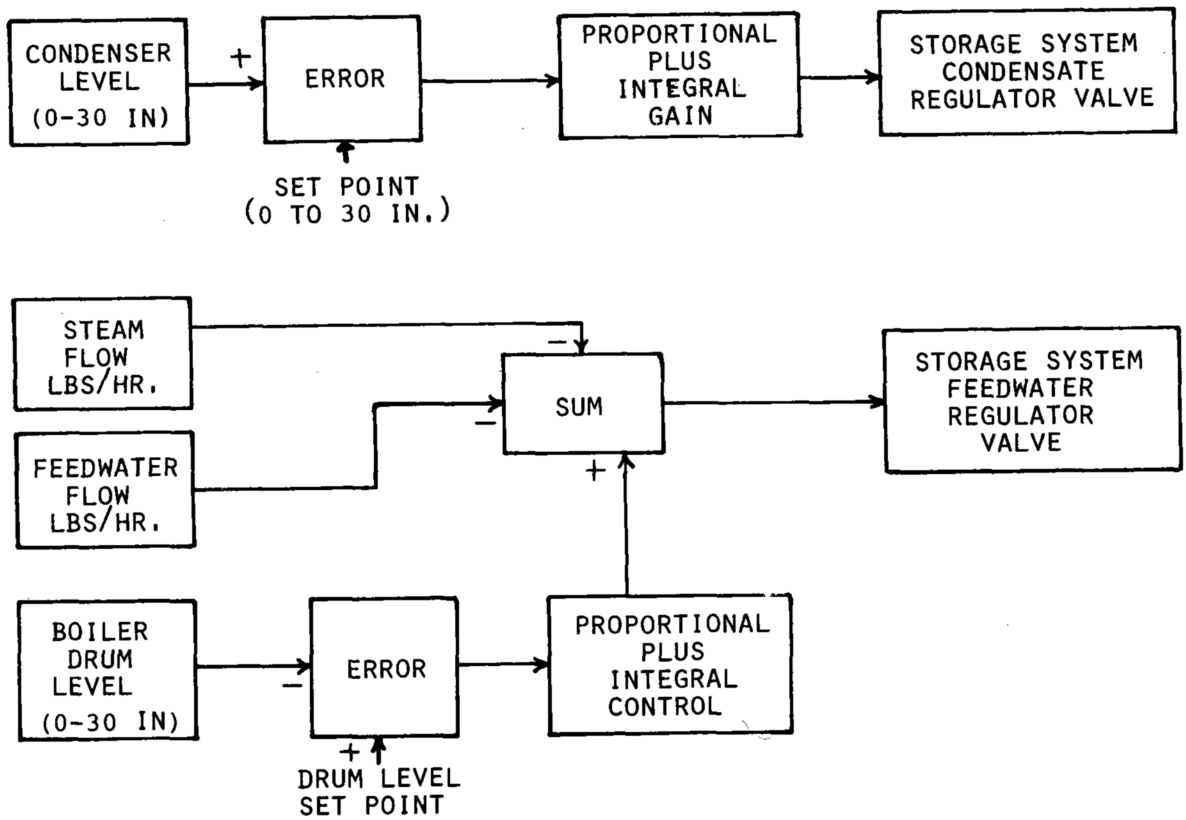
COMMUNICATIONS

All communications is centered in the master control center (Figure 3-50) with various forms of communication available. All areas such as the storage control center, receiver control room and turbine generator room are connected by intercom with the control center. Outside speakers can be used in areas where the intercom is not sufficient. There are two TV cameras on the receiver tower that scan the heliostat field. These are controlled from the control center and provide a constant monitor on the proper operation of the heliostat field.

A mobile radio is used to maintain contact with repair crews in the field or to storage areas in the vicinity. The usual phone communication is available to all areas.

SERVICE AND FIRE WATER SYSTEMS

Well water is brought to the site and provides the primary water source for service and fire protection (Figure 3-51). The fire water pump is a direct tap on the main header to the site. Two large pumps provide water to a 10,000 gallon storage tank with the level maintained by a level control.

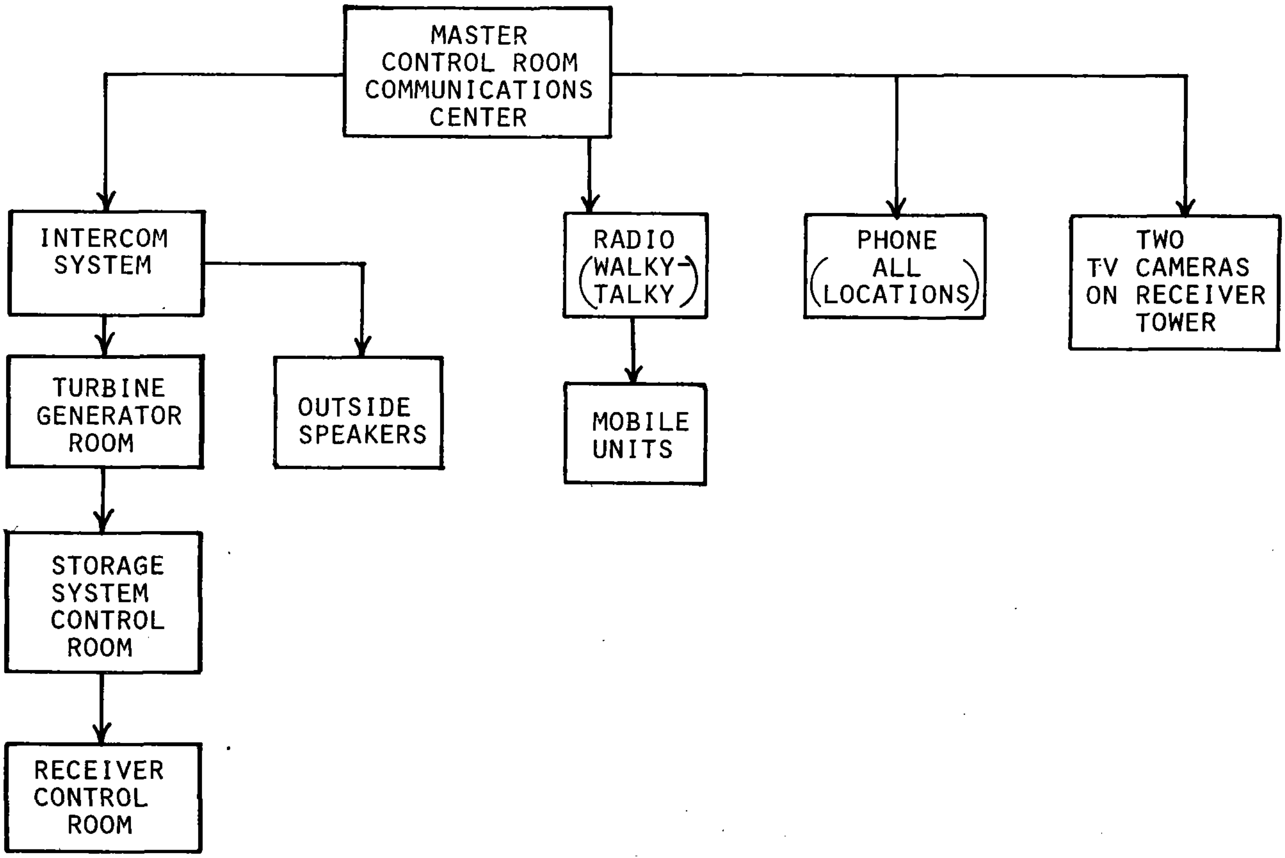


FUNCTION: CONTROL CONDENSATE VALVE
CONTROL FEEDWATER LEVEL IN BOILER

LOCATION: NEAR CONDENSER OR BOILERS

REFERENCE: VOLUME VI PAGE 3-85 & 3-82

Figure 3-49. Miscellaneous Controls -- Control Condensate Valve

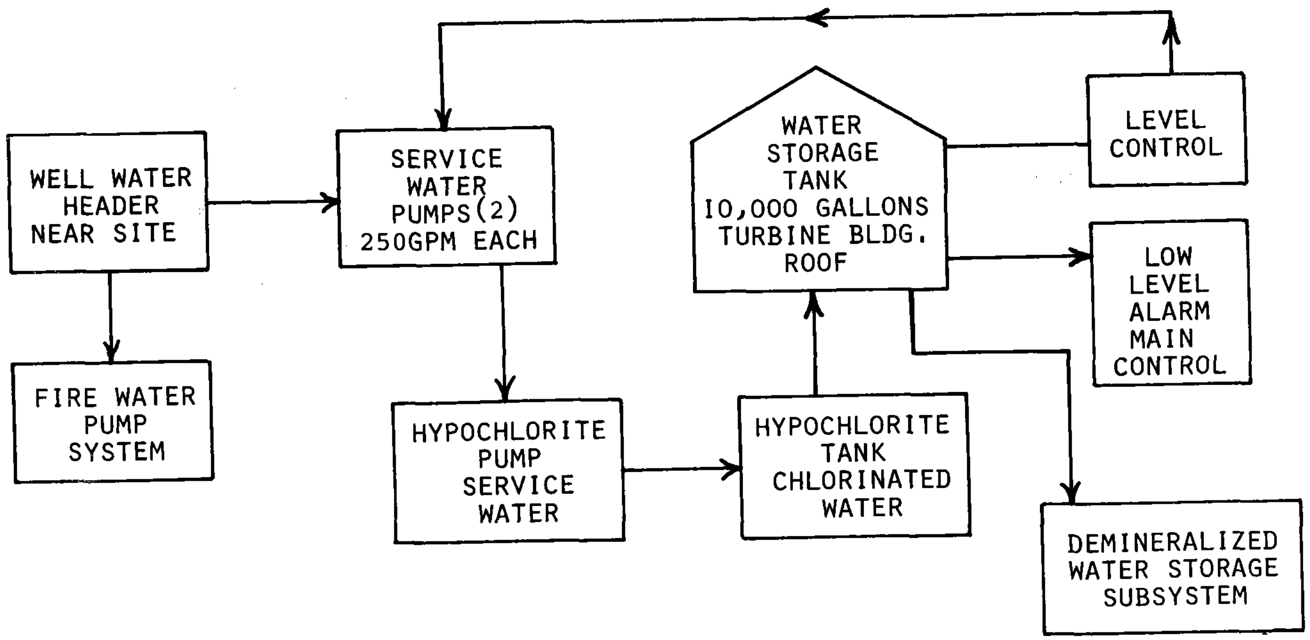


FUNCTION: PROVIDE VARIED COMMUNICATIONS WITH SUBSYSTEMS

LOCATION: MAIN CONTROL CENTER

REFERENCE: VOL. VI PAGE 3-116

Figure 3-50. Communications Control



FUNCTION: PROVIDE POTTABLE WATER FOR STAFF
SUPPLY WATER FOR STEAM GENERATION
SUPPLY WATER FOR FIRE PUMP SYSTEM
SUPPLY WATER FOR PLANT CLEANUP

LOCATION: TOP OF TURBINE GENERATOR BLDG.

REFERENCE: VOLUME VI PAGE C-37 & C-39

Figure 3-51. Service and Fire Water System

This storage tank provides water for the demineralized water system, and also for the chlorinated water used in the control centers.

DEMINERALIZED WATER STORAGE SYSTEM

This water storage system (Figure 3-52) provides the high-priority water needed for the condenser makeup. It also supplies the demineralized water to water booster pump, sample and analysis, hydrazine tank makeup, phosphate tank makeup and ammonia solution tank makeup.

Water obtained from the service water supply tank is pumped through the ion exchange vessels, forced draft degasifier and polishing filter before going to the storage tank. This 50,000 gallon tank supplies the high-priority water for the condensate makeup and other uses. Chemical waste is routed to a storage tank and eventually to the waste treatment center.

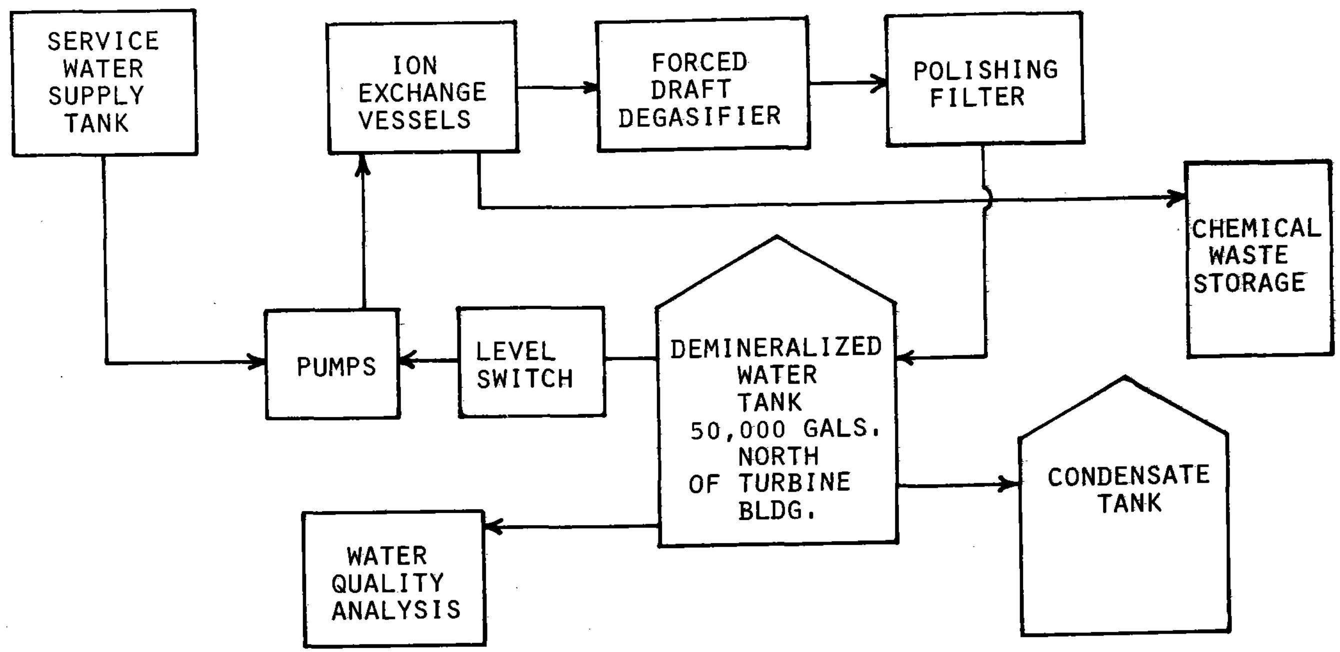
DEMINERALIZED WATER CONTROL

A demineralized water system provides the high-priority water needed for condenser makeup, water booster pump, sample and analysis, hydrazine tank makeup, phophate tank makeup and ammonia solution tank makeup. Three ion exchange vessels, a forced draft degasifier and a polishing filter are used to demineralize the water. In the regeneration phase, a sulpheric acid tank, two pumps for regeneration, a sodium hydroxide tank and water pumps.

FIRE PROTECTION SERVICE

Fire protection is provided for the electrical generation building, the thermal storage area, the receiver tower, heliostat control room and several yard areas.

Smoke detectors are used in the master control and computer area to control Halon fire extinguishers (Figure 3-53). In the storage area, ultra-violet detectors are used on outside poles to scan the storage tanks, pumps and lines. A light foam system floods the area in the event of a fire. A water fog system is used in the turbine generator transformer areas. Chemical fire extinguishers are used in all areas to supplement the automatic systems.

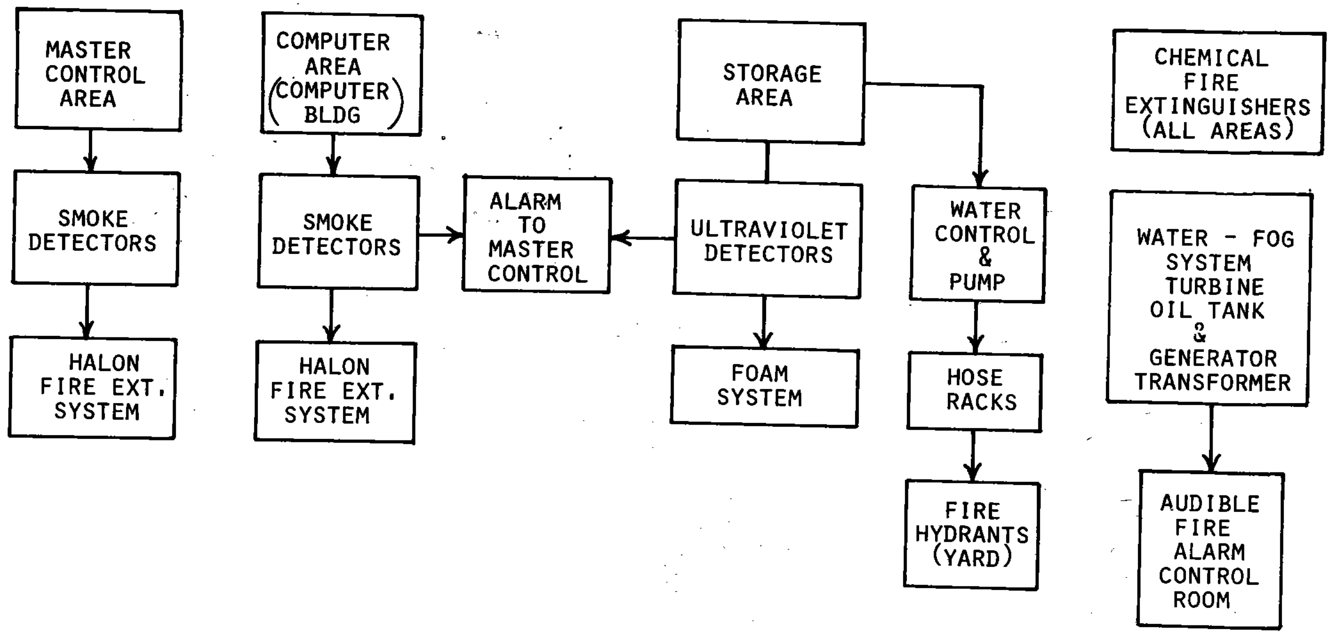


FUNCTION: PROVIDE DEMINERALIZED WATER FOR CONDENSER MAKE-UP AND OTHER NEEDS

LOCATION: POWER TOWER
TANK LOCATED 30 FEET NORTH OF BUILDING

REFERENCE: VOLUME VI C-21 TO C-24
VOLUME IV A1002
VOLUME I PAGE 81

Figure 3-52. Demineralized Water Storage System



FUNCTION: PROVIDE ADEQUATE FIRE PROTECTION

LOCATION: STORAGE AREA
COMPUTER AREA
ALL OTHER AREAS

REFERENCE: VOLUME VI PAGE C-25

Figure 3-53. Fire Protection Service

DEFINITION OF CONTROL TERMS

Some of the terminology used in solar steam generating control systems is used in a different manner than in conventional control. Essentially the controls used to position the valves in the system are basically analog systems with electronic summing amplifiers, and pneumatic actuators operating the valves. Feedbacks in the system such as temperature, pressure and flow rate are summed, amplified and integrated to provide an electrical input to the actuator. The digital controller provides all the high and low limiting, proportional gain, reset, change of set point and integration rate with less hardware than a comparable analog amplifier. Since the feedback parameters and actuator are analog, the digital control interface must be done with analog to digital and digital to analog conversion. It greatly simplifies communication with the master control and the heliostat digital computers to have the valve controller digital.

Hand/Auto Control Stations

As the name implies, this feature permits the operator to manually change a control valve that is normally under automatic control. With an integrator in the system, the automatic feature follows the manual change so that when the control reverts to automatic, the transfer is without a "bump".

Control Elements

Any one control system has some or all of the following elements. An electronic amplifier that combines the feedback signals to form the electrical signal for the actuator. A positioner that converts the electrical signal to a pneumatic signal for the actuator. A pneumatic actuator that is mounted on the valve and opens and closes the valve in response to signals. The pneumatic actuator has a diaphragm that acts as the piston in the actuator and a spring to either assist or oppose the diaphragm force. The spring is selected on the basis of fail-safe operation so that in the event of a power failure, the spring moves the valve to a safe closed or open position.

Proportional Gain

In this mode, there is a linear relation between the controlled variable and the position of the valve. In other words, the valve moves the same amount for each unit of deviation. The proportional band may extend over the entire variable range (100 percent) or it may control the valve over half the range (50 percent).

Offset or Droop

Proportional produces an exact correction for only one load condition and at all other loads there is some deviation or error left. This error, droop or offset is characteristic of proportional systems.

Proportional plus reset (integral control)

The normal correction takes place through the proportional gain while the reset portion begins to integrate. This integration or reset calls for additional valve opening at a rate dependent on its gain. If the valve was opened 10 degrees by the proportional gain and an additional 10 degrees by the reset of integral gain, the time it takes to open the valve the additional 10 degrees is called the reset or integral time.

Proportional plus rate (derivative)

An additional feedback is sometimes added to the proportional gain that is the first derivative of the controlled variable. If temperature is the controlled element, the rate at which the temperature is changing is used to position the valve. By opposing all change, the rate mode has a stabilizing effect on the control.

Open Loop Control

Control signals that are applied to a process based on a feedback that is not directly related to the variable is called open loop control.

Feedforward Control

A corrective action is applied to the variable before the disturbance is fed back via the normal process variables. Feedforward is sometimes called anticipation.

Time Lags

Lags are caused by capacitance, resistance and transportation time. Capacitance is the ability of metals and components to store heat energy which will tend to retard change. Resistance is the ability to retard flow or resist changes in temperature due to insulation effects. Transportation time is the lag associated with the time it takes for flow through the system.

Set Point

Master control establishes the set point which is the reference to which the variable is controlled. This set point can be varied so that the variable response is faster, merely by introducing a larger error. In some control loops, the master control can change the set point to compensate for droop or offset in the system.

Control System Design. The control functions described in the preceding paragraphs may be performed by use of an electronic analog system or by a digital computer based system.

Electronic analog control employs operational amplifiers to perform the control functions indicated on the control block diagrams presented in the previous section of this report. The control system would be located in a cabinet in the computer room, and would receive electrical measurement signals from remotely located transmitter devices. Operator commands also would be transmitted electrically between the control system and devices located on the control room panel. Final control actuator position order would be transmitted through an operator control station in the control room panel to provide the operator opportunity for direct intervention in the control process.

Digital computer based systems, known as direct digital control (DDC), perform the required control functions by converting the analogue control signals to digital form and making arithmetic calculations at frequent intervals. DDC is advantageous for applications subject to revision or alteration of control strategy and for applications having multiple identical control loops which can share the calculation routine. Although DDC has had only limited application in power generation control, the experience gained has been favorable. It is considered to be suitable for all of the control functions of the solar pilot plant with the exception of minor independent control loops. The physical arrangement of a DDC system would be as previously described for an analog system.

DDC is selected for the pilot plant because of the diverse conditions of operation anticipated for the plant and the ease with which DDC can accommodate changes in control strategy.

DDC may be implemented by an independent computer system, or may be a function added to a computer which also serves as a data system. The independent computer system has the advantage that the data system will continue to operate if the control computer fails. However, the combined system is generally less expensive than independent systems. Because of the importance of maintaining the data system during the operation of the pilot plant, an independent DDC system is to be provided.

Plant Operation Plan

The basic diurnal operations of the pilot plant include:

(1) Start-up: to return the plant to a specified level of electrical power generation after an overnight shutdown.
(2) Charging the thermal storage subsystem: to store the excess thermal energy that becomes available.
(3) Discharging the thermal storage subsystem: to continue electrical power generation when adequate solar energy is not available.
(4) Shutdown: to include readying the plant for start-up the following day.

With one or two exceptions unique to the solar plant, the shutdown operation is more or less typical of any power plant. The start-up, "storage-in" (i.e., thermal storage charge) and "storage-out" (i.e., thermal storage discharge) are the most interesting and important operations, and require the development of an operating strategy tailored to the solar plant. Consideration of the interrelation between these three operations and other factors important to the development of a general operating strategy are discussed in the following sections. A brief review of the solar plant operating constraints is presented as the background for the definition of a general operating strategy and the development of plant start-up sequences, plant shutdown sequences, and the analysis of a typical day's operation.

Background. Effective utilization of available solar energy requires that plant design permit rapid diurnal start-up. All high temperature plant components should therefore be designed to limit the amount of cooling overnight and, so far as possible, to cool by the same amount so as to limit temperature mismatch at start-up. Considering the major steam system components, experience to date with the SRE boiler indicates that an overnight cooldown of 90-120 C (200-250 F) may be experienced in the pilot plant, resulting in a boiler drum pressure of about 970-1400 kPa (140-200 psi) at morning start-up. The turbine is expected to cool by a similar amount, although accurate estimates are not currently available. Turbine cooling, however, can be controlled to some degree by the amount of insulation applied to the high temperature components. The steam lines of the pilot plant are much longer than those encountered in a conventional plant design and warming by the standard method of steam blowing through the drain valves requires an excessive start-up time. The main steam line of the pilot plant is, therefore, equipped with electric heaters to maintain the metal temperature at a minimum of about 370 C (700 F).

The limitations of the turbine and the steam generator to accept a finite rate of change in load, steam temperature, and steam pressure are important considerations in the start-up sequence. The turbine is expected to be limited to ramp load changes of about 4 per cent per minute and instantaneous changes ± 10 per cent. The boiler does not have specific limits on load change rate, but will be limited to pressure changes that result in saturated steam temperature changes not exceeding 370 C (700 F) per hour.

A large number of different strategies for start-up exist, any of which might be selected. This spectrum of possibilities occurs because of the widely varying solar heat flux during the start-up period and the possibility of using the thermal energy collected to charge thermal storage, drive the turbine, or both. There is also the possibility of supplementing the solar energy available at early morning with the remaining energy in the thermal storage subsystem.

Of the myriad possible strategies, several offer advantages over the others which might be desirable for plant operation. Ultimately it is necessary to select a single strategy whose characteristics most favor the power generation objectives of the plant. The primary consideration governing the selection of a start-up strategy is the desire to shorten the start-up period as much as possible, consistent with solar input and equipment limitations.

Operating strategies for thermal storage charging are more limited and are tied closely to the electrical power generation demand of the plant and the strategy selected for the stroage discharge operation. The principal consideration is that solar energy in excess of that used to directly generate electrical power be used to charge the thermal storage subsystem. This must be consistent with the thermal storage discharge operation which includes continued power generation after operation of the solar receiver ceases and maintaining a sufficient amount of stored energy for meeting the overnight hold and morning start-up requirements. It is desirable to maximize the electrical power generation consistent with available solar energy and thermal storage energy requirements.

Strategies for storage discharge consist of selecting electrial generation levels and durations to effectively utilize the energy stored during the preceding charging operation and the remaining direct solar energy that can be collected during the period of waning sunlight, leaving sufficient energy in storage to maintain turbine seals during the shutdown period with an adequate margin for the 20 hour hold design requirement.

Under partial cloud cover conditions, successful operating strategies include preferential allocation of available direct solar energy to electrical generation supplemented by energy from thermal storage to compensate for direct solar generation deficits, thereby maintaining demanded generation. An alternative plan is to use the steam generated from the solar energy collected under the conditions of cloud cover to charge thermal storage while generating electrical power by driving the turbine on steam developed in the thermal storage subsystem. This alternative is less efficient than the first but provides a buffer between the turbine-generator and the varying solar energy collection rate.

General Operating Strategy. As discussed previously, because solar plants are capital intensive, they will generally be operated to maximize electrical generation from the available solar energy. This translates to the requirement for the quickest practical diurnal start-up to full turbine load early in the operating period, and maximum used of stored energy towards the end of the operating day. The following paragraphs describe the diurnal operating strategy considered to be near optimum for the 10 MWe solar pilot plant when committed primarily to electrical power generation. The general operating strategy is discussed by first considering normal start-up and operation assuming clear air and then considering the operational impact of cloud cover.

Normal Start-up and Operation. Electric generation by use of receiver steam is the most energy effective use of solar energy. Energy that has been collected, stored, and recovered from storage has approximately 85 per cent of the theoretical generating capability of receiver steam, and parasitic losses of the storage system further reduce the energy ultimately recovered. The most effective strategy for operation under load is therefore to utilize fully the capability of the turbine-generator during the day and to store for later use only that energy that connot be accepted by the turbine.

It must be remembered that any operation involving charging of the storage system must be at design throttle pressure, so variable pressure operation can be used only during the morning start-up, when thermal storage is not being charged. The storage system capacity is sufficient to store a full day's capture of solar energy, and simultaneous charge and discharge operations are feasible, which offers the operator the opportunity to explore other operating strategies as well as the one outlined here.

Based on the above comments, the normal start-up and operation strategy is to start electrical generation at the earliest feasible time, increase electric load, and raise receiver pressure simultaneously until both full electric load and full pressure are achieved. During a normal diurnal start-up, the turbine throttle pressure (i.e., steam pressure at the turbine throttle valve) is allowed to vary between approximately 1380 kPa (200 psi) at synchronization to 10,000 kPa (1450 psi) at full load. Energy received in excess of electrical generation requirements is stored during the mid portion of the day. When the available energy declines in the afternoon below that required for full turbine load, the storage charge cycle is terminated. As solar energy declines in the late afternoon, the turbine load is allowed to decline, but design steam pressure and temperature are maintained. When electrical generation decreases to about 9 MWe the storage discharge cycle is initiated. Dual admission operation is then used until sunset, followed by use of only admission steam until storage is depleted to the minimum acceptable level. Sufficient stored energy must be retained to meet overnight requirements, primarily for the steam seal system.

Broken Cloud Operation. Plant operation with a continuous cloud cover is possible only if sufficient energy is available from thermal storage. However, with a broken cloud cover, operation at reduced capacity can be achieved by using the energy not intercepted by cloud or blocked by cloud shadows. The major adverse effects of broken cloud cover are:

(1) Intermittent reduction of total available energy.
(2) Imbalance of energy input between the receiver steam generator boiler and superheater.

Operating strategies capable of handling these effects are discussed below.

Intermittent reduction of total available energy. The variation of total energy available due to the passage of cloud shadows across the collector field is in the form of an irregular increase and decrease of solar insolation as a function of time. The steam generating rate of the solar boiler will fluctuate in a similar manner. Generator output can be allowed to fluctuate also, but this type of operation is undesirable from the standpoint of the electrical system receiving the generated power, and imposes undesirable thermal transients on the turbine-generator. To minimize these effects, operation under broken cloud conditions may require that receiver and storage generated steam be utilized simultaneously, with storage steam supplementing receiver steam to maintain the desired generation level, or receiver steam used to charge thermal storage while storage generated steam drives the turbine generator. In the latter case, the thermal storage subsystem is operated in both charge and discharge modes simultaneously. Selection of the generation level to be utilized is to be based on operating experience and no specific guidelines are established at this time.

An alternate strategy for broken cloud operation is to defer start-up of the turbine generator and store all available receiver energy until a substantial storage inventory is achieved. At that time a decision can be made concerning the advisability of turbine start-up and the generation level to be selected.

Imbalance of energy input. The collector field consists basically of an outer zone of heliostats supplying energy to the boiler, and an inner zone of heliostats supplying energy to the superheater. The movement of cloud shadows over a portion of the field results in a transient imbalance of the energy supplied by these two zones, which may cause a major variation in steam temperature depending on the control capability of the attemperator. To minimize this imbalance, the operating strategy requires that the heliostat be monitored continuously and heliostats within each zone be selectively defocused as required to maintain an energy balance. The exact strategy to be employed will have to be based upon plant operating experience; however, capability for convenient defocus of heliostats, either singly or in groups, is provided in the collector subsystem control software.

Plant Start-up Sequences. This section addresses the operational sequences required for plant start-up under the expected conditions of cold start-up, diurnal (warm) start-up, start-up to charge thermal storage, and start-up on stored energy.

Cold Start-up. A cold start-up of the plant is required following a period of more than two or three days without operation. The boiler is cooled to approximately ambient temperature, turbine steam seals are off, condenser vacuum is broken, and thermal storage is essentially depleted. No steam will be available for deaeration of feedwater; however, nitrogen blanketing of the boiler and feedwater heaters prevents oxygen corrosion. The general sequence of events for a cold start-up is as follows.

(1) Energize the plant's auxiliary electrical system using the reserve auxiliary power transformer.
(2) Start warming steam lines by use of electric heaters about 15 hours before sunrise.
(3) Start circulating water, auxiliary cooling water, and compressed air systems.
(4) Start boiler feed pumps as required to establish boiler water level.
(5) Start receiver boiler circulating pump.
(6) Expose receiver boiler heating surface.
(7) Initiate heating the boiler by selective use of heliostats at sunrise.
(8) Open steam line and turbine stop valve drain valves when steam generation begins.

(9) Start steam supply to deaerator when steam pressure reaches about 340 kPa (50 psi).
(10) Start one main circulating pump.
(11) Start steam supply to turbine steam seals.
(12) Start condenser vacuum pump.
(13) Start superheating steam by selective use of heliostats.
(14) Roll turbine off turning gear when pressure reaches 1380 kPa (200 psi), accelerate to synchronous speed and synchronize generator.
(15) Proceed with generation ramp after drum pressure has achieved operating pressure, and as permitted by available steam and/or solar energy.
(16) When steam pressure and temperature reach their rated values, place coordinated master control in automatic operation.

Selective use of heliostats is required during the start-up process since, in the initial phases of boiler warmup, only the heliostats serving the boiler section of the steam generator can be used until sufficient steam flow through the superheater tubes is established to cool the tubes. Heliostats serving the superheater, and a spray attemperator, are used during the latter phase of start-up for control of final steam temperature.

Assuming the cold start-up is initiated at sunrise, about 97 minutes will be required to reach 1380 kPa (200 psi) boiler pressure and turbine rolloff. The maximum rate of increase of boiler water saturation temperature will be about 320 C (600 F) per hour, which approaches the boiler design limit of 370 C (700 F) per hour. If start-up is delayed substantially after sunrise, some selective use of heliostats is required to avoid exceeding boiler design temperature ramp limits.

Figure 3-54 illustrates the estimated drum pressure and electrical generation loading ramp as a function of time after sunrise for the cold start-up sequence just described. The turbine is rolled off of turning gear about 97 minutes after sunrise, as the drum pressure passes through 1380 kPa (200 psi). The turbine is accelerated to synchronous speed and synchronized over the next 34 minutes. The turbine is then loaded at 4 per cent rated flow per minute (maximum turbine rate) until limited by the insolation increase rate, about 150 minutes after sunrise. Subsequent loading follows the increasing insolation, until rated generation is achieved about 180 minutes after sunrise.

Diurnal or Warm Start-up. This type of start-up is required for a normal operating day following overnight shutdown. Basically, all plant subsystems are required to be available for operation; however, the storage subsystem will not be required to operate all redundant equipment elements. The plant is assumed to have been maintained in a hold condition overnight for morning start-up with the following systems in operation.

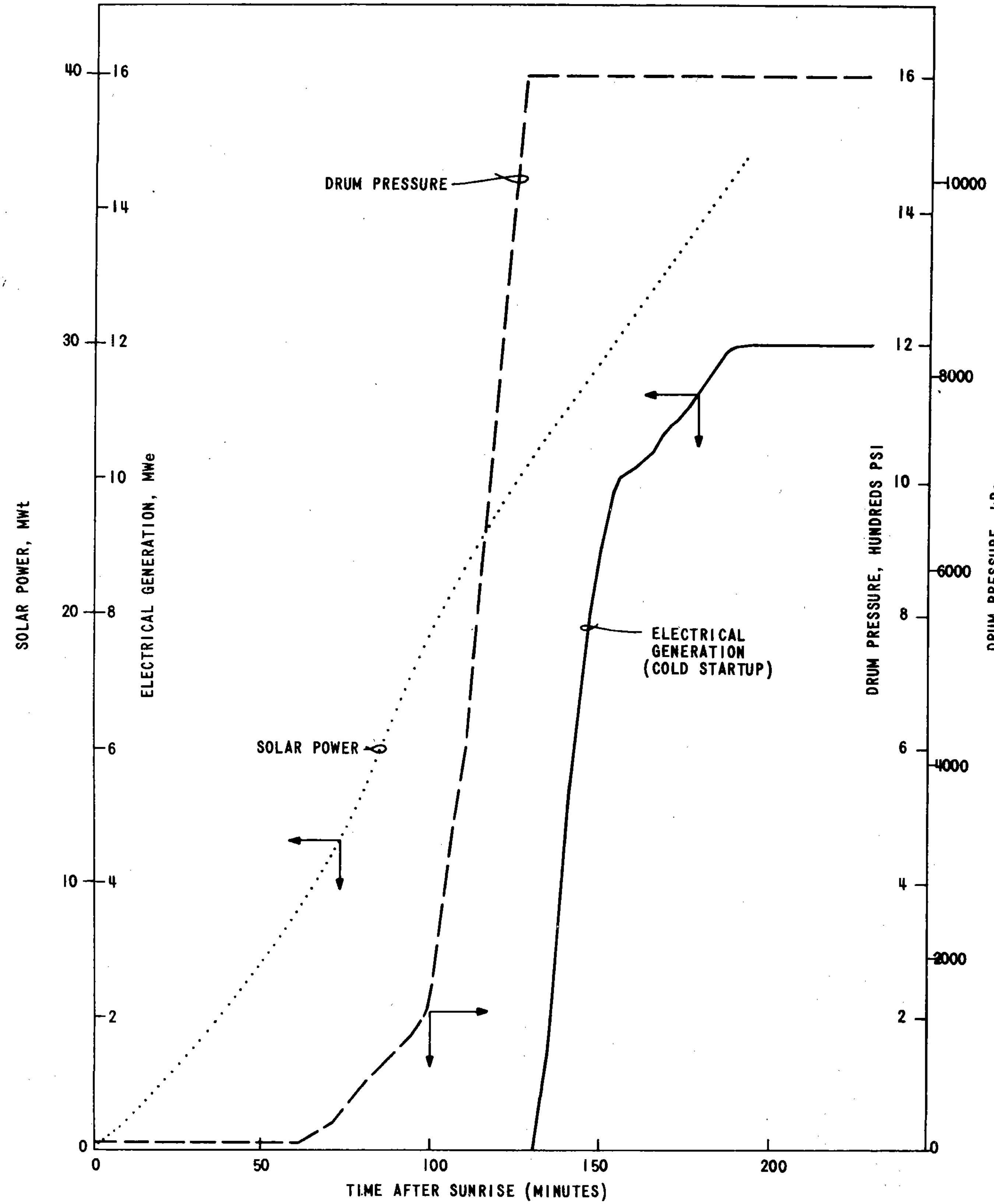


Figure 3-54. Cold Startup Pressure Ramp and Loading

(1) Auxiliary electric system.
(2) Auxiliary cooling water system.
(3) Control air system.
(4) Service air system.
(5) Condensate system.
(6) Condenser vacuum system.
(7) Steam line electric heat system.
(8) Storage discharge system.
(9) Circulating water system.

The condensate system, storage discharge system, and circulating water system are operated at reduced capacity during the overnight shutdown by use of small pumps, reduced speed of normal pumps, or other means.

The start-up sequence is as follows.

(1) Start one circulating water pump and one cooling tower fan.
(2) Start one condensate pump.
(3) Start one storage boiler feed pump.
(4) Start storage discharge oil pump.
(5) Start storage discharge Hitec pump.
(6) Operate receiver boiler feed pump as required to establish boiler drum level.
(7) Start receiver boiler circulating pump.
(8) Expose receiver boiler heating surface.
(9) At sunrise, place boiler heliostats in "track" mode.
(10) Transfer to receiver steam source, shut down storage discharge auxiliaries.
(11) Place all EPGS auxiliaries in full operation for load and pressure ramp.
(12) Raise steam pressure and load as permitted by available steam and/or solar energy.
(13) When steam pressure and temperature reach their rated values, place coordinated master control in operation.

The detail of diurnal (warm) start-up and operation is discussed in the paragraphs that describe the Analysis of a Typical Day's Operation. As developed there, the overall start-up time is approximately 180 minutes, which is very nearly the same as the time required for a cold start-up. This result is caused by the more or less arbitrary definition of start-up as the time period from sunrise to full load operation, and by the rate of insolation increase. Close examination of the warm start-up indicates the turbine is loaded earlier in the sequence and loaded at a more gentle rate. The cold start-up sequence necessitates deferring turbine loading until much later and then accelerating the turbine at its maximum rate until limited by the insolation available. The increased electrical generation developed during a warm start-up over a cold start-up is approximately 6.4 MWh or approximately 5.8 per cent of the daily generation. A comparison of the cold startup and diurnal startup pressure ramp and unit loading is given in Figure 3-55.

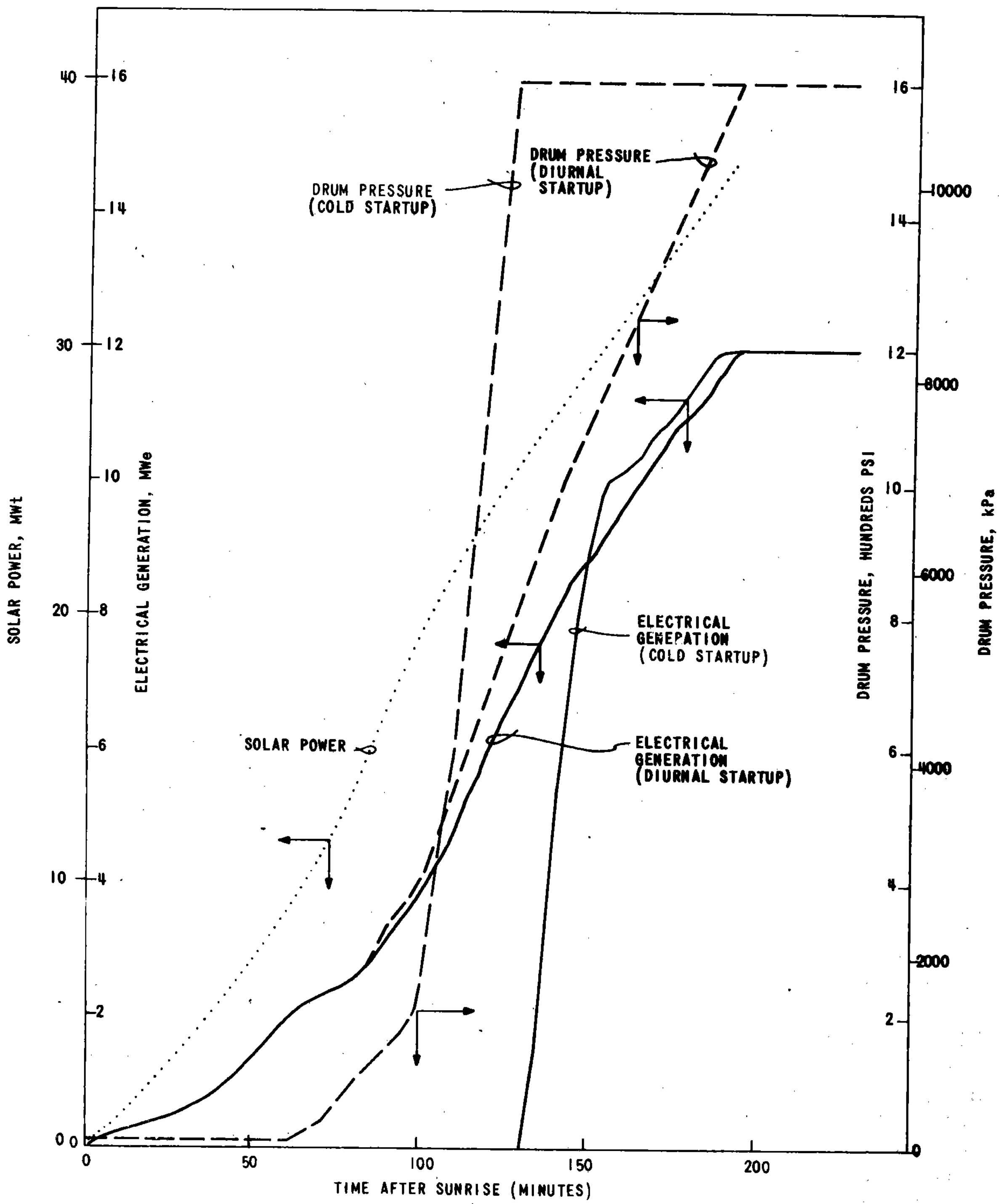


Figure 3-55. Comparison of Cold and Diurnal Pressure Ramp and Loading

Storage Charge Start-up. Start-up to only charge thermal storage may follow either a diurnal shutdown or an extended shutdown. The most probable storage charge start-up sequence is start-up following an extended shutdown. For this situation, the prestart-up conditions may be assumed equivalent to those for a cold start-up. The general sequence of events is as follows.

