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# 10 MWe Solar Thermal Central Receiver Pilot Plant Control System Description

McDonnell Douglas Astronautics Company
5301 Bolsa Avenue
Huntington Beach, CA 92647

Prepared by Sandia National Laboratories, Albuquerque, New Mexico 87185
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# 10 MWe SOLAR THERMAL CENTRAL RECEIVER PILOT PLANT CONTROL SYSTEM DESCRIPTION

Contract Report Prepared
Under SNLL Contract 90-1523

McDonnell Douglas Astronautics Company

## ABSTRACT

This report describes the control system for the 10 MWe Solar Thermal Central Receiver Pilot Plant located near Barstow, Ca. The plant, called Solar One, is a cooperative activity between the Department of Energy and the Associates: Southern California Edison, the Los Angeles Dept. of Water and Power and the California Energy Commission. This report provides an overview of the plant control system including the rationale for the design approach and the configuration which resulted in response to program requirements.

## SOLAR THERMAL TECHNOLOGY
## FOREWORD

The research and development described in this document was conducted within the U.S. Department of Energy's (DOE) Solar Thermal Technology Program. The goal of the Solar Thermal Technology Program is to advance the engineering and scientific understanding of solar thermal technology, and to establish the technology base from which private industry can develop solar thermal power production options for introduction into the competitive energy market.

Solar thermal technology concentrates solar radiation by means of tracking mirrors or lenses onto a receiver where the solar energy is absorbed as heat and converted into electricity or incorporated into products as process heat. The two primary solar thermal technologies, central receivers and distributed receivers, employ various point and line-focus optics to concentrate sunlight. Current central receiver systems use fields of heliostats (two-axis tracking mirrors) to focus the sun's radiant energy onto a single tower-mounted receiver. Parabolic dishes up to 17 meters in diameter track the sun in two axes and use mirrors or Fresnel lenses to focus radiant energy onto a receiver. Troughs and bowls are line-focus tracking reflectors that concentrate sunlight onto receiver tubes along their focal lines. Concentrating collector modules can be used alone or in a multi-module system. The concentrated radiant energy absorbed by the solar thermal receiver is transported to the conversion process by a circulating working fluid. Receiver temperatures range from 100°C in low-temperature troughs to over 1500°C in dish and central receiver systems.

The Solar Thermal Technology Program is directing efforts to advance and improve promising system concepts through the research and development of solar thermal materials, components, and subsystems, and the testing and performance evaluation of subsystems and systems. These efforts are carried out through the technical direction of DOE and its network of national laboratories who work with private industry. Together they have established a comprehensive, goal directed program to improve performance and provide technically proven options for eventual incorporation into the nation's energy supply.

To be successful in contributing to an adequate national energy supply at reasonable cost, solar thermal energy must eventually be economically competitive with a variety of other energy sources. Components and system-level performance targets have been developed as quantitative program goals. The performance targets are used in planning research and development activities, measuring progress, assessing alternative technology options, and making optimal component developments. These targets will be pursued vigorously to insure a successful program.

This report describes the control system for the 10 MWe Solar Thermal Central Receiver Pilot Plant (Solar One). This is part of the continuing evaluation of the pilot plant for the Solar Thermal Technology Program.

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# ACRONYMS AND ABBREVIATIONS

| | |
|---|---|
| ADF | Archive Disk File |
| AK | Annunciator Keyboard |
| ASCII | American Standardized Control for Information Interchange |
| AUX | Auxiliary |
| BAP | Bus Access Processor |
| BCS | Beam Characterized System |
| BOP | Balance of Plant |
| B/W | Black and White |
| CAL | Calibrate |
| CAP | Console Access processor |
| CB | Control Building |
| CCM | Communications Control Module |
| CCP | Communications and Control Processor |
| CCU | Central Control Unit |
| CO | Control Operator |
| CON | Console |
| CPU | Central Processing Unit |
| CRT | Cathode Ray Tube |
| CRTF | Central Receiver Test Facility in Albuquerque |
| CS | Collector Subsystem |
| CSM | Configuration Storage Module |
| CTM | Communications Translator Module |
| DARMS | Data Acquisition and Remote Multiplexing System |

| | |
|---|---|
| DAS | Data Acquisition System |
| EHC | Electro Hydraulic Control |
| EPGS | Electric Power Generating System |
| GE | General Electric Company |
| GLBDB | Global Common Area |
| HAC | Heliostat Array Controller |
| HC | Heliostat Controller |
| HCP | Host Communications Processor |
| HFC | Heliostat Field Controller |
| HP | Hewlett Packard Company |
| HTP | Historic Trend Processor |
| HZ | Hertz or Frequency |
| I/F | Interface |
| ILS | Interlock Logic System |
| I/O | Input/Output |
| IPAC | Trademark of IPAC Group, Inc. |
| ISC | Intelligent Systems Corporation |
| J-BOX | Junction Box |
| KB or Kb | Kilobit/Sec |
| KBP | Keyboard Processor |
| MAX (IV) | Trademark of MODCOMP Operating System Sotware |
| MAXNET (IV) | Trademark of MODCOMP Multicomputer Operating System Software |
| MB or Mb | Megabyte |
| MCS | Master Control Subsystem |

| | |
|---|---|
| MODACS | Trademark of MODCOMP for Modulator Data Acquisition and Control Subsystem |
| MODCOMP | Trademark for Modulator Computer Systems Incorporated |
| MUX | Multiplexer |
| MTU | Magnetic Tape Unit |
| MVCU | Multivariable Control Unit |
| NIP | Normal Incidence Pyroheliometer |
| OCS | Operational Control System |
| OLSF | On-Line Simulation Facility |
| OPIU | Operator Programmable Interface Unit |
| OSP | Operator Station Processor |
| PCI | Peripheral Control Interface |
| PEO | Plant Equipment Operator |
| PIP | Peripheral Interface Processor |
| PLC or PC | Program Logic Controller |
| PTF | Pointer File |
| PTL | Plant Trip Logic |
| RADL | Reports and Deliverables List |
| RAM | Random Access Memory |
| RGP | Report Generation Processor |
| RI | Rockwell International |
| RLU | Red Line Unit |
| RMU | Remote Multiplexer Unit |
| ROM | Read Only Memory |
| RS | Receiver Subsystem |

| | |
|---|---|
| RS-232-C | Telecommunications Interface Standard Specification |
| SCE | Southern California Edison |
| S/R | Stearns Roger Company |
| SCU | Signal Conditioning Unit |
| SDPC | Subsystem Distributed Process Control System |
| SDS | Steam Dump System |
| SETF | Solar Energy Test Facility |
| SFDI | Solar Facility Design Integration |
| SHIMMS | Special Heliostat Instrumentation and Meteorological Measurements System |
| SIL | System Integration Laboratory |
| SW | Switch |
| T/G | Turbine Generator |
| TCG | Time Code Generator |
| TR | Trend Recorder |
| TRF | Tag Reference File |
| TSS | Thermal Storage Subsystem |
| TSU | Thermal Storage Unit |
| UMU | Ullage Maintenance Unit |
| VAC | Alternating Current Voltage |
| VDC | Direct Current Voltage |
| WSM | Watts Per Square Meter |

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7. Solar One Plant Automation Objectives Document, October 1984. (MDC H0631).

8. Solar I Plant Control System Design Requirements Drawing No. 1D44755, Rev C. 24 November 1984.

9. OCS Supervisory Control Instructions for Plant Operations.

10. CS-MCS and CS Plant Interface Requirements (RADL Item 2-30-1) dated June 1982.

11. RCS-7 Operator's Guide, Document No. 04-99-01, dated 8/01/83.

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14. Thermal Storage Test Report, TSU Bed Conditioning (1040A), Thermal Storage System Controls Test (1040B), MDC-H0632, dated November 1983.

15. Mode 2, 3, 4 and 7 Test Report, Preliminary Draft, dated February 1985.

16. 10 MWe Solar Thermal Contral Receiver Pilot Plant, Mode 1 (Test 1110) Test Report, dated October 1984.

17. 10 MWe Solar Thermal Control Receiver Pilot Plant Modes 5 and 6 (Test 1150 and 1160) Test Report, (unreleased).

18. Solar One Automation Test Report - Preliminary draft, dated February 1985.

19. GEK-71561 - Operators Manual, Turbine and Generator, SCE Solar I Generating Station.

# Section 1

# INTRODUCTION

This document describes the control system for the 10 MWE Solar Thermal Central Receiver Pilot Plant, Solar One, located near Barstow, California. It provides an overview of the plant control system used at Solar One including the rationale for the design approach taken and the configuration that resulted in response to program design requirements.

A description of the control system topology is given in Section 2. This section includes a summary of the plant control system requirements, the design and development approach taken and the overall architecture of the control/monitor system chosen for the plant. Section 3 includes a functional and pictorial description of the subsystem hardware utilized in the control/monitor/evaluation functions including the CS, SDPC, HAC, ILS, OCS, DAS, and the plant trip logic. The software employed for the CS, SDPS, OCS, ILS and DAS systems are described in Section 4 including functional descriptions of the interfaces of each. Section 5 discusses the goals of automating the plant on the subsystem and plant levels including the design approach taken and the functions automated. It also includes a description of plant operation for a typical operating day. The Man-Machine Interface functions of monitor, display, and control are described in Section 6 for both subsystem control utilizing the SDPC and for plant control through OCS. Descriptions of the keyboards, printers, light pens, dedicated pushbuttons and special function keys are included. Finally, Section 7 provides an overview of the testing and verification effort for the control system beginning with the startup cold flow tests of the receiver and ending with the plant automation testing. A description of the steam generation controls tests for the receiver and thermal storage subsystem and the manual control plant testing are also included.

A reference list of control system documentation has also been provided for use in obtaining more detailed information regarding requirements, hardware and software configurations, operating instructions, test results, etc.

# Section 2

# CONTROL SYSTEM TOPOLOGY

There were many system design considerations included in the SOLAR I program objectives which affected the plant control system design. Among these were (1) provide sufficient control flexibility to determine the most feasible and economic method of operating a commercial plant, (2) gather sufficient data to assess pilot plant performance along with its application to a commercial plant and (3) include possibility of retrofit applications in the design. Using these objectives as guidance, the following plant control system requirements and design and development approaches were generated.

## 2.1 PLANT CONTROL REQUIREMENTS

The Solar I plant control requirements may be stated as follows:

A. Provide for single operator control with part time assistance using a single console.

B. Provide a control system which is adaptable to change.

C. Separate control functions from evaluation functions.

D. Provide three methods of controlling:

    1. System (RS, TSS, EPGS) - Manual
    2. System-Automatic
    3. Master Control System (MCS) - Automatic

E. Provide a separate Data Acquisition System (DAS) with a flexible and programmable data evaluation feature.

F. Provide a separate Interlock Logic System (ILS) using a programmable controller (PC).

G. The safety and trip functions should be accomplished independent of plant control.

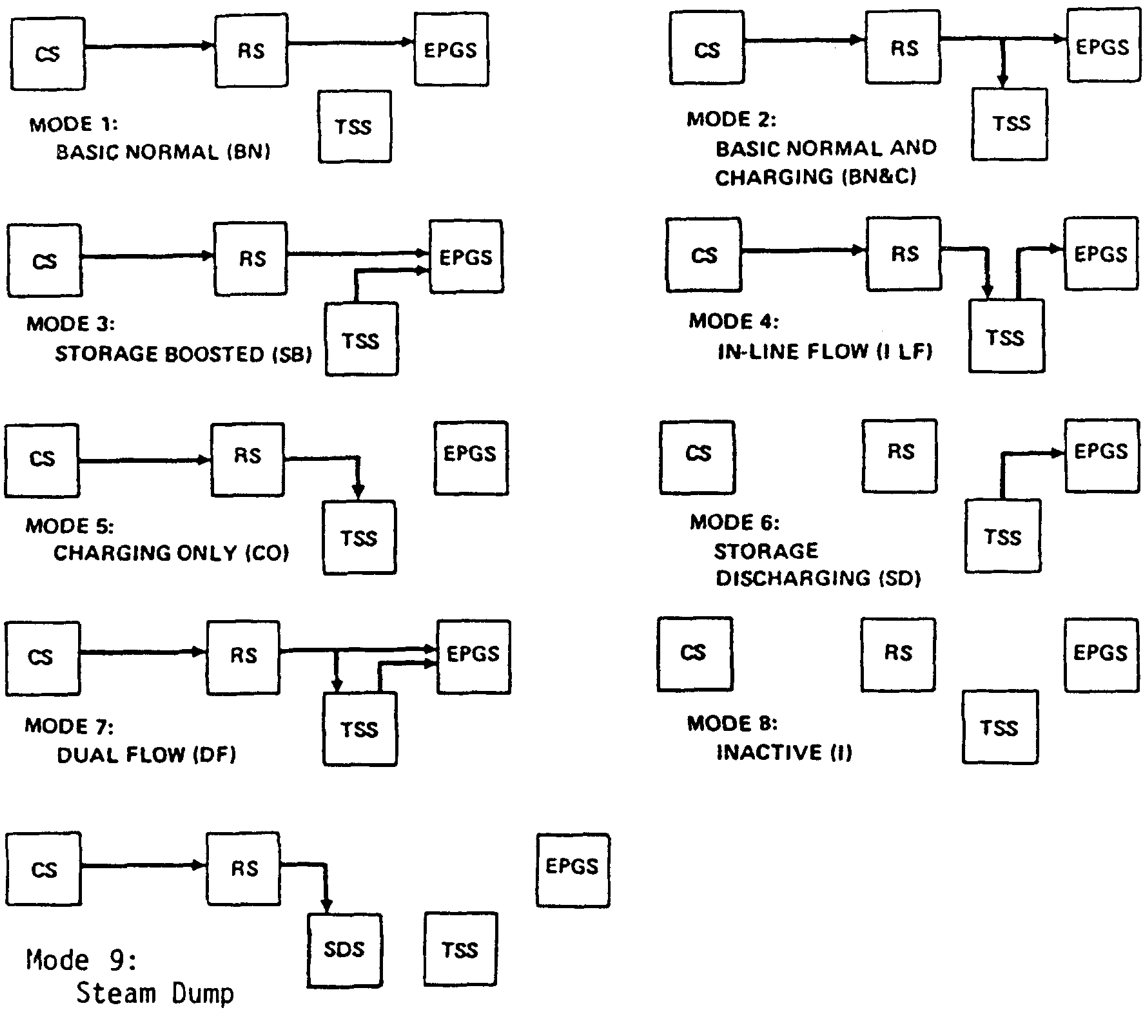
H. The control system should be capable of implementing one fully automatic "CLEAR DAY" scenario (excluding turbine startup and synchronization).

I. Minimize single point failures where cost effective.

## 2.2 DESIGN APPROACH

The Solar I plant implementation and operation is unique in the power generation industry. It was a first of a kind plant with 9 modes of operation (Figure 2-1). Some days it is subjected to non-normal cyclic, large dynamic disturbance due to clouds and wind. In addition it must be started and shut down every day, which is very unusual for a power plant. Thus, a control system was needed which could handle all these conditions and still require minimum operator interaction.

The major controls analysis effort was concentrated on the control loops which were required to support initial plant startup and turbine roll. The control loops, of which there were approximately 70, were assigned controls analyses priorities ranging from 1 to 3. Control loops assigned priority (1) were those loops which required fast response, large turndown ratios, had several feedback loops, had significant subsystem process interaction or non-linear performance characteristics. These generally were high pressure steam or high temperature oil loops. The loops assigned priority (2) were those which were critical for startup or shutdown; usually lower pressure/temperature oil or steam. Priority (3) control loops were single




| | |
|---|---|
| Mode 1 Turbine Direct: | Receiver-generated steam directly powers the turbine. |
| Mode 2 Turbine Direct and Charging: | Receiver-generated steam powers the turbine and charges storage. |
| Mode 3 Storage Boosted: | Steam from the receiver and storage powers the turbine. |
| Mode 4 In-line Flow: | Receiver steam charges storage, while storage steam is simultaneously discharged powering the turbine. |
| Mode 5 Storage Charging: | Receiver steam charges the storage system. |
| Mode 6 Storage Discharging: | Steam generated by the storage system is used to power the turbine. |
| Mode 7 Charging and Storage Boosted: | A combination of Modes 2 and 3 (probably only achieved during transitions). |
| Mode 8 Inactive: | Major systems are standing by for operation. |
| Mode 9 Steam Dump: | Receiver steam routed directly to the Condenser (used for startup, shutdown, and trips). |

Figure 2-1 Steady State Operating Modes

feedback, simple loops which were not performance critical; usually controlling water level and/or auxiliary services (steam, metering pumps, etc.). The controls analysis effort for the highest priority loops (1) included linear stability analysis at critical design conditions, transient analysis using digital simulations for responses to forcing functions (setpoints and disturbances), and an evaluation of subsystem coupling and transition responses using MDAC's OLSF facilities hybrid simulation of the plant. Priority 2 loops were designed with little or no linear stability analysis. The loop gains were established by minimum transient analysis using digital simulation techniques. Priority 3 loops were not simulated and no linear analysis conducted. The loops gains for these simple controllers were established at the site using "field tuning" techniques.

Figures 2-2 through 2-5 list the control loops (and priorities) for the Receiver (RS), TSS Charging, TSS Extraction and EPGS and Balance of Plant (BOP). The critical control loops (priority 1) for the RS included the Receiver Outlet Temperature Controllers for the 18 boiler panels, the Steam Dump System pressure controller, and the feedwater pump controllers. For the TSS Charge System, critical controllers included the TSS main inlet valve controller, the Desuperheater Outlet temperature controller, the charging Steam pressure controllers, the charging oil temperature controllers, and the charging oil pump speed controllers. For the TSS extraction system, the highest priority control loops were the extraction steam flow controllers, the extraction steam temperature controllers, the boiler water level controllers and the extraction oil pump controllers. For the EPGS and BOP there were no controllers that were considered to be of the highest priority. The EPGS and BOP controllers were all field tuned either by SCE or MDAC engineers.

Figure 2-2
RECEIVER CONTROL LOOPS

| System/Controller | Analysis Priority | Controller Tag Number(s) | Control Function |
|---|---|---|---|
| 1. Receiver Steam Outlet Temperature Controllers | (1) | TC2301,2,3 to TC2801,2,3 | Controls Steam Temperature at Outlet of Each of 18 Receiver Boiler Panels by Controlling Inlet Flow at Each Boiler Panel |
| 2. Flash Tank Discharge Routing and Control System | | | Controls Receiver Outlet Pressure During Startup-Shutdown or Any Time Dry Steam Not Produced by Receiver - Limited to 500 psia Operating Pressure |
| a. Receiver Flash Tank Pressure Controller | (2) | PC2906 | Controls Flash Tank Pressure by Venting Steam From Flash Tank to the Deaerator and Condenser |
| b. Flash Tank Steam Drain to Deaerator Pressure Controller | (2) | PC647B | Vents Steam From Flash Tank to Control Deaerator Pressure |
| c. Flash Tank Steam Drain to Condenser Desuperheater Pressure Controller | (2) | PC1000 | Vents Excess Steam Not Used By Deaerator to Condenser From Flash Tank |
| d. Flash Tank Steam Desuperheater Atomizing Steam Valve | (3) | Valve FV1007 | Open/Closed by ILS to Provide High Temperature Atomizing Flow to Mix Steam and Condensate in Desuperheater |
| e. Flash Tank Condensate Drain to High Pressure Heater No. 2 Level Controller | (2) | LC74A | Proportionately Controls Condensate Flow to High Pressure Heater No. 2 by Controlling Flash Tank Liquid to Low Level Set Point - Pressure Override Limits High Pressure Heater No. 2 Pressure to 115-125 psia |
| f. Flash Tank Condensate Drain to Condenser Level Controller | (3) | LC74C | Diverts Condensate to Condenser When Flow Decreases to High Pressure Heater No. 2 Because of Pressure Limit. Proportionally Controls Flash Tank Level to High Level Set Point |

Figure 2-2 (Continued)
RECEIVER CONTROL LOOPS

| | System/Controller | Analysis Priority | Controller Tag Number(s) | Control Function |
|---|---|---|---|---|
| 3. | Steam Dump System | | | Bypasses Flow Around Turbine to Condenser During Receiver Startup/Shutdown, Turbine Trip, TSS Trip, or RS Stand-Alone Operation |
| a. | Steam Dump Line Pressure Controller | (1) | PC1001 | Controls Receiver Back Pressure in Bypass Mode and Reduces Steam Pressure to Condenser to Acceptable Levels |
| b. | Steam Dump Line Desuperheater Temperature Controller | (3) | TCM1002 | Controls Temperature of Flow Out of Desuperheater to Condenser at 20 degrees Above Saturation Temperature Using Spray Water From Condensate Hotwell Pump |
| c. | Steam Dump Line Desuperheater Atomizing Steam Valve | (3) | Valve FV1006 | Open/Closed by ILS to Provide High Temperature Atomizing Flow to Mix Steam and Condensate in Desuperheater |
| 4. | Feedwater Pump Speed Controller | (1) | PC1105 | Controls the Feedwater Pump Speed to Maintain a Differential Pressure Across the Receiver Temperature Control Valves Such That the Maximum Commanded Valve Position is 75% Open |
| 5. | Downcomer Steam Inlet Position Controller | (3) | UCM2905 | Controls Steam Flow From RS to Downcomer During Transition Modes |
| 6. | RS Bypass Valve | (3) | HC2002 | By Operator Commands, Controls Bypass Valve at Receiver Inlet in Manual Mode During Condensate Cleanup Operations and During Initial Condensate Flow Through Receiver at Startup |

Figure 2-3
THERMAL STORAGE CHARGING CONTROL LOOPS

| System/Controller | Analysis Priority | Controller Tag Number(s) | Control Function |
|---|---|---|---|
| 1. TSS Main Inlet | (1) | UC3102 | Controls Turbine Inlet Pressure, TSS Steam Flow Rate, or Turbine Load by Controlling TSS Main Inlet Flow |
| 2. Desuperheater Outlet Temperature | (1) | TC3105 | Reduces Steam Temperature to Condenser by Controlling Additional Condensate - Steam Mixture |
| 3. Charging Steam Pressure | (1) | PC3110, PC3111 | Controls Charging Steam Pressure by Controlling Condensate Flow to the TSS Flash Tank |
| 4. Flash Tank Pressure | (2) | PC647C | Controls TSS Flash Tank Steam Pressure by Venting Flash Tank Steam Flow to the Deaerator |
| 5. Deaerator Pressure (TSS Flash Tank Steam) | (2) | PC640 | Vents Excess TSS Flash Tank Steam to the Condenser to Control the TSS Flash Tank High Pressure. (Has Condenser Pressure Override) |
| 6. Flash Tank Level | (2) | LC74B | Control No. 2 High Pressure Heater Pressure by Dumping Condensate from the TSS Flash Tank (Has Flash Tank Low Level Override) |
| 7. Flash Tank Level - High | (2) | LCM74D | Diverts Excess TSS Flash Tank Condensate to Condenser to not Exceed a High Level |
| 8. Charging Fluid Temperature | (1) | TC3411, TC3410 | Controls Charging Oil Temperature by Controlling Oil Flow Circulation |
| 9. Charging Fluid Pump | (1) | PCM3413, PCM3414 | Controls the Charging Fluid Pump Speed to Maintain a Differential Pressure Across the Charging Fluid Temperature Control Valve Such That the Maximum Commanded Valve Position Is 70% Open |

Figure 2-4
THERMAL STORAGE EXTRACTION CONTROL LOOPS

| System/Controller | Analysis Priority | Controller Tag Number(s) | Control Function |
|---|---|---|---|
| 1. Extraction Steam Flow | (1) | PC3702, FC3702, JC3702, PC3802, FC3802 JC3802 | Controls Extraction Steam Flow, Pressure, or Turbine Load by Controlling Corresponding Extraction Oil Flow Circulation |
| 2. Extraction Steam Temperature | (1) | TC3710, TC3810 | Controls Steam Temperature at TSS Outlet by Controlling Superheater Bypass Oil Flow |
| 3. Boiler Water Level | (1) | LC3505, LC3605 | Maintains Boiler Water Level Within Specified Limits |
| 4. Extraction Oil Pumps | (1) | PC3903, PC3904 | Controls Extraction Oil Pump Speed to Maintain a Differential Pressure Across the Extraction Oil Flow and Temperature Control Valves Such That the Largest of the Two Command Valve Positions is 80% Open |
| 5. Auxiliary Extraction Oil Flow | (3) | PC3910 | Controls Auxiliary Extraction Oil Flow Through Boilers to Provide Auxiliary Blanket Steam (Pressure and Temperature Set by Extraction Steam Flow and Temperature Controllers) |

Figure 2-5
EPGS AND BOP CONTROL LOOPS

| System/Controller | Analysis Priority | Controller Tag Number(s) | Control Function |
|---|---|---|---|
| 1. Turbine Inlet Valve | (2) | PCM926 | Controls Main Inlet Pressure Setpoint From SDPC if the GE Console COMPUTER ENABLE Switch is Active |
| 2. Admission Inlet | (2) | PCM937 | Controls Admission Pressure Setpoint From SDPC if the GE Console COMPUTER ENABLE Switch is Active |
| 3. Hotwell Low Level | (3) | LCM146A | Controls Condenser Hotwell Low Level by Controlling Condensate Flow From Condensate Storage Tank |
| 4. Hotwell High Level | (3) | LC146B | Controls Condenser Hotwell High Level by Controlling Condensate Return Flow to Storage From the Hotwell |
| 5. Condensate Hotwell Pump Recirculator | (3) | FC118 | Assures Adequate Flow Through the Condensate Hotwell Pump by Recirculation Back to the Hotwell |
| 6. First Point Heater Level | (3) | LC8 | Controls Level in First Point Heater by Draining Excess Fluid to Second Point Heater With Override on High Level to Close First Point Extraction Valve NV625 |
| 7. Second Point Heater | | | |
| a. Level | (3) | LC24A | Controls Level in Second Point Heater by Draining Excess Fluid to Deaerator. Has DA Overpressure, Override |
| b. High Level | (3) | LCM24B | Controls High Level in Second Point Heater by Draining Excess to Condenser |

Figure 2-5 (Continued)
EPGS AND BOP CONTROL LOOPS

| System/Controller | Analysis Priority | Controller Tag Number(s) | Control Function |
|---|---|---|---|
| 8. Deaerator | | | |
| a. Level | (3) | LC83B | Controls High Level in Deaerator Regulating Proper Flow of Condensate From Demineralizer Proportional to Flow Out of DA (RS and TS Feedwater Pumps) and Flow Out of Hotwell Pumps as Well as Level in DA |
| b. High Level | (3) | LC83A | Controls Level in Third Point Heater by Draining Excess to Condenser When Level Goes to 60 inches |
| 9. Fourth Point Heater | (3) | LC104 | Controls Fourth Point Heater Level by Draining Excess Water to Condenser |
| 10. Hydrazine Pump | (3) | AC725 | Controls Speed of Hydrazine Metering Pump |
| 11. Ammonia Pump | (3) | CC726 | Controls Speed of Ammonia Metering Pump |
| 12. Cooling Tower Basin Water Level | (3) | LC210 | Provides Adequate Water Level in Cooling Tower Basin |
| 13. Auxiliary Steam Control | | | |
| a. Main Steam Pressure | (3) | PC1003 | Maintains Receiver Steam Pressure to Provide 75 psia Steam at the Desuperheater Outlet |
| b. Admission Steam Pressure | (3) | PCM1005 | Maintains Extraction Steam Pressure to Provide 65 psia Steam at the Desuperheater Outlet |
| c. Desuperheater Temperature | (3) | TC1004 | Maintains Desuperheater Steam Outlet Temperature at 350 deg F When Providing Auxiliary Steam From the Main or Admission Lines |

Figure 2-5 (Continued)
EPGS AND BOP CONTROL LOOPS

| System/Controller | Analysis Priority | Controller Tag Number(s) | Control Function |
|---|---|---|---|
| d. Boiler Level for Auxiliary Steam | (3) | LC71 | Operates Auxiliary Boiler/TSS Feedwater Pump to Maintain Boiler Water Level in the Appropriate Boiler |
| e. Auxiliary Steam to Deaerator | (3) | PC647A<br>NPSH647A | Maintains Steam Pressure in the DA or NPSH for the Feedwater Pumps by Using Auxiliary Steam. This Use is the Main Requirement for Auxiliary Steam. |

The design approach taken for the highest priority controllers is flowcharted in Figure 2-6. A combination of testing, linear analysis, and simulation was required to arrive at the final control system design. Open loop tests conducted at the Central Receiver Test Facility (CRTF) at Albuquerque, New Mexico of a boiler panel similar to the Solar One Receiver panel was used to partially validate the dynamic model of the panel. The model was also validated with the Time and Frequency (TAF) Domain Analysis Program which accepts non-linear model equations and performs a numerical linearization about a nominal operating condition. Simplified linear models were developed using this approach for use in linear stability analyses programs to establish initial control loop gains and compensation. Higher order dynamic models were employed in the non-linear time domain digital and hybrid simulations. The hybrid simulation of the plant which included the actual hardware for the Beckman digital control unit (MVCU) was used to evaluate the final control gains, algorithms and digital logic for the critical control loops for both the Receiver and TSS.

## 2.3 CONTROL SYSTEM ARCHITECTURE

Figure 2-7 shows the overall architecture of the control/monitor system for the plant. It includes a Subsystem Distributed Process Control (SDPC) for control, a Data Acquisition System (DAS) computer to archive data and an Operational Control System (OCS) computer for master control. Also shown are the Heliostat Array Controller (HAC) computers and the Beam Characterization System (BCS) computer.

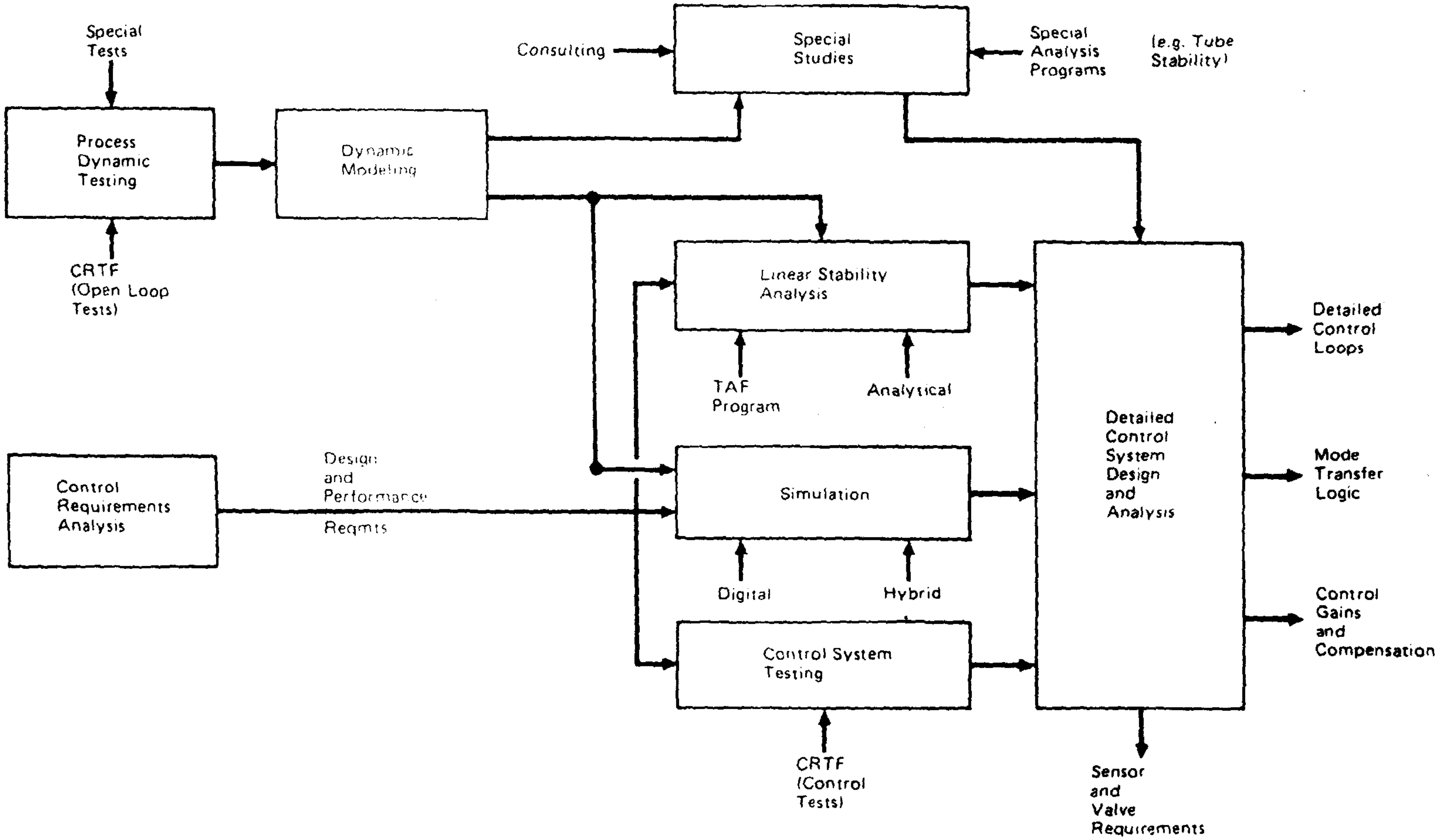



Figure 2-6. Control System Design Approach

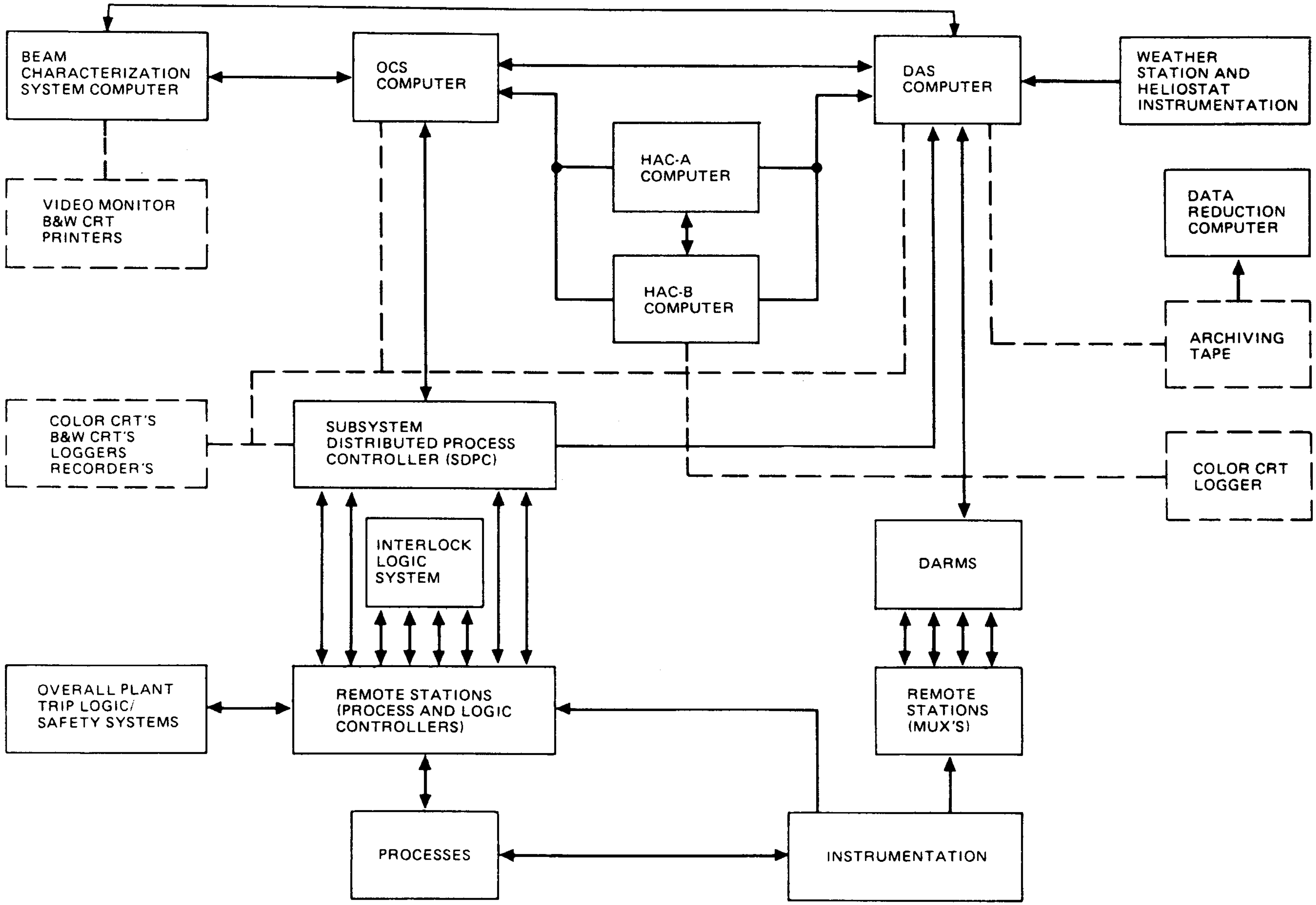



Figure 2-7. Solar One Control/Monitor Architecture

The SDPC provides the primary controls for all systems of the plant. Figure 2-8 shows pictorially the basic architecture for the SDPC. It is a distributed process control system utilizing a single control and display console with Multi-Variable Control Units (MVCU) located in various remote stations. Included are the Interlock Logic System (ILS) which has input/output modules in each remote station and the Operational Control System (OCS) computer which provides overall plant control.

