JUSTIFICATION OF DISTRIBUTIVE PROCESS CONTROL AND DATA ACQUISITION AT GIBSON GENERATING STATION

Presented to
the Industrial Management Faculty
University of Southern Indiana

In Partial Fulfillment
of the Requirements for the Degree
Master of Science in Industrial Management

By
Edward Joe Dick

May, 1990

Acceptance Page

Accepted by the Graduate Faculty, University of Southern Indiana, in partial fulfillment of the requirements for the degree Masters of Science in Industrial Management.

Augustine J. Fredrich ________________ date 4/24/90
Augustine J. Fredrich
Director of Engineering Technology

Larry D. Goss ________________ date 4/24/90
Larry D. Goss
Professor of Engineering Technology

JW McNeely ________________ date 4/24/90
Jeffery W. McNeely
Superintendent, Technical Services, PSI

TABLE OF CONTENTS

Figures

Abstract

Dick, Edward J. MSIM, University of Southern Indiana, August, 1989. Justification of Distributive Process Control and Data Acquisition at Gibson Generating Station.

On July 13, 1988, Public Service Indiana, an investor-owned utility, formed a task force to formulate a preliminary plan for future data acquisition and control system upgrades at Gibson Generating Station. The mission of this task force was to "look at available technology and map out a strategy to meet current and future needs identified by all departments."[1] The ensuing study provided the ground work necessary to convert a large generating station from an analog benchboard control system to a new distributive process control network.

This paper describes the strategic position of Public Service Indiana, including the need to improve the operating efficiency and operating availability of Gibson Station. It then describes the formation and final recommendations of the Computer Modernization Task Force. The paper identifies important advantages of new computer technology to the electrical power industry and provides an economic

---

[1]Gregory L. Hauger, Gibson Data Acquisition/Control Systems Upgrade, Inter-departmental mail letter, Gibson Generating Station, Public Service Indiana, 13 July 1988.

justification of the first phase of the plant computer control modification project.

Chapter 1

Introduction

Public Service Indiana is an investor-owned utility that provides electricity to 550,000 customers with a 69-county service territory that covers two-thirds of the state of Indiana. Public Service Indiana has a net operating capacity of approximately 6000 Megawatts (MW); 99% of the load comes from coal-fired facilities, consisting of two 500-MW units at Cayuga Station, two 40-MW units and one 60-MW unit at Edwardsport Station, four 160-MW units at Gallagher Station, four-635 MW units and one 625-MW unit at Gibson Station and six units ranging from 360 MW down to 100 MW at Wabash River Station. In addition the company has 81 MW of hydro-electric power at Markland Dam and 202 MW of oil-fired gas turbines.

On November 14, 1984, Public Service Indiana cancelled and abandoned two 1150-MW units at the Marble Hill nuclear power site near Madison, Indiana. The cost of the cancelled nuclear station was $2.72 billion. This setback brought the company to the brink of bankruptcy. Since the cancellation and abandonment of Marble Hill Station, Public Service Indiana has made a miraculous economic recovery by writing off Marble Hill as a loss, eliminating common stock dividends and deferring preferred stock dividends, acquiring an emergency rate increase and selling all salvageable equipment from the Marble Hill Station site.

Common equity for Public Service Indiana in 1985 was at a very low 9.8%.[2] By 1989, Public Service Indiana had raised its common equity level to 38%, still well below the industry average of 43%. The highest bond rating the company currently holds is a BBB+ rating. This bond rating needs to be improved because of major capital expenditures that probably will occur if acid rain legislation is passed in the near future. Between 1990 and 1994, Public Service Indiana is expecting to spend between $1.467 and $1.934 billion dollars to comply with Environmental Protection Agency requirements.[3]

In order to meet the huge expenses associated with the proposed acid rain legislation, Public Service Indiana is attempting to improve its cost effectiveness by implementing a cost containment program. In most electric utility companies, the majority of the cost is in construction or operation and maintenance of their power generating stations. When cost savings are sought at the generating station level, the main objectives usually are improvement to the station heat rate and operating

---

[2]Public Service Indiana, Annual Report 1985, Plainfield, IN, February 1986.

[3]PSI Holdings, Inc., Interim Report August 1989, Plainfield, IN, August 1989.

availability.

Gibson Generating Station. Public Service Indiana's Gibson Generating Station is one of the largest coal-fired generating stations in the United States (Figure 1). The five Gibson units combine for a maximum continuous net winter rating of 3165 MW. The total generating capacity of the Public Service Indiana distribution system is 6000 MW, which equates to Gibson Station providing 52.8% of the total capacity and over 60% of the actual load. Gibson Station is the newest generating station of the six company stations.

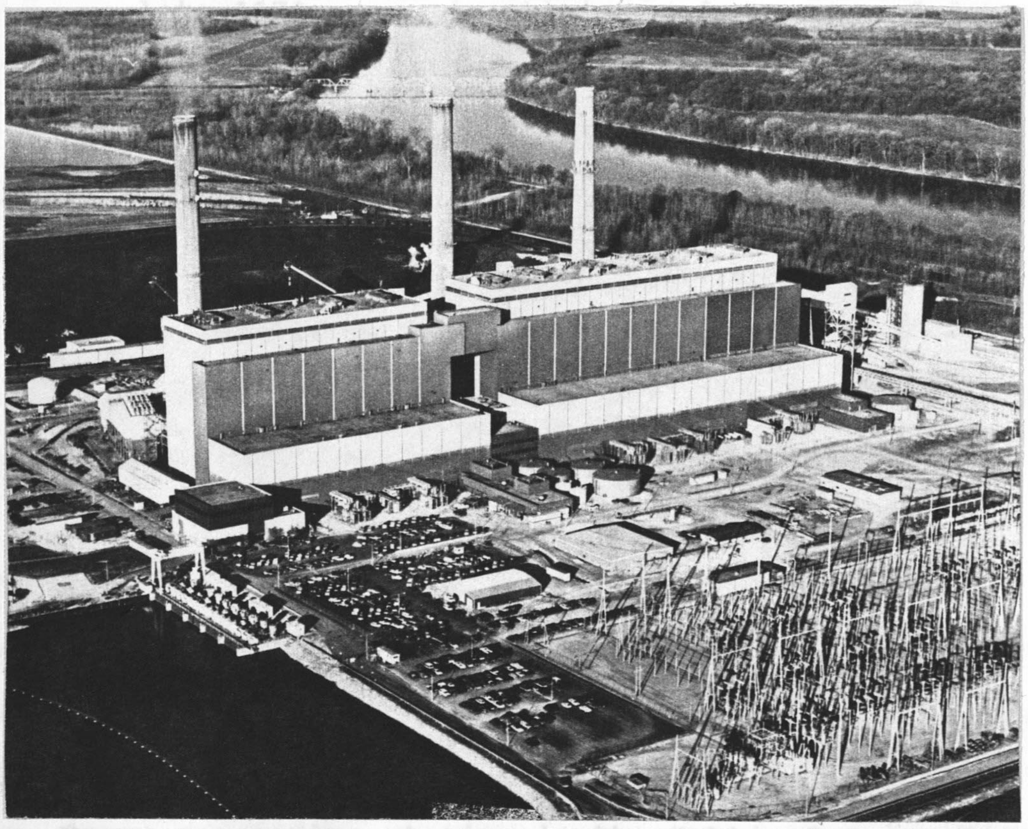


Figure 1. Gibson Generating Station.