(1) Energize the plant auxiliary electrical system.
(2) Start warming steam lines by electric heat about 15 hours before sunrise.
(3) Start circulating water, auxiliary cooling water, and compressed air systems.
(4) Start boiler feed pump as required to establish boiler water level.
(5) Start receiver boiler circulating pump.
(6) Expose receiver boiler heating surface.
(7) Start heating the boiler by selective use of heliostats at sunrise.
(8) Open steam line drain valves when steam generation begins.
(9) Open steam block valves to storage charge system.
(10) When pressure reaches design value, start Hitec and oil charge cycle pumps.
(11) Place superheat heliostats in "track" mode.
(12) Place coordinated master control in operation.

Assuming a March 21 clear air model day with 2.5 MWt loss due to wind, preliminary calculations indicate this startup requires approximately 97 minutes from sunrise to design steam pressure. The rate of increase of boiler water temperature will approach its design limit of 370 C (700 F) per hour. During this period the superheater heliostats are not used. After reaching rated steam pressure, the steam generator is operated with all heliostats in service while charging thermal storage. During the day, about 334 MWh (1.140 x 10^9 Btu) of thermal energy are stored. The drain pressure ramp is essentially that of the cold start-up.

Storage Discharge Start-up. The plant may be started using storage generated steam only; however, this is not expected to be frequently employed. One possible application of this sequence is an event in which the turbine experiences a forced shutdown of a few hours duration. The available solar energy is placed in storage and is used for electrical generation during the evening hours, when the turbine is again available for operation.

For purposes of illustration, it is assumed that the turbine is on turning gear, but condenser vacuum is broken and steam seals are turned off. All plant auxiliaries are assumed to be available for service. Direct solar energy is not available. The start-up sequence is as follows.

(1) Start one circulating water pump and one cooling tower fan.
(2) Start one condensate pump.

(3) Start one storage boiler feed pump.
(4) Start storage discharge oil pump.
(5) Start storage discharge Hitec pump.
(6) Start condenser vacuum pump.
(7) Place turbine steam seals in operation.
(8) Roll turbine off turning gear about 10 minutes after starting vacuum pump.
(9) Synchronize generator to the line about 20 minutes after roll off turning gear.
(10) Raise generation to 8.4 MW in about 20 minutes after synchronizing.
(11) Place coordinated master control in operation.

<u>Plant Shutdown Sequences</u>. This section addresses the operational sequences or events required for plant shutdown under the conditions of diurnal shutdown, extended shutdown, and emergency shutdown.

Diurnal Shutdown. The sequence of events of a diurnal or overnight shutdown is as follows.

(1) Reduce turbine load during the final 30 minutes of operation.
(2) Trip the turbine and generator when at least 3 MWh (10×10^6 Btu) remain in the thermal storage inventory.
(3) Supply steam to the turbine seal system from thermal storage.
(4) Shutdown receiver boiler feed pump and circulating pump, close receiver aperture (if operation was on receiver steam).
(5) Place turbine on turning gear after deceleration (about 30 minutes following trip).
(6) Operate storage discharge, condensate, and circulating water systems overnight at minimum capacity.
(7) Continue turbine seal system, condenser vacuum system in operation overnight.

The total time required for overnight shutdown is essentially the time used to back the load down to the point that the turbine-generator can be tripped off the line without undue upset to the power system or stress on rotating parts. At 4 per cent rated flow per minute from 8.4 MW to essentially zero load, this operation is expected to consume about 20 minutes. Tripping the turbine does not require a time for operation. Setting up equipment for overnight maintained systems can be accomplished in less than 10 minutes, bringing the total time to less than 30 minutes. Engagement of the turning gear can only occur when the rotor decelerates to very low speeds (<6 RPM), which typically occurs approximately 30 minutes after the trip. Therefore, the estimated total shutdown time is expected to be less than an hour, of which half is in waiting to engage the turning gear.

Extended Shutdown. An extended shutdown is similar to an overnight shutdown with the exception that the turbine is not steam sealed and no auxiliary systems are operated. The turbine is placed on turning gear if startup within two or three days is anticipated.

Emergency Shutdown. An emergency shutdown occurs as a consequence of equipment failure within the plant, or loss of the connection to the utility power transmission system. Emergency shutdowns are initiated automatically, or may be initiated by the control room operator by use of an emergency trip push button. A protective interlock circuit removes from service those plant components which require immediate protective action. Other plant components are subsequently removed from service by operator action if an immediate plant restart is not anticipated.

Analysis of Typical Day's Operation. A typical day's operation following overnight shutdown has been analyzed at 20 to 30 minute intervals throughout the day. The analysis is based on the insolation data of the clear air model for March 21 and assumes the plant was maintained overnight for a diurnal start-up. The analysis is discussed in the following paragraphs, with the results presented in Figures 3-56 through 3-59 and in Tables 3-5 through 3-7. (Tables 3-5a through 3-7a duplicate in English units the data presented in Tables 3-5 through 3-7.) Figure 3-56 summarizes the operation of the plant during a typical day as described below.

Morning Start-up. The start-up cycle commences with roll-off and synchronization of the turbine at 1380 kPa (200 psi). The turbine is subsequently loaded in accordance with the general start-up sequence, as permitted by insolation rates, while maintaining 1380 kPa (200 psi) steam pressure until the turbine valves are at full load position (49,696.4 kg/hr basis (109,332 lb/hr basis)). The start-up cycle concludes with a period of simultaneous increase of throttle pressure and electric load, with rated throttle pressure achieved at full load.

Figures 3-56 through 3-59 represent the expected changes in several important parameters during the start-up period from turbine synchronization to full load operation. The start-up strategy is to hold the 1380 kPa (200 psi) shutdown steam pressure condition using the turbine throttle valves in a "back pressure regulator" mode. The valve position for full load/full pressure condition is expected to correspond to 2 MWe at 1380 kPa (200 psi). Thus, the throttle valves open as insolation increases, raising turbine load at 1380 kPa (200 psi) throttle pressure until about 2 MWe is attained. At this point turbine valves are pegged and subsequent load increases follow the insolation increase with a concurrent pressure increase in the receiver drum, as shown in Figure 3-57. Figures 3-58 and 3-59 illustrate that the superheater heliostat effort and the desuperheating spray flow is varied as required to maintain the steam temperature program.

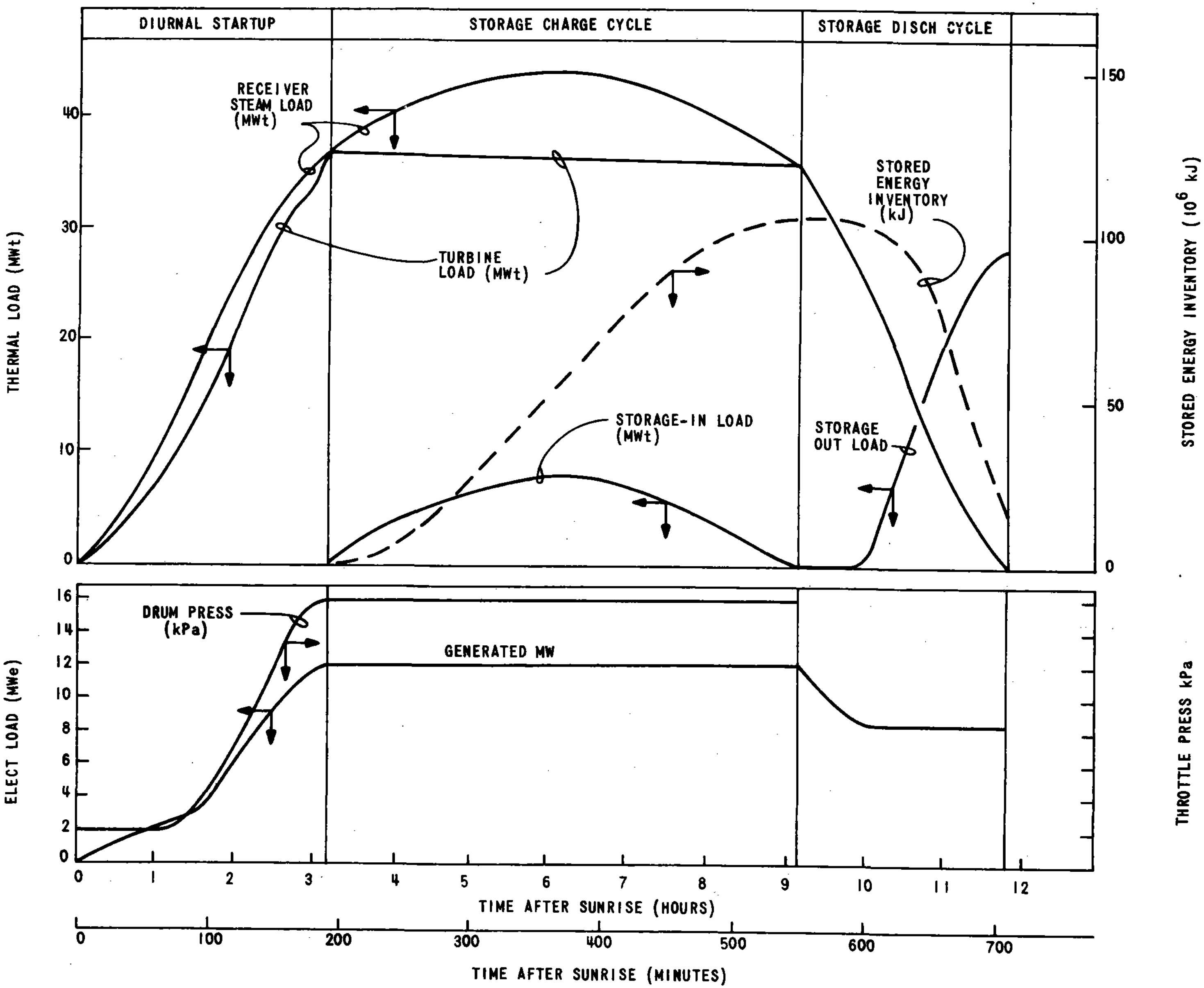


Figure 3-56. Typical Day's Operation

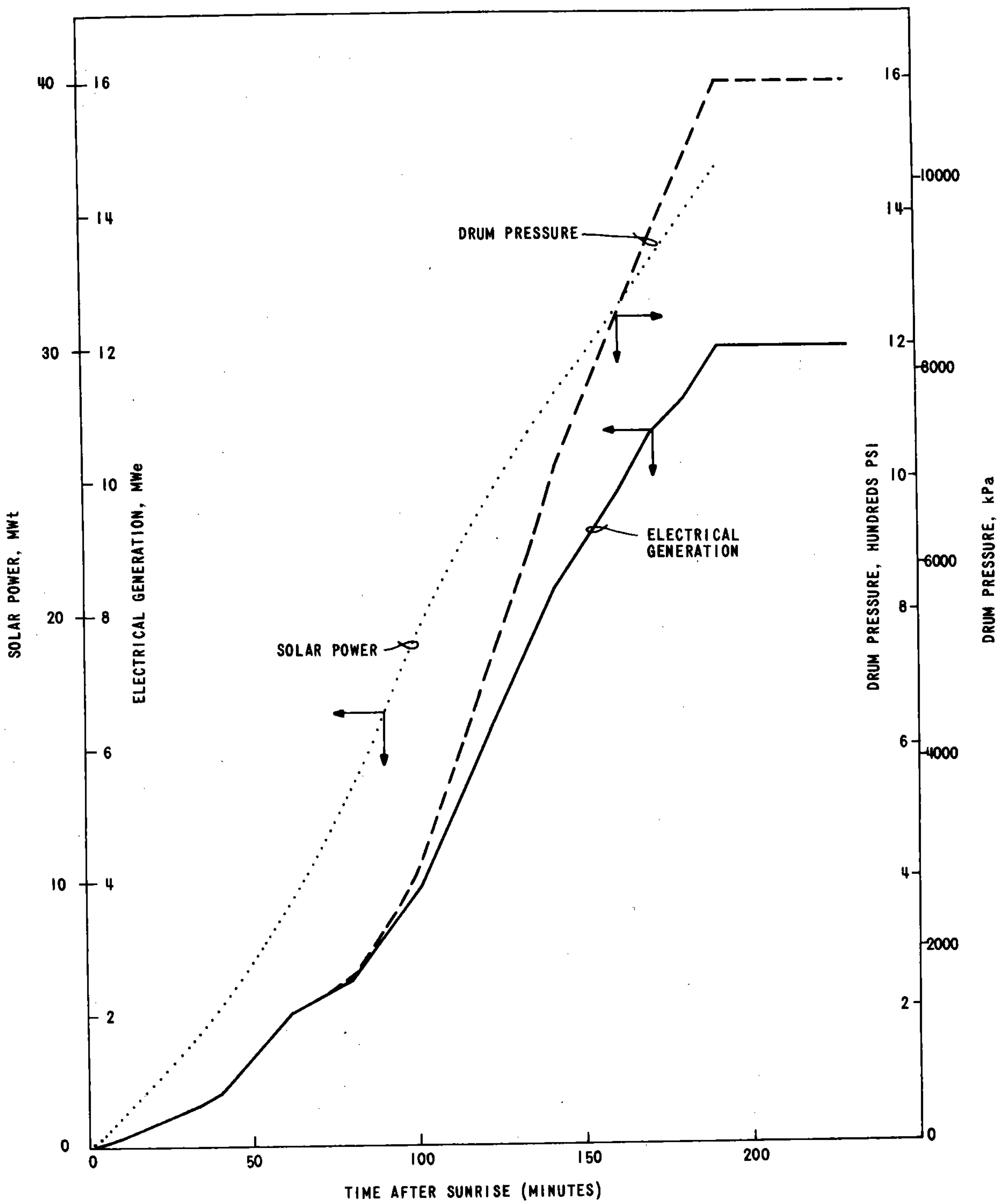


Figure 3-57. Diurnal Startup Pressure Ramp and Loading

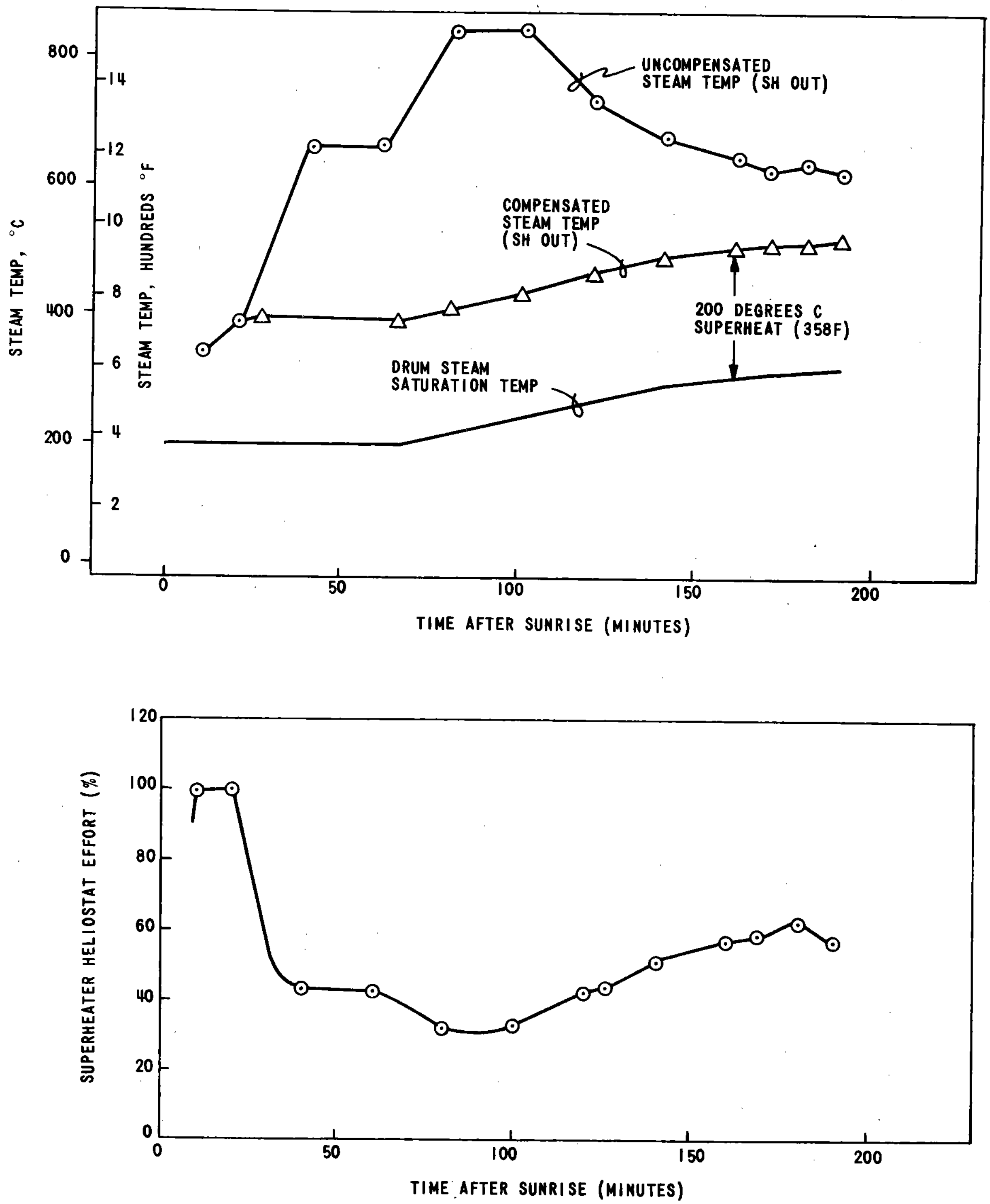


Figure 3-58. Receiver Steam Temperature Control Via Heliostat Focusing

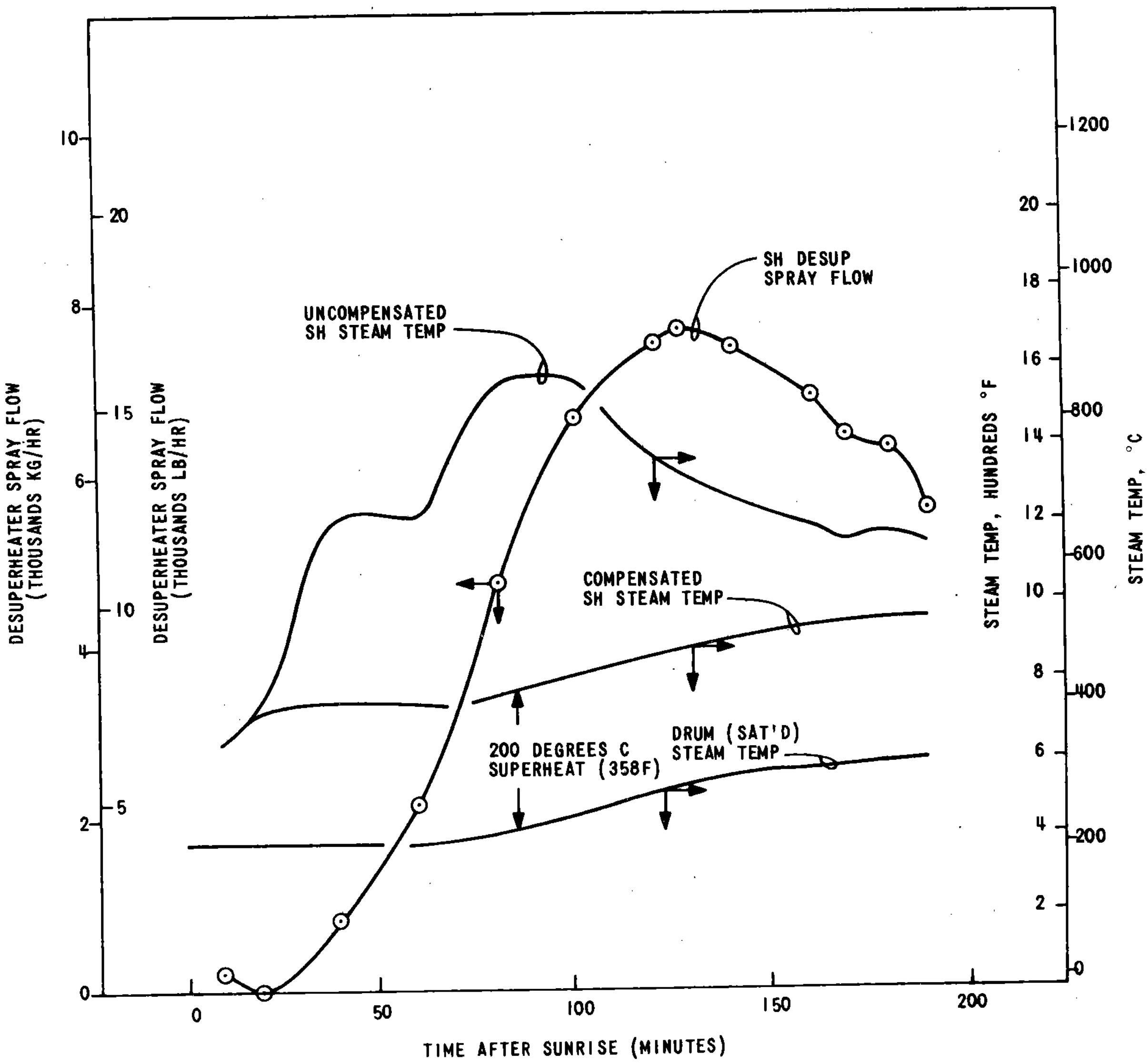


Figure 3-59. Receiver Steam Temperature Control Via Desuperheater Spray

TABLE 3-5

CALCULATION OF DIURNAL STARTUP
PRESSURE/LOAD RAMP

Time from Sunrise Minutes	Event	Receiver Energy MW	Turbine Load MWe	Turbine Energy MW	Boiler Enthalpy Rise kJ x 10^6	Boiler Drum Pressure kPa	Steam Flow kg/hr x 10^3
5	Roll Off Turning Gear and Synchronize	0.59	0	0	0	1379	0
20	Load Ramp	2.93	0.35	2.34	0	1379	1.82
40	Load Ramp	5.27	0.80	4.98	0	1379	3.64
60	Start Pressure Ramp	8.92	2.0	9.23	2.14	1379	8.41
80	Load/Pressure Ramp	14.4	2.5	10.55	5.24	1741	10.55
100	Load/Pressure Ramp	19.89	3.9	14.36	6.47	2896	16.36
120	Load/Pressure Ramp	25.38	6.25	20.51	5.00	4923	25.91
140	Load/Pressure Ramp	28.79	8.35	25.75	3.53	6964	34.32
160	Load/Pressure Ramp	32.20	9.8	29.33	3.28	8653	40.00
180	Load/Pressure Ramp	35.61	11.2	32.82	1.39	10170	45.68
190	End of Load/Pressure Ramp	36.04	12.0	36.04	0	11032	49.68

TABLE 3-5a

CALCULATION OF DIURNAL STARTUP
PRESSURE/LOAD RAMP

Time from Sunrise Minutes	Event	Receiver Energy Btu/hr x 10^6	Turbine Load MW	Turbine Energy Btu/hr x 10^6	Boiler Enthalpy Rise Btu x 10^6	Boiler Drum Pressure psi	Steam Flow lb/hr x 10^3
5	Roll Off Turning Gear and Synchronize	2	0	0	0	200	0
20	Load Ramp	10.0	0.35	8.0	0	200	4
40	Load Ramp	18.0	0.80	17.0	0	200	8
60	Start Pressure Ramp	30.43	2.0	31.5	2.03	200	18.5
80	Load/Pressure Ramp	49.16	2.5	36.0	4.97	252.5	23.2
100	Load/Pressure Ramp	67.90	3.9	49.0	6.13	420	36
120	Load/Pressure Ramp	86.63	6.25	70.0	4.74	714	57
140	Load/Pressure Ramp	98.26	8.35	87.9	3.35	1010	75.5
160	Load/Pressure Ramp	109.89	9.8	100.1	3.11	1255	88
180	Load/Pressure Ramp	121.53	11.2	112.0	1.32	1475	100.5
190	End of Load/Pressure Ramp	123.0	12.0	123.0	0	1600	109.3

TABLE 3-6

CALCULATION OF TYPICAL DAY
STORAGE CHARGE CYCLE

Time From Sunrise Minutes	Receiver Energy MW	Turbine Load MWe	Turbine Energy MW	Storage In Energy MWth	Integrated Energy Storage kJ x 10^6
190	36.04	12.0	36.04	0	0
210	38.13	12.0	36.04	2.09	1.26
240	40.64	12.0	36.04	4.61	7.28
270	41.68	12.0	36.04	5.64	16.50
300	42.71	12.0	36.04	6.67	27.58
330	43.52	12.0	36.04	7.49	40.32
360	44.35	12.0	36.04	8.31	55.07
390	43.52	12.0	36.04	7.49	69.29
420	42.71	12.0	36.04	6.67	82.04
450	41.68	12.0	36.04	5.63	93.11
480	40.64	12.10	36.04	4.61	102.34
510	38.13	12.0	36.04	2.09	108.37
530	36.04	12.0	36.04	0	112.13

TABLE 3-6a

CALCULATION OF TYPICAL DAY STORAGE CHARGE CYCLE

Time From Sunrise Minutes	Receiver Energy Btu/hr	Turbine Load MW	Turbine Energy Btu/hr x 10^6	Storage In Energy Btu/hr x 10^6	Integrated Energy Storage Btu x 10^6
190	123.0	12.0	123.0	0	0
210	130.13	12.0	123.0	7.13	1.19
240	138.72	12.0	123.0	15.72	6.9
270	142.24	12.0	123.0	19.25	15.64
300	145.76	12.0	123.0	22.76	26.14
330	148.55	12.0	123.0	25.55	38.22
360	151.35	12.0	123.0	28.35	52.20
390	148.55	12.0	123.0	25.55	65.68
420	145.76	12.0	123.0	22.76	77.76
450	142.24	12.0	123.0	19.24	88.26
480	138.73	12.10	123.0	15.73	97.0
510	130.13	12.0	123.0	7.13	102.72
530	123.0	12.0	123.0	0	106.28

TABLE 3-7

CALCULATION OF GENERATION DECLINE AND STORAGE DISCHARGE CYCLE

Time From Sunrise Minutes	Event	Receiver Energy MW	Storage Out Energy MW	Turbine Load MWe	Storage Energy Remaining kJ x 10^6
552	End of Storage Charge Cycle	34.574	0	12.0	112.13
570	Declining Turbine Load	30.495	0	10.29	112.13
600	Dual Admission Operation	25.38	0.44	8.4	111.34
630	Dual Admission Operation	17.15	10.03	8.4	101.92
660	Dual Admission Operation	8.92	19.62	8.4	75.23
690	Dual Admission Operation	3.21	26.64	8.4	33.58
704	Shut Unit Down	Off	28.25	8.4	10.55*

*Storage energy to be reserved for overnight steam sealing and morning startup to be determined when better turbine data is available.

TABLE 3-7a

CALCULATION OF GENERATION DECLINE AND STORAGE DISCHARGE CYCLE

Time From Sunrise Minutes	Event	Receiver Energy Btu/hr x 10^6	Storage Out Energy Btu/hr x 10^6	Turbine Load MW	Storage Energy Remaining Btu x 10^6
552	End of Storage Charge Cycle	118.0	0	12.0	106.28
570	Declining Turbine Load	104.08	0	10.29	106.28
600	Dual Admission Operation	86.63	1.49	8.4	105.54
630	Dual Admission Operation	58.53	34.23	8.4	96.61
660	Dual Admission Operation	30.43	66.98	8.4	71.31
690	Dual Admission Operation	10.95	90.93	8.4	31.83
704	Shut Unit Down	Off	96.42	8.4	10.0*

*Storage energy to be reserved for overnight steam sealing and morning startup to be determined when better turbine data is available.

The use of the heliostat effort or desuperheating spray as the sole control mechanism represents extremes of alternatives for steam temperature control. It is probable that both desuperheating spray and superheat heliostat defocusing might be simultaneously applied to maintain desired steam temperatures with due consideration of superheater tube metal protection. In each case, the heliostats or the desuperheating spray is assumed to be the sole temperature control mechanism. The maintenance of a constant 358 degrees of superheat from start-up to full load provides the best attainable temperature matching between the turbine metal parts and the driving steam for the assumed conditions of the turbine at initiation of start-up. Table 3-5 shows the results of the pressure and load ramp calculations. During this period slightly over 11 megawatt hours of electrical power is generated.

It should be mentioned that the rate of electrical generation increase and boiler increase are well within the equipment allowable limits.

Storage Charge Cycle. Following the load ramp, combined operation of generating electric power and charging thermal storage is initiated at about the third hour after sunrise. This phase of plant operation continues until the decline of available solar energy causes termination of thermal storage charging about 9 hours after sunrise. During this period about 75 MWh of electric energy are generated and 44 MWh (150 x 10^6 Btu) of thermal energy are stored. Table 3-6 presents the results of the storage cycle calculation.

Generation Decline and Storage Discharge. At the end of the storage charging operation the electrical power generation rate starts to decline as the energy absorbed by the receiver declines. After about 40 minutes the generation rate reaches approximately 8.4 MWe, which is the rated power delivery rate using storage generated steam. This rate is maintained until the storage is essentially depleted.

About 3 MWh (10 x 10^6 Btu) of storage energy are reserved in thermal storage to maintain the turbine steam seals overnight. Table 3-7 presents the results of the calculation of generation decline and storage discharge.

In the final 20 minutes of operation prior to depletion of storage to the 3 MWh (10 x 10^6 Btu) value, the generation is ramped down to zero load and the turbine-generation tripped. Shutdown activities are as discussed earlier, with the plant equipment required for an overnight shutdown placed in operation to maintain the plant in readiness for start-up the next morning.

Plant Instrumentation Systems

The pilot plant instrumentation includes plant monitoring instrumentation and experimental data acquisition instrumentation.

The plant monitoring instrumentation provides guidance to the plant operators when executing remote manual control functions. Remote manual functions are required when placing automatic controls in operation, or when conducting operations during periods when automatic control is inoperative. Plant monitoring instrumentation is also required for monitoring the performance of the automatic controls and for detection of operation close to equipment capacity limits. A substantial part of the experimental program data is required by the plant operators, although the information displayed for the operators is generally different than that required by the experimental program. Alarm conditions are displayed to the operator, while hard copy records of alarms and event sequences are required for analyses of the operation upsets. Monitoring instruments are, of course, functionally independent of control systems.

Selection of indicators, recorders, and other plant monitoring instrumentation are indicated in the control room panel layout drawings and instrument lists presented in Appendix F and discussed in the Plant Control Room section. Appendix G details local indicating instrumentation, and monitoring and control elements.

Virtually all aspects of the operating pilot plant are to some degree experimental in nature, and operating data are required for evaluation of performance. Hard copy data presentation is required, generally in digital form. Time averaging as well as maximum and minimum peak values are desirable for a large part of the data. Appendix H lists the items of experimental data now anticipated to be required.

The experimental data acquisition system is to be a computer based system which also provides monitoring of plant operation. The system is to include facilities for test engineers to organize data presentation as required for test purposes. A high speed line printer is required for large data outputs.

Plant Protective System

A plant protective system is required to provide comprehensive automatic protection of plant equipment and personnel in the event of a major disturbance to operation. Typical events for which automatic protective action are required include:

(1) Generator trip.
    (a) Reverse current relay.
    (b) Differential relay.
    (c) Loss of excitation.

(2) Turbine trip.
  (a) Overspeed.
  (b) Steam pressure high.
  (c) Low vacuum.
  (d) Thrust bearing, vibration.
(3) Collector field trip (if operating).
  (a) Low receiver boiler drum level.
  (b) Loss of receiver boiler circulating pump.
  (c) Steam temperature out of limits.
  (d) Heliostat pointing error.
  (e) Significant weather events.
  (f) Auxiliary power failure.
(4) Storage-Out trip (if operating).
  (a) Steam temperature out of limits.
  (b) Auxiliary power failure.

The collector field trip and storage-out trip functions are activated only if they are the sole steam source at the time. The protective interlock circuit initiates protective tripping of the operating equipment as follows.

(1) Collector field--defocus all heliostats.
(2) Receiver boiler--no automatic protective functions.
(3) Storage-in system--no automatic protective functions.
(4) Storage-out system--trip boiler and superheater storage medium pumps.
(5) Turbine--trip HP and IP stop valves.
(6) Generator.
  (a) Trip generator circuit breaker.
  (b) Transfer auxiliaries to reserve transformer.

Plant auxiliary motors require start-stop control from the control room, and the motor control systems incorporate protective interlocking appropriate to the needs of the motor and the driven equipment. Start-stop controls adjacent to the auxiliary motors are not considered necessary or desirable.

Motor control and protective interlock systems require relatively simple logic functions. Normal power plant applications require on-line test capability; however, for the Solar Pilot Plant, testing can satisfactorily be performed as a part of the shutdown sequence or during shutdown periods. Redundant logic systems are not required for the Solar Pilot Plant, also because of the feasibility of frequent testing.

Logic functions can feasibly be executed either by relay or solid state logic, and relay logic is the most cost effective. Relay logic power supply may be ac or dc. Motor control logic systems for 480 volt motors are customarily powered at 120 volts ac by auxiliary transformers associated with the motor starters so that the logic inherently enters a tripped condition when the power supply to the starter is interrupted. Motor control logic systems for 5 kV motors normally use dc power from the station battery since this voltage is required to operate the supply breakers close and trip coils. The plant protective system may use either ac power from the plant high reliability ac supply or may use dc power from the station battery. Some of the final trip devices, specifically the turbine stop valve trip and generator breaker, are inherently dc energize-to-trip devices, making the use of a dc energize-to-trip system a preferred arrangement.

The considerations described above led to the selection of relay type logic for plant protective system and motor control. All plant auxiliary motors with the exception of the main feedwater pump and feedwater booster pump motors operate at 480 volts and use 120 volt ac control logic of the deenergize-to-trip type. The plant protective system, main feedwater pump and feedwater booster pump use 125 volt dc power from the station battery and operate in the energize-to-trip mode.

Plant Control Room

The pilot plant control room layout is illustrated in Figure 3-60 taken from the Plant Arrangement Drawings given in Appendix C of Volume II. Control of the plant is required to be centered in such a control room area to provide control and monitoring of significant plant operating parameters. The major element of the control room is the control room panel which is designed for operation by two operators during the start-up phase and by a single operator during the balance of the day. The panel is designed for operation in a standing position, with all instruments and devices located for convenient viewing and for convenient manual operation. The control panel contains all of the instrumentation, alarms, and manual controls stations required for start-up, shutdown, remote manual operation, and monitoring of automatic operation of the plant.

Figure 3-61 shows a typical panel or benchboard profile which has proven to be the most satisfactory. It provides both benchboard and vertical panel surfaces, with the benchboard in two segments, providing acceptable distance for use of manual devices. Indicating and recording instruments are mounted on the vertical surface at approximately eye level. Visual annunciators are mounted at the top of the panel, permitting convenient vision from various locations in the control room.

The plan layout of the control panel and details of the arrangement of instruments and control devices on the panel are shown in Drawings 702132977-1 through 6 given in Appendix F. Although the plan layout of the control plan can assume a number of configurations, the U-configuration illustrated in Drawing 702132977-6 is best adapted to the requirements of

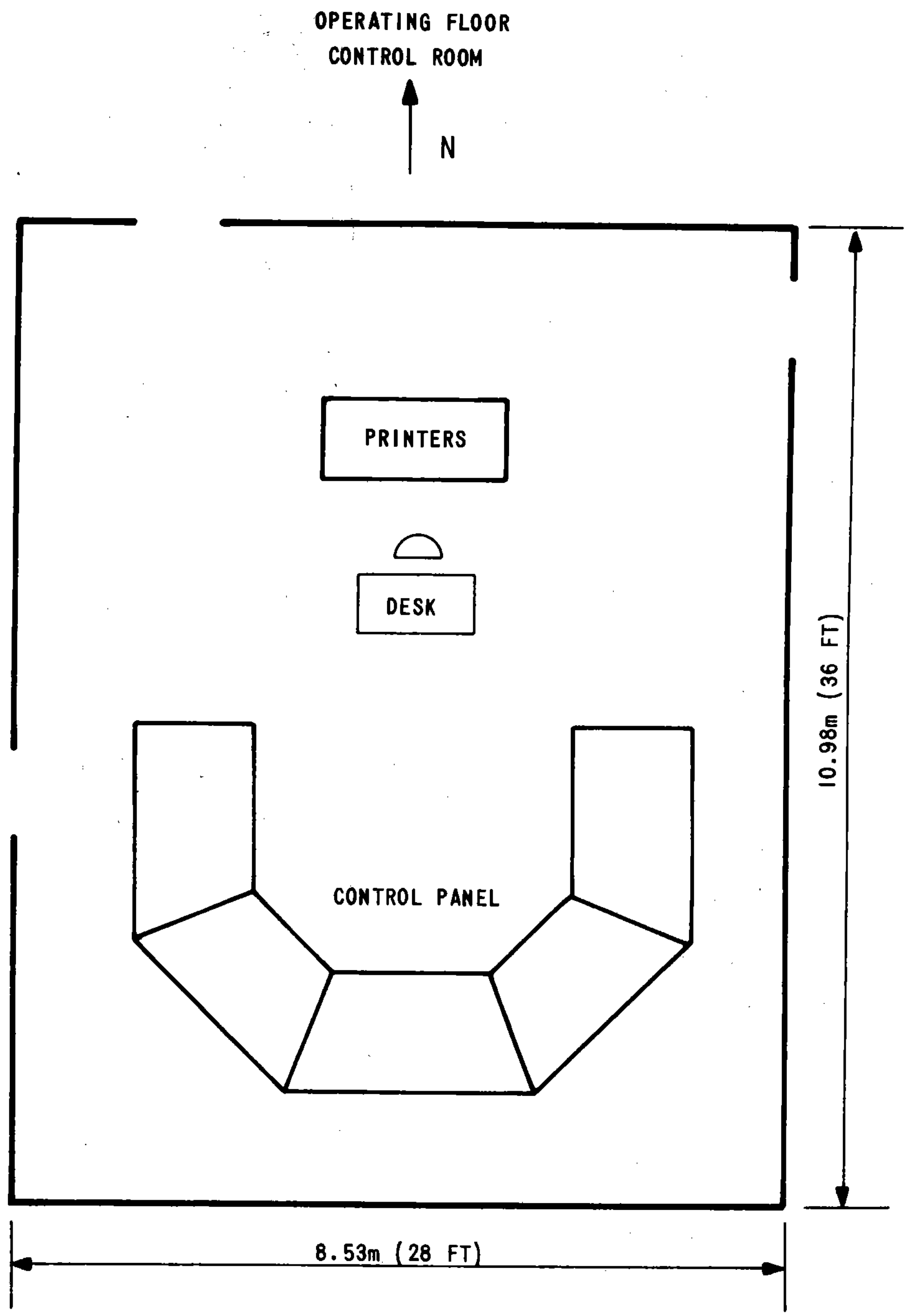


Figure 3-60. Operating Floor
Control Room

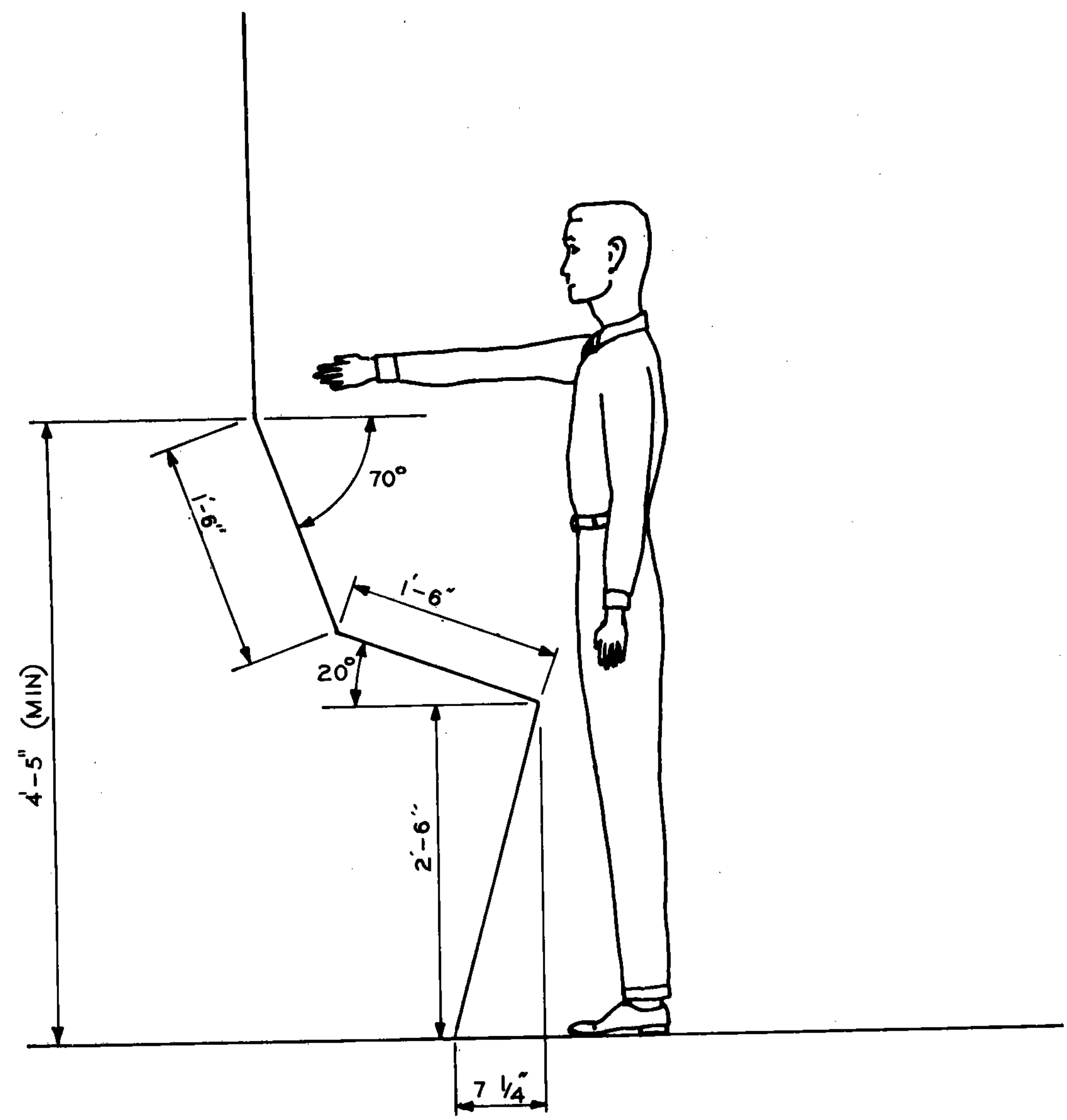


Figure 3-61. Typical Benchboard Profile
40703-VI

control room arrangement. This panel configuration consists of five straight segments, joining at 45 degree angles.

