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10 MWe Solar Thermal Central Receiver Pilot Plant Control System Evaluation

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10 MWe SOLAR THERMAL CENTRAL RECEIVER PILOT PLANT CONTROL SYSTEM EVALUATION

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ABSTRACT

This report describes the results of the evaluation of the Master 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 a description of the plant and control systems and compares the original control system requirements with the actual operation. It provides a qualitative evaluation of various plant control systems and summarizes an independent evaluation of the plant displays provided by Honeywell on contract to the Electric Power Research Institute. Finally the report describes the desired features of a future control system. The control system with its automated features has substantually increased electrical output of the plant by extending the number of hours of operation and increasing reliabilty over that which could be obtained with a conventional control system.

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 and evaluates the master control system of 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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EXECUTIVE SUMMARY

The 10 MWe Solar Thermal Central Receiver Pilot Plant near Barstow, California, is an excellent demonstration of what can be achieved with modern digital control system technology. It is unique in the U. S. electric utility industry in that the plant is automatically controlled by a Master Control System consisting of an Operational Control System (OCS) computer which supervises two collector field computers, three distributed process controllers that control the plant's main process loops, and four programmable process controllers which provide the plant's safety and interlock logic. The master control system has five computers which supervise the operation of the 1940 microprocessors in the plant.

There are very few analog controls, dedicated switches, control knobs, and meters in the control room. Information on plant operation is provided to the operator on color-graphic video displays, and the operator interacts with the system through keyboards, light pens, function keys, and function switches.

The majority of the information displayed on the video screens is in the form of functional diagrams. Real time data are displayed near the graphics symbols which represent plant components such as pumps, valves, steam lines, etc. Plots of plant data can be displayed in real time and for the previous 24 hours. Process out-of-limit conditions are annunciated through the color-graphic displays rather than through dedicated annunciator panels that are common to conventional power plants.

The plant operates automatically under the supervision of the operator. In the morning the operator, through keyboard commands, positions the heliostats at standby operating points (four tracking points in space near the receiver), initiates water circulation in the receiver and then issues a command to the Operational Control System (OCS) computer to start-up the plant. The OCS computer takes over and automatically directs heliostats to track the receiver, controls receiver flow and puts the various receiver components into operation. When receiver steam conditions are correct, steam is routed to the turbine. The operator then synchronizes the turbine to the electric grid. The plant operates for the rest of the day under the supervisory control of the OCS computer. If conditions change, such as a cloud interrupting the sun's energy, the control system will automatically make adjustments and attempt to keep the plant in the best operating state. If some abnormal event occurs, the operator receives alarm messages which indicate what parameters are out of normal operating range. The operator can at any time make changes in any plant operating condition.

The plant can also operate with the receiver providing steam to the thermal storage system. The equivalent energy of four hours of turbine operation at 7 MWe can be stored for use later for electrical generation or auxiliary steam generation.

A primary goal of the automation was to reduce the number of required operator actions so that the operators could devote more time to monitoring and controlling the plant's performance. This can result in better plant efficiency. This single system contrasts with systems in conventional power plants which contain a multitude of dedicated switches, dials, meters and annunciators on panels which in some cases fill a large room. Even though detailed information on plant operation is available in a conventional system, it is difficult to obtain an overall picture of the plant status and efficiency. In such cases an operator has to look at several meters and chart recorders and then do some analysis. This can take time and result in less efficient operation because rapid adjustments cannot be made.

The number of operations personnel for the plant has been reduced as a result of the plant automation and the experience gained during the first three years of operation. In 1982 it took the equivalent of twenty people (shift supervisors, plant operators, assistant plant operators and plant equipment operators) to operate the plant. In 1986 the plant is operated with fifteen people. The reductions have been in one shift supervisor, three plant equipment operators and the equivalent of one operator in overtime.

The control system at the pilot plant has been reliable, as have the independent microprocessor-based logic systems which have provided protection for the plant's equipment and personnel. The experience at the pilot plant can be extended to other generating plants, especially nuclear plants. Issues of reliability and redundancy have inhibited the application of computer control systems in nuclear plants. Computer monitoring of power plants has been introduced into nuclear plants, but so far there is no actual system-wide application of computer control of nuclear plants.

The master control system requirements developed in 1977 were compared with those which were actually achieved, and the majority of the features were incorporated. In some instances development took a different path than was proposed, but the net result was the same.

The 1977 conceptual design has an extra computer, the Peripheral Control System (PCS), which was eliminated, and some of the functions were included in other plant systems. One function that was eliminated was a backup for the Operational Control System (OCS), but this loss has not caused operational problems because the plant can be operated with the subsystem controllers.

The Subsystem Distributed Process Controller (SDPC) which handles the receiver, thermal storage, electric power generating system (EPGS) and balance of plant control has much more capability than was expected in the 1977 design. As a result, much more of the plant automation functions were included in the SDPC. This allowed the OCS to handle the master control graphics which was in the PCS in the 1977 design.

Extensive simulation of the subsystems, especially the receiver, was recommended in 1977. While there was considerable simulation work done, much of it was eliminated as a cost savings; also detailed simulations required more detailed plant characteristics than were available during the period that simulations were being performed. Much of the control system optimization was done after the plant was in operation. The operating plant provided an excellent model for control loop testing.

The collector system reliability has been good although there have been considerable problems with the heliostat array controller (HAC) software. Problems still remain in the HAC, but they occur infrequently.

The Electric Power Research Institute (EPRI) sponsored a study of the Solar One color graphic displays (Reference 1). One major purpose was to evaluate the EPRI guidelines for the design of nuclear power plant color graphic displays. The guidelines provided information on the design of displays for plant monitoring only. Since the Solar One uses the color graphic displays for controlling as well as monitoring the plant, they obtained information for extending the guidelines to include control system design.

While the Solar One control system was designed for controlling a water-steam central receiver solar plant, the basic functions and operating philosophy are readily adaptable to other power plants. Solar One has demonstrated that modern computer control technology can be successfully utilized in the electric utility industry. The operations and maintenance personnel have come from within the utility without any special job descriptions. The control system, coupled with equipment design, has provided a plant power turndown ratio of twenty to one which is far superior to conventional controls. In addition, the plant has operated during severe cloud transients without evidence of process upsets. In a demonstration, the heliostat images were removed from the receiver for three minutes and then reset on to the receiver with a resultant steam outlet temperature excursion of only 15 degrees F.

The Solar One control system allows the operator to devote more of his time to plant operational reliability and efficiency; this increases energy output. Future central receiver plant control systems is expected to extend the design approach used at Solar One to provide further increases in operating efficiency and reductions in maintenance costs.

Some of the key features expected in the future include:

1. Distributed digital control system, integrated at the master control level.
2. Redundancy in critical areas.
3. Sensor and controller degradation and failure detection
4. Alarm analysis
5. Maintenance database integrated into master control
6. Expert systems aids.

INTRODUCTION

The 10 MWe Solar Thermal Central Receiver Pilot Plant, called Solar One, located near Barstow, California, is a joint venture between the U. S. Department of Energy (DOE) and the Associates: Southern California Edison, the Los Angeles Dept. of Water and Power and the California Energy Commission. The pilot plant delivers 10 MWe peak of electric power (net) to the Southern California Edison distribution grid.

This report describes the results of the evaluation of the Master Control System for the plant. It also describes the plant and control systems and compares the requirements of the original control system with those actually in operation. A qualitative evaluation of the various plant systems is provided as well as a summary of an independent evaluation of the plant displays done by Honeywell on contract to the Electric Power Research Institute (EPRI).

Finally the report describes areas for future work. Included are some lessons learned and a summary of the work done by Honeywell, on contract to Sandia, to look at the requirements of the next solar plant as derived from the experience at the Solar One.

PLANT SYSTEM DESCRIPTION

The pilot plant consists of master control, collector, receiver, thermal storage, turbine-generator, beam characterization, and plant support systems. The energy from the sun is directed by a field of tracking mirrors to a cylindrical receiver, or boiler, located on top of a 250-foot tower. Water is pumped up the tower and is heated to superheated steam in the receiver. The steam flows down the tower directly to the turbine or to thermal storage heat exchangers. Electricity generated by the generator is fed to the Southern California Edison grid. Thermal storage is provided by transferring the thermal energy to oil which is then pumped into a tank containing rock and sand. This energy is retrieved by pumping oil through the tank and then again through another heat exchanger to again produce steam which is fed to the turbine. A brief description of each system follows. Major systems are shown in Figure 1.

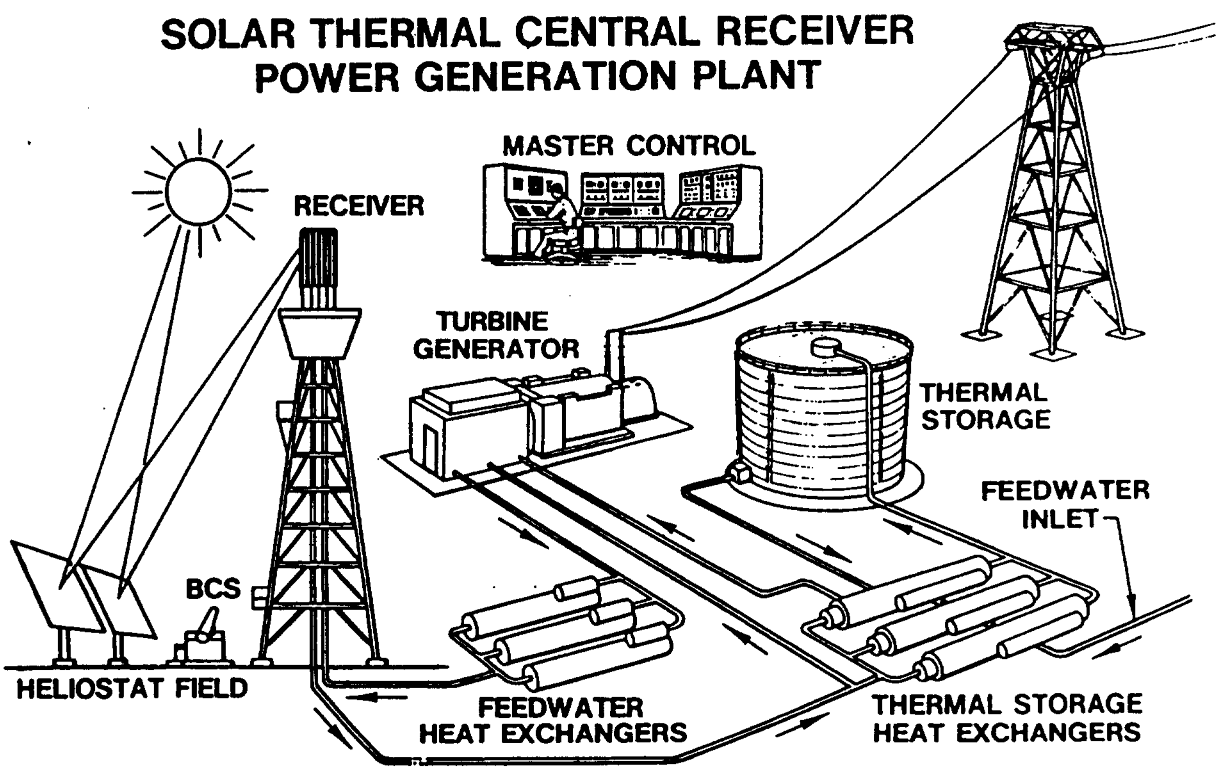

Figure 1 - Plant Systems

Master Control System

The master control system (MCS) is the overall command, control, and data acquisition system that integrates the controls of each of the other plant systems. The master control system provides a single console where the operator can control the major functional aspects of the plant and obtain top-level plant status in the form of plots, color graphic displays of piping and instrumentation diagrams with real time data. The MCS, Figure 2, consists of the plant operational control subsystem (OCS) and independent subsystem controllers. There is also a dedicated data acquisition system (DAS) which records engineering and scientific data for plant evaluation.

The plant can be operated in automatic mode, or manual mode using either the top level control (OCS) console or the individual system consoles. In the automatic mode the MCS controls the functions of plant start-up, operation, mode changes, and shut-down and contains capabilities for emergency actions on a plant basis.

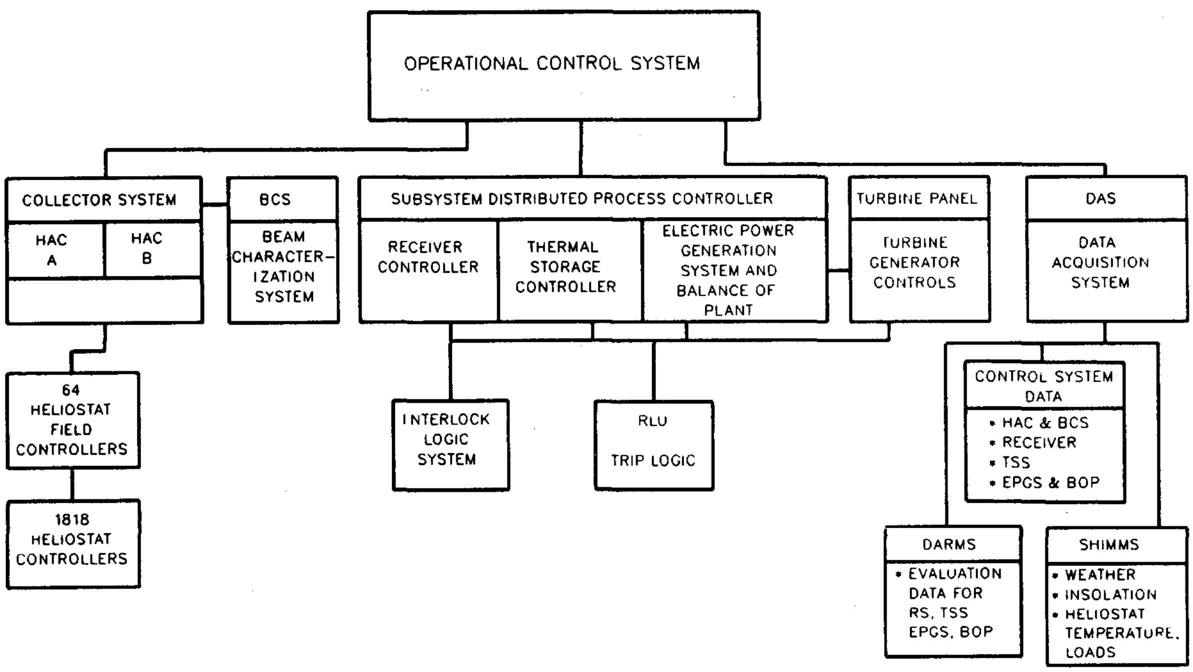

Figure 2 - Simplfied Control System Block Diagram

Collector System

The collector system consists of 1818 individually microprocessor-controlled reflectors (heliostats) that direct the available insolation onto the receiver. The heliostats are located in a circular field array that surrounds the receiver tower.