The first Gibson unit became operational in March of 1975 and the last in August of 1982. Since Gibson Station is the newest generating station in the system it was designed to have better heat rate and availability than the older units.

Gibson Generating Station is one of the newest large stations in the United States. Design of stations the size of Gibson were curtailed or eliminated because of excess generating capacities nation-wide in the late 1970s and early 1980s. There were several reasons for the excess generating capacities:

1. A steady load growth from World War II until the late 1970s caused optimistic forecasts of future load growth.
2. An economic slow down associated with large industries going overseas.
3. A time lag of between five and ten years to build a fossil-fired power plant and over ten years to build a nuclear power plant caused the utilities to continue the plants that were already under construction.

By the time many utilities saw the trend in power consumption leveling off, there were already many plants under construction that would not have been economically feasible to stop.

Every generating station in the Public Service Indiana service territory is important, since each of them has an impact on the total generating capacity and the revenues of the company. The size, efficiency, availability and age of the equipment at Gibson Station make it imperative that the station perform well for the company to compete in a steadily increasing competitive marketplace. For these reasons it is easy to understand the impact that a modification or revision to improve the availability and heat rate at Gibson Station could have on the entire company.

Gibson Generating Station equipment. Gibson Generating Station has five units with similar boilers, turbines, and auxiliary equipment. The boilers are Foster Wheeler once-through supercritical units, with a maximum continuous rating of 4,588,000 lbs/hr steam flow at 1005°F and a pressure of 3550 pounds per square inch (PSIG) (Figure 2). The turbine-generators are General Electric tandem-compound, four-flow with 30-inch last stage buckets (Figure 3). Unit 5 is currently the only Gibson unit that utilizes a flue gas desulfurization system.

The Gibson Station units are located in two separate buildings, with units 1 and 2 in one building sharing a common control room, and units 3, 4, and 5 in another building sharing a second control room. The two buildings are joined by an administration building and by coal conveying equipment. The flue gas desulfurization system is located directly behind unit 5 and has three separate

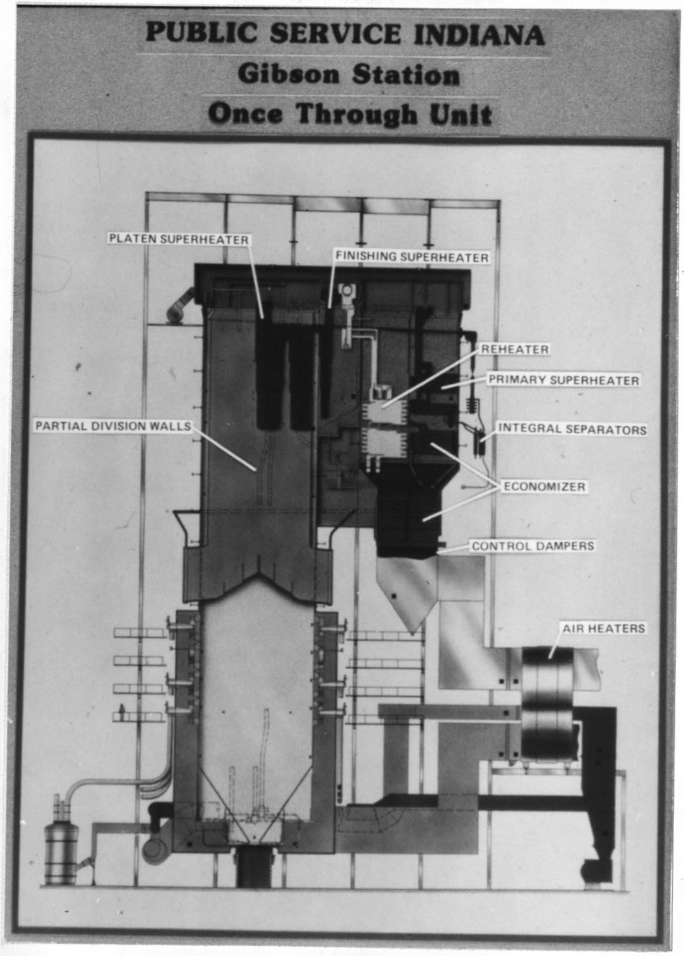


Figure 2. Typical Gibson Station boiler.

control rooms, one for "Air Quality Control Systems, Inc." equipment, one for "Control Systems, Incorporated," equipment and one for the ball mill equipment.

<u>Present controls and technology</u>. At present, Gibson Generating Station has a combination of analog, digital and distributive process control systems in the plant. The

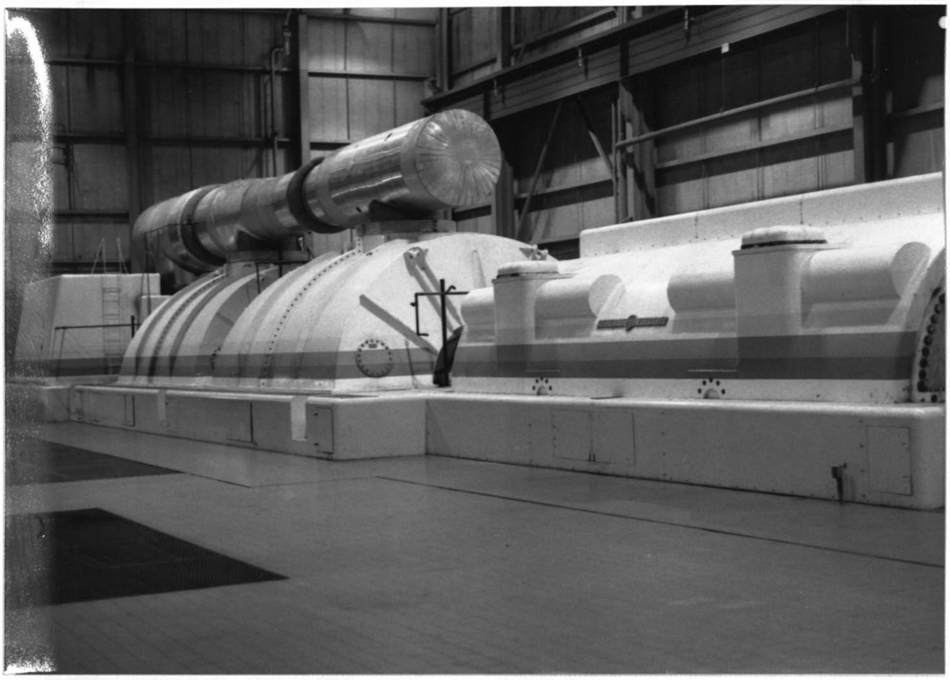


Figure 3. Turbine-generator on unit 2.

boiler combustion control system is a Westinghouse 7300 series. This system is a hybrid analog/digital control system. The turbine-generator controls are provided by General Electric Corporation. Units 1 and 2 have a Mark I Electro-Hydraulic Control (EHC) system; units 3 and 4 have a Mark II EHC system; and unit 5 has a Mark II Auto Mode Select (AMS) EHC system. The burner management system is provided by Forney Engineering Corporation. The first distributive process control system at the station is a Gould Modicon 984 programmable logic control system installed in 1987 and used in the coal handling facility. There is also a miscellaneous systems control package provided by Foxboro, the Spec 200 system.