The single console has the control and display functions for each of the major plant systems (RS, TSS, EPGS and BOP). The MVCU's provide the control algorithms needed for the control loops in each system and are easily reprogrammed or changed through the console. The Interlock Logic System (ILS) overlays the distributed control system to provide a separate interlock system which is also easily reprogrammed.

## 2.4 DEVELOPMENT APPROACH

The control and monitor system was developed using five levels of testing on each system:

A. System Integration Lab tests.

B. Preoperational tests.

C. Startup tests - manual mode.

D. Modes testing.

E. Plant automation testing.

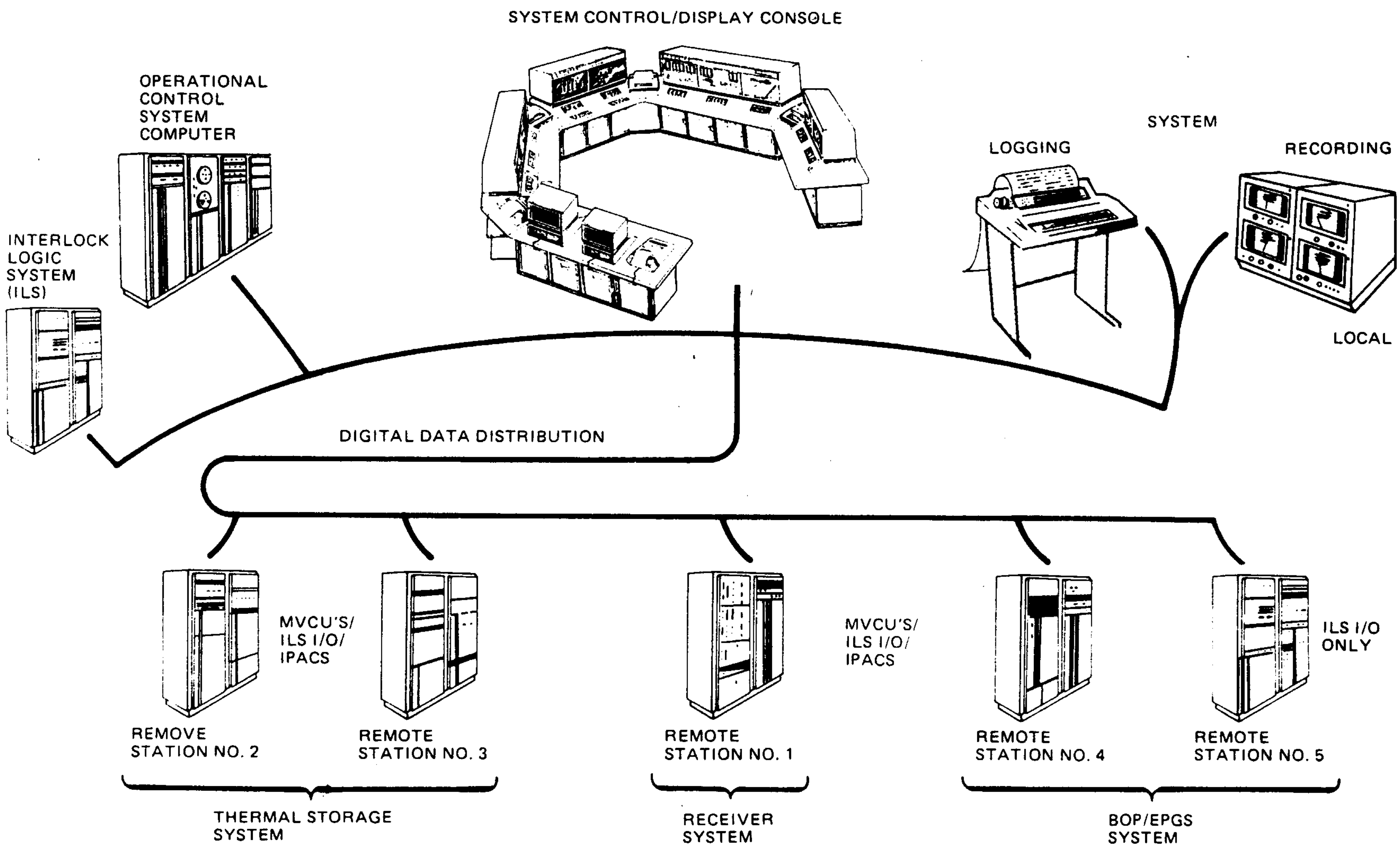



Figure 2-8. Subsystem Distributed Process Controller Layout

Once all systems were operational, additional tests verified proper overall plant control and eventually led to testing under automatic control using the OCS. The following paragraphs discuss the testing on the systems.

2.4.1 System Integration Lab (SIL) tests

The SIL was setup at the MDAC Huntington Beach facility to allow checkout and integration of the complete SDPC system. The hardware configuration consisted of the SDPC including the console, MV8000's, CRT's, MVCU's, and ILS PLC's and input/output modules. This allowed programming of the MVCU controllers and ILS and training and experience with the man-machine interface prior to installation at Solar One. Acceptance tests were run on each set of system hardware (RS, TSS, EPGS) in the console including communicating with the MVCU's and ILS. Since there were no sensors, inputs or outputs connected to the MVCU's and ILS, actual plant operation could not be simulated. Thus a hardware-in-the-loop simulation of the overall plant was set up in the MDAC OLSF lab using one MVCU which could be programmed with the controller for the system under study. This allowed investigation of a system, such as the receiver feedwater pump, being controlled by an MVCU which had been programmed with the actual algorithms to be used in the plant. When another system was to be studied, the MVCU would be reprogrammed with the appropriate controller.

In the SIL, the complete data base for each system was loaded into the data base core memory and MVCU's (as applicable). It also was stored on floppy disks for later use in loading the data base at the site after equipment installation.

The interlock logic was programmed in the ILS PLC and program tapes were made for use in loading the ILS program at the site. Logic which was considered critical to plant startup (e.g., receiver feedwater pump permissive logic) was checked out wherever possible using simulated inputs.

A training program was conducted in the SIL for the Southern California Edison operators who would be operating the plant. This program gave the operators their first look at the console and provided initial "hands-on" time to learn how to call up displays, service alarms, etc.

### 2.4.2 Preoperational Tests

At the conclusion of SIL testing the control and monitor equipment was moved to the Solar I site for installation. Acceptance testing was started on each system as it was installed. The SDPC data base core memory and MVCU's were loaded from the floppy disks and the ILS was loaded from the program tapes. The control system tests were done in four steps: functional checkout, open loop tests, loop tuning and closed loop tests.

The functional tests consisted of end-to-end checkout of each loop from the operator console to the equipment in the field for outputs, or from the field sensor back to the operator console for inputs. Simulated inputs were used where actual sensor outputs were not available or not feasible.

Once the functional tests were complete, open loop tests were accomplished on specific control loops (e.g., RS panel temperature control valves) to better determine the loop/process response characteristics. The results of these tests were used as inputs to update the analytical models being used in control loop design.

Loop tuning and closed loop tests were run in parallel on all control loops, especially those on which no analysis had been performed. In general, the final gain adjustments were made when subjecting the control loop to a step input and recording the closed loop response.

2.4.3 Startup Tests

Startup testing commenced on each system (RS, TSS, EPGS) as soon as preoperational testing was complete. Startup was done in a mode of operation known as SDPC "Manual" where one or more control loops were in closed loop operation (AUTO) with the operator in control of the setpoints for those loops. Other operating loops involving steam, condensate or oil flow paths were in manual control. An example would be where the operator would manually establish flow through the RS flash tank by a prescribed valve lineup. The flash tank condensate level would be controlled by a level controller in closed loop operation (LCM74C-AUTO). The operator would then manually cause the RS panels to fill until flow was established through the panels and the bypass around the receiver to the flash tank was closed. This type of manual procedure would be used until the receiver was flowing steam through the flash tank (heliostat field supplying heat to RS) and eventually to the downcomer and turbine.

This manual procedure was used on all systems for startup. As experience was gained in the operation of the system and plant, it was recognized that if various procedures and/or sequences were automated it would greatly improve the efficiency and availability of the plant. Much automation was accomplished and is discussed in Section 5.

### 2.4.4 Mode Testing

As soon as startup testing was complete on all systems required for a particular mode, testing of that mode would begin. Modes tested were modes 1 through 7. The tests were to designed to gather data on steady state operation in a mode, transition between modes and responses to trip. This test series is described in paragraph 7.2 Manual Control (1100 series tests).

### 2.4.5 Plant Automation Testing

When all modes required for plant automation were operational, automation testing was started. These tests were designed to demonstrate both manual and automatic plant operation under OCS control. This test series is described in paragraph 7.3 Automatic Control (1200 series tests).

## Section 3

## CONTROL SYSTEM HARDWARE DESCRIPTION

As shown in Figure 2-6 the control, monitor and evaluation functions for Solar I are performed by the SDPC, HAC, ILS, OCS, DAS, hardwired plant trip logic and various CRT's and printer/loggers (BCS shown for completeness but not discussed in this description). The equipment is located in the central control building and in remote locations distributed in the core area and the collector field. Figure 3-1 shows the location of the four remote stations in the core area. Remote Station 5 is located near the cooling tower.

The second floor of the control building, Figure 3-2, contains all the central control and instrumentation equipment. The Master Control Console, Figure 3-3, provides the operator interfaces to the computers and peripheral equipment located in the equipment room, Figure 3-4, and remote stations. The CRT's, data loggers, and strip charts interface to the computers and are used to evaluate the results of plant operation from locations in the evaluation room, Figure 3-5.

Figures 3-6, 3-7, and 3-8 show the locations of the equipment cabinets and J-boxes in the remote station used to interface the field devices to the central control building equipment.

The hardware for each of the systems is described in the following paragraphs. Reference 5 provides detailed descriptions of all these equipments.