Receiver System

The receiver is a cylindrical steam boiler consisting of 6 preheater and 18 once-through boiler panels. Also included is equipment to pump water to the top of the tower and to control the flow to the panels. Redirected solar energy is focused by the heliostats onto the external surface of the boiler. The dry, superheated steam from the boiler flows down to the ground level and can be directed to the turbine and/or thermal storage.

Thermal Storage System

The thermal storage system transfers energy from steam to oil for sensible heat storage in an oil-rock media contained within a cylindrical tank. Thermal energy transfer from the rock back to steam is accomplished again using the oil as the transfer media. The system is capable of performing both transfer operations simultaneously. The thermal storage system is used to provide auxiliary thermal energy needed by other systems as well as the generation of electric power.

Electric Power Generation System

The electric power generation system (EPGS) consists of a number of components necessary to convert thermal energy in the form of superheated steam to electricity. These include a turbine, generator, feedwater heaters, pumps and supporting water and cooling systems.

The turbine is an automatic admission, condensing unit. The high-pressure steam, available from the receiver system (950 degree F, 1465 psia nominal) for 10 MWe net, is supplied to the high-pressure inlet valves, and the low-pressure steam, available from the thermal storage system (529 degree F, 385 psia nominal) for 7 MWe net, is supplied to the low-pressure automatic admission port.

The generator is rated at 12.8 MWe gross electrical output at 13.8 kilovolts. The generator output is stepped up to 33 kilovolts for connection to the Southern California Edison grid.

Beam Characterization System

The beam characterization system permits rapid and automatic measurement and characterization of flux delivered by any single heliostat. This system is used to correct the pointing accuracy of the heliostat and to evaluate heliostat optical performance. Although this system is considered a separate system at Solar One, it would normally be included as part of the collector system.

Plant Support System

The plant support system (PSS) provides for interconnection of the major systems, utility distribution throughout the plant, and the necessary facilities such as roads, lighting, buildings, security, fire protection and communications.

PLANT CONTROL SYSTEM DESCRIPTION

The control system includes the operational control system (OCS) and system controllers for the collector, receiver, thermal storage, electric power generation and the plant support systems. The turbine generator has a control panel which can be partially controlled by the master control system and the rest is controlled by the operator. In addition, there is a data acquisition system (DAS) which collects data for plant evaluation. The DAS is separate from the functional part of the plant and will be discussed later. A list of plant control system related documents is included in the bibliography section.

Figure 3 shows a block diagram of the plant control system. The subsystems will be described first.

Collector System

The collector control system provides individual and group control of the 1818 heliostats in the field. The top level of control is through the heliostat array controller (HAC). There are two HAC computers, one operating and one on standby. The standby HAC can take over with minimal disturbance in the event the prime HAC fails.

The HAC is a Modcomp Classic minicomputer with an operator's console which is used to control the collector system functions and a color graphics display console which provides a graphic display of the heliostat field status. There is a printer for logging all commands and alarms. These components are located in the plant control room for easy access by the operator. Although there is only one set of these components, they are automatically switched to the other HAC if prime HAC fails. The color-graphics display is also a backup control console which can be used in the event that the operator's console fails.

The HAC communicates with the collector field through eight sets of redundant serial data lines to the heliostat field controllers (HFC). There are eight HFC's on a data line giving a total of 64 HFC's. The HFC's are responsible for message traffic between the HAC and the individual heliostat controllers and for controlling the movement of heliostats from the stow position to the standby position. Each HFC is responsible for up to 32 heliostats and communicates with them on a serial data line similar to the HAC-HFC line, except that they are not redundant.

The heliostat controller (HC) is responsible for controlling a single heliostat in all the various modes. Every second the HC receives a sun position vector from the HAC by way of the HFC, and this vector is used to calculate a new heliostat position. If the heliostat is currently in a tracking mode, the new position is compared with the actual position determined from encoders in the heliostat. If the position is incorrect, the heliostat motors are energized to bring the heliostat to the correct position.

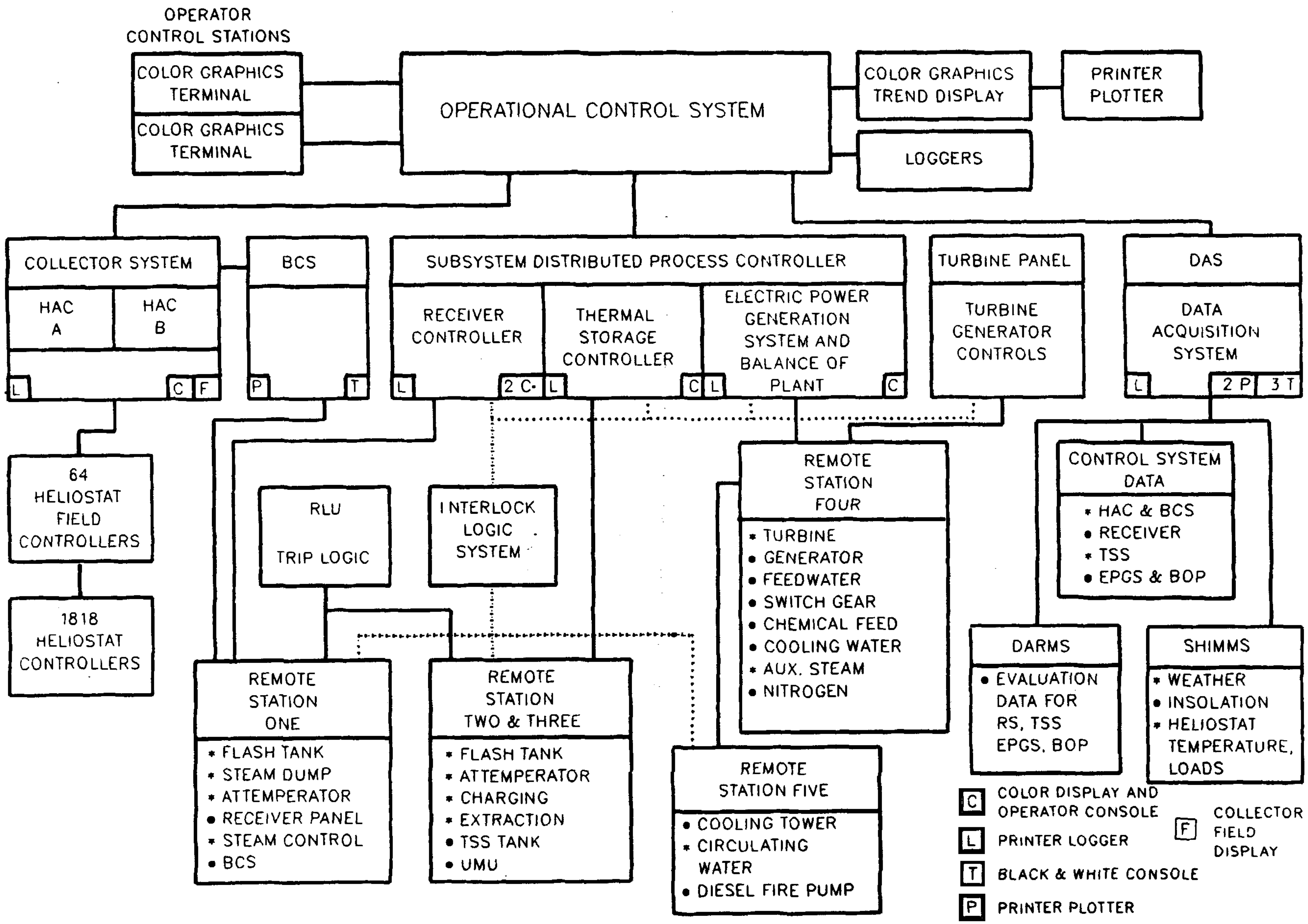

Figure 3 - Control System Block Diagram

Beam Characterization System

The Beam Characterization System (BCS) provides characterization of the reflected beams from a single heliostat and measurement of sun shape. Data available from the BCS include beam size, shape and centroid, flux distribution, total beam power and the radial radiance distribution of the sun. The BCS provides two functions: 1) heliostat pointing measurement and correction; and 2) heliostat beam performance evaluation.

The heliostat directs its beam to one of four targets located on the tower below the receiver. One of four video cameras located about 850 feet away in the collector field captures the beam image. This image is sent into the control building where it is converted to an array of digital data. Radiometers located on the target measure incident irradiance from the heliostat. A separate sun tracking video camera obtains sun shape data. The digitized video data are calibrated, and processed to characterize the image, and stored.

The BCS measurement has been automated so that operator involvement is minimized during the day time. Extensive communications occur between the BCS and the collector system Heliostat Array Controller computer to perform heliostat movement and measurements. Three measurements are performed on up to 60 heliostats on any given day. The three measurements are spaced to get a morning, noon and afternoon sample. The beam centroid information is converted to a beam centroid error in the BCS, and the HAC converts it into a heliostat pointing adjustment. This adjustment is then permanently installed in the collector system to correct any tracking error.

Receiver Control System

The receiver control system controls the inlet water and outlet steam conditions and various internal processes. Receiver inlet flow is regulated by 18 boiler panel control valves and the feedwater pump. Receiver outlet pressure is controlled by one of four controllers: the receiver flash tank pressure, TSS main inlet pressure, turbine throttle pressure and steam dump pressure controllers. Steam temperature at the turbine throttle valve and at the Thermal Storage System (TSS) main inlet is indirectly regulated by controlling the steam temperature at the outlet of each boiler panel.

The receiver controllers are described in the Solar One Plant Control System Design Requirements, drawing 1D44755 (Reference 2). The receiver controllers include:

1. Receiver steam outlet temperature controllers

   Controls the steam outlet temperature at each receiver panel.

2. Receiver feedwater pump

   Controls the receiver feed water pump in the scoop tube, speed, pressure and valve control modes.

3. Receiver feedwater bypass valve

   Controls the bypass valve at the receiver during condensate cleanup operations, initial startup and final shutdown.

4. Flash tank steam discharge

   Controls receiver outlet pressure during startup and shutdown or any time dry steam is not produced by the receiver.

5. Flash tank level

   Controls the receiver flash tank level during flash tank operation by diverting excess condensate to the second point heater or, on high level or second point heater overpressure, to the condenser.

6. Downcomer steam inlet controller

   Controls steam flow from the receiver to the downcomer.

7. Steam dump system

   Bypasses flow around the turbine to the condenser during startup and shutdown.

As an example of the function of one of the controllers the receiver steam outlet temperature controller will be briefly described. The steam outlet temperature is controlled by regulating the panel inlet water flowrate by modulating a control valve. The controller uses sensors of incident flux, panel metal temperature, outlet steam temperature and panel flow rate. The controller can operate in four modes: valve control, flow control, panel metal temperature control, and blended steam/metal temperature control. The mode and setpoints can be controlled manually by the operator or automatically by internal logic.

Valve control mode is used during receiver startup to provide a fixed valve opening for each panel. Once the panel reaches 400 degrees F, the mode is manually or automatically changed to flow control.

The flow control mode is used to provide a fixed flow rate as the receiver panel warms up to 600 degrees F. The loop consists of a flow sensor, the flow set point and the control valve. When the panel reaches 600 degrees F, the mode is manually or automatically changed to metal temperature control.

In the metal temperature control mode, the active control loops include the flow control, flux and metal temperature controls. Panel tube temperature is compared with the temperature set point and a difference signal is summed with the panel flux level feedforward signal to generate a new flow set point. The new flow set point is compared with the panel flow and a control valve change is generated. Variable gains are employed to compensate for variations in characteristics as a function of flowrate and the desired enthalpy increase through the panel. Metal temperature control mode is the primary mode of operation. It is used to provide steam to the turbine and to thermal storage.

The blended temperature mode is used only if the operator manually selects it. It was determined during the test phase of plant operation that this mode provided little improvement over metal temperature control. This mode operates like the metal temperature mode except that steam temperature is combined with metal temperature. Metal temperature during transients and steam temperature during steady-state operation are weighted to provide effective control.

Receiver Automation

Many of the receiver startup, shutdown and steady state operating functions have been automated. The automated functions are available to the operator and to the Operational Control System. The automatic sequences for the receiver are:

1. Receiver initialization

   Initialized receiver control loops. These are used prior to startup.

2. Automatic control mode transitioning of the boiler panels

   This is an autonomous function, that is, it operates independently of the operator. This function transitions the receiver panels thru the various modes.

3. Control mode detection of all boiler panels

   This is an autonomous function. The function determines if a pair of panels are in flow or temperature control.

4. Automatic temperature setpoint ramp

   Once all the panels are in temperature control, this function causes the receiver master temperature set point to be set to 775 degrees F. This causes the set point for each panel to be ramped up from 605 degrees F to 775 degrees F at rate of 30 degree F per minute.

5. Automatic receiver feedwater pump control mode transitioning

   This sequence implements automatic startup and shutdown of the receiver feedwater pump.

6. Automatic downcomer pressurization sequence

   This sequence pressurizes the downcomer for startup and opens and closes bootleg drains to drain the condensate. It also ensures that the downcomer steam temperature is above the saturation temperature so that no condensation of superheated steam takes place.

7. Automatic transition from receiver flash tank to steam dump system sequence.

   This sequence removes the receiver flash tank from service and places the steam dump into service for startup. The system pressure is ramped to 850 psig once the steam dump is in service.

8. Automatic hot standby sequence

   This sequence removes the downcomer and steam dump from service and places the receiver flash tank into service. This sequence is used for shutdown and for long duration clouds.

9. Automatic auxiliary steam from main steam on/off

   This autonomous function turns on the auxiliary steam from the main steam when the downcomer pressure is greater than 250 psig and turns it off when the pressure drops below 100 psig.

Thermal Storage Control System

The thermal storage controller is part of the SDPC. It provides control for both charging and extraction of energy from the thermal storage unit. In the charging mode, steam from the receiver is desuperheated and is routed through a heat exchanger to heat oil which is circulated into the thermal storage unit to heat the rock and sand in the tank. In the extraction mode, oil is circulated through the tank, which gains energy from the rock and sand, and then through another heat exchanger to heat water to produce superheated steam.

Thermal Storage Charging Mode

The thermal storage charging mode uses the following control loops:

1. TSS main inlet

   Controls the receiver outlet pressure, the TSS charging steam flow rate or turbine load by controlling TSS charging main inlet flow valve.

2. Desuperheater outlet

   Reduces steam temperature to the TSS by regulating inlet spray water.

3. Charging steam

   Controls the charging steam condenser pressure by controlling condensate flow to the TSS flash tank.

4. Charging oil pump

   Controls the charging oil pump speed to maintain a differential pressure across the charging oil temperature control valve such that the maximum commanded valve position is 70 percent open.

5. Charging oil

   Controls charging oil outlet temperature by controlling the oil flow rate.