The arrangement of instruments and control devices are shown in Drawings 702132977-1 through 5. Each figure shows one of the five segments of the control and instrument panel. The assignment of functions of these segments follows the general energy flow in the plant, and equipment arrangements are, as far as possible, in functionally related groupings. Devices are identified on the panel drawings by tag numbers and the accompanying instrument list, given in Appendix F, provides descriptions of the devices.

The use of computer video displays and backlighted visual annunciators, etc. dictate that lighting levels in the control room be maintained at a low value, generally not greater than about 540 lux (50 foot-candles). The room arrangement and panel arrangement adopted permit control of illumination at the desired level.

Operator surveillance of the sky and the heliostat field is desirable, and during operation with broken cloud cover is considered essential. Surveillance may be by direct observation through windows or by use of closed circuit television. Windows providing observation are considered preferable to television systems because of the superior orientation provided, but the plant location and arrangement make viewing of the heliostat field less effective than television. It is therefore planned that the heliostat field will be monitored by use of two television cameras mounted on the receiver tower. Cameras will be provided with remote control of direction and will have zoom lenses for adjustment of field dimension.

Plant Personnel

The pilot plant staff will be organized to address the unique operating and maintenance problems associated with this first-of-a-kind solar electric plant. Staff will fall into one of the following categories.

(1) Administration
(2) Operation
(3) Maintenance
(4) Technical

The technical staff will include professional engineers who are knowledgable about the solar central receiver plant design and equipment. This staff will also have responsibility for heliostat inspection and maintenance, an activity which is given special attention because of the large number of heliostats and the fact that their operation is essential to pilot plant success.

The following paragraphs describe each of these staff categories and the personnel required.

Plant Administration. The following personnel are required.

Plant Superintendent. The Plant Superintendent has overall responsibility for the plant and its personnel. He interfaces with the utility management, with ERDA, and meets with visiting dignitaries, foreign representatives, and the general public.

Assistant Plant Superintendent. The Assistant Plant Superintendent has responsibility for and supervises plant operation. He replaces the Plant Superintendent in his absence.

Maintenance Supervisor. The Maintenance Supervisor has responsibility for maintenance of all plant equipment and components except for the heliostat field. He coordinates and plans the activities of the various maintenance shifts.

Plant Engineer. The Plant Engineer heads the technical engineering staff and has responsibility for acquisition and evaluation of plant operating data to satisfy pilot plant objectives. He is also responsible for heliostat inspection and maintenance.

This responsibility is given special attention because the heliostats are critically important to the technical and economic viability of the central receiver system. The pilot plant will be the first opportunity for a utility to gain operating experience with a large number of heliostats and to feed back this experience to those responsible for design changes and improvements.

Plant Operation. Operating staff for the pilot plant is expected to be organized on the basis of three, eight hour shifts: a morning shift, 5 a.m. to 1 p.m.; an evening shift, 1 p.m. to 9 p.m.; and an overnight shift, 9 p.m. to 5 a.m.

Morning Shift. The morning shift will operate the plant under diurnal start-up, initial loading, and subsequent full load operation; toward the latter part of the morning shift charging of the thermal storage subsystem will generally occur.

The morning shift is to include a lead plant operator who will act as shift supervisor, a control room/plant equipment operator, and one roving plant attendant.

Evening Shift. The evening shift is to continue full load operation, conclude storage subsystem charging operations, and as solar input declines, continue operation using storage generated steam. The evening shift operations will conclude with diurnal shutdown of all equipment except maintained auxiliaries.

The evening shift is expected to have a work load similar to that of the morning shift. Accordingly, the shift is similarly organized to include a lead plant operator, a control room operator, and one roving plant attendant.

Overnight Shift. The duties of the overnight operating shift will include the operation of maintained auxiliaries and operational assistance to the overnight maintenance crew. The staff requirement is 1-2 people who know the plant and its control functions, i.e. plant equipment operators.

Operating Stations and Duties. The lead plant operator/shift supervisor is to remain primarily in the control room except as required to assist the control room operator and roving plant attendant in assessing operational difficulties in the plant. His duties are primarily supervisory, although he is available to relieve the control room operator for short periods during the shift. He is responsible for plant operation during the shift, the establishment and maintenance of unit load requirements and implementation of thermal storage subsystem operational strategies.

The control room/plant equipment operator is to be stationed at the control board and is to monitor plant operational status and act to implement unit load requirements and storage subsystem strategies necessary to meet the load demand.

One roving plant attendant, or auxiliary equipment operator, is to be on duty during the morning and evening shifts. This attendant is to operate equipment not controlled from the control room, monitor and confirm proper operation of auxiliary equipment and local control loops, and investigate and correct alarm annunciators as required by the shift supervisor or control room operator.

Operating Staff Requirements. Shift assignments are expected to be rotated between shift supervisors and between plant operators on an individual basis (as opposed to "team" shift rotations) to promote maximum flexibility in shift assignment. Accounting for vacations and reasonable sick leave requirement estimates, it appears that the following operator categories and numbers of people apply.

Lead Plant Operator/Shift Supervisor	3
Control Room/Plant Equipment Operator	5- 6
Roving Plant Attendants	5- 6
Total	13-15

The uncertainty in the totals reflects the uncertainty in estimating the requirements for the overnight shift, a number which will depend primarily on the magnitude of heliostat maintenance, realignment, and repair.

Plant Maintenance. Plant maintenance is here defined to mean normal maintenance and repair of all equipment and components except the heliostats. This distinction is made because it is believed that the large number of heliostats and their distinctive nature (i.e., different from any current power plant equipment) will require, at least at this stage of development, staff with unique skills. The primary responsibilities of the plant maintenance crew will therefore be auxiliary equipment, thermal storage, the steam generator, and the turbine-generator.

Maintenance efforts for the 10 MWe Solar Pilot Plant are now expected to be emphasized during the overnight shutdown shift periods in order to minimize interference with solar generating and storage operations. Accordingly, maintenance manpower requirements are heaviest during overnight shutdown in contrast to the operator requirements just discussed. Maintenance staff is now expected to be organized on a two, eight hour shift basis: an overnight shift, 9 p.m. to 5 a.m., which coincides with plant shutdown; and a day shift, 8 a.m. to 5 p.m. The gaps in the morning and evening when no maintenance personnel are available are thought to be consistent with maintenance demands during plant operation. In the event of unexpected requirements, maintenance personnel from the nearby Coolwater Plant of Southern California Edison can be called.

Overnight Maintenance Shift. The overnight shift will bear the main responsibility for normal maintenance and repair and accordingly is apportioned the greatest part of the maintenance personnel. Diurnal cycling of the solar pilot plant is expected to require a greater than normal maintenance effort on all equipment with moving parts, especially valves.

The overnight maintenance shift is expected to include the following categories and numbers of people.

Machinist/Foreman	1
Instrument Technician	1
Electric	1
Pipefitter/Welder	1
Repairman/Apprentices	2
Laborer	1

All of these people will probably belong to the International Brotherhood of Electrical Workers (IBEW) and, hence, the senior person (in this case the machinist, more than likely) could serve as shift foreman. In actual practice, the personnel policies and duties will be consistent with SCE practices.

Day Maintenance Shift. The day shift will have the responsibility for keeping the plant running smoothly. This shift is to include two instrument technicians, one electrician, and one repairman or apprentice. In the event of unexpected requirements, maintenance staff from the nearby Coolwater Plant of SCE can be called in for assistance.

Maintenance Staff Requirements. It is not currently believed necessary to employ maintenance personnel in excess of specific shift requirements for a 5-day week. Vacations would be scheduled to avoid undue conflicts with scheduled maintenance, and overtime hours would be used during periods of abnormally heavy maintenance requirements, either scheduled or emergency. The following maintenance categories and numbers of people therefore apply.

Machinist/Foreman	1
Instrument Technician	3- 4
Electrical	2
Pipefitter/Welder	1
Repairman/Apprentice	3
Laborer	1
Total	11-12

The uncertainty in the total number reflects the possibility that an instrument technician may be required around the clock depending on heliostat performance and reliability.

Technical Staff. The plant technical staff is to have responsibility for operational and equipment problems which may arise due to the developmental nature of the solar pilot plant, and which are of such a technical nature as to fall outside the scope of the normal operation and maintenance staff capabilities. The technical staff is also to have responsibility for acquiring and evaluating operational data so that the objectives of the pilot plant can be achieved.

A portion of the technical staff will be assigned the responsibility of heliostat inspection, maintenance and performance evaluation. It is expected that heliostat inspection (breakage, dirty surfaces, etc.) will be made during daylight hours. Repair and/or realignment will be done at night.

The technical staff will be organized into two shifts: a day shift, 8 a.m. to 5 p.m.; and an overnight shift, 9 p.m. to 5 a.m.

Day Technical Shift. The day shift will have responsibility for technical analysis and decisions and/or directions regarding plant operation and equipment. This shift is to include the following professional engineers.

Mechanical Engineer	1
Analyst/Computer Engineer	1
Heliostat Engineer	1

In addition, the heliostat engineer is to have a supporting staff for heliostat inspection and emergency repair, consisting of one inspector and one instrument technician.

Overnight Technical Shift. The overnight shift has the responsibility for maintenance, repair, and alignment of heliostats. Included is cleaning of the mirror surfaces, as required. This shift is to include the following categories and numbers of people.

Instrument Technician/Foreman	1
Electrician	1
Mechanic	1
Repairman	1

Plant Organization and Personnel Requirements Summary. A proposed organization of the pilot plant staff is given in Figure 3-62.

The following tabulation gives a summary of the pilot plant staff requirements.

Administrative		
Plant Superintendent		1
Assistant Plant Superintendent		1
Maintenance Supervisor		1
Plant Engineer		1
	Total	4
Operating		
Lead Plant Operator		3
Control Room Operator		5- 6
Roving Plant Attendant		5- 6
	Total	13-15

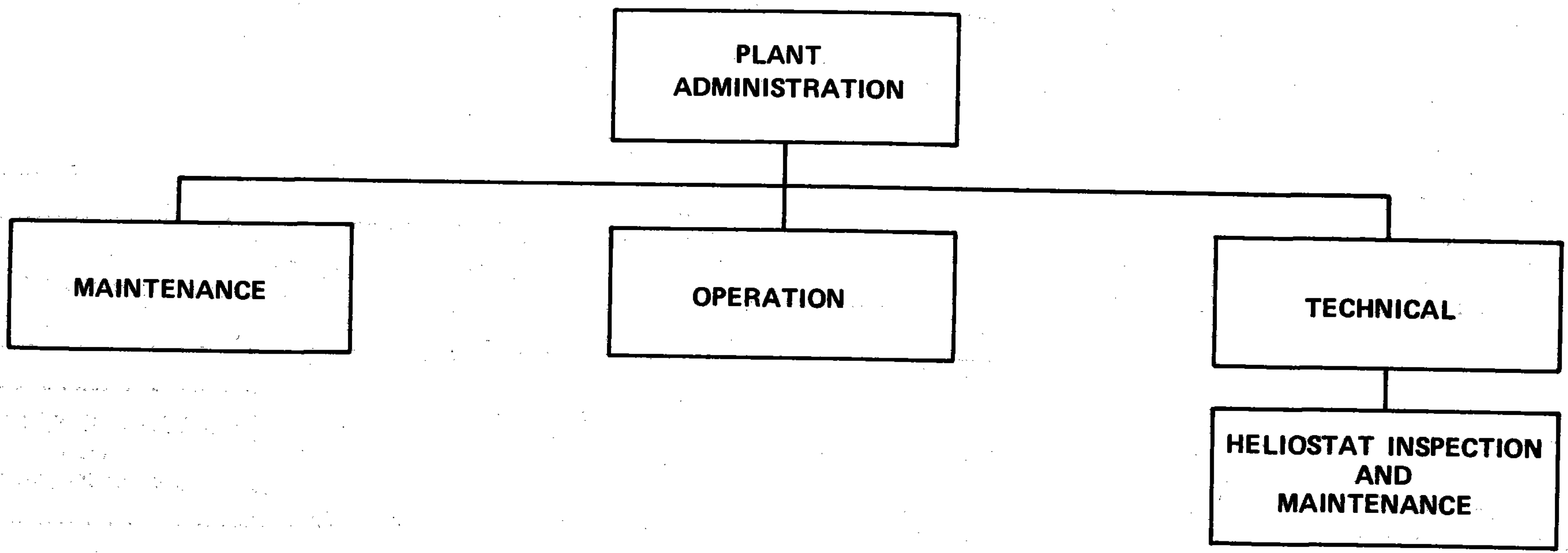


Figure 3-62. Proposed Pilot Plant Staff Organization

Maintenance		
Machinist		1
Instrument Technician		3- 4
Electrician		2
Pipefitter/Welder		1
Repairman		3
Laborer		1
	Total	11-12
Technical		
Mechanical Engineer		1
Analyst/Computer Engineer		1
Heliostat Engineer		1
Instrument Technician		1
Electrician		1
Mechanic		1
Repairman		1
	Total	7
	Total Staff	35-38

This organization and total staff requirement will doubtless change as operating experience is obtained. However, they represent the best estimates that can now be made for a first-of-a-kind solar central receiver system.

LIST OF ABBREVIATIONS AND ACRONYMS

ac	alternating current
AGMA	American Gear Manufacturers Association
ANSI	American National Standards Institute
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
AWG	American wire gage
AWWA	American Water Works Association
B&V	Black & Veatch
BIL	basic impulse level
Btu	British thermal units
Btu/hr	British thermal units per hour
C	degrees Centigrade
cc	cubic centimeters
cm	centimeters
CRT	cathode ray tube
CSP	chlorsulfonated polyethylene
CT	current transformer
dc	direct current
DDC	direct digital control
DIA.	diameter
ECT	excitation current transformer
EEI	Edison Electric Institute
EGS or EPGS	Electrical Power Generation Subsystem
E.H.	electro-hydraulic

LIST OF ABBREVIATIONS AND ACRONYMS (Continued)

EHC	electro-hydraulic controller
EL.	elevation
EPR	ethylene-propylene rubber
EPT	excitation potential transformer
ERDA	Energy Research and Development Administration
F	degrees Fahrenheit
FAA	Federal Aviation Administration
FCC	Federal Communication Commission
fpm	feet per minute
FRP	fiberglass reinforced piping
FRXLP	flame resistant cross-linked polyethylene
ft	feet
ft^2	square feet
ft/sec	feet per second
g	gravitational acceleration
gal	gallons
gpd	gallons per day
gpm	gallons per minute
HEI	Heat Exchanger Institute
HP	high pressure
hp	horsepower
HVAC	heating, ventilating and air conditioning
Hz	Hertz
IBEW	International Brotherhood of Electrical Workers

LIST OF ABBREVIATIONS AND ACRONYMS (Continued)

ID	inside diameter
IEEE	Institute of Electrical and Electronic Engineers, Inc.
IES	Illuminating Engineering Society
in.	inches
in. Hg	inches of mercury
IP	intermediate pressure
IPCEA	Insulated Power Cable Engineers Association
kg	kilograms
kg/hr	kilograms per hour
kg/s	kilograms per second
kJ/hr	kilojoules per hour
kPa	kilopascals
kV	kilovolts
kVA	kilovolt amperes
kW	kilowatts
kWh	kilowatt-hour
lb/hr	pounds per hour
LED	light emitting diode
LP	low pressure
m	meters
m^2	square meters
m^3	cubic meters
MCC	motor control center
Mcm	thousand circular mils

LIST OF ABBREVIATIONS AND ACRONYMS (Continued)

m^3/min	cubic meters per minute
MPa	megapascals
mph	miles per hour
m/sec	meters per second
MVA	megavolt amperes
MW	megawatts
MWe	megawatts (electric)
MWh	megawatt-hour
MWt	megawatts (thermal)
NACE	National Association of Corrosion Engineers
NEC	National Electrical Code
NEMA	National Electrical Manufacturers' Association
NPSH	net positive suction head
OD	outside diameter
OSHA	Occupational Safety and Health Act
PKG	packings
psi	pounds per square inch
psia	pounds per square inch absolute
psig	pounds per square inch gage
PT	potential transformer
PTC	Performance Test Code
PVC	polyvinyl chloride
RAD.	radius
rpm	revolutions per minute

LIST OF ABBREVIATIONS AND ACRONYMS (Continued)

SCE	Southern California Edison
SCFM	standard cubic feet per minute
SOW	Statement of Work
SUS	secondary unit substation
TEMA	Tubular Exchanger Manufacturers' Association
TYP	typical
UL	Underwriters Laboratories
V	volts
XLP	cross-linked polyethylene

APPENDIX A

LIST OF DATA AND INFORMATION ITEMS

APPENDIX A

LIST OF DATA AND INFORMATION ITEMS

DESIGN CHARACTERISTICS

1. Turbine Generator Type and Size - Automatic admission, nominal 15 MWe.
2. Turbine Inlet Steam Conditions - 10,101 kPa (1465 psia), 510 C (950 F).
3. Admission Steam Conditions - 3275 kPa (475 psia), 388 C (730 F).
4. Feedwater Heating Extractions - One high pressure feedwater heater, one deaerating heater, and one low pressure feedwater heater. All three extractions are located between the admission port and the exhaust duct.
5. Condenser Type and Configuration - Two pass surface condenser.
6. Feedwater Pump Stages - Main feedwater pump and feedwater booster pump. Both are single stage pumps.
7. Auxiliary Steam Supply - None.
8. Sealing Steam Requirements - See Turbine Generator Design in the EPGS/BOP, Section 3.
9. Start-up and Shutdown Characteristics and Constraints - See Plant Operation Plan in the Master Control Subsystem, Section 3.

DESIGN DISCUSSION

1. Discuss Rationale/Tradeoffs for Turbine Selection - See Turbine Generator Design in the EPGS/BOP, Section 3.
2. Discuss Rationale/Tradeoffs for Inlet/Admission Steam Condition Selection - See Turbine Generator Design in the EPGS/BOP, Section 3.

3. Discuss Rationale/Tradeoffs for Feedwater Heating Stages, Condenser Type, and Feedwater Pumping Stages - See Turbine Generator Design in the EPGS/BOP, Section 3, and also Appendix D material.
4. Describe Principal Parasitic Losses During Each Mode of Operation - See Electrical Design in the EPGS/BOP, Section 3.
5. Discuss Various Start-up/Shutdown Methods and Times for Turbine - See Plant Operation Plan in the Master Control Subsystem, Section 3.
6. Discuss Rationale/Tradeoffs for Master Control Concept - See Plant Overall Control System in the Master Control Subsystem, Section 3.

PERFORMANCE

Table A-1, Plant Performance Summary, defines pilot plant parameters and performance indicators for winter and summer solstice and equinox at 12 noon and 2 p.m. when operating from receiver steam only, and when operating from thermal storage at 7 MWe net generator output. It should be noted that the design point for the plant described is winter solstice at 2 p.m.

TABLE A-1. PLANT PERFORMANCE SUMMARY

Parameter	Plant Performance						
	Receiver Steam						Storage Steam
	Winter Solstice		Summer Solstice		Equinox		7 MWe Net
	12 Noon	2 pm	12 Noon	2 pm	12 Noon	2 pm	
Gross Turbine Efficiency	34.8	34.5	34.9	34.8	35.0	34.8	28.5
Net Turbine Efficiency	33.2	32.8	33.3	33.2	33.5	33.2	27.9
Net Plant Efficiency	26.6	25.8	26.8	26.6	27.0	26.6	
Gross Cycle Heat Rate, (kJ/kW-hr)	10,355	10,428	10,324	10,355	10,295	10,355	12,644
Net Cycle Heat Rate, (kJ/kW-hr)	10,854	10,995	10,821	10,854	10,756	10,854	12,915
Net Plant Heat Rate, (kJ/kW-hr)	13,547	13,933	13,446	13,547	13,346	13,547	
Turbine Exhaust Pressure, kPa	6.76	6.76	6.76	6.76	6.76	6.76	6.76
Feedwater Temperature, C	210	204	212	210	215	211	206
Steam Flow to Turbine, kg/hr	55,209	49,592	56,667	55,038	59,153	55,681	49,024

APPENDIX B
DESIGN REQUIREMENTS

This information is presented in Volume II, Appendix B

APPENDIX C

PRELIMINARY SYSTEM DESCRIPTIONS

ENERGY RESEARCH AND
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10 MWe SOLAR PILOT PLANT

PRELIMINARY SYSTEM DESCRIPTION
FOR
AUXILIARY COOLING WATER

GENERAL DESCRIPTION AND FUNCTION

The auxiliary cooling water system supplies condensate quality cooling water for removing waste heat from plant auxiliaries. The auxiliary cooling water is cooled in the auxiliary cooling water heat exchangers by circulating water.

The auxiliary cooling water system is shown on Piping and Instrument Diagram M1008. It is designed to provide approximately 5.7 m^3/min (1500 gpm) of 35 C (95 F) cooling water for plant waste heat removal.

The auxiliary cooling water system includes two full-capacity auxiliary cooling water pumps, auxiliary cooling water heat exchangers, auxiliary cooling water booster pumps, an auxiliary cooling water tank, auxiliary cooling water pot feeder, temperature and pressure control valves for the system and for individual items or equipment, and the interconnecting piping between these components.

The following plant equipment is served by the Auxiliary Cooling Water System.

- Air compressors
- Condenser exhausters
- EHC coolers
- Turbine lubricating oil coolers

Generator coolers

Sample table

Receiver circulating pumps

Thermal storage circulating pumps

DESCRIPTION OF MAJOR COMPONENTS

Major components in the Auxiliary Cooling Water System include the auxiliary cooling water pumps, auxiliary cooling water heat exchangers, auxiliary cooling water booster pumps, auxiliary cooling water tank, and the auxiliary cooling water pot feeder.

Auxiliary Cooling Water Pumps. The two, full-capacity auxiliary cooling water pumps are of the horizontal, split-case type. The auxiliary cooling water pumps are rated at approximately 5.7 m^3/min (1500 gpm) and 24 m (80 ft) TDH. The auxiliary cooling water pumps take suction from the outlets of the auxiliary cooling water heat exchangers and provide cooling water to the equipment served.

Auxiliary Cooling Water Heat Exchangers. The auxiliary cooling water heat exchangers are of the counterflow type designed to cool approximately 5.7 m^3/min (1500 gpm) of 41 C (105 F) auxiliary cooling water to 35 C (95 F) using 30 C (86 F) circulating water. They are provided with a control valve bypass to maintain a 35 C (95 F) auxiliary cooling water outlet under all modes of plant operation.

Auxiliary Cooling Water Booster Pumps. The two full-capacity auxiliary cooling water booster pumps are of the horizontal, split-case, two-stage type. They provide sufficient head for cooling the receiver recirculation pumps which are located near the top of the tower. The auxiliary cooling water booster pumps are rated at approximately .38 m^3/min (100 gpm) and 137.2 ft (450 ft) TDH.

Auxiliary Cooling Water Tank. The auxiliary cooling water tank is a 1,500 gallon vertical surge tank vented to the atmosphere. The tank provides suction head for the auxiliary cooling water pumps. The return header from the receiver recirculation pumps and the other plant auxiliaries empties into the tank. Makeup to the auxiliary cooling water storage tank is piped from the condensate system.

Auxiliary Cooling Water Pot Feeder. Sodium bichromate corrosion inhibiter and sodium hydroxide for pH control are introduced into the system through the auxiliary cooling water pot feeder.

SYSTEM OPERATION

The auxiliary cooling water supply is regulated to maintain pressure and temperature within acceptable limits. A differential pressure controller and control valve are installed between the cooling water supply header and return header to maintain a constant differential pressure across the various coolers within the system. The temperature of the cooling water is controlled by a temperature controller and control valve installed as a bypass around the auxiliary cooling water heat exchangers. A system supply temperature of 35 C (95 F) is maintained by mixing cooled water with uncooled water.

Independent control of the cooling water supply is required by plant equipment, the cooling requirements of which are subject to appreciable change under varying plant operation conditions, and by equipment that requires precise temperature control. Items of equipment provided with independent controls are as follows.

EHC coolers

Turbine lubricating oil coolers

Generator coolers

Air compressors are provided with automatic shutoff valves in cooling water outlet piping.

The auxiliary cooling water inlet and outlet piping for the individual items of equipment served by the system are provided with the following accessories.

An inlet isolation gate valve

A valved test connection on the inlet and outlet

A sentinel relief valve on the outlet

A temperature indicator on the outlet

A sight flow indicator on the outlet (2" and smaller lines)

An outlet isolation or throttling globe valve

Above accessories are located between the isolation valves.

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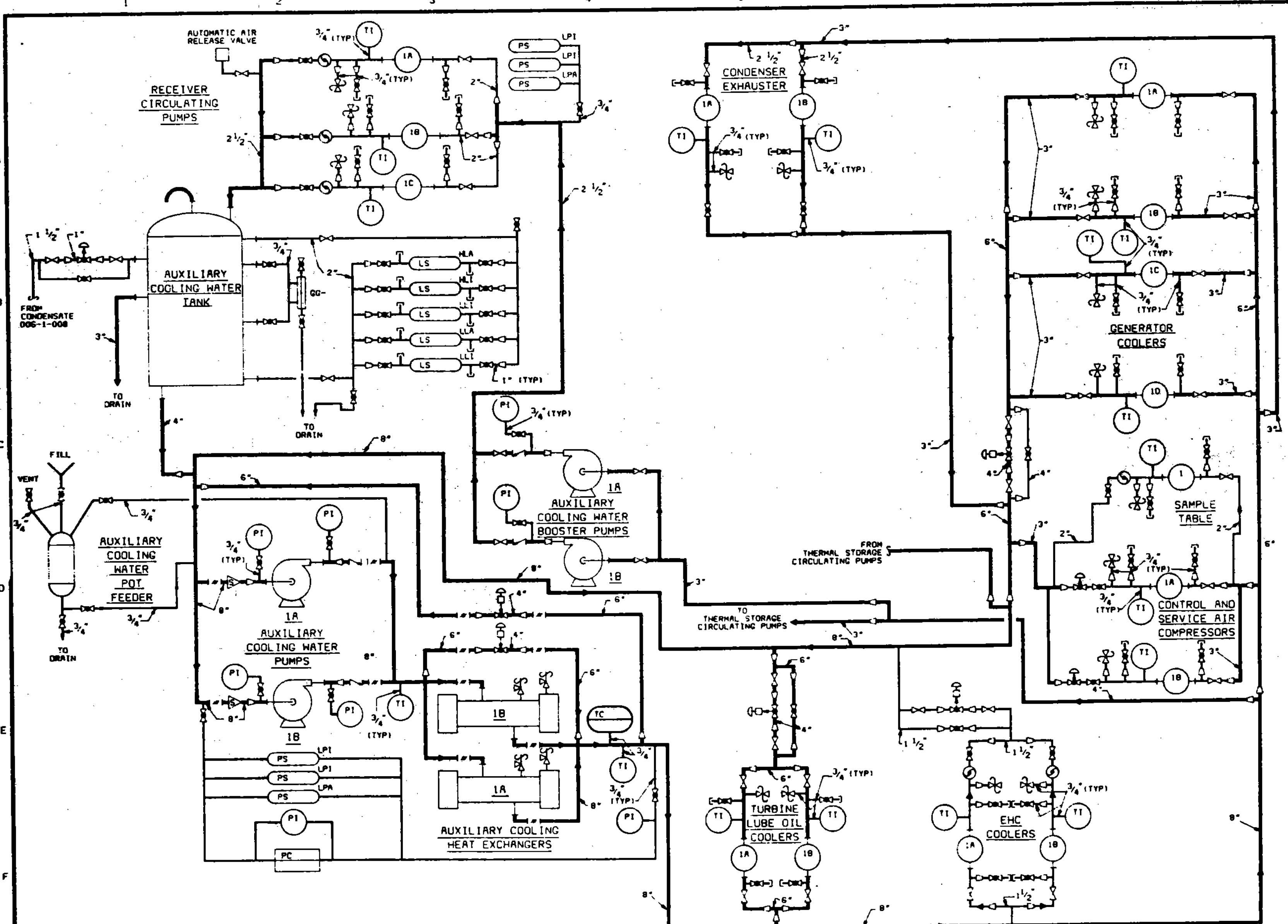

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ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION
10 MWe SOLAR PILOT PLANT

PIPING AND INSTRUMENT DIAGRAM

B&V DWG NO. | REV.

A-D NO. 800588

ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION 10 MWe SOLAR PILOT PLANT

PRELIMINARY SYSTEM DESCRIPTION FOR CHEMICAL CLEANING SYSTEM

GENERAL DESCRIPTION AND FUNCTION

The Chemical Cleaning System includes the temporary piping required for chemical cleaning the receiver, thermal storage and the presteam cycle which includes the condensate, feedwater, and the feedwater heater shells.

DESCRIPTION OF MAJOR COMPONENTS

The major components of the Chemical Cleaning System are the equipment furnished by the chemical cleaning contractor and temporary piping.

Equipment Furnished by Chemical Cleaning Contractor. This equipment includes a temporary chemical cleaning pump and a temporary heat exchanger.

Temporary Piping. Temporary piping is required for circulating, heating, and disposing of the chemical cleaning and flushing solutions.

SYSTEM OPERATION

The chemical cleaning is divided into the following sections.

(a) Condensate and feedwater system flush with demineralized water. The demineralized water is supplied to the condenser hotwell through the condensate makeup. A condensate pump forces the flushing water through the condensate system and the temporary deaerator bypass. The flushing continues through the feedwater piping and the temporary piping to drain.

(b) Feedwater heater shells hot water soak. Demineralized water is supplied from the condensate pump to the direct contact, inline heater where the water is heated. The heated water is pumped by the temporary chemical cleaning pump to the high pressure feedwater heater. Similarly, hot water is supplied to the low pressure feedwater heater through temporary pipe. After the soaking period, the water is drained through the floor drain system.

(c) Prereceiver system alkaline cleaning. The system is filled with demineralized water from the condensate pumps and heated with the inline heater. The hot water is circulated through the systems and returned to the temporary chemical cleaning pump. The alkaline cleaning chemicals are added through the temporary chemical feed line from the chemical cleaning contractor's equipment. The temperature of the solution during circulation is maintained by the temporary heat exchanger.

The chemical solution is displaced with demineralized water upon completion of the alkaline cleaning. The alkaline solution is pumped to the neutralization basin where the solution is stored for neutralization with the acid solution waste.

A relief valve is provided to dump excess solution resulting from expansion and the condensation of the heating steam.

(d) Prereceiver system acid cleaning. The acid cleaning follows the same operations as the alkaline cleaning.

(e) Receiver alkaline cleaning. The receiver is filled with demineralized water and alkaline chemicals through the temporary piping to the lower receiver header chemical cleaning connections. The solution is circulated through the tubes by the receiver recirculation pumps.

The alkaline solution is then drained by gravity to the neutralization basin for storage and mixing with the acid cleaning solution.

(f) Receiver acid cleaning. The superheater is filled and back flushed during acid cleaning operation with treated demineralized water through the superheat desuperheaters by using a condensate pump. Minimum flow through the condensate pump is maintained by the condensate recirculation system.

The receiver is filled with the acid cleaning solution through the lower receiver header chemical cleaning connections. A receiver recirculation pump is used to circulate the solution through the receiver.

A portion of the acid solution is drained from the lower receiver header to the temporary chemical cleaning pump which circulates the solution through the temporary heat exchanger to maintain the desired temperature in the receiver.

The acid solution is drained under a nitrogen blanket to the neutralization basin for neutralization upon completion of the acid cleaning phase.

(g) Thermal storage alkaline and acid cleaning. Thermal storage is chemically cleaned in a manner similar to that used for the receiver.

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PRELIMINARY SYSTEM DESCRIPTION
FOR
CHEMICAL FEED SYSTEM

GENERAL DESCRIPTION AND FUNCTION

The Chemical Feed System supplies water conditioning chemicals for the condensate-feedwater cycle and to the circulating water system.

In order to minimize corrosion in the condensate-feedwater cycle, ammonia is fed to the condensate to maintain a pH of approximately 9.4 to 9.6, and hydrazine is fed to the condensate for oxygen scavenging. Sodium phosphate is fed to the feedwater booster pump suction in order to produce the desired low level of alkalinity and phosphate residual in the feedwater.

The circulating water system is treated with sulfuric acid to reduce alkalinity and to control pH, an alkaline organic phosphate to inhibit scale, and chlorine gas to prevent biofouling of heat transfer surfaces.

DESCRIPTION OF MAJOR COMPONENTS

The major components for the Chemical Feed System are the ammonia, hydrazine and sodium phosphate feed assemblies and the chlorine gas feed equipment.

Ammonia, Hydrazine, and Sodium Phosphate Feed Assemblies. The storage and feed of all chemicals except chlorine is accomplished by the use of chemical solution tanks and positive displacement type metering pumps. The ammonia, hydrazine, and sodium phosphate feed assemblies each consist of a rectangular polypropylene tank with mixer and level switch, and two full-capacity metering pumps. Sulfuric acid and organic phosphate feed assemblies consist of a horizontal cylindrical tank and two full-capacity metering pumps.

Chlorine Gas Feed Equipment. The chlorine gas feed equipment consists of a chlorine gas cylinder, a chlorinator, and an injector.

SYSTEM OPERATION

The feed rate for each of the chemicals fed by the Chemical Feed System, except for sodium phosphate, is automatically controlled. In the condensate-feedwater cycle, hydrazine is fed in proportion to condensate flow, with ammonia being fed in proportion to condensate specific conductance. The sodium phosphate feed rate is manually adjusted as required to maintain the established alkalinity and phosphate residuals in the feedwater.

In the circulating water system, sulfuric acid is fed in proportion to cooling tower makeup water flow rate with a pH bias. The alkaline organic phosphate is also fed in proportion to the cooling tower makeup water flow rate. Chlorine is fed intermittently as required on a shock chlorination basis, with the frequency and duration of chlorine feed manually adjustable as required.

ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION 10 MWe SOLAR PILOT PLANT

PRELIMINARY SYSTEM DESCRIPTION FOR CIRCULATING WATER MAKEUP AND BLOWDOWN SYSTEM

GENERAL DESCRIPTION AND FUNCTION

The Circulating Water Makeup and Blowdown System provides makeup to and blowdown from the circulating water system. Makeup water comes from the well water header which is designed for a flow rate of 4.5 m^3/min (120 gpm). Blowdown is removed through an overflow type drain located in the cooling tower basin, and is designed for a flow rate of .15 m^3/min (40 gpm).

DESCRIPTION OF MAJOR COMPONENTS

The major components of the Circulating Water Makeup and Blowdown System are the makeup control valve and the makeup flow tube.

Makeup Control Valve. The makeup control valve is a diaphram-operated, cage-guided control valve with a positioner. It controls the amount of makeup water being added to the Circulating Water System.

Makeup Flow Tube. The makeup flow tube is a velocity head, impact, differential producing flow metering device. It is coupled with a flow transmitter for recording the makeup flow rate.

SYSTEM OPERATION

The makeup flow rate is regulated by three independent, superimposed control schemes as described below.

(1) Condensate Flow--Circulating water makeup flow is regulated as a percentage of condensate flow.

(2) Solids Concentration--Circulating water makeup flow is regulated to limit the solids concentration of the circulating water.

(3) Cooling Tower Basin Level--Circulating water makeup flow is regulated to maintain a minimum water level in the cooling tower basin.

The control schemes are superimposed in such a way that the one which requires the most makeup water overrides the others and controls the makeup control valve.

The blowdown line limits the maximum water level in the cooling tower basin by draining any excess water through an overflow type drain. It is an essential part of the solids concentration makeup flow rate.

ENERGY RESEARCH AND
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PRELIMINARY SYSTEM DESCRIPTION
FOR
CONDENSATE POLISHING SYSTEM

GENERAL DESCRIPTION AND FUNCTION

The Condensate Polishing System enables the quality of the condensate in the receiver cycle to be maintained at a high purity level during startup and normal operation.

The Condensate Polishing System is capable of removing dissolved solids by ion exchange and by filtering out suspended solids, thus preventing their deposition in the receiver and turbine.

The Condensate Polishing System protects the receiver cycle from damage caused by leakage of highly mineralized water due to condenser tube failure. In case of a massive tube leak, the Condensate Polishing System will permit orderly shutdown of the unit within a reasonable length of time.

DESCRIPTION OF MAJOR COMPONENTS

The Condensate Polishing System consists of two full-capacity, powdered resin type filter-demineralizers complete with recoating facilities. The entire Condensate Polishing System will be shop piped and mounted on a common skid.

Filter Demineralizer. Each filter-demineralizer is an ASME coded vessel, each having a filter area of approximately 7 m^2 (75 ft^2). One unit is capable of polishing the normal design condensate flow of .76 m^3/min

(200 gpm) at 1480 kPa (214.7 psia), 52 C (125 F), with the other unit being held on standby.

Recoating Facilities. Recoating facilities consist of a precoat tank, a resin tank, a mixer for each tank, and a recoat pump. Additional facilities include two holding pumps, a control panel, and associated piping and valves.

SYSTEM OPERATION

Control of the Condensate Polishing System is from a local control panel and from toggle switch control in the control room. Toggle switch control is used for placing a filter-demineralizer in service, returning a filter-demineralizer to standby status, and operating the Condensate Polishing System bypass valve.

The cation conductivity and differential pressure across each filter-demineralizer is continuously monitored. In the event of either a high-cation conductivity or high-differential pressure alarm, the filter-demineralizer is manually transferred from service status to off status as the standby unit is transferred to service status. From the off status, the recoat operation is automatically accomplished following push-button initiation. Upon completion of the recoat sequence, the filter polisher is placed in standby status, ready for service.

If a reduction in flow through a filter-demineralizer occurs, the holding pump is started automatically to maintain flow through the unit sufficient to hold the precoat in place on the filter elements.

ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION 10 MWe SOLAR PILOT PLANT

PRELIMINARY SYSTEM DESCRIPTION FOR CONDENSATE STORAGE SYSTEM

GENERAL DESCRIPTION AND FUNCTION

The Condensate Storage System provides storage for condensate makeup and dump. An adequate tank level is maintained by the Demineralized Water Storage System.

DESCRIPTION OF MAJOR COMPONENT

The major component of the Condensate Storage System is the condensate storage tank.

Condensate storage tank. The condensate storage tank has a capacity of 189 m^3 (50,000 gallons). It is located approximately 9.2 m (30 feet) north of the turbine generator building.

SYSTEM OPERATION

Level switches mounted on the condenser maintain a constant hotwell level by operating control valves in the makeup and dump lines to and from the condensate system. Makeup flows to the condenser by gravity, aided by the condenser vacuum. Condensate system dump is from the discharge of the condensate pumps.

ENERGY RESEARCH AND
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PRELIMINARY SYSTEM DESCRIPTION
FOR
CONDENSER AIR REMOVAL

GENERAL DESCRIPTION AND FUNCTION

The Condenser Air Removal System removes noncondensible gases such as air, ammonia, and carbon dioxide from the condenser shell. These gases, if not removed, would blanket the tubes and reduce the heat transfer to the circulating water if not properly eliminated. A mechanical condenser-exhauster removes the gases from the condenser, which operates at below-atmospheric pressure, and discharges them to the atmosphere.

The condenser shell is provided with a motor-operated vacuum breaker valve which admits air into the condenser to aid in turbine rotor deceleration after a unit trip.

The Condenser Air Removal System is shown on Piping and Instrument Diagram M1012.

DESCRIPTION OF MAJOR COMPONENTS

The major components of the Condenser Air Removal System are the condenser exhausters.

Condenser Exhausters. Two full-capacity condenser exhausters are provided. Only one will be in operation at any time with the other serving as a standby. The capacity of each unit is .14 m^3/min (5 SCFM) at 3.39 (1.0 inch HG abs.) suction pressure.

Each exhauster unit consists of a two-stage, water-ring, vacuum pump, an air-water separator, a seal water pump, and a heat exchanger. A silencer is located in the air discharge to the atmosphere.

SYSTEM OPERATION

During the initial high volume air removal, or hogging operation, the first stage vacuum pump handles the entire load as the condenser pressure is lowered from atmospheric to approximately 23.7 kPa (7 inches HG abs). The volume of gas is greater than the inlet capacity of the second stage, so the air and water mixture discharged from the first stage pump is released into the separator through a check valve on the interstage piping. The water remains in the separator and air flows through the check valve to the atmosphere.

The holding operation begins automatically when the volume of gas discharged from the first stage is equal to the second stage inlet capacity. This occurs at approximately 23.7 kPa (7 inches HG abs). The second stage pump suction closes the check valve, and the two stage combination then continues to lower the condenser pressure to operating level. The second stage then discharges into the separator.

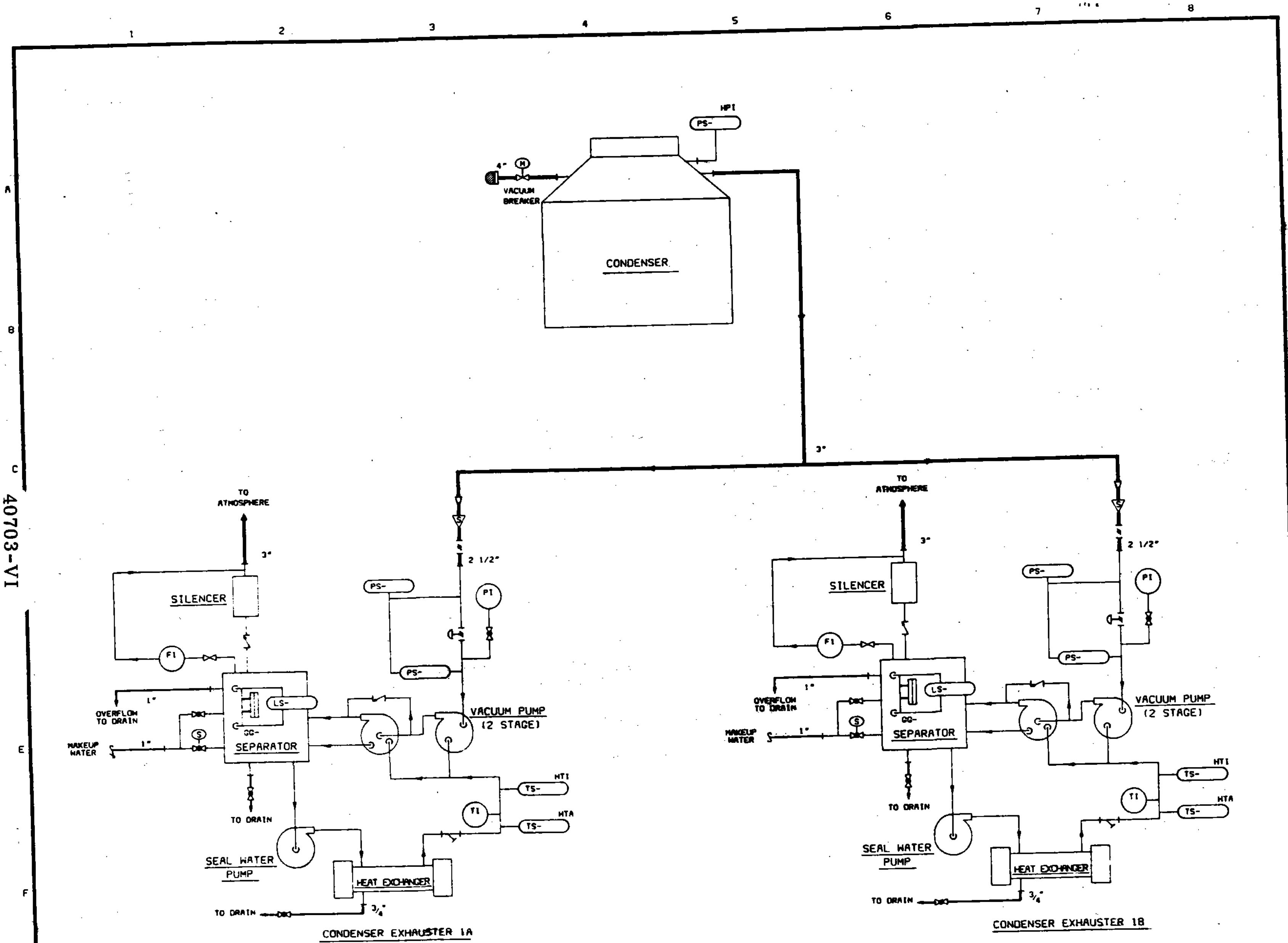
During holding operation the system leakage may be measured with a rotameter mounted on the separator, by opening the meter shut-off valve and holding the atmospheric discharge check valve closed.