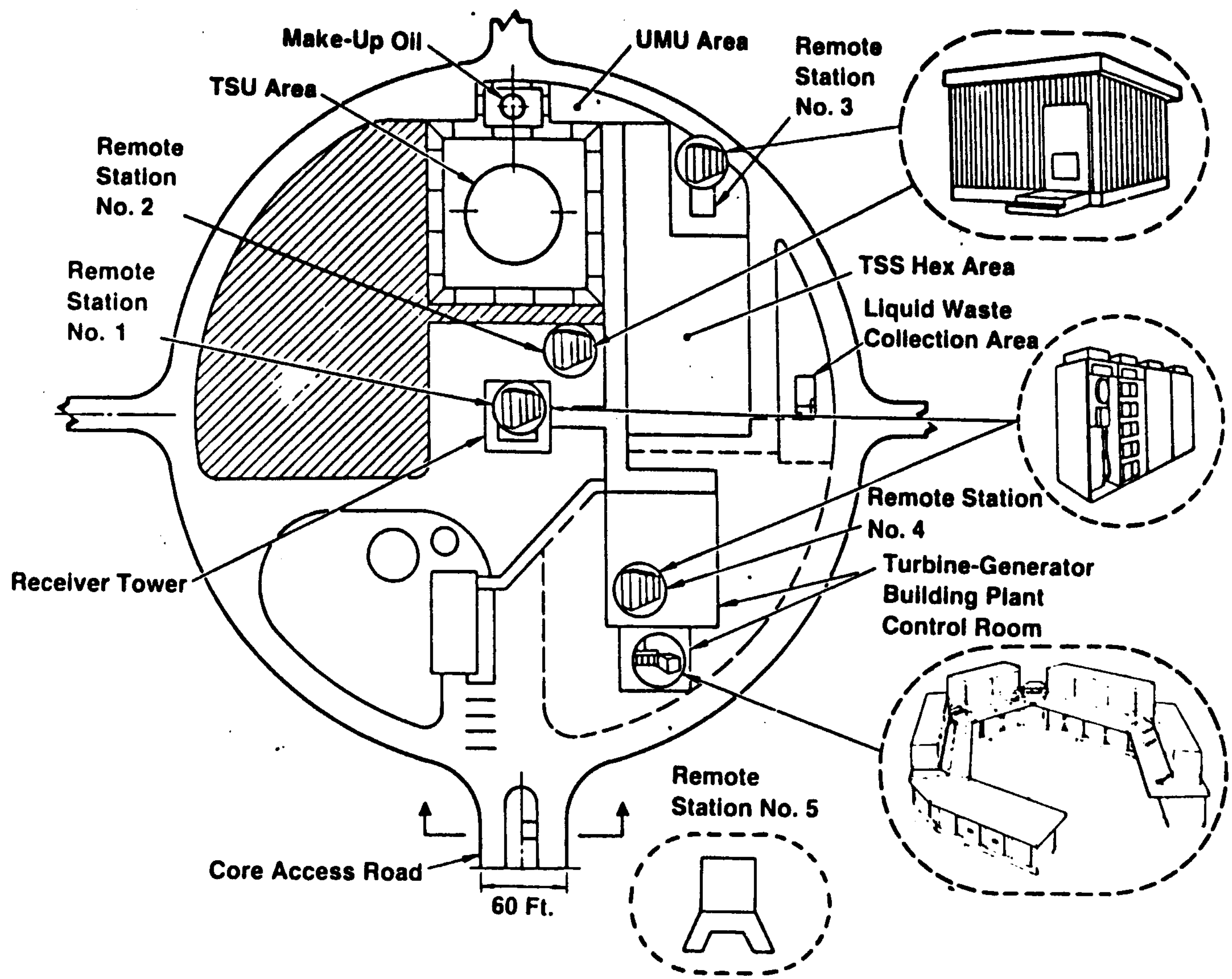



Figure 3-1. Core Area Equipment Locations

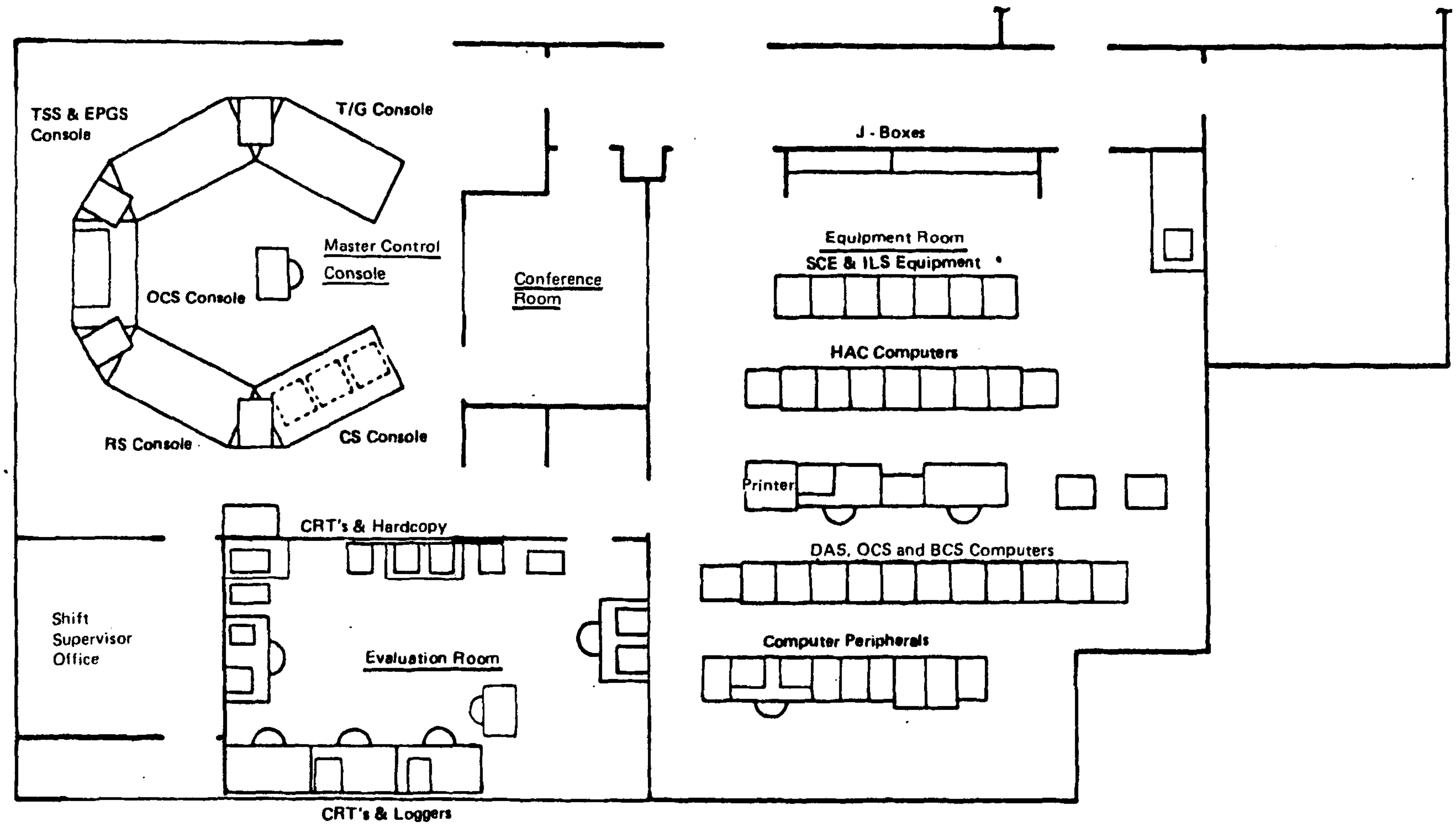



Figure 3-2. Control Building – Second Floor

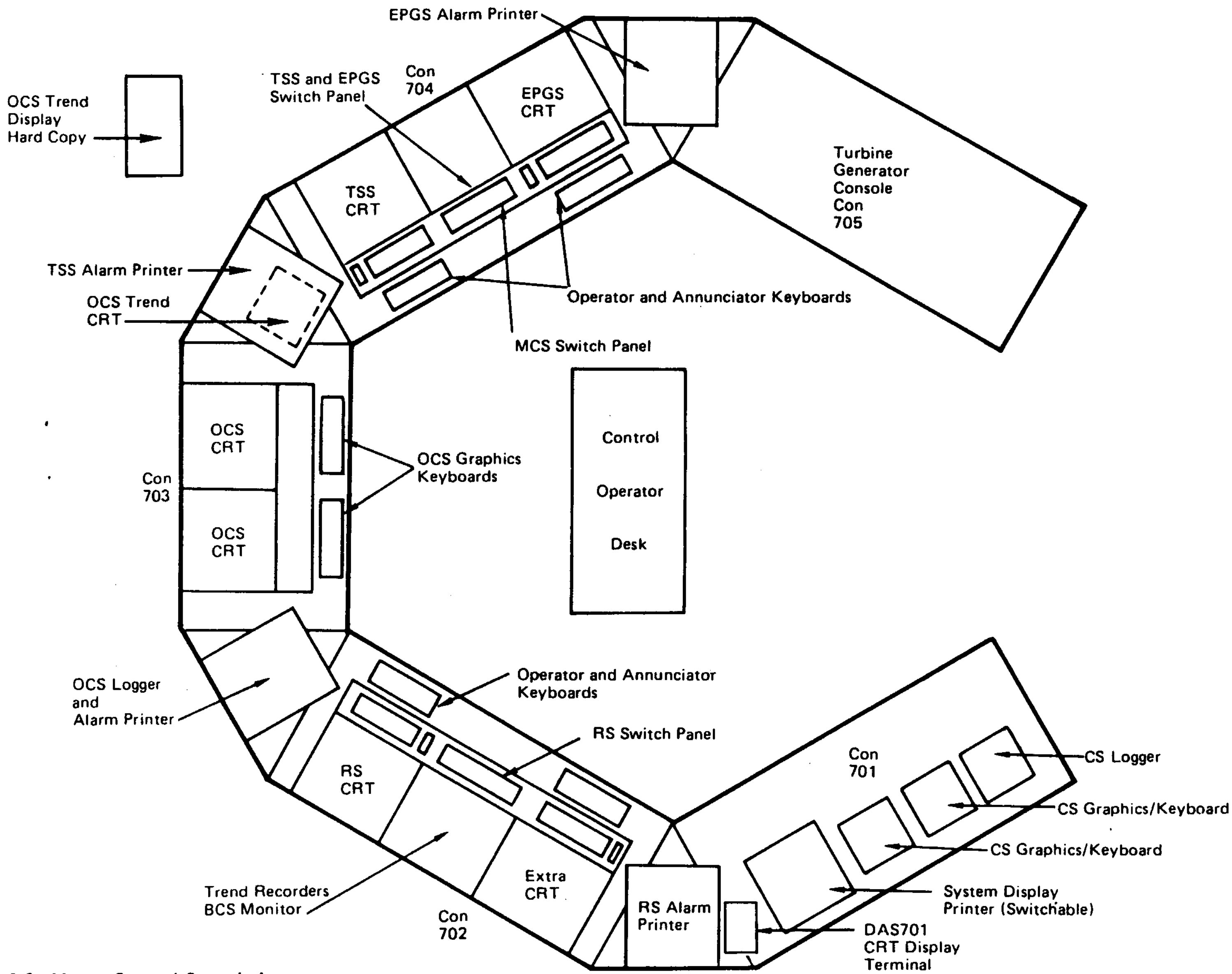



Figure 3-3. Master Control Console Layout

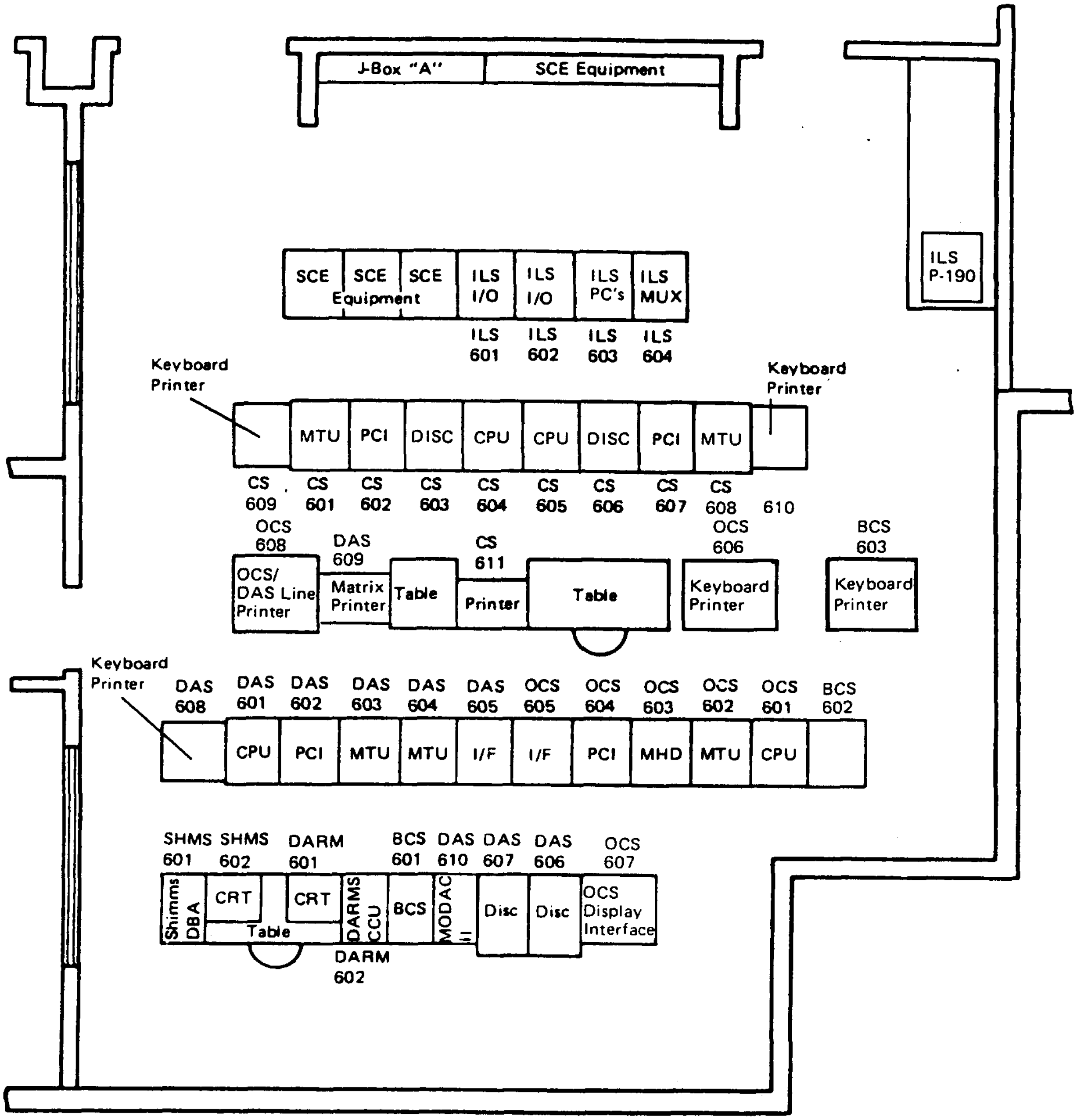



Figure 3-4. Equipment Room

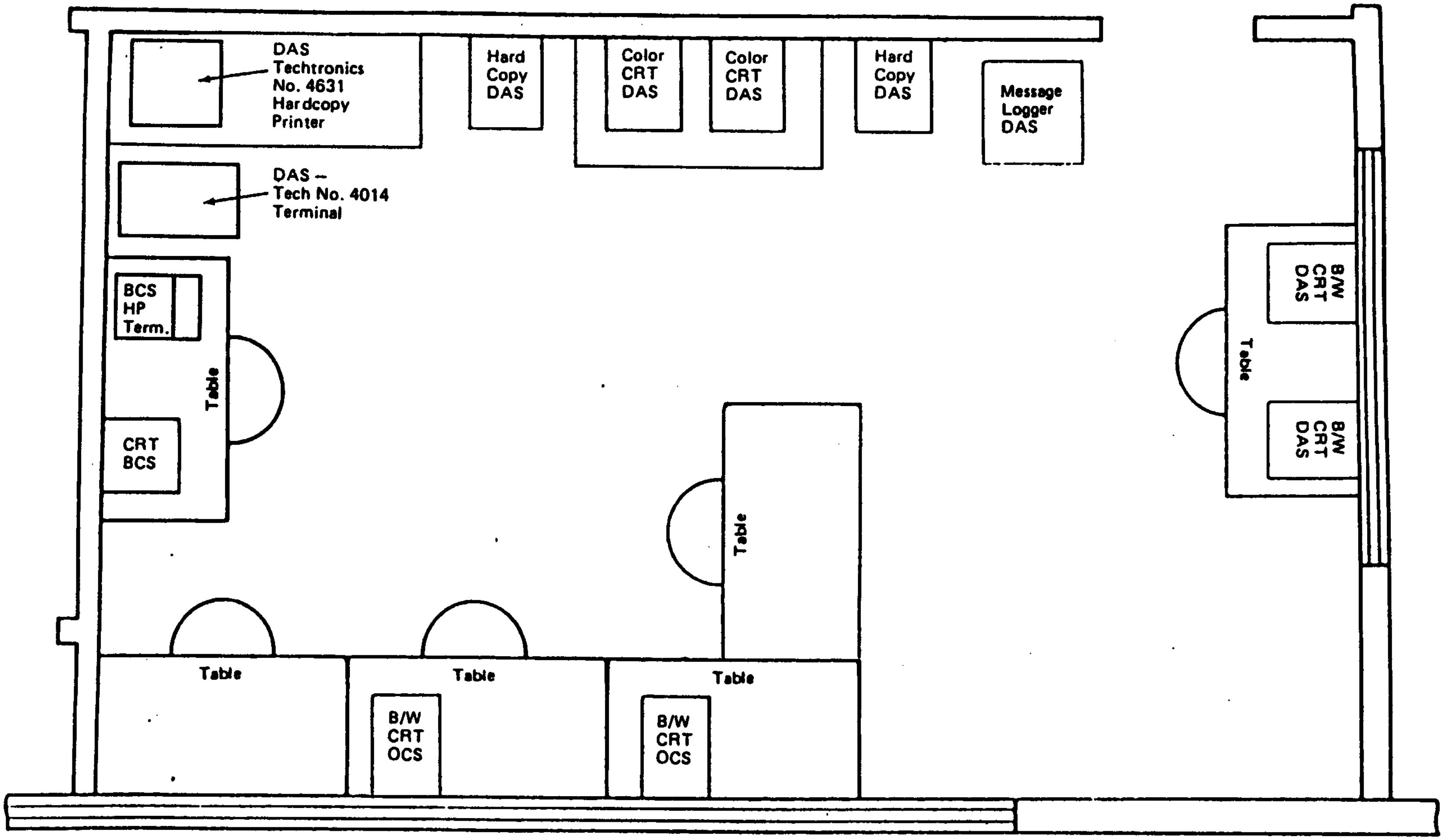



Figure 3-5. Evaluation Room

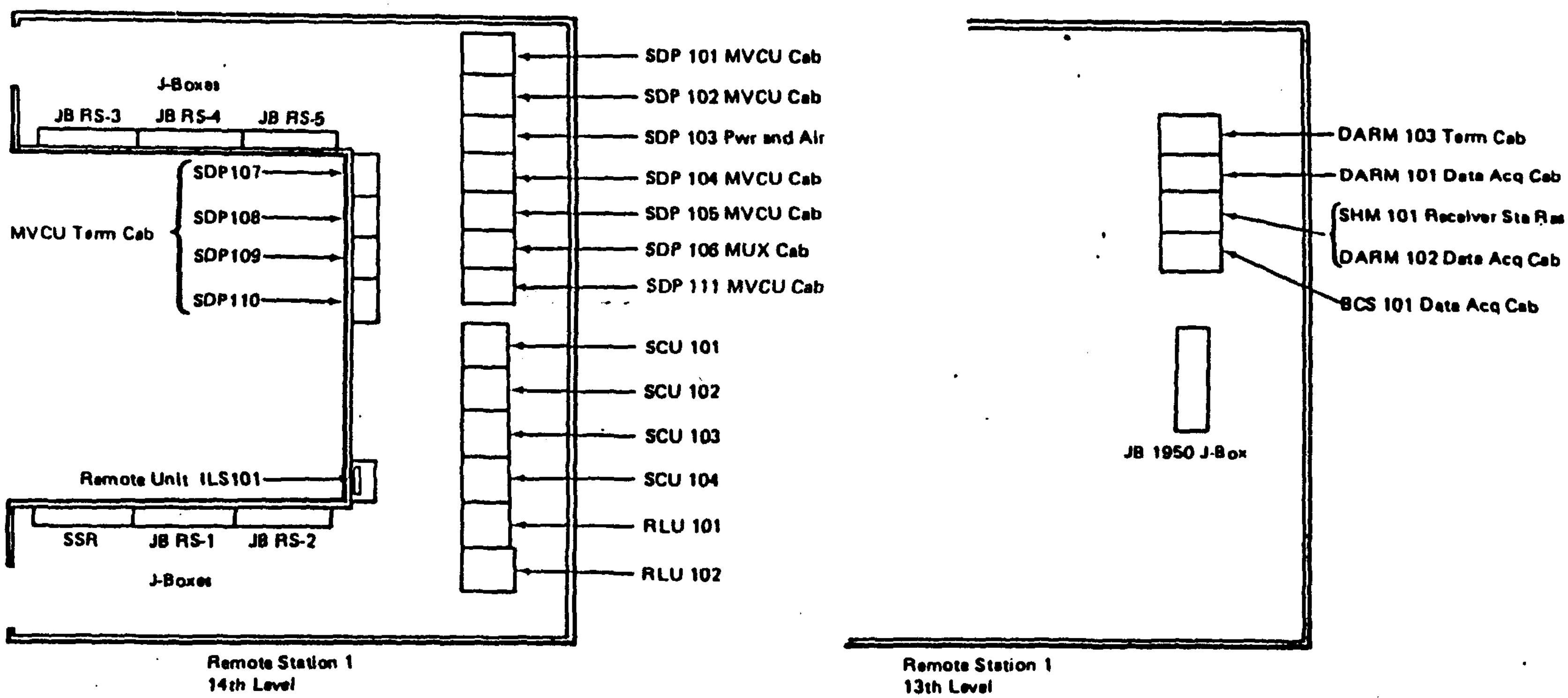



*Figure 3-6. Remote Station 1 Layout*

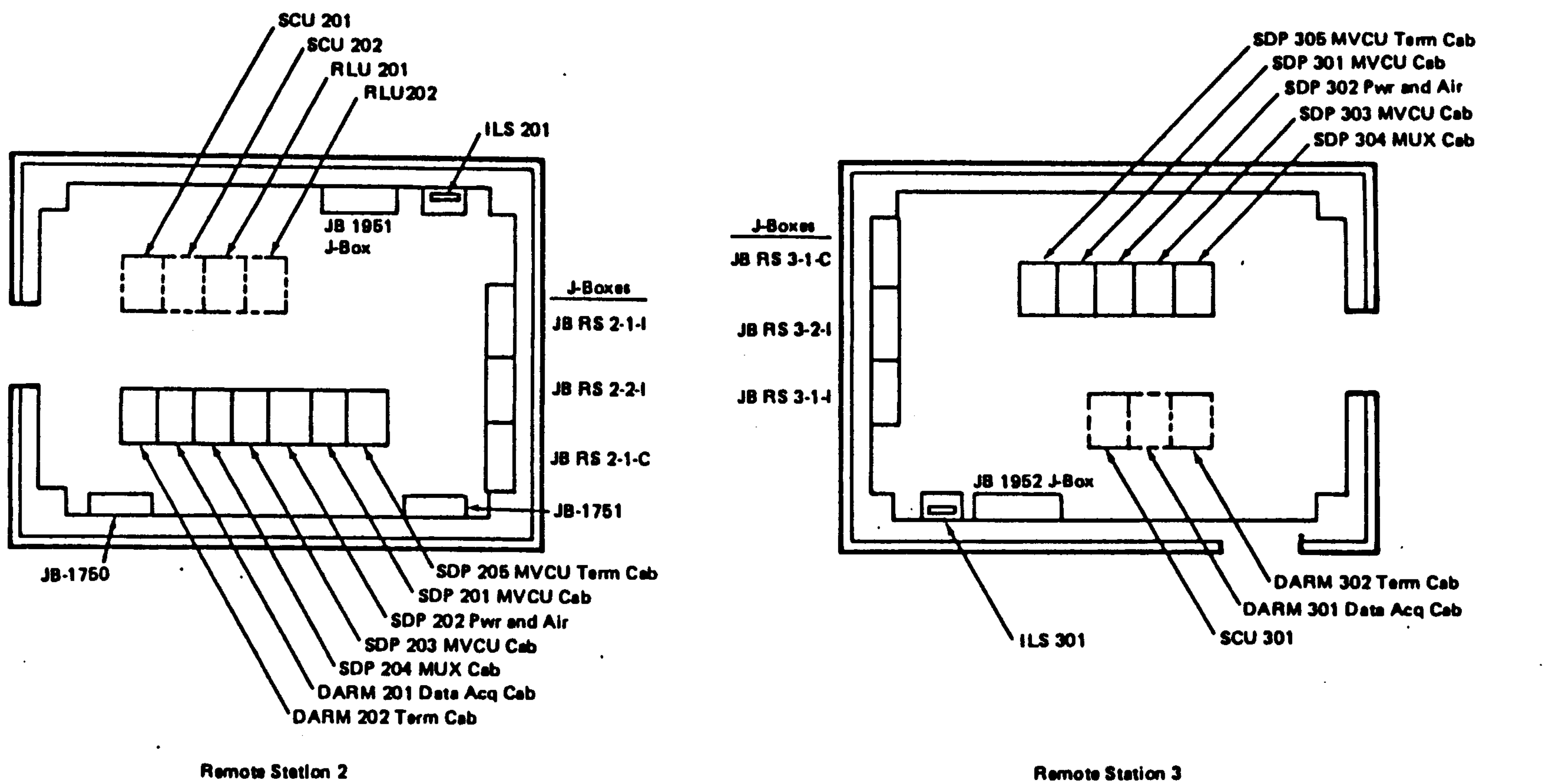



Figure 3-7. Remote Station 2 and 3 Layout

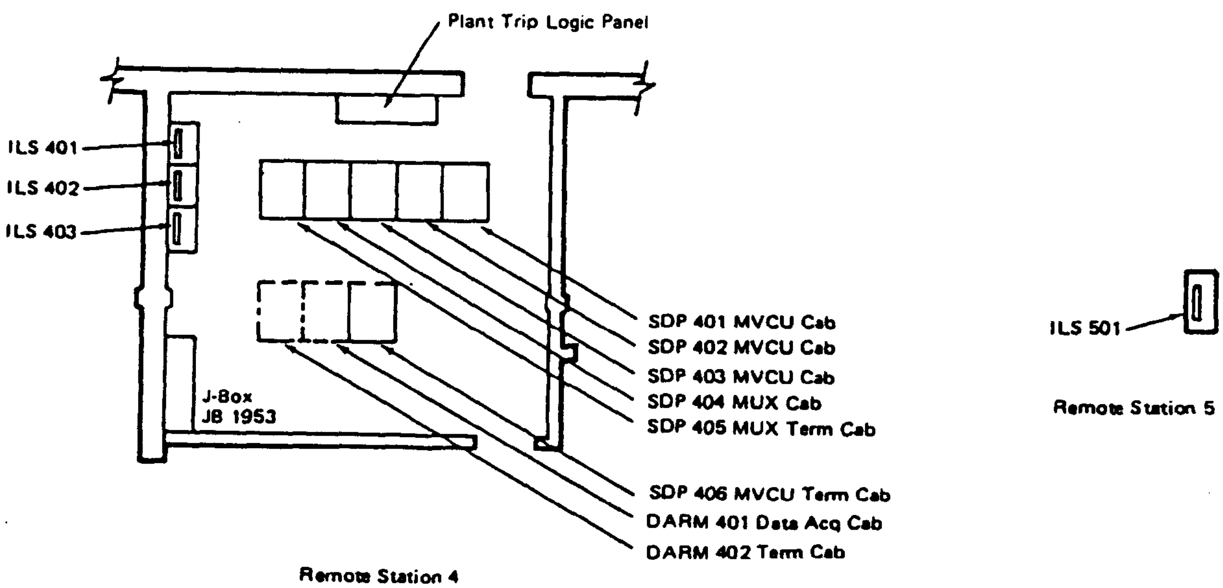



Figure 3-8. Remote Station 4 and 5 Layout

## 3.1 COLLECTOR FIELD HARDWARE

The Heliostat Array Controller (HAC) system provides redundant computers for control of the Collector Subsystem (CS). The collector control system is also a distributed system using a central computer (HAC) to supervise the pointing and tracking functions of the heliostat controllers located on each heliostat. Figure 3-9 shows the equipment and physical locations. There are two color graphic CRT's in the control room; one for operator use for controlling the field and one to display status of the entire field. A message/alarm logger is also located in the control room.

The two HAC's are located in the Equipment room and include a peripheral switch which allows all outside interface to be directed to only one computer at a time. Each HAC has its own console device, 10 m byte disk and magnetic tape deck used to load and run programs. A line printer is available for special printout. The OCS, BCS and DAS computers are connected to the HAC to record field status or send commands during some modes of operation.

Communication of the HAC with each heliostat in the field is accomplished through two controllers: the Heliostat Field Controller (HFC) and the Heliostat Controller (HC). There are 64 HFC's spread throughout the field. Each HFC can control up to 32 HC's. There are 1818 HC's, one for each heliostat.

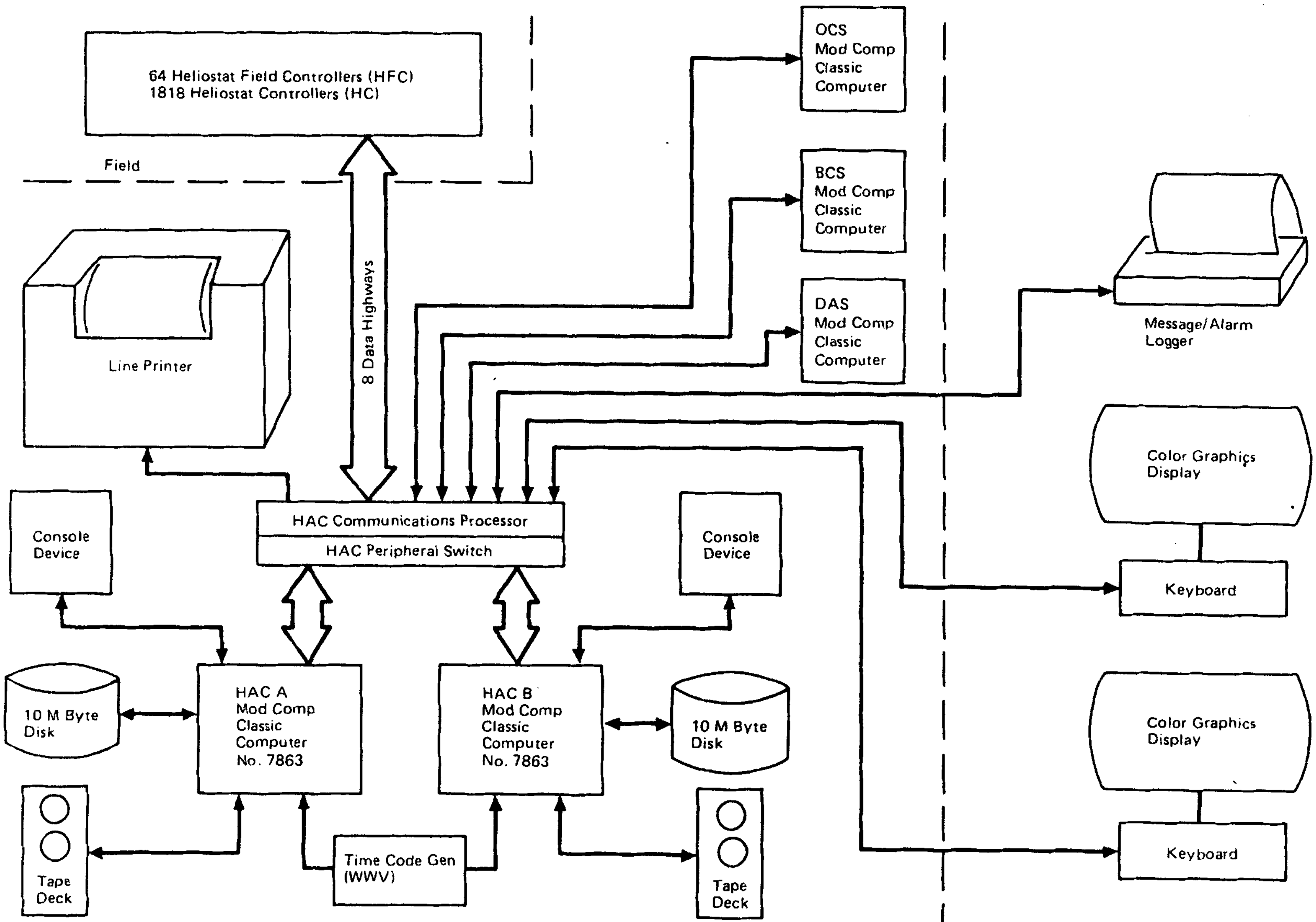



Figure 3-9. Collector Field Control Equipment and Physical Locations

## 3.2 SUBSYSTEMS DISTRIBUTED PROCESS CONTROLLER (SDPC)

The SDPC equipment provides independent centralized control of the Receiver Subsystem (RS), the Thermal Storage Subsystem (TSS) and the Electrical Power Generation Subsystem (EPGS). The system consists of functionally and physically distributed monitoring and control devices that provide manual control capability and access for automatic computer control. It is composed of three Beckman MV8000 process control systems tailored for Solar I monitor and control applications. The generic MV8000 distributed control and display system features stand alone field equipment connected to centralized operator consoles via a distributed highway system. Major components of the system are:

A. Local
   1. Operator Station Processor (OSP).
   2. Keyboard Processor (KBP).
   3. Communications Control Module (CCM).
   4. Historic Trend Processor (HTP).
   5. Plant Graphics Processor (PGP).
   6. Report Generation Processor (RGP).

B. Remote (field devices)
   1. Multivariable Control Unit (MVCU)
   2. Programmable Controller (PC).

The Solar I tailored system enables the operator to select any of the four operator stations for control/display of any of the three subsystems. The selection is accomplished by a Console Access Processor (CAP) controlled by a selector switch (CAP switch) to the left of each operator station keyboard.

The tailored system also includes IPAC Group, Inc. multiplexers as part of the field equipment. The multiplexers are connected via dedicated data highways for minimum response time.

The Programmable Controller is a GOULD MODICON 584 system interfaced to the Beckman MV8000 system. Separate data highways connect the programmable controller of the Interlock Logic System with remote analog and digital monitor and control elements (see Paragraph 3.3).

The Receiver Systems (RS) SDPC and its component locations are shown in Figure 3-10. This architecture is typical for the TSS and EPGS with one exception. The RS has 14 MVCU's, the TSS has 6 MVCU's, and the EPGS has two MVCU's. Layouts for the operator console hardware are shown in Figure 3-3. Layout of the remote stations are shown in Figures 3-6 to 3-8.

## 3.3 INTERLOCK LOGIC SYSTEM HARDWARE

The Interlock Logic System (ILS) provides control and decision making logic for process control devices, pumps, motors, valves, circuit breakers, alarms, etc., using analog and discrete inputs from the system sensors and SDPC system. The system provides the independent interlock logic and plant permissives required to safely operate the plant. The ILS Program logic verifies equipment status prior to executing a command and provides shutdown of equipment in the event established permissives are not satisfied.

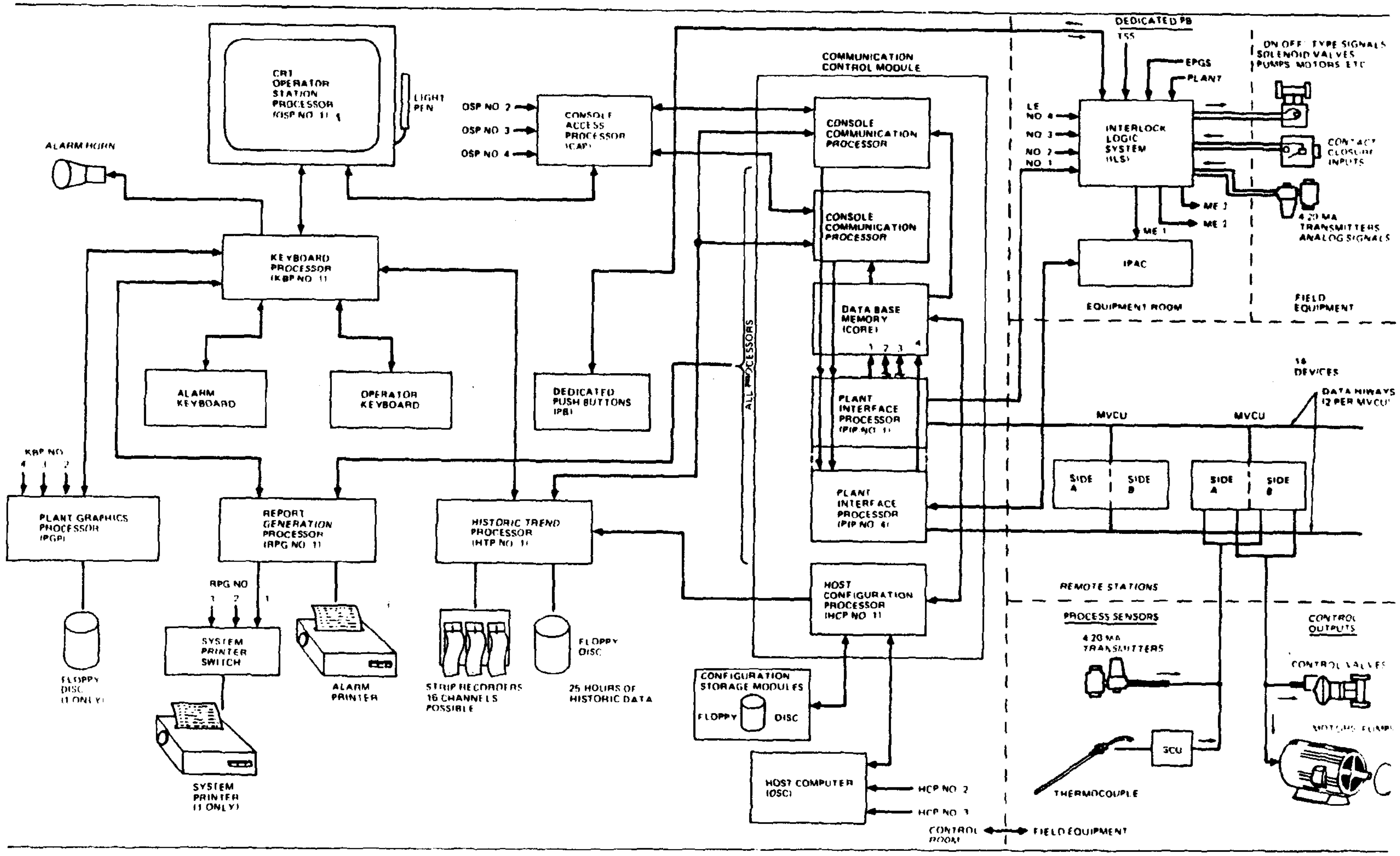



**Figure 3-10. RS SDPC Operator Station and Distributed Control Interfaces**

The computer for the ILS consists of two Gould Modicon 584 systems (No. 1 and No. 2). PC No. 1 contains the primary programmed interlock logic. PC No. 2 is used for communication between PC No. 1 and the SDPC consoles for the RS and TSS. The input/output (I/O) units, which are located in the five remote stations, communicate to the PC No. 1 logic in the equipment room via high speed serial data links using coaxial transmission lines with taps at the I/O devices.

Figure 3-10 shows the relationship between the ILS and the SDPC. Figure 3-11 shows the interconnection of the two 584 PC's and their remote I/O. The Solar I ILS 584 #1 is configured to support up to 22 I/O channels. The "As Built" program uses only channels 1, 2, 3, 4, 5, 7, 9, 11, 13, 14, 15 and 17. Thus some expansion capability still exists.

Programming of the 584's is accomplished through use of a GOULD MODICON P-190 connected to one of the 584 MODBUS ports (MODBUS is the GOULD MODICON system for communicating between two devices, e.g. from a P-190 to a 584 PC). The P-190 is a smart device with a built-in tape drive and three program tapes. When loaded with the proper program, it can be used to program a 584, change its configuration, load a program from tape, record a program on tape, simulate the process to check logic, and many other functions for troubleshooting and evaluation.

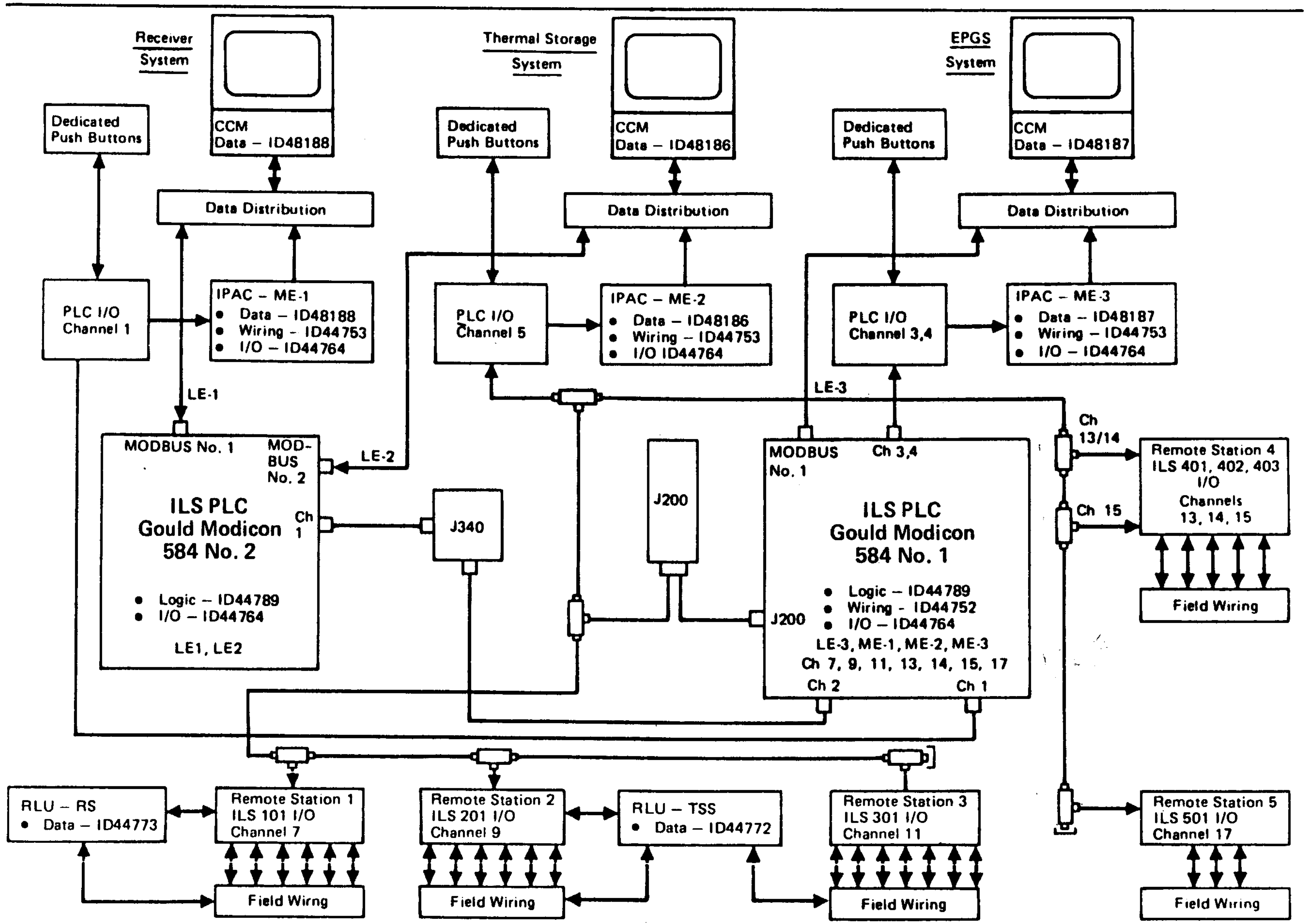



Figure 3-11. Interlock Logic System I/O Interconnection Diagram

## 3.4 OPERATIONAL CONTROL SYSTEM HARDWARE

The Operational Control System (OCS) is the control element of the Master Control System (MCS) which provides for automated monitoring and supervision of the integrated plant subsystems during various operating modes. Plant operating commands can be initiated either by the operator or directly from plant operating software via the OCS computer interfaces to the SDPC and HAC systems.

The OCS equipment and physical locations are shown in Figure 3-12. It consists of a Modcomp Classic computer with the following peripheral and I/O equipment:

A. Two OCS color graphic displays and keyboards

B. Alarm logger.

C. Message logger.

D. Console device.

E. Disk drives (10 mbyte, 67 mbyte).

F. Three Hazeltine terminals for programming.

G. Trend display and hardcopy printer.

H. Line printer.

I. I/O required to communicate with the SDPC, DAS, HAC A and HAC B.

Figures 3-3, 3-4 and 3-5 show the actual locations of this equipment in the Control room, Equipment room and Evaluation room.

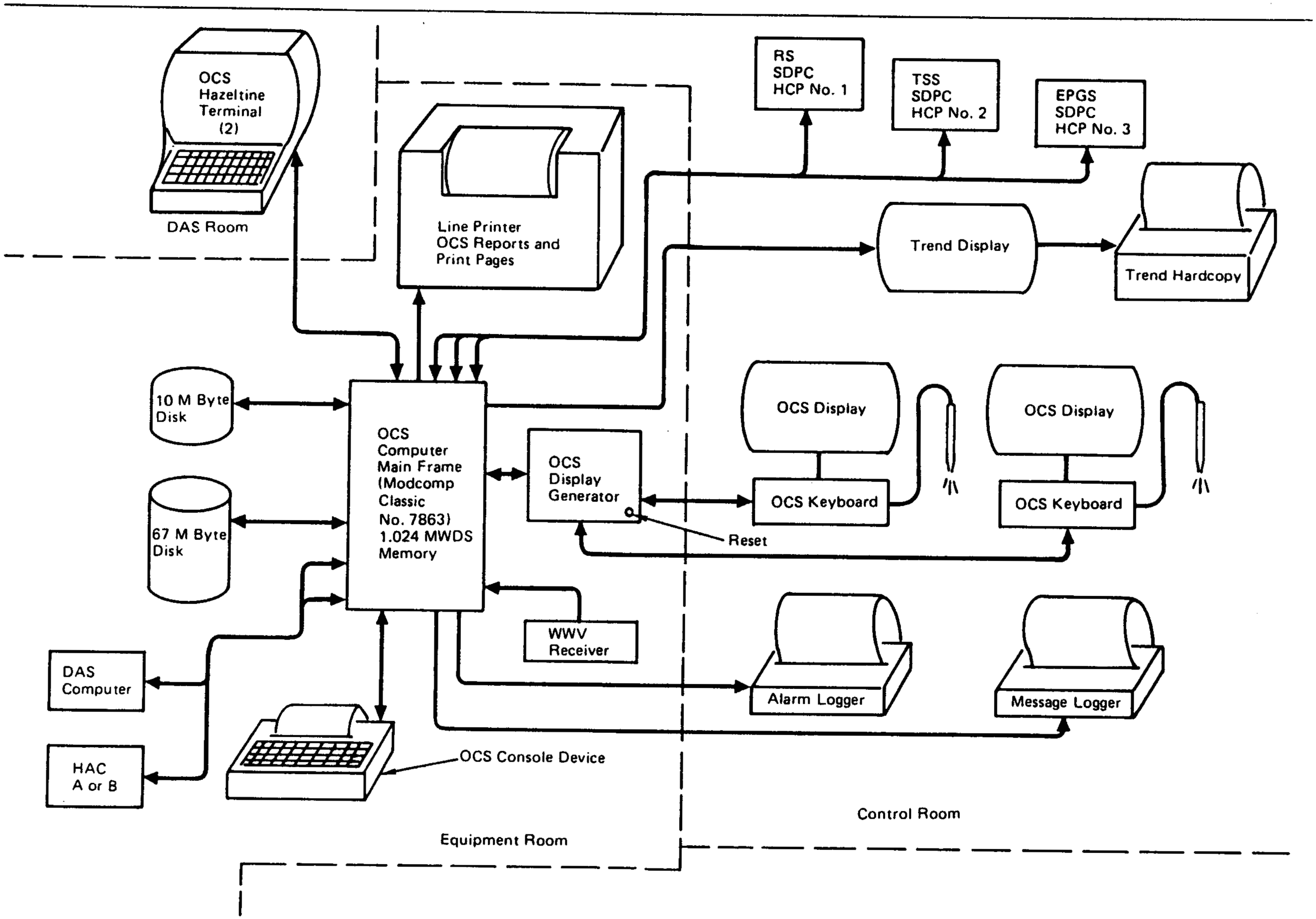



Figure 3-12. Operational Control System (OCS) Equipment and Physical Locations

### 3.5 DATA ACQUISITION SYSTEM HARDWARE

The Data Acquisition System (DAS) computer is the data gathering element of the Master Control System. This system collects, processes, displays, stores and transmits plant performance data from the plant systems.

The DAS equipment and physical locations are shown in Figure 3-13. It consists of a Modcomp Classic computer with the following peripheral and I/O equipment:

A. Two color CRT's, keyboards and hardcopy printers to display trend data.

B. Three black and white (B/W) Hazeltine terminals for programming and displaying data.

C. Console device.

D. Message printers (2).

E. Time code generator.

F. One 67 mb disk drive.

G. I/O required to communicate with the SDPC, OCS, HAC A and HAC B, DARMS and SHIMMS.

Figures 3-3, 3-4 and 3-5 show the actual locations of this equipment in the Control room, Equipment room and Evaluation room.

### 3.6 RED LINE UNIT/PLANT TRIP LOGIC HARDWARE

System safety is provided by different methods for the several plant systems. The receiver (RS) and thermal storage (TSS) each have a Red Line Unit (RLU) for safety. The turbine/generator has an internal safety system

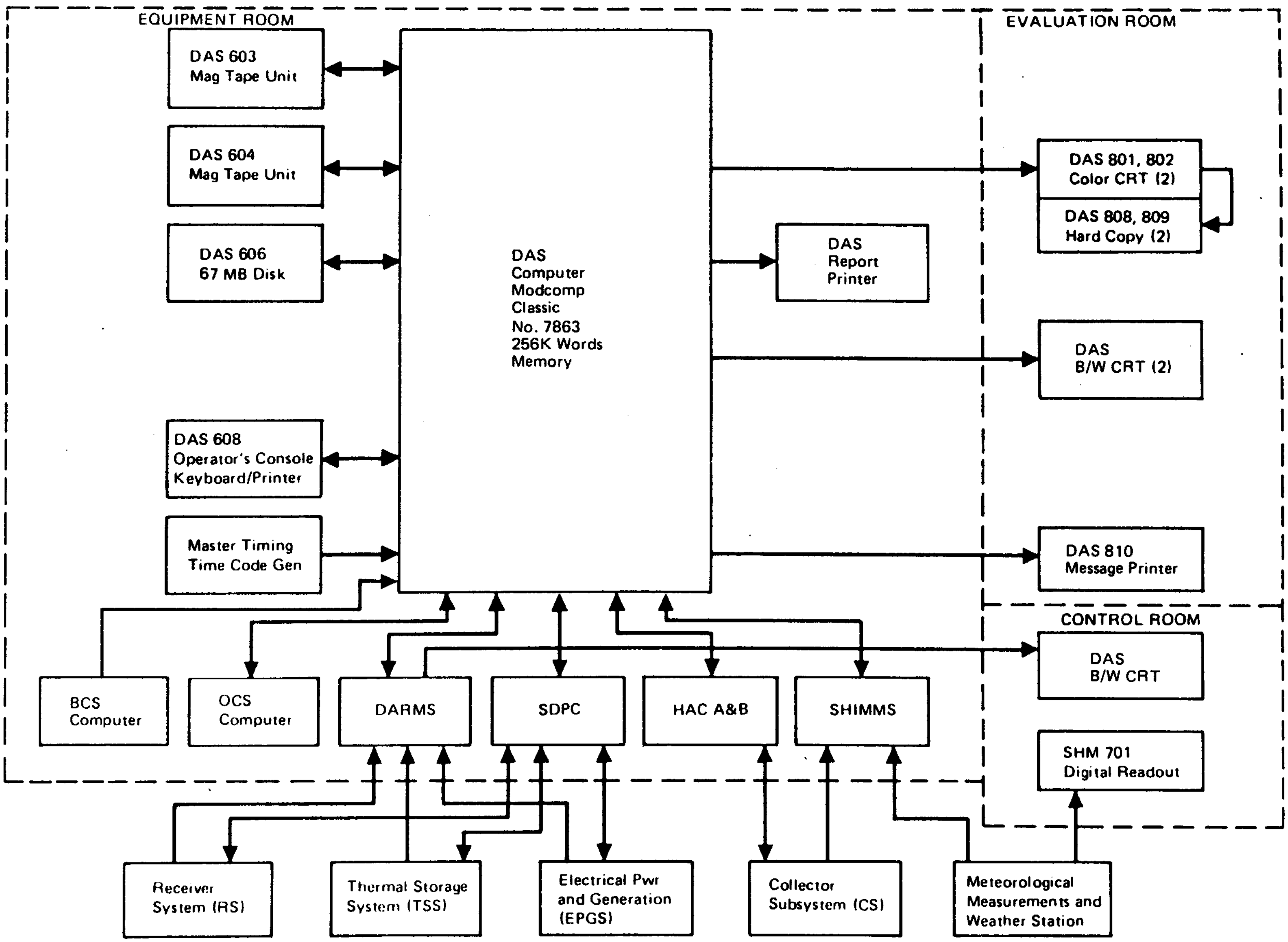



Figure 3-13. Data Acquisition System Block Diagram

provided by GE. The Plant Trip Logic (PTL) provides safety for all systems based upon hardwired information about trips occurring in each system. In addition to the hardwired trips from the Receiver RLU and PTL, the HAC provides its own safety for the collector field by use of "Defocus" and "High Wind Stow" operator pushbuttons on the HAC console. An overview of the way these various safety systems work together is shown in Figure 3-14. The equipment for the Collector system HAC's was described in Paragraph 3.2. The equipment for the RLU's and PTL is described in the following paragraphs.