6. 2nd point heater

   Controls the 2nd point heater pressure by diverting the condensate flow from the TSS flash tank to the condenser using a floating pressure set point based on flash tank level.

7. TSS flash tank high level

   Controls the high level in the flash tank by diverting excess condensate to the condenser.

8. TSS flash tank low pressure

   Controls TSS flash tank low pressure by venting flash tank steam to the deaerator.

9. TSS flash tank high pressure

   Controls TSS flash tank high pressure by venting flash tank steam to the condenser.

An example of the TSS charging control loop is the main steam inlet controller. There are four modes of operation: flow control, receiver pressure control, turbine electrical load control and TSS charging system inlet pressure control (used only for startup pressurization).

The flow control mode is used during TSS startup and during plant mode transitions (Mode 1 to Mode 2, Mode 5 to Mode 2). The main inlet valve is used to control the desired flow rate into the charging system. The flow sensor can be one of three sources: main steam inlet flow, main steam plus desuperheater spray water flow or charging train steam flow.

The pressure control mode is used when the steam dump system is out of service for control in Mode 5. The receiver outlet pressure is controlled by sensing the pressure at the bottom of the downcomer.

The load control mode can be used when the plant is operating in Mode 2. The TSS main inlet valve is used to vary the steam flow so that the turbine electrical load follows the load setpoint.

Thermal Storage Extraction Mode

The following control loops are used for the thermal storage extraction mode.

1. Extraction main oil valve

   Controls extraction steam flow or pressure, or turbine load, by controlling the corresponding extraction oil circulation.

2. Extraction steam temperature

   Controls the steam temperature at the thermal storage outlet by controlling the superheater bypass oil flow.

3. Boiler water level

   Maintains boiler water level by modulating the feedwater control valve.

4. Extraction oil pumps

   Controls the extraction oil pump speed to regulate the differential pressure across the extraction oil flow valve so that the valve is maintained at a 80 percent open position.

5. Auxiliary extraction oil flow-steam pressure

   Controls the auxiliary extraction oil flow through boilers to control the steam header pressure thereby providing auxiliary blanket steam and provides warm-up of the extraction trains.

Thermal Storage Automation

Thermal storage charging and extraction automation sequences can be initiated by the operator or from the Operational Control System. The sequences are:

1. Charging train pressurization
2. Charging train start and stop sequences
3. Extraction train auxiliary steam start and stop sequences
4. Extraction train warm and run sequences.

Electric Power Generation System and Balance of Plant

Controllers included in the third part of the Subsystem Distributed Process Controller include the turbine, generator, condenser, condensate system, associated pumps, deaerator, heaters, circulating water system, waste systems and the auxiliary steam system.

Turbine System

Many of the turbine controllers in the SDPC can command motor driven potentiometers in the General Electric Turbine panel. The turbine controllers are:

1. Speed/load potentiometer controller

   This controller rolls, and initially loads the turbine after synchronizing to the grid. It is used for startup from main receiver or thermal storage admission steam.

2. Turbine main steam pressure control

   This controller uses the General Electric panel to control the turbine main inlet control valve pressure set point.

3. Turbine admission steam pressure control

   This controller uses the General Electric panel to control the turbine admission inlet control valve pressure set point.

Auxiliary Equipment Controllers

There are a number of control loops which provide a number of auxiliary functions.

1. Hotwell low- and high-level controllers
2. 1st point heater level controller
3. 2nd point heater level controller
4. Deaerator low- and high-level controllers
5. 4th point heater level controller
6. Hydrazine and ammonia pumps
7. Cooling tower basin level controller
8. Circulating water PH controller
9. Deaerator vent valve
10. Non-return valve (2nd and 3rd point) control
11. Turbine lube oil cooling
12. GE computer enable switch

Auxiliary Steam System

The auxiliary steam system provides blanket steam for the plant, seal steam for the turbine and steam for the deaerator. Auxiliary steam can come from three sources, the receiver, thermal storage or an electric boiler. The auxiliary steam controllers are:

1. Main steam pressure controller
2. Admission steam pressure controller
3. Auxiliary desuperheater temperature controller
4. Auxiliary electric boiler
5. Thermal storage auxiliary feedwater pump
6. Deaerator pressure/Net Positive Suction Head control

EPGS and Plant Support System Automation

A number of automatic sequences are included in the SDPC for the EPGS and plant support system functions.

1. Turbine Operation

   The turbine automated sequences are: main steam startup, main steam shutdown, admission steam startup and shut down and turbine-generator low load shutdown.

2. Deaerator Vent Valve

3. Deaerator pressure/net positive suction head control - auxiliary steam

4. Cooling tower fans

5. Turbine drains and extraction ports

Plant Operational Displays

The Plant Operational Display System (PODS) of the operational Control System (OCS) is designed to obtain and display the overall plant operating data and status and to provide the man-machine interface for top level control of the plant operation. The PODS is a software component of the OCS computer and was developed by McDonnell Douglas and SGM Inc. The SGM program RCS-7 was modified by McDonnell Douglas to match the requirements of the plant.

This system communicates with and acquires data from the System Distributed Process Control (SDPC), the Heliostat Array Controller (HAC), and the Data Acquisition System (DAS).

The display's software has several functional features which can be divided into maintenance, control and display groups. The maintenance group provides a means for initializing the OCS system, creating and modifying graphic displays and data base maintenance. The control group provides a means for the operator to issue commands to the OCS automation software, and to the receiver, thermal storage, and EPGS, through the SDPC and to the collector system. The displays group provides color-graphic displays of the plant and subsystem status, alarms and OCS internal status. Figure 4 shows the plant control room. Figure 5 shows an example of a plant overview P & I D from OCS. Figure 6 shows the OCS receiver startup status display. Figure 7 shows the OCS clear day mode 1 status display.

Data Acquisition System

The plant has two forms of data acquisition. Information required to operate the plant is acquired by the control system which uses the information. Engineering information for plant evaluation is collected by the Data Acquisition System (DAS).

The DAS is completely separated from the operating control system of the plant. The connections to the operating control system are for data monitoring only. There is no control capability in DAS. The DAS collects, stores and displays plant information in real time. Information is collected from the plant controllers and from separate data acquisition systems connected only to the DAS. Figure 8 shows a block diagram of the control system with the relationship DAS has to the rest of the control system.