There are several systems installed at Gibson Station that are used for operator alarms. These systems are: The switchyard supervisory system, consisting of an Advanced Controls System (ACS) digital system, used presently for scan alarm and log functions only; the main unit computer systems consisting of Honeywell 45000 systems on units 1 and 2, Westinghouse 2500 systems on units 3 and 4, and a Honeywell 4500 computer system on unit 5; and the overhead annunciator systems with each unit, supplied by Beta for units 1 through 4 and Rockwell International on unit 5. The installation dates for the computer systems are unit 1 (1986), unit 2 (1985), unit 3 (1978), unit 4 (1979), and unit 5 (1982).

Chapter 2

The Reason for Investigating Control Modernization

Changing controls technology. The instrumentation and controls on the oldest units at Gibson Station are fifteen years old. In the electronics industry, technology is moving at such a rapid pace that the instrumentation and controls manufacturers must always update their systems to stay competitive. This continual updating of controls makes it difficult for many manufacturers to maintain spare stock inventories for all of their older generation of controls and instrumentation. This places the consumer in the position of trying to maintain a stock inventory of spare parts while repairing the boards that fail, or purchasing new systems every ten to fifteen years.

When Gibson Station was built, the control and instrumentation philosophy was to use competitive bids for the major control systems. On small plant equipment packages, the vendor often supplied the controls associated with the plant equipment bid. This often caused the boiler turbine-generator (BTG) board to have a large number of different vendors' control equipment on the same board. The ergonomics involved with analog technology of this time period allowed multiple vendor equipment on the BTG board because most of the hard manual/auto stations (Figure 4), (Appendix A) were of a similar design.

The instrumentation and controls installed at Gibson

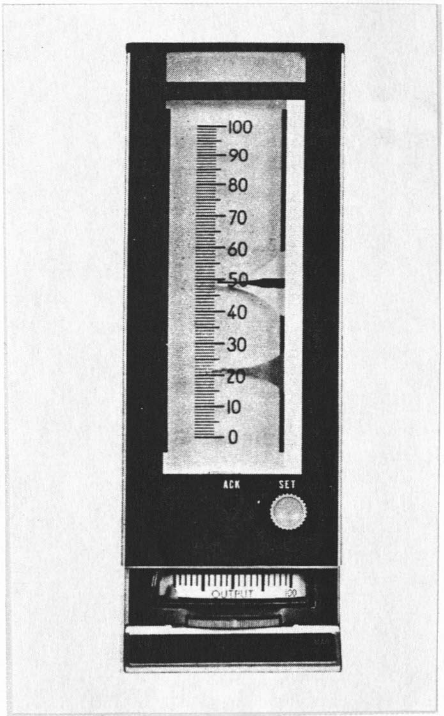


Figure 4. Hard manual/auto station.

Station were mostly electronic sensor devices with analog controller and signal conditioning boards. Relay and transistor/transistor logic (TTL) was used for permissives and sequencing, and very few pneumatic controls were installed. These instruments and controls were state-of-the-art in the early 1970s when they were purchased, but by the early 1980s when the last Gibson unit was being built the technology had changed from analog controllers to distributive process controls.

Analog control systems consisted of analog field signals being brought to the control system through an input/output cabinet; the control signal was then sent to the proper signal conditioning cards; from there it went to its controller, to an auto/manual station, and back to the input/output cabinet to be sent to the final field process that is to be controlled. All of the control cabinet cards are solid-state operational amplifier-based technology.

David E. Hamme and David O'Conner in a recent Electric Power Research Institute (EPRI) paper defined distributive process control as "multiple microprocessor hardware functionally and geographically distributed with multiple cathode ray tube screens."[4] The CRT screens are now the complete operator interface as the controls are handled by soft manual/auto stations from the control board (Figure 5).

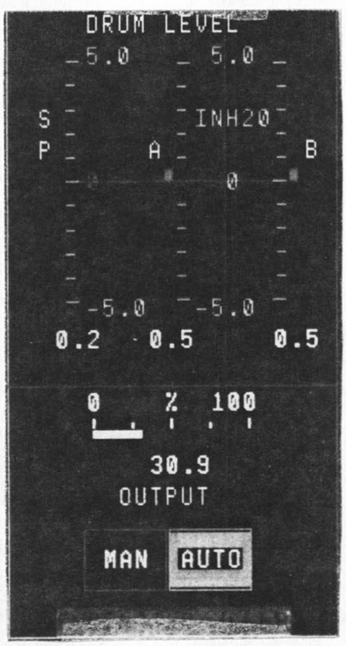


Figure 5. Soft manual/auto station.

---

[4] David E. Hamme and David O'Connor, <u>Today's Distributed Systems Capabilities</u>, EPRI Conference on Power Plant Controls and Automation, Miami, FL, 6-9 Feb 1989, p. 2.

The majority of control manufacturers began changing from analog control technology to completely distributive process control designs during the 1980's. The availability of spare parts for current analog systems became a major concern for many of the technical staff at Gibson Station and Public Service Indiana's Corporate Offices.

As the control systems became older at Gibson Station, the engineering staff and the individual maintenance groups responsible for maintaining the equipment began exchanging the old analog or digital/relay equipment with new controls. The new control systems were not being coordinated through a common department, therefore a plant-wide controls philosophy had not been developed.

The new digital equipment installed at Gibson Station was not of similar design and incorporated completely different operator interfaces. The different operator interfaces caused a learning problem for operators and resulted in increased spare parts inventories. It was soon apparent that a plant-wide instrument and controls philosophy must be developed at Gibson Station in order to meet the plant's objectives of improving plant operating availability, thermal efficiency, and to reduce overall costs.

Chapter 3

Formation of the Computer Modernization Task Force

Many informal discussions and formal meetings led to the decision to form an official company task force to investigate the available technology and develop a strategy to deal with Gibson Station's future control and data acquisition needs.[5] Greg Hauger, Engineering Manager at Gibson Station selected Edward Joe Dick, (author of this paper), as chairman of the newly formed task force. The duties of the chairman were to establish task force meetings, contact vendors, confirm field trips, acquire outside consulting services, direct activities of the task force and to keep station management informed on the progress of the group. At the first task force meeting the group selected the name, " Computer Modernization Task Force."

The Computer Modernization Task Force consisted of company personnel having different experience and background that had sometime in their careers been closely associated with the instrumentation and controls at Gibson Station. The members of the Computer Modernization Task Force were: Paul Doane, Superintendent, Instrument and Control, Gibson Station; Jeffery W. McNeely, Superintendent, Maintenance

---

[5] Gregory L. Hauger, Gibson Data Acquisition/Control Systems Upgrade, Inter-departmental mail letter, Gibson Generating Station, Public Service Indiana, 13 July 1988.

Planning, Gibson Station; Dennis M. Zupan, Senior Engineer, Instrument and Control, Corporate Offices; Edward J. Dick, Supervisor, Production Engineer, Gibson Station; Brian D. Wininger, Sr. Production Engineer, Gibson Station; and Mark Zatlokowicz, Production Engineer, Gibson Station.

The first directive of the task force was to investigate new technology. The new technology associated with instrumentation and control for power plant use was distributive process control systems.

Several of the leading control manufacturers in the utility industry were contacted by the task force to investigate the new distributive process control systems. These manufacturers were selected on recommendations to the task force by engineers within Public Service Indiana who had recent experience in the modernization of plants with new distributive process controls. The only control manufacturers that were considered were those capable of supplying a system to Gibson Station that could provide replacement controls for all of the station's current controls and provide design personnel with experience in design and start-up of supercritical boilers.