### 3.6.1 Red Line Units (RLU)

The two RLU's are each Gould Modicon 584 programmable logic computers. The RS RLU is located in remote Station 1 (see Figure 3-6, RLU 101 and 102) along with its I/O modules. Included with the RS-RLU is an Uninterruptible Power Supply (UPS) which uses a static inverter and will maintain proper operations of the 584 for 10 to 15 minutes on loss of AC power to the unit.

The TSS RLU is located in remote Station 2 (see Figure 3-7, RLU 201 and 202) along with its I/O modules. There is no UPS for this unit.

### 3.6.2 Plant Trip Logic (PTL)

The PTL location is shown in Figure 3-8. The equipment consists of 125 VDC relays and switches, hardwired, with trip switches for each system wired from the operator consoles in the control room. The 125 VDC power is supplied by the station UPS located on the first floor of the control building.

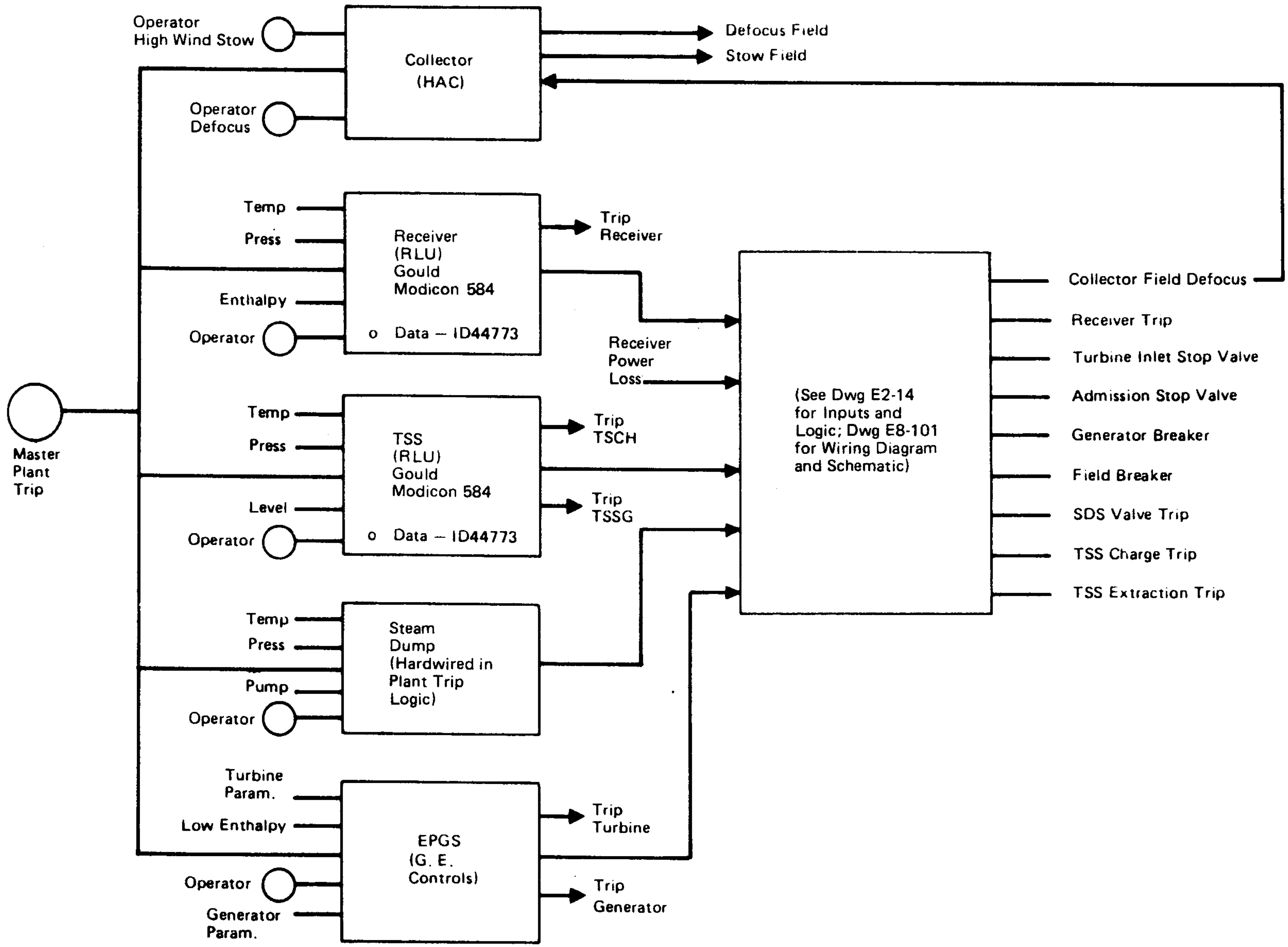



Figure 3-14. Overview of Plant Trip and System Overrides Interfaces

## 3.7 SYSTEM HARDWARE INTERFACES

Paragraphs 3.1 through 3.6 have described the hardware for the various control and monitor systems for Solar I. The interfaces between these systems is shown in Figure 3-15. The following paragraphs describe these interfaces.

### 3.7.1 SDPC Interface

Data highways are the data and control links between the SDPC and the OCS, DAS and ILS. Communication with the OCS is via 9600 baud, RS 232-C links from the Host Configuration Processor (HCP) in each of the three Communications Control Modules (CCM) to the OCS communications processor. A total of six 9600 baud, RS 232-C links connect the DAS computer to the SDPC with two lines coming from the HCP in each of the three CCM's. Communication for ILS comes out of one Plant Interface Processor (PIP) in each of the three CCM's. As shown in Figure 3-15, ILS 584 No. 2 is used primarily for communication between the RS and TSS SDPC and the primary ILS logic in 584 No. 1.

### 3.7.2 OCS Interfaces

In addition to communicating with the SDPC (Paragraph 3.7.1), the OCS collects data from and/or sends data to the HAC's, DAS and MCS timing system. Communication with the HAC is between the OCS communications processor and the HAC communication processor. This is a Modcomp Maxnet link operating at 19.2K baud.

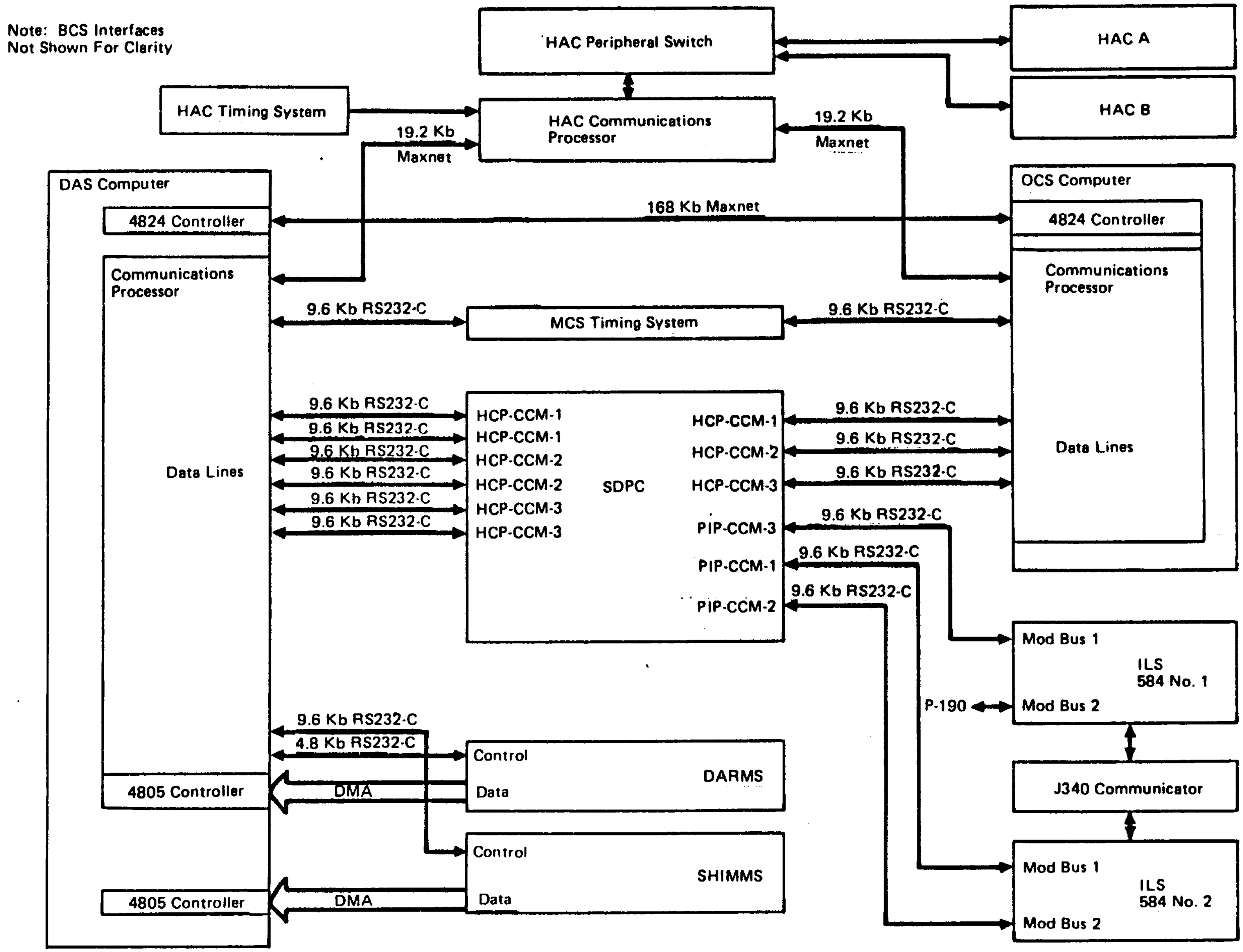


Figure 3-15. Solar I Systems Hardware Interfaces

OCS interfaces with DAS over a high speed serial computer to computer connection (Modcomp Model 4824). The Model 4824 controllers operate at 168K baud via a pair of transformer isolated coaxial cables, one for each direction of data flow.

The OCS computer receives universal standard time via an asynchronous RS232-C OCS communication processor link from the MCS timing system (see Paragraph 3.7.5). The link operates at 9600 baud.

### 3.7.3 DAS Interfaces

The DAS communicates with the SDPC (Paragraph 3.7.1), the OCS (Paragraph 3.7.2), the HACS, DARMS, SHIMMS and the MCS timing system.

The HAC interface is between the DAS Communications Processor and the HAC Communications Processor. This is a Modcomp Maxnet link operating at 19.2K baud.

Data from the DARMS CCU is transmitted to the DAS computer via a Model 4805-1 General Purpose 16-bit data terminal. This link provides parallel word transfer at rates up to 100K words per second. Control signals are received in DARMS via an asynchronous RS-232C link from the DAS Communications Processor.

The Special Heliostat Instrumentation and Meteorological Measurements System (SHIMMS) has separate DAS computer interfaces for control and data transmission identical to the DARMS interfaces. Control signals are received in the SHIMMS Data Behavior Analyzer (DBA) via an asynchronous RS-232-C Communications Processor Interface and SHIMMS data is transmitted to the DAS computer via a Model 4805-1 general purpose 16-bit data terminal.

The DAS computer receives universal standard time via an asynchronous RS-232-C Communications Processor link from the MCS Timing System Time Code Generator (see Paragraph 3.7.5). This link operates at 9600 baud.

### 3.7.4 HAC Interfaces

The HAC communicates with the OCS (Paragraph 3.7.2), the DAS (Paragraph 3.7.3) and the MCS timing system. Universal standard time is received via an asynchronous RS-232-C link from the HAC Timing System Time Code Generator to the HAC Communications Processor (see Paragraph 3.7.5). This link operates at 9600 baud.

### 3.7.5 MCS Timing System

The Master Control System (MCS) Timing System, shown in Figure 3-16 consists of a roof mounted receiving antenna, a WWVB receiver and a time code generator. The Model A-60 FS antenna and the Model 60-TLC WWVB receiver are supplied by Scientific Devices. The Systron-Donner Model 8155 synchronized time code generator supplies universal time in days, hours, minutes, and seconds to four independent outputs either in a continuous mode or an "on request" mode. The receiver and timecode generator are located in the equipment room. The antenna is located on the roof of the control room.

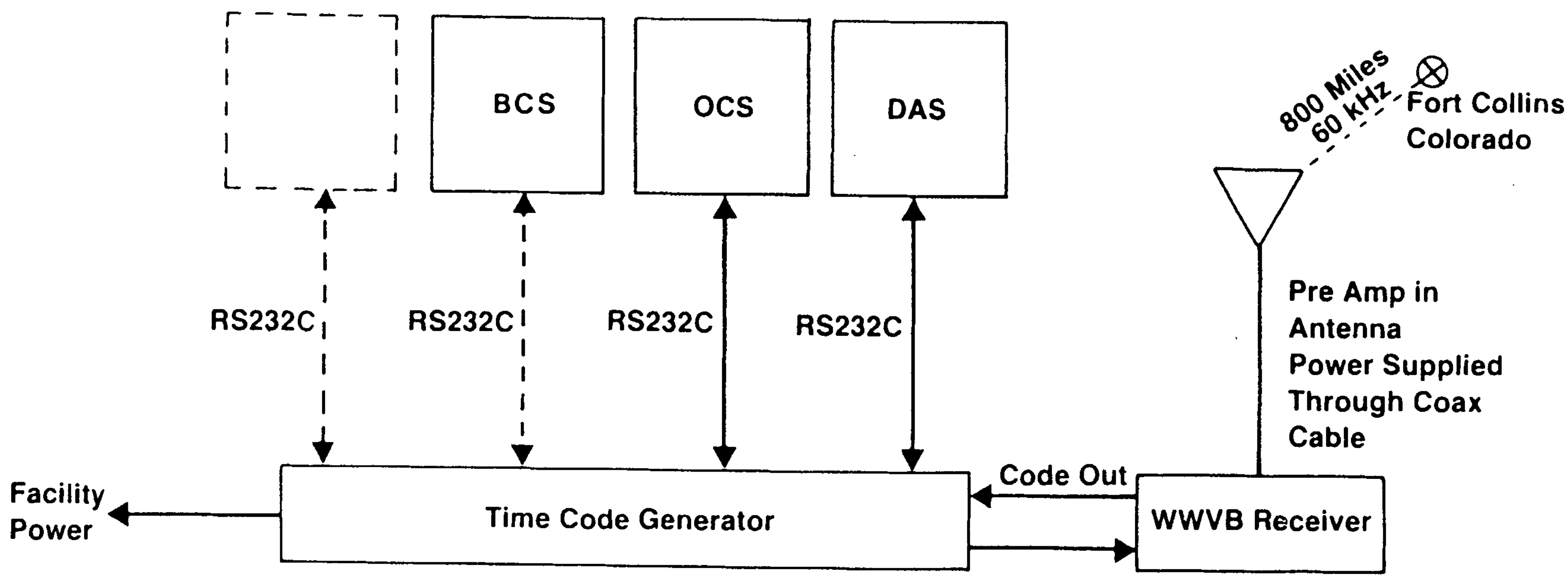



Figure 3-16. MCS Timing System

## Section 4

## CONTROL SYSTEM SOFTWARE DESCRIPTION

The software for each of the systems described in paragraph 3.0 are described in the following paragraphs. This includes software for the Heliostat Array Controllers (HAC), the System Distributed Process Control (SDPC), the Operational Control System (OCS), the Interlock Logic System (ILS), the Data Acquisition System (DAS) and the various interfaces.

### 4.1 COLLECTOR FIELD CONTROL SOFTWARE

The collector field control equipment is shown in Figure 3-9. The system is a distributed computer control system with dual, redundant central computers (HAC) for overall control. The HAC software processes operator commands, communicates with the Heliostat Controller (HC) through the Heliostat Field Controllers (HFC), displays status of the field, commands the field and provides a printout of alarm and status messages.

The operator commands available for normal operations are STOW, UNSTOW, STANDBY, TRACK, INCREASE, DECREASE, WASH and STATUS. Two emergency commands, DEFOCUS and STHWIND (stow due to high winds), are available through function keys on the HAC console keyboard.

The HAC computes the sun position and transmits it to all HFC's once per second over a 19,200 Baud data line. Also included is a request for heliostat status. The HFC uses these data to generate the output command sequences it sends to up to 32 HC's associated with it over a 9600 Baud data line. These sequences consist of sun vector commands, status polling commands, and operational commands. Upon loss of communication with the HAC, the HFC will not attempt to propogate sun position but will control stow of all heliostats attached to it, using an approximate corridor walk (using the last sun vector received).

Each HC's firmware will execute by calculating the desired azimuth and elevation angles based on sun vector and operational commands from the HFC. It will control the azimuth and elevation motors to achieve the desired position. Also, the HC will provide status and gimbal angle information to the HFC upon a poll command to transmit to the HAC. If communication with the HFC is lost, the HC will hold the heliostat at its current position.

The HAC receives status from each heliostat once every eight seconds and displayed on the color CRT terminal showing status. Changes in status and alarms are printed on the Message/Alarm logger in the control room. The status can be viewed for an individual heliostat, a ring or segment or the entire field.

## 4.2 SYSTEM DISTRIBUTED PROCESS CONTROL (SDPC) SYSTEM SOFTWARE

The SDPC (Beckman MV 8000) has several microprocessors located in the control room and others located in the Remote Stations in the field. The devices in the control room provide centralized communications, system data base, interface with the operator consoles and data highways to the

Multivariable Control Units (MVCU), IPAC (multiplexers) and Interlock Logic System (ILS) devices in the field. The MVCU's provide the control algorithms required for control and monitoring of the various processes.

The MV 8000 system is designed to keep the plant operations as simple and straight forward as possible. Plant operations are simplified by providing each operator station with identical operator capabilities. The same process data and control capabilties are available from each operator station. This is accomplished by centralizing communication and data acquisition capability in a module termed the Comunication Control Module (CCM).

The Communication Control Module (CCM) contains seven microprocessors and a memory. Each microprocessor has a unique responsibility. Four microprocessors (Plant Interface Processors) are utilized in communicating with the field devices. They interface with the field devices by directing serial communications across multiple data highways.

The process data is gathered from the field devices across the data highways and stored in the Communication Control Module's memory. The process data is stored in a loop and group information format designated the "Data Base."

Two other microprocessors (Console Communications Processors) are responsible for interfacing with the operator stations. They handle requests from the operator stations to display process data from the data base and direct operator commands to send out to the field devices across the data highways.

A Plant Graphics Processor (PGP) is included in the system to provide interactive graphic display and control capabilities. Plant models were developed on the graphics displays so that operators can monitor and control the process from these displays.

A Historic Trend Processor (HTP) was also included in the system providing trending capabilities. Process variables are trended for up to 25 hours. Trended variables can be displayed with 10 minute, 100 minute, 500 minute and 25 hour time spans. Hourly averages are calculated and can be displayed for each process variable.

The MVCU's contain the algorithms for implementing the process controllers. The basic algorithms available for analog signals are the Proportional, Integral, Differential (PID), lag-lead, multiply, summer, auto/manual station, ratio station, function generator, divide, high select, low select, square root, integrator/totalizer and manual loading station. Special algorithms are a variable gain PID, an analog switch with set point tracking, ramp generator and rate limits.

There are 13 digital functions available: And, On, Triggered And/On, And Mode Transfer, Or Mode Transfer, And Jump, Or Jump, Timer, Counter, Dual Pulse and Analog Function Alarm Status 1 or 2. Mode transfer tables are available for transferring analog or digital functions to auto or manual on detection of process state.

Configuration of the data base and MVCU's is accomplished through the operators console. The MV 8000 configuration procedures are designed to eliminate the need to learn a low-level type programming language. The procedures utilize a high-level "Fill-In the Blank" configuration method. Configuration of loops for the IPAC and ILS are accomplished in the same manner.

The data base is stored on a floppy disc in the Configuration Storage Module (CSM) shown in Figure 3-10. Another capability was developed for storing the data base in the OCS and is described in paragraph 4.3.

### 4.3 OCS SOFTWARE

The Operational Control System (OCS) is the control element of the Master Control System (MCS) which provides for automated modes of plant operation. Its function is to monitor and supervise the plant during various operating modes.

The OCS provides the capability to execute application programs which will control plant operation via commands to the Subsystem Distributed Process Control System (SDPC). A capability is also provided to permit plant operators to initiate control commands through the Man/Machine Interface. The OCS collects data from the subsystems and maintains a real time data base which is the source of information for all OCS data processing functions.

Figure 3-12 shows in block diagram form the OCS computer and the various systems and peripheral equipment. The basic OCS data flow and processing functions are shown in Figure 4-1. The OCS software breaks down into two main parts: the Automation Software and the Plant Operational Display System (PODS).

The automation software provides real time control of the plant through the application program (OCS Command File) tasks and the Aimpoint Control Tasks. The application programs are the various programs used to start, run or stop the plant as well as transition from mode to mode (see paragraph 5.0). The aimpoint control tasks sets up where each heliostat aims on the receiver, when in track, by commanding the HAC to run various aimpoint change files dependent on time of day and time of year. Three modes of operation for aimpoint control are available: manual, semi-automatic and automatic. In the manual mode, the operator sends change commands to the HAC without any prompts or messages from the software. In the semi-automatic mode, messages are printed when aimpoint changes are required, but the aimpoint change commands are not sent unless operator permission is granted. In the controlled automatic modes, messages are printed out when aimpoint changes are required. The aimpoint commands will be sent unless they are inhibited by the operator.

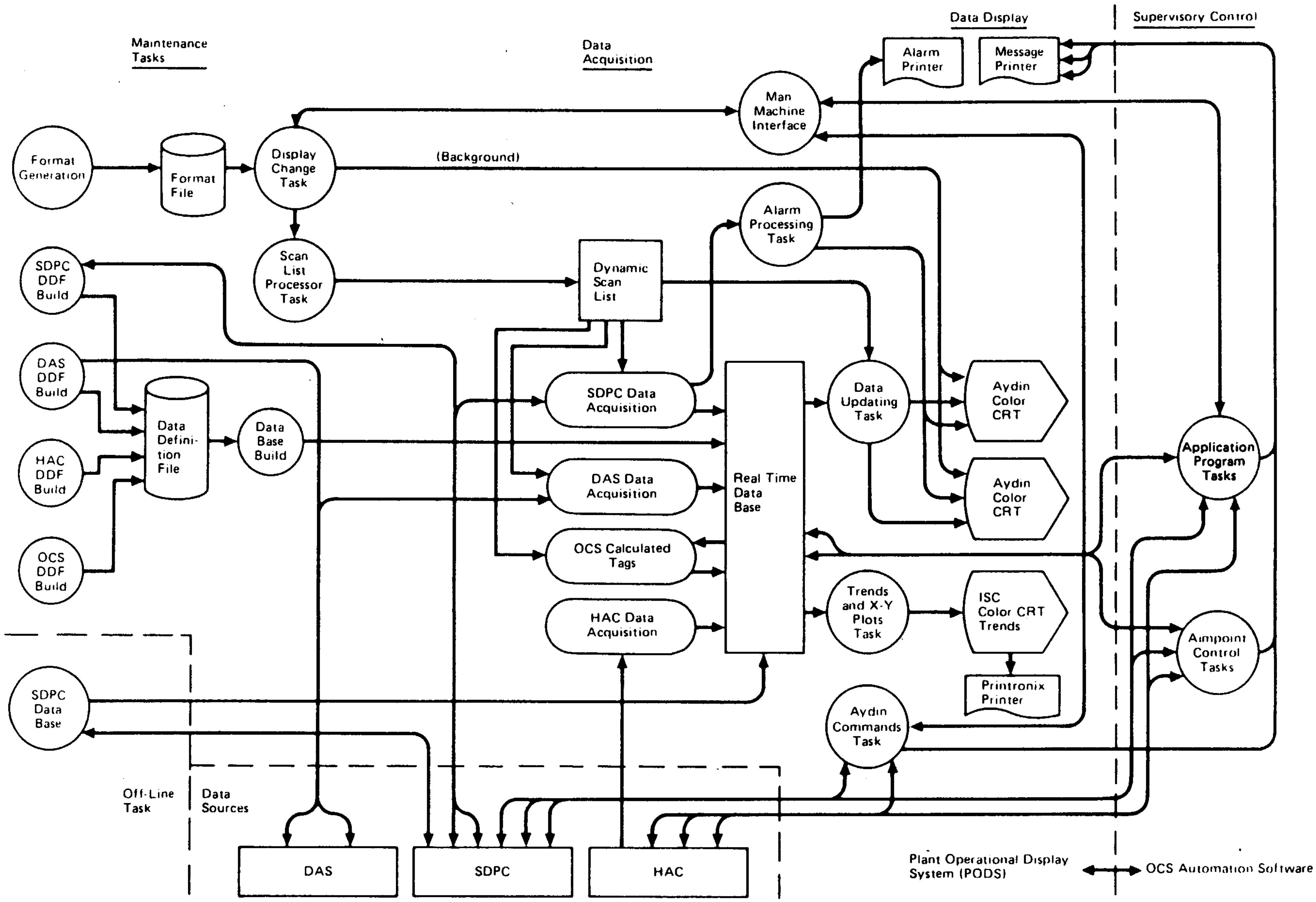


Figure 4-1. OCS Data Flow and Processing Functions

The PODS software is designed to obtain and display the overall plant data and status. This system communicates with and acquires data from the SDPC, HAC and DAS. In addition, it makes use of SGM's RCS-7 system, which is a part of the OCS software, to store and display data and communicate with the operator via the Aydin color CRT terminals. Another task is used to rebuild the real time data base for any one of the sources, if that source data base has been changed. The alarm function processes alarms from the HAC and SDPC, integrating them into an alarm summary display and allowing acknowledgment and silencing of all plant alarms from the OCS keyboards.

Trending and X-Y plots are included as part of PODS. Trends are time-history plots of up to four variables on one plot. A trend list provides 24-hour trending of up to 60 variables. The trend plots may be real time or historical. X-Y plots are snapshots of a group of up to 24 variables using values available at the time the display is called up. An update may be made at any time by depressing a function key, UPDATE TREND.

The Aydin commands task in PODS allows the operator to send commands to the SDPC. A function key (CONTROL INPUT) on the OCS keyboard activates this task. After responding to a prompt by typing the tag ID or program desired, the operator can operate a program, change the state of a discrete tag ID or change the host setpoint (HS), the controlled output (CO) and the AUTO/MANual flag for analog tag ID's.

The primary tool used to communicate with PODS (through RCS-7) is the "format". Formats convey system data on the CRT and receive input data and control requests. Formats are also used for hardcopy reports on the line printer. The term format is a way of referring to a page oriented, organized presentation of system information. The mechanism for creating these formats for the OCS Man-Machine Interface is through the RCS-7 Format Generation (FORGEN) task. All formats, or displays, are defined as having three parts: format characteristics, format picture (background) and dynamic fields. The characteristics refer to the display name and number, update type, update rate, etc. The picture or background is drawn on the screen exactly as it is to appear in actual use. The dynamic fields are the portions of the format that give information about the current system state or that specify functions which can be initiated on demand by the operator.

Three miscellaneous PODS tasks are WWV, UPDATE, and CHFILE. WWV updates the CPU clock and calender with the current time from the WWV. UPDATE allows the operator to change the year and the daylight savings time flag. These are used by WWV and other OCS tasks. CHFILE allows the operator to display and change any of several data files used by the applications tasks.

A separate program in the OCS, performed as an offline maintenance task, is used to monitor the data base of the SDPC. It is called "SDPC Data Base Operations" and provides the capability for storing the SDPC data bases on the OCS computer disk files as an alternative to the Beckman MV 8000 Configuration

Storage Module floppy disc. The programs allow the following function to be performed through a "Menu" format: Compare, Store, Download, Backup files to tape, Restore files from tape and various print options.

The "store" function puts the data base configuration currently in the SDPC device into one of two OCS disk "SAV" files. Once stored, the file can be compared to what is currently in the SDPC data base (print the differences) or one can "Download" the SAV file into the respective parts of the SDPC (CCM or MVCU's). The SAV file may be dumped onto magnetic tape for safekeeping or restored from magnetic tape in an emergency. The print options allow printing the current SDPC data base, printing "SAV" file only, print the non-compares or print what was downloaded.

This program allows a simple method for checking the validity of the SDPC data base at any time. The only restriction is that it will not start if any of the following tasks are executing: a Command file, Format Generation, Data Base Generation or OCS Data Base Rebuild. This is not a real limitation since these functions are performed infrequently and usually when the plant is shut down.

## 4.4 ILS SOFTWARE

Figure 3-11 shows in block diagram form the interconnection of the ILS and the SDPC and Remote Stations. The Gould Modicon 584 used in ILS is a general purpose Programmable Controller capable of doing logic, timing, counting and arthimetic functions. It consists of a Central Processing Unit (CPU) which receives input data, performs logical decisions based upon a program and data stored in memory and generates commands to the outputs through the output modules.

The 584 programming logic is a form of relay ladder diagrams, formulated in "Networks", solving the logic by column from left to right. Normally open, normally closed contacts and relay coils are used along with counters, timers, add, subtract, multiply, and divide blocks and various other data manipulation functions. An example of this logic is shown in Figures 4-2, 4-3 and 4-4. The desired logic for the auxilary extraction oil pump, P-305, is shown in Figure 4-2. The input/output wiring and coil or register where the information is stored is shown schematically in Figure 4-3. The resultant relay ladder logic diagram is shown in Figure 4-4. As shown, all of the permissives must be true before the pump can be started (turn coil 1242 "ON"). If any of the permissives go false or the operator pushes the STOP, the pump will stop. This logic is typical of that used for other equipment throughout the plant.

A P-190 is used for programming, editing, and troubleshooting. Three software programs are available for use with the P-190. The first is the "Tape Loader" program which will dump the 584 logic program onto a tape for storage or emergency backup. This program will also load a previously recorded program back into the 584.

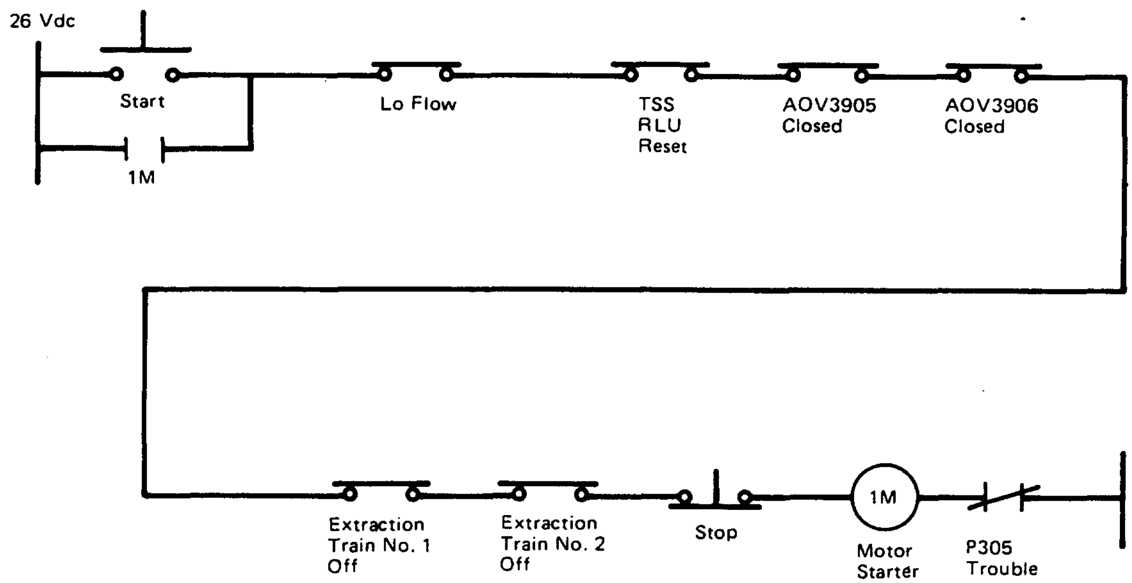



Figure 4-2. Logic for Aux Extraction Oil Pump – P305

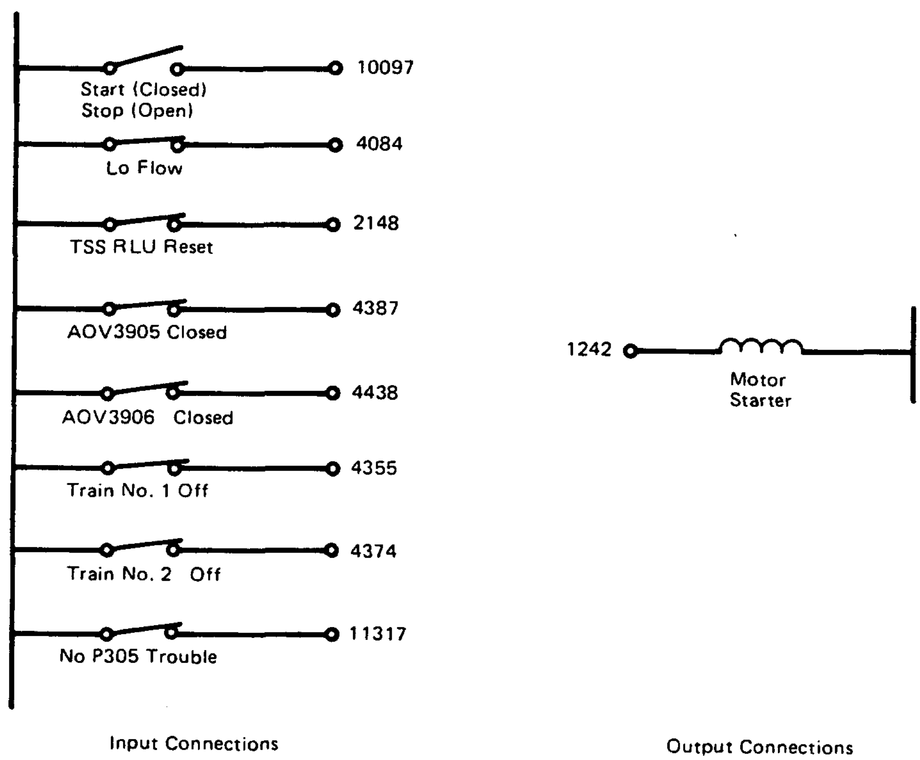



Figure 4-3. Input/Output Wiring – P305

```
    NETWORK: 00126       SEGMENT: 003   P305 - Aux Extraction Oil Pump

+---] [-+
I 04486!
I       !
+---] [-+
I 04478!
I       !
+---] [-+---] [----] [----]\[----]\[----]\[----]\[----]\[----]\[--.........---( )- Keystroke - HS3909
I 10097  11317  02148  02500  04387  04438  04355  04374  04084          00097
I
+---] [----]\[--...................................................---( )- Energize to Run P305
I 00097  04084                                                        01242
I                                            Note:  11317 = No Trouble (UI3909)
                                                    2148 = TSS RLU Reset
                                                    4387 = AOV-3905 Closed
      REF                                           4438 - AOV3906 Closed
COIL# TYPE    CROSS REFERENCE BY NETWORKS           4355 = Train #1 In Run
                                                    4374 = Train #2 In Run
00097 ] [     00126-00127                           4084 = Lo Flow
01242 ] [     00269,00654
      ]\[     00268,00661
```

Note: Power Flows From Left to Right; Network Logic Solved One Element at a Time, Top to Bottom, Left to Right.