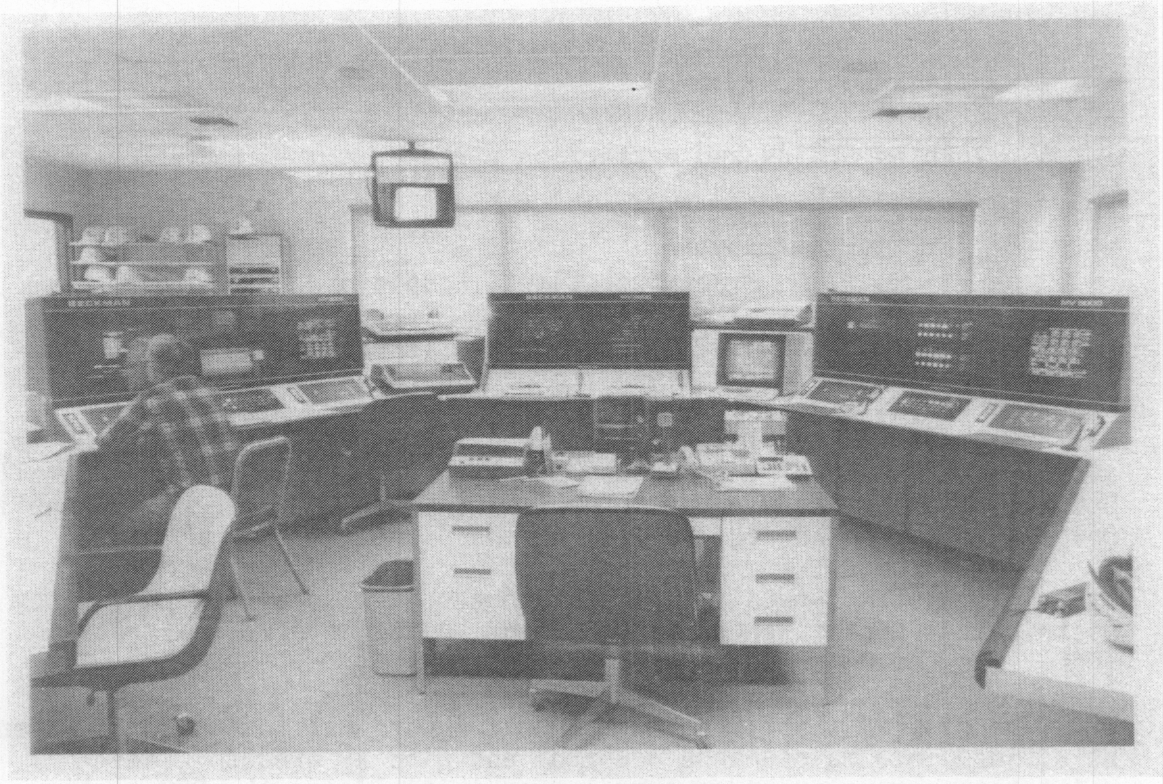

Figure 4 - Plant Control Room

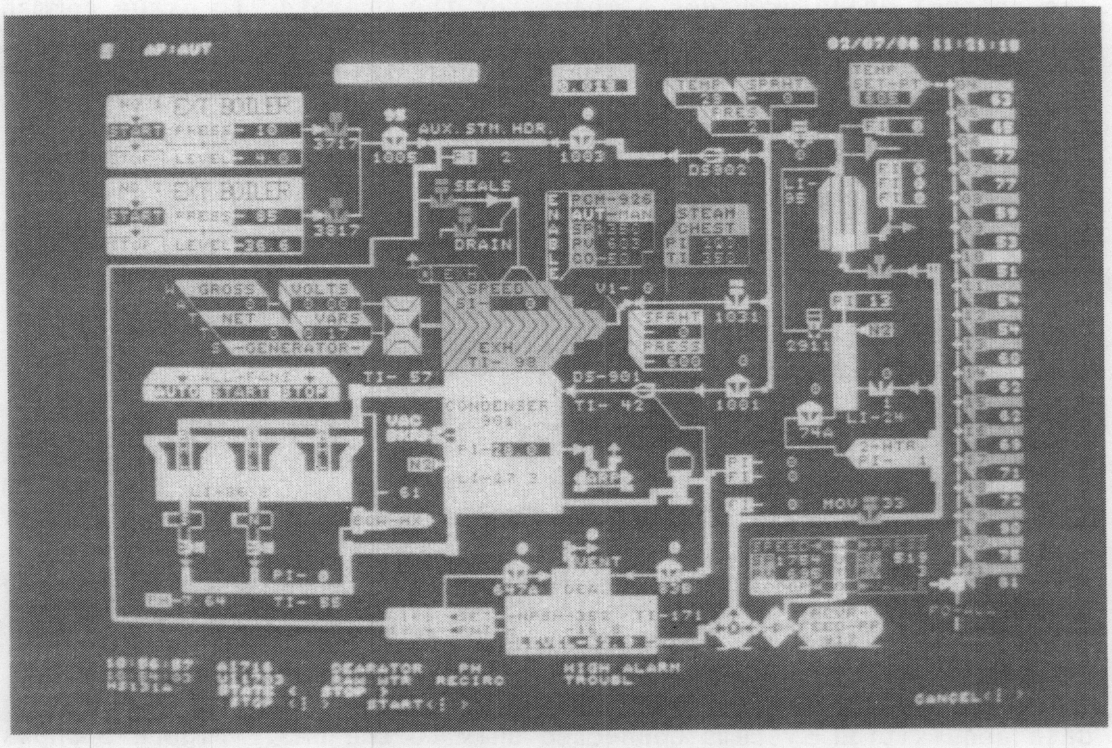

Figure 5 - OCS Display, Plant Overview, Mode 1

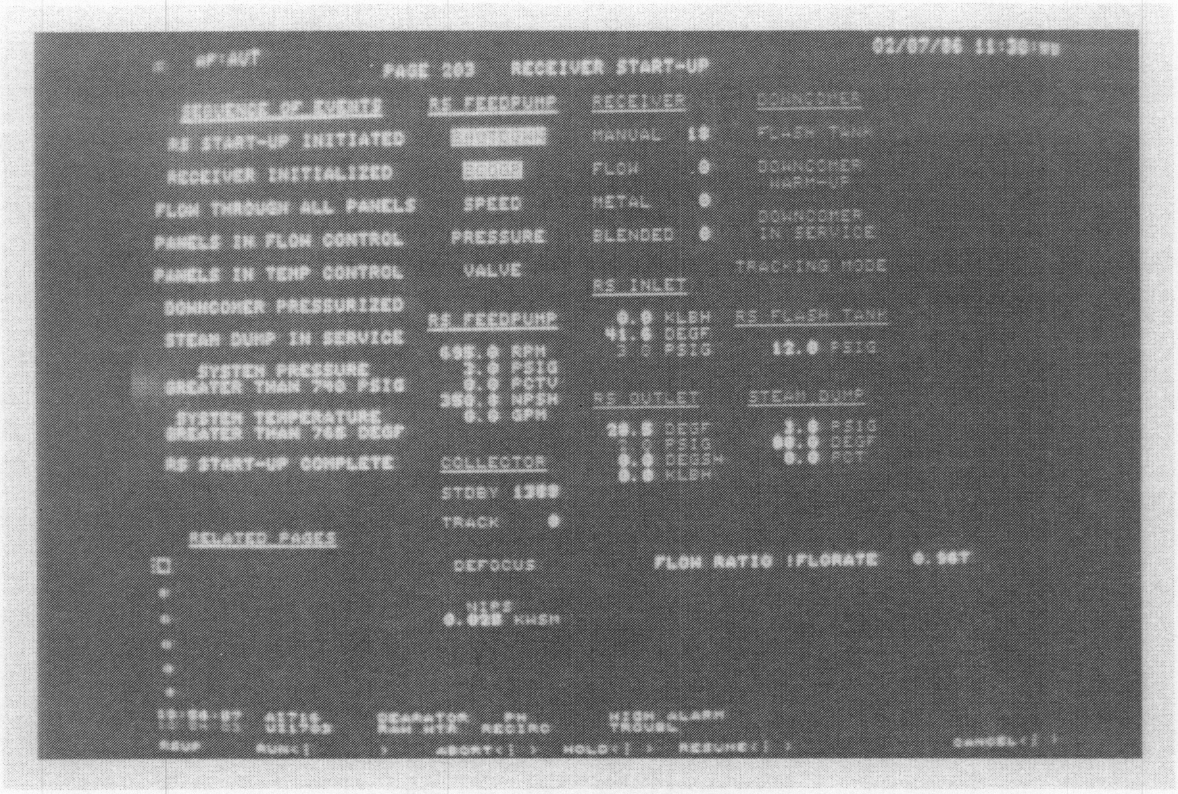

Figure 6 - OCS Display, Receiver Start-up

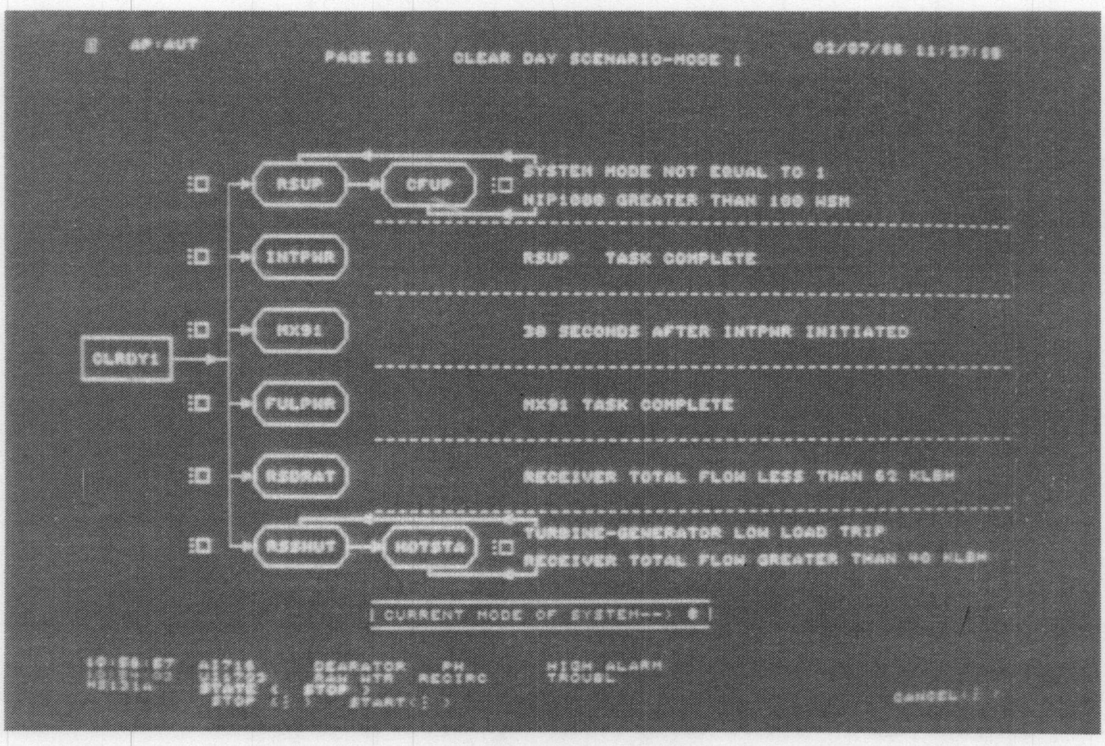

Figure 7 - OCS Display, Clear Day Mode 1

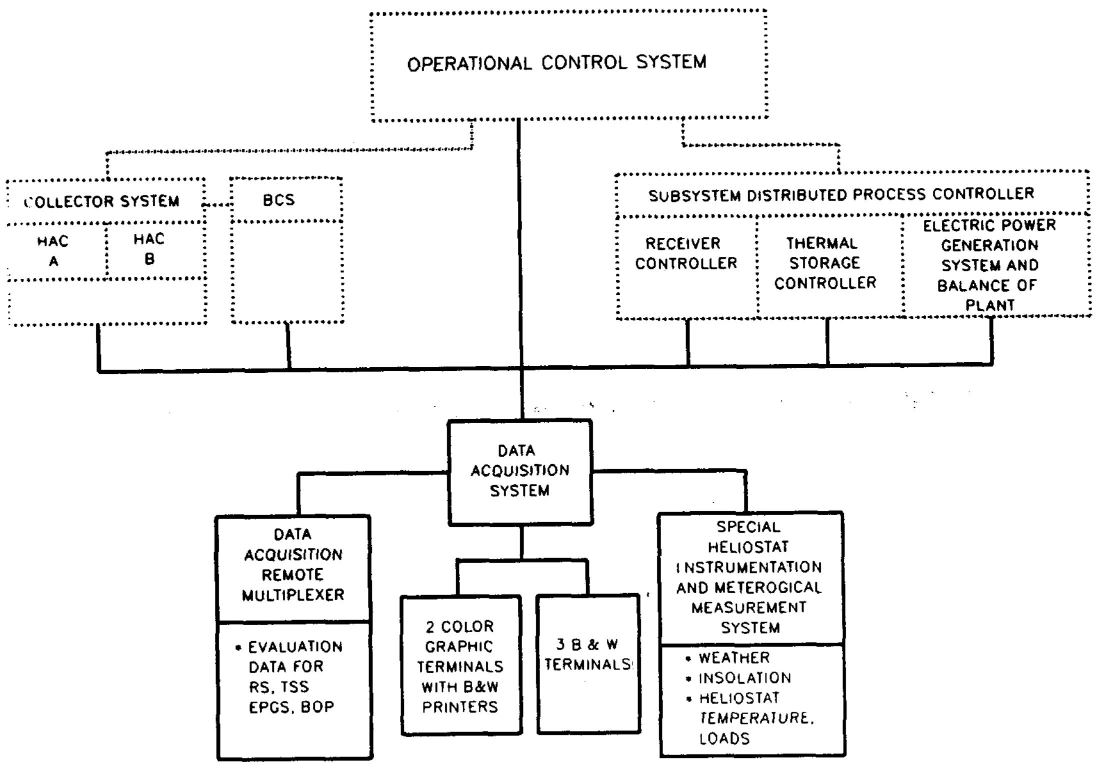

Figure 8 - Data Acquisition System Block Diagram

The DAS collects information from three major sources:

1. Plant control system data.

   This information comes to the DAS over interface connections from the collector system controller in the HAC, and receiver, thermal storage and EPGS/balance of plant controllers in the SDPC. There is no OCS data collected by the DAS. There is an OCS interface and OCS does acquire some information from the DAS.

2. Data Acquisition and Remote Monitoring System (DARMS)

   This is a separate data acquisition system which monitors separate sensors for the receiver, thermal storage and EPGS/Balance of plant. The information collected is for plant evaluation only and is not required for operation.

3. Special Heliostat Instrumentation and Meterological Monitoring System. (SHIMMS)

This is a data acquisition system which monitors all of the plant weather instrumentation and special heliostat instrumentation for evaluation. The hardware is similar to that used in the DARMS.

The DAS collects information and stores it onto disk files. The information is also available for display in the Engineering Evaluation room next to the control room at the plant. Engineering data can be displayed in three forms:

1. Scroll Tabular form.

   In this form a line of up to 8 channels can be displayed at user specified intervals. Each succeeding line is displayed at the top and the previous lines are scrolled down. A time history of the channels is displayed in this manner. Up to 20 time points can be displayed on the screen. A hardcopy of the screen can be made at any time by the user.

2. Fixed Tabular form

   In this form a screen full of data points is displayed for a single time. A total of 48 channels can be displayed on the screen. At the next time sample, the entire screen is refreshed with new values. In this form more data channels can be sampled, but no time history is displayed. The user can get a hardcopy on a screen at any time and make a time history that way.

3. Time history plots.

   A time history plot of up to four channels can be displayed on a color-graphics video screen, and a black and white hardcopy can be made. The user has the option of selecting any four channels and selecting the minimum and maximum range of the plot. The time range of the plot can be 100 seconds, 10 minutes, 60 minutes or 5 hours.

   There are two color-graphics plotters and printers in the engineering evaluation room so a total of eight channels can be plotted at one time. The hardcopy of the plots can be made automatically as a plot is finished (data gets to the limit of the plot time axis) or by the user by entering a command.

The information the DAS collects is defined in a measurement information file and scan lists. The data acquisition and control system monitor and control functions are assigned identifying names called Tag ID's. The measurement information file (MIF) (Reference 3) defines the channel by Tag ID, type, descriptor, range and location. It also defines channels which are logical (on/off), The MIF contains 3700 Tag ID's, but only about 2000 can be scanned at one time.

PLANT OPERATION

The plant is automatically controlled by a Master Control System consisting of an Operational Control System (OCS) computer which supervises two collector field computers, three distributed process controllers, which control the plant's main process loops, and the four programmable process controllers which provide the plant's safety and interlock logic. The master control system has five computers which supervise the operation of the plant's 1940 microprocessors.

Information on plant operation is provided to the operator on color-graphic video displays, and operator interaction with the system is through keyboards, light pens, function keys and function switches. The majority of the information displayed on the video screens is in the form of functional diagrams. Real time data are displayed near the graphics symbols which represent plant components such as pumps, valves, steam lines, etc. Plots of plant data can be displayed in real time and for the previous 24 hours. Process out-of-limit conditions are annunciated through the color-graphic displays.

The plant operates automatically under the supervision of the operator. In the morning the operator, through keyboard commands, positions the heliostats at standby operating points (four tracking points in space near the receiver), initiates water circulation in the receiver and then issues a command to the Operational Control System (OCS) computer to start-up the plant. The OCS computer takes over and automatically directs heliostats to track the receiver, controls receiver flow, and puts the various receiver components into operation. When receiver steam conditions are correct, steam is routed to the turbine. The operator then synchronizes the turbine to the electric grid. The plant operates for the rest of the day under the supervisory control of the OCS computer. If conditions change, such as a cloud interrupting the sun's energy, the control system will automatically make adjustments and attempt to keep the plant in the best operating state. If some abnormal event occurs the operator is provided alarm messages which indicate what parameters are out of normal operating range. The operator can at any time make changes in any plant operating condition.

The plant can also operate with the receiver providing steam to the thermal storage system. The equivalent energy of four hours of turbine operation at 7 MWe can be stored for use later for electrical generation or auxiliary steam generation.

The eight steady state operating modes were selected to allow evaluation of this plant and for possible operating modes in future plants which would use a different thermal transport fluid. The eight modes are shown in Figure 9 and are:

Mode 1 - Turbine Direct

The plant operates with the collector system directing solar energy to the receiver, which then provides superheated steam directly to the electric power generating system, turbine-generator. The generator provides electricity to the electic grid. Thermal storage is inactive.

Mode 2 - Turbine Direct and Charging

The plant operates as described for Mode 1 and some of the receiver steam is diverted to charge thermal storage.

Mode 3 - Storage Boosted

The plant operates as described for Mode 1 and thermal storage provides additional energy in the form of steam to the electric power generating system. The generator provides electricity to the electic grid.

Mode 4 - In-line

The plant operates with the collector system directing solar energy to the receiver, which then provides superheated steam to the thermal storage system. Thermal storage energy is extracted and delivered to the electric power generating system, turbine-generator. The generator provides electricity to the electic grid.

Mode 5 - Charging Only

The plant operates with the collector system directing solar energy to the receiver, which then provides superheated steam to the thermal storage system. The electric power generating system is not operating and the plant is not producing electricity.

Mode 6 - Discharging Only

The plant operates with the thermal storage system providing steam to the electric power generating system. The generator provides electricity to the electric grid. The collector and receiver systems are not operating.

Mode 7 - Storage Boosted and Charging

This is a combination of Modes 1, 5 and 6. All portions of each subsystem are operating. It is considered a transition mode and would not normally be used for continous operation.

Mode 8 - Inactive

In this mode all of the plant main process systems are shut down. The control and auxiliary steam systems are operational.

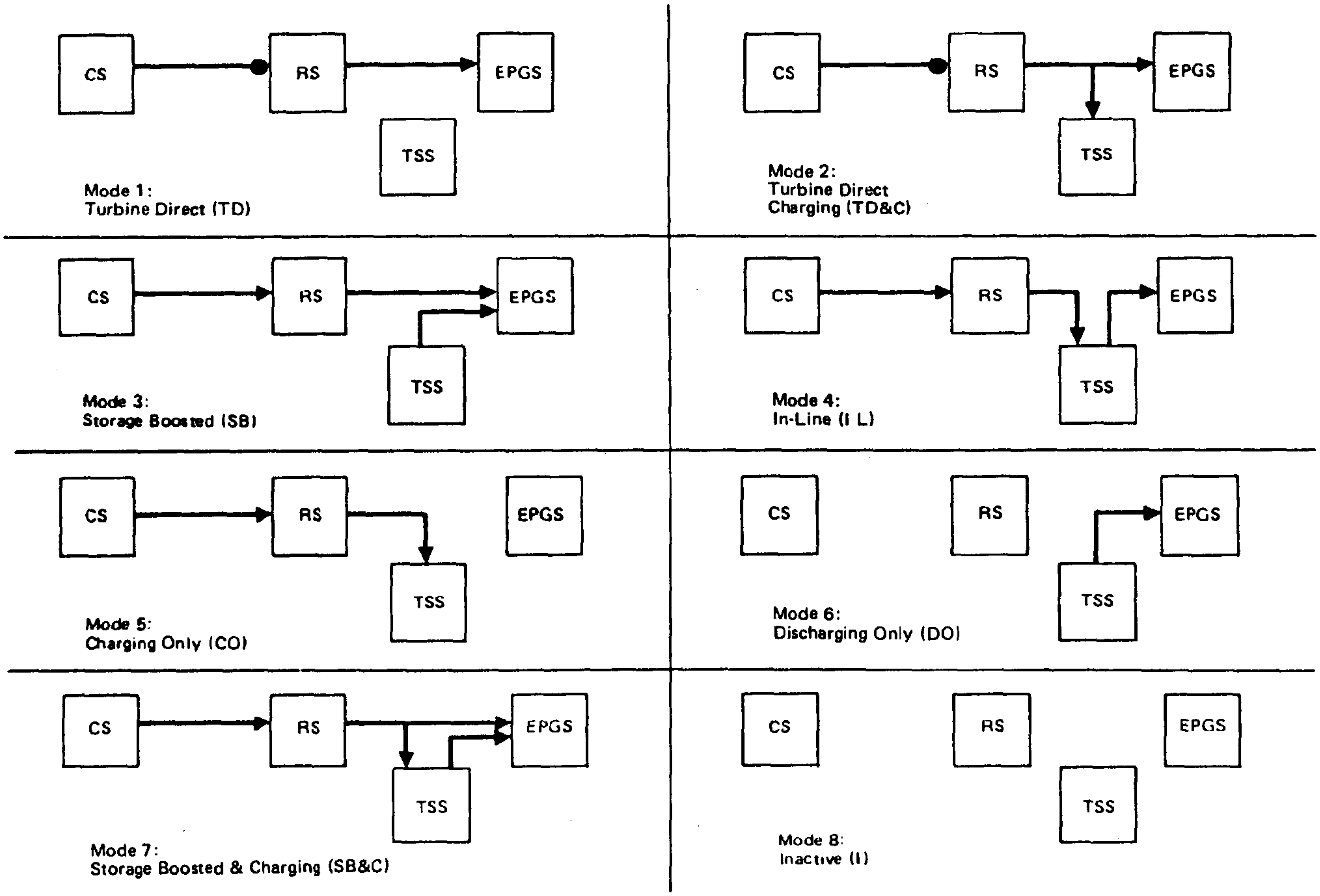

Figure 9 - Plant Steady State Modes

Automatic Operation

Plant automation has been implemented in three levels, 1) Subsystem Distributed Process Controller (SDPC), 2) Operational Control System (OCS) process tasks and 3) the OCS clear day supervisory control tasks.