Water accumulated in the separator is used to provide seal water for the vacuum pump. This water is supplied to both stages of the vacuum pump by a seal water pump and is cooled to operating temperature as it flows through a heat exchanger supplied with the condenser exhauster unit. Excess water in the separator is discharged through an internal float type overflow valve. Makeup water is supplied through a solenoid operated valve which is actuated by a level switch.

Two temperature switches are located in the seal water piping between the heat exchanger and the vacuum pumps. One switch initiates an alarm based on high seal water temperature, and the second switch trips the exhauster unit if the temperature continues to rise to the trip setting.

A pressure switch located in the neck of the condenser initiates operation of the standby exhauster. When one of the exhausters is in operation and the condenser pressure approaches a level which can cause a unit trip, the standby unit is started and the malfunctioning unit is shut down.

The condenser vacuum breaker valve is operated remotely from the control room. Its operation is interlocked with the turbine control system to prevent accidental breaking of the vacuum at high turbine speeds.



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10 MWe SOLAR PILOT PLANT

PIPING AND INSTRUMENT DIAGRAM
CONDENSER AIR REMOVAL

B&V DWG NO. M1012

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ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION
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PRELIMINARY SYSTEM DESCRIPTION FOR DEMINERALIZED WATER STORAGE SYSTEM

GENERAL DESCRIPTION AND FUNCTION

The Demineralized Water Storage System provides the high purity water needed for condenser makeup. It also supplies water to the demineralized water booster pump, sample and analysis, hydrazine tank makeup, phosphate tank makeup, and ammonia solution tank makeup.

DESCRIPTION OF MAJOR COMPONENTS

The major components of the demineralized water storage system include the demineralized water storage tank and the demineralized water booster pump.

Demineralized Water Storage Tank. The demineralized water storage tank has a capacity of 189 m^3 (50,000 gallons). It is located approximately 9 m (30 feet) north of the turbine generator building.

Demineralized Water Booster Pump. The demineralized water booster pump has a capacity of .04 m^3/min (10 gpm) at 24 m (80 ft) TDH. It provides water for sample and analysis, hydrazine tank makeup, phosphate tank makeup, and ammonia solution tank makeup.

SYSTEM OPERATION

The demineralized water storage tank level is maintained by the demineralized water supply system which operates from level switches located on the tank. The system provides water for condensate makeup by gravity flow to the condensate storage tank. A check valve is located in the line between these two tanks to prevent chemically treated condensate from mixing with the high purity demineralized water.

The demineralized water booster pump operates continuously to provide a sample for the Water Quality Control System as well as providing water for chemical dilution when required.

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PRELIMINARY SYSTEM DESCRIPTION
FOR
DEMINERALIZED WATER SUPPLY SYSTEM

GENERAL DESCRIPTION AND FUNCTION

The Demineralized Water Supply System supplies high purity water for chemical cleaning, hydrostatic testing, condensate-feedwater cycle fill and makeup, and auxiliary cooling water system fill and makeup. Water supply to the demineralizer is from existing on-site wells. The effluent from the demineralizer is directed to the demineralized water storage tanks. The regenerant is 66 Baume sulfuric acid for cation resins, and 50 per cent sodium hydroxide for the anion resins.

DESCRIPTION OF MAJOR COMPONENTS

The major components of the Deminerlized Water Supply System are the demineralizer, regeneration facilities and a control panel.

Demineralizer. The demineralizer consists of a polishing filter, three ion exchange vessels, a forced draft degasifier, and associated piping and valves. The demineralizer is arranged with a strong acid cation exchanger followed by a weak base anion exchanger followed by the degasifier. A mixed bed exchanger polishes the degasifier effluent before transfer to storage.

Regeneration Facilities. The regeneration facilities include a sulfuric acid tank, two pumps for regeneration of the cation and mixed bed exchangers, a sodium hydroxide tank, two pumps for regeneration of the anion and mixed bed exchangers, and two regeneration water pumps.

Control Panel. The control panel provides control and monitoring of the Demineralized Water Supply System.

SYSTEM OPERATION

The Demineralized Water Supply System control allows for semi-automatic or manual operation. Under normal semi-automatic service operation, the system is started and stopped by the level controls on the demineralized water storage tanks. Manual override of the semi-automatic control system is provided. System flow rates are manually set.

Regeneration of an exchanger proceeds automatically following manual initiation. Chemical wastes from regeneration are directed to an acid-brick lined, concrete basin for neutralization on a batch basis before discharge to an evaporation pond.

ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION 10 MWe SOLAR PILOT PLANT

PRELIMINARY SYSTEM DESCRIPTION FOR FIRE PROTECTION

GENERAL DESCRIPTION AND FUNCTION

The Fire Protection System for the 10 MWe Solar Pilot Plant is designed to provide fire protection for the electrical generation building, the thermal storage area, the receiver tower, and the several yard structures.

The Fire Protection System water piping is shown on Piping and Instrument Diagram M1011.

The Fire Protection System design is based on the assumption that potable well water is available at the site. This reliable source of water is available from a header that is adjacent to the plant.

A diesel engine-driven fire pump discharges into a .25 m (10 inch) header which supplies water to structures inside the heliostat field and to an underground ring header surrounding the central plant complex inside the heliostat field. The underground ring header provides the water requirements for the fire hydrants which are located approximately 61 m (200 feet) apart. Piping from the inner ring header provides fire water for the electrical generation building and the thermal storage area. A ring header is located in the generation building to supply water to the fire hose rack cabinets, sprinkler, and water deluge systems.

Water deluge systems provide protection for the generator transformer and the turbine lubricating oil system.

A halon system is provided for fire protection of the computer room and control room.

Potable fire extinguishers are provided in the control wing, receiver tower, and yard buildings for general fire protection.

Hose carts are maintained in the electrical generation building for transporting hose to the various yard hydrants. A hose house will be maintained in the vicinity of hydrants located outside the heliostat field.

DESCRIPTION OF MAJOR COMPONENTS

Major components in the fire protection system are the fire pump, fire protection equipment, and the chemical fire protection systems.

Fire Pump. One diesel engine-driven fire pump is provided for reliable operation of the fire protection system. The fire pump is a horizontal split-case, centrifugal unit selected for a capacity of 5.7 m^3/min (1,500 gpm) at 64 m (210 feet) TDH. The fire pump is located inside the heliostat field in the receiver tower.

The fire pump is furnished with an approved anti-water hammer check valve in the discharge line. A connection between the discharge check valve and the shutoff valve permits pump tests to be performed at required intervals. A permanently installed metering device arranged to discharge to plant drains is provided in the test line and will be capable of handling water flows to 175 per cent of the pump rated capacity.

The fire pump diesel engine provides engine brake horsepower of 120 per cent of rated pump requirement. The engine is furnished with governing devices, a cooling system, batteries, starting equipment, a fuel oil system, and an oil day tank.

<u>Fire Protection Equipment</u>. Manual and automatically initiated fire protection systems are provided in the generation building and in the yard structures. The various fire protection equipment provided is as follows.

(a) Fire hydrants are supplied water from the underground ring headers. A post indicating gate valve, located at the inlet of each fire hydrant, can be used to isolate the hydrant from the fire water supply.

(b) Hose cabinets with a maximum hose length of 23 m (75 feet) are provided in the generation building. Each hose cabinet includes the following.

3.8 cm (1-1/2 inch) shutoff valve.

23 m (75 feet) of 3.8 cm (1-1/2 inch) Dacron covered neoprene-lined hose. The hose cabinet design requires glass breakage for entry to the latch system.

(c) An automatically actuated water fog deluge system is provided for each of the following items of equipment.

Turbine Lube Oil Reservoir

Turbine Lube Oil Drain Tank

Turbine Lube Oil Conditioning Unit

Generator Transformer

Each water fog deluge system consists of a water supply ring piping header, fog nozzles mounted on the header, a deluge valve to control the water flow, and heat sensing devices. The deluge valve opens on a signal from a heat sensing device, admitting water to the system.

An audible fire alarm is provided in the control room to signal when a system is activated.

The automatic actuated water fog deluge systems are actuated by a combination rate of heat rise and fixed temperature device. For normal day-to-day temperature changes, the device will not be actuated. When a fire occurs, the air temperature rises very rapidly, causing the device to activate the deluge valves and fire alarms. The rate of rise action is not related to any fixed temperature and will be activated when the rate of temperature increase exceeds 8.3 C (15 F) per minute. The devices are automatic resetting with fixed temperature settings of 82 C to 88 C (180 F to 190 F).

Chemical Fire Protection Systems. Chemical fire protection is provided for Class B flammable liquid or gas and Class C electrical equipment fires. Portable hand carried fire extinguishers of multipurpose dry chemical or carbon dioxide type are provided in the control wing, receiver tower operating floor, main plant, and yard buildings for general fire protection. The multipurpose dry chemical extinguishers are suitable for protection of ordinary combustible materials as wood, paper, and rubber in Class A fires, as well as combustible liquids and electrical fires. The carbon dioxide extinguishers are suitable for fires created by flammable liquids and electrical equipment. Carbon dioxide extinguishers are located in areas of electrical equipment, since carbon dioxide does not leave a dry powder residue as do the multipurpose dry chemical extinguishers. The control room and computer room are each protected by a separate halon system, designed specifically for protection of the computer and main control panel. The halon systems will be automatically actuated by smoke detection devices.

A fire detection and alarm system is installed in the control wing for monitoring and detecting the presence of smoke or fire. The system consists of adjustable threshold ionization smoke detectors, fixed temperature thermostat detectors, an indicating panel, and audio fire alarms located in the control room. Detection circuits sound a trouble alarm located in the control room.

SYSTEM OPERATION

The elevated service water storage tank normally maintains the service and firewater system pressure.

In the event of fire, or activation of related fire protection systems which will cause the water level in the elevated service water storage tank to drop below the normal operating level of the service water system, an alarm is initiated and the diesel engine-driven fire pump is automatically started. The fire pump will continue to operate until stopped by the action of operating personnel.

The diesel engine-driven fire pump is suitable for starting manually from the central control room, or locally.

The pump is stopped manually, only from local control, after the operator has determined there is no need for continuing operation.

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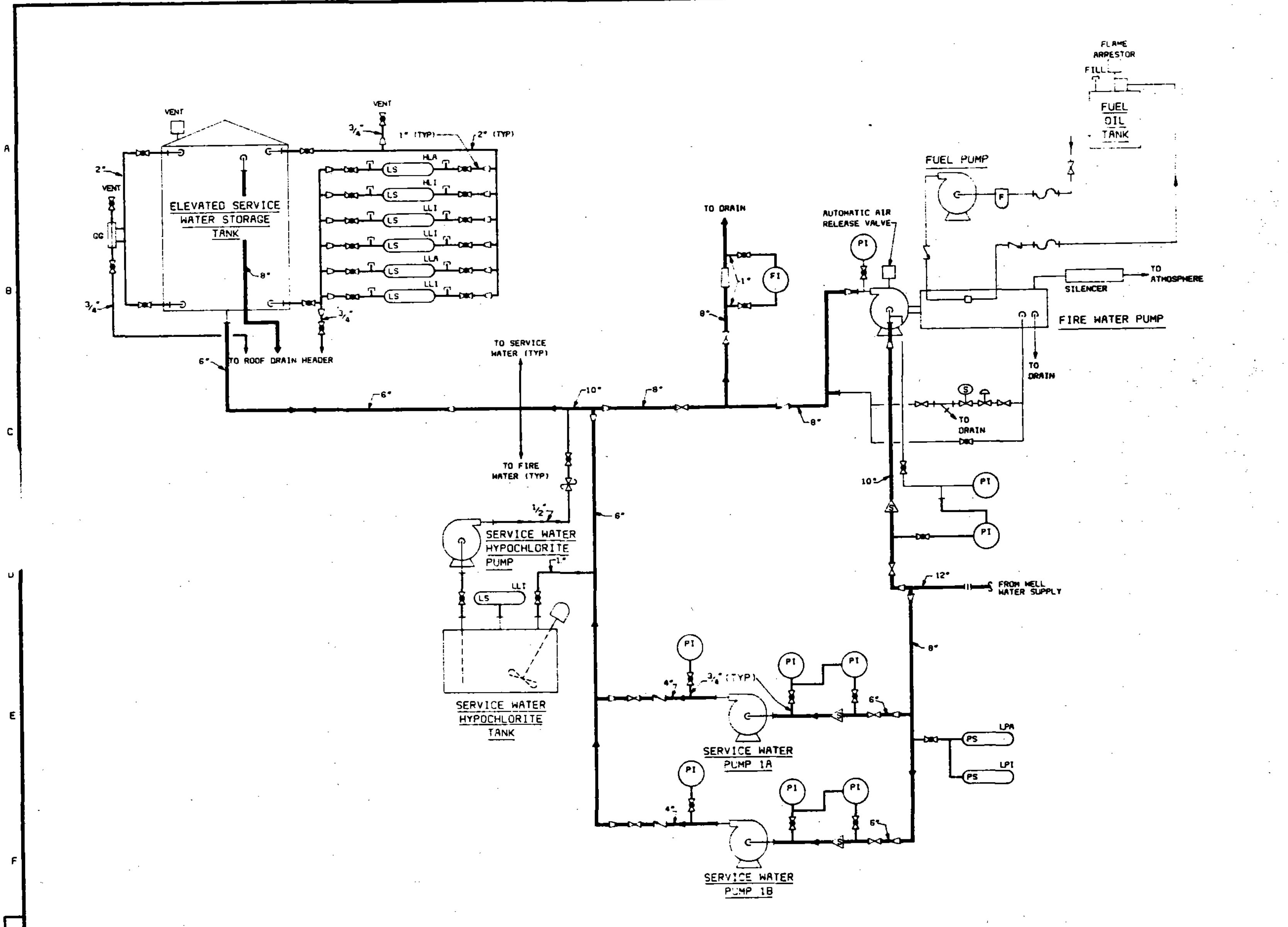

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ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION
10 MWe SOLAR PILOT PLANT

PIPING AND INSTRUMENT DIAGRAM
SERVICE AND FIRE WATER SYSTEM

B&V DWG NO. M1011

REV.

A-G NO. 800798

ENERGY RESEARCH AND
DEVELOPMENT ADMINISTRATION
10 MWe SOLAR PILOT PLANT

PRELIMINARY SYSTEM DESCRIPTION
FOR
HEATER VENTS AND DRAINS SYSTEM

GENERAL DESCRIPTION AND FUNCTION

The heater vents and drain system includes the operating and startup vents and safety relief valve vents for the deaerator and the closed feed-water heaters and the drains for the shell and channel (tube) side of the closed feedwater heaters.

Each feedwater heater, including the deaerator, is provided with a venting system for removal of noncondensible gases from the heater shell, thus allowing the heater to perform in accordance with design conditions. Improper venting reduces the thermal efficiency of the heater. Two types of vents, normal operating and startup, are utilized.

Each heater is provided with safety valves on the shell side for protection from over-pressurization due to a tube leak. Channel side relief valves are provided on the closed feedwater heaters for protection from over-pressurization due to thermal expansion of the fluid if the heaters are isolated on the channel side only. The shell side vent from the high pressure heater is vented to the deaerator which in turn is vented to atmosphere. The low pressure heater, which operates at below atmospheric pressure, is vented to the condenser.

The closed feedwater heaters are provided with drains on the shell side, and vents and drains on the channel side. These vents and drains facilitate the filling and draining of the heaters.

DESCRIPTION OF MAJOR COMPONENTS

The major components of the Heater Vents and Drains System are normal and startup operating vents, isolation valves, relief valve vents and drains.

Normal Operating and Startup Vents. The normal operating vents are in continuous service whenever the heater is in operation. Orifices restrict the vents to an optimum flow. Valved bypasses around the orifices are provided to facilitate faster venting during startup.

Isolation Valves. Air-operated isolation valves are provided in the vent headers from the high pressure and low pressure heaters. These valves are operated in conjunction with the shutdown corrosion protection system.

Relief Valve Vents. The high pressure heater shell side relief valve vent is routed to a vertical section of pipe where flashing steam is vented to the atmosphere and liquid is drained to a plant drains header.

The low pressure heater shell side relief valve vent is routed directly to a plant drains header since only a minimum amount of flashing occurs when this relief valve discharges.

Drains. The feedwater heater drains permit draining of the heaters for maintenance.

SYSTEM OPERATION

During system startup the heater normal operating and startup vents are open for rapid venting. The startup vents are closed after the shell has been vented.

During shutdown the air operated heater vent valves are closed to prevent the escape of steam (during diurnal shutdown) or nitrogen (during extended shutdown) which are used for corrosion protection.

ENERGY RESEARCH AND
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10 MWe SOLAR PILOT PLANT

PRELIMINARY SYSTEM DESCRIPTION
FOR
MISCELLANEOUS VENTS AND DRAINS SYSTEM

GENERAL DESCRIPTION AND FUNCTION

The Miscellaneous Vents and Drains System consists of all necessary vents and drains not covered in other specified vent and drain systems. It includes roof drains, plant drains, and equipment drains for which piping is required. Also included are relief valve vents and miscellaneous vents which require drain piping. Drain piping is not located above or adjacent to electrical equipment.

DESCRIPTION OF MAJOR COMPONENTS

Components of the Miscellaneous Vents and Drains System include vents, drains, piping, and bell-ups.

Vents. Vents are provided on different pieces of equipment and piping runs for safety relief valves and to facilitate draining operations.

Drain Piping. Drain piping material is dependent upon the use of the drain. Fluids carried by gravity drains are primarily noncorrosive; however, for the drainage of corrosive fluids, special pipe material is required.

Bell-ups. Bell-ups are installed in the floor near the equipment they serve.

SYSTEM OPERATION

Drain piping from the equipment is piped to the bell-ups which gravity drain to the neutralization basin. On high level, the contents of the basin are pumped to the evaporation pond.

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PRELIMINARY SYSTEM DESCRIPTION
FOR
SERVICE AND CONTROL AIR

GENERAL DESCRIPTION AND FUNCTION

The Service and Control Air System supplies compressed air to equipment and instruments. The Service and Control Air System is shown on Piping and Instrument Diagram M1010.

The system consists of two packaged reciprocating air compressor units each rated at 3.54 m^3/min (125 scfm) and 964 kPa (139.7 psia). Normal operations require that one compressor be in use. For high air usage periods, the second compressor is automatically started.

Air for use in the Service and Control Air System which does not require moisture-free air is supplied directly from the air receivers. This air is supplied to quick-disconnect couplings located conveniently throughout the plant facilities.

Two heatless desiccant air dryers are provided to dry the air intended for control and instrumentation applications. Normally one dryer is used with the other as a standby.

DESCRIPTION OF MAJOR COMPONENTS

Major components in the Service and Control Air System are the air compressors and the desicant air dryers.

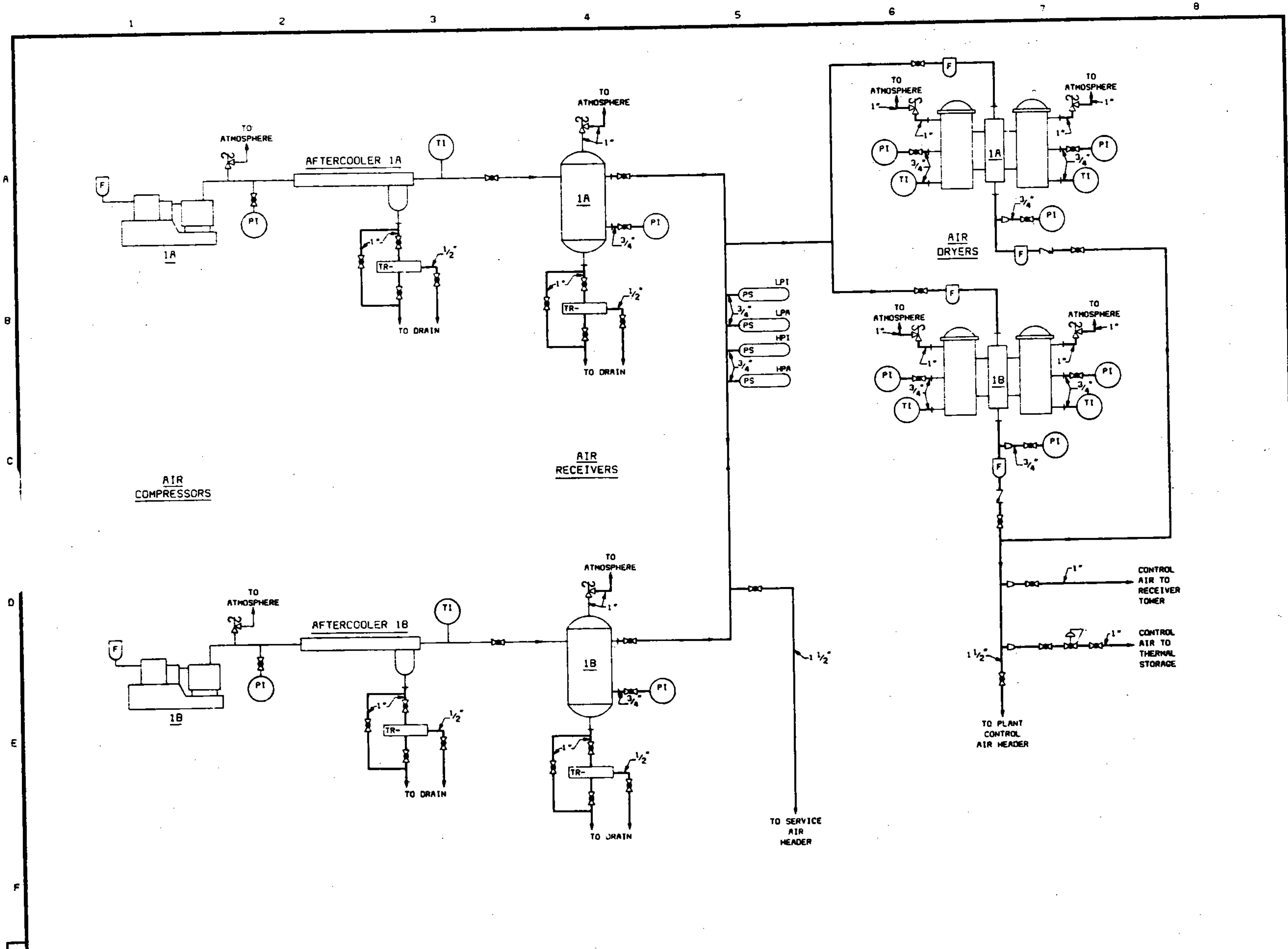
Air Compressors. Air Compressors 1A and 1B are reciprocating, non-lubricated, cylinder type compressors, each complete with its drive motor, controls, instrument panel, intake filter, aftercooler, and receiver; completely piped and mounted on a common baseplate.

Desiccant Air Dryers. The desiccant air dryers are of the dual tower, fully automatic heatless reactivation type, completely piped and mounted on a baseplate. Each air dryer is rated at 3.54 m^3/min (125 scfm) at 964 kPa (139.7 psia). A control air prefilter and afterfilter are provided for each dryer.

SYSTEM OPERATION

The air compressors are designed to cycle automatically as required to maintain air supply pressure within acceptable limits.

The desiccant air dryers are equipped to automatically cycle and reactivate to maintain the dewpoint of the discharge air below -40 C (-40 F) at line pressure.



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ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION

10 MWe SOLAR PILOT PLANT

PIPING AND INSTRUMENT DIAGRAM

B&V DWG NO. | REV.

A-C NO. 800758

ENERGY RESEARCH AND
DEVELOPMENT ADMINISTRATION
10 MWe SOLAR PILOT PLANT

PRELIMINARY SYSTEM DESCRIPTION
FOR
SERVICE WATER

GENERAL DESCRIPTION AND FUNCTION

The service water system receives potable well water from a header running by the site. Two full-capacity service water pumps take suction from the well water header and supply water to the elevated service water storage tank which supplies water to the service water system. The service water system is used for demineralizer makeup, potable water, pump seal water, and general plant service water. Maximum expected service water requirements are .53 m^3/min (140 gpm) for sanitary purposes and .23 m^3/min (60 gpm) for pump seals and plant cleanup. The Service Water System is shown on Piping and Instrument Diagram M1011.

DESCRIPTION OF MAJOR COMPONENTS

The major components of the Service Water Syster are the service water pumps.

Service Water Pumps. Each of the two full-capacity service water pumps is rated at .97 m^3/min (250 gpm) and 84 m (275 feet) TDH. The elevated service water storage tank has a capacity of 38 m^3 (10,000 gallons). A hypochlorinator tank of polyethylene construction, mixer, and manual stroke positioned chemical feed pump are located to provide potable water chlorination at the pump discharge.

SYSTEM OPERATION

The service water pumps are started and stopped by level switches mounted on the elevated service water storage tank. The level switches will allow 60 per cent of the tank capacity to be used before starting a service water pump. If one service water pump is unable to keep the water level from dropping further, the second pump will be started. Should the water level continue to fall, an alarm is sounded.

The hypochlorinator chemical feed pump will operate whenever a service water pump is running.

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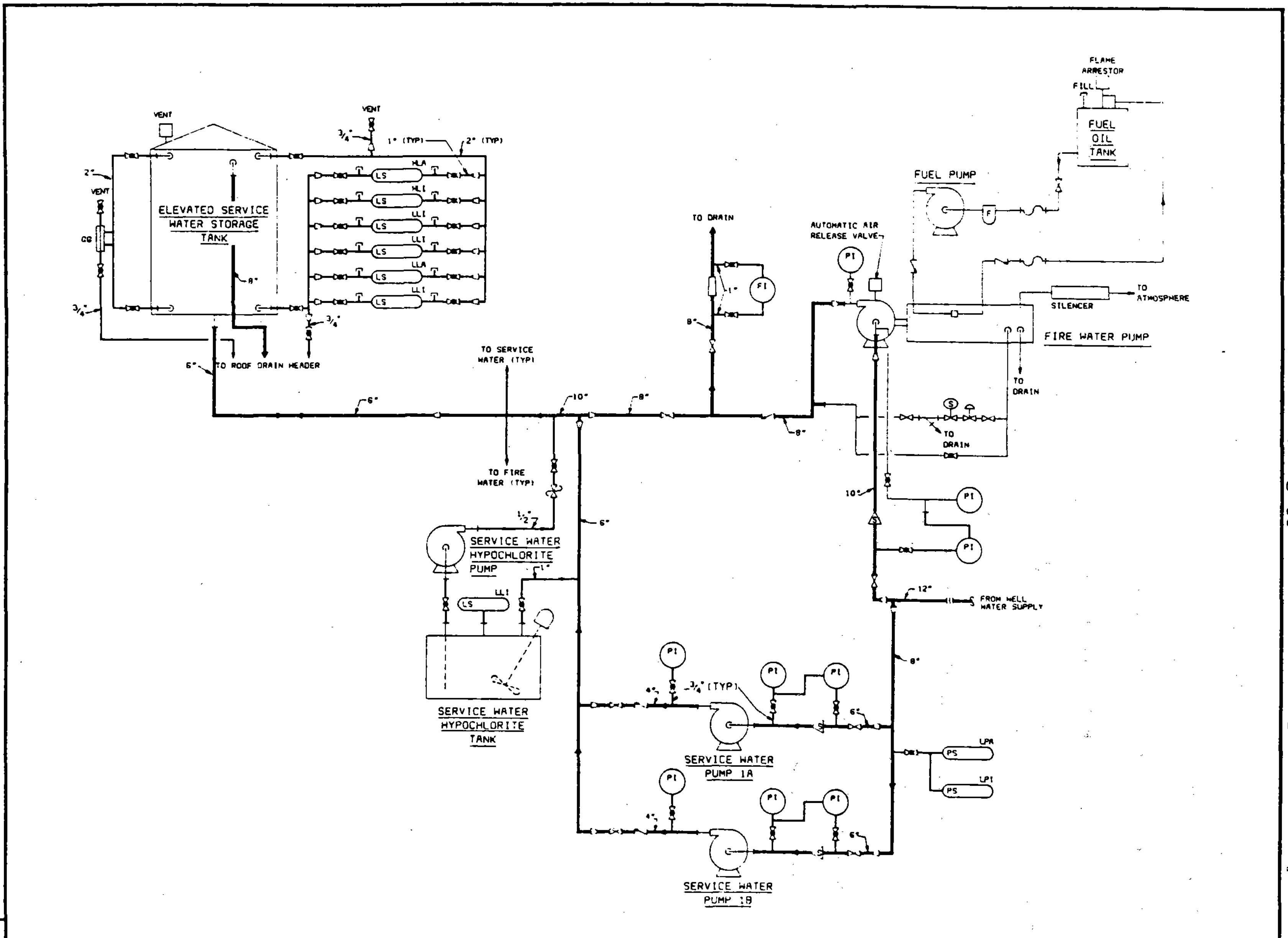

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ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION
10 MWe SOLAR PILOT PLANT

PIPING AND INSTRUMENT DIAGRAM
SERVICE AND FIRE WATER SYSTEM

B&V DWG NO. M-011
REV.

ENERGY RESEARCH AND
DEVELOPMENT ADMINISTRATION
10 MWe SOLAR PILOT PLANT

PRELIMINARY SYSTEM DESCRIPTION
FOR
SHUTDOWN CORROSION PROTECTION SYSTEM

GENERAL DESCRIPTION AND FUNCTION

The Shutdown Corrosion Protection System is used to protect the feedwater heaters, deaerator, and receiver from corrosion while the equipment is not in operation.

During diurnal shutdown the feedwater heaters are protected by maintaining approximately 136 kPa (19.7 psia) steam pressure in the heater shell, using steam generated by the thermal storage system. The deaerator is operated during diurnal shutdown, and does not require corrosion protection. The receiver pressure does not decay below atmospheric pressure during this shutdown period and therefore the receiver does not require corrosion protection.

During long-term shutdown, nitrogen blanketing is used for corrosion protection of each piece of equipment listed above.

DESCRIPTION OF MAJOR COMPONENTS

The major components of the shutdown corrosion protection include storage facilities and pressure regulators for the nitrogen system.

Storage Facilities. Storage is provided by 6649 kPA (2414.7 psia) nitrogen bottles. A bottle rack is located in the area of the feedwater heaters and deaerator to provide nitrogen for these pieces of equipment. Bottles of nitrogen for protecting the receiver are stored on the site and transported to the receiver operating floor in the tower when required.

Pressure Regulators. The permanently piped nitrogen system serving the feedwater heaters and deaerator contains a pressure reducing valve in the main distribution header. A pressure reducing valve is also located in the nitrogen piping from the receiver. These valves regulate system pressure to approximately 136 RP (19.7 psia).

SYSTEM OPERATION

During diurnal shutdown, only the feedwater heaters require corrosion protection. This is accomplished by steam blanketing with the steam generated by thermal storage. A corrosion protection steam line from the thermal storage admission steam header leads to a connection at each feedwater heater. An isolation valve is located at each heater which is open for use and closed otherwise.

During extended shutdown the feedwater heaters, deaerator, and receiver require nitrogen blanketing. Nitrogen is supplied to the feedwater heaters and deaerator by a bottle rack located near the equipment. Each piece of equipment has a corrosion protection connection which is permanently piped to a main header leading to the bottle rack. An isolation valve located in the piping near each piece of equipment is open when the nitrogen system is required; otherwise it is locked closed.

The receiver nitrogen connection is permanently piped to a bottle connection located at the operating floor of the tower. When receiver nitrogen fill is required, bottles located on the site are transported to the operating floor and connected for use.

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PRELIMINARY SYSTEM DESCRIPTION
FOR
SPACE CONDITIONING

GENERAL DESCRIPTION AND FUNCTION

The Space Conditioning System provides heating and ventilating for the enclosed areas of the plant and support structures and air conditioning for the turbine building control area.

These systems are designed to maintain an adequate environment for personnel junctions and equipment protection.

DESCRIPTION OF MAJOR COMPONENTS

The major components of the Space Conditioning System include electric unit heaters, fans and ventilaion, air handling units, water chillers, chilled water pumps, and electric resistance coils.

Electric Unit Heaters. The turbine area, maintenance building, chemical area, mechanical room, electrical switchgear area, and receiver operating floor are heated with electric unit heaters.

Fans and Ventilators. These areas heated with electric unit heaters are ventilated with supply and/or exhaust fans or power roof ventilators.

Air Handling Units. Two full-capacity air handling units are utilized. These units supply conditioned air to the control area.

Water Chillers. Two full-capacity packaged air cooled water chillers provide chilled water for the air handling units cooling coils.

<u>Chilled Water Pumps</u>. Two full-capacity chilled water pumps circulate chilled water through the water chillers and air handling units cooling coils.

<u>Electric Resistance Coils</u>. Electric resistance coils are used to heat the control area.

SYSTEM OPERATION

The space conditioning equipment serving the control areas utilizes automatic temperature controls. Temperatures in individual zones are controlled by local thermostats.

Areas requiring only heating and ventilating have electric unit heaters controlled by individual local thermostats. Ventilation fans or power roof ventilators have local manual controls.

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PRELIMINARY SYSTEM DESCRIPTION
FOR
TURBINE LUBRICATING OIL

GENERAL DESCRIPTION AND FUNCTION

The Turbine Lubricating Oil System is designed to provide continuous purification of the oil stored in the turbine lube oil reservoir. In addition to the purification equipment, the system includes lubricating oil storage facilities and transfer equipment. The Turbine Lubricating Oil System is shown in Piping and Instrument Diagram M1009.

The lubricating oil stored in the turbine lubricating oil reservoir is continuously circulated through a conditioning unit which filters the oil and also removes any accumulated water.

A Turbine Lubricating Oil Drain Tank is provided to hold the lubricating oil when it is removed from the turbine lubricating oil reservoir.

The Turbine Lubricating Oil Transfer Pump is used to move the lubricating oil from the drain tank to the reservoir or conditioner as required.

DESCRIPTION OF MAJOR COMPONENTS

The major items of equipment in the Turbine Lubricating Oil System are the turbine lubricating oil reservoir, oil conditioner, oil drain tank, and the oil transfer pump.

Turbine Lubricating Oil Reservoir. The turbine lubricating oil reservoir, supplied with the turbine generator, contains the operating lubricating oil for the turbine generator. The oil reservoir capacity is estimated to be approximately 4.5 m^3 (1,200 gallons).

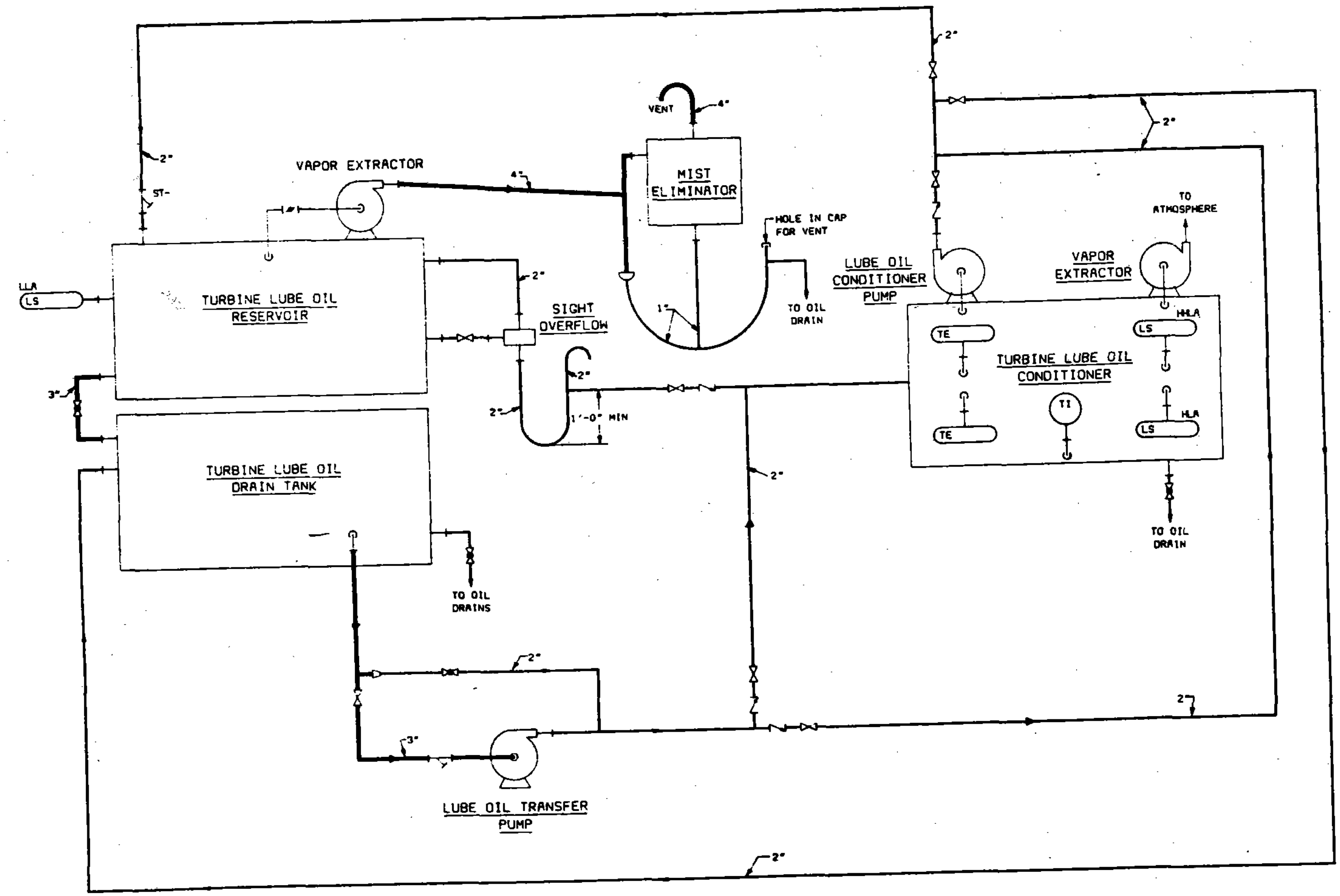
Turbine Lubricating Oil Conditioner. The oil conditioner complete with associated pumping equipment is estimated at approximately .015 m^3/min (4 gpm) capacity.

Turbine Lubricating Oil Drain Tank. The drain tank has a storage capacity of approximately 6.8 m^3 (1,800 gallons), and is sized to hold the entire volume of the lubrication system.

Turbine Lubricating Oil Transfer Pump. The oil transfer pump is a positive displacement type pump designed for an estimated capacity of .23 m^3/min (60 gpm).

SYSTEM OPERATION

The Turbine Lube Oil System is designed to continuously circulate approximately 20 per cent of the capacity of the lubricating oil reservoir through the conditioner each hour to maintain purity levels in accordance with the turbine manufacturer's recommendations. In addition, should the oil become badly contaminated, the entire charge of oil may be drained to the drain tank when the turbine is shut down. It can then be circulated through the conditioner and back to the tank, until the contaminants have been removed, and then pumped back into the reservoir.



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10 MWe SOLAR PILOT PLANT

PIPING AND INSTRUMENT DIAGRAM

B&V DWG NO.

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ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION 10 MWe SOLAR PILOT PLANT

PRELIMINARY SYSTEM DESCRIPTION FOR TURBINE SEAL STEAM AND DRAINS SYSTEM

GENERAL DESCRIPTION AND FUNCTION

The Turbine Seal Steam and Drains System regulates the seal steam supply pressure and provides a low pressure chamber for the seal steam drains.

During normal turbine operation the system prevents steam leakage to the atmosphere through the shaft seals, where the turbine shaft penetrates the shell. During diurnal shutdown the system prevents air leakage into the turbine through the shaft seals.

DESCRIPTION OF MAJOR COMPONENTS

Major Components of the turbine seal steam and drains system include a spray chamber, seal steam exhauster, and gland steam desuperheater.

Spray Chamber. The Spray Chamber condenses the steam removed from the glands, another term for seals, by the seal steam exhauster. It utilizes condensate as the spray water and returns the condensate and condensed steam to the main cycle.

Seal Steam Exhauster. The seal steam exhauster prevents seal steam from leaking to the atmosphere by providing a pressure of approximately 100 kPa (5 inches of water vacuum) at the outer shaft seal.

Gland Steam Desuperheater. The gland steam desuperheater is used to limit the seal steam temperature to approximately 204 C (400 F) by spraying the seal steam with condensate.

SYSTEM OPERATION

The seal steam system prevents air leakage into the condenser and steam leakage from the turbine. The steam seal header is maintained at approximately 136 kPa (19.7 psia). Seal steam is supplied to the header from the receiver or the thermal storage. Excess steam will automatically discharge through the three-way diverting valves.

A steam packing exhaust system consists of a spray chamber and seal steam exhauster. The system maintains a pressure of approximately 100 kPa (5 inches of water vacuum) at the shaft packing outer annulus which prevents steam leakage to atmosphere. Air which has leaked into the annulus from the atmosphere and sealing steam are routed to the spray chamber where the steam is condensed and returned to the main cycle. Air is exhausted to the atmosphere by the seal steam exhauster.

Continuous drains are provided at low points in the steam seal supply and return headers. Motor-operated valves are provided for above- and below-seat drains for the main steam stop valve. Motor-operated valves are also provided for the admission steam stop valve after seat drain.

Steam seal regulating valves maintain the pressure in the supply header at approximately 136 kPa (19.7 psia). The main steam supply and the thermal storage steam supply are regulated by pneumatic diaphragm operated control valves. Each valve is provided with a motor-operated shutoff valve for remote operations. Excess steam is dumped by a direct acting diaphragm control valve. Motor-operated bypass valves are provided for the main steam seal feed valve and the unloading valve. Relief valves on the seal steam supply header provide overpressure protection.

ENERGY RESEARCH AND
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PRELIMINARY SYSTEM DESCRIPTION
FOR
WASTE TREATMENT SYSTEM

GENERAL DESCRIPTION AND FUNCTION

The Waste Treatment System collects and treats all liquid waste streams emanating from the plant. All waste streams, except cooling tower blowdown and sanitary waste, are directed to a neutralization basin and are subsequently pumped to an evaporation pond. Cooling tower blowdown flows directly to the evaporation pond; sanitary waste is directed to on-site septic tanks.

DESCRIPTION OF MAJOR COMPONENTS

The Waste Treatment System consists a septic tank, a neutralization basin, a neutralization basin mixer, two wastewater transfer pumps, and an evaporation pond.

Septic Tank. The plant septic tank is sized to handle the sanitary waste from 20 persons per day. Another septic tank for the proposed Visitor's Center is a future installation.

Neutralization Basin. Te neutralization basin is an acid resistant basin of sufficient size to allow seven-day retention of the different wastewater streams. These streams include acid and caustic regenerant wastes from the Demineralized Water Supply System, backwash wastes from the Condensate Polishing System, steam cycle blowdown, and miscellaneous plant drains. The neutralization basin also provides for collection of plant rainfall runoff before transfer to the evaporation pond.

Neutralization Basin Mixer. The neutralization basin mixer is an electric motor-driven turbine impeller type mixer, and is mounted atop the neutralization basin. The mixer enhances the self-neutralization of acid and caustic wastes and allows the contents of the neutralization basin to be discharged at a relatively constant water quality.