Figure 4-4. Equivalent ILS Program (See Reference 12 for Complete Logic Diagrams)

The second program is the "Utility Tape" which is used to configure a 584 (number of coils, inputs, outputs, etc.), examine memory or print the ladder networks.

The third program is the "Programmer Tape". It is used to generate the ladder logic program, do troubleshooting (observing logic operation, generating or forcing required inputs or outputs, etc.), and obtaining status of all outputs (coils), inputs, and registers. Programming and/or troubleshooting can be done in real time, on-line, without affecting surrounding logic not involved in the area of interest.

## 4.5 DAS SOFTWARE

The Data Acquisition System (DAS) is the data gathering element of the Master Control System (MCS). The DAS function is to act independently to (1) acquire data from the plant subsystems during the various plant operations; (2) provide limited real-time data display and evaluation capability; and (3) store subsystem data for subsequent performance evaluation. The stored data may also be sent to other local computers (OCS and BCS) or recorded on magnetic tape for subsequent processing by computers at other locations.

Figure 3-13 shows in block diagram form the DAS computer and its various systems from which it gathers data. The acquired data is stored (archived) on a portion of a 67 megabyte hard disk drive at operator selectable time intervals which may be different for each data source. The disk drive also stores all the system and application program code and data files needed to support DAS operation.

The acquired data may be displayed in real time on 3 monochrome alphanumeric CRT termnals (Hazeltine) and 2 color graphic CRT terminals (ISC). Tabular type displays on the Hazeltine or ISC terminals may be printed on the Report Printer (Texas Instruments TI-810) and plot type displays on the ISC terminals may be printed on the graphics printers (Printronix).

The measurement values saved on the disk archive file may be copied to magnetic tape reels on either of two tape drives.

Selected current measurement values may also be transferred at periodic intervals to the Operational Control System (OCS) and Beam Characterization System (BCS) computers.

Printing of large DAS reports may be performed on a high speed line printer attached to the OCS computer via a high speed data link. The log printer (TI-810) is used to print system status and alarm messages.

The control panel and console device are used to initially "boot" up the system for maintenance.

The basic DAS data flow and processing functions are shown in Figure 4-5. There are three mutually exclusive modes of operation defined as "OFF LINE", "RUNTIME INITIALIZATION" and "RUNTIME". The Off line software includes programs and/or subroutines to perform the following functions:

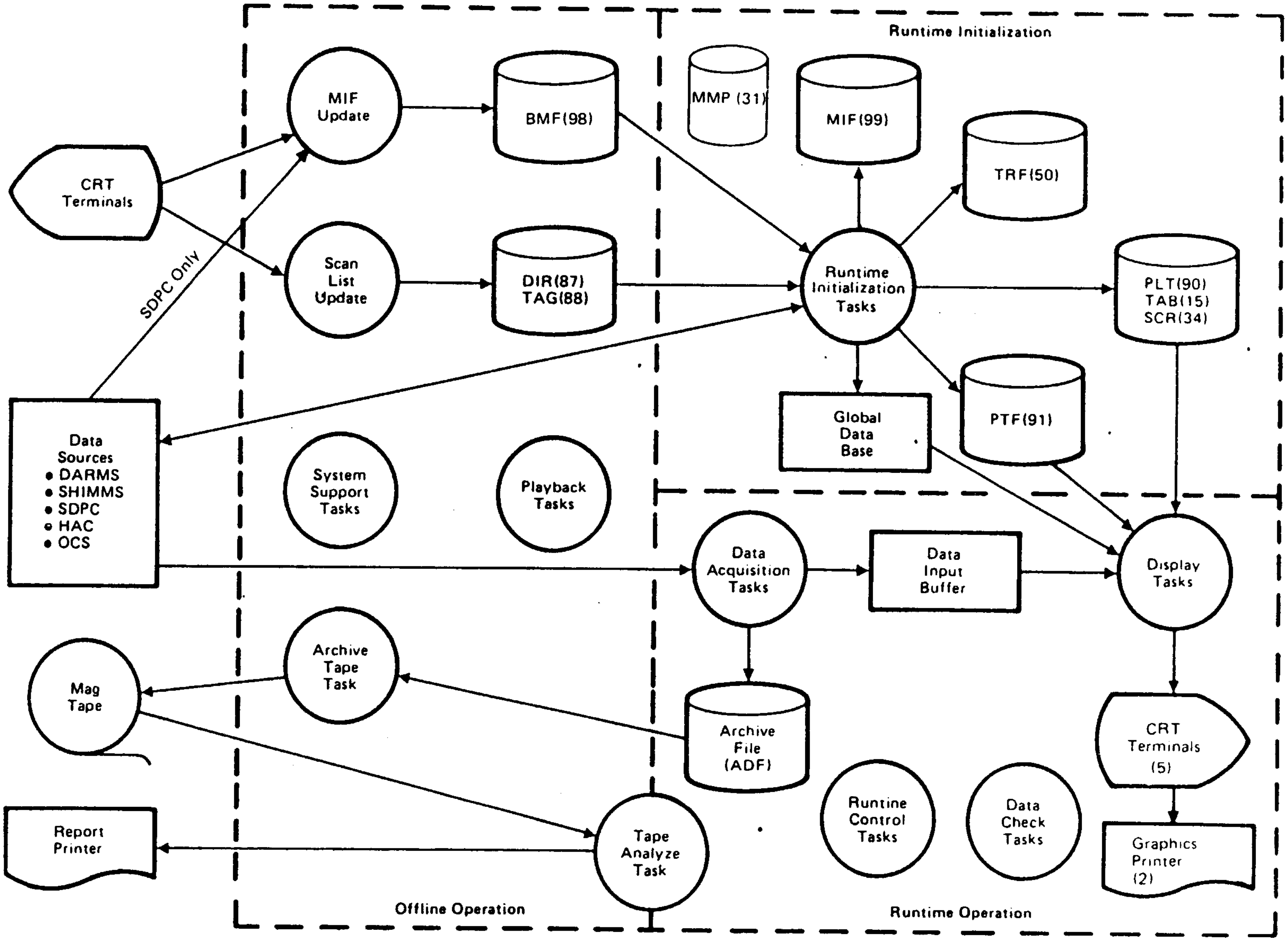



Figure 4-5. DAS Data Flow and Processing Functions

1. Creating a Master Measurement Information File (BMF) which contains all measurements which may be used by the Runtime function.
2. Creating a Scanlist and Menu Directory file (DIR) and Measurement Identifier file (TAG) which are used by the Runtime function.
3. Provide capability to update the year, day and time.
4. Copy measurement values saved on the archive disk (ADF) to magnetic tape.
5. Analyze recorded magnetic tapes for errors and print a summary report on contents.
6. Playback measurement values saved on ADF or magnetic tapes on the DAS CRT terminals.
7. Copy and restore all critical DAS disk files to and from magnetic tape.
8. Control execution of the Offline processing functions and start the Runtime Initialization Processing.

The Runtime Initialization software includes programs and/or subroutines to initialize disk files, global common areas and data sources required for execution of the Runtime operation. The processing functions are as follows:

1. Create the Runtime Measurement Information file (MIF) for all measurements on the scan list.
2. Create a Tag Reference file (TRF) for each measurement in the MIF.
3. Initialize a Global Common area (GLBDB) with conversion units (raw counts to engineering units) and location of data.
4. Create a pointer file (PTF) for each measurement on the MIF.

5. Create files containing records for each display menu requested.
6. Initialize the data sources selected for data acquisition.

The Runtime software includes programs and/or subroutines to perform the following functions:

1. Acquire and record on the archive file (ADF) a set of data measurements from all data sources at operator selected multiples of the basic scan time.
2. Display current measurement values on the CRT terminals or Color Graphic terminals (up to 48 fixed tabs, 8 scroll tabs or 4 plots).
3. Display current acquisition and archive status on the CRT terminals.
4. Display current values in global data base on the CRT terminals.
5. Analyze recorded magnetic tape for errors and print a summary report on contents.
6. Conduct data checks on validity and value of measurements from a selected data source.
7. Provide capability to send current measurement values to OCS and BCS computers.
8. Initialize data sources selected for data acquisition.
9. Update the computers clock from the MCS timing system.
10. Control execution of the Runtime processing functions including termination.

## 4.6 SOLAR I SOFTWARE INTERFACES

Figure 3-15 shows the hardware interfaces between the various Solar I systems. Paragraphs 4.1 through 4.5 have described the software for each of these systems. The following paragraphs describe the software interfaces for these systems.

### 4.6.1 Collector Field Software Interfaces

The Collector field software (HAC) interfaces with the OCS, DAS, and the MCS Timing System. The OCS to HAC interface consists of OCS commands to the HAC to Stow, Unstow, Standby, Track, Decrease, Increase, Defocus, Stow-Hi-Wind (STHIWIND) and Status. HAC to OCS responses are alarms or errors and status. The status includes the field (all heliostats), Individual Heliostat Controllers (HC) and ring status.

The HAC to DAS interface is limited to status requests from DAS every 64 seconds. The HAC response shows the total field status, ring-track status and up to 20 individual heliostats status each interrogation.

The HAC updates its computer clock once each day using universal standard time information from the HAC Timing System.

### 4.6.2 SDPC Software Interfaces

The SDPC interfaces with the OCS, DAS and ILS. These interfaces are only to the Communication Control Modules (CCM) in the three MV8000's (RS, TSS EPGS) as described in paragraph 3.7.1. For OCS, commands can be sent to the SPDC to change the state of discretes or change various controllable attributes of analog variables. Commands may also be sent to request display of the current values of analog or digital information. The commands are primarily generated by the automation software for startup, mode transition, etc.

The DAS interface is strictly for data gathering. The DAS requests analog and digital information from the SDPC based on a scan list set up by the operator.

The ILS interface provides for accepting operator commands over a data highway and transmitting these commands to the field to start or stop pumps, open or close valves, etc. Analog and digital talkback (pump running, valve closed, variable value, etc.) are available over the same data highways.

4.6.3 OCS Software Interfaces

In addition to interfacing with the HAC (paragraph 4.6.1) and the SDPC (paragraph 4.6.2) the OCS interfaces with the DAS and the MCS Timing System. The OCS/DAS interface is strictly for data gathering. OCS requests analog and digital information from the DAS based on scan lists for displays made up by the operator. There is no software for DAS to receive data from OCS.

The OCS updates its computer clock once per day at midnite using universal standard time information from the MCS Timing System.

4.6.4 ILS Software Interfaces

ILS only interfaces with the SDPC as described in paragraph 4.6.2.

#### 4.6.5 DAS Software Interfaces

In addition to interfacing with the HAC, SDPC and OCS (paragraphs 4.6.1 through 4.6.3), DAS interfaces with the DARMS, SHIMMS and MCS Timing System. The DARMS interface is for gathering data throughout the plant which is separate from and in addition to SDPC data. These data are used for engineering evaluation of system and plant performance.

The SHIMMS interface is for gathering data on specially instrumented heliostats and meterological measurements. These data are sent to DAS once per second per the scan list set up by the operator.

The DAS updates its computer clock every five minutes. Universal standard time information is requested from the MCS Timing System for that purpose.

## Section 5

## CONTROL SYSTEM AUTOMATION

The design goal of plant automation was to increase the plant operating efficiency and was concentrated in two areas. The first was to improve the measureable plant output performance and the second was to decrease the workload of the control room operator to achieve more efficient operation. Improving the plant output performance included reducing the time required to startup the plant and achieve net positive output power, increasing the maximum output power levels, extending daily operating time, reducing parasitic loads and effectively managing the available energy resources from the receiver, thermal storage and auxiliary steam sources. Improving the operator effectiveness included providing the operator with enhanced displays for operating the plant, providing direct measures of plant efficiency so the operator could effectively manage energy resources, reducing the operator interaction required for routine tasks and by providing a simple, effective man-machine interface between the operator and the plant, A more detailed discussion of the plant automation objectives can be found in Reference (7).

### 5.1 AUTOMATION DESIGN APPROACH

The method of approach used to define specific automation requirements to meet design goals was based on observations and experience gained in operating Solar One. The existing plant operations and control room procedures for startup, operation, and shutdown of the major systems were examined and analyzed in order to streamline the procedures to reduce startup time as well as minimize operator interactive tasks with the control console. Specific operational sequences were analyzed for possible performance improvements and automation flow charts generated. Specific tasks or sequences were identified for performance improvement by either manual operation, SDPC or ILS automation or OCS automation. A diagram of the method of approach is shown in Figure 5-1.

In the initial automation phase emphasis was placed on using existing hardware and firmware within the SDPC and ILS for plant automation in order to reduce the requirements for new software within the OCS computer. As more experience in operating the plant was attained further requirements for improving plant performance via operating strategies, procedures, modifications to process equipment and further automation through the OCS and SDPC systems were generated. This total effort resulted in achieving the original plant design goals of power production operating strategies, as well as an automated plant capable of performing a clear day scenario and being controlled from a single operator console.

## 5.2 SUBSYSTEM AUTOMATION IMPLEMENTATION

As discussed in Section 5.1, specific tasks or sequences that were best done manually by the operator, by SDPC/ILS, or by OCS were identified as candidates for automation. Those tasks or sequences selected for implementation in SDPC/ILS are listed in Table 5-1 for each of the 3 major subsystems; RS, TSS, and EPGS (including BOP). Each of these tasks or sequences were flowcharted based on the required manual operating procedure. The flow chart information was then utilized to determine the preliminary

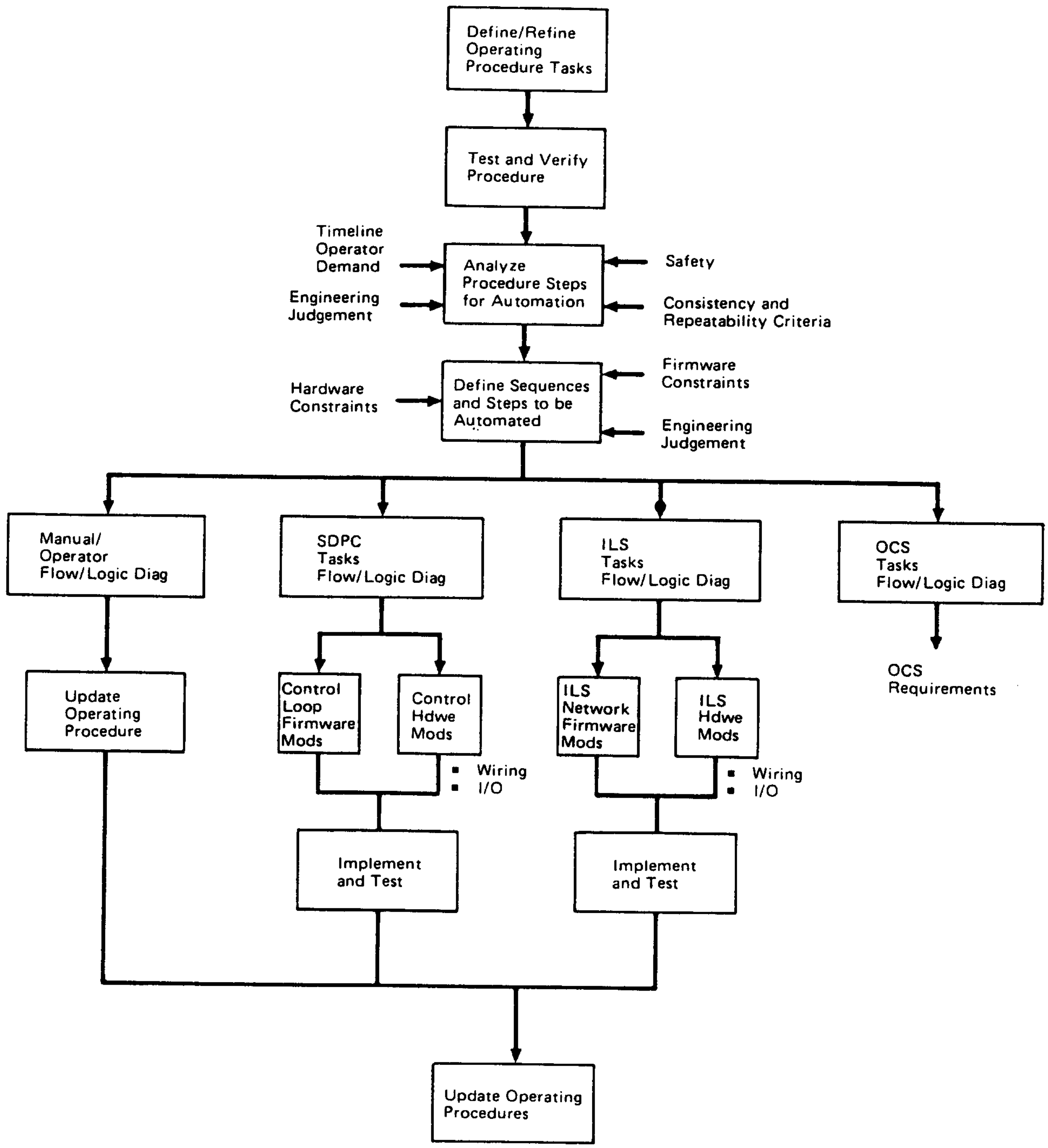



**Figure 5-1. Plant Automation Design Approach**

Table 5-1
SDPC/ILS Subsystem Automation Sequence/Tasks

| Subsystem | Sequence/Operation |
|---|---|
| Receiver | 1. RS Initialization |
| | 2. Control mode transitioning of the boiler panels |
| | 3. Control Mode detection of boiler panels |
| | 4. Temperature setpoint ramp |
| | 5. Feedwater pump control mode transitioning |
| | 6. Downcomer pressurization sequence |
| | 7. Transition from RS flash tank to steam dump system. |
| | 8. Hot standby sequence (Transition from downcomer back to RS flash tank) |
| | 9. Auxiliary steam from main steam automation |
| Thermal Storage | 1. Charging pressurization |
| | 2. Charge shutdown |
| | 3. Charging train start and stop sequences |
| | 4. Extraction train auxiliary steam sequence and stop sequence |
| | 5. Extraction train warm sequence and run sequence |
| Electrical Power System and Balance of Plant | 1. Turbine startup on main steam |
| | 2. Turbine shutdown on main steam |
| | 3. Turbine startup on admission steam |
| | 4. Turbine shutdown on admission steam |
| | 5. Turbine generator low load shutdown |
| | 6. DA vent valve automation |
| | 7. DA pressure/NPSH control-aux steam automation |
| | 8. Cooling tower fan automation |
| | 9. Turbine main steam drain automation |
| | 10. Turbine admission steam drain automation |
| | 11. Turbine extraction drain automation |
| | 12. Extraction port MOV's and non-return valve automation |

analog and digital configuration for the task/sequence and to define the analog I/O requirements. The Beckman MVCU limits of 40 analog lines, 150 digital lines, 32 analog inputs, 16 analog outputs and the analog I/O requirements were considered in assigning automation tasks/sequences to MVCU's for each subsystem. These assignments and the need for new measurements and the need to pass information between MVCU's (via hardwiring) determined the requirements for new SDPC hardware such as additional MVCU's, analog I/O wiring and I/O boards, SCU cards, etc. The additional hardware required to implement the automation design for both the Beckman system and the Gould Modicon-ILS is summarized in Table 5-2. To implement all of the automation features in the RS subsystem, one new MVCU was required (MVCU C1-12) and one additional MVCU was relocated to remote station 1 from remote station 3 (MVCU C3-2 became MVCU C1-11). The analog and digital functions that resided in MVCU C3-2 were reconfigured in MVCU C3-1 and MVCU C2-1 which were under utilized.

The SDPC automation is implemented within the Beckman and the ILS systems in two forms; autonomous and sequential automation. The autonomous type of automation is implemented to operate independently of the operator. When the SDPC logic detects that a pre-determined process condition exists, the logic will command the control loop within the subsystem to transition or change modes accordingly. The sequential type of automation sends commands if the operator or the host computer (OCS) has enabled the logic via a digital switch which is configured within the subsystem CCM data base with a designated tag identification number (tag ID). Implementation of these subsystem automation

Table 5-2
SDPC/ILS Hardware

| Description | Number Used for Subsystem Control | Number Added for Automation |
|---|---|---|
| Beckman equipment | | |
| MVCU | 21 | 1 |
| Analog Input Cards | 104 | 13 |
| Analog Output Cards | 34 | 5 |
| Analog Conditioning Module | - | 1 |
| Analog Terminal Board | - | 1 |
| Gould Modicon - ILS | | |
| Analog Mux Input Cards | 5 | 2 |
| Analog Output Cards | 0 | 3 |
| Signal Conditioning Unit Cards | - | 2 |
| Rack for New MVCU | - | 1 |

tasks and sequences provided the foundation for implementation of supervisory control. Using the OCS as the host computer, OCS is able to access and manipulate the tag ID's within a subsystem (digital switches, setpoints, auto/manual state, etc.) to interact with the process to perform the supervisory control function. (A detailed description of the SDPC subsystem automation is documented in Reference 8.)

## 5.3 PLANT AUTOMATION IMPLEMENTATION

Supervisory control was implemented within the OCS computer in the form of FORTRAN programs called "Application Program (OCS Command File)" tasks. Prior to development of the application programs, supporting subroutines were coded which were common to several command files such as reading or setting a value of a SDPC tag ID, writing a message to a printer, waiting before continuing, etc.

The next phase of application program development required the capability to transition the Solar One plant from one steady-state operating mode to another, and establish optimum operating setpoints for each power producing mode of operation. Transitioning from one operating mode to another required first the capability to startup and shutdown each of the four major subsystems (CS, RS, TSS, EPGS). The OCS startup and shutdown procedures were developed making extensive use of the SDPC automation capability as the foundation for plant automation. The startup software was implemented, tested, and modified as individual tasks, then integrated into mode transition programs as subroutines. The exceptions to this are the RS startup and shutdown application programs, RSUP and RSSHUT respectively. These programs along with the automatic collector field control programs CFUP, INTPWR, FULPWR, and HOTSTA are standalone tasks. A brief description of these programs including mode transitions is given in Table 5-3.

The ultimate goal of plant automation was implementation of a clear day scenario for operating the plant throughout the day. This was accomplished by structuring an application program for 3 different clear day scenarios (CLRDY1, CLRDY2, and CLRDY5), utilizing the previously developed program. Originally the only requirement was for clear day operations in Mode 2 (storage boosted). In order to give the operators the flexibility to run the turbine on RS steam only (Mode 1) or to charge only with the TSS (Mode 5), the two additional clearday scenarios (CLRDY1 and CLRDY5) were implemented. The clear day scenario application programs activate lower level program task as certain process conditions become true. The order of execution is illustrated by the pie-diagrams of Figures 5-2, 5-3, and 5-4 for the 3 clearday scenario modes. The clear day application programs which reside in the center activate only those files adjacent to them. The application programs in the outer (third) circle are activated by the application programs in the inner (second) circle. Execution of these files progresses in a clockwise direction until either the file normally terminates after RS shutdown is complete or aborts due to a trip condition. The OCS is intentionally limited to executing only three application programs simultaneously in order to not overburden the CPU while performing other OCS functions such as alarms, graphics, surveillance, etc.

Table 5-3
OCS Supervisory Control Application Program Description

| Program Name | Functional Description |
|---|---|
| CFUP | Controls collector field during receiver startup |
| INTPWR | Add power after transitioning from RS flashtank to downcomer |
| FULPWR | Add power to put entire field in track at time turbine brought on line |
| HOTSTA | Returns collector field to power level compatible with RS flashtank operating conditions |
| RSUP | Receiver startup sequencing |
| RSSHUT | Receiver shutdown sequencing |
| RSDRAT | Derates receiver operating conditions |
| MX91 | Mode 9 to mode 1 transition |
| MX95 | Mode 9 to mode 5 transition |
| MXT9 | Mode 1, 2, or 5 to mode 9 transition |
| MX12 | Mode 1 to mode 2 transition |
| MX21 | Mode 2 to mode 1 transition |
| MX25 | Mode 2 mode 5 transition |

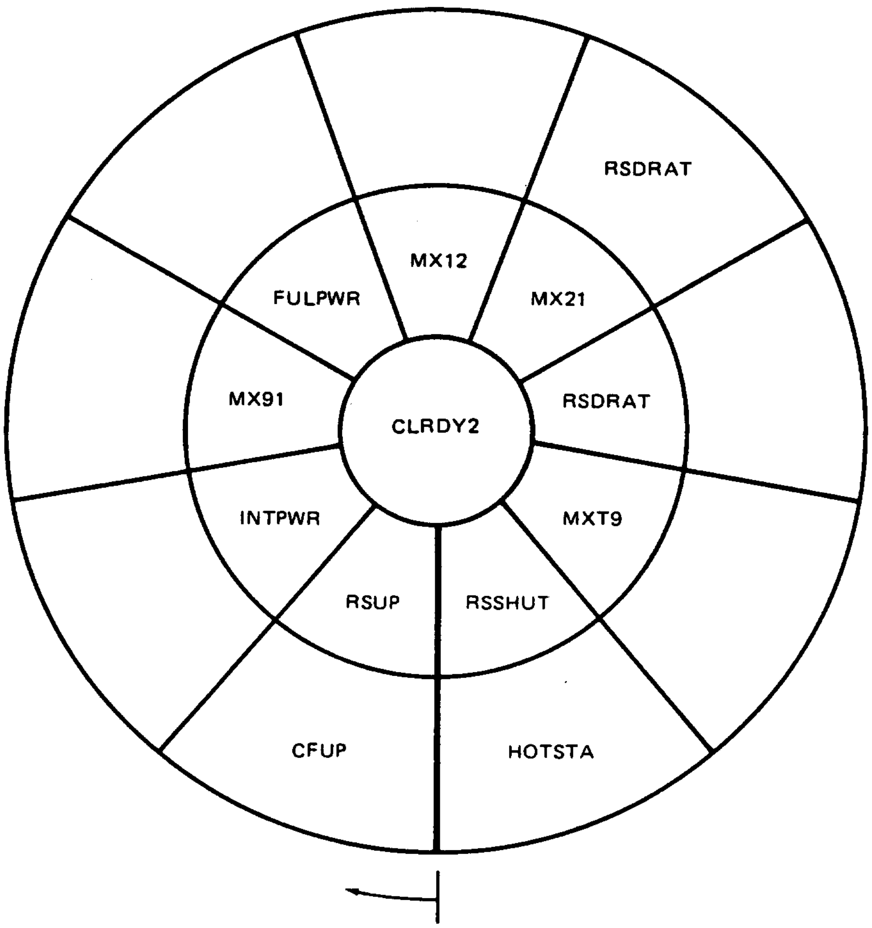



**Figure 5-2. Pie-Diagram of Clear Day Scenario for Mode 2**

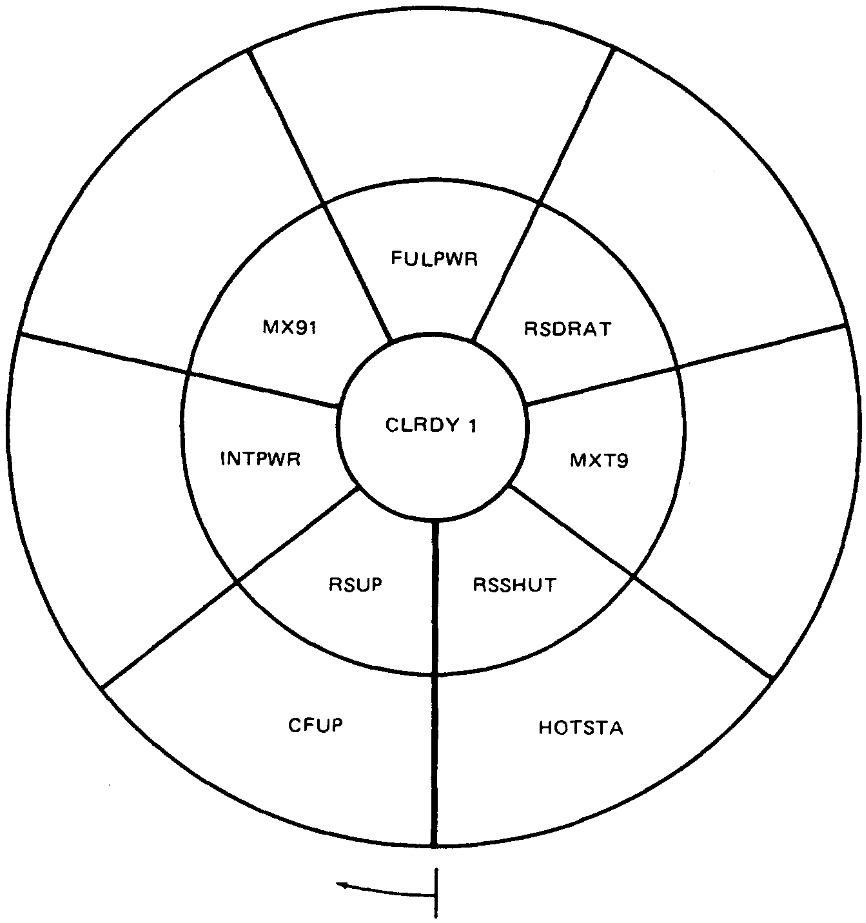



**Figure 5-3. Pie-Diagram of Clear Day Scenario for Mode 1**

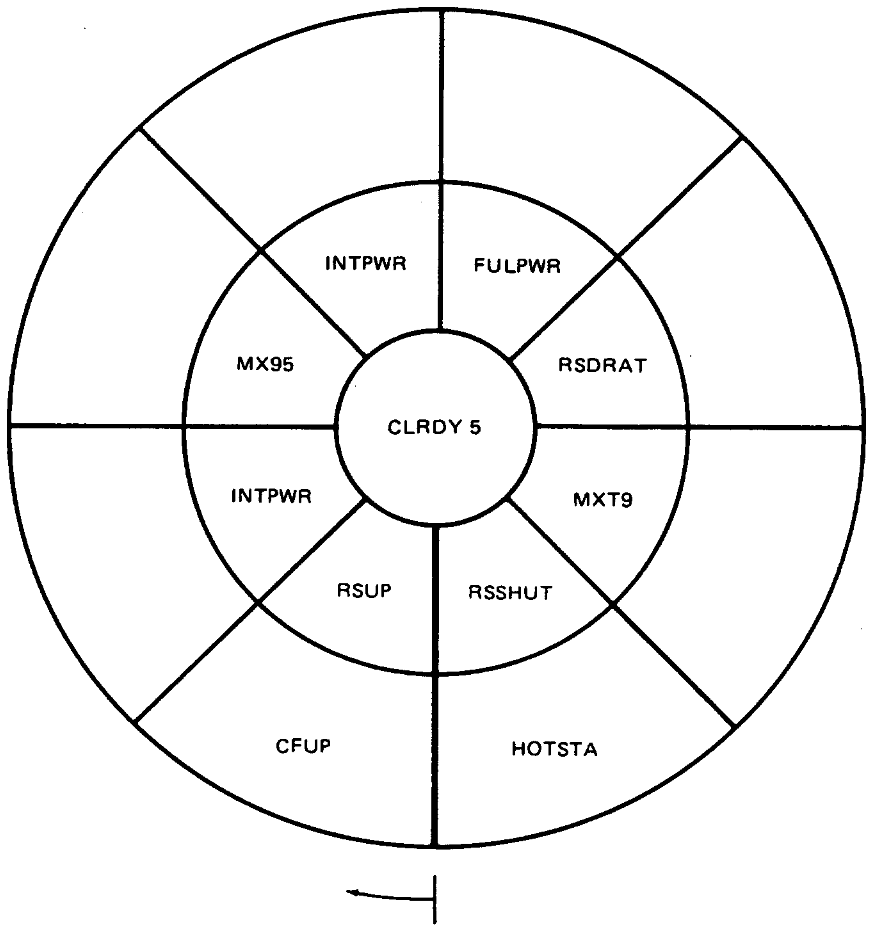



**Figure 5-4. Pie-Diagram of Clear Day Scenario for Mode 5**

The interface for operator manipulation of OCS command files is through the two OCS console keyboards and CRT's. There are three dedicated push buttons used primarily for control of the plant. The "Control Input" push button is used to send commands as selected by the cursor placement and depicted on the command line located at the bottom of the screen. The "Select" button is used to request a certain graphic page from a menu or another graphic page via "poke points." The third push button is the "Operations Menu." This push button is used to display the "Operations Menu" page which contains a list and brief description of all application program names, and the operator input labels required to "RUN" a program. In addition to the RUN capability, the operator can also ABORT, HOLD, or RESUME a program. A detailed description of the OCS supervisory control operating procedures and application program sequence of events can be found in Reference 9.