Extensive automation has been done at the subsystem (SDPC) level which goes beyond set point or switch control. Software "Pushbuttons" have been created which provide the equivalent of hardware pushbutton control, especially for the TSS. Therefore, the majority of the plant automated sequences via the OCS computer deal primarily with the manipulation of these SDPC pushbuttons. The various SDPC automation functions have been discussed in the previous section.

The OCS integrates each of the subsystem control automation functions into one control point and coordinates the function of the subsystems. The level 2 automation is performed by the OCS and includes subsystem start-up and shutdown, mode transitions and functions which integrate more than one subsystem.

The level 3 functions are also performed by the OCS and they include steady-state and mode transition management and clear day operation in Modes 1, 2 and 5.

Clear Day Mode 1 -- Start-up, operation and shutdown of the plant in Mode 1, receiver to turbine direct.

Clear Day Mode 5 -- Start-up, operation and shutdown of the plant in Mode 5, receiver charging thermal storage

Clear Day Mode 2 -- Start-up, operation in Mode 1, receiver to turbine, transition to Mode 2, receiver to turbine and charging thermal storage, transition back to Mode 1 and shutdown of the plant.

The automatic clear day operating mode is designed for a nearly fully automatic "hands off" operation of the plant from sunrise to sunset on a clear day. Some operator interaction with the automatic sequence is required to perform manual functions such as water chemistry tests, start pumps, fill and purge of receiver, roll the turbine, etc. The clear day scenario links together in a logical sequence the automatic startup sequences, automatic mode transitions and automatic shutdown sequences.

Plant Startup

All the subsystems in the plant (RS, TSS, EPGS) require some manual operator control during startup. Some reasons for manual operation are:

1. SCE operations require all major pumps to be started by the operator with a plant equipment operator standing by the equipment.
2. Some automation control logic would be too complex in comparison to an operator control decision and action.
3. Some conditions are not easily detected by the control system such as:

a. Some equipment may be out of service for maintenance and an alternate, manual, step is required.

b. A control loop is not functioning properly

c. An equipment failure occurs during startup

Therefore, the startup remains under operator supervision. OCS startup sequences are geared for "startup enhancement" instead of fully "automated OCS startup".

Receiver Subsystem Startup

OCS receiver startup automation sequencing is summarized below in chronological order. Startup events such as water clean-up, establishing flow through the panels, and nitrogen system operation are initiated by the operator and are not included in the automated sequence.

1. Initialize receiver subsystem
2. Start feedwater pump
3. Establish flow to flash tank
4. Water cleanup
5. Apply nitrogen
6. Establish flow through all panels
7. Apply solar power to all panels (automatic collector field startup task)
8. Vent all nitrogen to deareator once receiver produces steam
9. Bring all panels to flow control
10. Bring all panels to temperature control
11. Add solar power to lagging panels (due to anomalous conditions)
12. Ramp all panel temperature setpoints to 775 degrees F
13. Pressurize downcomer
14. Establish steam dump operation
15. Ramp system pressure to 750 psig

Items 2 through 6, 8 and 11, are operator, manual, controlled; all others except 7 are automated on the SDPC level.

Item 7, apply solar power to all panels, is automated in the OCS by the receiver startup routine. This routine checks to see that valves are aligned properly and flows and pressures are reasonable. Once these are true, a message is printed notifying the operator the "HAC startup" command file is to be executed in 60 seconds. The operator has the option of either allowing the sequence to continue or issue a HOLD or an ABORT command. The receiver startup routine is complete once proper outlet pressure and temperature of the receiver are reached with the downcomer and steam dump in operation.

Thermal Storage Subsystem (TSS) Startup

There are two identical trains for charging/extraction of the thermal storage unit. Automatic sequences in the SDPC level for each individual train are in software "pushbutton" form that can be initiated by the operator or they can be used by OCS as part of the automation. There are two sequences to accomplish startup of the TSS; one for charging and one for extraction. The operator must select which train is to be used and OCS will do the rest.

Plant Shutdown

Receiver Subsystem Shutdown

There are two different sequences to accomplish receiver shutdown. The first sequence is called "Derated". The "Derated" sequence decreases both the receiver temperature setpoint and the receiver outlet pressure to their minimum which is dependent on the steady-state operating mode. The second sequence is called "shutdown". This sequence ramps the receiver temperature setpoint down to 775 degrees F and sets the pressure setpoint to 550 psig. The receiver flash tank is then brought into service and the downcomer is taken out of service. Once this transition is complete the collector field is commanded to DEFOCUS.

Thermal Storage Subsystem (TSS) Shutdown

Shutdown of the TSS is quite similar to startup. There are separate switches to accomplish complete shutdown of each individual train. The OCS computer is only required to command these SDPC switches to their appropriate state. There are two sequences to accomplish shutdown of the TSS; one is for charging and the other for extraction.

Clear Day Operation

The clear day operation begins with the start up of the receiver and the collector field. This results in the receiver providing steam to the steam dump system. This transition mode is sometimes called Mode 9 (50 klb/hr receiver flow). Then the OCS commands the collector field to the intermediate power mode. Depending on which clear day task is running, the system is then transitioned to Mode 1 or Mode 5. The full power (FULPWR) task is then activated to put the whole collector field in tracking mode. The OCS then waits until 1:30 pm or 2:30 pm, depending on which clear day operation is in effect, clear day Mode 1/2 or clear day mode 5. At that time the receiver is derated when the receiver total flow is less than 62 klb/hr and is shut down when the average electrical generation is less than 1000 kWe.

The clear day scenario, operation with no clouds, is started by the operator at approximately sunrise, and it runs automatically and shuts itself off at sunset. In case of clouds or any problem with the system, the operator can abort, or hold the clear day operation. The OCS also monitors conditions and can issue an abort if required.

There are three clear day operating modes:

Clear day Mode 1 (CLRDY1)

This task performs the clear day scenario which will bring the system to receiver direct to the turbine (Mode 1) after the collector field and receiver are started up. It supervises the operation of the plant in Mode 1 through the day. The receiver operation is derated when the receiver total flow is less than 62 klb/hr and the system is shut down when the average electrical load is less then 1000 kWe.

Clear day Mode 2 (CLRDY2)

This task performs the clear day scenario which will bring the plant first to Mode 1 and then to Mode 2 after the collector field and receiver are started up. Transition to Mode 2 is performed when the load exceeds 7000 kWe. At this point energy is divided between the turbine and thermal storage. An equivalent energy of 3500 kWe is routed to thermal storage and the remainder is routed to the turbine. When the turbine load drops below 1500 kWe the plant is transitioned back to Mode 1. The receiver operation is derated when the receiver total flow is less than 62 klb/hr and the system is shut down when the average electrical load is less then 1000 kWe.

Clear day Mode 5 (CLRDY5)

This task performs the clear day scenario which will bring the system to Mode 5 after the collector field and receiver are started up. It then derates the receiver when the receiver total flow is less than 62 Klb/hr and shuts down the thermal storage when either the tank is charged, the charging inlet oil temperature is greater than 450° F, or when there is insufficient steam (TSS main steam inlet valve is being controlled to less than 8 percent open for 5 minutes).

OCS Automation Tasks

The operational control system has a number of intermediate tasks which provide the function of the clear day automation and mode transitions. These tasks acquire information from each of the subsystems and issue commands to the subsystems. The OCS initiates automated functions within the SDPC for the receiver, thermal storage, EPGS and plant support systems as required for the task in operation.

There is a steady-state mode finder routine which is used to verify the plant operating mode. Table 1 gives a brief task description of the automated functions and transitions.

Table 1 - OCS Automation Tasks

Task Name	Task Function
CFUP	Collector Field Start-up
INTPWR	Collector Field Intermediate Power. Adds power after the transition from RS flash tank to downcomer.
FULPWR	Collector Field Full Power. Increases the number of heliostats in track by 25 percent increments until all heliostats are in track.
RSUP	Receiver Subsystem Start-up
HOTSTA	Collector Field Hot Standby. Returns collector field to a power level compatible with RS flashtank operating conditions. For cloud disturbances.
MX95	Mode 9 to Mode 5 Transition
MXT9	Mode 1, 2 or 5 to Mode 9 Transition
MX91	Mode 9 to Mode 1 Transition
MX12	Mode 1 to Mode 2 Transition
MX21	Mode 2 to Mode 1 Transition
MX25	Mode 2 to Mode 5 Transition
RSDRAT	Receiver Subsystem Derated Shutdown
RSSHUT	Receiver Subsystem Shutdown
RUNMOD	System Mode Finder

CONTROL SYSTEM EVALUATION

Early MCS Development

In the mid-1970's several contractors were funded to develop solar central receiver conceptual designs. Separate evaluation panels reviewed each subsystem. The master control evaluation panel felt that none of the designs proposed by the contractors were completely acceptable. The MCS evaluation panel then selected the best parts from each of the contractor proposals and from experience at the Central Receiver Test Facility and recommended a master control system design (Reference 4).

The master control committee consisted of representatives of Aerospace Corp., Southern California Edison, and Sandia National Laboratories. They prepared the MCS requirements and an MCS statement of work. These documents were the basis for the final statement of work for the plant. There were many changes in the way it was implemented, the software for the plant automation was delayed until plant construction was completed. The end result is a master control system that is not significantly different from that recommended in 1977.

Master Control Requirements

The requirements for the master control system evolved into several documents which now reflect the "as built" design. (References 1 and 5) A comparison is made between the proposed design requirements made by the evaluation panel in 1977 and that which was actually incorporated into the plant.

A part of the comparison was made by Dr. M. A. Soderstrand, University of California, Davis, in 1983. This information was updated to reflect activities which occurred after his study was complete. A summary of Dr. Soderstrand's study is provided in Appendix A.

The proposed design is shown in Figure 10. If you compare it with the final design (Figure 3), there is little actual difference. One major difference is that the plant does not include the Peripheral Control System.

A comparison of the recommended and actual plant control capabilities is given in Table 2 for the major subsystems of the plant control system. The table shows that most recommended capabilities were implemented to some extent. The major differences between recommended and actual capabilities can be grouped into four areas:

1. The evaluation panel recommended that a single computer language be used for the software in the plant. For a variety of reasons this was not done. Microcomputer assembly language was used in several places where optimized operation was required and/or the hardware was such that high level languages were not usable. High level languages were used that matched the capabilities of the hardware.

2. A Peripheral Control System (PCS), which was recommended originally, was not incorporated into the Pilot Plant. The elimination of the PCS had a minimal impact because the data reduction features of the PCS were to a large extent incorporated in the OCS and DAS. Alternatives were also available for backup control of the plant, using the SDPC, and for software development, using the OCS, HAC, and DAS computers.

3. Schedule delays and design improvements led to the use of more advanced equipment, e.g., the Beckman MV-8000 distributed digital control system, than was initially available.

4. The lack of a full plant simulator led to the use of the "plant" as an important "simulator" for plant controls development. This caused some schedule delays but was not a serious problem.

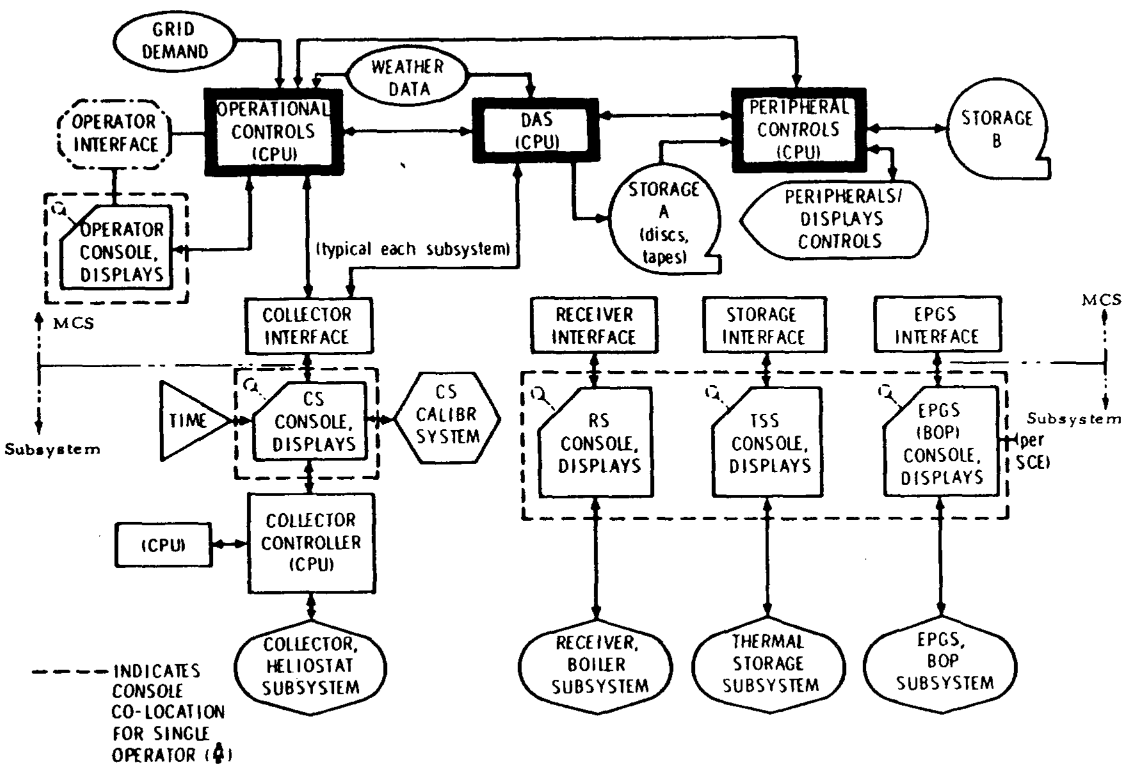

Figure 10 - 1977 Proposed Master Control Design

TABLE 2. COMPARISON OF RECOMMENDED AND ACTUAL PLANT CONTROL CAPABILITIES

SYSTEM	CAPABILITY RECOMMENDED	CAPABILITY ACTUAL
Overall System	Independent control	Each subsystem is independent and OCS is not required for operation.
	Subsystem manual control	Semiautomatic (set point and command sequence control) and manual control available.
	Identical computers	Identical OCS, HAC, BCS, and DAS computers. Identical SDPC computers.
	Identical keyboards and graphics	RS, TSS, EPGS share a common keyboard, OCS and CS are different.
	Single programming language	Not available
	Simple Interface between systems	Interfaces with varying complexity. OCS-SDPC interfaces are simpler because of advanced features of the SDPC.
Operational Control System	Keyboard and/or light pen input	Available
	Color-graphic display output	Available
	Automatic control	Automatic computer control available for: clear day Mode 1, clear day Mode 2, and clear day Mode 5.
	OCS manual control	Semi-automatic (set point and command sequence control)

TABLE 2. COMPARISON OF RECOMMENDED AND ACTUAL PLANT CONTROL CAPABILITIES (Continued)

SYSTEM	CAPABILITY RECOMMENDED	CAPABILITY ACTUAL
Peripheral Control System	Peripheral Control System	Eliminated from plant
	Backup control system for OCS	Not available
	Software development	Available by using OCS, HAC, and DAS computers at night and sometimes during plant operations.
	Plant simulation programs	Not available on site
	Evaluation of DAS data on site	Limited capability provided by DAS and telephone connections to offsite computers at Sandia and McDonnell Douglas.
Data Acquisition System	Data acquisition system	Available
	Keyboard or light pen input	Keyboard input
	Color-graphic display output	Color plots with black and white hard copy. Data tabulations with hard copy. Real time data display.
	Data storage for offline evaluation	Disk storage. Limited onsite evaluation. Considerable offsite evaluation capability.
	Interfaces independent of OCS.	Separate interfaces with OCS, RS, TSS, CS, EPGS and BCS.
	Log all OCS commands.	Not available, OCS commands logged on an OCS printer.