Wastewater Transfer Pumps. Two full-capacity wastewater transfer pumps are supplied for transferring the contents of the neutralization basin to the evaporation pond. Each pump is of sufficient capacity to transfer the runoff which would be collected during a rainstorm of fifty-year occurrence.

Evaporation Pond. The evaporation pond collects plant wastes which include effluent from the neutralization basin, cooling tower blowdown and local rainfall runoff.

SYSTEM OPERATION

The neutralization basin collects the various wastewater streams and combines them to produce a relatively neutral effluent. The wastewater is retained in the neutralization basin until startup level is reached. At startup level, the mixer starts first and the wastewater transfer pumps start after a short time delay. The basin is pumped down to low level where the pumps and mixer are automatically turned off.

ENERGY RESEARCH AND
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10 MWe SOLAR PILOT PLANT

PRELIMINARY SYSTEM DESCRIPTION
FOR
WATER QUALITY CONTROL SYSTEM

GENERAL DESCRIPTION AND FUNCTION

A Water Quality Control System is provided to maintain the water quality control limits established for the various steam and water systems in the power plant. The system utilizes continuous monitoring of the receiver-turbine-condenser cycle, the circulating water system, and the thermal storage system. The system also provides automatic control signals for cycle chemical feed.

The pressures and temperatures of all samples are controlled to about 446 kPa (64.7 psia) and below 38 C (100 F) before analysis. Instrumentation for analysis is provided for pH, specific conductance, and cation conductivity testing. All analyzed values are indicated on the water quality panel.

In the event that significant variations from the established water quality limits occur, annunciation is provided to allow remedial action or emergency shutdown of the plant.

DESCRIPTION OF MAJOR COMPONENTS

The Water Quality Control System consists of a water quality panel and associated wiring and piping.

Water Quality Panel. The water quality panel is one-piece, free-standing, totally enclosed panel with a wet section and dry section separated by a bulkhead. The wet section contains equipment for sample pressure and temperature reduction, conductivity cells, and pH cells. The wet section also provides sample temperature indication and grab sample collection points. The dry section contains conductivity and pH monitors, a visual and audible annunciator, and control stations and switches for chemical feed pumps. Signals of selected analyses and annunciation points are retransmitted to the control room for recording and annunciation.

SYSTEM OPERATION

Proper temperature, pressure, and flow control of all samples is maintained in order for the sampling system to provide accurate and reproducible measurements.

Sample temperature indicators placed downstream of the cooling coils provide assurance of proper cooling system operation.

The pressure of each sample is controlled by a series of manually operated valves, including a rate set valve and a pressure regulating valve. Safety relief valves are also provided for each sample, and pressure reducing capillaries are provided for high pressure samples.

The rate-set valves also provide manual flow rate control of each sample.

APPENDIX D

ERDA 10 MWe SOLAR PILOT PLANT

FEEDWATER PUMPING SYSTEM

SUMMARY

This report addresses the selection of a feedwater pumping system for the 10 MWe Solar Pilot Plant. Four alternative considerations were identified and evaluated, and from these a feedwater pumping system was chosen. The four alternative considerations are pump type, pump arrangement, pump capacity, and the potential use of an auxiliary feedwater pump for diurnal operation. The evaluation considered capital cost, operating power requirements, reliability, and other specific considerations.

The selected feedwater pumping system utilizes a single stage, high-speed centrifugal feedwater booster pump in series with a single stage, high speed centrifugal main feedwater pump. Full-capacity backup for each pump is also provided.

1.0 INTRODUCTION

The selection of a feedwater pumping arrangement for the 10 MWe solar pilot plant requires many additional considerations compared to a typical fossil plant feedwater pumping design. This is primarily due to two system design requirements.

(1) The feedwater system must be capable of supplying high pressure feedwater to the receiver and/or intermediate pressure feedwater to thermal storage for the purpose of generating steam to drive the turbine. In addition, a low pressure feedwater supply is required to thermal storage for generating steam required during diurnal shutdown.

(2) This combination of unit size and receiver operating pressure requires an extremely low-flow, high-head pump input.

The feedwater pumping system must be capable of meeting the following requirements.

(1) Supplying feedwater to the receiver. The receiver drum feedwater inlet design conditions are 351 gpm at 1890 psia.

(2) Supplying feedwater to thermal storage. The thermal storage feedwater inlet design conditions are 327 gpm at 640 psia.

(3) Supplying feedwater to thermal storage for the purpose of generating the seal steam required for diurnal shutdown. The thermal storage feedwater inlet design conditions are approximately 20 gpm at approximately 10 psia.

In establishing the criteria for selecting a feedwater pumping system, four considerations were analyzed.

(1) Pump Type. Consideration was given to the use of centrifugal pumps and positive displacement plunger type pumps.

(2) Pump Arrangement. This consideration involves the decision to use a single feedwater pump which requires throttling the feedwater supply to thermal storage, or two feedwater pumps in series.

(3) Pump Capacity. This consideration involves the decision to use full-capacity or half-capacity pumps.

(4) Auxiliary Feedwater Pump. This consideration examines the desirability of using a small auxiliary pump for the diurnal shutdown operation.

The remainder of this report is divided into two sections: Section 2.0, ANALYSIS and Section 3.0, RECOMMENDATIONS. In the analysis section, evaluation criteria were established, alternative considerations were described and evaluated, and the proposed pumping arrangement was selected. The recommendations section includes the following:

(1) Suggested areas which should be rigorously evaluated to determine the final feedwater pumping system detailed design.

(2) Specific areas to be considered in determining the pumping arrangement for a commercial sized unit.

2.0 ANALYSIS

This analysis presents the evaluation criteria, a description of the alternative considerations, an evaluation of the alternative considerations, and the selected feedwater pumping system concept.

2.1 EVALUATION CRITERIA

Three criteria were used to evaluate the alternative pumping considerations. These criteria are as follows.

(1) Capital cost.

(2) Operating power requirements.

(3) Other specific considerations.

In addition, reliability was used to evaluate the pump types.

2.2 ALTERNATIVE CONSIDERATIONS

The four alternative considerations are pump type, pump arrangement, pump capacity, and the potential use of an auxiliary feedwater pump.

2.2.1 Pump Type

Three specific pump types were considered: a multi-stage centrifugal pump, a single stage, high speed centrifugal pump, and a positive displacement plunger type pump.

The multi-stage centrifugal pump considered was an engineered pump. The arrangement consists of a motor, speed increaser, and pump. The speed increaser was required since the pump operating speed was approximately 4000 rpm.

The single stage, high speed centrifugal pump arrangement consists of a motor, speed increaser, and pump. The pump will operate at a single high speed (between 10,000 to 20,000 rpm).

The plunger type pump was a vertical positive displacement pump with motor and variable speed coupling. The variable speed coupling was required since positive displacement pumps cannot be throttled to meet varying system hand-flow requirements.

2.2.2 Pump Arrangement

The pump arrangement considers the use of a single feedwater pump versus a booster pump in series with a main feedwater pump.

In the single feedwater pump arrangement (see Figure 1), the pump takes suction from the deaerator and boosts the pressure as required to deliver feedwater to the receiver. The flow path is from the pump, through the high pressure heater, and to the receiver and/or thermal storage. When delivering feedwater to thermal storage, a throttling valve must be used since the thermal storage supply pressure is much less than the receiver supply pressure.

In the second arrangement (see Figure 2), a feedwater booster pump takes suction from the deaerator and increases the feedwater pressure to that required by the thermal storage unit. The main feedwater pump then increases the pressure to receiver supply pressure. The flow path is from the booster pump, through the high pressure heater, to thermal storage and/or the main feedwater pump which delivers water to the receiver.

2.2.3 Pump Capacity

The use of two half-capacity pumps versus one full-capacity pump was considered for each combination of pump type and arrangement listed above.

2.2.4 Auxiliary Feedwater Pump

For delivering low pressure feedwater to thermal storage during diurnal shutdown operation, the use of an auxiliary feedwater pump was considered. The auxiliary feedwater pump would take suction from the deaerator and pump feedwater directly to the thermal storage supply line, bypassing the primary feedwater pumps and high pressure heater.

2.3 EVALUATION OF ALTERNATE CONSIDERATIONS

Each of the four alternate considerations is evaluated with respect to the evaluation criteria previously listed.

2.3.1 Pump Type

2.3.1.1 Multi-stage Centrifugal Pump

2.3.1.1.1 Capital Cost. The capital cost is high. If a single feedwater pump is used, it would be a nine stage engineered pump. This same pump would serve as the main feedwater pump when using two pumps in series.

2.3.1.1.2 Operating Power Requirements. Operating power requirements are high. Multi-stage pumps are designed to operate at much higher flows than 351 gpm. The low flow required for this application results in the pump operating at a low effiency (approximately 25 per cent) and thus, a high power requirement.

2.3.1.1.3 Reliability. These pumps have high reliability. Backup feedwater pumps would not be required when using the multi-stage pumps.

2.3.1.1.4 Other Specific Considerations. The NPSH required by these pumps operating at 4000 rpm would be approximately 50 feet. Long manufacturing lead times are required for this pump type.

2.3.1.2 Single Stage High Speed Centrifugal Pump

2.3.1.2.1 Capital Cost. The simplicity of a small single stage pump results in a low capital cost. The required speed increaser does add to the cost, but the combined cost of the pump motor and speed increaser is approximately 1/4 to 1/3 that of the multi-stage centrifugal or positive displacement pump cost.

2.3.1.2.2 Operating Power Requirements. Operating power requirements are moderate. These pumps are designed specifically for high head, low flow requirements. However, the required high speed results in only moderate efficiency (approximately 50 per cent).

2.3.1.2.3 Reliability. The high speed may cause excessive wear and low bearing life. Backup pumps would be required.

2.3.1.2.4 Other Specific Considerations. The required NPSH is approximately 20 feet. An inducer can be added to lower the NPSH to approximately 12 feet.

2.3.1.3 Positive Displacement Plunger Type Pump

2.3.1.3.1 Capital Cost. The capital cost is high. This is an engineered pump requiring a variable speed coupling.

2.3.1.3.2 Operating Power Requirements. The operating power requirements are low. The volumetric efficiency is approximately 92 per cent.

2.3.1.3.3 Reliability. Reliability is good.

2.3.1.3.4 Other Specific Considerations. NPSH required is low. The feedwater system would require a means of damping flow and pressure pulsations. There would be a long manufacturing lead time.

2.3.2 Pump Arrangement

2.3.2.1 Single Feedwater Pump

2.3.2.1.2 Capital Cost. The capital cost is probably lower than supplying a booster and main feedwater pump.

2.3.2.1.3 Operating Power Requirements. The operating power requirements are high. This is due to the throttling loss when supplying feedwater to thermal storage.

2.3.2.1.4 Other Specific Considerations. The high pressure feedwater heater tube side design pressure would be approximately 2100 psia. Required floor space would be low.

2.3.2.2 Two Pumps in Series

2.3.2.2.1 Capital Cost. The capital cost is slightly higher than the single pump arrangement.

2.3.2.2.2 Operating Power Requirements. The operating power requirements are low. There will not be a throttling loss when supplying feedwater to thermal storage. In addition, when feedwater is not required by the receiver, the main pump need not be operating.

2.3.2.2.3 Other Specific Considerations. If the high speed centrifugal pumps are used, both pumps would be identical, thus reducing the spare parts required. The high pressure feedwater heater design pressure would be approximately 960 psi. Floor space required would be greater than using one pump.

2.3.3 Pump Capacity

2.3.3.1 Capital Cost. Half-capacity pumps would be more expensive than full-capacity pumps because the particular system requirements result in the use of the same pump for both alternatives: one full-capacity or two half-capacity pumps.

2.3.3.2 Operating Power Requirements. With the exception of the positive displacement type pump, half-capacity pumps would have high operating power requirements due to low efficiency (multi-stage pumps--10 per cent; single stage pumps--30 per cent). The positive displacement pump would be about the same for half-capacity or full-capacity pumps.

2.3.3.3 Other Specific Considerations. Half-capacity pumps would require additional floor space.

Half-capacity pumps are at advantage when continuous operation at reduced load is required, and then it is generally necessary that the two half-capacity pump cost be not much more than the single, full-capacity pump cost. Because the half-capacity pumps would be identical to the full-capacity pumps (refer to Subsection 2.3.3.1 above), which implies double the cost, and because continuous reduced load operation is not anticipated, the use of half-capacity pumps is not advantageous to this particular situation. It is accordingly dismissed from further consideration.

2.3.4 Auxiliary Feedwater Pump

2.3.4.1 Capital Cost. Although an additional cost is involved in supplying this pump, the cost is small since the pump is well within the range of most pump manufacturers line of small pumps.

2.3.4.2 Operating Power Requirements. This pump would only operate during diurnal shutdown and would significantly reduce the feedwater system power requirements during this operation. The feedwater pressure required at thermal storage during diurnal shutdown is approximately 100 psi. If this water is supplied by a main feedwater pump, as required by a single pump concept, the operating horsepower would be approximately 1500 hp. If the water is supplied by the booster pump of a booster pump-main feedwater pump concept, the operating horsepower would be approximately 250 hp. The operating horsepower of the auxiliary feedwater pump is approximately 0.75 hp.

2.3.4.3 Other Specific Considerations. Some additional floor space and piping would be required. Backup would not be required because the primary feedwater pump could be used during diurnal operations when the auxiliary pump is out of service.

2.4 SELECTED CONCEPT

The selected arrangement is shown on Figure 3.

Based on capital cost and pump operating power requirements, the high speed, single stage centrifugal pumps were chosen. Although full backup should be provided when using these pumps, the capital cost would still be less than supplying either the multi-stage centrifugal or positive displacement pumps.

The concept of using two pumps in series was also chosen due to the operating power requirement savings when delivering feedwater to thermal storage.

The use of an auxiliary feedwater pump for diurnal shutdown also provides for a large power savings and was thus incorporated into the feedwater pumping scheme.

3.0 RECOMMENDATIONS

The analysis section of this report was based on information received from pump manufacturers. This information was approximate and cost information is subject to escalation. The final pump concept should be based on a detailed evaluation of capital cost and operating cost for each pumping arrangement.

The selected pumping concept is specifically for the 10 MWe solar pilot plant. When considering a commercial plant, the increased flow requirement will provide the multi-stage centrifugal pumps with a better design point. The commercial plant would also require a larger model high speed centrifugal pump, which is more expensive. These considerations will tend to make the pump alternatives more comparable, and thus a detailed evaluation would be required.

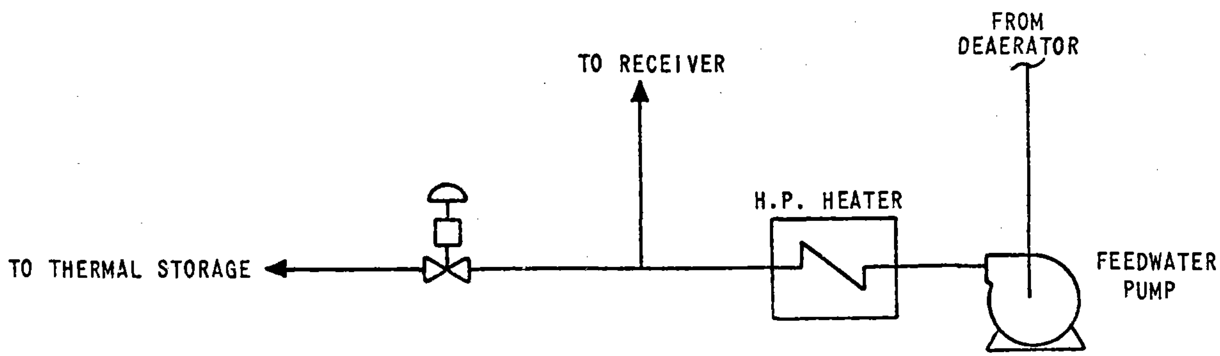
TABLE 1

ADVANTAGES AND DISADVANTAGES OF FEEDWATER PUMPING SYSTEMS

Criteria	Advantages	Disadvantages
Pump Type		
Multi-stage centrifugal	High reliability would not require a backup pump.	High cost. Long manufacturing lead time. Low efficiency. High NPSH would require raising the deaerator. Minimum required recirculation is above pump operating flow thus requiring recirculation to the deaerator at all operating conditions.
High speed centrifugal	Low cost. Higher efficiency than multi-stage pump. Single stage, easy to maintain. Low required NPSH.	High speed may cause excessive wear. Reliability is lower due to the high operating speed. Backup of 100 per cent would be required.

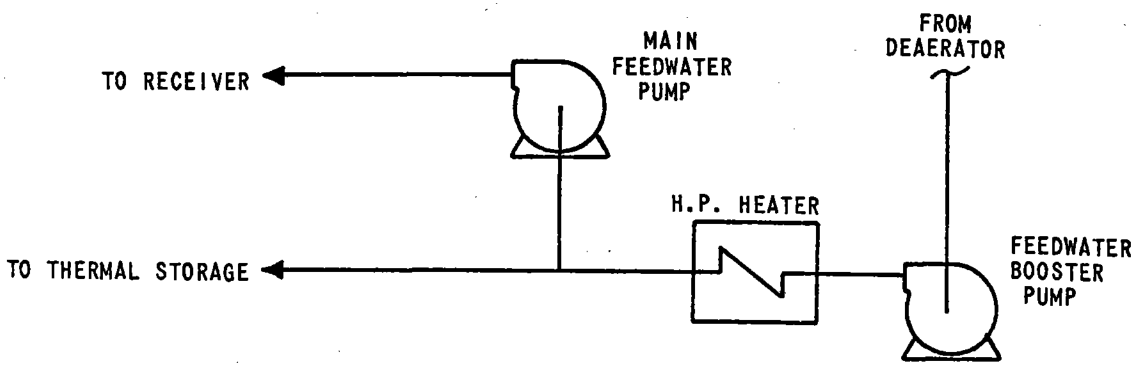
TABLE 1 (Continued)

Criteria	Advantages	Disadvantages
Plumger pump	High efficiency. No NPSH problem.	High cost. Pulsating pressure would require some type of pulsation dampner. Long manufacturing lead time.
Pump Arrangement		
Single pump	One pump used, thus less floor space required.	Throttling to thermal storage required. High heater design pressure.
Booster & main pump	No throttling required. Lower heater design press.	Two pumps required instead of one, thus more required floor space.
Pump Capacity		
Full capacity	Less expensive.	Higher operating power requirements at less than 50 per cent load.
Half capacity	Lower operating power requirements at less than 50 per cent load.	More expensive.
Auxiliary Feedwater Pump	Reduced operating power requirements during diurnal shutdown.	Additional cost. Additional floor space and piping required.



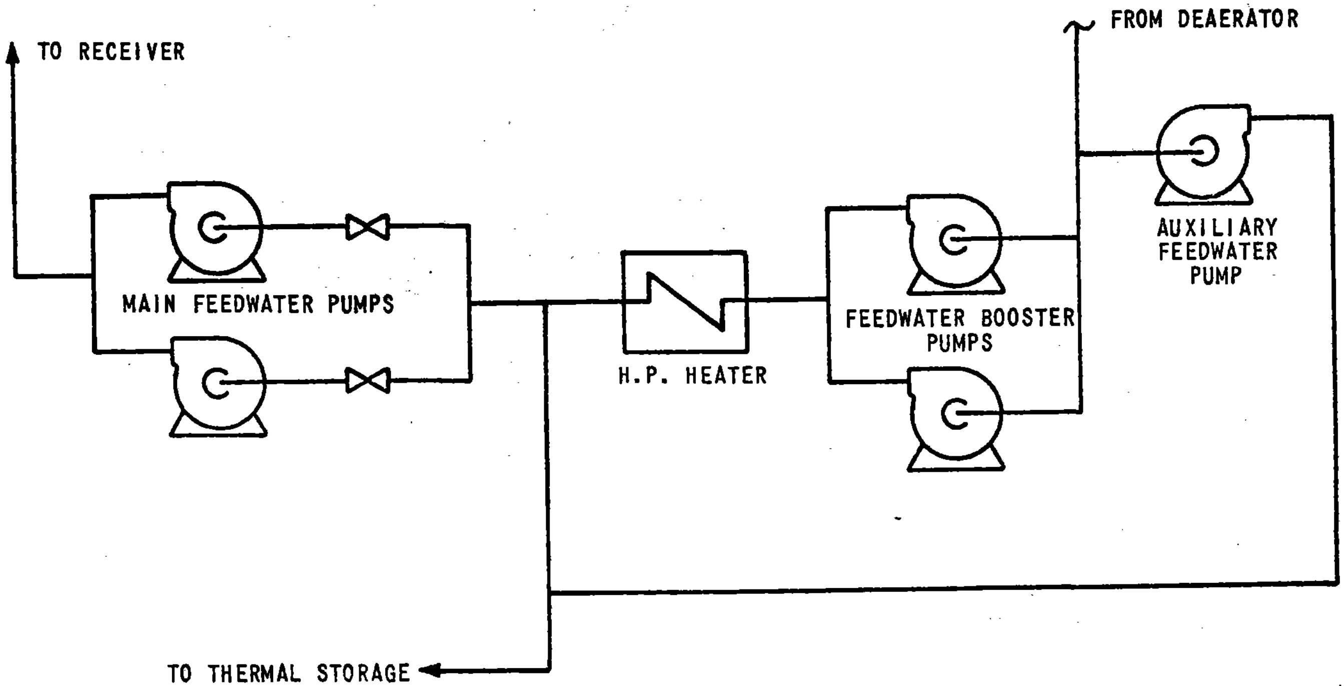
SINGLE FEEDWATER PUMP WITH THROTTLING

FIGURE 1



SERIES FEEDWATER PUMPS

FIGURE 2



SELECTED FEEDWATER PUMPING CONCEPT

FIGURE 3

ERDA 10 MWe SOLAR PILOT PLANT

HEAT REJECTION SYSTEM

SUMMARY

The plant Heat Rejection System consists of a surface condenser, wet cooling tower, and circulating water system. The Heat Rejection System dissipates heat loads of the condenser and Auxiliary Cooling Water system.

A study was performed to establish certain system conditions and to analyze and select condenser tube length and water flow configuration. System conditions established include a condenser pressure of 6.76 kPa (2 in. Hg abs), tube material of type 304 stainless steel, a condenser tube outside diameter of 22 mm (7/8 in.), a condenser tube water velocity of 2.1 m/sec (7 ft/sec), and a wet cooling tower with an 8 C (14 F) approach temperature. Based on the study results, a 6.1 meter (20 foot) tube length and a two-pass water flow configuration were selected for the condenser. Based on the established system conditions and the chosen condenser tube length and water flow configuration, two half-capacity, vertical, wet pit, circulating water pumps and concrete circulating water piping were selected.

1.0 INTRODUCTION

A heat rejection system is required to dissipate the condenser and Auxiliary Cooling System heat loads. The condenser heat load consists of turbine exhaust and seal steam heat of condensation, and also heat from the heater drains that are cascaded to the condenser. The auxiliary cooling load consists of heat removed from turbine lubricating oil coolers, generator air coolers, air compressors, and other auxiliary system coolers.

The purpose of this analysis is to evaluate systems that can be used to reject plant waste heat. The report presents requirements which the heat rejection system must satisfy, the system conditions which were established for this study, the analysis of alternate system conditions, and the recommendations for the pilot plant detailed design and 100 MWe commercial plant Heat Rejection Systems.

2.0 REQUIREMENTS

The requirements listed below and detailed in Table 1 govern this analysis.

(1) The Heat Rejection System will be capable of dissipating the 12 MWe condenser duty during winter solstice. The system will also be capable of simultaneously rejecting the Auxiliary Cooling System heat load and the condenser heat load.

(2) A wet mechanical draft cooling tower system will be used to dissipate the heat to the atmosphere.

(3) The Condenser and Condensate System will be copper free.

(4) The condenser will be positioned perpendicular to the turbine generator axis within an envelope defined by the turbine foundation.

3.0 ESTABLISHED SYSTEM CONDITIONS

The requirements of the analysis, along with experience and good engineering practice, establish the design of a portion of the Heat Rejection System. The system properties established by the above considerations are described below.

(1) Condenser Pressure. The condenser is designed to provide a turbine back pressure of 6.76 kPa (2.0 in. Hg abs) as a design basis. This is based on a proprietary Black & Veatch study of solar power plant cooling systems. That study showed that the lowest capital cost cooling system, utilizing a wet cooling tower system for a 10 MWe plant, is in the range of back pressures of 6.76 to 10.14 kPa (2 to 3 in. Hg abs).

(2) Condenser Tube Material. Type 304 stainless steel tube material was selected, because of the non-copper alloys which are considered to be acceptable tubing materials, it is the most economical.

(3) Condenser Tube Diameter. A tube with outside diameter of 22 mm (7/8 in.) was selected. For the condenser surface area required for the pilot plant, the 22 mm (7/8 in.) diameter tube is recommended by the Heat Exchange Institute Standards and is utilized by manufacturers in their standard condenser designs.

(4) Condenser Tube Water Velocity. A water tube velocity of 2.1 m/sec (7 ft/sec) represents a velocity which ensures turbulent flow, but is low enough to prevent erosion and excessive pressure drop.

(5) Cooling Tower. The wet cooling tower has an approach temperature of 8 C (14 F). This is an economical choice based on site weather data. The tower is located outside and downwind (during prevailing winds) of the heliostat field to minimize the amount of drift reaching the heliostats.

4.0 ANALYSIS

The analysis is presented in terms of identifying the alternate system conditions, evaluating the two conditions, and describing the selected concept.

4.1 ALTERNATE SYSTEM

With the above conditions fixed, the condenser was analyzed to determine tube length and flow configuration, i.e. single or two pass.

4.2 EVALUATION

4.2.1 Tube Length

Tube lengths of 4.9, 5.5, 6.1, and 6.7 meters (16, 18, 20, and 22 feet) were considered. A tube length of 6.1 meters (20 feet) is considered optimum. A 6.1 meter (20 foot) tube length makes maximum use of the space provided by the turbine foundation while keeping the condenser extension past the turbine foundation to a minimum. Tubes longer than this would waste turbine building space. Tubes shorter than this would result in a larger turbine foundation and a larger circulating water flow.

4.2.2 Condenser Water Flow Configuration

Using a 6.1 meter (20 foot) tube length, the condenser was analyzed to determine the most favorable flow configuration: single or two pass. The single pass condenser results in 20 per cent less surface area than a two pass condenser; however, it requires 40 per cent more circulating water flow. The single pass condenser is less expensive than a two pass condenser due to less surface area and size; however, the overall cooling system costs are greater for the following reasons.

(1) The larger circulating water flow for the single pass condensers would require a 1.07 meter (42 inch) diameter circulating water line as opposed to a 0.91 meter (36 inch) line for the two pass system.

(2) The larger circulating water flow would also require larger circulating water pumps and increased pumping energy.

(3) The single pass condenser has a smaller temperature rise, 2.3 C versus 4.0 C (4.3 F versus 7.2 F), than the two pass condenser, thus decreasing the duty on the cooling tower. However, the larger circulating water flow, requiring a larger cooling tower, more than offsets the decrease in duty. The larger temperature rise also allows the cooling tower to operate more efficiently.

(4) The single-pass condenser requires routing a circulating water line either around, through, or under the turbine foundation. This would result in a longer circulating water line or a more expensive turbine foundation.

4.3 SELECTED CONCEPT

The two pass condenser, with a 6.1 meter (20 foot) tube length, is the system selected for the pilot plant. Based on the circulating water flow required by the two pass system, two half-capacity, vertical, wet pit pumps were selected for circulating water pumps. These pumps were chosen over horizontal, dry pit pumps; however, both pump types are comparable with respect to cost and performance. Two half-capacity pumps are considered adequate since a vertical, wet pit pump of this small size is reliable and of proven design. Concrete circulating water piping was selected because it is in economical choice for the long lengths of circulating water pipe required. The design properties of the heat rejection system are shown in Table 2.

5.0 RECOMMENDATIONS

5.1 PILOT PLANT DETAILED DESIGN

This preliminary evaluation of the solar pilot plant is based on assumptions that are the result of engineering experience. The detailed design of the pilot plant Heat Rejection System should include an analysis that considers various combinations of the following parameters.

(1) Cooling tower approach temperature.

(2) Condenser tube diameters.

(3) Condenser tube lengths.

A more nearly optimum design may be established by varying the above parameters in the detailed study.

5.2 100 MWe COMMERCIAL PLANT

The results of this analysis do not apply to a commercial size solar power plant. The optimum design condenser pressure will probably change due to different economic criteria and power output requirements. A detailed study of the cooling tower, the condenser, and the circulating water pumps and piping will be required.

TABLE 1

DESIGN REQUIREMENTS

Item	Value
Atmospheric Conditions	
Design Wet Bulb, C (F)	23 (74)
Winter Solstice Wet Bulb, C (F)	23 (74)
Cooling Tower	
Type	Wet, Mechanical Draft
Condenser	
Tube Material	Non-Copper Alloy
Duty, kJ/hr (Btu/hr)	8.2×10^7 (7.8×10^7)
Maximum Width Based on Turbine Foundation, meters (feet)	2.7 (9)
Maximum Height Based on Turbine Foundation, meters (feet)	4.3 (14)
Turbine	
Type	Condensing
Design Exhaust Flow, kg/hr (lb/hr)	36,644 (80,802)

TABLE 2

HEAT REJECTION SYSTEM DESIGN PARAMETERS

Condenser	
Surface Area, m^2 (ft^2)	1,597.9 (17,200)
Tube Material	304 SS
Tube Outside Diameter, mm (inches)	22 (0.875)
Tube Length, meters (feet)	6.1 (20)
Tube Water Velocity, m/s (fps)	2.13 (7)
Tube Thickness, BWG	22
Design Heat Load, kJ/hr (Btu/hr)	8.2×10^7 (7.8×10^7)
Design Back Pressure, kPa (in. Hg abs)	6.76 (2.0)
Design Cold Water Temperature, C (F)	31 (88)
Design Temperature Rise, C (F)	4 (7.2)
Circulating Water Flow, m^3/min (gpm)	82 (21,670)
Design Cleanliness Factor	0.85
Cooling Tower	
Approach Temperature, C (F)	8 (14)
Range, C (F)	4 (7.2)
Design Wet Bulb Temperature, C (F)	23 (74)
Water Flow, m^3/min (gpm)	94.6 (25,000)
Circulating Water Pipe	
Material	Concrete
Water Velocity, m/sec (ft/sec)	2.4-2.7 (8.0-9.0)

TABLE 2 (Continued)

Circulating Water Pumps	
Number	2
Per Cent Capacity, each	50
Type	Vertical Wet Pit
Capacity, m^3/min (gpm)	47 (12,500)

APPENDIX E

PIPING AND INSTRUMENT DIAGRAMS

PIPING AND INSTRUMENT DIAGRAM LEGEND

ABBREVIATIONS

AT	ANALYZER TRANSMITTER
CC	CONDUCTIVITY CELL
CD	CONTROL DRIVE
CP	CONTROL PANEL
EH	EXHAUST HEAD
EJ	EXPANSION JOINT
FC	FLOW CONTROLLER
FE	FLOW ELEMENT
FH	FLEXIBLE HOSE
FI	FLOW INDICATOR
FS	FLOW SWITCH
FT	FLOW TRANSMITTER
GG	GAUGE GLASS
GP	GAUGE PANEL
HFI	HIGH FLOW INTERLOCK
HLA	HIGH LEVEL ALARM
HLI	HIGH LEVEL INTERLOCK
HPA	HIGH PRESSURE ALARM
HPI	HIGH PRESSURE INTERLOCK
HTA	HIGH TEMPERATURE ALARM
HTI	HIGH TEMPERATURE INTERLOCK
L	LEVEL
LC	LEVEL CONTROLLER
LFA	LOW FLOW ALARM
LFI	LOW FLOW INTERLOCK
LI	LEVEL INDICATOR
LLA	LOW LEVEL ALARM
LLI	LOW LEVEL INTERLOCK
LPA	LOW PRESSURE ALARM
LPI	LOW PRESSURE INTERLOCK
LS	LEVEL SWITCH
LT	LEVEL TRANSMITTER
LTA	LOW TEMPERATURE ALARM
LTI	LOW TEMPERATURE INTERLOCK
PC	PRESSURE CONTROLLER
PI	PRESSURE INDICATOR
pH	pH
PS	PRESSURE SWITCH
PT	PRESSURE TRANSMITTER
RD	RUPTURE DISC
SC	SAMPLE COIL
SJ	SWIVEL JOINT
SS	STAINLESS STEEL
ST	STRAINER OR FILTER
TC	TEMPERATURE CONTROLLER
TE	TEMPERATURE ELEMENT
TI	TEMPERATURE INDICATOR
TR	TRAP
TS	TEMPERATURE SWITCH
TT	TEMPERATURE TRANSMITTER
TW	TEMPERATURE WELL
UH	UNIT HEATER
VT	VACUUM PRESSURE TRANSMITTER
VS	RELIEF VALVE VENT SEAL
ZS	LIMIT SWITCH

PREFIX H, HIGH
PREFIX L, LOW

FLOW DIAGRAM CONNECTION NUMBERING SYSTEM:

XXX-XX-XXX

- TERMINATING FLOW DIAGRAM NUMBER
- CONNECTION NUMBER
- ORIGINATING FLOW DIAGRAM NUMBER

THE FLOW DIAGRAM PREFIX "M1" WILL NOT BE INCLUDED.

VALVES

- GATE
- GLOBE
- PLUG
- BALL
- NEEDLE
- CHECK
- STOP CHECK
- AIR OPERATED CHECK
- AIR OPERATED CHECK WITH CLOSING HANDWHEEL
- BUTTERFLY
- VALVE BYPASS
- SAFETY OR RELIEF
- DIAPHRAGM
- IN-LINE SAFETY OR BACK PRESSURE
- ANGLE
- THREE WAY
- FOUR WAY
- MOTOR OPERATED
- SOLENOID OPERATED
- PISTON OPERATED WITH POSITIONER
- DIAPHRAGM OPERATED WITH POSITIONER
- PISTON OPERATED
- SELF CONTAINED CONTROL
- DIAPHRAGM OPERATED SPRING CLOSING
- DIAPHRAGM OPERATED SPRING OPENING
- DIRECT FLOAT OPERATED
- AUTOMATIC RECIRCULATION CONTROL

ACCESSORIES

- RATE OF FLOW METER
- DISPLACEMENT METER
- SIGHT FLOW INDICATOR
- STRAINER, Y-TYPE
- STRAINER, CONE OR PLATE TYPE
- STRAINER, BASKET TYPE
- FILTER, CARTRIDGE
- STRAINER, DUPLEX BASKET TYPE
- EXPANSION JOINT
- TR — TRAP
- GAUGE GLASS
- ORIFICE
- FLOW NOZZLE
- PITOT TUBE, ANNUBAR
- FLOW TUBE
- OPEN DRAIN FUNNEL
- FLEXIBLE HOSE
- ROOF OR FLOOR DRAIN
- CLOSURE, SCREWED
- CLOSURE, WELDED CAP
- HEAD CHAMBER
- EXHAUST HEAD
- SAFETY VALVE DRIP PAN
- VENT SEAL
- LINE SIZE CHANGE
- INSULATING FLANGE OR BUSHING
- PRESSURE BREAKDOWN ELEMENT
- BLIND FLANGE
- DETECTOR

INSTRUMENTS

LOCAL INSTRUMENT

** LOCAL ELECTRICAL DEVICE

** ELECTRONIC TRANSMITTER OR CONTROLLER
- FIRST LINE - TRANSMITTER DESIGNATION
- SECOND LINE - TRANSMITTER DESIGNATION OR SERVICE
- THIRD LINE - DESIGN SET POINT (FOR LOCAL CONTROL)

** PNEUMATIC TRANSMITTER OR CONTROLLER
- FIRST LINE - TRANSMITTER DESIGNATION
- SECOND LINE - RECEIVER DESIGNATION
- THIRD LINE - DESIGN SET POINT (FOR LOCAL CONTROL)

** INSTRUMENT FUNCTIONS
- CMP - COMPUTER (DATA LOGGING)
- CNT - CONTROL
- EHC - TURBINE CONTROL
- IND - INDICATOR
- RCD - RECORDER
- LCNT - LOCAL CONTROL
- LIND - LOCAL INDICATION

PIPING

- PIPING 2-1/2" AND LARGER
- PIPING 2" AND SMALLER
- TEMPORARY PIPING
- PIPING FURNISHED WITH EQUIPMENT
- EXISTING PIPING
- FUTURE PIPING

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10 MWe SOLAR PILOT PLANT
PIPING AND INSTRUMENT DIAGRAM LEGEND

B&V DWG NO. M1001
REV.

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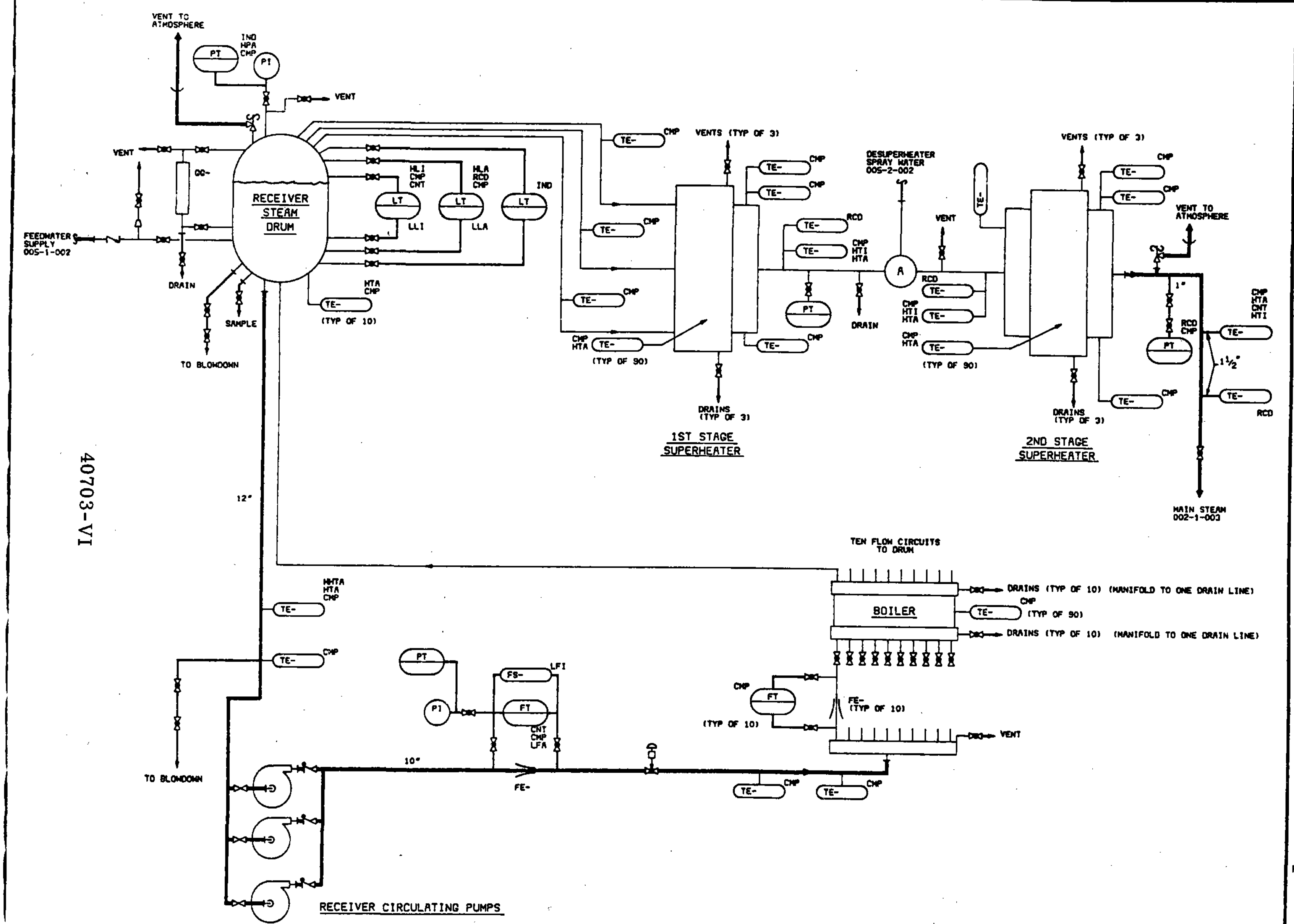

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10 MWe SOLAR PILOT PLANT

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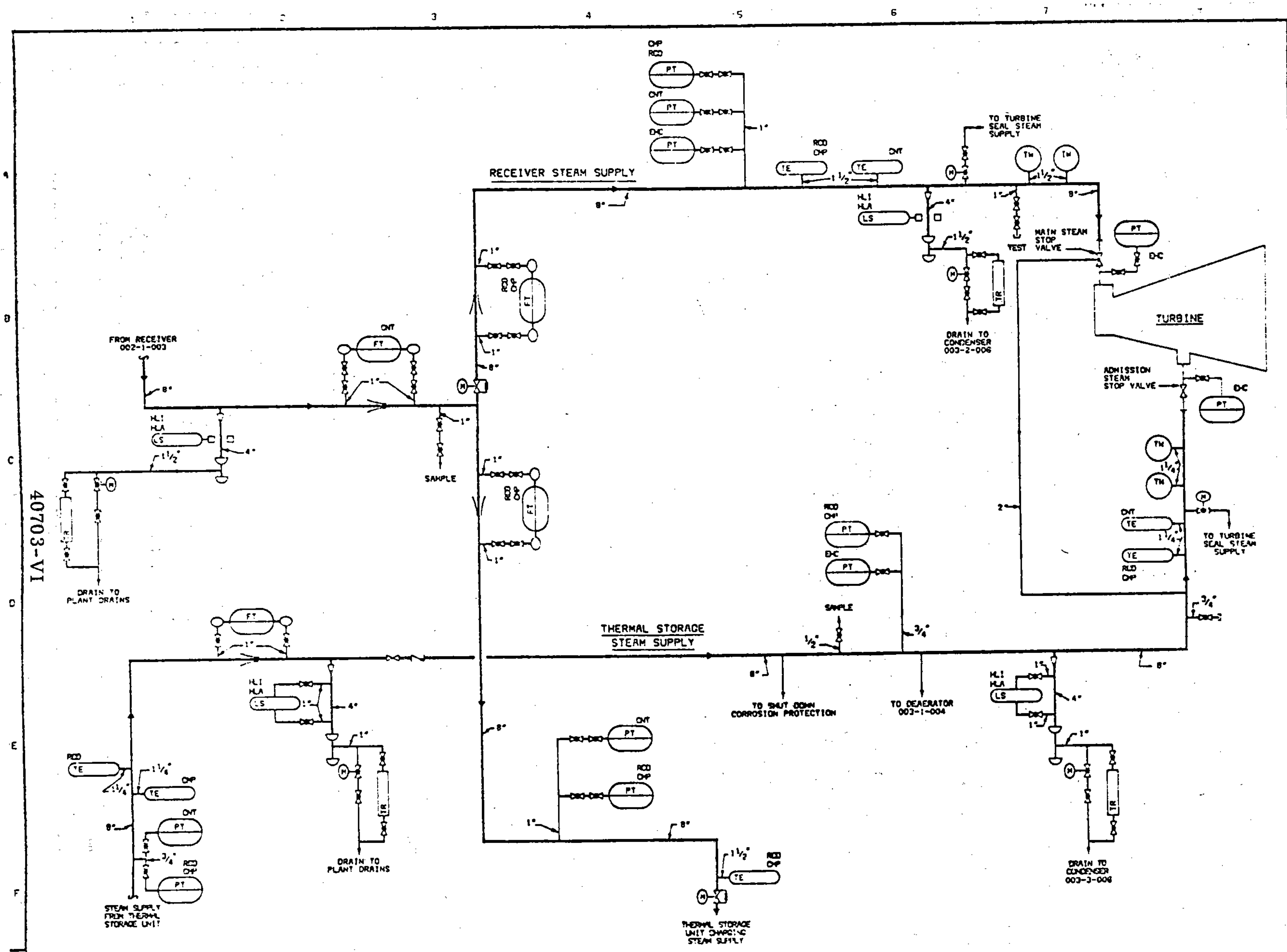