## 5.4 PLANT OPERATION

Plant operation for power production can be described in terms of seven major activities. Associated with each of the seven activities are a series of subtasks which may be manual operations or computer controlled operations. The seven activities are : 1) initial plant startup, 2) initial circulation, 3) collector field startup, 4) receiver startup, 5) turbine activation or TSS charge startup, 6) shutdown systems, and 7) plant shutdown to Mode 8.

The following paragraphs describe a typical operating day for two operating Modes (1 and 5) from initial plant startup to plant shutdown to Mode 8. OCS automatic operation is assumed in both cases.

### 5.4.1 Mode 1 Operation

A typical 24 hour Solar I activity cycle for mode 1 is shown in figure 5-5. The time-phasing of the tasks are shown for both a summer and winter solstice. The type of control and equipment used by the operator to carry out the required actions are also shown.

The Initial Plant Startup begins between 2:00 AM and 3:00 AM depending on time of year. This task includes starting up the auxiliary steam system, condensor vacuum system, deaerator pressure control and the condensate and circulating water systems. This involves having a PEO in the field to valve in the systems, rack in breakers and monitor each system as it starts up. The CO starts each system from SDPC switches in the control console. This effort takes approximately 1 1/2 hours to complete.

The Initial Condensate Circulation through the receiver is started as soon as the water chemistry is within the required specifications. The receiver feedpump is started from the SDPC and flow is established through the receiver flash tank bypassing the receiver. The water chemistry is tested again and when it is satisfactory, flow is established through the receiver panels. This is accomplished by the CO through the SDPC console. The PEO tests the water chemistry, observes the receiver fill and venting and, once it is filled and pressurized, climbs up into the receiver to inspect for leaks.

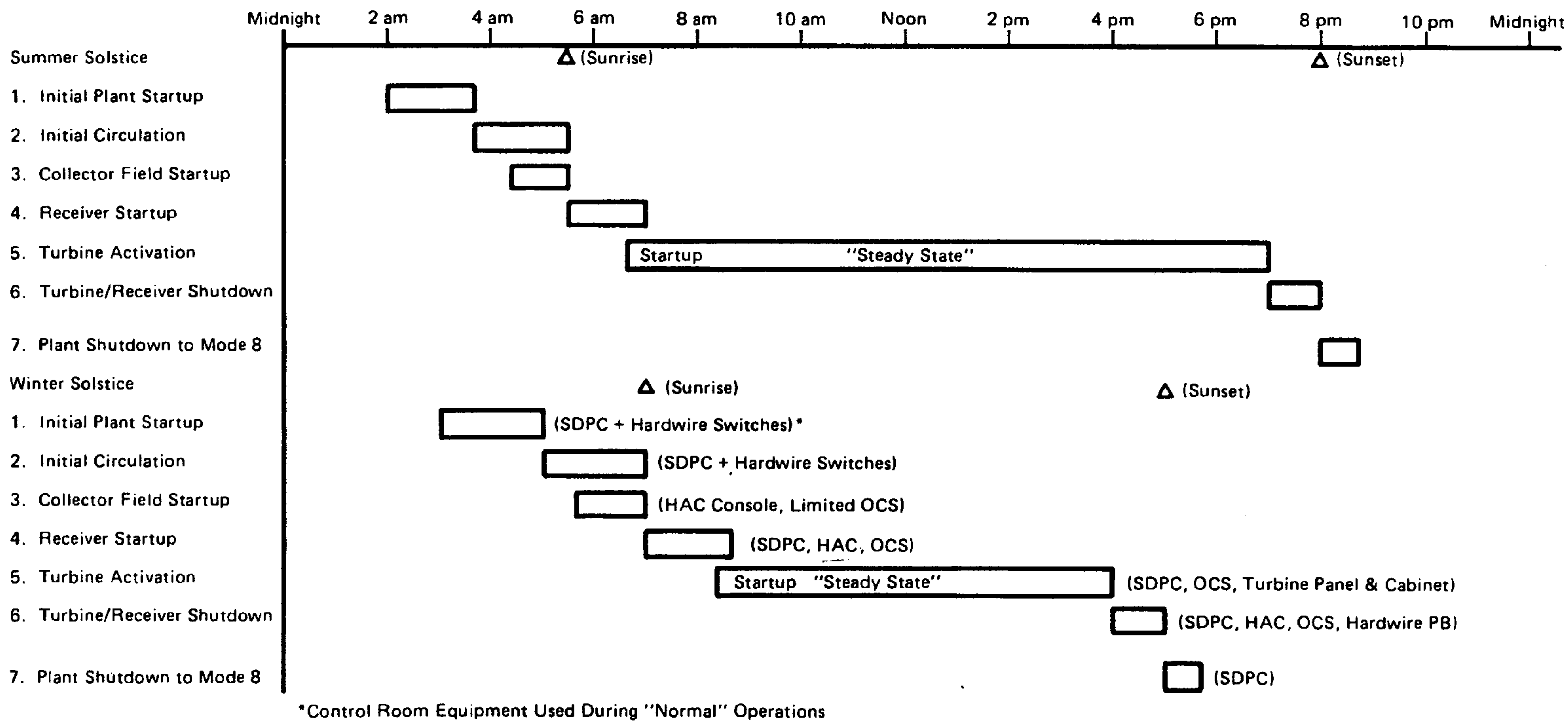



Figure 5-5. Typical "24 Hr" Solar One Activity Cycles – Mode 1

During the initial circulation the collector field will be readied for service. This involves having the CO work at the HAC console to release the DEFOCUS command, put in the proper aimpoint file, and unstow the field. Unstow causes all heliostats to point at a standby point, away from the receiver, ready to be put into track on the receiver. The PEO tours the field to verify it is clear of objects, free stuck heliostats and report problems with any heliostats.

Once these three activities are complete receiver startup can begin. All operations so far have been manual or through the SDPC console. From this point on, operation will be controlled by an OCS application program with some operator assistance or permission (see References 4 and 9 for details). To operate in Mode 1, the CO starts the "CLRDY1" program through the OCS console. This program starts the receiver startup task which initializes the receiver (checks for proper valve alignment, puts $GN_2$ on RS flash task to maintain adequate pressure, checks equal preheat panel flow, etc) and waits for the insolation to increase (NIP≥100 WSM) before proceeding. When the NIP is greater than 100 WSM the collector field startup task is enabled (CFUP). The heliostats are put in track on the receiver in 7 steps which allows the power to be brought on gradually (15-20 minutes). The number of heliostats put in track on each panel for each step is computed by an algorithm which includes time-of-day, insolation and panel flow rate as inputs. Each panel goes into flow control when the panel metal temperature exceeds 400°F. Each panel goes into temperature control when the panel metal temperature exceeds 600°F.

When all 18 panels are in temperature control the OCS monitors and maintains receiver flow at 35 KLBH by modulating the collector field. As soon as the RS outlet steam superheat exceeds 75°F the downcommer is automatically pressurized and the steam dump put into service. The RS flash tank is now removed from service and the steam pressure and temperature are brought up to 740 psia and 765°F respectively. The TSS extraction aux. steam system can be shutdown. At this point receiver startup is complete.

Since starting the CLRDY1 task the CO and PEO have been monitoring the different activities as they occurred. As the Turbine Activation is started the CO and PEO will checkout and adjust the various subsystems required for turbine startup and operation. The OCS CLRDY1 program will continue by commanding the collector field to intermediate power (50 KLBH receiver flow) and automatically aligning EPGS valves for turbine warmup and drainage and starting the turbine EHC systems. The CO must ENABLE the GE computer switch on the turbine panel so the SDPC can control selected turbine controllers. The CO will manually warm, roll and synchronize the turbine to the SCE grid. Once on-line, the SDPC will automatically load the turbine, put the turbine in pressure control, raise the pressure setpoint to 1300 psia and ENABLE the steam dump at 1350 psia as a safety in case of turbine trip. The OCS will then command the collector field to full power (all available heliostats in track). The plant is now in Mode 1 operation with the CO and PEO only required to perform normal monitoring of plant status.

Mode 1 operation will continue until the insolation reduces enough to cut total receiver flow rate to less than 62 KLBH. If this occurs after 1:30 PM, the OCS starts the receiver derated program (RSDRAT) which monitors the RS flowrate over a seven minute window and based on the results (and the amount of superheat available) slowly reduces the turbine pressure setpoint and RS temperature setpoint until specified lower limits are reached (720 psig, 705°F). At this time the turbine/receiver shutdown sequence (RSSHUT) is activated by the OCS. The turbine is taken offline on low-load by transfering pressure control back to the steam dump valve. The SDPC turns all motor driven pots on the turbine panel to zero. The OCS initiates a hot standby task (HOTSTA) which removes heliostats from track until the total receiver flow is 35KLBH. At this point the flow is switched to the flash tank and the downcomer is shutdown. The CO will then manually "DEFOCUS" the collector field through a hardwired pushbutton on the receiver console. This will defocus all heliostats and close all RS temperature control valves to allow the receiver to cool down slowly. The bypass valve to the RS flash tank is opened 25% to allow filing of the flash tank to 32 inches. When this occurs, the OCS shuts down the receiver feedwater pump and aligns all receiver valves to a shutdown condition. During this period the CO has been monitoring the RS shutdown and has manually sent the heliostats to a stow position at the HAC console. The PEO puts the turbine on turning gear, racks out the generator, breaker, and performs various other tasks to shut down the turbine.

Final plant shutdown to Mode 8 involves the CO stopping much of the plant equipment through the SDPC while the PEO carries out a wide variety of shutdown related tasks throughout the plant. These tasks primarily involve valving systems out of service to prevent natural circulations or control valve leak thru from draining or flooding system components. In addition, $GN_2$ is selectively valved into service to provide the necessary blanketing environment.

5.4.2 Mode 5 Operation

A typical 24 hour Solar I activity cycle for Mode 5 is shown in Figure 5-6. As shown, it is the same as the activity cycle for Mode 1 (Figure 5-5) except the TSS charging system is started and used instead of the turbine-generator. Thus, the first three activities (initial plant startup, initial condensate circulation, and collector field startup) will be the same (see paragraph 5.4.1) except for deleting any early tasks involving the turbine and including tasks required for TSS charging operation.

Once these three activities are complete receiver startup can begin. As in the Mode 1 receiver startup, the operation will be controlled by an OCS application program with some operator assistance or permission (see Reference 4 and 9 for details). To operate in mode 5, the CO starts the CLRDY5 program through the OCS console. The CO will specify at this time which charging train (1 or 2 or both) is to be used.

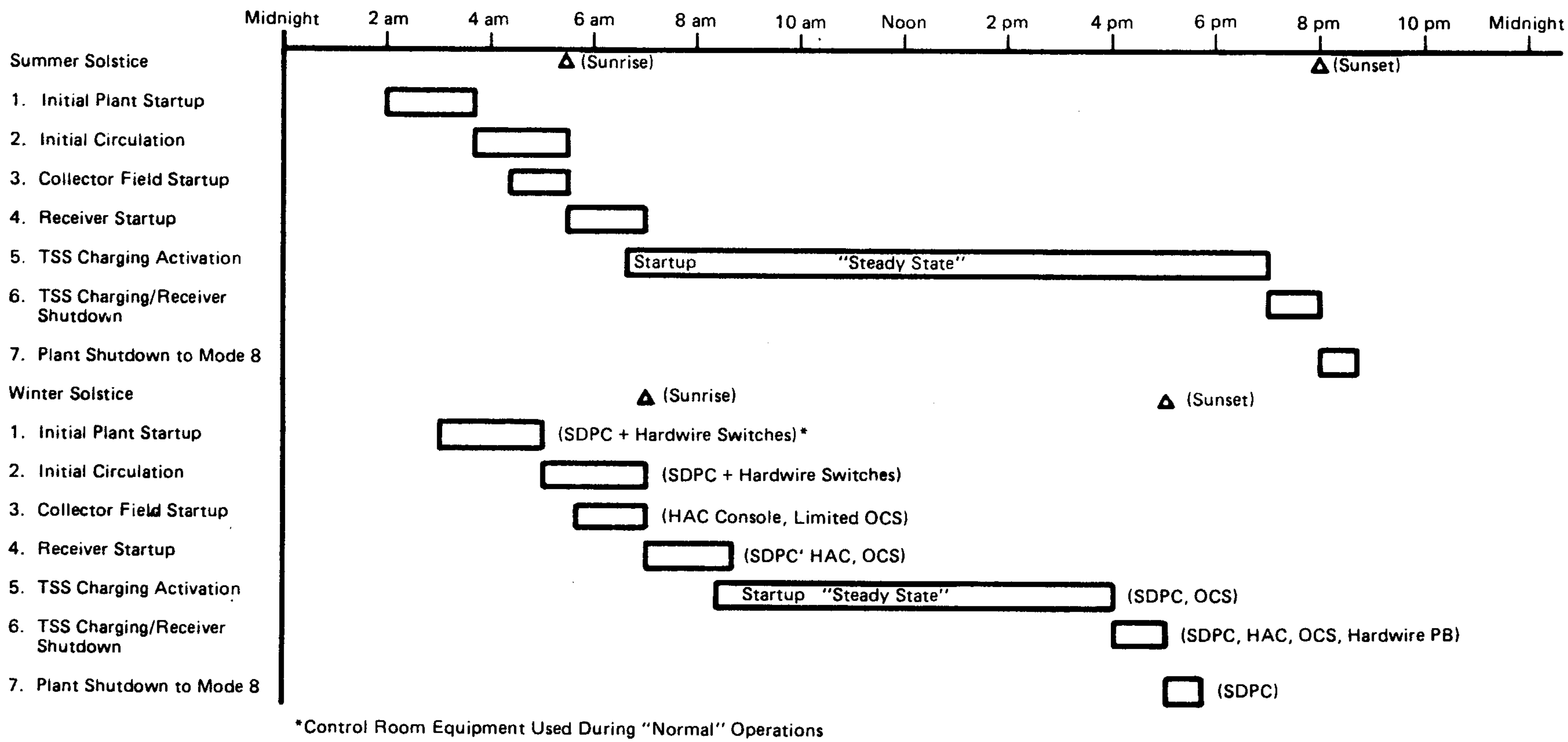



**Figure 5-6. Typical "24 Hr" Solar One Activity Cycles – Mode 5**

Receiver startup will be the same as described for mode 1 in paragraph 5.4.1. The tasks include initializing the receiver, startup of the collector field, getting all panels into temperature control, pressurizing the downcomer, and finally putting the steam dump in service and taking the RS flash tank out of service. At this point receiver startup is complete.

The OCS CLRDY5 program will continue by commanding the collector field to intermediate power (50 KLBH receiver flow) and automatically aligning drain valves for warmup of the TSS charging systems. The OCS program will bring the charge system up to the point where one or both of the oil pumps must be started. When the CO starts the pump, through a hardwired pushbutton, the program continues by pressurizing the train, setting up the TS flash tank for charging operation, and finally moving RS pressure control from the steam dump to the TSS charging steam inlet valve. At this time the oil is being heated by recirculating it through the TSU bypass line. As soon as the oil temperature is above 500°F the program automatically aligns valves to route the hot oil to the top manifold of the TSU. When the oil temperature goes above 570°F the oil temperature controller is put in automatic and the plant is now in Mode 5. The CO and PEO are required only to perform normal monitoring of the plant status.

Mode 5 operation will continue until one of several conditions occur. If the oil being drawn out of the bottom of the tank is greater than 450°F, the OCS will put the plant in Mode 9 and shut down the charging train. If, before this happens, the receiver flow rate becomes less than 42 KLBH and this occurs after 2:30 P.M., the OCS starts the receiver derated program (RSDRAT). This program monitors the RS flowrate over a seven minute window and, based on the result (and the amount of superheat available), slowly reduces the temperature setpoint until a specified lower limit is reached (755°F). At this time the OCS takes the charging train out of the service and puts the plant in mode 9. If the RS flowrate is greater than 35 KLBH the CLRDY5 program will abort, leaving the plant in mode 9 and notifying the CO of the plant status. If the flowrate is less than 35 KLBH the OCS starts the RS shutdown sequence (RSSHUT) which takes the receiver out of service as described in paragraph 5.4.1. The CO and PEO then put the plant into mode 8.

## Section 6

## MAN-MACHINE INTERFACE

### 6.1 GENERAL

The Man-Machine Interface function is defined in terms of monitor and display and controls. It consists of information exchange between the operator and the control hardware and software through color CRT's, keyboards, function keys, light pens, printers and audible annunciators. Monitor and display covers alarms, operator messages, printers, status, trends, x-y plots and graphics for each of the systems and the overall plant. Controls covers implementation of operator commands through use of the keyboards or function keys or using the light pens through the graphics.

At Solar I, the Man-Machine Interface is accomplished by the Master Control Console shown in Figure 6-1. This console provides status information for all systems and control capability in either a manual or automatic mode of operation. A layout of the console configuration is shown in Figure 3-3. A front view of the receiver console is shown in Figure 6-2. The cabinet contains two operator stations as well as the BCS monitor CRT and a 6 channel trend recorder. The TSS and EPGS console is shown in Figure 6-3. The TSS and EPGS dedicated pushbutton panels are clearly shown in this figure. Figure 6-4 shows the OCS console layout which includes a CRT for OCS trends. Figure 6-5 shows the operator station for the Collector System. It includes a status display, graphics display, a printer for alarms and operator messages and floppy disc storage. The turbine console is a separate console, as shown in Figure 6-6. It provides controls to warm and run up the turbine to sync

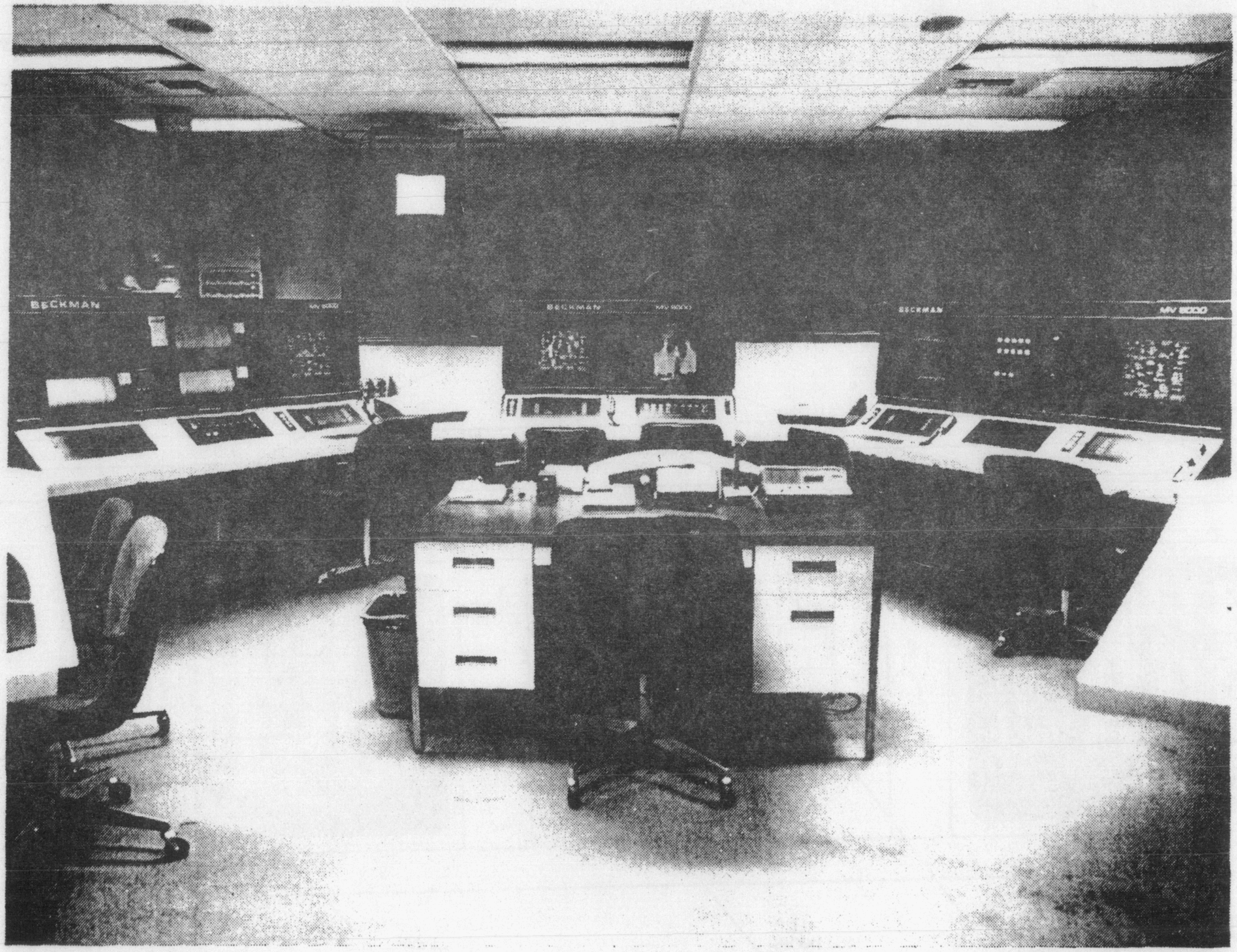


Figure 6-1. Master Control Console

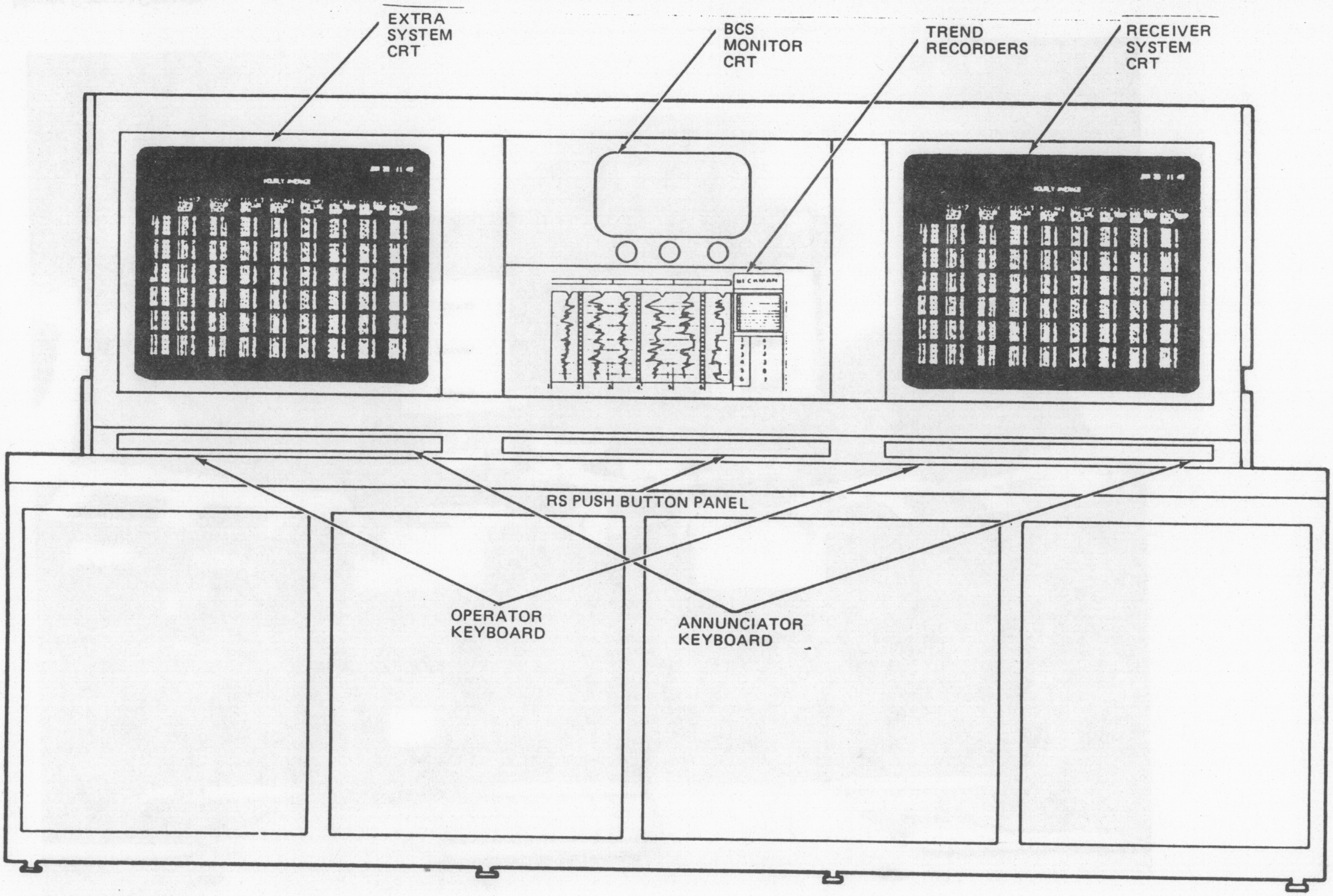



Figure 6-2. RS Console

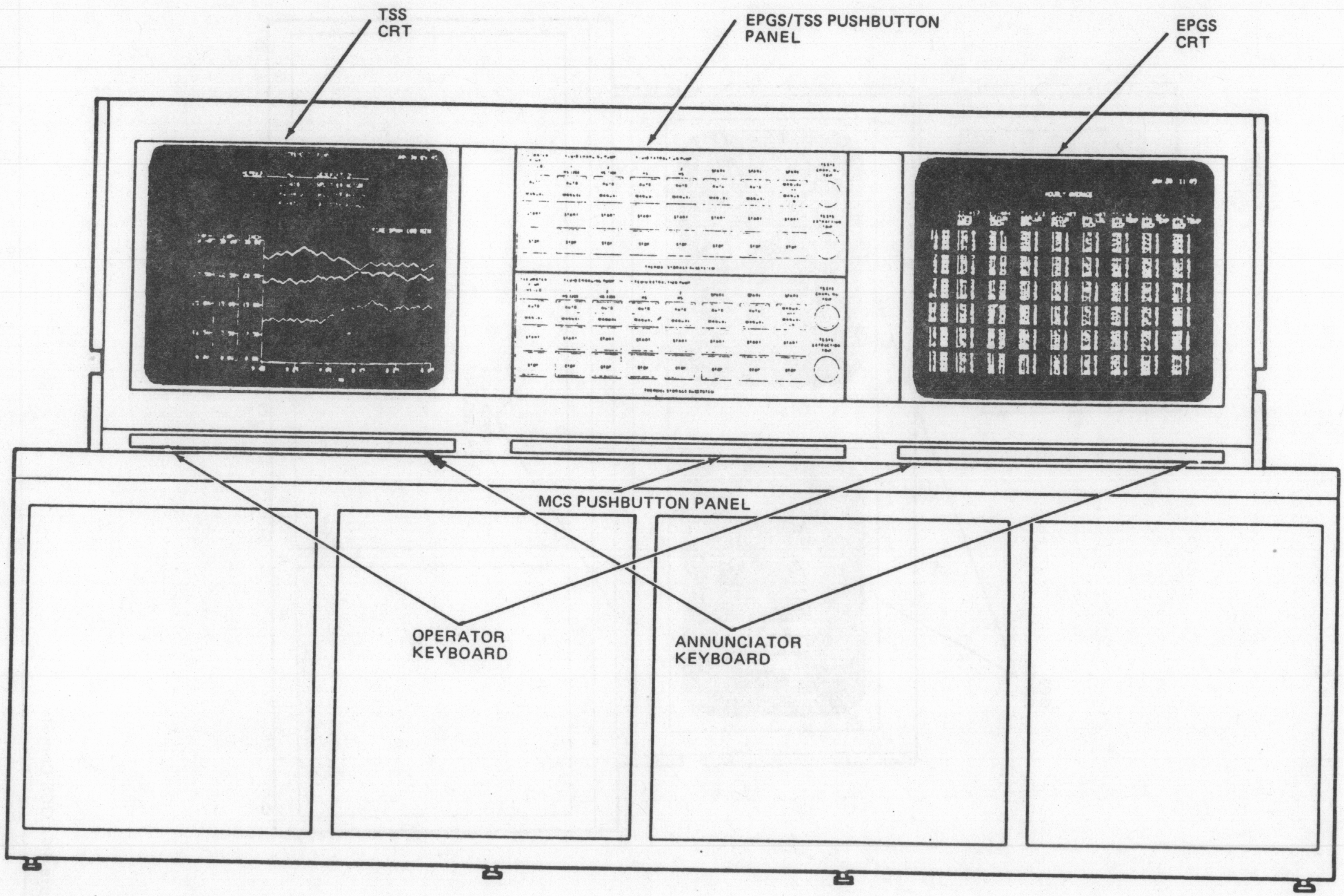



Figure 6-3. TSS and EPGS Console

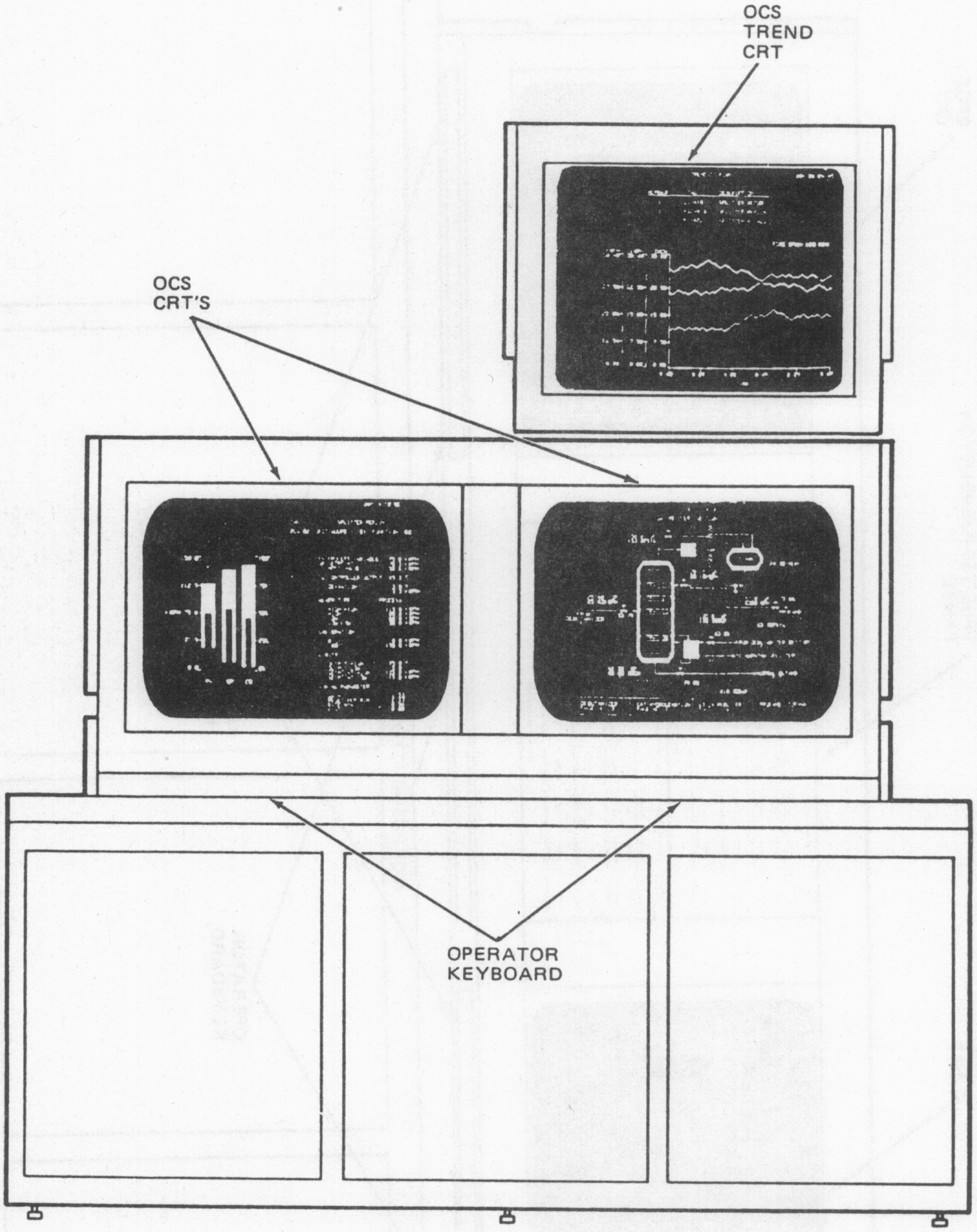



Figure 6-4. OCS Console

Figure 6-5. Collector System Operator Station

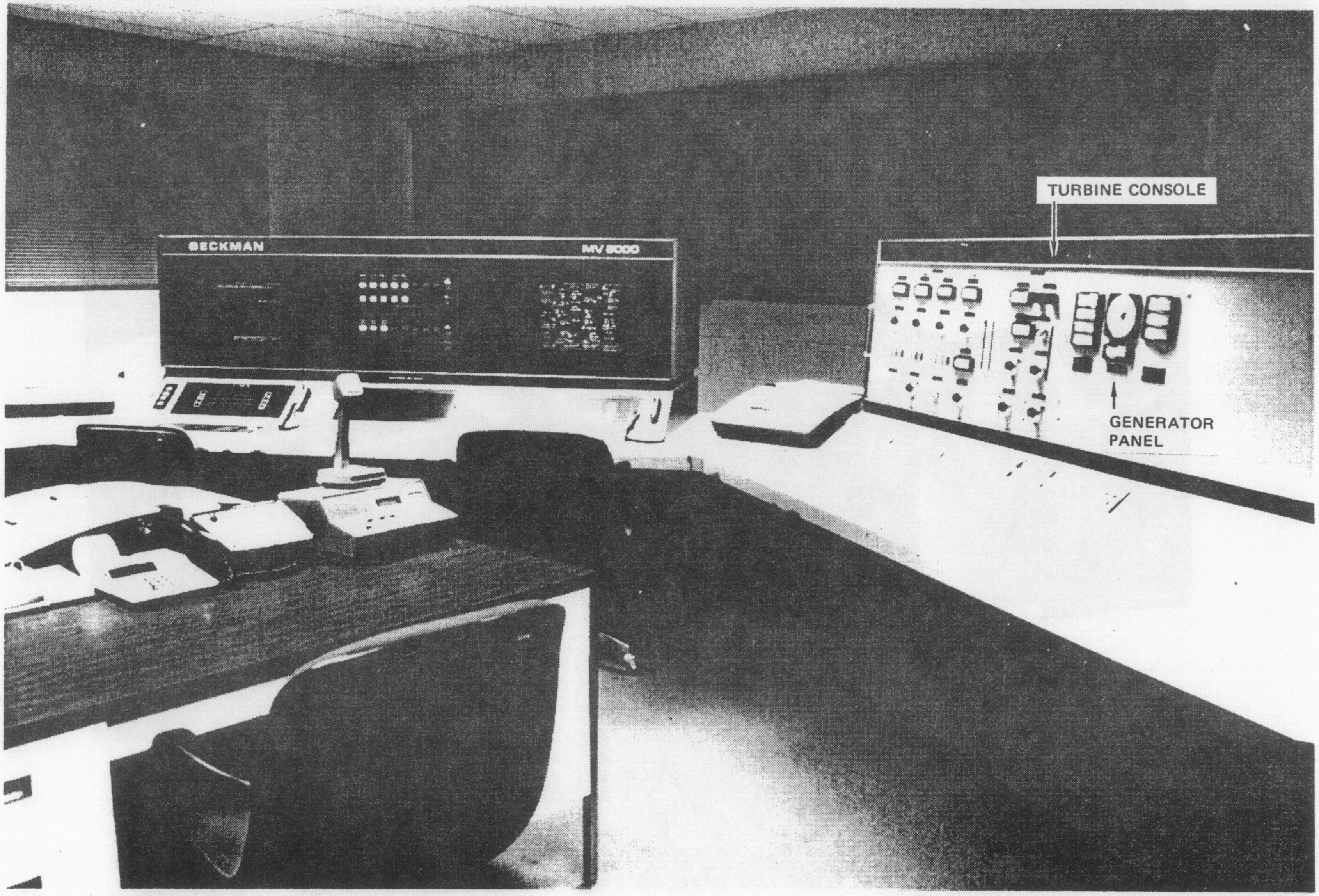



Figure 6-6.  Turbine Console

speed, synchronize the generator on line and load the turbine. The turbine can be operated using main steam from the receiver or admission steam from the TSS extraction system.