Operational Control System

The proposed design and the final design are very similar. One major difference is that several types of computers and microprocessors were used in the plant. The 1977 panel recommended that all the computers in the plant be the same. However, there are many different computers, minicomputers and microcomputers in the plant. The operational control system, heliostat array controller, data acquisition system, and beam characterization computers are all the same and are Modcomp Classic computers. The subsystem distributed process controller for the receiver, thermal storage, electric power generation system, and balance of plant use a type of microcomputer. Other parts of all systems use various types of microprocessors. There are valid technical and cost reasons to support the use different computers. One result was an indeterminate amount of increased maintenance cost. The tradeoff, of course, is between the capital cost and the operations cost. From a capital cost standpoint, it was cost effective to use the variety of computer types in the plant as they fit appropriately into the desired application. The trend in the future is towards specialized microprocessor controllers with a high level command/programming capability which would keep the number of different types of hardware to a minimum.

The subsystem controllers for the receiver, thermal storage and EPGS have much more capability than was contemplated in the 1977 design. The use of the Beckman MV8000 as the subsystem distributed process controller has allowed much of the plant automation functions to be done in the subsystem rather than in OCS as was proposed. This allowed the OCS to do more of the graphics functions which were proposed to be included in the PCS.

In the 1977 design OCS was to include the necessary data acquisition required for plant control. The plant OCS actually does no direct data acquisition since the information it needs can be obtained from the subsystem controllers. The OCS derives some information from data received and a little information is also obtained from DAS. The use of DAS data was a departure from the 1977 recommendation, but the requirement was developed late in the program, and it was not cost effective to add hardware to the controller data acquisition systems.

Collector System

The collector control system was the first to operate at the plant site. It was required during the final stages of heliostat field construction. The collector system operated for several months out of a trailer before the control building was available.

Some of the features demonstrated by the system include:

1. Control of 1818 heliostats, individually, in groups, and all at once.

2. Emergency defocus and stow in the event of a receiver trip or a total loss of communication.

3. Current status to the operator in the form of tables and graphic displays.

4. A backup computer with bump-less failover.

5. Communication connections with computers in other parts of the plant. Both status and control capability exists.

Although there have been some anomalies in the collector control system operation the collector system outage time has been small. The problems which did occur caused short outages.

The Honeywell color-graphics display evaluation (Appendix B) provided some good suggestions for improvement of the man-machine interface to the collector system. The commands used were somewhat cryptic; the choice of colors on the displays make them hard to see and interpret. The response time of the collector field graphic display was very slow, 65 seconds average time to generate a field display.

Features in the collector system which need improvement include:

1. Error and Alarm handling does not provide sufficient information on the true cause of the problem.

2. Many status numbers are in hexidecimal. This takes some adjustment for any non-computer person. Some inputs are also in hexidecimal.

3. Status information is presented as a code rather than a word description.

4. Some internal status information is not readily available to the operator.

5. Insufficient thought was given to system diagnostics. As a result many command functions installed for engineering use were left in a cryptic form. Many of these commands were very valuable for problem diagnosis. SCE has adjusted to the cryptic form.

6. The back room man-machine interface was poorly done. Error messages were very cryptic. Some messages which indicated serious problems were so unclear that they were ignored. The original design had serious traps in the computer startup process which could result in an incorrect startup without the operator knowing it. Many of these problems were fixed during the first three years of plant operation.

7. The HAC to HFC timing was much too critical for industrial operation. However, this has been more of an harrassment than a major problem. This design would not scale up to a 100 MW plant.

The collector system software has been through considerable revision since the plant was installed in 1982. The major problem has been in communicating between the HAC, DAS, OCS, BCS and the collector field. Various other problems have resulted from communication and timing related problems.

The HAC console has locked up, preventing operator commands from being accepted. There have been HAC failovers. Some of the failovers result in loss of control to parts or all of the collector field.

A large number of software changes were made in an attempt to correct the problems; however, the true cause of the problem was never found, and the failovers still occur, although at a reduced rate.

None of these problems have caused damage to the plant or caused significant plant outage time. Overall, the collector system has been very reliable.

Subsystem Distributed Process Controller

The Subsystem Distributed Process Controller (SDPC) provides the man-machine interfaces for the receiver, thermal storage, and turbine generator and balance of plant. There are three separate controllers, and the operation is discussed in the control system description section.

The subsystem controller requirements were primarily developed after the Solar Facilities Design Integrator contract was started. The 1977 evaluation panel did not provide much in the way of requirements for the subsystems.

The SDPC provides good subsystem control flexibility for the plant and was the main man-machine interface for plant operation for the first two and one-half years of operation. The level of control varies from a single element (pump, valve, breaker) to a whole process (receiver start-up). This control system provided a departure from the conventional power plant control system in that the control logic, set points, limit points, gain settings, safing logic, and alarm points are all contained in data bases in the controller and not hardwired in. Changes are easily made from the control room without plant wiring changes or hardware adjustments. This capability allowed the start-up of the plant to proceed much more efficiently and has provided added operational flexibility. The utility can easily make changes in the controller to use an alternate sensor when there is a failure. When a sensor is replaced, the new calibration information is easily installed.

The man-machine interface with the SDPC is through color graphic video terminals. The displays can easily be changed by the operator, and the operators generated the majority of the displays.

There are few deficiencies in the system, and the availability has been good. The more notable deficiencies include a very slow graphic page generation time. It takes approximately 10 to 17 seconds to completely generate a graphic page with dynamic data on it.

The system generates excessive alarms. This is especially true when the plant is starting up or shutting down. Alarm limits are not tied to operating mode so that when there is a normal transition alarms occur which are not real.

The floppy disks used to store information have not been very reliable. Regular preventive maintenance by SCE has reduced the problem, but some other disk design, such as a sealed winchester, would be preferred for future plants.

Honeywell Technology Strategy Center, on contract to EPRI, conducted a study of the Solar One control system color graphic displays. A summary of this study is included in Appendix B (Reference 1).

A number of changes were made in the displays in the plant after the Honeywell study, but it is difficult to determine whether the changes were made as a result of the study or would have been made naturally as the plant automation was completed.

DAS Evaluation

The DAS is a complicated data base management and data acquisition system. One minicomputer and several microprocessors are included in the DAS. The hardware reliability has been average; there have been outages which have lasted several days, but since DAS is not needed to run the plant, the only loss was evaluation data. Individual sensor and signal conditioning failures have occurred but at the expected failure rate.

The software performance has also been average. It still has some random problems, for which the cause is unknown. There are documented "work-arounds" provided and these are mainly nuisance items.

One function of DAS does not work. The data playback from a DAS archive tape has not worked. At the end of the test phase of the plant operation, it was decided not to spend further money attempting to fix this.

Originally there were strip chart recorders connected to the DAS to provide higher time resolution plots. This capability was needed during the first year of plant operation while the control loops were being tuned. There were problems with the hardware and software and the strip charts did not work. After the need went away, no further work was done on this feature.

The user documentation of DAS is poor. The users manual gives step by step operations, but there is no background information on how DAS operates or what the purpose of the features is. The best section in the manual is the problem work-around section in which the problem is described and steps are described to correct the problem. It was decided not to spend the money the correct the documentation. The designer has been available to assist with any operational problems.

For software maintenance there are several volumes of Unit Development Folders (UDF). The UDF's are complete software descriptions for each module in the system. However, it is not practical for the user to use this document to determine background information. The UDF's are well done and will be very valuable if changes are required to the software.

The DAS has been functioning satisfactorly during the power production phase of plant operation with only SCE operating it. As long as changes are not required to the measurement information or scan lists there should be no problems. If changes are required the DAS designer will be needed for assistance.

Plant Computer Programming Languages

The MCS committee recommended that a single computer language be used for the software in the plant. For a variety of reasons this was not done.

Micro computer assembly language is used in several places where optimum operation is required and/or the hardware is such that high level languages are not usable. High level languages were used, each of which matched the capabilities of the hardware.

Collector System

The heliostat controllers and heliostat field controllers programs are written in microprocessor assembly language. The programs were then put into electrically programmed read only memories and thus become "firmware". There have been no changes to the firmware since the plant started operation.

The heliostat array controller computer is programmed in Fortran and some Modcomp assembly language. The assembly language was used when speed was most important. It has been observed that there are some routines written in assembly language which could have been written in Fortran. This would have made them easier to change.

The collector field status display is generated on a Chromatics microcomputer and the program was written in a structured Basic.

Subsystem Distributed Process Controller

The controllers for the receiver, thermal storage and turbine generator were written in assembly language by Beckman. However, the controller provides a high level control language which is used to actually build the control loops and and functions of the controller. In addition graphic generation features are used to create the graphic displays and control features of the system.

Redline Unit and Interlock Logic System

These units contain assembly language firmware provided by Modicon and are programmed in a high level language which simulates a relay logic ladder diagram.

Beam Characterization System

The Modcomp computer is programmed in fortran with a little assembly language. The BCS console is a Hewlett Packard computer which uses Basic language. The man-machine interface and plotting software for the BCS is written in Basic.

Data Acquisition System

The DAS software is mostly Fortran for the Modcomp computer. The remote data acquisition systems use a high level data acquisition language.

Operational Control System

The OCS software in mostly written in Fortran for the Modcomp computer. The Plant Operational Displays software was written in Fortran and assembly language by SGM Inc and McDonnell Douglas.

Conclusion

The plant design used too many computer languages, but they were the best for the particular hardware in each system. The lower level language parts of the plant have had few software bugs. The bulk of the changes have been to systems using high level control or Fortran languages.

Future plants are expected to use high level control languages which use firmware written in assembly language. Further integration of the hardware functions should result in fewer languages.

FUTURE SOLAR PLANT CONTROL SYSTEMS

Solar One has a modern digital control system which is considered a first of its kind in the utility industry. The next generation of central receiver plant control systems is expected to extend the Solar One concept to provide further increases in operating efficiency and reductions in maintenance costs.

Some of the key features expected in the future include:

1. Distributed digital control system, integrated at the master control level.

2. Redundancy in critical areas.

3. Sensor and controller degradation and failure detection

4. Alarm analysis

5. Maintenance database integrated into master control

6. Expert systems aids.

<u>Distributed Digital Control System</u>

The next control system will be a distributed digital system similar to Solar One except that the functions at the top level would be integrated into one redundant master control system. The separate subsystem controllers in Solar One would become a single master control system which would provide the man-machine interface, graphics, logging, top level control integration, and communications with process controllers located elsewhere in the plant. There would be better cross communications between various process controllers and the master control system. A sensor output could be used by master control or any process controller without separate wiring. Interconnection would be via a high speed data highway. Figure 11 shows the new control system architecture.

The master control system should be able to maintain the characteristics of the process controllers. This means that there should be a capability for programming and verifying the data in each of the controllers. The master data would be maintained in master control and would be sent to the process controller any time there is a need to re-initialize that controller. Data base maintenance would be in engineering units and not in internal format.

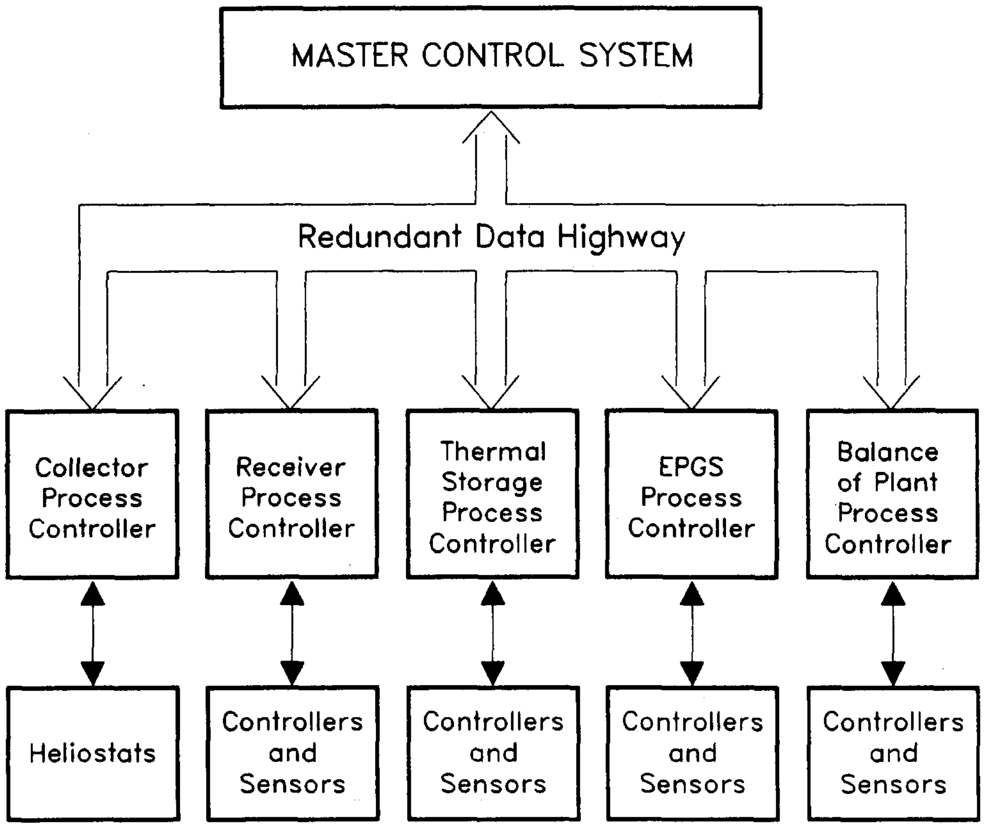

Figure 11 - Control System Architechure

Redundancy

The control system should be redundant at various levels consistent with cost of a failure. The main point is that total redundancy may not be required or may not be cost effective. Components which would result in extended plant outages or are required for safety would be considered for redundancy. Analytic redundancy is another way of obtaining redundancy without extra hardware. If a sensor value can be calculated from other sensors in the plant, even if less accurate, this calculated value could be used to replace a failed sensor until it is repaired.