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ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION

10 MWe SOLAR PILOT PLANT

PIPING AND INSTRUMENT DIAGRAM HIGH PRESSURE STEAM

M1003

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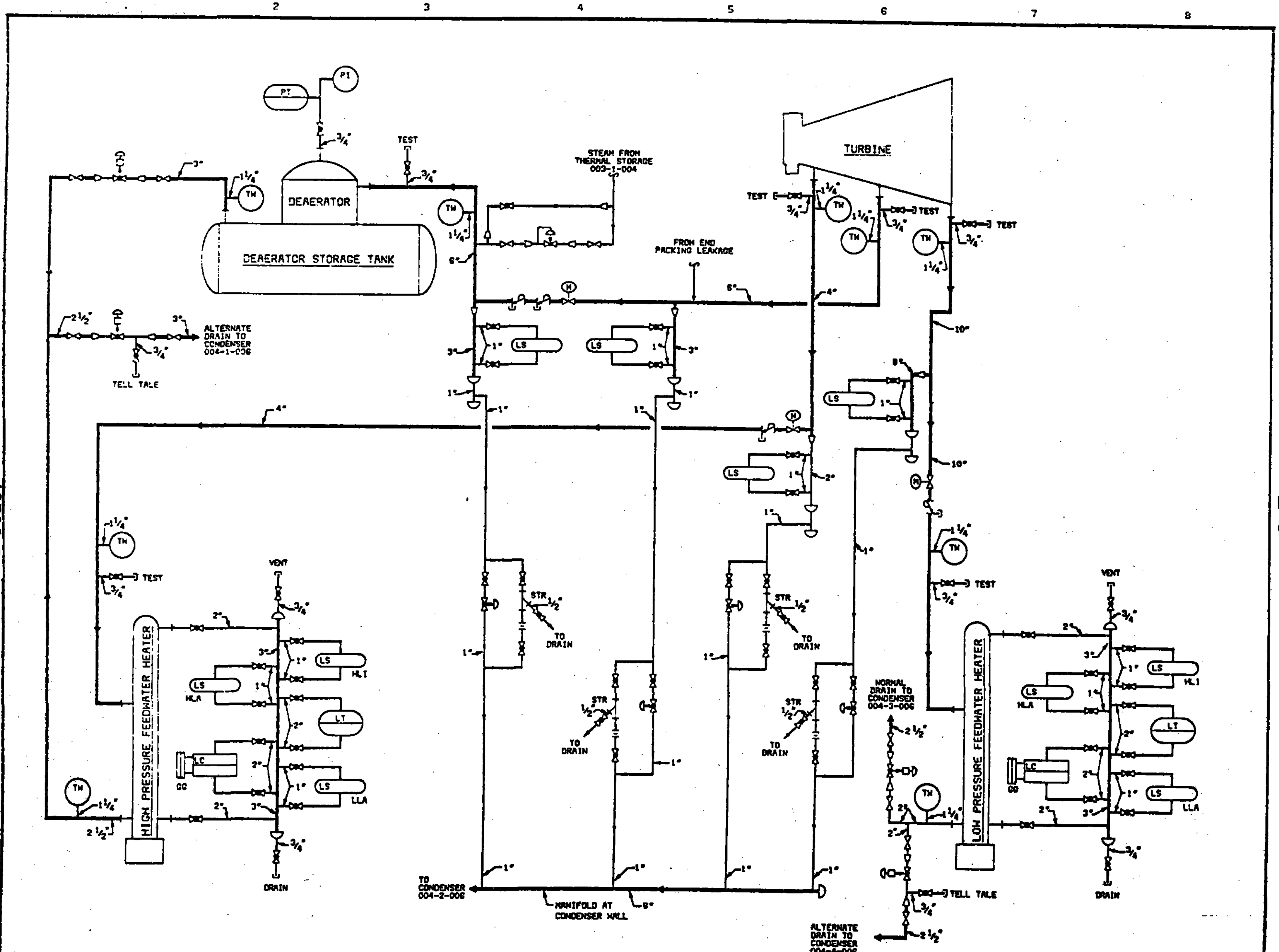

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ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION
10 MWe SOLAR PILOT PLANT

PIPING AND INSTRUMENT DIAGRAM
EXTRACTION STEAM AND HEATER DRAINS

B&V DWG NO. M1004

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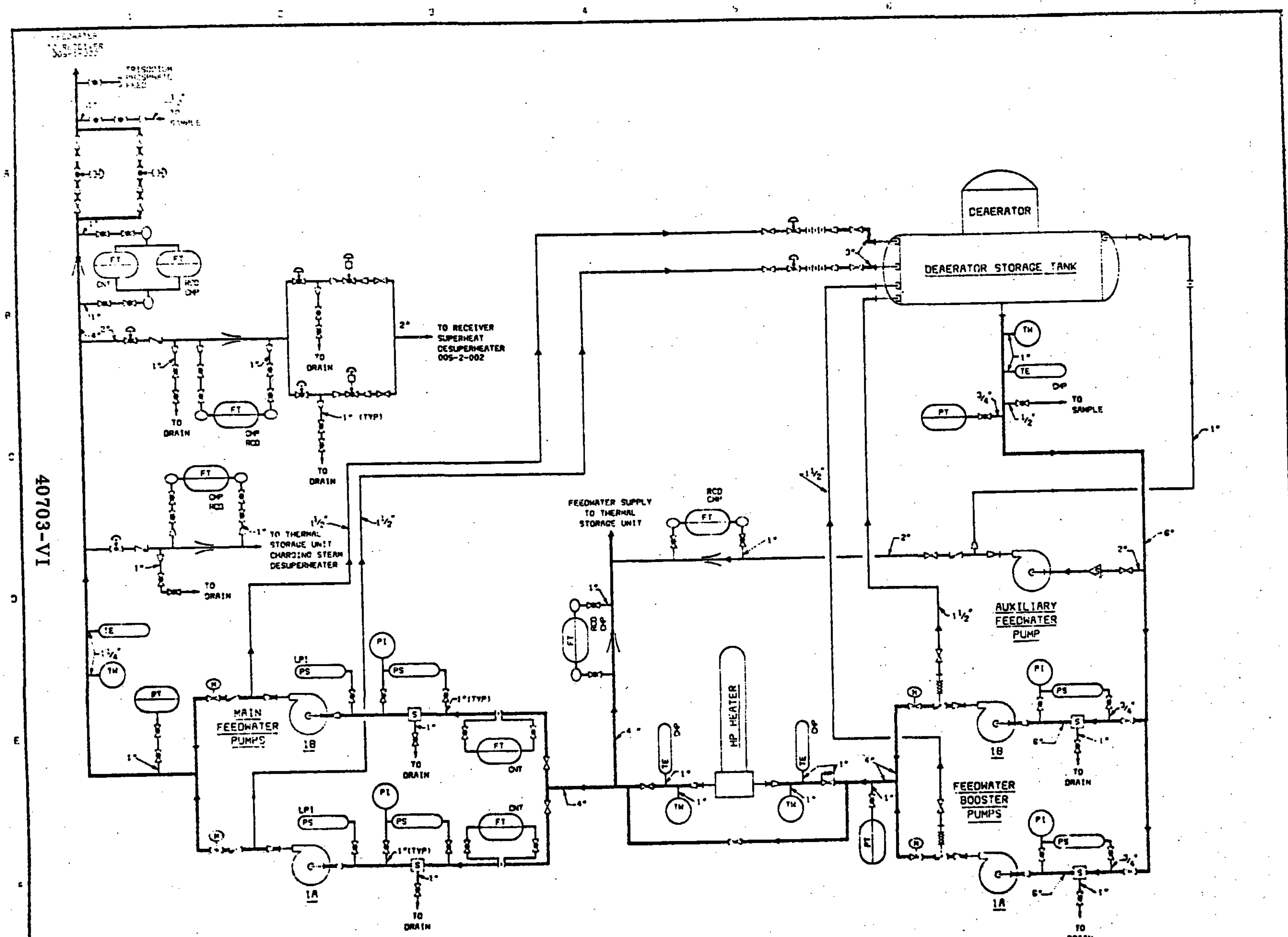

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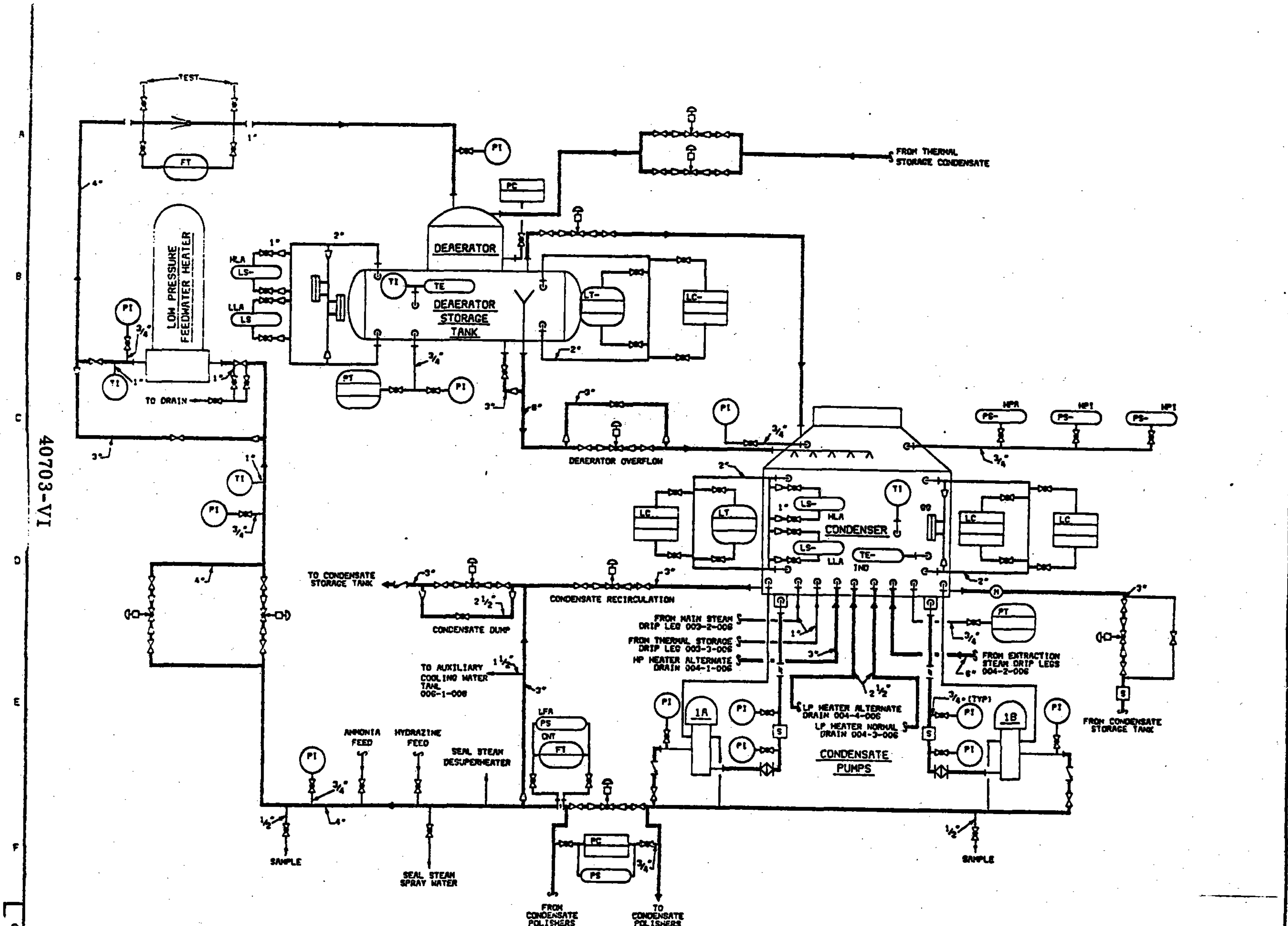

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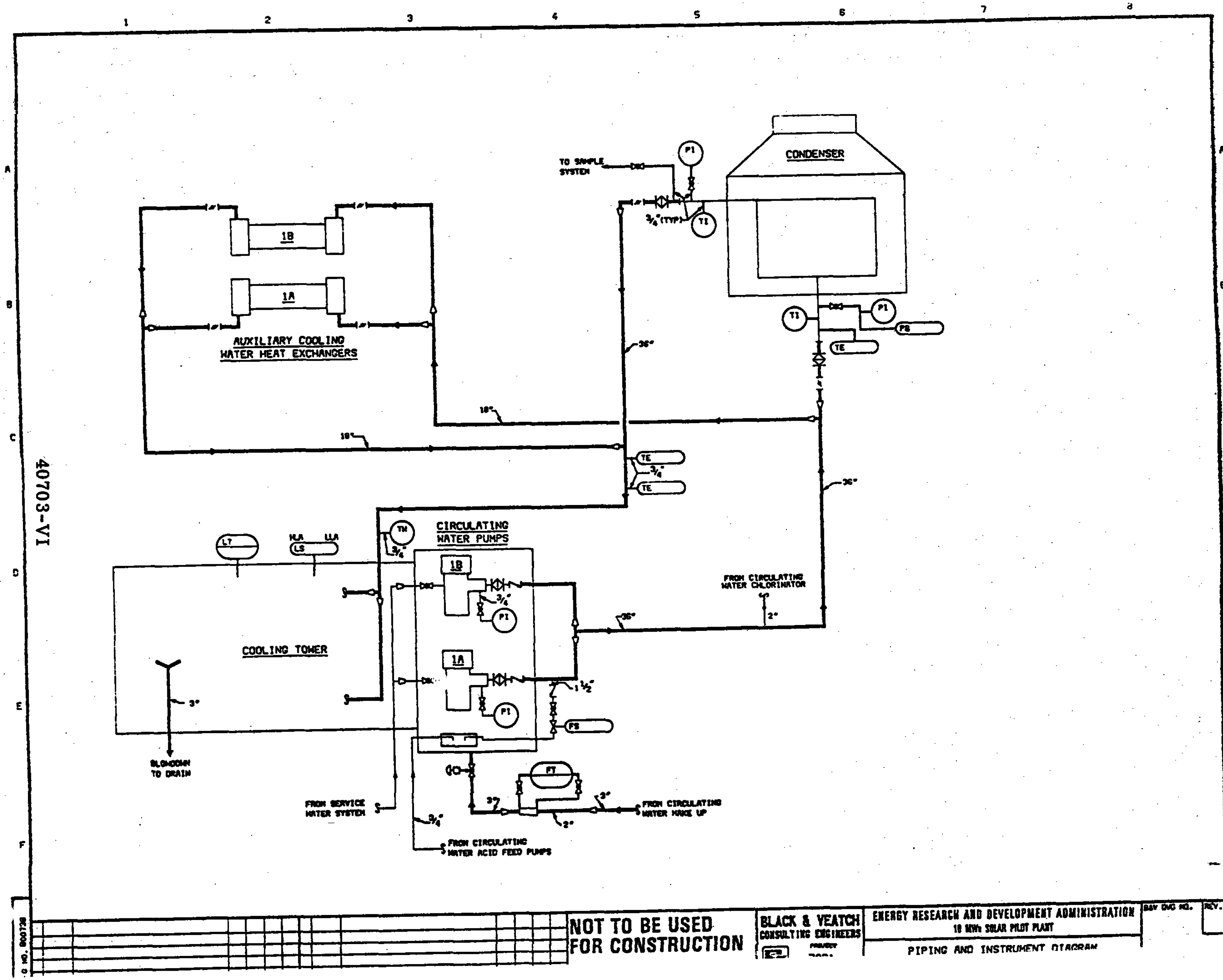
ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION
10 MWe SOLAR PILOT PLANT

PIPING AND INSTRUMENT DIAGRAM
CONDENSATE

B&V DWG NO. M1006

REV.

40703-VI



CONDENSER
TO SAMPLE SYSTEM
PI
TI
3/4" (TYP)
1B
1A
AUXILIARY COOLING WATER HEAT EXCHANGERS
36"
18"
PS
TE
3/4"
CIRCULATING WATER PUMPS
TW
LT
HLA LLA
LS
FROM CIRCULATING WATER CHLORINATOR
2"
COOLING TOWER
3"
1 1/2"
BLOWDOWN TO DRAIN
FT
FROM SERVICE WATER SYSTEM
FROM CIRCULATING WATER MAKE UP
FROM CIRCULATING WATER ACID FEED PUMPS
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10 MWe SOLAR PILOT PLANT
PIPING AND INSTRUMENT DIAGRAM

E-8

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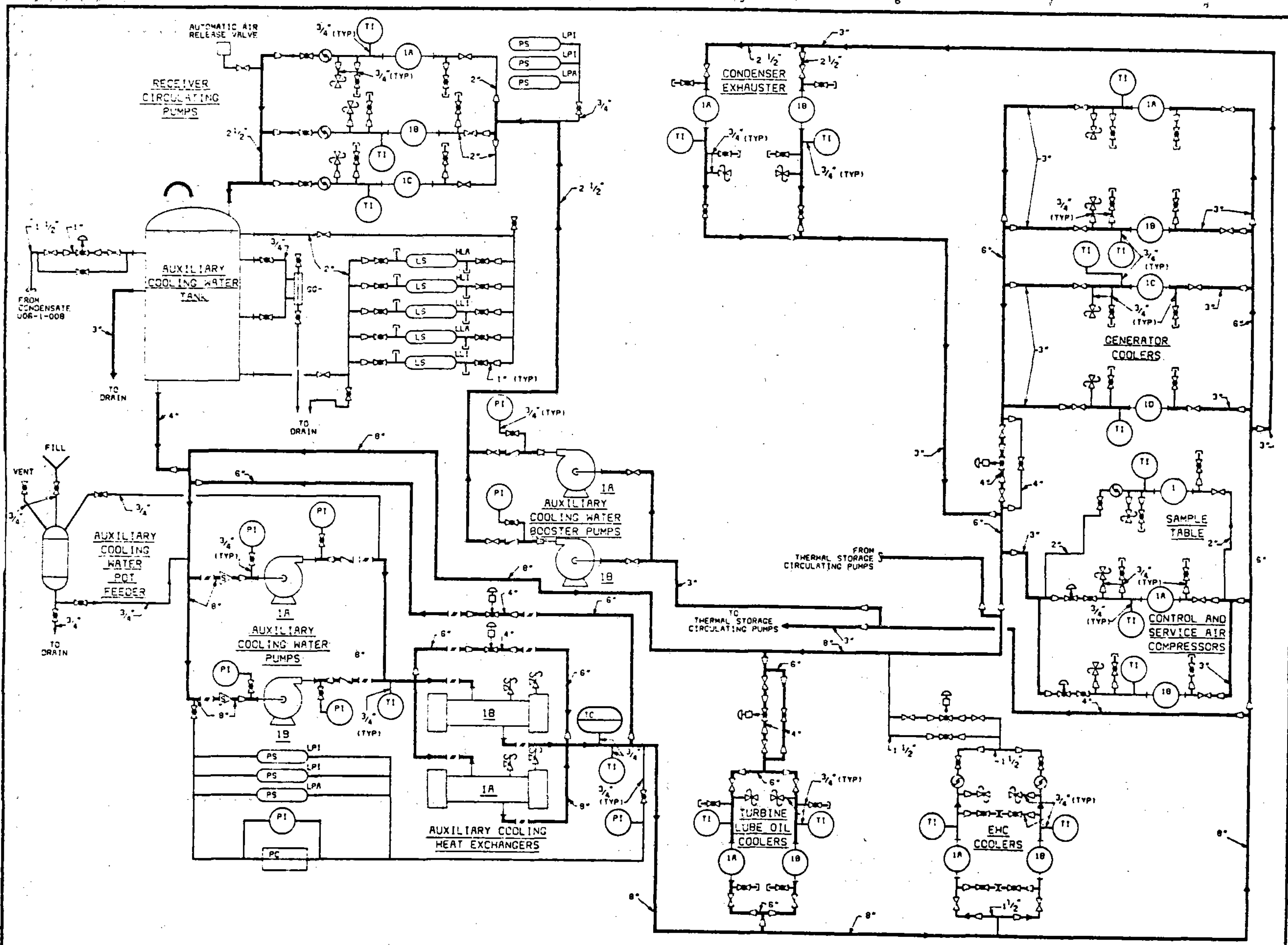


E-9

NO	DATE	REVISIONS	DWN	CK	ACC	APP

NOT TO BE USED FOR CONSTRUCTION

BLACK & VEATCH CONSULTING ENGINEERS
PROJECT 7021

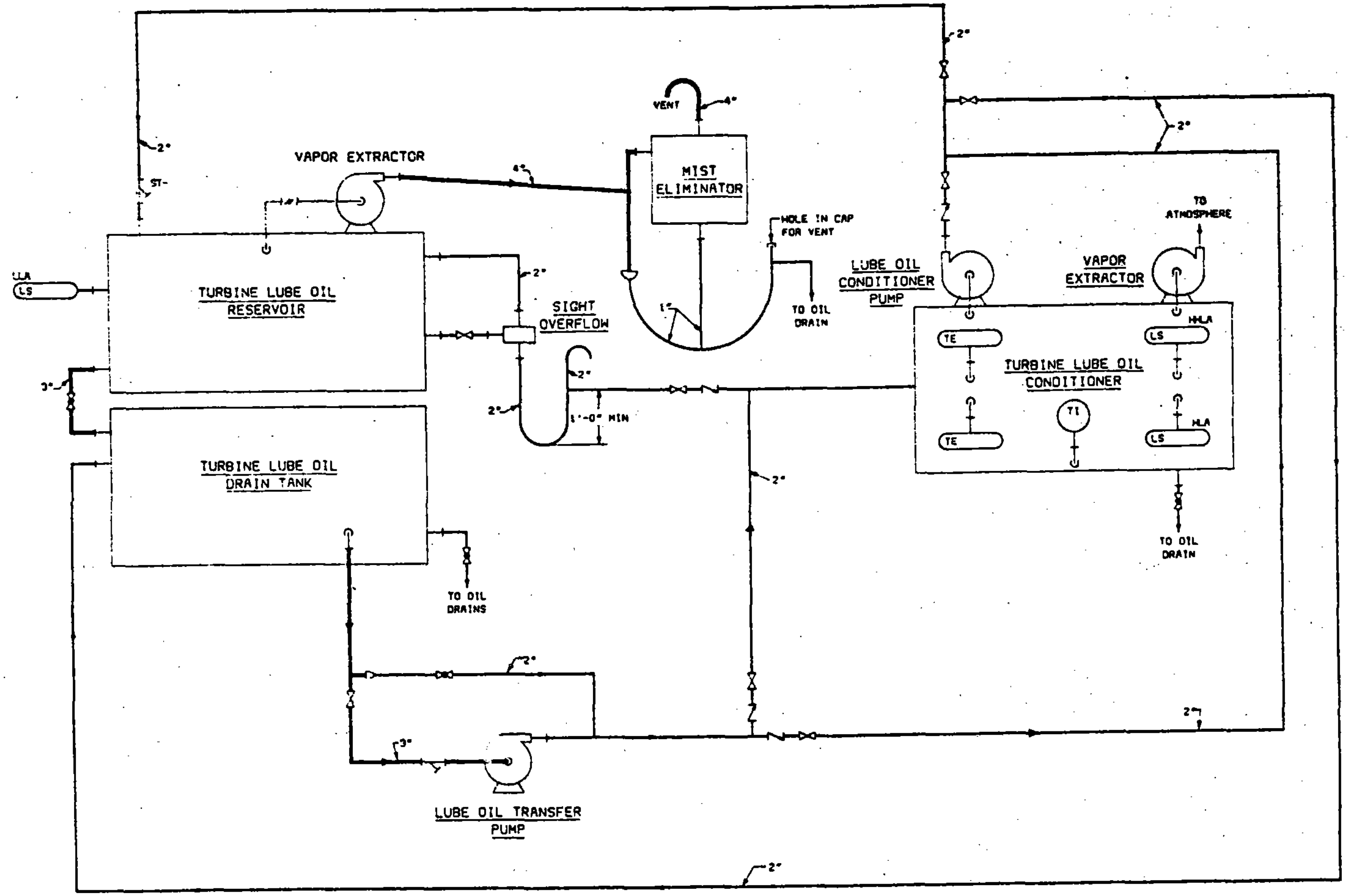
ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION
10 MWe SOLAR PILOT PLANT

PIPING AND INSTRUMENT DIAGRAM
AUXILIARY COOLING WATER

B&V DWG NO. M1008
REV.

A-G NO. 805888

40703-VI



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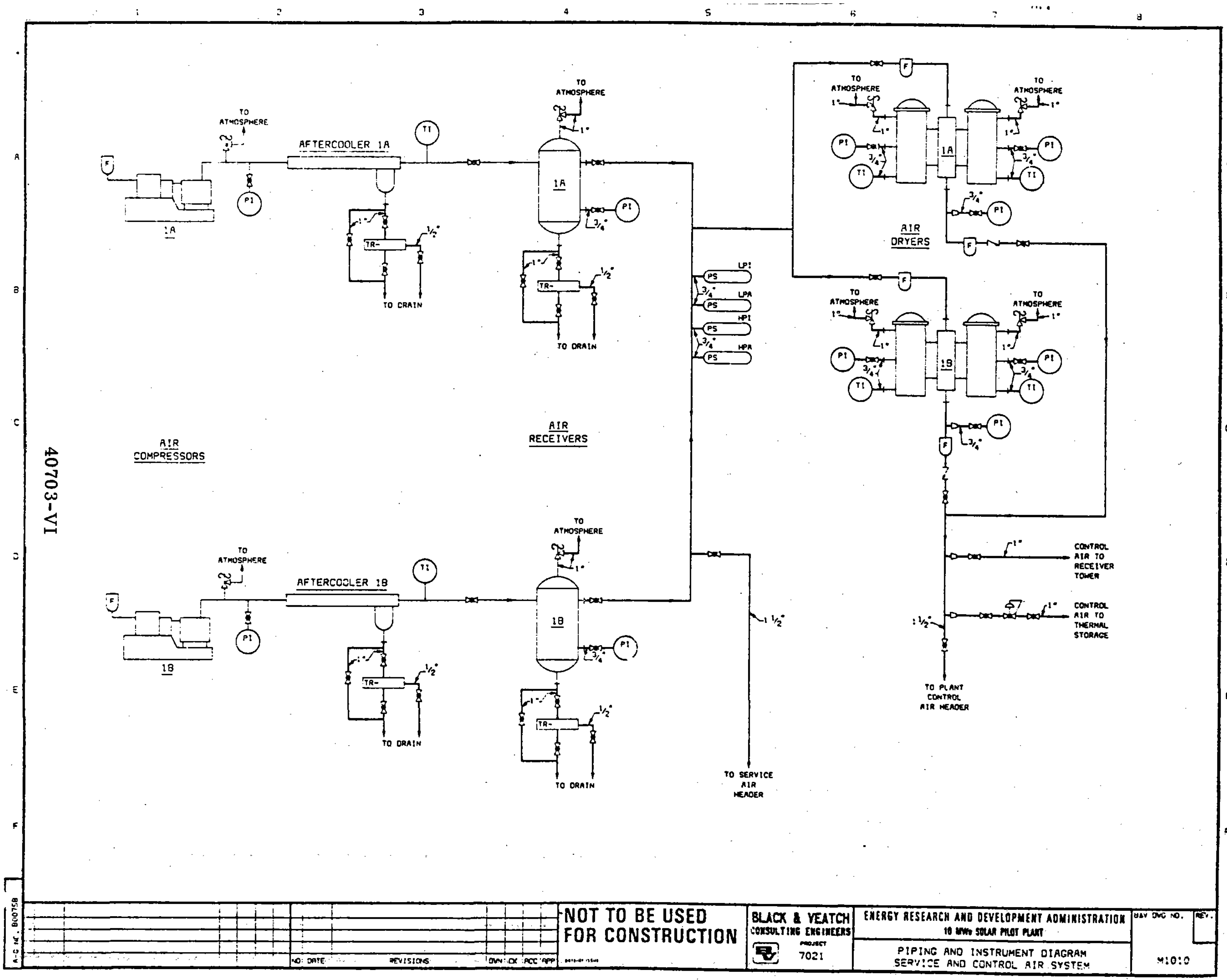
		PIPING AND INSTRUMENT DIAGRAM TURBINE LUBRICATING OIL	REV.

NO. DATE REVISIONS DWN CK REC APP

A.C. NO. 800678


AIR COMPRESSORS
1A
1B
TO ATMOSPHERE
AFTERCOOLER 1A
AFTERCOOLER 1B
TI
PI
TR-
TO DRAIN
AIR RECEIVERS
1A
1B
LPI
LPA
HPI
HPA
PS
TO SERVICE AIR HEADER
AIR DRYERS
CONTROL AIR TO RECEIVER TOWER
CONTROL AIR TO THERMAL STORAGE
TO PLANT CONTROL AIR HEADER
NOT TO BE USED FOR CONSTRUCTION
BLACK & VEATCH CONSULTING ENGINEERS
PROJECT 7021
ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION
10 MWe SOLAR PILOT PLANT
PIPING AND INSTRUMENT DIAGRAM
SERVICE AND CONTROL AIR SYSTEM
B&V DWG NO. M1010
REV.
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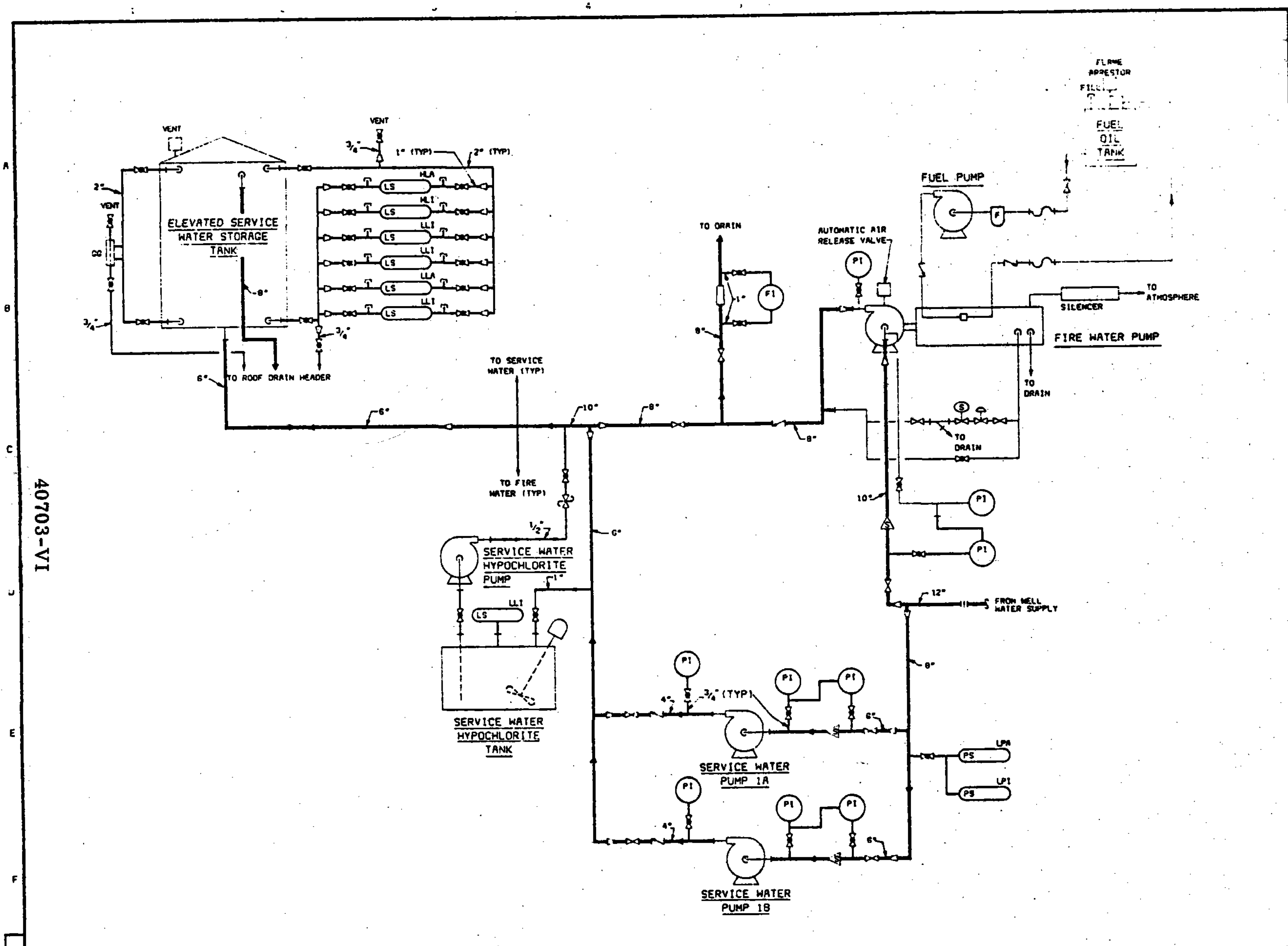
40703-VI



40703-VI

E-12

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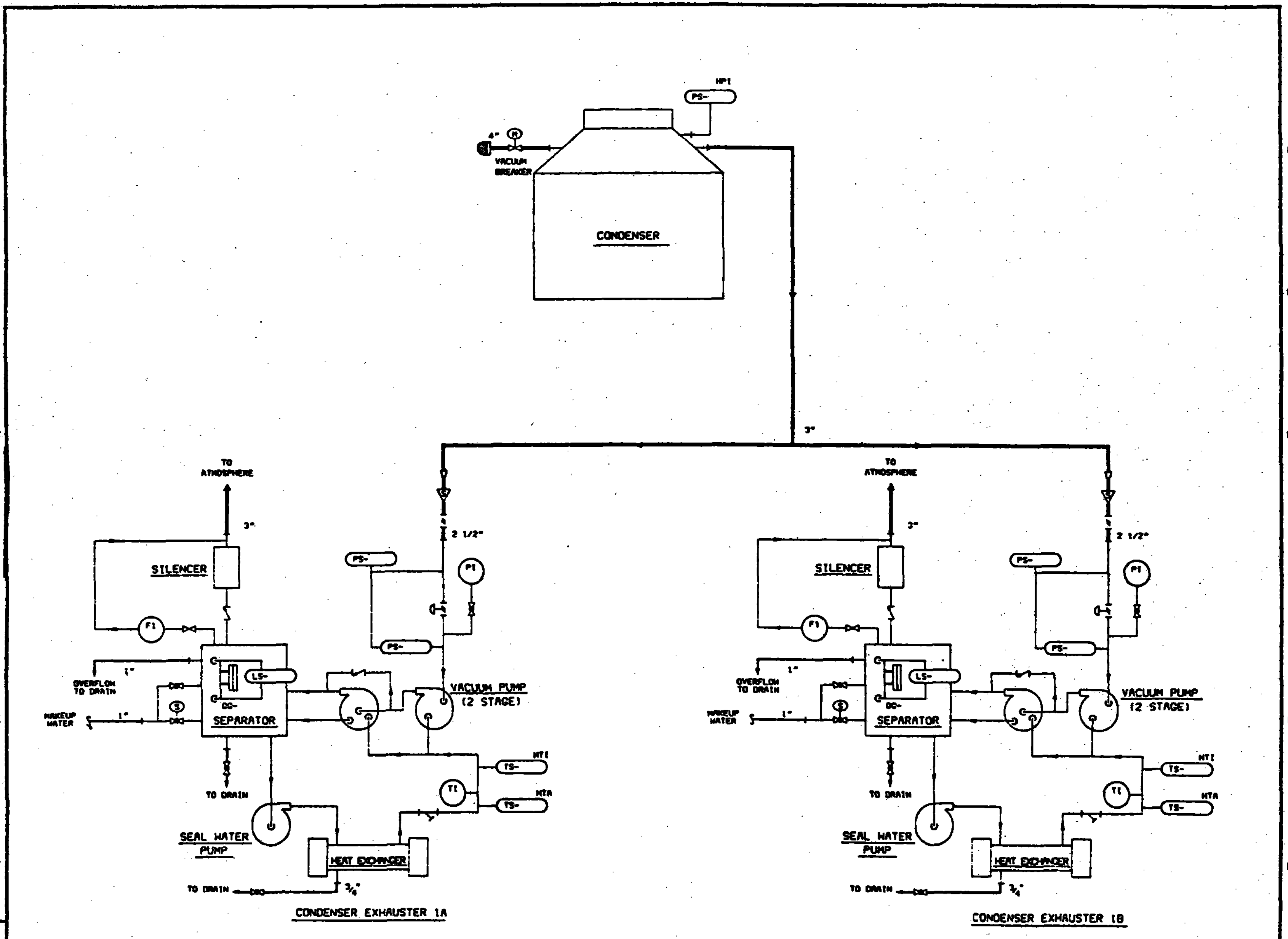
PROJECT 7021

ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION
10 MWe SOLAR PILOT PLANT

PIPING AND INSTRUMENT DIAGRAM
SERVICE AND FIRE WATER SYSTEM

B&V DWG NO. M1011
REV.



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NOT TO BE USED FOR CONSTRUCTION

BLACK & VEATCH CONSULTING ENGINEERS
PROJECT 7021

ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION
10 MWe SOLAR PILOT PLANT

PIPING AND INSTRUMENT DIAGRAM
CONDENSER AIR REMOVAL

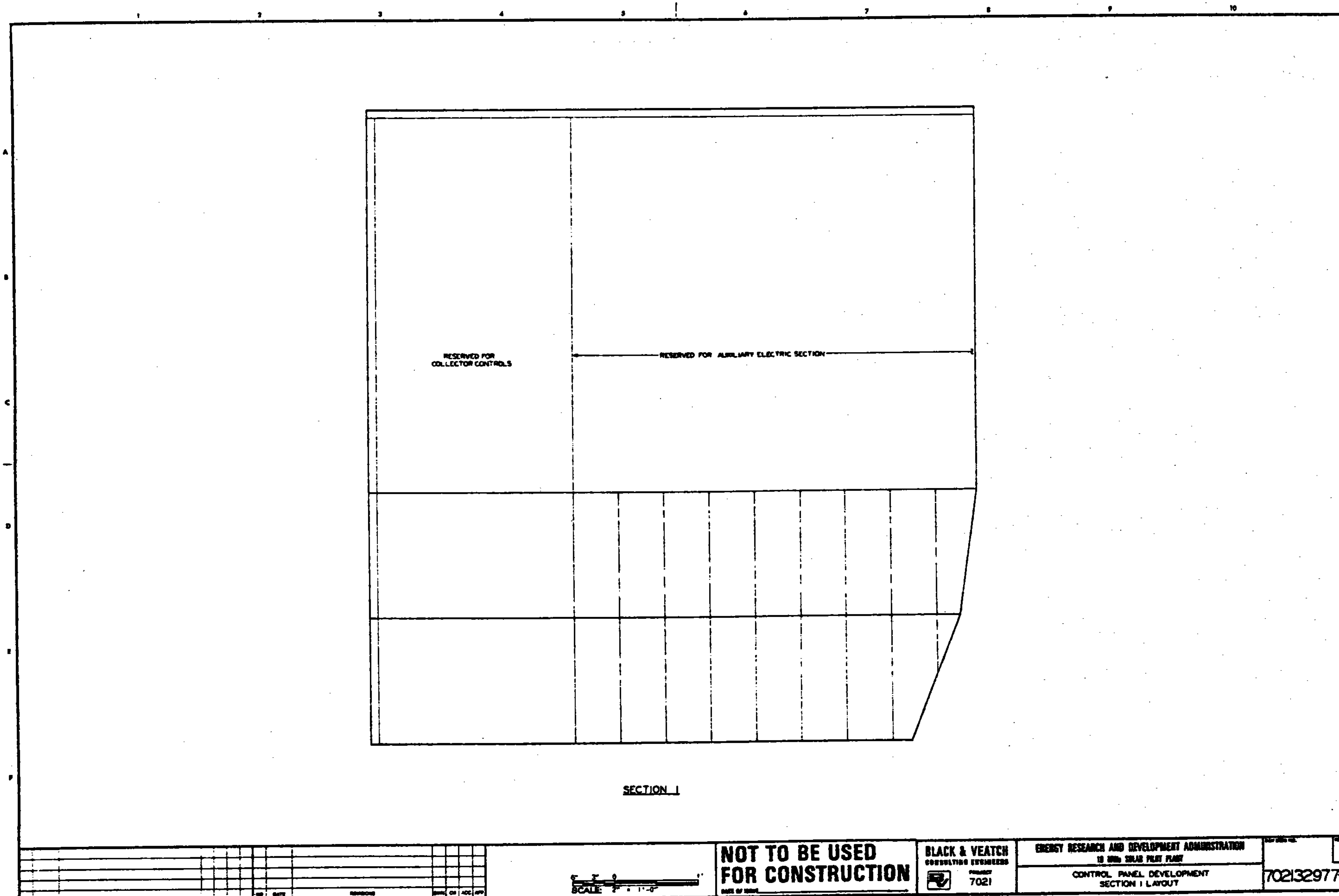
B&V DWG NO. M1012
REV.