<u>New control and technology advantages</u>. Control system technology has been developing at a very rapid pace over the last 15 years and closely parallels the technological

advances associated with the electronics industry[6]. Many of the analog control and mainframe data acquisition systems purchased at Gibson in 1972 are not available for purchase today. A majority of instrument and control vendors have eliminated their lines of analog control and mainframe data acquisition systems and have replaced them with computer-based distributive process control systems. The following topics are a few of the technological advantages of the new distributive control systems.

Single operator interface. The operator interface is the control room instrumentation. This interface is used for communications between the operator and the equipment the operator is controlling. From the time period of approximately 1945 until 1970, the operator interface was a bench-board known as the boiler turbine-generator board or BTG board (Figure 6). The BTG board normally consisted of indicators, recorders, hand switches, and controllers located on a large steel bench-board for ease of operation. Around 1970, the first cathode ray tubes (CRT) began appearing on the BTG boards. These CRT screens were usually interfaced to a mainframe computer used for scan alarm and log functions[6].

The key to a properly designed operator interface is

---

[6]Hamme and O'Connor, p. 2.

[6]J. A. Moore, and Thomas C. Elliott, "SPECIAL REPORT, Control-Room Instrumentation," Power, August, 1988, p. 15.

Figure 6. BTG board Gibson unit 2.

human factors engineering. It is important that the interface between the operator and the equipment is properly designed to provide the operator with information in a rapid and easily understandable manner. Information is collected visually and audibly by the operator from the instruments located on the BTG board. The instruments must be located in the proper position to allow the operator good hand-eye coordination to make control adjustments from the information he received from the BTG board. It is important on a BTG board to have indicators and recorders located properly and of the proper size so the operator can see the values of the quantitative displays.

The operator must constantly monitor the length of the BTG board to determine if the equipment is operating properly. On large BTG boards the operator usually must walk from one end of the board to the other while monitoring the indicators, controller, annunciators, and recorders. It is possible for the operator to have events critical to the operation of the plant taking place at different ends of the BTG board at the same time. Even with an ergonomically designed BTG board it is difficult for the operator to properly respond to all of the information he receives because it is laid out over a large area.

Properly designed computer-based distributive process controls are considered superior to the BTG board design in the area of human factors engineering. All of the information and control functions available from the bulky BTG board and many more, can now be replaced by a small computer-based operator interface.

On the computer-based distributive process controls the operator interface consists of only a small group of CRT's and one or more computer keyboard consoles (Figure 7). All of the indicators that were formerly on the BTG board are now replaced by CRT screen information. This information can be shown in alphanumeric text on a color graphic display. The color graphic displays are computer-generated symbols that emulate the actual power plant equipment in

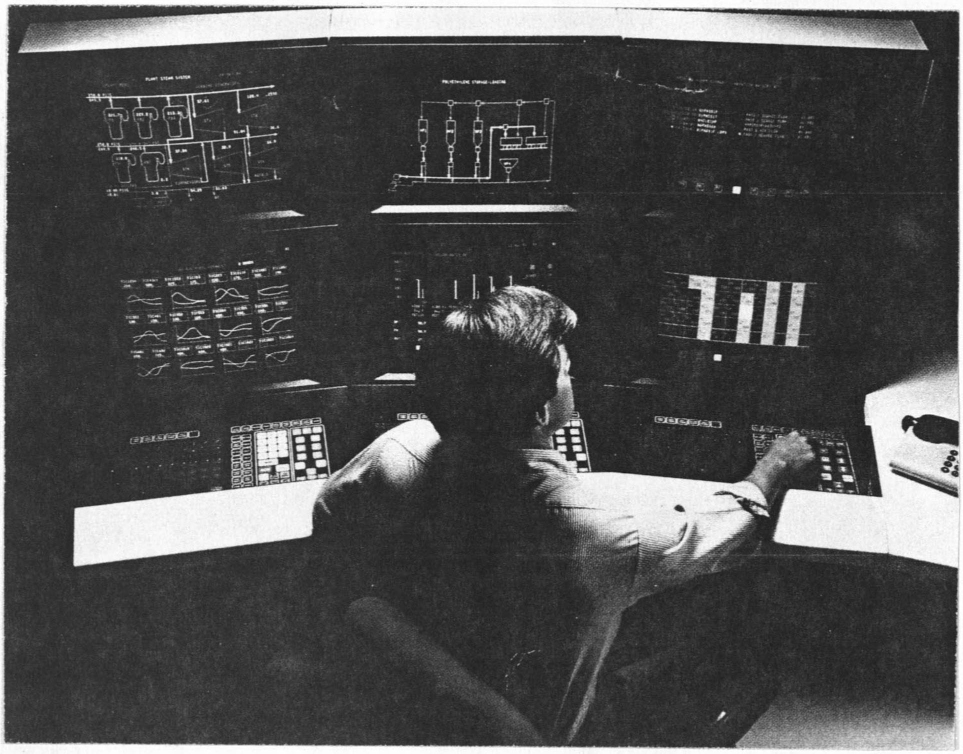


Figure 7. Computer-based distributive process control operator work station.

graphic and alphanumeric symbols that are easy for the operator to recognize and understand. The color is an added feature that can be used to help the operator distinguish different systems, alarm levels, or plant changes such as red symbolizing that a valve is open and green symbolizing that it is closed.

The control functions associated with the BTG board, normally an electrical hand switch to start a motor or a manual/automatic station, are now operated on the distributive process control board by means of the operator's console or through a touch screen. There are many advantages of using a CRT screen instead of a BTG board to control equipment and annunciate alarms. Many of the BTG boards were spread out over a large area in order for all of the controls and indicators to be located along the board. Computer-based distributive control systems allow the operator to remain stationary and select the different screens that he needs to operate the equipment.

The change in technology from analog BTG board technology to distributive process control CRT consoles is quite easy in a new plant where the whole system can be designed with a single control system and one operator interface. This becomes a large problem when dealing with instrument and controls modernization where many different types of controls with different operator interfaces are involved.

The single operator interface is almost essential when the different control packages are examined. If Gibson Station exchanged every control and data acquisition system with the original equipment manufacturer's new distributive control systems, there would be a total of seven operator interfaces for the operator to learn. With the new distributive process control systems, all of the different control systems can be added to a single operator interface. The single operator interface concept reduces the operator's learning curve by requiring that he learn only one interface system and one set of operating software.

Alarm management systems. In most power plant control rooms throughout the country, alarms are presented to the operators by annunciator systems that have windows with printed messages on them to provide operators with the nature of the incoming operational alarms. These alarms are triggered by digital contacts from field devices. When an alarm occurs, the window associated with the proper printed message blinks on and off from a light connected behind the window. An audible alarm is usually also sounded giving the operator both a visual and an audible display. In control rooms that have data acquisition systems, these alarms are usually also displayed on a CRT in an alphanumeric display and printed out on a computer printer.