The following paragraphs give an overview of the various man machine interface components. Detailed operational information may be found in References 1, 2, 3, and 19.

## 6.2 SYSTEM CONTROL -SDPC

The SDPC contains four independent "operator stations," each consisting of a 19 inch color graphic CRT, an alarm annunciator keyboard, an operator keyboard, a light pen and printers. Figure 3-10 depicts the interfaces for the RS station which is typical for all stations. As shown, any operator station can be connected to any one of the three Beckman MV8000 systems (RS, TSS or EPGS) by using the Console Access Processor (CAP) switch. Also all three systems are connected to the OCS (host computer) through their respective Host Configuration Processor (HCP).

Figure 6-7 shows the receiver system operator station with the operator keyboard, alarm keyboard, CAP switches, light pen and CRT. The functions available through this typical SDPC operator station are described below.

### 6.2.1 Operator Keyboard

The Operator Keyboard is a capacitive touch-pad type of solid state construction. This construction provides a hermetic seal against the

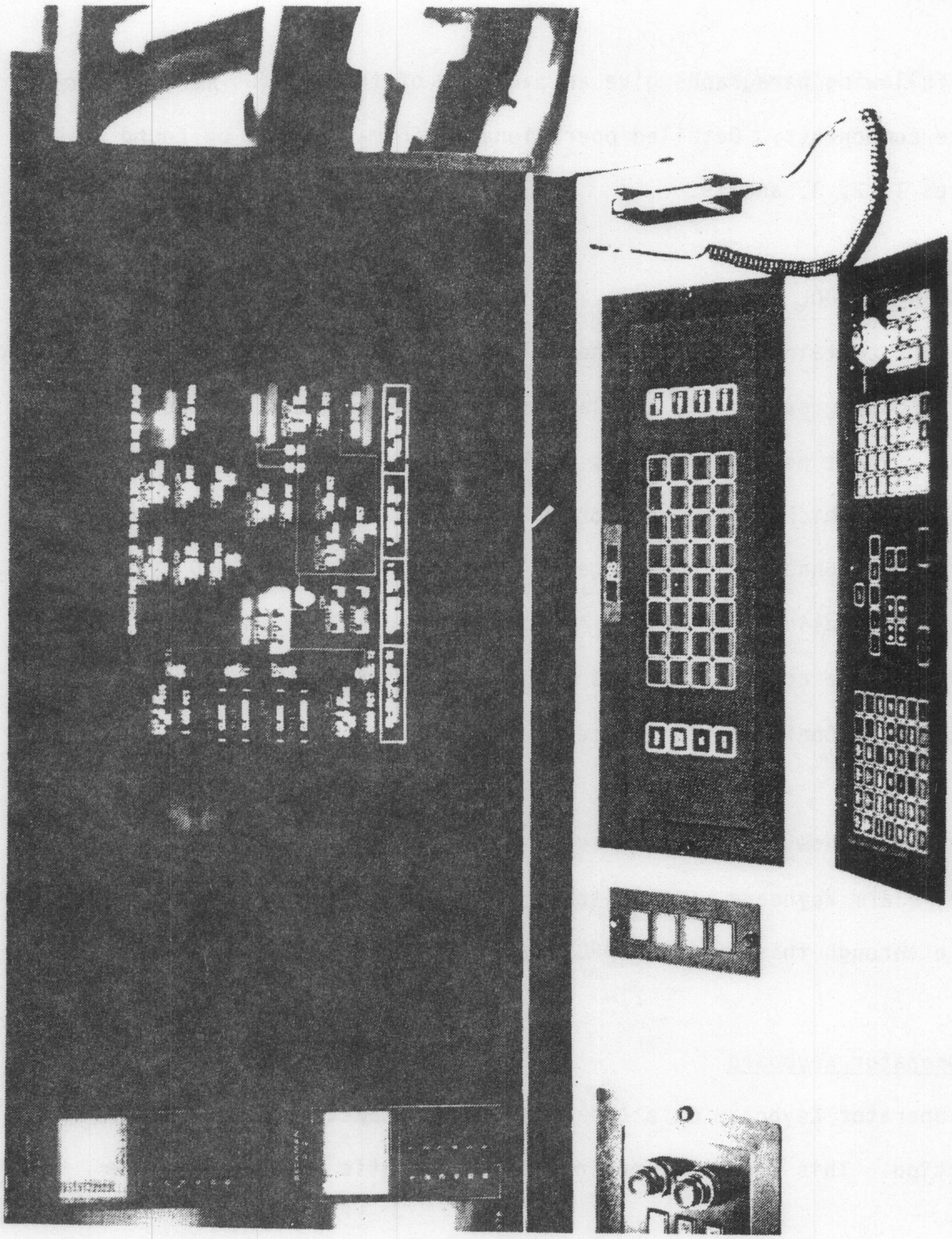


Figure 6-7. SDPC Operators Station

environment, and eliminates moving parts. The Operator Keyboard is divided into three (3) basic functional categories: DISPLAY REQUEST KEYS, LOOP CONTROL KEYS, ALPAH-NUMERIC KEYS. Figure 6-8 shows a typical operator keyboard.

The display request keys are the starting point for all display requests. The displays available for process monitoring and control are divided into five (5) basic categories:

1. Overview Displays
2. Group Displays
3. Loop Detail Displays
4. Plant Graphics Displays
5. Historic Trends Displays

Loop Control keys provide for changing setpoints and outputs on controlled loops, changing control modes for loops from "automatic" to "manual," and/or "console" to "cascade", and vice-versa. All actions are directed to a loop which is being displayed and is active.

The Alpha-Numeric keys are used for inputting combinations of numerical and alphabetical information into the system. For example, numeric data would include actual values for manipulation of loops, numbers of groups, or display pages for display requests. The alphabetical keys provide for inputting letters which are used in the system along with numbers to further identify loops, system components, and their associated displays. Note that the additional nomenclature printed on these keys is associated with their use in generating graphics.

### 6.2.2 Alarm Keyboard

The alarm keyboard is shown in Figure 6-8. It has 32 group keys and 4 page keys. The function of a group key is to indicate an alarm state for a group by turning red or yellow. Also, by pressing a group key you can call up the alarm status display for that group. The function of the page keys is to associate the group keys to one of the four overview pages. In other words, the page keys cause the group keys to represent groups 1-32, or 33-64, or 65-96, or 97-128. A green backlighted region on each page key indicates when the group keys are indexed to its page.

Four other keys on this panel allow the operator to test all the LEDS on the panel (TEST), call up the diagnostic summary display showing diagnostic information from the system (DIAG SUM), silence the console based alarm horn (SIL) and acknowledge alarms and diagnostics (ACK).

### 6.2.3 Alarm Printer

When an alarm occurs, it is automatically printed out with tag, description, and time of occurrence. Alarm acknowledgement and return to normal will also be printed out with their time of occurrence. If the Alarm Printer fails, the System Printer will automaticaly take over the duties of the Alarm Printer. Normal duties of the System Printer will then be interrupted any time that system broadcasts alarm information.

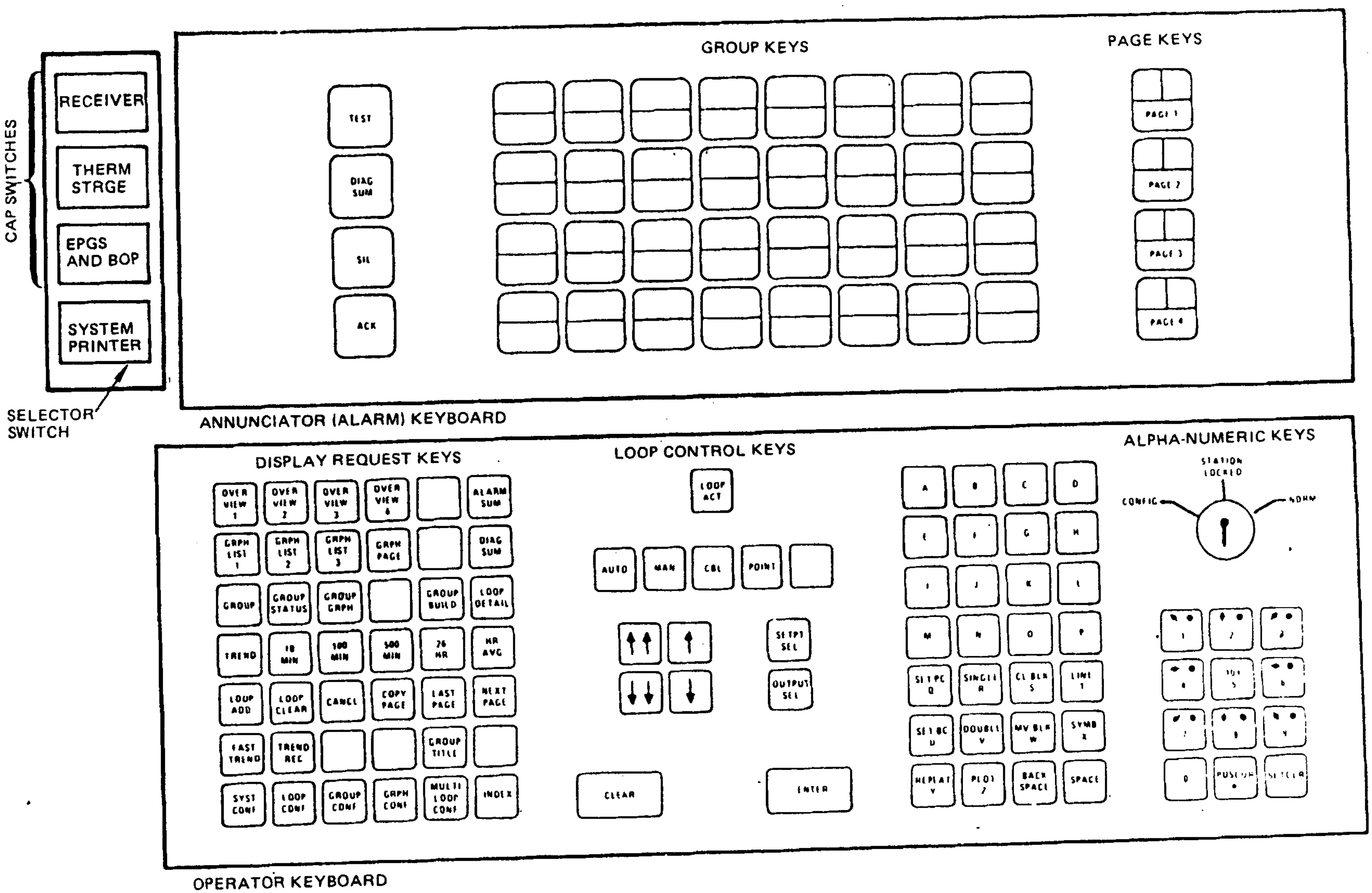



Figure 6-8. Typical SDPC Operator and Annunciator Keyboards

### 6.2.4 <u>System Printer</u>

When the COPY PAGE key is pressed the System Printer will print out the information currently on the screen. If the System Printer is also handling the alarm printer's duties, the "copy page" function will be automatically terminated when that system starts transmitting alarm information. The "copy page" funcion has to be requested again after the alarm information has been printed out.

The System Printer is connected to a particular systems (RS, TSS, EPGS) through the SYSTEM PRINTER selector switch shown on Figure 6-8.

### 6.2.5 <u>Light Pen</u>

The MV8000 provides a light pen as an operator convenience item. The light pen can be used to reduce the number of required keystrokes in several ways:

1. For calling Group Displays from the Overviews.

2. For calling up Graphics Displays from the Overviews or another Graphics Display.

3. For entering loop tags for Loop Detail Displays; adding the tags to the Trend Display (any time base, and also Hourly Average Display); for adding tags to a Temporary Group Build Display.

4. For activating a loop for control changes.

The light pen is used by pointing it at the target area, i.e., the tag or group number, and touching the fingertip to the capacitive portion of the pen.

### 6.2.6 Dedicated Pushbuttons

The dedicated pushbutton panels allow the operator easy access to the controls for various major pieces of equipment. The panels also include emergency trip pushbuttons for each system and the overall plant as well as dedicated system trip/reset and other important status lights. Figures 6-9 and 6-10 show the panel configuration for the RS, TSS and EPGS. Figure 6-11 shows the configuration for the Master Control System (Plant) panel.

## 6.3 PLANT CONTROL - OCS

The man-machine interface for OCS consists of information exchange between the OCS computer and the operator through the two 19-inch color graphic CRT's, operator keyboards, function keys, light pens and printers. Figure 6-5 shows the OCS control room consoles. Detailed operation of the keyboards, function keys, etc., may be found in Reference 4.

### 6.3.1 Operator Keyboards

The operator keyboards contain alphanumeric keys which are used for inputting combinations of numerical and alphabetical information into the OCS for control and monitoring. In addition, the extra nomenclature printed on these keys is associated with their use in generating graphics.

### 6.3.2 Function Keys

Twenty-four special function keys are included on the OCS keyboard. Figure 6-12 shows the configuration and assignment of these keys. The keys are color coded to aid in operation. The primary functions are control, display menu's, paging, trend displays and servicing alarms. Since alarms are

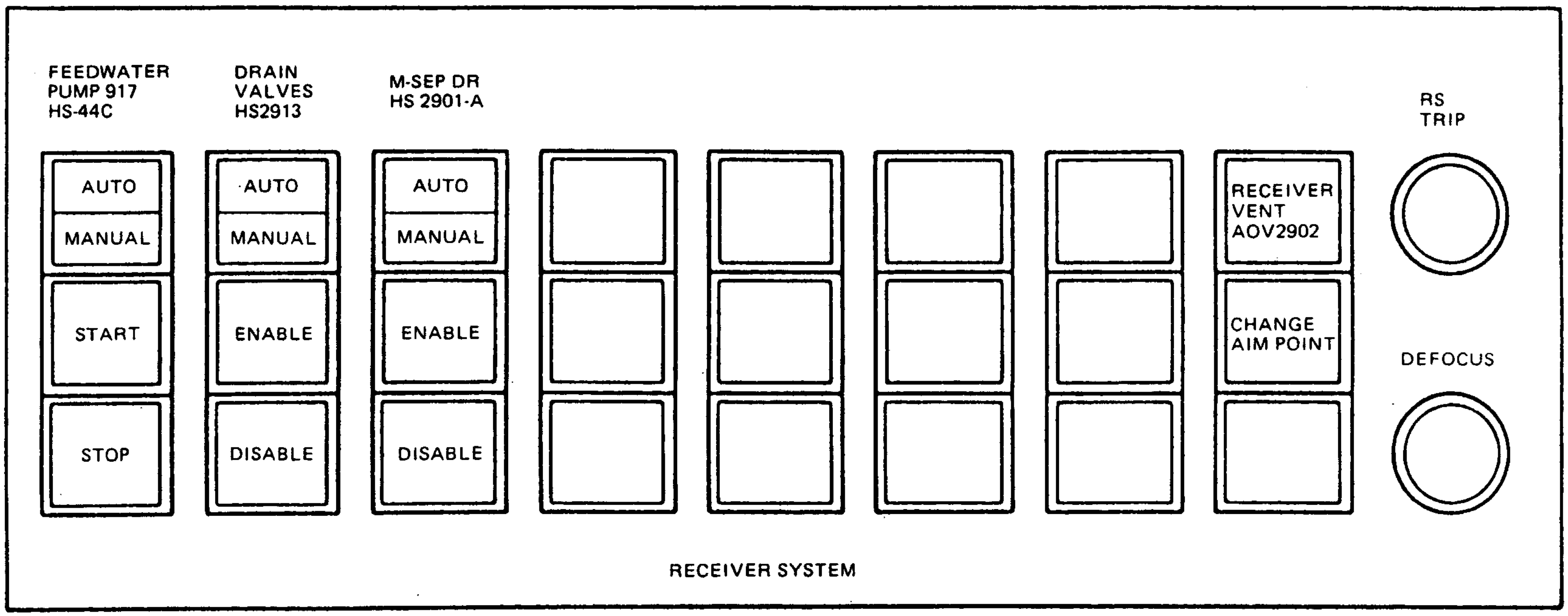



Figure 6-9. RS Dedicated Pushbutton Panel

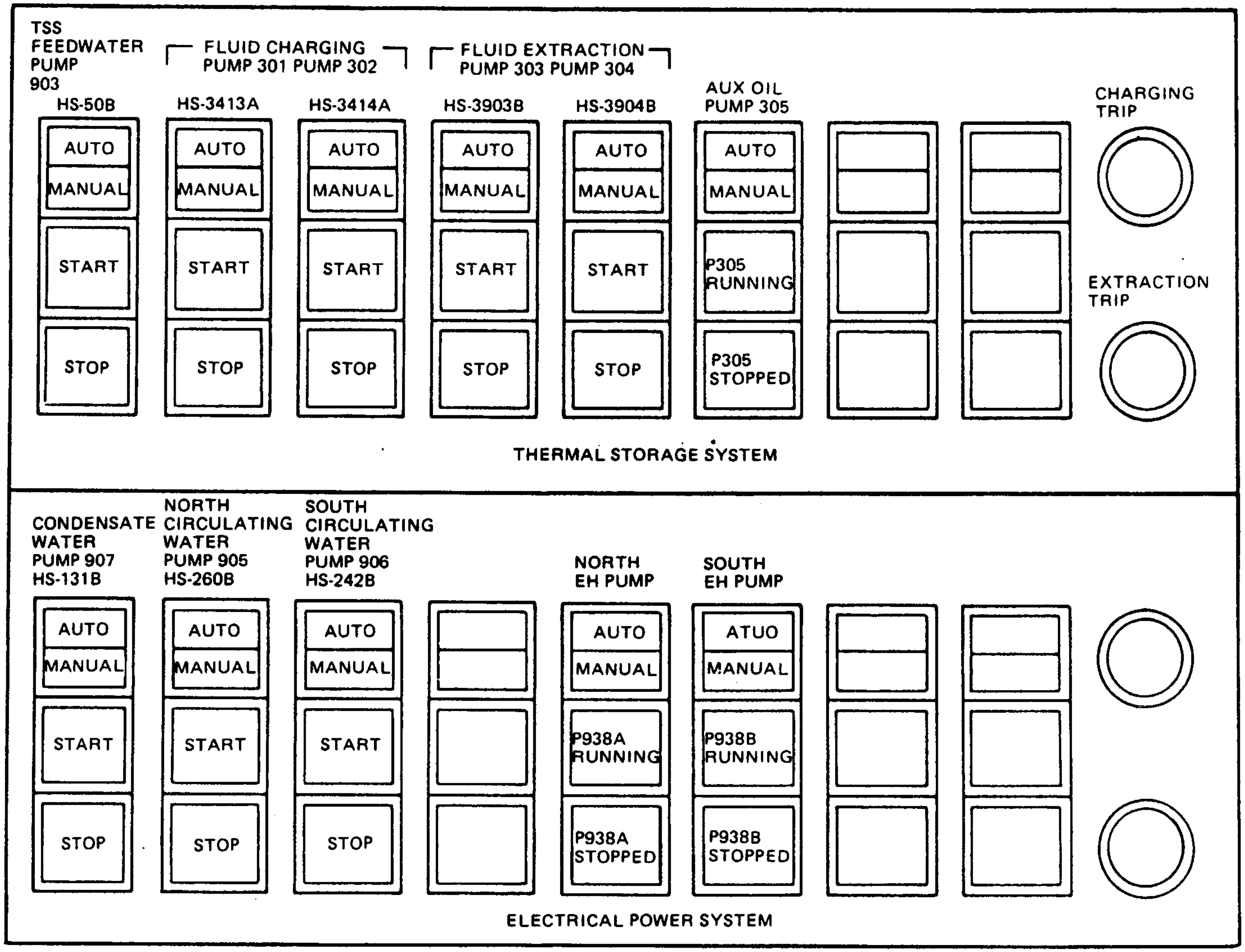



Figure 6-10. TSS and EPGS Dedicated Pushbutton Panels

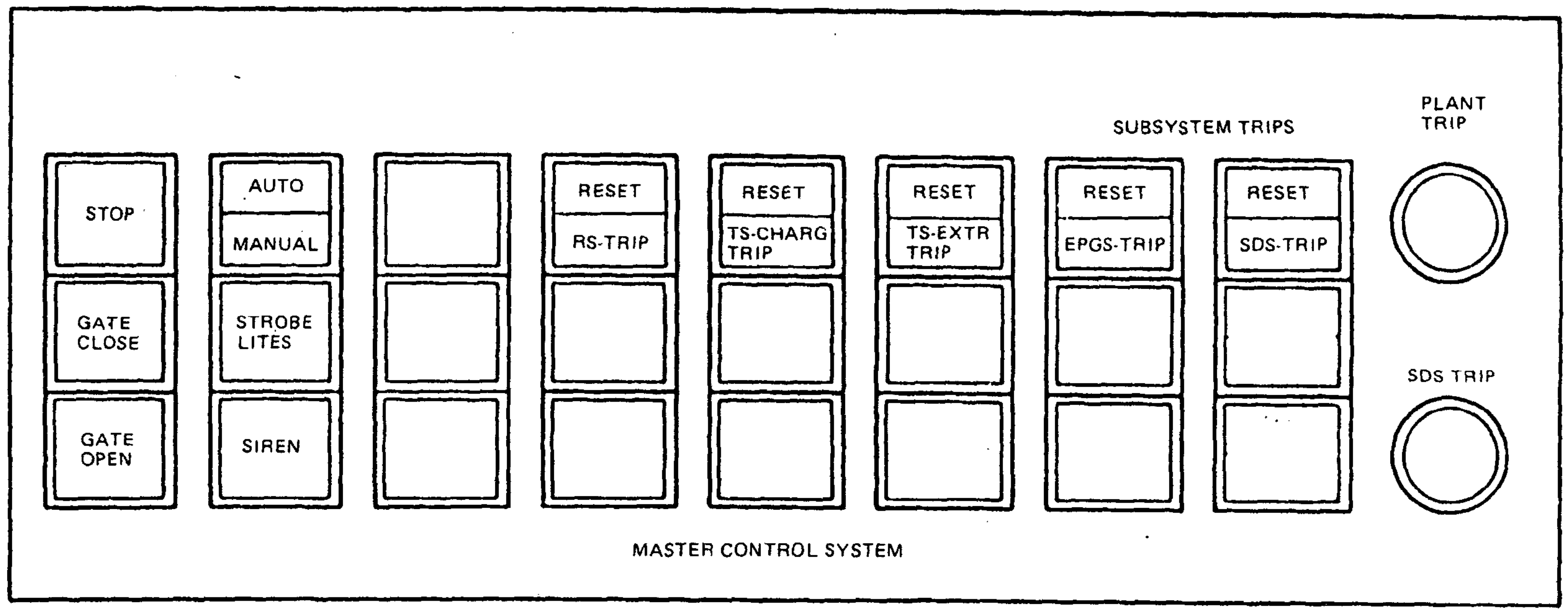



Figure 6-11. MCS Dedicated Pushbutton Panel

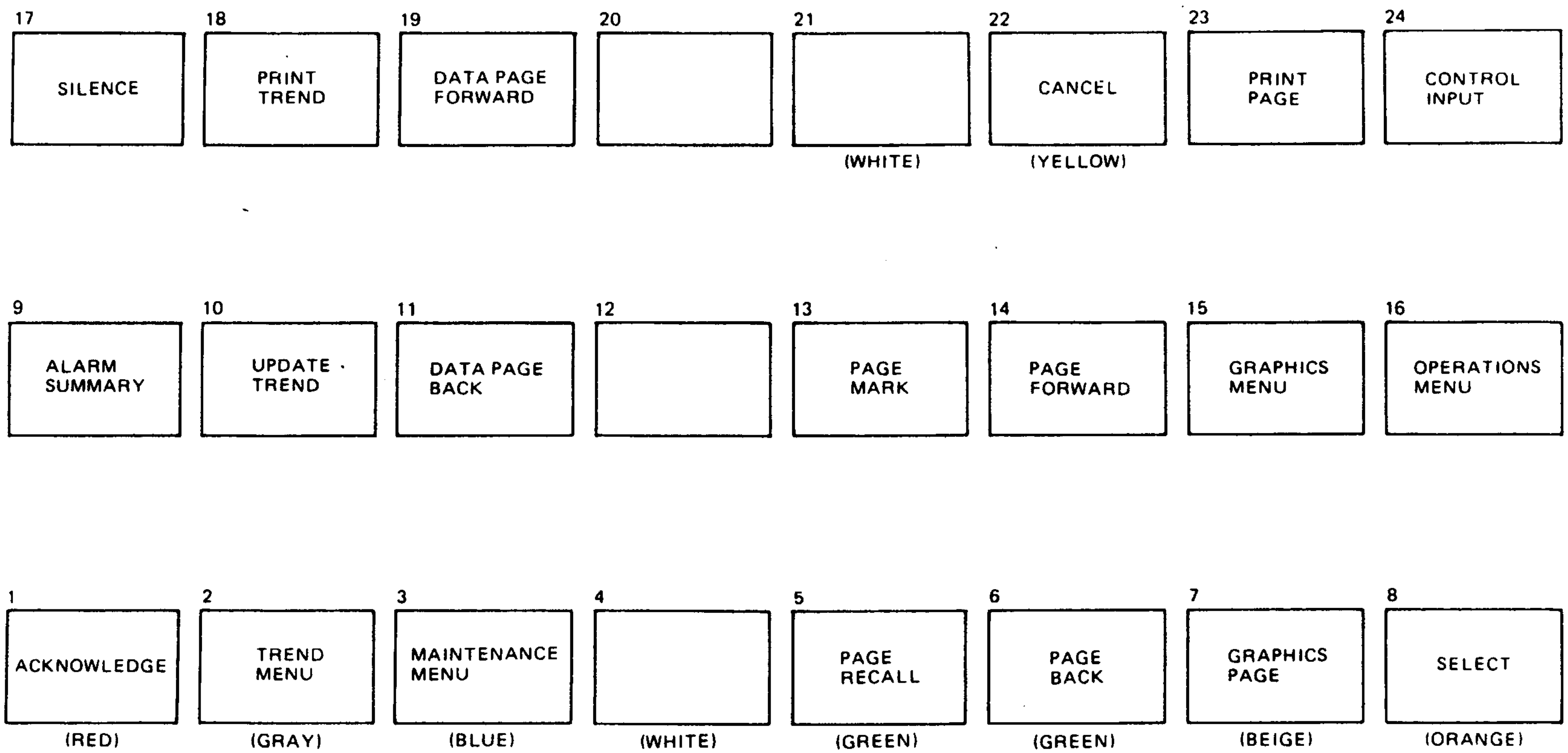



**Figure 6-12. OCS Special Function Keys Layout**

handled from a plant standpoint in OCS a few more words here are needed. The SILENCE function key will silence an audible horn on any one of the three SDPC systems (RS, TSS, EPGS). The ACKNOWLEDGE function key will acknowledge an alarm on any system as long as the loop appears on the respective OCS CRT. The ALARM SUMMARY key will display the last 20 alarms from all systems, integrated in time, with up to 5 pages available (last 100 alarms). The OCS alarm printer prints all system alarms, as they occur, are acknowledged and clear.

### 6.3.3 Light Pen

The light pen is used to quickly position the cursor anywhere on the CRT. It is normally the first step an operator takes when performing an action (start, stop, change setpoint, etc.). The cursor can be moved manually at operator discretion.

### 6.3.4 Trend/X-Y Displays

Time history plots of up to four variables per plot are available on the OCS Trend CRT. A trend list provides 24 hour trending of up to 60 variables. The trend plots may be real time or historical. Real time trends are not limited to those tag ID's on the trend list. X-Y plots are available which are snapshots of up to 24 variables using the values availabe at the time the display is called up. An update may be made at any using the TREND UPDATE function key.

The Trend or X-Y plot may be printed on the Trend hardcopy printer using the PRINT TREND function key.

## 6.4 TURBINE CONTROL

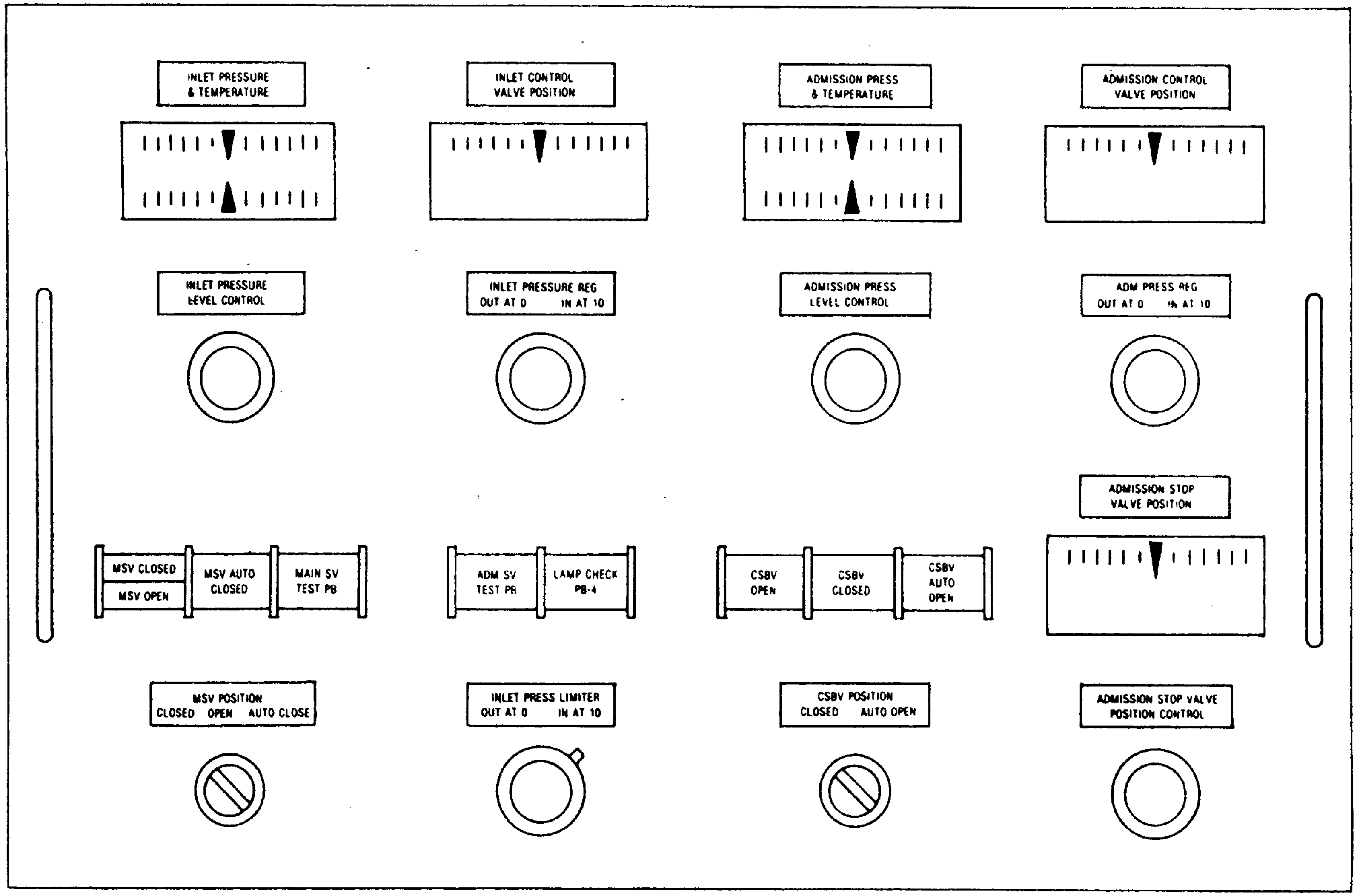
Turbine control is accomplished through five panels on the turbine console shown in Figure 6-6. From these panels the CO can warm and roll the turbine, synchronize the generator to the line, load the turbine and setup the main inlet valve to control receiver pressure. The following paragraphs briefly describe the panel operations. (see Reference 19 for detailed operating descriptions).