Sensor and Controller Degradation and Failure Detection

Detection of sensor degradation requires that both expected values of sensor output be known and a time history of the sensor be kept. The computer would analyze this information and report both failures and possible failures to the operator and maintenance database.

Alarm Analysis

The goal here is to provide sensible information to the operator when alarms occur. Alarms should not occur for changes in operating mode or during initialization. These are not abnormal conditions and should not be alarmed. The analysis should provide the operator with information on the source of the alarm. An example may help to understand this:

A sensor in a control loop fails in the zero position. The process controller attempts to change the control device to restore the correct value from the sensor. This results in some other sensor value exceeding the limit. An alarm occurs and the plant protection system causes a trip. The alarm analysis would indicate that the failed sensor was the cause of all the rest of the alarms. Some alarms might be suppressed if they add no additional information.

Alarm limits would be tied to the subsystem operating mode. This would suppress alarms during start-up and shut down and during mode changes.

Maintenance database integrated into master control

Maintenance database support would provide a means of automatically posting maintenance orders for failures. The data base could be used to look for failure trends and to automatically issue preventive maintenance orders. Sensor degradation could be monitored and a maintenance order issued when some limit is reached. Energy calculations could be used to detect leaks and other energy losses. Historical data would assist in this analysis to warn of changes in operating efficiency. The heliostats would be aided considerably by a maintenance database. With such a large number of identical items, statistical techniques would be useful. Also computer aided reporting, problem logging and trends analysis would be very helpful.

Expert Systems Aids

Expert systems are a subset of artificial intelligence. The expert system controller could use a knowledge database, a set of condition-rules, for the operation of the plant. These rules need to be developed with the help of people who have learned the plant operation well, and this would require considerable manpower to fully develop. At first some critical portion of the plant should be selected and operations and maintenance aids provided. Expansion capability should be included so that the knowledge data base can be expanded in the future. On-line help feature is a subset of a expert system aid. Help functions can provide assistance in operating with the man-machine interface, and provide instructions for special situations, such as plant start-up, shut down and special emergency conditions i. e. plant power failure. Some of these help aids could be programmed to come up automatically if certain conditions occur.

Automatic Operation

The natural extension of automation is to support remote or unattended operation of the plant. A single control room could be used to control several plants located at some distance or in a cluster. Since many functions would be handled by the control system, one operator would be able to handle more than one plant. The operator would decide on operating modes and handle emergency situations. Should a failure occur, the control system would attempt a work-around so that the plant would continue to operate. The operator would get involved only in extreme situations. Maintenance reports would be automatically generated on failures and on observed degradation.

A feasibility study was conducted by McDonnell Douglas to provide remote operation of Solar One (Reference 11), and it was clear that remote operation should be considered early in the design. Solar One was not designed for remote operation, and the study points out some of the resulting problems. The study also provides a good description of the various operational steps required to put Solar One into daily operation.

In order to complete the design of a fully automatic plant, the plant static and dynamic characteristics, failure modes, strengths and weaknesses must be well understood. Computer simulation can be very helpful in the design phase; however it must be recognized that good models can be costly to develop and affordable models may not have the degree of accuracy required to fully simulate some modes of plant operation. It is reasonable to expect that the plant design will be achieved from a combination of computer simulation and actual plant operating experience. This suggests that the first fully automatic plant will need to be operated with operators on site for a period of time, possibly a full year, so that the characteristics can be fully defined and the control system design can be fine tuned. Subsequent plants should require much less time for adjustments. This is similar to the way the OCS design was completed at Solar One. There is some probability that each new plant will require some tuning as improvements are made from the previous plant. Changes in control and computer technology can make a design obsolete in a few years. This is one reason why we cannot transfer the Solar One control system design directly to the next plant.

The plant design must take into account the various plant, systems, and subsystems requirements necessary for full automatic operation with high plant availability. Some of the major considerations are:

a. Personnel and equipment safety

b. Plant start-up and shut-down

c. Turbine-generator automation

d. Off design operation

e. Adaptive compensation for failures

Plant safety is the primary consideration in a design, but in a fully automatic plant different monitoring philosophy will be required to account for the missing "human" element. Additional sensors and protection equipment may be required.

A solar plant sees daily start-up and shut-down activities which need to be considered in automation design. For example, Solar One has a number of manual operations required for daily start-up. Operations of this nature will need to be motorized and automated so that they can be remotely operated. Additional instrumentation may be required to replace some activities performed by plant equipment operators. It is common practice to listen to major equipment during start-up. Periodic observation is also done during the day. The extent to which additional control and instrumentation is included depends upon safety requirements and cost. This cost includes lost revenue as well as the repair costs for the failure and any other damage which might result if failure is not detected immediately.

One limitation to full automation of Solar One is the turbine-generator. A number of steps associated with turbine start-up and generator synchronization are performed by the operator. Little emphasis was placed on turbine-generator automation during the design phase because it was considered a "non-solar" component. This ommission has left an automation gap in the Solar One control system.

A solar plant spends much of the time operating at off-design conditions. The fully automatic plant must be capable of adapting the operating conditions to optimize power production for a wide range of insolation. Plant energy management is important. This includes plant parasitics, plant efficiency and net power generation. The Solar One experience has shown that the power consumption during non-operating periods plays a considerable role in net power generation. For example, in 1985 30 percent of the plant parasitic power was consumed when the turbine-generator was offline.

A failure mode and effects analysis of the plant design should be done and then repeated when the control system design is near completion. This second analysis should include the actual control implementation as this can have significant influence on the failure modes of a plant.

The plant must be able to do more that just trip if there is a failure. Sensors and equipment which are single points of failure or have high failure rates should be redundant or there should be some alternate method of providing the function. Analytic redundancy is one alternate method. The control system would then be able to switch to the alternate sensor, alternate equipment, or change an algorithm if a primary failure occurs.

Weather prediction is another area which should be considered for an automatically operated plant. It is desirable to minimize unnecessary plant start-ups and to do this, good weather information is required. Such weather information could come from satellite and local and remote ground based stations.

Some decisions made by plant operators may be difficult to automate and the cost may be too high. The affect of any compromises on the automation of the plant operation must be evaluated and the reduced efficiency or increased outage time determined. The increase in outage time may be acceptable if the reduced operating costs still more than offset the revenue lost by the outage or lost energy.

In conclusion, the cost savings achieved from a fully automatic plant come from a reduction in the number of plant operators by combining operations of several plants, an improved plant operating efficiency, and a reduction in outage time from equipment failure and degradation and the reduction in repair time from improved failure reporting and diagnostics.

APPENDIX A

Comparison of the Master Control Design Requirements with Actual Design

Dr. M. A. Soderstrand, University of California, Davis, consultant to Sandia, conducted a review of the master control system in 1983 (Reference 6). This is a summary of the comparision of the design proposed in 1977 is compared with the operating plant. The review consisted of the following:

1. Provide a comparison of the Master Control System at the Solar Central Receiver Plant in Daggett with the Pilot Plant design as specified in 1977 by the Master Control System Evaluation Panel

2. Make recommendations for additional MCS work and/or test and evaluation procedures to be carried out at the Pilot Plant before the start of the power generation phase

3. Make recommendations for the design of MCS in a future commercial plant

The differences between the 1977 design and what exists at the Pilot Plant can be grouped into three parts:

1. Differences resulting from removal of the Peripheral Controls System (PCS)

   Elimination of the PCS had minimal effect primarily because the data reduction features of PCS were to a large extent incorporated into DAS or OCS and alternatives were available for software development. The main impact of elimination of the PCS was some delay and minor restrictions in data reduction area.

2. Differences due to availability of improved equipment (eg: the Beckman MV-8000 multi-variable controller) and to design improvements during construction.

3. Differences resulting from the lack of a full systems analysis of the MCS and the resulting use of the "plant" as an important "simulator" for MCS and subsystem controls development

The availability of improved equipment, of course, represents a positive benefit from the delayed schedule for MCS while the lack of a full systems analysis might be viewed as a negative factor due to the schedule delay.

Summary of Comparisons of the 1977 MCS Design and Pilot Plant MCS

In summary, the following comments can be made about the comparison of the 1977 conceptual design and the existing implementation:

1. The design philosophy and actual design are consistent with the 1977 MCS design recommendations.

2. Most differences in the existing design represent improvements over the 1977 design.

   a. The subsystem controls are far more powerful than contemplated in the 1977 design due to the availability of the Beckman MV-8000.

   b. Far more extensive simulation of the subsystems (especially the receiver) was carried out.

   3. The lack of a full systems analysis for MCS represents more of a lost opportunity than a serious problem.

Summary of Recommendations for Additional Pilot Plant MCS Work

Although there is a legitimate concern with providing the necessary control functions for smooth operation and accurate data acquisition during the remainder of the test and evaluation phase and through the power production phase of the Pilot Plant, the primary focus of the recommendations of this report is on providing information that will be useful in the design and implementation of future commercial power plants. Toward that end the following recommendations are made:

1. An optimized algorithm for coordinated control of the subsystems should be developed and tested at the pilot plant.

2. The effect of controls on the operational efficiency of the Pilot Plant should be quantified and reported.

3. Software checks should be added to data bases to assure operators cannot inadvertently use out-dated disks for plant operation or DAS, thus affecting the integrity of gathered data.

4. Various plant operating strategies utilizing thermal storage should be investigated. Different strategies would be required on clear days and on partly cloudy days. The strategy would be affected by the time of day, frequency and size of the clouds.

APPENDIX B

Control System Displays Evaluation by Honeywell

Honeywell Technology Strategy Center, on contract to EPRI, conducted a study of the Solar One control system color-graphic displays (Reference 1).

The objectives of the evaluation were the following:

1. Provide independent feedback on the capability of the existing system to support operator actions.

2. Provide independent evaluation of color-graphic display guidelines and the methodology developed for the nuclear power industry and adapted for use on a control system.

3. Identify areas where further effort is required to adapt digital computer based control and display systems for enhancing utility power plant operations.

The study was divided into 4 major areas:

1. Display guideline and evaluation methodology review

   Evaluation guidelines (Reference 7) were developed by EPRI for use in evaluating nuclear power plant color graphic displays. The guidelines covered only monitoring functions and did not include a digital control system evaluation since that function is not currently included in nuclear power plants. Honeywell was asked to extend the guidelines to include evaluation of a digital control system.

2. Subsystem Control system review and evaluation.

   The review included several visits to the Solar One site to observe, photograph, and discuss the plant operation. Participants include the Southern California Edison operators and supervisors, McDonnell Douglas and Sandia Engineers.

3. Master Control system review and evaluation.

   The review of this part of the plant control system was conducted before all of the features were installed and operating. The evaluation was based on what was installed and what was planned to be installed and was conducted in January 1984, about 6 months before the completion of the control system.

4. Dissemination of results.

   Reviews were given at the Solar One site, discussing the results of the evaluation and a report was written (to be published).

The evaluation assessed the compatibility of the operator's capabilities and limitations with the physical aspects of the man-machine interface and how well the display layout, dynamics, control input devices, dialogue structure and workspace/environment matched the physical abilities of the operator.

Conclusions (Reference 8)

1. The color-graphics Display/control system at the SDPC and HAC level is adequate for support of power production operations with a three-person operating staff and generally meets the objectives defined for master control system design.

2. Effective inter-subsystem monitoring, coordination, and control is difficult through SDPC/HAC control alone and can be improved substantially with top-level master control capabilities now being developed with OCS.

3. Control console design and layout are generally adequate to support operations and maintenance but there is inconsistency in keyboard/keypad design and operation between the various consoles.

4. Alarm acknowledgement, interpretation, and response is poorly supported in the present design and subject to wide variance in effectiveness from factors such as operator workload and alertness.

5. SDPC display page formatting and content do not pose substantial problems in subsystem effectiveness but do allow for significant improvement through configuration control of mimic symbology, color coding, and display organization.

6. Response time for display page access is problematic on the HAC and SDPC systems and causes some disruption of optimal operating sequences.

The study was conducted in 1983 when very little of the Operational Control System was in operation. The majority of the evaluation was conducted on the subsystem control system and displays. The subsystems had most of the planned automation features installed and operating. At that time the plant was operating with each subsystem controller separately. The HAC and SDPC have no communication capability so that the operator must move between consoles to control and monitor plant operation. The Operational Control System provides single console control capability both in an automatic mode and a manual mode.

The plant keyboard designs are inconsistent. Commercially available hardware was used in many cases to reduce cost. Some keyboards are alphabetical and others are typewriter style. Some keyboards have many unused keys. These items would be corrected in a commercial plant.

On the SDPC the criticality of alarms is not identified except for which of the two limits the parameter value exceeds, i.e., LOW-LOW for red alarms vs. LOW for yellow alarms. The HAC also has two levels of alarms. Many of the HAC alarm messages tend to provide little information. The alarm algorithm collects problems of a similar nature and reports them as a single alarm at a higher level. Multiple heliostat controller communications problems will be reported as a field controller problem or a HAC to HFC line problem which covers up the real source of the problem.

Honeywell considered that many of the displays were too cluttered and poorly organized. Since the operators developed most of the displays and they can easily change them, it was not considered a major problem. However, it should be noted that there is a conflict between the human factors guideline of less complex displays and the desire of the operator to display as much information as possible on a graphic page. The casual observer is confused by the displays, but the operators have found them very useful as they are.

The SDPC graphic page response time is very slow, about 14 seconds to complete a page change. The HAC collector field display takes 30 seconds to generate. All those involved agree that this would have to change in the next plant. Some improvement was made when the operational control system display was completed. That display completes a change in about 2 seconds.

Some additional comments include:

1. There were many more instances of compliance with the guidelines than non-compliance.

2. The operators show a preference for the digital control system and color-graphic displays over others in their experience.

3. The plant is protected from operator error and many hardware failures by the redline unit and interlock logic units.

4. No problems affecting health and safety were found, and few problems have the potential of affecting equipment.

In general, the study provided some suggestions for changes and pointed out some areas where the guidelines have conflicts with real world applications. A number of changes were made in the displays in the plant after the Honeywell study, but it is difficult to determine whether the changes were made as a result of the study or would have been made naturally as the plant automation was completed.

APPENDIX C

Summary of
Solar Central Receiver Power Plant
Control System Concept

Technology Strategy Center
Honeywell Inc.

This is a summary of a study conducted by the Technology Strategy Center of Honeywell Inc. for Sandia National Labs. (Reference 9) The objectives of this study were to determine the control system design features and to propose innovative conceptual approaches necessary to increase the productivity of operating and maintenance personnel required to operate a solar central receiver electric power plant and to maximize plant performance efficiency.