The software associated with many distributive process control systems has alarm packages developed to allow annunciation and alarming to be handled from the CRT screen or from back-lit panels at the operator's console. The alarm message is brought to the operator instead of the operator having to scan the entire length of the BTG board looking for the annunciator alarm. The alarms on the CRT screen can also be prioritized by identifying the important alarms in a different manner than the less important alarms. In some systems the alarms will come in as different colors depending on the priority of the alarm. This allows the operator to quickly determine which alarm to respond to first. Another way to annunciate alarms on CRT-based data acquisition systems is to use the color graphic screen. The color graphic software is designed to blink, change color, and/or give audible signals to indicate an alarm condition.

Station hold out procedures. One of the big concerns in any manufacturing facility is the safety of its employees. In most major manufacturing facilities and power companies, a very rigid set of guidelines called hold card procedures is observed when shutting down equipment for maintenance. These procedures list the sequence of events necessary to disconnect all power sources from the equipment that needs maintenance. The operators properly disconnect the equipment and tag the devices that need to be "held out" so that others know the equipment is being worked on and should not be operated.

On generating stations that have BTG boards in their control rooms, most of the electrical equipment is started and stopped from the BTG board. When maintenance is to be performed on the equipment, hold cards will be placed on the proper power sources outside the control room as well as hold cards being placed on the start/stop switches in the main control rooms. A major concern of companies that exchange their BTG boards for a distributive process control system is how they could identify the equipment to be held out on the CRT screens. To contend with the hold card procedures at plant sites many of the distributive process control companies have developed a program that would:

1. Create a file on the computer control system listing all equipment held out.
2. Provide a visual status on the color graphic display that indicates the equipment is held out.
3. Inhibit the controls so equipment cannot be operated until someone with the proper authority removes the equipment from the "held" position.
4. Log the time, date and name of the authorized person who made the change.

The distributive process control hold card software becomes an enhancement for the operators because the equipment gets held out properly with greater accuracy in a shorter time period.

System expandability. The system architecture of the distributive process controls are designed so the control functions are executed in the software programs. If the system needs to be modified or expanded, input/output cards can be added, connected to a data bus, and new modifications can be made in the software programs. In analog and digital control systems like the ones at Gibson Station, the control functions are located on the individual integrated-circuit board cards and each change is made by moving components on the actual control cards. To expand the current control systems at Gibson Station, new input/output boards would need to be added for the new process to be controlled. The back planes of the control cabinets would also have to be altered by disconnecting and rewiring the existing controls. The manpower associated with hard-wiring the old control system is enormous, and errors could easily be introduced into the system.

Power plant mainframe computers are usually purchased with a number of spare input/output circuit boards available for expansion purposes. Most computer systems are supplied with between ten and thirty percent of excess capacity. When a mainframe computer runs out of available inputs and outputs, usually a system regeneration is necessary to expand the computer's capabilities. The system regeneration is usually completed by the original equipment manufacturer and is very expensive.

Redundant control capabilities. The ability to have completely redundant process controllers is probably the single most important advantage that the distributive process controls have over the older solid state analog control systems. In the analog control systems, the controlling signal was usually one signal from the field transducer through the entire control system and out to the process device being controlled in the field. This system allows for any single point of card failure in the control loop to cause a system upset on the final control element (Figure 8).

The new distributive process controls provide redundant

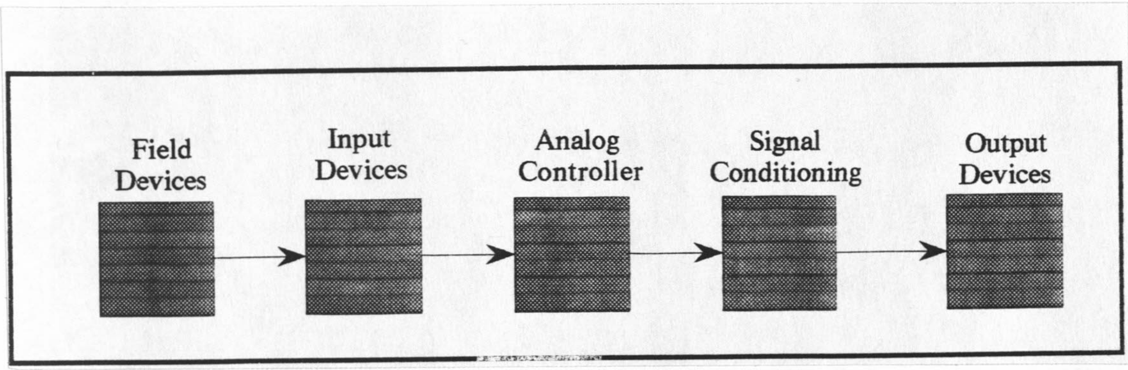


Figure 8. Typical analog control system.

control signals from the point that the transducer enters the input module until it is sent back to the final control element. This occurs by sending the control signal to a set of microprocessors. The main process controller receives the control signal and performs the control function. The process controller then sends the information to a data highway; the back-up process controller receives the same control signal at the same time as the main processor, but only sends information to the data highway in the event that the main process controller fails. From the controllers, the information is sent on redundant data highways to the final control devices and to the operator interface module if the operator selects it. The operator CRTs and keyboards are usually supplied in a redundant configuration. If any single point of failure occurs inside the distributive process system, it automatically switches to the redundant system, then tells the operator which card or system failed. The final control process is not affected by the single point of failure (Figure 9).

<u>Training simulator</u>. Training simulators were made popular by nuclear-powered generating stations because