APPENDIX F

CONTROL PANEL LAYOUT AND INSTRUMENTATION

Control Panel Layout:

Control Panel Instrumentation: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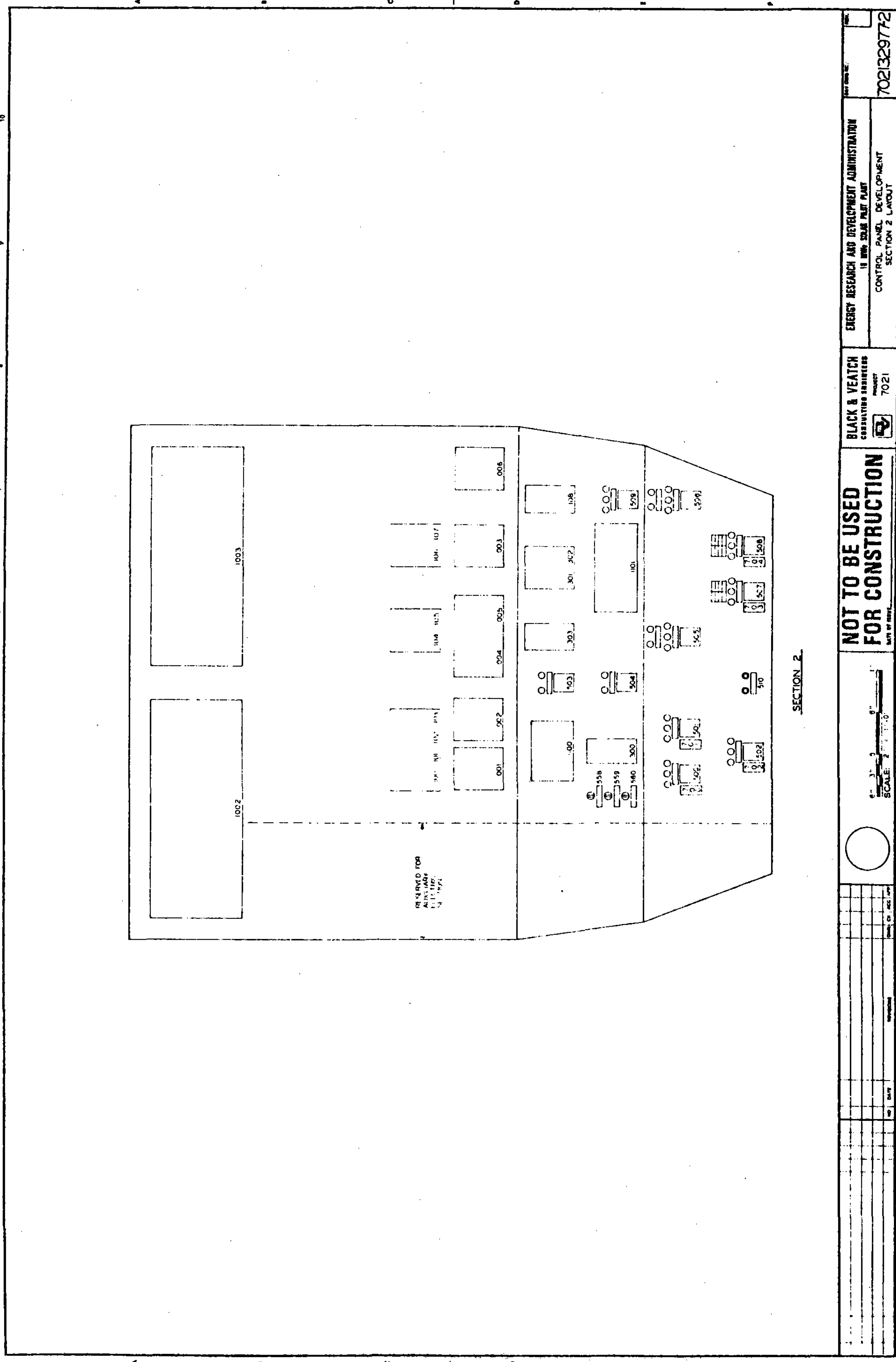
RESERVED FOR AUXILIARY ELECTRIC SECTION
SECTION 1
SCALE 2" = 1'-0"
NOT TO BE USED FOR CONSTRUCTION
BLACK & VEATCH
CONSULTING ENGINEERS
7021
ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION
10 MWe SOLAR PILOT PLANT
CONTROL PANEL DEVELOPMENT
SECTION 1 LAYOUT
702132977-1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7021
ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION
10 MWe SOLAR PILOT PLANT
CONTROL PANEL DEVELOPMENT
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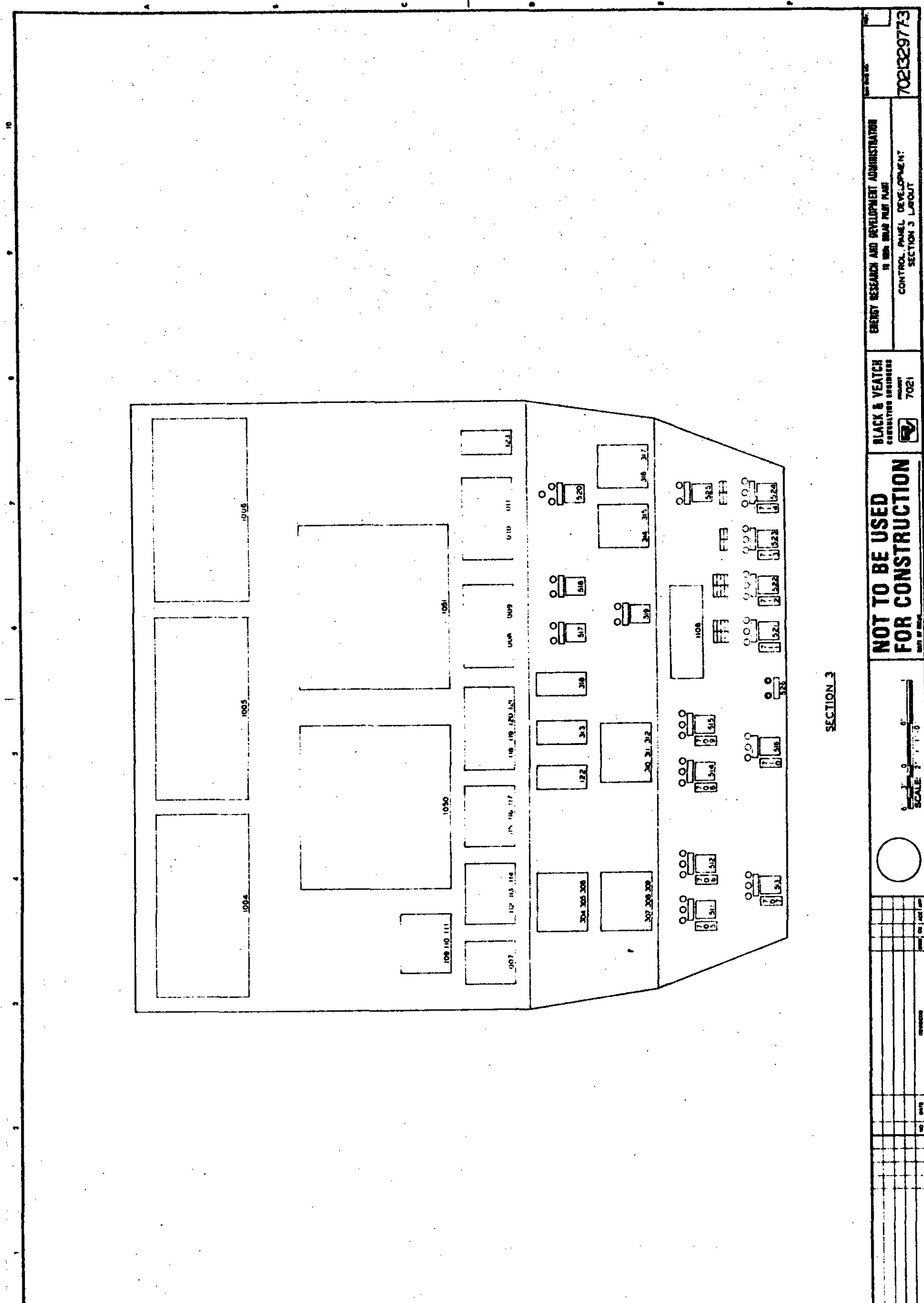
SECTION 2
1002
1003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FOR CONSTRUCTION
BLACK & VEATCH
7021
ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION
CONTROL PANEL DEVELOPMENT
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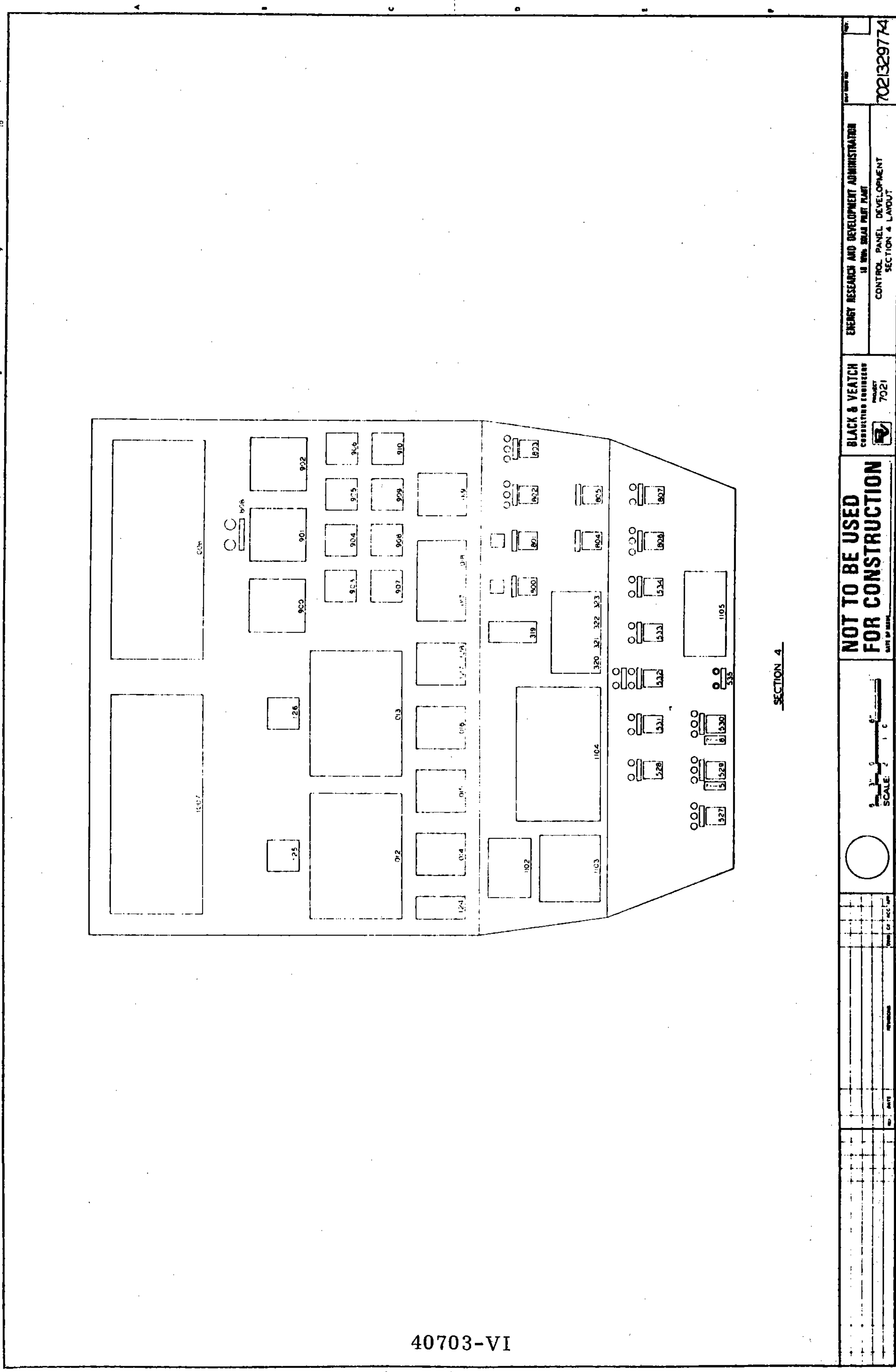
1005
1006
1050
1051
1108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BLACK & VEATCH
PROJECT 7021
ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION
CONTROL PANEL DEVELOPMENT
SECTION 4 LAYOUT
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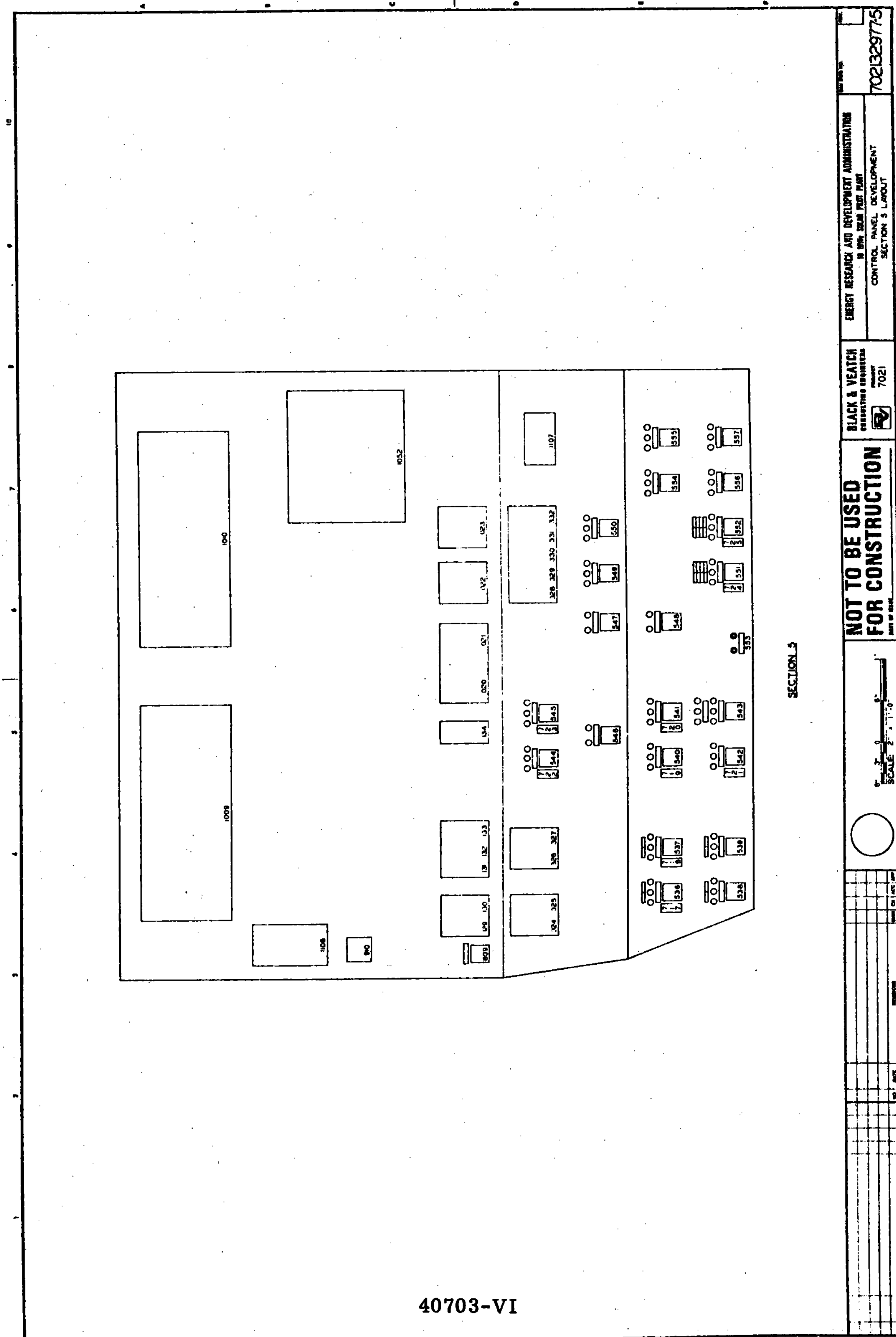
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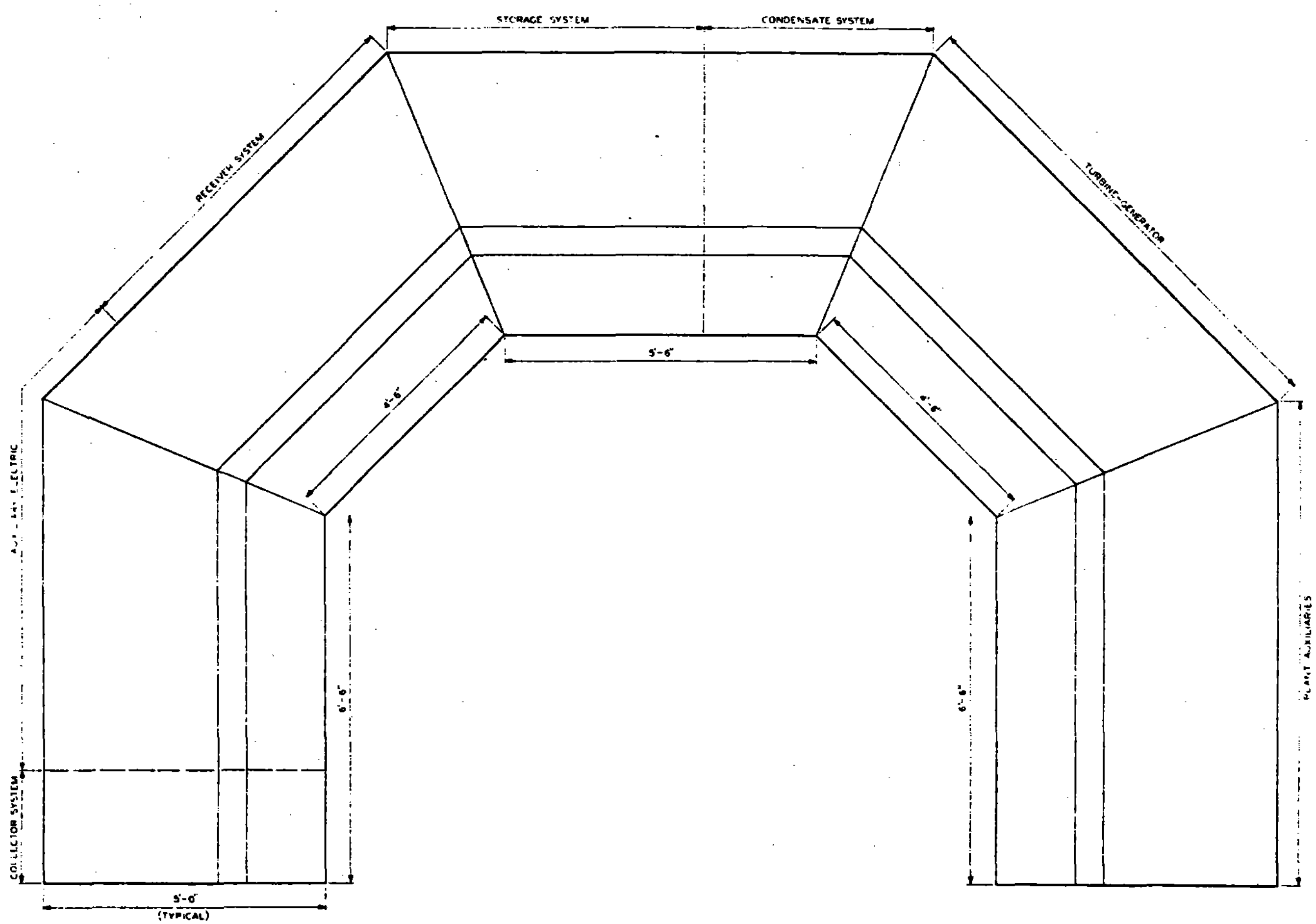
ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION
10 MWe SOLAR PILOT PLANT
CONTROL PANEL DEVELOPMENT
SECTION 5 LAYOUT
BLACK & VEATCH
CONSULTING ENGINEERS
7021
NOT TO BE USED
FOR CONSTRUCTION
7021329775



NOT TO BE USED FOR CONSTRUCTION

BLACK & VEATCH
CONSULTING ENGINEERS
PROJECT 7021

ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION
10 MWe SOLAR PILOT PLANT
CONTROL PANEL
PLAN VIEW

702132977-6

CONTROL PANEL SECTION 2 Sheet 1

INSTRUMENTATION

Recorders:

CP-001	Receiver Drum 1-Level 2-Pressure 3-Temperature
CP-002	Superheater Outlet 1-Pressure 2-Temperature
CP-003	Desuperheater 1-Spray Flow 2-Inlet Temperature 3-Outlet Temperature
CP-004	Trend Recorder #1 Section 2
CP-005	Trend Recorder #2 Section 2
CP-006	Feedwater 1-Flow to Receiver 2-Flow to Storage

Indicators:

CP-100	Receiver Boiler Total Recirc Flow
CP-101	Receiver Boiler Recirc Flow #1
CP-102	Receiver Boiler Recirc Flow #2
CP-103	Receiver Boiler Recirc Flow #3
CP-104	Receiver Boiler Drum Level
CP-105	Receiver Boiler Drum Pressure
CP-106	Feedwater Booster Pump Discharge Pressure

CONTROL PANEL SECTION 2 Sheet 2

INSTRUMENTATION

Indicators:

CP-107	Feedwater Pump Discharge Pressure
CP-108	Auxiliary Feedwater Pump Flow

Hand/Auto Control Stations:

CP-300	Receiver Recirculation Flow Control
CP-301	Feedwater Startup Flow Control
CP-302	Feedwater Flow Control
CP-303	Receiver Superheater Temperature Control

Switches and Lights:

CP-500	Receiver Recirculation Pump A
CP-501	Receiver Recirculation Pump B
CP-502	Receiver Recirculation Pump C
CP-503	Receiver Steam to Turbine Block Valve
CP-504	Receiver Steam to Thermal Storage Block Valve
CP-505	Feedwater Booster Pump A
CP-506	Feedwater Booster Pump B
CP-507	Feedwater Pump A
CP-508	Feedwater Pump B
CP-509	Auxiliary Feedwater Pump
CP-510	Annunciator Test and Acknowledge Push Button

CONTROL PANEL SECTION 2 Sheet 3

INSTRUMENTATION

Switches and Lights:

CP-558	Recirc Flow Indicator 101 Selector
CP-559	Recirc Flow Indicator 102 Selector
CP-560	Recirc Flow Indicator 103 Selector

Ammeters:

CP-700	Receiver Recirc Pump A Ammeter
CP-701	Receiver Recirc Pump B Ammeter
CP-702	Receiver Recirc Pump C Ammeter
CP-703	FW Pump A Ammeter
CP-704	FW Pump B Ammeter

Annunciator Visual Displays:

CP-1002	40 Point Display
CP-1003	40 Point Display

Subpanels:

CP-1100 Steam Line Drains

(A) Receiver Main Steam Line Drain Valve

(B) Receiver Steam Line to Turbine Drain Valve

(C) Receiver Steam Line to Thermal Storage Drain Valve

(D) Thermal Storage Steam Line to Turbine Drain Valve

CONTROL PANEL SECTION 2 Sheet 4

INSTRUMENTATION

Subpanels:

CP-1101 Feedwater

(A) Thermal Storage Charging Steam Attemperator Spray Shutoff Valve

(B) Receiver Desuperheater Spray Block Valve

(C) Receiver Desuperheater Spray Shutoff Valve A

(D) Receiver Desuperheater Spray Shutoff Valve B

(E) Feedwater Pump A Recirculation Valve

(F) Feedwater Pump B Recirculation Valve

CONTROL PANEL SECTION 3 Sheet 1

INSTRUMENTATION

Recorders:

CP-007	Storage Charging Attemperator
	1. Spray Flow
	2. Attemp #1 Outlet Temperature
	3. Attemp #2 Outlet Temperature
CP-008	Trend Recorder #3 Section 3
CP-009	Trend Recorder #4 Section 3
CP-010	Condenser
	1. Level
	2. Condenser Pressure
	3. Condenser Temperature
CP-011	Condensate
	1. Flow
	2. Make-Up Flow
	3. Dump Flow

Indicators:

CP-109	Storage Condenser
	1. Water Temperature In
	2. Water Temperature Out
CP-110	Storage Condenser Oil
	1. Temperature In
	2. Temperature Out

CONTROL PANEL SECTION 3 Sheet 2

INSTRUMENTATION

Indicators:

CP-111 Storage Condenser Oil

1. Flow to Condenser
2. Flow from Tank

CP-112 Storage Desuperheater Steam

1. Temperature In
2. Temperature Out

CP-113 Storage Desuperheater Hitec

1. Temperature In
2. Temperature Out

CP-114 Cold Hitec Flow

1. To Desuperheater
2. From Cold Tank

CP-115 Storage Superheater Steam

1. Temperature In
2. Temperature Out

CP-116 Storage Superheater Hitec

1. Temperature In
2. Temperature Out

CP-117 Hot Hitec Flow

1. Flow to Desuperheater
2. Flow From Hot Tank

CONTROL PANEL SECTION 3 Sheet 3

INSTRUMENTATION

Indicators:

CP-118	Storage Boiler Level
CP-119	Storage Boiler Steam Flow
CP-120	Storage Boiler and Preheater Water
	1. Preheater In Temperature
	2. Boiler Out Temperature
CP-121	Storage Boiler and Preheater Oil
	1. Boiler Oil In Temperature
	2. Preheater Oil Out Temperature
CP-122	Hot Oil Flow
	1. Flow to Boiler
	2. Tank Return Flow
CP-123	Condensate Minimum Flow

Hand/Auto Control Stations:

CP-304	Storage Attemperator #1 Temperature Control
CP-305	Storage Attemperator #2 Temperature Control
CP-306	Storage Desuperheater HITEC Flow Control
CP-307	Storage Condenser Oil Flow Control
CP-308	MPA Oil Pump Suction Flow Control
CP-309	Storage Condenser Water Level Control
CP-310	Storage Boiler Oil Flow Control

CONTROL PANEL SECTION 3 — Sheet 4

INSTRUMENTATION

Hand/Auto Control Stations:

CP-311	Storage Boiler Water Level Control
CP-312	MPA Oil Discharge Pump Suction Flow Control
CP-313	Storage Superheater HITEC Flow Control
CP-314	Receiver Condensate Startup Flow Control
CP-315	Receiver Condensate Flow Control
CP-316	Turbine Condenser Hotwell Make-up
CP-317	Turbine Condenser Hotwell Dump
CP-318	Throttle Pressure Controller

Switches and Lights:

CP-511	MPA Cold Oil Pump A
CP-512	MPA Cold Oil Pump B
CP-513	Cold HITEC Pump
CP-514	MPA Hot Oil Pump A
CP-515	MPA Hot Oil Pump B
CP-516	Hot HITEC Pump
CP-517	LP FW HTR Condensate Inlet Isolation Valve
CP-518	LP FW HTR Condensate Outlet Isolation Valve
CP-519	LP FW HTR Condensate Bypass Valve
CP-520	Condensate Recirculation Control Valve
CP-521	Condensate Pump A

CONTROL PANEL SECTION 3 Sheet 5

INSTRUMENTATION

Lights and Switches:

CP-522	Condensate Pump B
CP-523	Condenser Exhauster A
CP-524	Condenser Exhauster B
CP-525	Vacuum Breaker
CP-526	Section 3 Annunciator TEST-ACK Push Buttons

Ammeters:

CP-705	Cold Oil Pump A Ammeter
CP-706	Cold Oil Pump B Ammeter
CP-707	Cold HITEC Pump Ammeter
CP-708	Hot Oil Pump A Ammeter
CP-709	Hot Oil Pump B Ammeter
CP-710	Hot HITEC Pump Ammeter
CP-711	Condensate Pump A Ammeter
CP-712	Condensate Pump B Ammeter
CP-713	Condenser Exhauster A Ammeter
CP-714	Condenser Exhauster B Ammeter

Annunciator Visual Displays:

CP-1004	32 Point Display
CP-1005	32 Point Display
CP-1006	32 Point Display

CONTROL PANEL SECTION 3 Sheet 6

INSTRUMENTATION

Cathode Ray Tubes:

CP-1050	Alarm CRT
CP-1051	Utility CRT

Subpanels:

CP-1108	CRT Keyboard

CONTROL PANEL SECTION 4 — Sheet 1

INSTRUMENTATION

Recorders:

CP-012	Turbine Metal & Steam Temperature
CP-013	Turbine Vibration, ECC, DIFF & Casing Expansion
CP-014	Turbine Speed and Governor Position
CP-015	Turbine Rotor Position
CP-016	Turbine Steam Flow 1. HP Steam 2. LP Steam
CP-017	Trend Recorder #5 Section 4
CP-018	Trend Recorder #6 Section 4
CP-019	Generator 1. Megawatts 2. Megavars 3. Mega Volt Amps

Indicators:

CP-124	Gland Steam Pressure
CP-125	Turbine Vibration Phase Angle
CP-126	Turbine Eccentricity Phase Angle
CP-127	Turbine HP Throttle Steam Temperature
CP-128	Turbine LP Throttle Steam Temperature

CONTROL PANEL SECTION 4 Sheet 2

INSTRUMENTATION

Hand/Auto Control Stations:

CP-319	Master Megawatt Controller
CP-320	Turbine Lube Oil Temp Control
CP-321	EH Fluid Temp Control
CP-322	Turbine Cooling Air Temperature Control
CP-323	Exciter Cooling Air Temperature Control

Switches and Lights:

CP-527	Turbine Bearing Oil Pump
CP-528	Turbine HP Throttle Steam Line Warmup & Drain Valve
CP-529	EH Fluid Pump A
CP-530	EH Fluid Pump B
CP-531	Turb LP Throttle Steam Line Warmup & Drain Valve
CP-532	Turbine Turning Gear
CP-533	Receiver Steam Gland Steam Supply Shutoff
CP-534	Storage Steam Gland Steam Supply Shutoff
CP-535	Annunciator Test-Oil Push Buttons Section 4

Ammeters:

CP-715	EH Fluid Pump A Ammeter
CP-716	EH Fluid Pump B Ammeter

CONTROL PANEL SECTION 4 Sheet 3

INSTRUMENTATION

Switches and Lights:	(Auxiliary Electric Equipment)
CP-800	Generator Voltage Regulator Voltage Adjuster
CP-801	Generator Voltage Regulator Base Adjuster
CP-802	Generator Voltage Regulator
CP-803	Generator Volt Reg Supply Bkr
CP-804	Gen Sync SW
CP-805	Generator Voltage SW
CP-806	Generator Breaker
CP-807	Generator Motor Operated Disconnect
CP-808	Sync Lights

Electric Meters:

CP-900	Line Volts Incoming
CP-901	Synchroscope
CP-902	Volts Running
CP-903	Generator Phase A Amps
CP-904	Generator Phase B Amps
CP-905	Generator Phase C Amps
CP-906	Generator Megawatts
CP-907	Exciter Field DC Volts
CP-908	Exciter Field DC Amps
CP-909	Voltage Regulator Balance
CP-910	Generator Volts

CONTROL PANEL SECTION 4 Sheet 4

INSTRUMENTATION

Visual Annunciator Displays:

CP-1007	40 Point Display
CP-1008	40 Point Display

Subpanels:

CP-1102	Turbine Drain Valves
CP-1103	Extraction Valves
	(A) Turbine Side HP Extraction Drain Valve
	(B) Turbine Side IP Extraction Drain Valve
	(C) Deaerator Side IP Extraction Drain Valve
	(D) Turbine Side LP Extraction Drain Valve
	(E) HP Extraction Block Valve
	(F) IP Extraction Block Valve
	(G) LP Extraction Block Valve
CP-1104	Turbine EH Control Panel
CP-1105	Turbine EH Valve Test Panel

CONTROL PANEL SECTION 5 — Sheet 1

INSTRUMENTATION

Recorders:

CP-020	Trend Recorder #7 Section 5
CP-021	Trend Recorder #8 Section 5
CP-022	Cooling Tower 1. Make-Up Flow 2. Level
CP-023	Circ Water 1. PH 2. Conductivity

Indicators:

CP-129	HP Feedwater Heater Level
CP-130	LP Feedwater Heater Level
CP-131	Deaerator Pressure (High Range)
CP-132	Deaerator Pressure (Low Range)
CP-133	Deaerator Level
CP-134	Air Receiver Pressure

Hand/Auto Control Stations:

CP-324	HP Feedwater Heater Level Control
CP-325	LP Feedwater Heater Level Control
CP-326	Deaerator Overflow Control

CONTROL PANEL SECTION 5 Sheet 2

INSTRUMENTATION

Hand/Auto Control Stations:

CP-327	Deaerator Pressure Control
CP-328	Circulating Water PH Control
CP-329	Circulating Water Acid Feed Pump Speed Control
CP-330	Circulating Water Conductivity Control
CP-331	Cooling Tower Phosphate Pump Stroke
CP-332	Cooling Tower Level

Switches and Lights:

CP-536	ACW Pump A
CP-537	ACW Pump B
CP-538	ACW Booster Pump A
CP-539	ACW Booster Pump B
CP-540	Service Water Pump A
CP-541	Service Water Pump B
CP-542	Fire Water Pump A
CP-543	Fire Water Pump B
CP-544	Air Compressor A
CP-545	Air Compressor B
CP-546	Emergency Service Water Valve
CP-547	Condenser Circulating Water Inlet Isolation Valve
CP-548	Condenser Circulating Water Outlet Isolation Valve

CONTROL PANEL SECTION 5 Sheet 3

INSTRUMENTATION

Switches and Lights:

CP-549	Cooling Tower Fan A
CP-550	Cooling Tower Fan B
CP-551	Circulating Water Pump A
CP-552	Circulating Water Pump B
CP-553	Annunciator Test and Acknowledgement Push Buttons
CP-554	Acid Feed Pump A
CP-555	Acid Feed Pump B
CP-556	Phosphate Pump A
CP-557	Phosphate Pump B

Ammeters:

CP-717	ACW Pump A Ammeter
CP-718	ACW Pump B Ammeter
CP-719	Service Water Pump A Ammeter
CP-720	Service Water Pump B Ammeter
CP-721	Fire Water Pump A Ammeter
CP-722	Air Compressor A Ammeter
CP-723	Air Compressor B Ammeter
CP-724	Circulating Water Pump A Ammeter
CP-725	Circulating Water Pump B Ammeter

CONTROL PANEL SECTION 5 Sheet 4

INSTRUMENTATION

Switches and Lights:	(Auxiliary Electric Equipment)
CP-809	Generator Ground Detector
Electric Meters:	
CP-911	Generator Megavars
Visual Annunciator Displays:	
CP-1009	40 Point Display
CP-1010	40 Point Display
Cathode Ray Tubes:	
CP-1052	Cloud Cover Monitor TV
Subpanels:	
CP-1106	Sync Verify Relay
CP-1107	Cloud Cover Monitor TV Control

APPENDIX G

LOCAL INDICATING INSTRUMENTATION AND CONTROL ELEMENTS

LEGEND

LOCAL INDICATING INSTRUMENTATION

- Pressure Indicators
- Temperature Indicators
- Test Wells

MONITORING AND CONTROL ELEMENTS

- Flow Switches
- Flow Transmitters
- Level Controllers
- Level Switches
- Level Transmitters
- Pressure Controllers
- Pressure Switches
- Pressure Transmitters
- Temperature Controllers
- Temperature Elements
- Temperature Switches

LEGEND

CMP - Computer (Data Logging)

CNT - Control

EHC - Turbine Control

HLA - High Level Alarm

HLI - High Level Interlock

HPA - High Pressure Alarm

HPI - High Pressure Interlock

HTA - High Temperature Alarm

HTI - High Temperature Interlock

IND - Indicator

LFA - Low Flow Alarm

LFI - Low Flow Interlock

LLA - Low Level Alarm

LLI - Low Level Interlock

LPI - Low Pressure Interlock

RCD - Recorder

TDA - Test Data Acquisition

LOCAL INDICATING INSTRUMENTATION

PRESSURE INDICATORS

Sheet 1

Item No.	Description	Function
PI-0001	DEAERATOR PRESS	IND
PI-0002	CONDENSATE PRESS INTO DEAERATOR	IND
PI-0003	CONDENSATE PRESS LP HTR DISCH	IND
PI-0004	CONDENSATE PRESS CONT VLV DISCH	IND
PI-0005	CONDENSATE PRESS CONT VLV INLET	IND
PI-0006	CONDENSATE PUMP 1A DISCH PRESS	IND
PI-0007	CONDENSATE PUMP 1A STRAINER INLET PRESS	IND
PI-0008	CONDENSATE PUMP 1A STRAINER OUTLET PRESS	IND
PI-0009	CONDENSATE PUMP 1B STRAINER INLET PRESS	IND
PI-0010	CONDENSATE PUMP 1B STRAINER OUTLET PRESS	IND
PI-0011	CONDENSATE PUMP 1B DISCH PRESS	IND
PI-0012	MFP 1A INLET PRESS	IND
PI-0013	MFP 1B INLET PRESS	IND
PI-0014	F W BOOSTER PUMP 1A INLET PRESS	IND
PI-0015	F W BOOSTER PUMP 1B INLET PRESS	IND

LOCAL INDICATING INSTRUMENTATION (cont'd)

PRESSURE INDICATORS Sheet 2

Item No.	Description	Function
PI-0016	DEAERATOR PRESS	IND
PI-0017	CONDENSER PRESS	IND
PI-0018	AUX CLG WTR PUMP 1A INLET PRESS	IND
PI-0019	AUX CLG WTR PUMP 1A OUTLET PRESS	IND
PI-0020	AUX CLG WTR PUMP 1B INLET PRESS	IND
PI-0021	AUX CLG WTR PUMP 1B OUTLET PRESS	IND
PI-0022	AUX CLG WTR PUMPS DIFF PRESS	IND
PI-0023	AUX CLG WTR CLR OUTLET PRESS	IND
PI-0024	AUX CLG WTR BOOSTER PUMP 1A OUTLET	IND
PI-0025	AUX CLG WTR BOOSTER PUMP 1B OUTLET	IND
PI-0026	CIRC WTR CONDENSER OUTLET PRESS	IND
PI-0027	CIRC WTR PUMP 1A DISCH PRESS	IND
PI-0028	CIRC WTR PUMP 1B DISCH PRESS	IND
PI-0029	CIRC WTR PRESS CONDENSER OUTLET	IND
PI-0030	SERVICE WTR PUMP 1A OUTLET PRESS	IND
PI-0031	SERVICE WTR PUMP 1A STRAINER OUTLET	IND

LOCAL INDICATING INSTRUMENTATION (cont'd)

PRESSURE INDICATORS Sheet 3

Item No.	Description	Function
PI-0032	SERVICE WTR PUMP 1A STRAINER INLET	IND
PI-0033	SERVICE WTR PUMP 1B OUTLET PRESS	IND
PI-0034	SERVICE WTR PUMP 1B STRAINER OUTLET	IND
PI-0035	SERVICE WTR PUMP 1B STRAINER INLET	IND
PI-0036	FIRE WATER PUMP STRAINER INLET	IND
PI-0037	FIRE WATER PUMP STRAINER OUTLET	IND
PI-0038	FIRE WATER PUMP DISCH PRESS	IND
PI-0039	AIR COMP 1A DISCH PRESS	IND
PI-0040	AIR COMP 1B DISCH PRESS	IND
PI-0041	AIR RECEIVER 1A PRESSURE	IND
PI-0042	AIR RECEIVER 1B PRESSURE	IND
PI-0043	DESICCANT AIR DRYER 1A INLET	IND
PI-0044	DESICCANT AIR DRYER 1A OUTLET	IND
PI-0045	AIR AFTER FILTER 1A INLET PRESS	IND
PI-0046	DESICCANT AIR DRYER 1B INLET	IND

LOCAL INDICATING INSTRUMENTATION (cont'd)

PRESSURE INDICATORS

Sheet 4

Item No.	Description	Function
PI-0047	DESICCANT AIR DRYER 1B OUTLET	IND
PI-0048	AIR AFTER FILTER 1B INLET PRESS	IND
PI-0049	COND EXHAUSTER 1A SUCTION	IND
PI-0050	COND EXHAUSTER 1B SUCTION	IND
PI-0051	RECEIVER PUMPS DISCH PRESS	IND
PI-0052	RECEIVER STEAM DRUM TEMP	IND

LOCAL INDICATING INSTRUMENTATION (cont'd)

TEMPERATURE INDICATORS Sheet 1

Item No.	Description	Function
TI-0001	CONDENSER TEMP	IND
TI-0002	DEAERATOR TEMP	IND
TI-0003	REC CIRC PUMP 1A INLET	IND
TI-0004	REC CIRC PUMP 1B INLET	IND
TI-0005	AUX COOLING WTR COOLERS OUTLET	IND
TI-0006	AUX COOLING WTR COOLERS OUTLET	IND
TI-0007	THERMAL STR CIRC PUMP 1A OUTLET	IND
TI-0008	THERMAL STR CIRC PUMP 1B OUTLET	IND
TI-0009	TURB LUBE OIL CLR 1A WTR OUTLET	IND
TI-0010	TURB LUBE OIL CLR 1B WTR OUTLET	IND
TI-0011	EHC 1A CLR WTR OUTLET	IND
TI-0012	EHC 1B CLR WTR OUTLET	IND
TI-0013	CONTROL AIR COMP 1A CLG WTR OUTLET	IND
TI-0014	CONTROL AIR COMP 1B CLG WTR OUTLET	IND
TI-0015	GEN AIR CLR 1A CLG WTR OUTLET	IND

LOCAL INDICATING INSTRUMENTATION (cont'd)

TEMPERATURE INDICATORS

Sheet 2

Item No.	Description	Function
TI-0016	GEN AIR CLR 1B CLG WTR OUTLET	IND
TI-0017	EXCITER CLR 1A WTR OUTLET	IND
TI-0018	EXCITER CLR 1B WTR OUTLET	IND
TI-0019	CONDENSER EXH 1A CLR WTR OUTLET	IND
TI-0020	CONDENSER EXH 1B CLR WTR OUTLET	IND
TI-0021	CIRC WTR TEMP CONDENSER OUTLER	IND
TI-0022	CIRC WTR TEMP CONDENSER INLET	IND
TI-0023	AFTER COOLER 1A DISCH AIR TEMP	IND
TI-0024	AFTER COOLER 1B DISCH AIR TEMP	IND
TI-0025	DESICCANT AIR DRYER 1A INLET	IND
TI-0026	DESICCANT AIR DRYER 1A OUTLET	IND
TI-0027	DESICCANT AIR DRYER 1B INLET	IND
TI-0028	DESICCANT AIR DRYER 1B OUTLET	IND
TI-0029	TURBINE LUBE OIL CONDITIONER TK	IND
TI-0030	COND EXHAUSTER 1A SEAL WTR TEMP	IND

LOCAL INDICATING INSTRUMENTATION (cont'd)

TEMPERATURE INDICATORS

Sheet 3

Item No.	Description	Function
TI-0031	COND EXHAUSTER 1B SEAL WTR TEMP	IND

LOCAL INDICATING INSTRUMENTATION (cont'd)

TEST WELLS Sheet 1

Item No.	Description	Function
TW-0001	TURBINE H P HDR STM TEMP	TDA
TW-0002	TURBINE H P HDR STM TEMP	TDA
TW-0003	TURBINE L P HDR STM TEMP	TDA
TW-0004	TRUBINE L P HDR STM TEMP	TDA
TW-0005	H P HTR INLET TO DEAERATOR	TDA
TW-0006	EXT STM TO DEAERATOR	TDA
TW-0007	H P HTR STM SIDE DISCH	TDA
TW-0008	H P HTR STM SIDE INLET	TDA
TW-0009	TURB H P EXTRACTION HDR	TDA
TW-0010	TURB I P EXTRACTION HDR	TDA
TW-0011	TURB L P EXTRACTION HDR	TDA
TW-0012	L P HTR STM SIDE INLET	TDA
TW-0013	L P HTR STM SIDE OUTLET	TDA
TW-0014	FEEDWATER TEMP MFP DISCH	TDA
TW-0015	FEEDWATER TEMP H P HTR OUTLET	TDA

LOCAL INDICATING INSTRUMENTATION (cont'd)

TEST WELLS

Sheet 2

Item No.	Description	Function
TW-0016	FEEDWATER TEMP H P HTR INLET	TDA
TW-0017	FEEDWATER TEMP DEAERATOR OUTLET	TDA
TW-0018	CIRC WTR TEMP COOLING TWR INLET	TDA
TW-0019	STM FROM THERMAL STORAGE	TDA
TW-0020	HITEC TO S H	TDA
TW-0021	HITEC FROM S H	TDA
TW-0022	STM TO THERMAL STORAGE S H INLET	TDA
TW-0023	HITEC FROM DESUP	TDA
TW-0024	STM TO DE S H INLET	TDA
TW-0025	HITEC TO DESUP S H	TDA
TW-0026	ATTEMPERATOR NO 2 INLET	TDA
TW-0027	PREHEATER OIL OUTLET	TDA
TW-0028	STORAGE F W TO PREHEATER	TDA
TW-0029	STORAGE COND STM INLET	TDA
TW-0030	STORAGE COND WTR OUTLET	TDA

LOCAL INDICATING INSTRUMENTATION (cont'd)

TEST WELLS

Sheet 3

Item No.	Description	Function
TW-0031	STORAGE COND OIL INLET	TDA
TW-0032	STORAGE COND OIL OUTLET	TDA

MONITORING AND CONTROL ELEMENTS

FLOW SWITCHES

Sheet 1

Item No.	Description	Function
FS-0001	COOLING TWR ACID FEED MIXING WATER	INTERLOCK
FS-0002	RECEIVER CIRC FLOW	LFI

MONITORING AND CONTROL ELEMENTS (cont'd)