### 6.4.1 Panel 1

Panel 1 is shown in Figure 6-13. This panel is the controls for the main steam and admission steam (low pressure) stop valves, the pressure level (setpoint) controls and the IN-OUT control used to change the controllers from load control to pressure control. Control valve position indicators and pressure and temperature indicators are also provided. The controls on this panel are used to warm up the turbine during startup and put the control valves under pressure control (IN/OUT) after the generator is on-line.

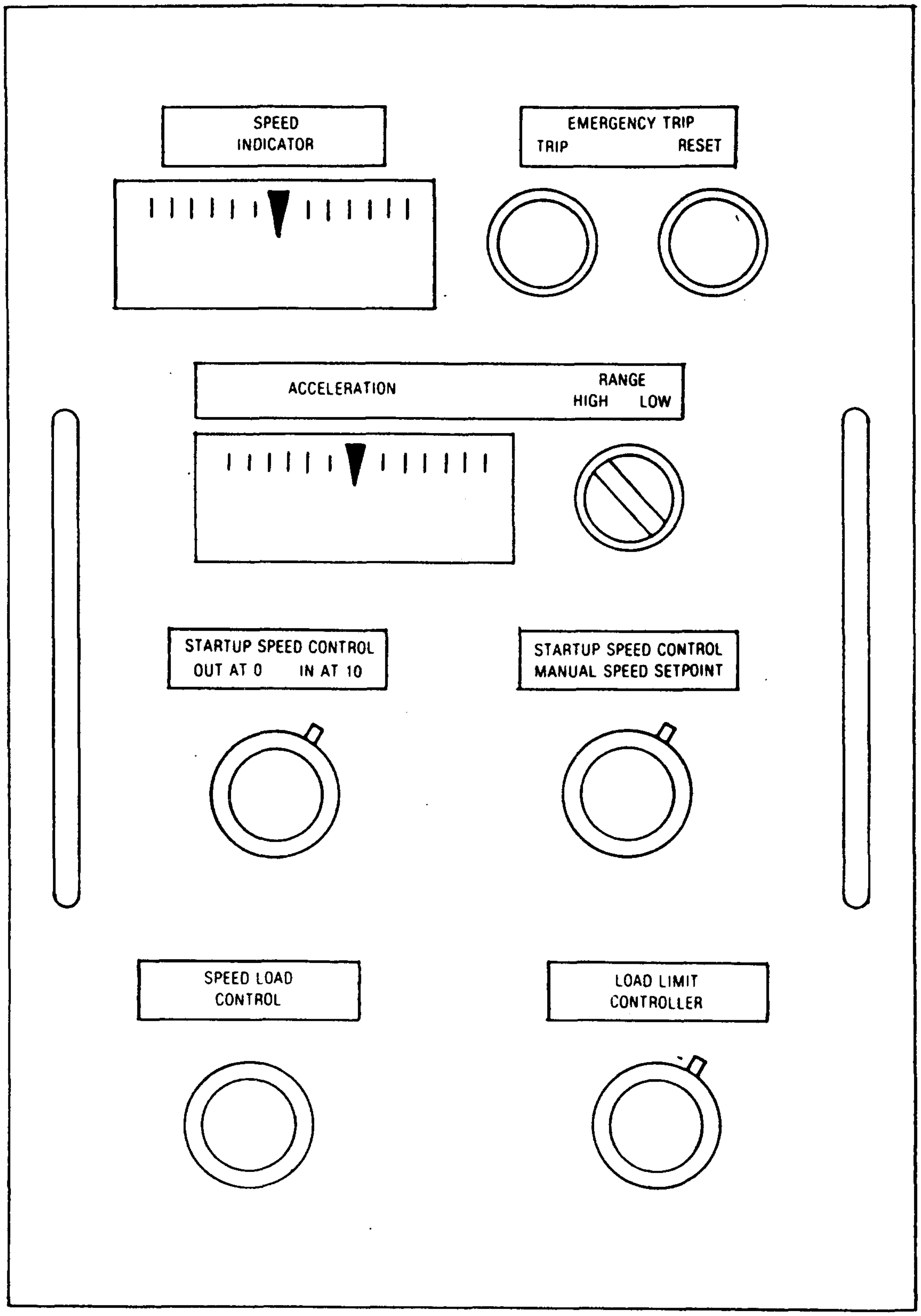
### 6.4.2 Panel 2

Panel 2 is shown in Figure 6-14. This panel has the startup speed/load control, speed indicator, acceleration indicator and load limit control. The speed load control is used to roll the turbine and bring it up to sync speed. Once the generator is on-line, the startup speed IN/OUT will be set at OUT and the speed control will be used to initially load the turbine until the CO is ready to put the control valves in pressure control. An emergency trip and reset pushbutton is hardwired on this panel.




Panel No. 1

Figure 6-13. Turbine Console – Panel Nc 1




**Panel No. 2**

**Figure 6-14. Turbine Console — Panel No. 2**

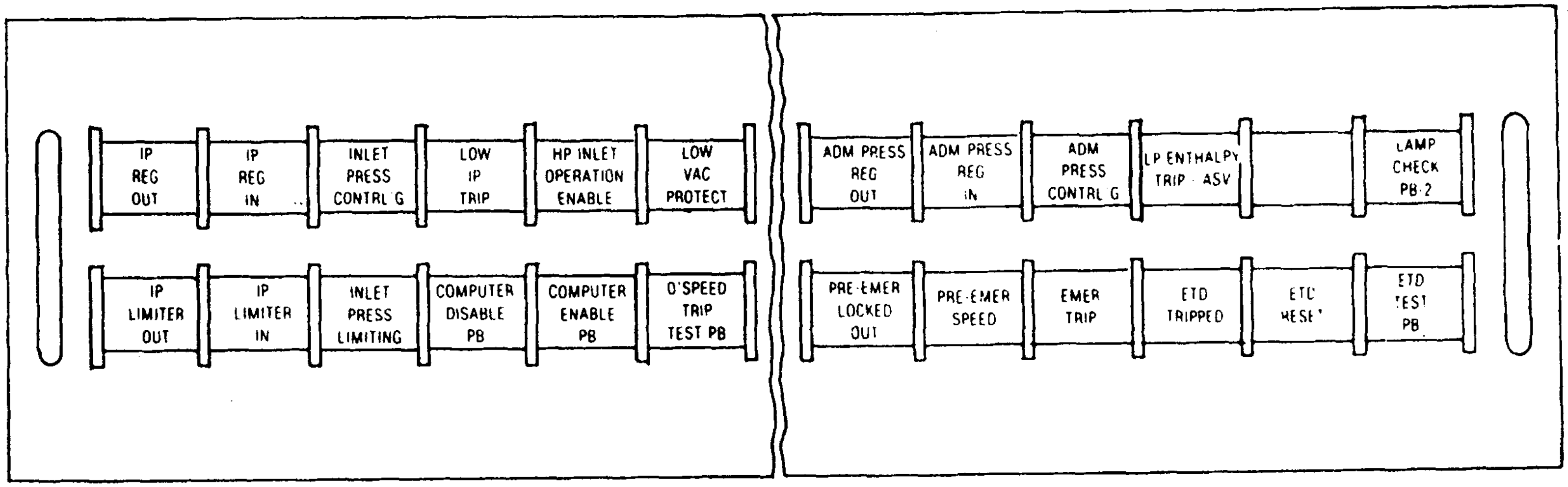
### 6.4.3 Panels 3 and 4

Panels 3 and 4 are shown in Figure 6-15. These panels contain various push buttons and status lights required during startup and normal turbine operation. Included on panel 3 is a special pushbutton (COMPUTER ENABLE PB) to allow the operator to connect the SDPC to the turbine panel for various startup/shutdown operations.

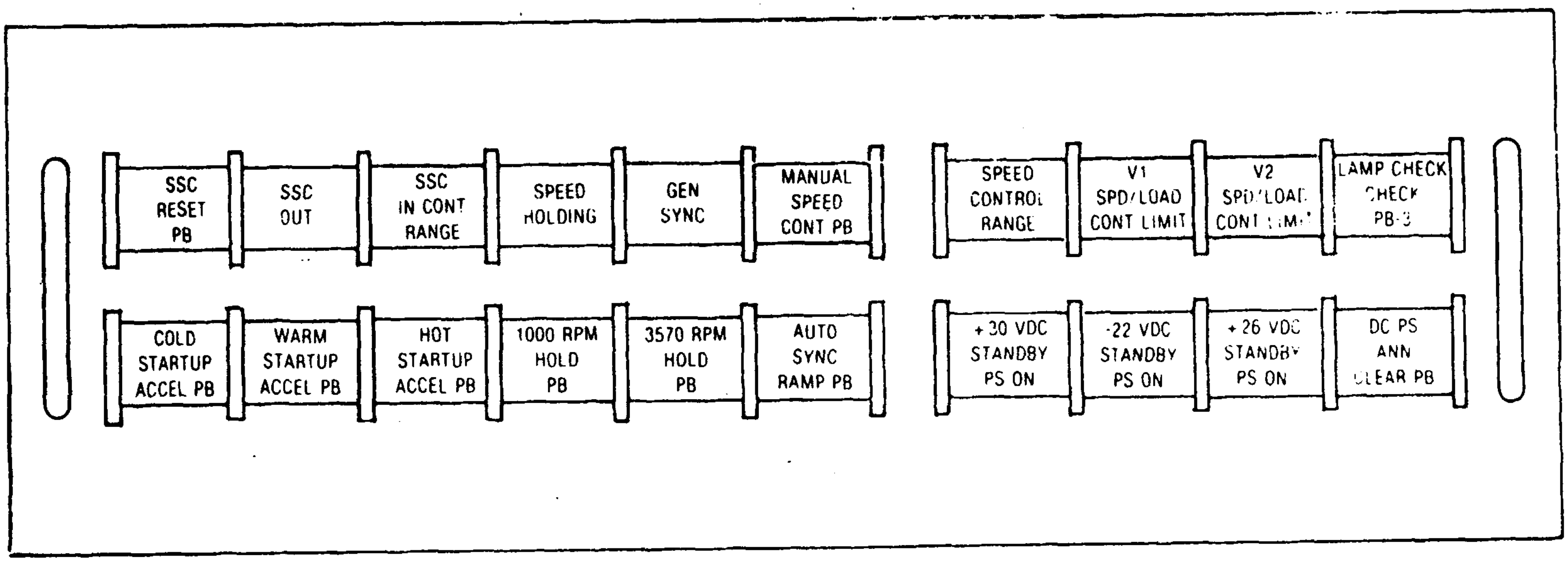
Panel 4 includes the controls and indicators required for the automatic startup and sync feature available with this turbine. This feature has the capability to roll the turbine automatically to 1000 RPM, hold until the operator releases, roll up to 3750 RPM, hold until the operator releases, and the synchronize the generator to the grid. The CO (or SDPC/OCS) would take over at this point to put the turbine in pressure control.

### 6.4.4 Generator Panel

The generator panel, shown in Figure 6-6, contains the sync scope as well as indicators showing the generator output voltage, current, power and volt amp reactance, field excitation voltage and current and the grid (running) line voltage. The operator must match up the appropriate voltages and set up the field excitation before putting the generator on-line. Various other electrical related indications (breaker closed, 33KV line voltage, etc) are also available on this panel.




Panel No. 3




Panel No. 4

Figure 6-15. Turbine Console — Panels 3 and 4

## Section 7

## CONTROL SYSTEM VERIFICATION AND TESTING

The plant control system verification and testing was accomplished as part of the overall operational test program for Solar One. This test program, which began in December of 1981, consisted of three series of tests which were designed to fully demonstrate the plant operating capabilities and to gather operating, maintenance, performance and related cost data applicable to future central receiver programs. The test series, which are documented in References 13, 14, 15, 16, 17 and 18 consisted of:

I. Startup (1000 Series Test)

II. Manual Control (1100 Series Tests)

III. Automatic Control (1200 Series Tests)

The scope of each test series and the specific plant control system tests conducted as a part of each series is discussed in the following paragraphs.

### 7.1 STARTUP (1000 SERIES) TESTS

The 1000 Series tests included the testing required to startup the receiver and thermal storage systems and bring them into a fully operational status. The specific goals were to:

(i) demonstrate the integrated operation of the solar portion of the plant (receiver and thermal storage) with other plant systems and

(ii) verify satisfactory control system operation under actual operating conditions.

The major elements of the 1000 Series Tests were

(i) 1010 - Receiver "Cold Flow" (Controls)
preoperational test

(ii) 1030A&B - Receiver Steam Generation (Controls Test

(iii) 1040A - Thermal Storage Activation

(iv) 1040B - Thermal Storage Charging and Extraction (Controls) Test

### 7.1.1 1010 - Receiver "Cold Flow" (Controls) Test

The 1010 Receiver "cold flow" controls tests were conducted only on those controller loops required for condensate flow to the flash tank with no power applied to the receiver. The principal flow paths for the 1010 test are shown in Figure 7-1. Tests were run at the lower operating pressure (≤ 485 psia) and flows (<40,000 LBH) for the receiver flash tank. Two types of controls tests were conducted; closed loop and open loop. The acceptance criteria for the closed loop tests were as follows; 1) closed loop response is stable and well behaved in the presence of setpoint changes and process disturbances, 2) mode switching transients do not degrade plant operation or cause conditions to exceed design requirements, 3) all alarms and limits are acceptable for safe, controlled operation, 4) control logic for initialization, mode transfers, and shutdown is satisfactory.

The objectives for the two types of 1010 controls tests and the control loops tested were as follows:

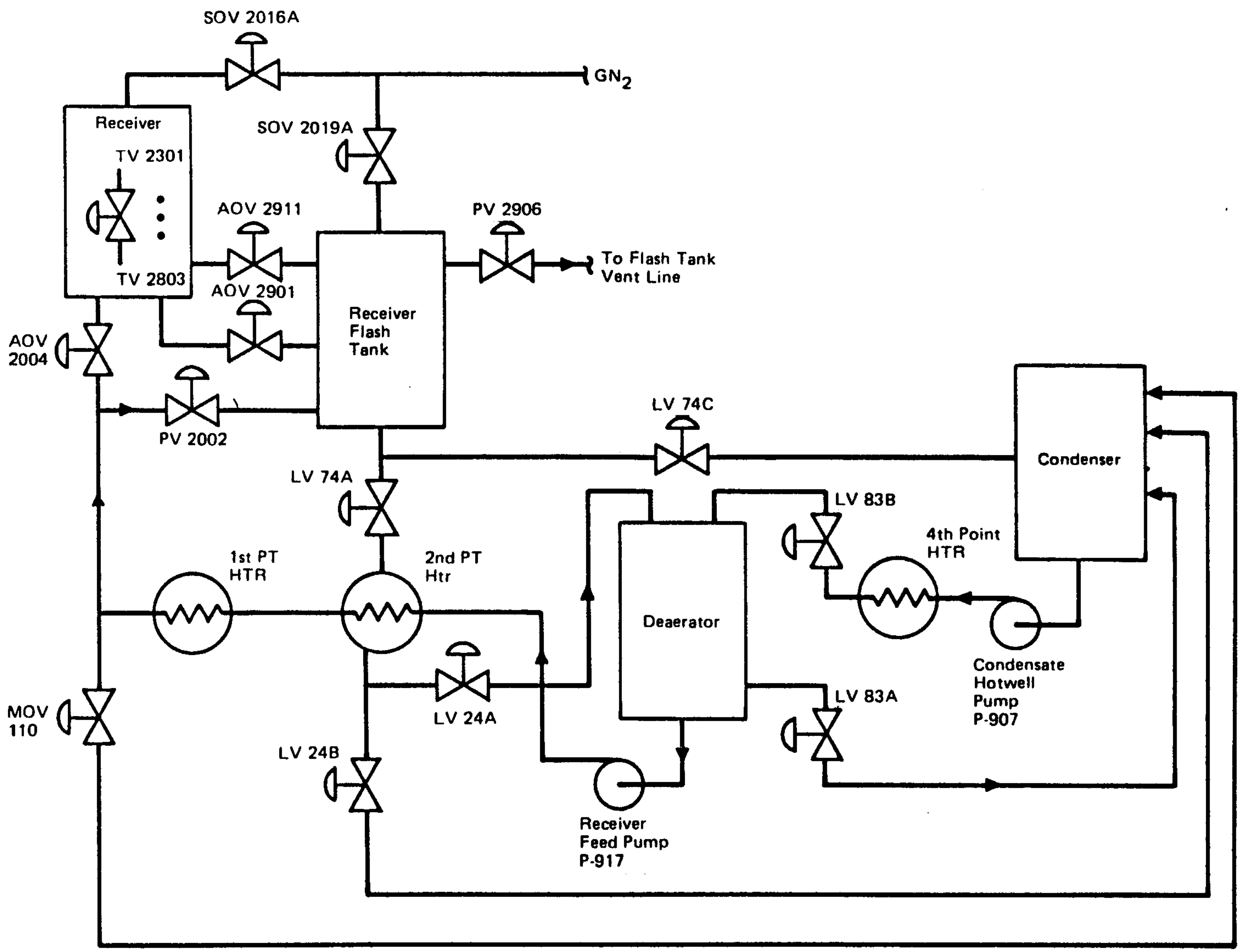



Figure 7-1. Test 1010 (Receiver Cold Flow) Principal Flow Paths

1. Obtain process control open loop data (frequency response and step input transient response data) required for model verification and field tuning for the following controllers:

   a. Receiver panel flow control loops - FCM 2301 through FCM 2803.

   b. Receiver feedpump controller - PC 1105.

2. Demonstrate satisfactory closed loop operation and field tune the following controllers:

   a. Flash tank level controllers - LC74A and LCM74C.

   b. Second point heater level controllers - LC24A and LCM24B.

   c. Deaerator level controllers LIC83A and LC83B.

   d. Receiver panel flow controllers - FCM 2301 through FCM 2803.

   e. Receiver feedpump controller for all modes - speed (SCM 1105), pressure (PC 1105), valve (UC 1105).

In addition to these tests, tests were also conducted to obtain valve flow coefficient ($C_V$) data on all 18 temperature control valves (TV2301 through TV2803) for comparison to manufacturer's data and for tuning of panel flow control loops.

### 7.1.2 1030 - Receiver Steam Generation (Controls) Test

The 1030 receiver steam generation (controls) test was the second of the two receiver controls development tests. These tests included application of power to the receiver to achieve the desired water/steam conditions while flowing 1) hot water to the receiver flash tank, 2) steam to the flash tank or 3) steam to the steam dump system (SDS), through the main steam downcomer.

The principal flow paths for the 1030 series tests are shown in Figure 7-2. The controls tests for 1030 were designed to obtain open loop test data required to tune controllers and to confirm control system operation, stability, and transient response at the maximum and minimum design conditions for temperature, pressure, flow, and disturbances.

The objectives for the 1030 controls tests and the controllers tested were as follows:

1. Demonstrate satisfactory closed loop operation of the following receiver flash tank steam venting controllers:

    a. Flash tank low pressure controller - PCM 2906.

    b. Flash tank high pressure controller - PC 1000.

    c. Deaerator pressure controller - PC 647B

2. Obtain process control open loop data, (step and frequency response data) for both valve and flux inputs at steam temperatures of 660$^{o}$F and 850$^{o}$F for panels 9, 10, 11 and 12.

3. Obtain closed loop response data on all panel temperature controllers (TC 2301 through TC 2803). Determine response to temperature setpoint and flux changes at steam temperatures of 660$^{o}$F and 850$^{o}$F in both the metal temperature and blended temperature control modes.

4. Demonstrate satisfactory closed loop operation of the steam dump system pressure controller PC 1001 and the desuperheater temperature controller TCM 1002 at flash tank pressure and rated pressure.

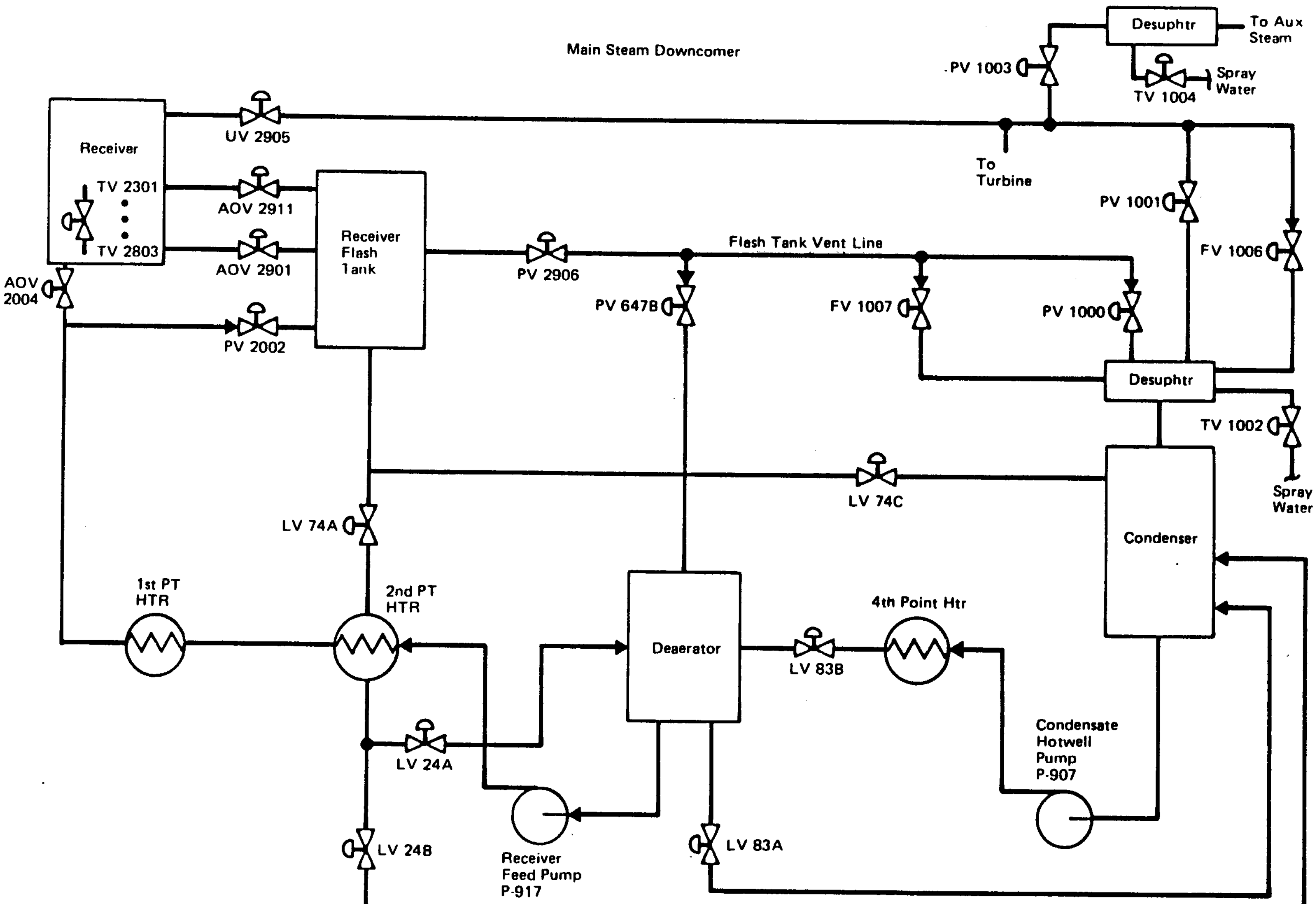



Figure 7-2. Test 1030 Principal Flow Paths

5. Demonstrate satisfactory <u>closed loop</u> operation of the receiver feedwater pump controller in the valve control mode during flux disturbances and in response to outlet pressure setpoint ramping.

6. Demonstrate satisfactory <u>closed loop</u> control of auxiliary steam pressure controller PC 1003 and desuperheater temperature controller TCM 1004.

### 7.1.3 <u>1040 - Thermal Storage Subsystem Tests</u>

The 1040 tests for the thermal storage subsystem included preoperational tests, initial test conditioning of the TSU tank, clean-up of the oil and steam sides of both charging and extraction trains and controls verificaton of all TSS control loops. The objectives of these tests were to:

a) Verify the process operation of the solar specific portions of the plant.

b) Develop the control functions and/or field tune the individual plant controllers.

c) Verify selected portions of the Plant Operating Procedures.

Test activities included verification of the following:

(i) Main steam inlet pressurization operation.

(ii) TSS flash tank operation including steam/condensate distribution system.

(iii) Charging condenser system operation including both steam and oil sides (Trains 1 and 2)

(iv) Extraction steam generator system including feedwater, steam, and oil side operation (Trains 1 and 2).

(v) Auxiliary steam equipment.

(vi) Turbine admission steam opertion.

(vii) TSU thermocline.

The principal flow paths included in the 1040 TSS testing are shown in Figure 7-3. The control test objectives for the 1040 TSS tests were as follows:

1.) Demonstrate satisfactory closed loop operation and field tune the controllers for the portions of the TSS system identified in (i) through (v) above.

2.) Obtain open loop frequency response data and step input transient response data for the charging oil temperature in response to valve disturbances for comparison to model data and for tuning of controllers TC3411 and TC3410.

3.) Demonstrate satisfactory control and operation of the integrated RS, TSS, and EPGS subsystems using main steam and admission steam in pressure and load control modes.

## 7.2 MANUAL CONTROL (1100 Series Tests)

The 1100 series tests were designed to demonstrate plant operation in several different modes under operator manual control through the SDPC of each of the plant subsystems (CS, RS, TSS, EPGS, BOP). The goals of the 1100 series tests were to gather test data in 3 areas of plant operation for subsequent analysis and comparison to design requirements. The 3 areas were:

1. Steady state operation within each operating mode.
2. Transitions between modes.
3. Trip responses.

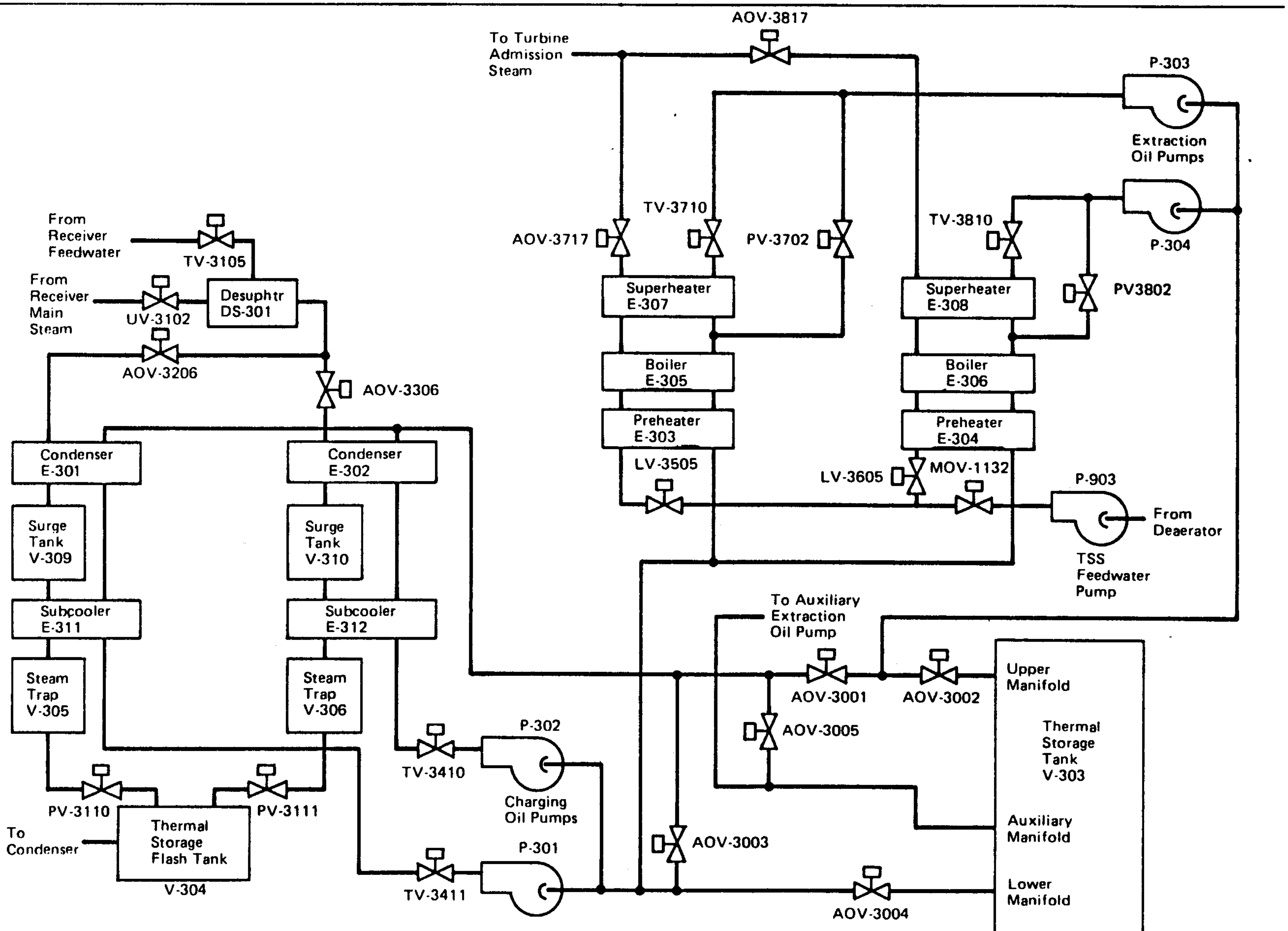



**Figure 7-3. Test 1040 Principal Flow Paths**

The goal of the steady state operational testing involved gathering sufficient data in order to make plant performance estimates for each operating mode. Attempts were made to gather performance related data over a wide range of plant operating conditions subject to the limitations of the collector field and receiver to gather and deliver available energy to the turbine and charging system. The benefit of these data was not only to estimate absolute plant performance for comparison to performance predictions but to make comparative evaluation between various operating modes to determine preferred plant operating strategies.

The transition testing involved transitions from startup to each mode and from each mode to shutdown. In addition transitions to and from modes were tested. The critical mode transition issues involved demonstrating the necessary manual operational sequences through the SDPC for each subsystem and developing timeline data which could be used in the evaluation of each mode and as an aid to develop automation transition sequences. Automatic transition sequences which are initiated and controlled by OCS were discussed in Section 5, Control System Automation.

Trip tests were of interest to verify that the plant would continue to operate appropriately in a lower level mode. The stated requirement regarding trips is that the plant be capable of transitioning to a safe condition (or shutting down if appropriate) if an anomalous (trip) condition exists. Types of trips include charging system (TSS) trip, turbine trip, or receiver trip.

From a actual test standpoint, no dedicated trip tests were conducted since sufficient data were gathered from naturally occurring trips during routine operations as a result of process upsets or instrumentation malfunctions.

The 1100 series tests for the 7 operating modes are summarized in Table 7-1. The mode transitions tested, the control strategies examined, and the trip conditions evaluated are shown. The detailed test results are discussed in the appropriate reference document given in the last column of Table 7-1.

### 7.3 AUTOMATIC CONTROL (1200 Series Tests)

The 1200 Series tests were intended to demonstrate both manual and automated plant operation under control of the OCS. The plant control system testing which satisfies the intent of the planned 1200 Series tests is documented in the Automation Test Report, Reference 18. The 1200 Series test objectives which are applicable for the "as built" automated plant are as follows:

1. Demonstrate that the plant operates in a stable and controlled fashion under OCS control, both manual and automatic, in modes 1, 5, and 2.

2. Demonstrate that the plant can be transitioned, both manually and automatically, between the folowing modes:

   a. Mode 9 to Mode 5

   b. Mode 1, 2, or 5 to Mode 9.

   c. Mode 9 to Mode 1

   d. Mode 1 to Mode 2

   e. Mode 2 to Mode 1

   f. Mode 2 to Mode 5

Table 7-1. Manual Control (Series 1100) Tests

| Test | Steady state mode | Mode transitions | Control strategy | Trip conditions | Test results (reference no.) |
|---|---|---|---|---|---|
| 1110 | 1 | Startup → 1<br>1 → Shutdown | SF | RS, T | 16 |
| 1120 | 2 | 1 → 2<br>2 → 1 | SF, LF | RS, TSS, T | 15 |
| 1130 | 3 | 1 → 3<br>3 → 1<br>3 → 6 | SF, LF | RS, TSS, T | 15 |
| 1140 | 4 | 5 → 4<br>6 → 4<br>4 → 5<br>4 → 6 | SF | RS, TSS, T | 15 |
| 1150 | 5 | Startup → 5<br>5 → Shutdown | SF | RS, TSS | 17 |
| 1160 | 6 | Startup → 6<br>6 → Shutdown | SF | TSS, T | 17 |
| 1170 | 7 | 2 → 7<br>3 → 7<br>4 → 7<br>7 → 2<br>7 → 3<br>7 → 4 | SF, LF, FF | RS, TSS, T | 15 |

SF = Sun Following
LF = Load Following
FF = Fixed Flow

RS = Receiver Subsystem
TSS = Thermal Storage Subsystem
T = Turbine

3. Demonstrate that the OCS can properly control the plant through a typical clear day scenario by performing the following automatic transitions:

   a. Startup to Mode 1

   b. Mode 1 to Mode 2

   c. Mode 2 to Mode 1

   d. Mode 1 to Shutdown

The automation testing which began in late 1983 and ended in July 1984 demonstrated that all of the above objectives were satisfactorily met. In addition, clear day scenarios for Mode 1 and for Mode 5 were designed, implemented, and tested to give added flexibility for clear day operations. The detailed test results are documented in Reference 18.

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