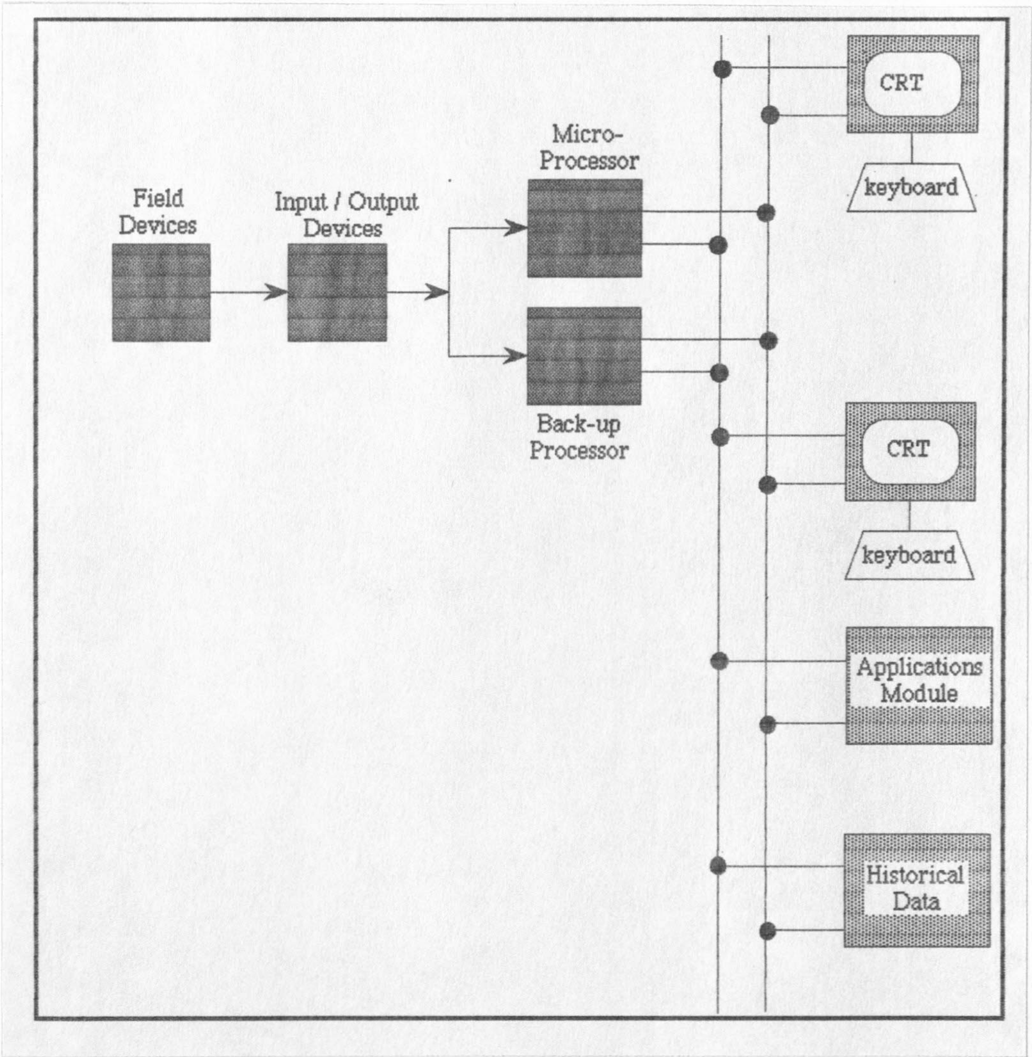


Figure 9. Typical distributive process control system with redundant microprocessor controllers.

simulators gave operators a chance to utilize "hands on" training without possible damage to the equipment or possible hazards to lives or the environment. The nuclear training simulators were a complete duplication of the BTG board of the actual operating unit. Large mainframe computers were utilized to make the simulated control system react as close as possible to the actual operating control system. Operating problems were entered into the simulators by instructors. Operators were then expected to take corrective actions to return the unit back to normal operation. A complete training simulator of this type costs between $10 and $15 million dollars.

On the distributive process control systems, the single computer-based operator interface makes any operator work station a possible training simulator. This is because all of the hardware needed to perform a unit simulation is accessible from the single operator interface. This operator station can replace the BTG boards filled with indicators, recorders, switches and manual/auto stations which are expensive and complex. All of the unit simulation can now be done by software which allows trainers to put unit upsets into the system for the operator to correct, play back the events to show the operator what actions he took and show the operator how the unit would respond if the correct operator actions were made. The cost of the hardware and software necessary to perform complete unit simulation with computer-based equipment and an operator interface is one-tenth as great as the cost with the BTG board simulators.

Performance calculations. Performance calculations are a set of mathematical equations used to determine the efficiencies of plant equipment. Performance testing in the past was accomplished by taking instrument readings visually and calculating the equations longhand or on a calculator. This method was very time consuming, and the accuracy of the instrumentation was often questionable. The accuracy of new plant instrumentation in conjunction with the computational abilities of modern computers make performance testing simpler and more accurate.

Performance calculations at a generating station are used to determine the thermal efficiencies of each unit by performing a heat balance. The equipment efficiencies measured during the heat balance are compared to unit design curves to determine if the thermal efficiencies have degraded. The performance calculations can be used to diagnose plant problems and determine where maintenance dollars should be spent.

Distributive process controls are not necessary to do plant performance calculations. Performance calculations are often included in computer and control upgrades because of the easy accessibility the computer system has to all of the instrument points in the existing data base.

Chapter 4

Field Research

Plant visits. The Computer Modernization Task Force investigated all of the technology that was made available to them through the instrument and control vendors chosen by the task force. These vendors were carefully selected on the basis of recommendations of other Public Service Indiana employees who have worked on replacement control systems for other plants. The second priority of the Computer Modernization Task Force was to visit different plant locations that were currently using distributive process controls to determine how successful the technology has been in the industry. Several items were of particular concern to Gibson Station management personnel; they were the basis for the following questions asked at all of the plants the task force visited:

1. Did redundant controls eliminate inadvertent unit trips? (See Appendix B for definition of unit trip.)
2. Did operator interface stations effectively replace BTG boards?
3. What type of operator and maintenance training was necessary?
4. Which maintenance group worked on the new controls?
5. Did the new controls provide better controllability and dependability of the unit?

In all, eight plant trips were made by the task force to help determine the feasibility of installing distributive process controls at Gibson Station. The plant sites were chosen from user lists provided by the vendors. Each vendor's equipment was represented at least twice among the various plants selected for visitation by the task force.

Synopsis of plant visits. The concept of totally redundant microprocessor controls and their effect on generating availability was the single most important item the task force investigated at each station visited. Seven of the eight plants the task force visited never experienced a unit trip as the direct result of a single component failure associated with the distributive process control systems. The one plant that did report lost power generation due to the new control system had an early design of controller that failed to switch to the back-up controller when the primary unit failed. This problem was rectified after several revisions to the microprocessor boards. Another plant experienced lost power generation associated with the control system. This failure was associated with a power supply surge that occurred when input/output cabinet fans were shorted to ground when being changed while the equipment was controlling an operating unit. The task force did not find a single case of lost generation associated with one of the three vendors involved in the research.

Each vendor appeared to have a different degree of problems with card failures. The vendor's equipment that did not cause any lost generation due to microprocessor redundancy also had a very low card failure rate. In one case, the plant claimed a seven-year period before a single card failed. The other two vendors' cards failed more frequently. One station budgeted $10,000 per month for card replacement cost. It is important to consider that the size of the data base at the different plants was not equivalent. One plant had a data base of close to 16,000 points and others had only a few hundred points.

The stations the task force decided to visit had a wide variation in the type of operator interface employed. Each of the vendors represented at the different stations were capable of enhancing the operator station through the use of color graphics and alarm management techniques. Only three of the eight stations were using the distributive process control operator interface stations to their full capabilities. Three stations were starting and stopping equipment from the CRT screen, and the same three were operating the units with soft manual/auto stations from the CRT screen. Only one station chose to add instrumentation to the BTG board at the same time they installed the new control systems.

On all units the task force visited that had been retrofitted with new controls, better controllability was achieved. This was not considered an unusual discovery because most stations received some control design enhancements to resolve certain control problems associated with the old control system. The analog control systems were susceptible to electronic drift that does not occur in the digital controllers.

Training of the operating and maintenance personnel was not an apparent problem at any of the locations the task force visited. The single operator interface concept makes training on the system easier than training on BTG boards because the same function keys are used repetitively on different CRT screen pages. Maintenance training is also improved because the number of different circuit boards is reduced. Maintenance is not performed on the individual discrete component level because intelligent diagnostics are incorporated by the microprocessors to identify the particular part of the system that contains the problem.

The issue involving which maintenance group should work on the new controls was a concern at every plant visited. The majority of generating stations across the country use two maintenance groups to work on electrical or electronic controls in the plants: The Electrical Maintenance Department and the Instrument and Control Department. The Electrical Department usually deals with high voltage equipment, relays and the controls associated with them, while the Instrument Department is involved in the maintenance of low voltage instrumentation, computers, and solid state controlling equipment. As the new distributive process control systems evolve, the equipment that once quite clearly belonged in one department or the other now is using the same technology to do the controlling of all equipment. Two of the eight stations visited by the task force joined the Instrument and Control Department with the Electrical Department, while the other six had their Instrument and Controls personnel do all of the work associated with maintenance of the distributive process control systems.