FLOW TRANSMITTERS

Sheet 1

Item No.	Description	Function
FT-0001	RECEIVER STEAM TOTAL FLOW	CNT
FT-0002	RECEIVER STEAM FLOW TO STORAGE	RCD CMP
FT-0003	RECEIVER STEAM FLOW TO TURBINE	RCD CMP
FT-0004	STEAM FLOW FROM THERMAL STORAGE UNIT	RCD CMP
FT-0005	CONDENSATE TOTAL FLOW	CNT
FT-0006	FEEDWATER FLOW M.F.P. 1A	CNT
FT-0007	FEEDWATER FLOW M.F.P. 1B	CNT
FT-0008	DESUP FLOW THERMAL STORAGE UNIT	CMP RCD
FT-0009	FEEDWATER FLOW TO RECEIVER	CNT
FT-0010	FEEDWATER FLOW TO RECEIVER	RCD CMP

MONITORING AND CONTROL ELEMENTS (cont'd)

FLOW TRANSMITTERS

Sheet 2

Item No.	Description	Function
FT-0011	DESUP FLOW TO RECEIVER	CMP RCD
FT-0012	CONDENSATE FLOW	CMP CNT
FT-0013	AUXILIARY FEED PUMP FLOW	RCD CMP
FT-0014	CIRC. WTR. MAKE UP FLOW	RCD
FT-0015	RECEIVER CIRC. FLOW	CNT CMP LFA
FT-0016	RECEIVER BOILER STM FLOW	CMP IND
FT-0017	RECEIVER BOILER STM FLOW	CMP IND
FT-0018	RECEIVER BOILER STM FLOW	CMP IND
FT-0019	RECEIVER BOILER STM FLOW	CMP IND
FT-0020	RECEIVER BOILER STM FLOW	CMP IND
FT-0021	RECEIVER BOILER STM FLOW	CMP IND
FT-0022	RECEIVER BOILER STM FLOW	CMP IND
FT-0023	RECEIVER BOILER STM FLOW	CMP IND
FT-0024	RECEIVER BOILER STM FLOW	CMP IND
FT-0025	RECEIVER BOILER STM FLOW	CMP IND

MONITORING AND CONTROL ELEMENTS (cont'd)

FLOW TRANSMITTERS

Sheet 3

Item No.	Description	Function
FT-0026	STM FROM THERMAL STORAGE	CMP IND
FT-0027	HITEC FROM S.H.	CMP
FT-0028	HITEC TO COLD STR. TK.	CMP
FT-0029	HITEC TO DE S.H. INLET	CMP
FT-0030	HITEC FROM COLD STORAGE TANK	CMP
FT-0031	THERMAL STORAGE OIL FROM PREHEATER	CMP
FT-0032	THERMAL STORAGE FEEDWATER FLOW	CMP
FT-0033	THERMAL STORAGE OIL FLOW TO STORAGE TANK	CMP
FT-0034	MAIN CHARGE PUMP FLOW	CMP
FT-0035	HITEC FLOW FROM CONDENSER	CMP
FT-0036	THERMAL STORAGE OIL FLOW TO CONDENSER	CMP

MONITORING AND CONTROL ELEMENTS (cont'd)

LEVEL CONTROLLERS

Sheet 1

Item No.	Description	Function
LC-0001	H. P. HTR. LEVEL CONTROLLER	CNT
LC-0002	L. P. HTR. LEVEL CONTROLLER	CNT
LC-0003	DEAERATOR LEVEL CONTROLLER	CNT
LC-0004	MAIN COND. LEVEL CONTROLLER	CNT
LC-0005	MAIN COND. MAKEUP CONTROLLER	CNT
LC-0006	MAIN COND. DUMP CONTROLLER	CNT

MONITORING AND CONTROL ELEMENTS (cont'd)

LEVEL SWITCHES — Sheet 1

Item No.	Description	Function
LS-0001	RECEIVER STM HDR DRAIN POT LEVEL	HLI HLA
LS-0002	TURBINE H P HDR DRAIN POT LEVEL	HLI HLA
LS-0003	TRUBINE L P HDR DRAIN POT LEVEL	HLI HLA
LS-0004	THERMAL STORAGE HDR DRAIN POT LEVEL	HLI HLA
LS-0005	DEAERATOR HDR DRAIN POT LEVEL	
LS-0006	H P TURB SIDE DRAIN POT LEVEL	
LS-0007	I P TURB SIDE DRAIN POT LEVEL	
LS-0008	L P TURB SIDE DRAIN POT LEVEL	
LS-0009	H P HTR EMER HIGH LEVEL	HLI
LS-0010	H P HTR HIGH LEVEL	HLA
LS-0011	H P HTR LOW LEVEL	LLA
LS-0012	L P HTR EMER HIGH LEVEL	HLI
LS-0013	L P HTR HIGH LEVEL	HLA
LS-0014	L P HTR LOW LEVEL	LLA
LS-0015	DEAERATOR LEVEL HIGH	HLA

MONITORING AND CONTROL ELEMENTS (cont'd)

LEVEL SWITCHES

Sheet 2

Item No.	Description	Function
LS-0016	DEAERATOR LOW	LLA
LS-0017	CONDENSER LEVEL HIGH	HLA
LS-0018	CONDENSER LEVEL LOW	LLA
LS-0019	AUX CLG WTR TANK LEVEL HIGH	HLA
LS-0020	AUX CLG WTR TANK LEVEL EMER HIGH	HLI
LS-0021	AUX CLG WTR TANK LEVEL EMER LOW	LLI
LS-0022	AUX CLG WTR TANK LEVEL LOW	LLA
LS-0023	AUX CLG WTR TANK LEVEL EMER LOW	LLI
LS-0024	COOLING TWR BASIN LEVEL	HLA LLA
LS-0025	ELEVATED SVCE WTR TANK HIGH	HLA
LS-0026	ELEVATED SVCE WTR TANK HIGH	HLI
LS-0027	ELEVATED SVCE WTR TANK LOW	LLI
LS-0028	ELEVATED SVCE WTR TANK LOW	LLI
LS-0029	ELEVATED SVCE WTR TANK LOW	LLA
LS-0030	ELEVATED SVCE WTR TANK LOW	LLI

MONITORING AND CONTROL ELEMENTS (cont'd)

LEVEL SWITCHES

Sheet 3

Item No.	Description	Function
LS-0031	TURBINE LUBE OIL RESERVOIR LOW	LLA
LS-0032	TURBINE LUBE OIL CONDITIONER TK HIGH	HLA
LS-0033	TURBINE LUBE OIL CONDITIONER TK HIGH	HLA
LS-0034	SEPARATOR TK 1A LEVEL	HLA
LS-0035	SEPARATOR TK 1B LEVEL	HLA

MONITORING AND CONTROL ELEMENTS (cont'd)

LEVEL TRANSMITTERS

Sheet 1

Item No.	Description	Function
LT-0001	H. P. HEATER LEVEL	CNT
LT-0002	L. P. HEATER LEVEL	CNT
LT-0003	DEAERATOR LEVEL	CNT
LT-0004	CONDENSER LEVEL	CNT
LT-0005	COOLING TOWER BASIS LEVEL	CNT
LT-0006	RECEIVER STEAM DRUM LEVEL	CMP RCD CNT
LT-0007	RECEIVER STEAM DRUM LEVEL	HLI CMP CNT LLI
LT-0008	RECEIVER STEAM DRUM LEVEL	HLA CMP RCD LLA
LT-0009	THERMAL STORAGE BOILER LEVEL	IND CMP
LT-0010	THERMAL STORAGE BOILER LEVEL	CNT
LT-0011	THERMAL STORAGE SUB COOLER	CNT
LT-0012	THERMAL STORAGE SUB COOLER	CNT

MONITORING AND CONTROL ELEMENTS (cont'd)

PRESSURE CONTROLLERS

Sheet 1

Item No.	Description	Function
PC-0001	AUX COOLING WTR. PRESS CONTROLLER	CNT

MONITORING AND CONTROL ELEMENTS (cont'd)

PRESSURE SWITCHES

Sheet 1

Item No.	Description	Function
PS-0001	CONDENSATE LOW FLOW	LFA
PS-0002	MFP 1A INLET PRESS	LPI
PS-0003	MFP 1B INLET PRESS	LPI
PS-0004	MFP 1A STRAINER PRESS DIFF	HPA
PS-0005	MFP 1B STRAINER PRESS DIFF	HPA
PS-0006	F W BOOSTER PUMP 1A STRAINER PRESS DIFF	HPA
PS-0007	F W BOOSTER PUMP 1B STRAINER PRESS DIFF	HPA
PS-0008	CONDENSER PRESS	HPA
PS-0009	CONDENSER PRESS	HPI
PS-0010	CONDENSER PRESS	HPI
PS-0011	AUX CLG WTR PUMPS EMER LOW△P	LPI
PS-0012	AUX CLG WTR PUMPS EMER LOW△P	LPI
PS-0013	AUX CLG WTR PUMPS LOW△P	LPA
PS-0014	AUX CLG WTR BOOSTER PUMPS PRESS EMER LOW	LPI
PS-0015	AUX CLG WTR BOOSTER PUMPS PRESS EMER LOW	LPI
PS-0016	AUX CLG WTR BOOSTER PUMPS PRESS LOW	LPA

MONITORING AND CONTROL ELEMENTS (cont'd)

PRESSURE SWITCHES

Sheet 2

Item No.	Description	Function
PS-0017	CIRC WTR PRESS CONDENSER INLET	CMP
PS-0018	SERVICE WTR PUMP 1A INLET	LPA
PS-0019	SERVICE WTR PUMP 1B INLET	LPI
PS-0020	SERVICE & CONTROL AIR EMER LOW	LPI
PS-0021	SERVICE & CONTROL AIR LOW PRESS	LPA
PS-0022	SERVICE & CONTROL AIR EMER HIGH	HPI
PS-0023	SERVICE & CONTROL AIR HIGH	HPA
PS-0024	CONDENSER VACUUM	HPI
PS-0025	COND EXHAUSTER 1A STRAINER INLET	HPA
PS-0026	COND EXHAUSTER 1A VALVE HIGH DIFF	HPI
PS-0027	COND EXHAUSTER 1B STRAINER INLET	HPA
PS-0028	COND EXHAUSTER 1B VALVE HIGH DIFF	HPI

MONITORING AND CONTROL ELEMENTS (cont'd)

PRESSURE TRANSMITTERS

Sheet 1

Item No.	Description	Function
PT-0001	RECEIVER HEADER STEAM PRESSURE	RCD CMP
PT-0002	TURBINE H.P. HEADER STEAM PRESSURE	CMP RCD
PT-0003	TURBINE H.P. HEADER STEAM PRESSURE	CNT
PT-0004	TURBINE H. P. HEADER STEAM PRESSURE	EHC
PT-0005	TURBINE H.P. STEAM CHEST PRESSURE	EHC
PT-0006	TURBINE L.P. STEAM CHEST PRESSURE	EHC
PT-0007	TURBINE L.P. HEADER STEAM PRESSURE	RCD CMP
PT-0008	TURBINE LP HEADER STEAM PRESSURE	EHC
PT-0009	STEAM PRESSURE FROM THERMAL STORAGE	CNT
PT-0010	STEAM PRESSURE FROM THERMAL STORAGE	RCD CMP

MONITORING AND CONTROL ELEMENTS (cont'd)

PRESSURE TRANSMITTERS

Sheet 2

Item No.	Description	Function
PT-0011	THERMAL UNIT CHARGING STM PRESS	CNT
PT-0012	THERMAL UNIT CHARGING STM PRESS	RCD CMP
PT-0013	DEAERATOR PRESSURE	
PT-0014	FEEDWATER BOOSTER PUMPS DISCH PRESSURE	CMP IND
PT-0015	DEAERATOR DISCH PRESSURE	CMP
PT-0016	MAIN FEEDWATER PUMPS DISCH. PRESSURE	CMP IND
PT-0017	CONDENSER PRESSURE	IND
PT-0018	DEAERATOR PRESSURE	IND
PT-0019	RECEIVER STEAM DRUM PRESSURE	IND HPA CMP
PT-0020	RECEIVER 1ST STAGE S.H. OUTLET PRESS	CMP

MONITORING AND CONTROL ELEMENTS (cont'd)

PRESSURE TRANSMITTERS

Sheet 3

Item No.	Description	Function
PT-0021	RECEIVER 2ND STAGE S.H. OUTLET PRESS	RCD CMP
PT-0022	THERMAL STORAGE S.H. STM OUTLET	RCD
PT-0023	HOT HITEC TO S.H. INLET	RCD
PT-0024	HOT HITEC FROM S.H. OUTLET	RCD
PT-0025	STM TO THERMAL STORAGE S.H. INLET	RCD
PT-0026	COLD HITEC TO DESUP	RCD
PT-0027	HITEC DE. S.H. OUTLET	RCD
PT-0028	DESUP INLET	RCD
PT-0029	ATTEMPERATOR No.2 INLET	RCD
PT-0030	THERMAL STORAGE OIL BOILER INLET	RCD

MONITORING AND CONTROL ELEMENTS (cont'd)

PRESSURE TRANSMITTERS

Sheet 4

Item No.	Description	Function
PT-0031	THERMAL STORAGE OIL FROM COND. OUTLET	RCD
PT-0032	THERMAL STORAGE F.W. PREHEATER OUTLET	RCD
PT-0033	THERMAL STORAGE F.W. PREHEATER INLET	RCD
PT-0034	THERMAL STORAGE OIL PREHEATER OUTLET	RCD
PT-0035	THERMAL STORAGE OIL TK OUTLET	RCD
PT-0036	THERMAL STORAGE OIL TO COND INLET	RCD
PT-0037	THERMAL STORAGE OIL COND. OUTLET	RCD
PT-0038	HITEC TO CONDENSER INLET	RCD
PT-0039	HITEC CONDENSER OUTLET	RCD
PT-0040	REC. CIRC. PUMPS DISCH. PRESS.	RCD

MONITORING AND CONTROL ELEMENTS (cont'd)

TEMPERATURE CONTROLLERS

Sheet 1

Item No.	Description	Function
TL-0001	AUX COOLING WTR TEMP CONTROLLER	CNT

MONITORING AND CONTROL ELEMENTS (cont'd)

TEMPERATURE ELEMENTS Sheet 1

Item No.	Description	Function
TE-0001	RECEIVER HDR STM TEMP	CMP
TE-0002	RECEIVER HDR STM TEMP	RCD
TE-0003	TURBINE H P HDR STM TEMP	RCD CMP
TE-0004	TURBINE H P DHR STM TEMP	CNT
TE-0005	TURBINE L P HDR STM TEMP	CNT
TE-0006	TURBINE L P HDR STM TEMP	RCD CMP
TE-0007	THERMAL UNIT CHARGING STM TEMP	RCD CMP
TE-0008	STEAM TEMP FROM THERMAL STORAGE	RCD
TE-0009	STEAM TEMP FROM THERMAL STORAGE	CMP
TE-0010	FEEDWATER TEMP DEAERATOR OUTLET	CMP
TE-0011	FEEDWATER TEMP H P HTR INLET	CMP
TE-0012	FEEDWATER TEMP H P HTR OUTLET	CMP
TE-0013	FEEDWATER TEMP M F P DISCH	CMP
TE-0014	CONDENSATE TEMP L P HTR IN	CMP
TE-0015	CONDENSATE TEMP L P HTR OUT	CMP

MONITORING AND CONTROL ELEMENTS (cont'd)

TEMPERATURE ELEMENTS Sheet 2

Item No.	Description	Function
TE-0016	DEAERATOR TEMP	IND
TE-0017	CONDENSER TEMP	IND
TE-0018	CIRC WTR TEMP CONDENSER INLET	CMP
TE-0019	CIRC WTR TEMP COOLING TWR INLET	CMP
TE-0020	CIRC WTR TEMP COOLING TWR INLET	CMP
TE-0021	TURBINE LUBE OIL CONDITIONER TANK	CMP
TE-0022	TURBINE LUBE OIL CONDITIONER TANK	CMP
TE-0023	RECEIVER STEAM DRUM TEMP	HTA CMP
TE-0024	RECEIVER STEAM DRUM TEMP	HTA CMP
TE-0025	RECEIVER STEAM DRUM TEMP	HTA CMP
TE-0026	RECIEVER STEAM DRUM TEMP	HTA CMP
TE-0027	RECEIVER STEAM DRUM TEMP	HTA CMP
TE-0028	RECEIVER STEAM DRUM TEMP	HTA CMP
TE-0029	RECEIVER STEAM DRUM TEMP	HTA CMP
TE-0030	RECEIVER STEAM DRUM TEMP	HTA CMP

MONITORING AND CONTROL ELEMENTS (cont'd)

TEMPERATURE ELEMENTS

Sheet 3

Item No.	Description	Function
TE-0031	RECEIVER STEAM DRUM TEMP	HTA CMP
TE-0032	RECEIVER STEAM DRUM TEMP	HTA CMP
TE-0033	REC 1ST STAGE S H INLET	CMP
TE-0034	REC 1ST STAGE S H INLET	CMP
TE-0035	REC 1ST STAGE S H INLET	CMP
TE-0036	REC 1ST STAGE S H TUBES	HTA CMP
TE-0037	REC 1ST STAGE S H TUBES	HTA CMP
TE-0038	REC 1ST STAGE S H TUBES	HTA CMP
TE-0039	REC 1ST STAGE S H TUBES	HTA CMP
TE-0040	REC 1ST STAGE S H TUBES	HTA CMP
TE-0041	REC 1ST STAGE S H TUBES	HTA CMP
TE-0042	REC 1ST STAGE S H TUBES	HTA CMP
TE-0043	REC 1ST STAGE S H TUBES	HTA CMP
TE-0044	REC 1ST STAGE S H TUBES	HTA CMP
TE-0045	REC 1ST STAGE S H TUBES	HTA CMP

MONITORING AND CONTROL ELEMENTS (cont'd)

TEMPERATURE ELEMENTS

Sheet 4

Item No.	Description	Function
TE-0046	REC 1ST STAGE S H TUBES	HTA CMP
TE-0047	REC 1ST STAGE S H TUBES	HTA CMP
TE-0048	REC 1ST STAGE S H TUBES	HTA CMP
TE-0049	REC 1ST STAGE S H TUBES	HTA CMP
TE-0050	REC 1ST STAGE S H TUBES	HTA CMP
TE-0051	REC 1ST STAGE S H TUBES	HTA CMP
TE-0052	REC 1ST STAGE S H TUBES	HTA CMP
TE-0053	REC 1ST STAGE S H TUBES	HTA CMP
TE-0054	REC 1ST STAGE S H TUBES	HTA CMP
TE-0055	REC 1ST STAGE S H TUBES	HTA CMP
TE-0056	REC 1ST STAGE S H TUBES	HTA CMP
TE-0057	REC 1ST STAGE S H TUBES	HTA CMP
TE-0058	REC 1ST STAGE S H TUBES	HTA CMP
TE-0059	REC 1ST STAGE S H TUBES	HTA CMP
TE-0060	REC 1ST STAGE S H TUBES	HTA CMP

MONITORING AND CONTROL ELEMENTS (cont'd)

TEMPERATURE ELEMENTS

Sheet 5

Item No.	Description	Function
TE-0061	REC 1ST STAGE S H TUBES	HTA CMP
TE-0062	REC 1ST STAGE S H TUBES	HTA CMP
TE-0063	REC 1ST STAGE S H TUBES	HTA CMP
TE-0064	REC 1ST STAGE S H TUBES	HTA CMP
TE-0065	REC 1ST STAGE S H TUBES	HTA CMP
TE-0066	REC 1ST STAGE S H TUBES	HTA CMP
TE-0067	REC 1ST STAGE S H TUBES	HTA CMP
TE-0068	REC 1ST STAGE S H TUBES	HTA CMP
TE-0069	REC 1ST STAGE S H TUBES	HTA CMP
TE-0070	REC 1ST STAGE S H TUBES	HTA CMP
TE-0071	REC 1ST STAGE S H TUBES	HTA CMP
TE-0072	REC 1ST STAGE S H TUBES	HTA CMP
TE-0073	REC 1ST STAGE S H TUBES	HTA CMP
TE-0074	REC 1ST STAGE S H TUBES	HTA CMP
TE-0075	REC 1ST STAGE S H TUBES	HTA CMP

MONITORING AND CONTROL ELEMENTS (cont'd)

TEMPERATURE ELEMENTS

Sheet 6

Item No.	Description	Function
TE-0076	REC 1ST STAGE S H TUBES	HTA CMP
TE-0077	REC 1ST STAGE S H TUBES	HTA CMP
TE-0078	REC 1ST STAGE S H TUBES	HTA CMP
TE-0079	REC 1ST STAGE S H TUBES	HTA CMP
TE-0080	REC 1ST STAGE S H TUBES	HTA CMP
TE-0081	REC 1ST STAGE S H TUBES	HTA CMP
TE-0082	REC 1ST STAGE S H TUBES	HTA CMP
TE-0083	REC 1ST STAGE S H TUBES	HTA CMP
TE-0084	REC 1ST STAGE S H TUBES	HTA CMP
TE-0085	REC 1ST STAGE S H TUBES	HTA CMP
TE-0086	REC 1ST STAGE S H TUBES	HTA CMP
TE-0087	REC 1ST STAGE S H TUBES	HTA CMP
TE-0088	REC 1ST STAGE S H TUBES	HTA CMP
TE-0089	REC 1ST STAGE S H TUBES	HTA CMP
TE-0090	REC 1ST STAGE S H TUBES	HTA CMP

MONITORING AND CONTROL ELEMENTS (cont'd)

TEMPERATURE ELEMENTS Sheet 7

Item No.	Description	Function
TE-0091	REC 1ST STAGE S H TUBES	HTA CMP
TE-0092	REC 1ST STAGE S H TUBES	HTA CMP
TE-0093	REC 1ST STAGE S H TUBES	HTA CMP
TE-0094	REC 1ST STAGE S H TUBES	HTA CMP
TE-0095	REC 1ST STAGE S H TUBES	HTA CMP
TE-0096	REC 1ST STAGE S H TUBES	HTA CMP
TE-0097	REC 1ST STAGE S H TUBES	HTA CMP
TE-0098	REC 1ST STAGE S H TUBES	HTA CMP
TE-0099	REC 1ST STAGE S H TUBES	HTA CMP
TE-0100	REC 1ST STAGE S H TUBES	HTA CMP
TE-0101	REC 1ST STAGE S H TUBES	HTA CMP
TE-0102	REC 1ST STAGE S H TUBES	HTA CMP
TE-0103	REC 1ST STAGE S H TUBES	HTA CMP
TE-0104	REC 1ST STAGE S H TUBES	HTA CMP
TE-0105	REC 1ST STAGE S H TUBES	HTA CMP

MONITORING AND CONTROL ELEMENTS (cont'd)

TEMPERATURE ELEMENTS

Sheet 8

Item No.	Description	Function
TE-0106	REC 1ST STAGE S H TUBES	HTA CMP
TE-0107	REC 1ST STAGE S H TUBES	HTA CMP
TE-0108	REC 1ST STAGE S H TUBES	HTA CMP
TE-0109	REC 1ST STAGE S H TUBES	HTA CMP
TE-0110	REC 1ST STAGE S H TUBES	HTA CMP
TE-0111	REC 1ST STAGE S H TUBES	HTA CMP
TE-0112	REC 1ST STAGE S H TUBES	HTA CMP
TE-0113	REC 1ST STAGE S H TUBES	HTA CMP
TE-0114	REC 1ST STAGE S H TUBES	HTA CMP
TE-0115	REC 1ST STAGE S H TUBES	HTA CMP
TE-0116	REC 1ST STAGE S H TUBES	HTA CMP
TE-0117	REC 1ST STAGE S H TUBES	HTA CMP
TE-0118	REC 1ST STAGE S H TUBES	HTA CMP
TE-0119	REC 1ST STAGE S H TUBES	HTA CMP
TE-0120	REC 1ST STAGE S H TUBES	HTA CMP

MONITORING AND CONTROL ELEMENTS (cont'd)

TEMPERATURE ELEMENTS

Sheet 9

Item No.	Description	Function
TE-0121	REC 1ST STAGE S H TUBES	HTA CMP
TE-0122	REC 1ST STAGE S H TUBES	HTA CMP
TE-0123	REC 1ST STAGE S H TUBES	HTA CMP
TE-0124	REC 1ST STAGE S H TUBES	HTA CMP
TE-0125	REC 1ST STAGE S H TUBES	HTA CMP
TE-0126	REC 1ST STAGE S H OUTLET HDR	CMP
TE-0127	REC 1ST STAGE S H OUTLET HDR	CMP
TE-0128	REC 1ST STAGE S H OUTLET HDR	CMP
TE-0129	REC DESUP INLET STM	RCD
TE-0130	REC DESUP INLET STM	CMP HTI HTA
TE-0131	REC 2ND STAGE S H INLET	RCD
TE-0132	REC 2ND STAGE S H INLET	CMP HTI HTA
TE-0133	REC 2ND STAGE S H OUTLET	CMP HTA CNT, HTI
TE-0134	REC 2ND STAGE S H OUTLET	RCD

MONITORING AND CONTROL ELEMENTS (cont'd)

TEMPERATURE ELEMENTS Sheet 10

Item No.	Description	Function
TE-0135	REC 2ND STAGE S H TUBES	CMP HTA
TE-0136	REC 2ND STAGE S H TUBES	CMP HTA
TE-0137	REC 2ND STAGE S H TUBES	CMP HTA
TE-0138	REC 2ND STAGE S H TUBES	CMP HTA
TE-0139	REC 2ND STAGE S H TUBES	CMP HTA
TE-0140	REC 2ND STAGE S H TUBES	CMP HTA
TE-0141	REC 2ND STAGE S H TUBES	CMP HTA
TE-0142	REC 2ND STAGE S H TUBES	CMP HTA
TE-0143	REC 2ND STAGE S H TUBES	CMP HTA
TE-0144	REC 2ND STAGE S H TUBES	CMP HTA
TE-0145	REC 2ND STAGE S H TUBES	CMP HTA
TE-0146	REC 2ND STAGE S H TUBES	CMP HTA
TE-0147	REC 2ND STAGE S H TUBES	CMP HTA
TE-0148	REC 2ND STAGE S H TUBES	CMP HTA
TE-0149	REC 2ND STAGE S H TUBES	CMP HTA

MONITORING AND CONTROL ELEMENTS (cont'd)

TEMPERATURE ELEMENTS Sheet 11

Item No.	Description	Function
TE-0150	REC 2ND STAGE S H TUBES	CMP HTA
TE-0151	REC 2ND STAGE S H TUBES	CMP HTA
TE-0152	REC 2ND STAGE S H TUBES	CMP HTA
TE-0153	REC 2ND STAGE S H TUBES	CMP HTA
TE-0154	REC 2ND STAGE S H TUBES	CMP HTA
TE-0155	REC 2ND STAGE S H TUBES	CMP HTA
TE-0156	REC 2ND STAGE S H TUBES	CMP HTA
TE-0157	REC 2ND STAGE S H TUBES	CMP HTA
TE-0158	REC 2ND STAGE S H TUBES	CMP HTA
TE-0159	REC 2ND STAGE S H TUBES	CMP HTA
TE-0160	REC 2ND STAGE S H TUBES	CMP HTA
TE-0161	REC 2ND STAGE S H TUBES	CMP HTA
TE-0162	REC 2ND STAGE S H TUBES	CMP HTA
TE-0163	REC 2ND STAGE S H TUBES	CMP HTA
TE-0164	REC 2ND STAGE S H TUBES	CMP HTA

MONITORING AND CONTROL ELEMENTS (cont'd)

TEMPERATURE ELEMENTS

Sheet 12

Item No.	Description	Function
TE-0165	REC 2ND STAGE S H TUBES	CMP HTA
TE-0166	REC 2ND STAGE S H TUBES	CMP HTA
TE-0167	REC 2ND STAGE S H TUBES	CMP HTA
TE-0168	REC 2ND STAGE S H TUBES	CMP HTA
TE-0169	REC 2ND STAGE S H TUBES	CMP HTA
TE-0170	REC 2ND STAGE S H TUBES	CMP HTA
TE-0171	REC 2ND STAGE S H TUBES	CMP HTA
TE-0172	REC 2ND STAGE S H TUBES	CMP HTA
TE-0173	REC 2ND STAGE S H TUBES	CMP HTA
TE-0174	REC 2ND STAGE S H TUBES	CMP HTA
TE-0175	REC 2ND STAGE S H TUBES	CMP HTA
TE-0176	REC 2ND STAGE S H TUBES	CMP HTA
TE-0177	REC 2ND STAGE S H TUBES	CMP HTA
TE-0178	REC 2ND STAGE S H TUBES	CMP HTA
TE-0179	REC 2ND STAGE S H TUBES	CMP HTA

MONITORING AND CONTROL ELEMENTS (cont'd)

TEMPERATURE ELEMENTS

Sheet 13

Item No.	Description	Function
TE-0180	REC 2ND STAGE S H TUBES	CMP HTA
TE-0181	REC 2ND STAGE S H TUBES	CMP HTA
TE-0182	REC 2ND STAGE S H TUBES	CMP HTA
TE-0183	REC 2ND STAGE S H TUBES	CMP HTA
TE-0184	REC 2ND STAGE S H TUBES	CMP HTA
TE-0185	REC 2ND STAGE S H TUBES	CMP HTA
TE-0186	REC 2ND STAGE S H TUBES	CMP HTA
TE-0187	REC 2ND STAGE S H TUBES	CMP HTA
TE-0188	REC 2ND STAGE S H TUBES	CMP HTA
TE-0189	REC 2ND STAGE S H TUBES	CMP HTA
TE-0190	REC 2ND STAGE S H TUBES	CMP HTA
TE-0191	REC 2ND STAGE S H TUBES	CMP HTA
TE-0192	REC 2ND STAGE S H TUBES	CMP HTA
TE-0193	REC 2ND STAGE S H TUBES	CMP HTA
TE-0194	REC 2ND STAGE S H TUBES	CMP HTA

MONITORING AND CONTROL ELEMENTS (cont'd)
TEMPERATURE ELEMENTS

Sheet 14

Item No.	Description	Function
TE-0195	REC 2ND STAGE S H TUBES	CMP HTA
TE-0196	REC 2ND STAGE S H TUBES	CMP HTA
TE-0197	REC 2ND STAGE S H TUBES	CMP HTA
TE-0198	REC 2ND STAGE S H TUBES	CMP HTA
TE-0199	REC 2ND STAGE S H TUBES	CMP HTA
TE-0200	REC 2ND STAGE S H TUBES	CMP HTA
TE-0201	REC 2ND STAGE S H TUBES	CMP HTA
TE-0202	REC 2ND STAGE S H TUBES	CMP HTA
TE-0203	REC 2ND STAGE S H TUBES	CMP HTA
TE-0204	REC 2ND STAGE S H TUBES	CMP HTA
TE-0205	REC 2ND STAGE S H TUBES	CMP HTA
TE-0206	REC 2ND STAGE S H TUBES	CMP HTA
TE-0207	REC 2ND STAGE S H TUBES	CMP HTA
TE-0208	REC 2ND STAGE S H TUBES	CMP HTA
TE-0209	REC 2ND STAGE S H TUBES	CMP HTA

MONITORING AND CONTROL ELEMENTS (cont'd)

TEMPERATURE ELEMENTS

Sheet 15

Item No.	Description	Function
TE-0210	REC 2ND STAGE S H TUBES	CMP HTA
TE-0211	REC 2ND STAGE S H TUBES	CMP HTA
TE-0212	REC 2ND STAGE S H TUBES	CMP HTA
TE-0213	REC 2ND STAGE S H TUBES	CMP HTA
TE-0214	REC 2ND STAGE S H TUBES	CMP HTA
TE-0215	REC 2ND STAGE S H TUBES	CMP HTA
TE-0216	REC 2ND STAGE S H TUBES	CMP HTA
TE-0217	REC 2ND STAGE S H TUBES	CMP HTA
TE-0218	REC 2ND STAGE S H TUBES	CMP HTA
TE-0219	REC 2ND STAGE S H TUBES	CMP HTA
TE-0220	REC 2ND STAGE S H TUBES	CMP HTA
TE-0221	REC 2ND STAGE S H TUBES	CMP HTA
TE-0222	REC 2ND STAGE S H TUBES	CMP HTA
TE-0223	REC 2ND STAGE S H TUBES	CMP HTA
TE-0224	REC 2ND STAGE S H TUBES	CMP HTA

MONITORING AND CONTROL ELEMENTS (cont'd)

TEMPERATURE ELEMENTS — Sheet 16

Item No.	Description	Function
TE-0225	REC 2ND STAGE S H OUTLET TEMP	CMP
TE-0226	REC 2ND STAGE S H OUTLET TEMP	CMP
TE-0227	REC 2ND STAGE S H OUTLET TEMP	CMP
TE-0228	REC BOILER WTR INLET	CMP
TE-0229	REC BOILER WTR INLET	CMP IND
TE-0230	REC DRUM DISCH TO CIRC PUMPS	HTA CMP
TE-0231	REC DRUM DISCH TO CIRC PUMPS	CMP
TE-0232	REC BOILER TUBES	CMP
TE-0233	REC BOILER TUBES	CMP
TE-0234	REC BOILER TUBES	CMP
TE-0235	REC BOILER TUBES	CMP
TE-0236	REC BOILER TUBES	CMP
TE-0237	REC BOILER TUBES	CMP
TE-0238	REC BOILER TUBES	CMP
TE-0239	REC BOILER TUBES	CMP

MONITORING AND CONTROL ELEMENTS (cont'd)

TEMPERATURE ELEMENTS Sheet 17

Item No.	Description	Function
TE-0240	REC BOILER TUBES	CMP
TE-0241	REC BOILER TUBES	CMP
TE-0242	REC BOILER TUBES	CMP
TE-0243	REC BOILER TUBES	CMP
TE-0244	REC BOILER TUBES	CMP
TE-0245	REC BOILER TUBES	CMP
TE-0246	REC BOILER TUBES	CMP
TE-0247	REC BOILER TUBES	CMP
TE-0248	REC BOILER TUBES	CMP
TE-0249	REC BOILER TUBES	CMP
TE-0250	REC BOILER TUBES	CMP
TE-0251	REC BOILER TUBES	CMP
TE-0252	REC BOILER TUBES	CMP
TE-0253	REC BOILER TUBES	CMP
TE-0254	REC BOILER TUBES	CMP

MONITORING AND CONTROL ELEMENTS (cont'd)

TEMPERATURE ELEMENTS Sheet 18

Item No.	Description	Function
TE-0255	REC BOILER TUBES	CMP
TE-0256	REC BOILER TUBES	CMP
TE-0257	REC BOILER TUBES	CMP
TE-0258	REC BOILER TUBES	CMP
TE-0259	REC BOILER TUBES	CMP
TE-0260	REC BOILER TUBES	CMP
TE-0261	REC BOILER TUBES	CMP
TE-0262	REC BOILER TUBES	CMP
TE-0263	REC BOILER TUBES	CMP
TE-0264	REC BOILER TUBES	CMP
TE-0265	REC BOILER TUBES	CMP
TE-0266	REC BOILER TUBES	CMP
TE-0267	REC BOILER TUBES	CMP
TE-0268	REC BOILER TUBES	CMP
TE-0269	REC BOILER TUBES	CMP

MONITORING AND CONTROL ELEMENTS (cont'd)

TEMPERATURE ELEMENTS Sheet 19

Item No.	Description	Function
TE-0270	REC BOILER TUBES	CMP
TE-0271	REC BOILER TUBES	CMP
TE-0272	REC BOILER TUBES	CMP
TE-0273	REC BOILER TUBES	CMP
TE-0274	REC BOILER TUBES	CMP
TE-0275	REC BOILER TUBES	CMP
TE-0276	REC BOILER TUBES	CMP
TE-0277	REC BOILER TUBES	CMP
TE-0278	REC BOILER TUBES	CMP
TE-0279	REC BOILER TUBES	CMP
TE-0280	REC BOILER TUBES	CMP
TE-0281	REC BOILER TUBES	CMP
TE-0282	REC BOILER TUBES	CMP
TE-0283	REC BOILER TUBES	CMP
TE-0284	REC BOILER TUBES	CMP

MONITORING AND CONTROL ELEMENTS (cont'd)

TEMPERATURE ELEMENTS

Sheet 20

Item No.	Description	Function
TE-0285	REC BOILER TUBES	CMP
TE-0286	REC BOILER TUBES	CMP
TE-0287	REC BOILER TUBES	CMP
TE-0288	REC BOILER TUBES	CMP
TE-0289	REC BOILER TUBES	CMP
TE-0290	REC BOILER TUBES	CMP
TE-0291	REC BOILER TUBES	CMP
TE-0292	REC BOILER TUBES	CMP
TE-0293	REC BOILER TUBES	CMP
TE-0294	REC BOILER TUBES	CMP
TE-0295	REC BOILER TUBES	CMP
TE-0296	REC BOILER TUBES	CMP
TE-0297	REC BOILER TUBES	CMP
TE-0298	REC BOILER TUBES	CMP
TE-0299	REC BOILER TUBES	CMP

MONITORING AND CONTROL ELEMENTS (cont'd)

TEMPERATURE ELEMENTS

Sheet 21

Item No.	Description	Function
TE-0300	REC BOILER TUBES	CMP
TE-0301	REC BOILER TUBES	CMP
TE-0302	REC BOILER TUBES	CMP
TE-0303	REC BOILER TUBES	CMP
TE-0304	REC BOILER TUBES	CMP
TE-0305	REC BOILER TUBES	CMP
TE-0306	REC BOILER TUBES	CMP
TE-0307	REC BOILER TUBES	CMP
TE-0308	REC BOILER TUBES	CMP
TE-0309	REC BOILER TUBES	CMP
TE-0310	REC BOILER TUBES	CMP
TE-0311	REC BOILER TUBES	CMP
TE-0312	REC BOILER TUBES	CMP
TE-0313	REC BOILER TUBES	CMP
TE-0314	REC BOILER TUBES	CMP

MONITORING AND CONTROL ELEMENTS (cont'd)

TEMPERATURE ELEMENTS Sheet 22

Item No.	Description	Function
TE-0315	REC BOILER TUBES	CMP
TE-0316	REC BOILER TUBES	CMP
TE-0317	REC BOILER TUBES	CMP
TE-0318	REC BOILER TUBES	CMP
TE-0319	REC BOILER TUBES	CMP
TE-0320	REC BOILER TUBES	CMP
TE-0321	REC BOILER TUBES	CMP
TE-0322	THERMAL STORAGE S H STM OUTLET	CNT
TE-0323	THERMAL STORAGE S H STM OUTLER	RCD
TE-0324	HOT HITEC TO S H INLET	RCD
TE-0325	HOT HITEC S H OUTLET	RCD
TE-0326	HOT HITEC S H OUTLET	CNT
TE-0327	HITEC COLD STORAGE TK INLET	CNT
TE-0328	STORAGE S H STM INLET	RCD
TE-0329	COLD HITEC STORAGE OUTLET	CNT

MONITORING AND CONTROL ELEMENTS (cont'd)

TEMPERATURE ELEMENTS

Sheet 23

Item No.	Description	Function
TE-0330	COLD HITEC STORAGE OUTLET	CNT
TE-0331	HITEC DESUP INLET	RCD
TE-0332	HITEC DESUP INLET	CNT
TE-0333	HITEC DESUP OUTLET	RCD
TE-0334	HITEC DESUP OUTLET	CNT
TE-0335	ATTEMPERATOR NO 1 OUTLET	CNT
TE-0336	DE S H STM INLET	RCD
TE-0337	ATTEMPERATOR NO 2 INLET WTR	CNT
TE-0338	F W TO THERMAL PREHEATER	CNT
TE-0339	F W TO THERMAL PREHEATER	RCD
TE-0340	PREHEATER F W DISCH	RCD
TE-0341	THERMAL STORAGE OIL TO COND INLET	RCD
TE-0342	THERMAL STORAGE OIL TO COND OUTLET	RCD
TE-0343	THERMAL STORAGE OIL PREHEATER INLET	CNT
TE-0344	THERMAL STORAGE OIL PREHEATER OUTLET	RCD

MONITORING AND CONTROL ELEMENTS (cont'd)

TEMPERATURE ELEMENTS

Sheet 24

Item No.	Description	Function
TE-0345	THERMAL STORAGE OIL TANK OUTLET	CNT
TE-0346	THERMAL STORAGE OIL TANK OUTLET	RCD
TE-0347	THERMAL STORAGE OIL TO STORAGE TANK	CNT
TE-0348	HITEC CONDENSER INLET	RCD
TE-0349	HITEC CONDENSER OUTLET	RCD
TE-0350	THERMAL STORAGE OIL COND OUTLET	RCD
TE-0351	THERMAL STORAGE OIL COND OUTLET	CNT
TE-0352	THERMAL STORAGE OIL COND INLET	CNT
TE-0353	THERMAL STORAGE OIL COND INLET	RCD

MONITORING AND CONTROL ELEMENTS (cont'd)

TEMPERATURE SWITCHES Sheet 1

Item No.	Description	Function
TS-0001	COND EXHAUSTER 1A SEAL WATER HIGH	HTI
TS-0002	COND EXHAUSTER 1A SEAL WATER HIGH	HTA
TS-0003	COND EXHAUSTER 1B SEAL WATER HIGH	HTI
TS-0004	COND EXHAUSTER 1B SEAL WATER HIGH	HTA

APPENDIX H

EXPERIMENTAL PROGRAM DATA REQUIREMENTS

APPENDIX H

EXPERIMENTAL PROGRAM DATA REQUIREMENTS

Experimental program data requirements are not developed in detail; however, the following are anticipated.

<u>Collector Subsystem</u>

Data requirements for the Collector Subsystem are reported in Volume III.

<u>ReceiverSubsystem</u>

Heat Flux:

- Boiler
- First Stage Superheater
- Second Stage Superheater
- Boiler to First Stage Superheater Ratio
- Boiler to Second Stage Superheater Ratio
- First Stage Superheater Flux to Steam Flow Ratio
- Second Stage Superheater Flux to Steam Flow Ratio

Temperatures:

- Tube Metal
  - Boiler Average
  - First Stage Superheater Average
  - Second Stage Superheater Average
  - Drum Saturated Steam
  - First Stage Superheater Outlet Steam
  - Second Stage Superheater Outlet Steam
  - Feedwater

Pressures:

Recirculation System Differential

Feedwater

Attemperator Outlet

Superheater Outlet

Drum Level

Mass Flows

Feedwater (Precision)

Steam to Turbine

Steam to Storage

Recirculation Loops

Attemperator (Precision)

Miscellaneous Measurements

Saturated Steam Quality

Water Chemistry Data

<u>Generation Subsystem</u>

1. Turbine Generator

Temperatures

High Pressure Inlet Steam

Low Pressure Inlet Steam

Each Extraction

Pressures

High Pressure Inlet Steam

Low Pressure Inlet Steam

Each Extraction

Exhaust

Flows

High Pressure Inlet Steam

Low Pressure Inlet Steam

Steam Seal, Valve Leakoff, Cooling Steam

Electrical

Generator, kW, kVa, Volts, Amps

Exciter Volts, Amps

2. Condenser

Temperatures - Ambient Air In and Out

Exhaust Pressure

Miscellaneous

Wind Velocity and Direction

Fan Motor Power

Vacuum Pump Data

3. Condensate and Feedwater System

Temperatures

Condensate Receiver

Condensate Pump Discharge

Condensate to Low Pressure Heater

Condensate to Deaerator

Feed Pump Suction

Feed Pump Discharge

High Pressure Heater Inlet

High Pressure Heater Outlet

High Pressure Heater Drips

Low Pressure Heater Drips

Deaerator Level

Pressures

Deaerator Shell

Feed Pump Discharge

Flows

Condensate to Deaerator (Precision)

Feedwater to Storage

Heater Drips (Calculated)

Miscellaneous

Feed Pump Motor Power

Thermal Subsystem

Data requirements for the Thermal Storage Subsystem are reported in Volume V.

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