This study utilized the experience gained on the 10 MWe Solar Pilot Plant (Solar One) program at Daggett, California, as a primary basis for assessing the requirements for future commercially sized (100 MWe) central receiver solar power plants.

Technical Approach

The study methodology consisted of:

- Identifying the commercial solar power plant control system related needs primarily by utilizing the inputs from the operators and the engineers at Solar One.

- Prioritizing the needs to focus the study on critical requirements.

- Assessing the technology trends and state-of-the-art technologies that can address the requirements.

- Proposing innovative and conceptual approaches leading toward solving the critical needs.

- Recommending conceptual approaches for next-generation solar power plants.

Results

Many of the solar power plant requirements are typical of a large digitally controlled process plant. By utilizing the Solar One expertise, the requirements for a next-generation solar power plant to meet the increased operating and maintenance personnel productivity and the increased performance efficiency objectives of a commercialized system were identified. The requirements are categorized as follows:

1. Control Strategies and System Architecture

- Coordination between "nonsolar" and "solar" portions of the plant.
- Some integration of receiver and heliostat controls.
- Good controller performance at all operating points.
- Efficient field communications.
- More distribution of control down to local level.

2. Monitoring and Diagnostics

- On-Line sensor failure detection.
- Prevention of plant trips.
- Degradation detection.
- Estimation of events likelihood.
- Alarm analysis.
- Rapid diagnostics of out-of-tolerance conditions through alarm annunciation.
- Reduction or elimination of false alarms.
- Preprocessing of information for operators.

3. Man-Machine Interface (MMI)

- Reduction of extraneous data presented to operators.
- Different formats for operators, maintainer, engineer.
- Display structure and graphical format.
- Embedded procedures for on-line guidance to operators.
- Capability to run diagnostics during operations.
- All-around access of data base.
- Overall system status overview.
- Status display of entire heliostat field on single CRT.
- Timely operator help function

4. Maintenance

- Self-diagnostics of computer hardware.
- Trend analysis of equipment maintenance problems.
- Separate operational data base.
- Preventive maintenance rather than corrective maintenance.
- Preventive maintenance

A qualitative assessment primarily based on inputs from Solar One personnel resulted in prioritizing and identifying the following critical requirements for a commercial solar power plant.

1. Control Strategies and System Architecture

- Efficient communications and control system architecture.

- Controller performance equally good for all operating points--solar plants do not always operate at one design point.

2. Monitoring and Diagnostics

   - Instrumentation related needs:

     * On-line sensor failure detection, especially for receiver instrumentation.

     * Redundancy required in receiver instrumentation.

     * Reduction of monitoring instrumentation.

   - Alarm monitoring and processing.

3. Man-Machine Interface

   - Alarm handling;

   - Effective operator interface;

     * Integrated control console.

     * Overview of system status across subsystems.

     * Separate data base and information format for operator, engineer and maintainer.

This study focused on providing candidate solution approaches to address these critical requirements for next-generation solar power plants. The other noncritical needs are briefly addressed.

The technologies and techniques summarized above comprise a response to the requirements. To address these requirements, it will be necessary to look at the advances in optimal estimation techniques, color-graphics for alarm status, colorgrapics display structure, embedded operator aiding, and multi-input multi-output (MIMO) control strategies. Breakthroughs in technologies such as robust MIMO controller synthesis, expert systems, and MMI techniques have been made since the Solar One plant was designed. Since it is not practical to approach every possible new technology innovation for application to the control systems at Solar One and the next-generation power plant, it would be fruitful to consider gradual improvements.

Candidate solution approaches to solving some of the critical requirements are listed below:

1. Control strategies and system architecture categories are:

   - Distributed control system architecture.

   - Robust multi-input/multi-output (MIMO) controller synthesis.

2. Monitoring and diagnostic categories are:

   - Analytical redundancy and parity space representation, and filter residual techniques.

   - Optimal estimation.

   - Computer-based alarm system -- elimination of alarm inflation.

3. Man-machine interface categories are:

   - color-graphics for alarm status.

   - Enhanced color-graphics display structure.

   - Embedded aiding. Ranges from simple help function, built in procedure aids and a full knowlege based system for making decisions.

It is recommended that cost/benefit analyses be conducted to determine the "high-payoff", next-step, and best-solution approaches. The data available from Solar One operation and from other sites can be utilized to determine the feasibility of these conceptual approaches.

The conceptual features and functions of a solar control system design are shown in Figure C.1. The salient features and functions necessary to improve performance efficiency and operator productivity requirements are the following:

- Network-based control system architecture.

- Integrated data base tailored for the operator, maintainer and engineer.

- color-graphics for alarm status.

- Enhanced color-graphics display structure.

- Advanced diagnostics algorithms for sensor failure detection, especially for the receiver.

- Adaptive and MIMO control strategies.

- Intelligent heliostat field controllers capable of calculating the sun position and monitoring and controlling an individual heliostat under normal operation.

- Redundant heliostat array controller for off-normal operations and for beam characterization of heliostats.

- Improved alarm system, which utilizes the processing capabilities of the computer to eliminate alarm inflation and to group alarms in an easy-to-interpret manner.

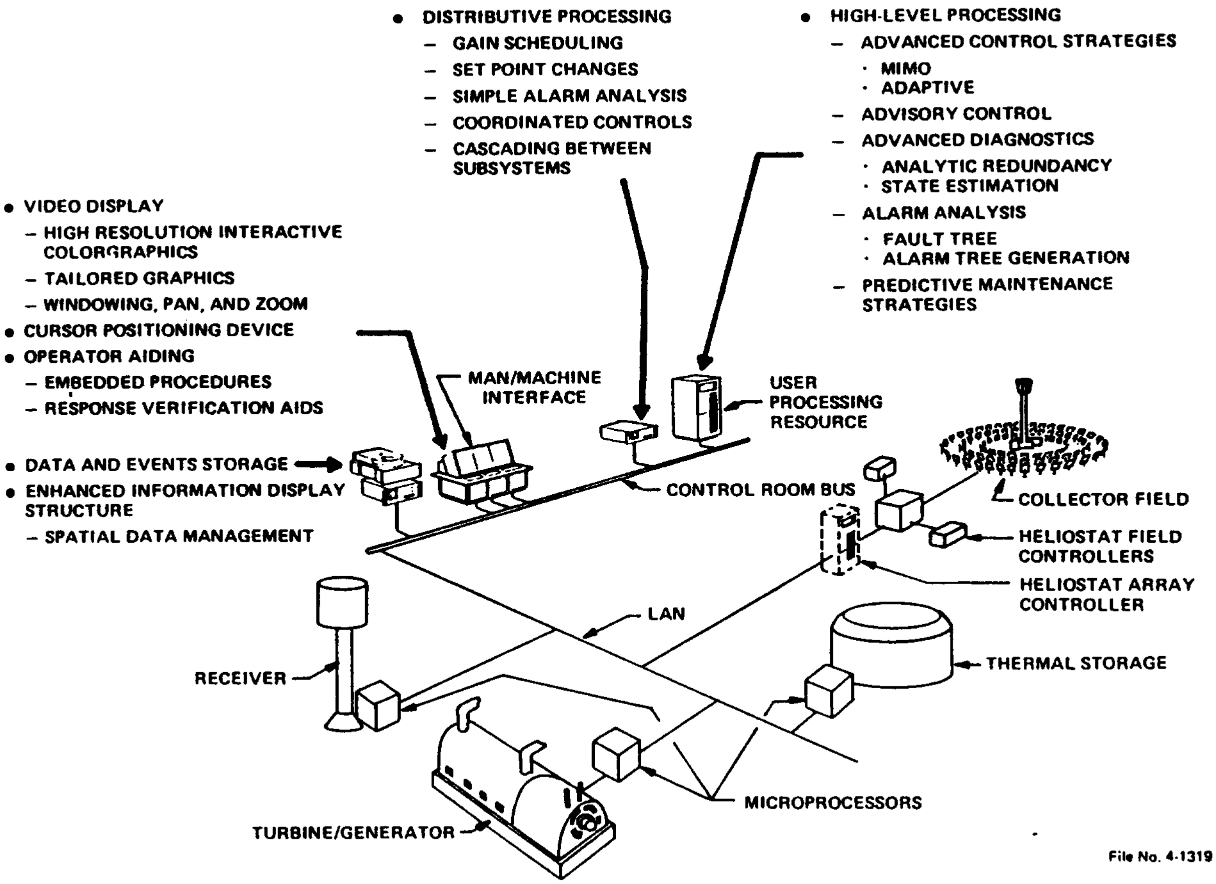

Figure C.1 Conceptual Design -- Functions and Features

Conclusions

The technologies and techniques that were identified to address the requirements of sensor detection, control system architecture, and alarm monitoring are:

1. Analytic redundancy and filter residual techniques.

2. Distributed control system architecture.

3. Alarm analysis to limit the number of alarms (eliminate alarm inflation) and group the alarms for easy interpretation.

Table C.1 summarizes the man-machine interface technologies and techniques considered central to the design concepts of (1) enhanced alarm annunciation, (2) enhanced display structure, and (3) embedded aiding.

PROPOSED APPROACH	APPLICABLE TECHNOLOGIES
ENHANCED ALARM ANNUNCIATION	• HIGH-RESOLUTION DOT-ADDRESSABLE COLOR-GRAPHICS • TAILORED GRAPHICS • VIRTUAL FUNCTION KEYS • VOICE RECOGNITION • NATURAL LANGUAGE • AUDITORY ANNUNCIATION • COMPUTER-AIDED DECISION MAKING • RESPONSE VERIFICATION AIDS
ENHANCED DISPLAY STRUCTURE	• HIGH-RESOLUTION DOT-ADDRESSABLE COLOR-GRAPHICS • TAILORED GRAPHICS • OPTICAL VIDEODISC • LARGE-SCREEN DISPLAY • ENHANCED TREND DISPLAY • INFORMATION DISPLAY STRUCTURE • SPATIAL DATA MANAGEMENT
EMBEDDED AIDING	• TAILORD GRAPHICS • OPTICAL VIDEODISC • VOICE RECOGNITION • NATURAL LANGUAGE • COMPUTER-AIDED DECISION MAKING • EMBEDDED PROCEDURES • RESPONSE VERIFICATION AIDS

Table C.1 Applicable Technologies

These technologies represent different stages of development as potential "products". Some are presently available from vendors and can be applied with no additional research and development. Others will require some degree of feasibility study and development before they can be successfully applied to the approaches discussed in this report.

An estimate of the availability of applicable technologies and techniques for the proposed man-machine interface enhancement approach is provided in Table C.2. The three categories of availability are defined as follows:

- Present--The technology or technique is proven in similar applications and presently available from vendors. A specification can be written to procure and implement necessary hardware/software. Only minimal development would be required to configure the components of the system.

- Near-term--The technology or technique is very promising and may be proven in prototype applications that are similar, but it probably cannot be implemented without prototype development and demonstration.

- Future--The technology or technique has been shown in research or laboratory settings but may not have been applied in any similar application. It would require a feasibility study for potential application and some additional research and development.

Some of the technologies are the subject of extensive research and development by research firms and manufacturers. Primary among these are high-resolution color-graphics, voice recognition, and computer-aided decision making (especially practical applications of expert systems). The analytic redundancy techniques for sensor diagnostics will require extensive software development. However, on-line system identification techniques for control reconfiguration due to actuator or sensor failure have been used in the aerospace industries. Major breakthroughs have been recently reported in the design of robust multi-input multi-output controllers which guarantee stability and robustness with respect to the sensor or actuator failures, and potential for a cost-optimizing controller. We predict that techniques exploiting these technologies will be implemented increasingly in complex, advanced control systems within the next five years.

Recommendations

The following are the specific recommendations for the next-generation solar plant:

- Conduct a feasibility study (cost/benefit) of analytical concepts for sensor malfunction detection.

- Design and evaluate color-graphics display options for alarm status representation, showing process and instrumentation diagram schematic, chronological listing of alarms and embedded aiding (built in help, procedures, and knowledge based decision making).

- Conduct a feasibility study of rule-based processor system for alarm analysis and operator aiding.

TECHNOLOGY AREAS	PARAMETER	AVAILABILITY
SENSOR MALFUNCTION DETECTION	PHYSICAL REDUNDANCY	PRESENT
	FILTER RESIDUAL	NEAR TERM
	ANALYTIC REDUNDANCE	NEAR TERM
	SYSTEM IDENTIFICATION	FUTURE
	RULE-BASED EXPERT SYSTEM	FUTURE
ALARM MONITORING	ANNUNCIATOR PANELS (HIGH/LIMITS)	PRESENT
	COMPUTER-BASED	
	• CHRONOLOGICAL LISTING	PRESENT
	• FIRST IN, FIRST OUT	PRESENT
	• FAULT TREES	PRESENT
	• SPURIOUS ALARM REDUCTION	NEAR TERM
	• FAULT/CONSEQUENCES	NEAR TERM
	• EXPERT SYSTEM	FUTURE
MAINTENANCE	CORRECTIVE	PRESENT
	PERIODIC	PRESENT
	PREVENTIVE (MTBF, MTTR)	PRESENT
	PREVENTIVE (TREND BASED)	NEAR TERM
	COST OPTIMUM (TREND BASED)	NEAR TERM
	EXPERT SYSTEM	FUTURE
CONTROLS (DESIGN AND IMPLEMENTATION)	SINGLE INPUT, SINGLE OUTPUT (PID'S)	PRESENT
	SELF-TUNING CONTROLLER	PRESENT
	ADAPTIVE CONTROLLER	NEAR TERM
	ROBUST MULTI-INPUT MULTI-OUTPUT (MIMO)	NEAR TERM
	ADAPTIVE TUNER	NEAR TERM
	FUZZY CONTROLS	FUTURE
	EXPERT-SYSTEM-BASED CONTROLS	FUTURE
MAN-MACHINE INTERFACE	• HIGH-RESOLUTION DOT-ADDRESSABLE COLORGRAPHICS	PRESENT
	• OPTICAL VIDEODISC	PRESENT
	• VIRTUAL FUNCTION KEYS	PRESENT
	• VOICE RECOGNITION	PRESENT
	• EMBEDDED PROCEDURES	PRESENT
	• TAILORED GRAPHICS	NEAR TERM
	• ENHANCED TREND DISPLAY	NEAR TERM
	• AUDITORY ANNUNCIATION	NEAR TERM
	• COMPUTER-AIDED DECISION MAKING	NEAR TERM
	• INFORMATION DISPLAY STRUCTURE	NEAR TERM
	• LARGE-SCREEN DISPLAY	FUTURE
	• NATURAL LANGUAGE	FUTURE
	• RESPONSE VERIFICATION AIDS	FUTURE
	• SPATIAL DATA MANAGEMENT	FUTURE

Table C.2 Availability of Technologies and Techniques

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