Seven of the eight plants the task force visited stated that their new control systems improved the overall availability and controllability of the plant. Each of the seven plants suggested that the control upgrades were extremely beneficial in the improvement of their plants.

All of the problems associated with the control systems were not the fault of the different vendors. Each of the different plants had a varying degree of engineering, planning, and prior experience with the new control systems at their plants[7]. Some of the plants visited by the task force designed the new control system operator interface in a manner that fully utilized the human factors enhancement

---

[7]Edward J. Dick, Paul E. Doane, Jeffery W. McNeely, Computer Modernization Task Force Update. Inter-departmental mail letter, Gibson Generating Station, Public Service Indiana, 30, November 1988.

capabilities of the system. These plants were able to minimize BTG board recorders, hard manual/auto stations, and indicators. Other plants utilized the distributive process controls for control only and actually increased the instrumentation on the BTG board.

Flue gas desulfurization control strategy. One of the early jobs of the Computer Modernization Task Force was to determine the feasibility of adding data acquisition and/or control to the flue gas desulfurization (FGD) (Appendix C) system on unit 5. The flue gas desulfurization system is a chemical process that removes sulfur dioxide from the boiler flue gas. This system utilizes three distinctly different processes. The first process incorporates a limestone slurry that is brought into contact with the flue gas in the absorber module (Appendix D). Then the sulfur dioxide is removed from the flue gas and mixed with the limestone slurry in reactor modules. This process is controlled from the Air Quality Control Systems control room (Figure 10).

The second chemical process involves dewatering the limestone slurry, and changing it from an acidic slurry into a neutralized powder substance so it can be taken to a landfill area. The area from which the dewatering process is controlled is called the Conversion Systems Incorporated control room (Figure 11). The third chemical process is the reactant preparation process. This process prepares the limestone slurry that is used in the absorber/reactor

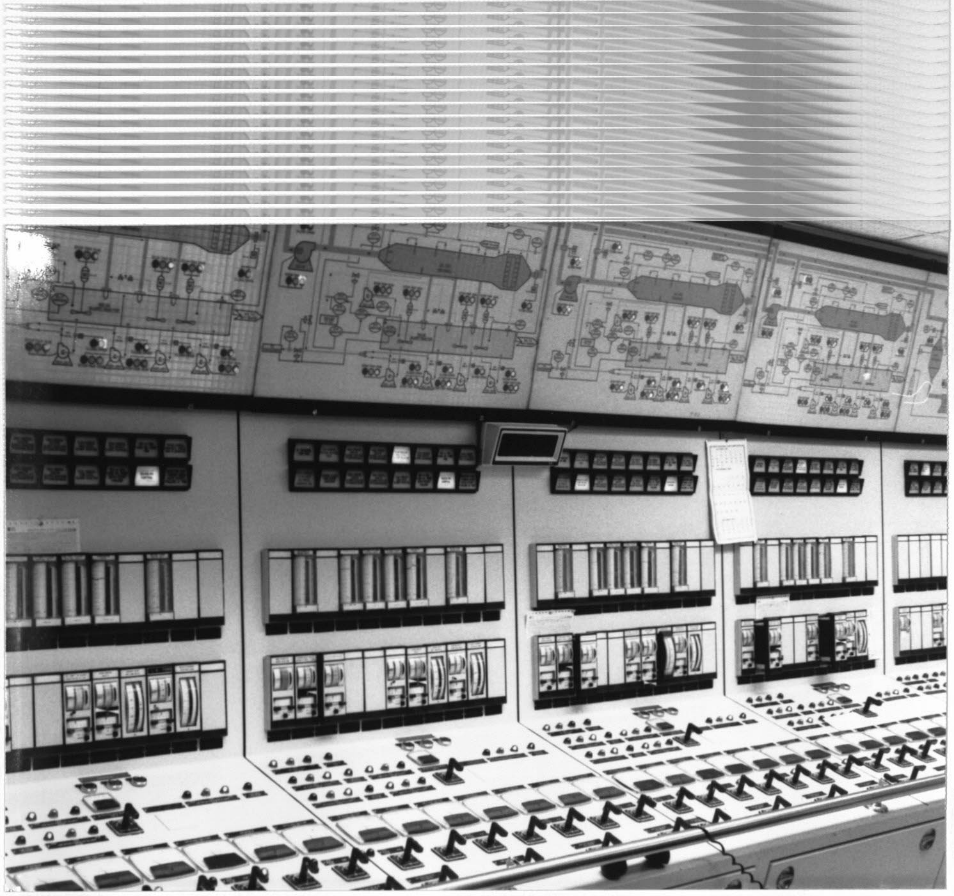


Figure 10. The FGD Air Quality Control Room BTG board.

equipment. The control room for the reactant preparation process is called the ball mill control room (Figure 12) because a ball mill pulverizer is used to grind limestone into a slurry.

Adding data acquisition to the FGD system was being considered because of its value as a log, alarm and scan device. If the system could reduce cost by providing operator alarming functions that could result in less equipment maintenance or improved FGD reliability, the system could easily pay for itself in a few years. Members of the Computer Modernization Task Force and others in management believed that other savings could occur if a full

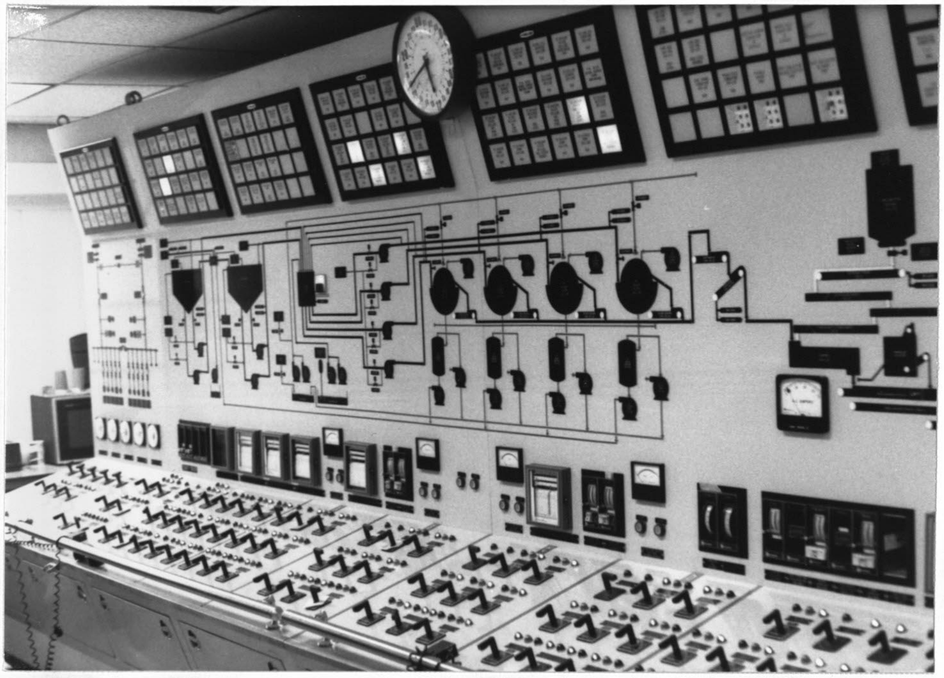


Figure 11. The FGD Conversion Systems Incorporated control room BTG board.

distributive process control system was installed to improve the overall efficiency of the process.

Since this was the first area that was examined in detail by the task force, the chairman of the task force decided to use an outside consulting engineer firm. The engineering firm was to verify the recommendations of the task force for the justification of the computer system for the FGD area. The services of Burns and McDonnell were retained to perform the FGD system study.

Burns and McDonnell's scope of work was to perform a study to determine the feasibility of replacing the existing

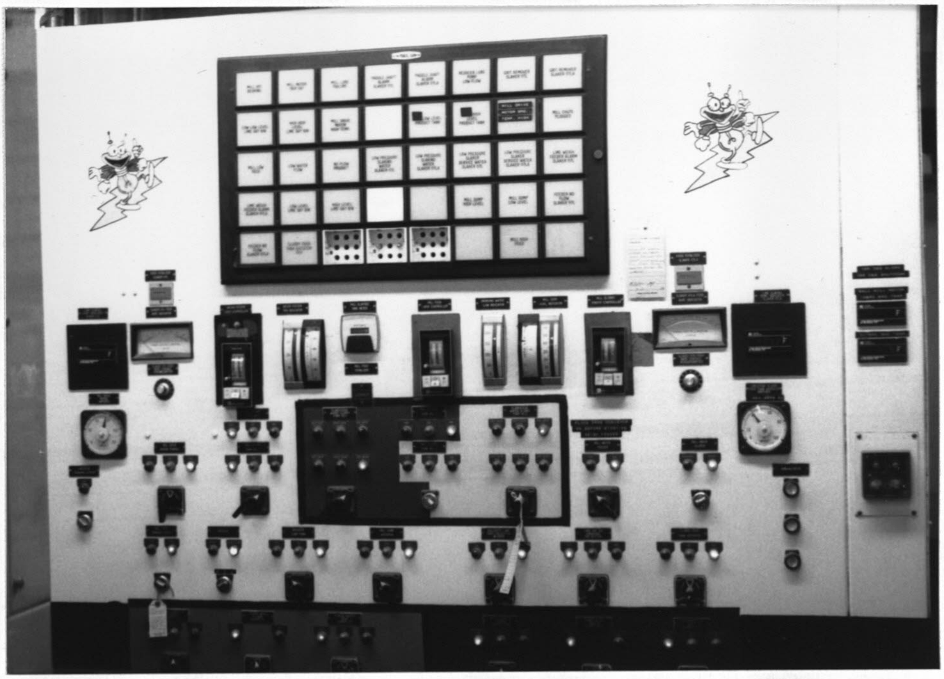


Figure 12. The FGD ball mill control room BTG board.

analog hard-wired control system with a distributed process control system and to:

1. Determine the appropriate control system architecture.
2. Determine the control system installed cost.
3. Perform a cost/benefit ratio economic analysis.

The main reason that plant management believed a potential savings existed by converting the old controls to a new distributive system was because of the original FGD design layout. It was perceived that the three current FGD control rooms could be replaced by a single control room using distributive process controls.

The Burns and McDonnell study concluded that the new distributive process control system could be installed for a cost of $1,105,438. This price includes hardware, programming, engineering, and installation. The break-even point for this project would occur in the fifth year with a ten-year net benefit of $977,770. The report states that the greatest savings from the installation of new controls would be a reduction of one and one-half operators per shift due to the consolidation of the control rooms[8].

A project of this magnitude, projecting a five-year pay-back period, normally would have been submitted to management for approval. This project was not submitted to management for approval because of the uncertainties associated with pending acid rain legislation. Currently unit 5 is the only unit at Gibson Station that requires a FGD system. Several of the bills that have been submitted to Congress could require between one and four additional FGD systems to be added at the station. The possibility of new FGD systems on other units at Gibson caused the task force to delay the new control system for unit 5 until after the new FGD systems are designed. The task force decided that by integrating controls and new FGD systems there would potentially be even greater savings in the future.

---

[8]Jack G. Passmore, P.E. "Gibson Unit 5 FGD Control System Study for Public Service Indiana, Inc.," Burns and McDonnell Engineering Co., January, 1989, p. 4.

Long term computer modernization plan. The original mission statement for the Computer Modernization Task Force was to develop a plan for future controls at Gibson Station. To accomplish this task, the members of the group assumed that every control system at the station had a useful life of 10 to 15 years and that eventually each system would have to be replaced.

The other major assumption the task force made was that there would never be a planned maintenance outage of long enough duration to completely equip a generation unit with new controls. The normal time frame of planned outages at Gibson Station usually is three to four weeks for a boiler outage, six weeks for a turbine high pressure/intermediate pressure overhaul, and six to eight weeks for a complete turbine overhaul. Using the time frame of the planned unit outages as a guideline, the task force determined that only one or two major control systems could be exchanged during each planned maintenance outage.

The computers on unit 1 and unit 2 were replaced in 1985 and 1986, because of poor reliability and the unavailability of spare parts. Unit 1, unit 2, and unit 5 have modern computers that utilize color graphics with four operator CRTs to assist the operator. The unit 3 and unit 4 computers are an older vintage of computer that does not have color graphic capabilities. The operator has two CRT display screens that are only capable of displaying alphanumerical text. Spare parts for the main computer system are still available for purchase, but much of the accessory computer equipment such as hard disk drives, operator consoles, magnetic tape drives and card readers is no longer available. The computers on unit 3 and unit 4 were selected as the first systems to be replaced.

The next control system considered for exchange was the boiler combustion control system. The combustion control system operates all the major control functions of the boiler except for burner management control. The combustion control system utilizes a load demand computer for selecting modes of operation, indexing the unit to the proper megawatt load and rate of load change. This signal is used to index the boiler master and turbine master controllers. The boiler master controls all the air, fuel, and feedwater controllers associated with the boiler. The turbine master controls the signal sent to the turbine control system to determine the proper turbine valve position for a given load (Appendix E).

The main problems associated with the combustion control system are a high card failure rate, setpoint drift, ambient temperature sensitivity, and the human errors and cost associated with system revisions.

Nine unit trips attributable to card failures occurred at Gibson Station between January and October of 1989. These nine unit trips cost the company $150,000 to $200,000 in replacement power cost alone. This does not include the cost of damaged equipment, unit thermal cycling, or start-up costs. As the control system becomes older, the card failure rate will probably increase.

Setpoint drift is a problem that is inherent in analog control systems. This is caused mostly by capacitors that change value as the components become older. Many of the setpoints that are associated with the combustion process are very important to the heat rate of the unit. A small change in the setpoint of main or reheat steam temperature can cause a large decrease in thermal efficiency.

The combustion control equipment at Gibson Station is very sensitive to heat and humidity fluctuations. There have been several occasions when units have tripped because of an equipment room air conditioning problem. On other occasions units did not trip but major equipment upsets occurred.

The combustion controls at Gibson Station are similar to most other hard-wired analog controls concerning problems encountered when revisions are made on the original design. Each new card installed must be hard-wired to the back plane of the printed circuit card assembly. This procedure requires many hours of manpower. Most analog integrated-circuit boards are made in a generic manner that enable several different functions to be performed on the same integrated-circuit board. To change the integrated-circuit board from one function to another involves removing or adding jumpers, resistors, capacitors and so on. The process of reconfiguring the integrated-circuit boards allows the potential for mistakes because of human error.

The task force also decided that the small miscellaneous control package would be changed at the same time as the combustion controls. The miscellaneous control package has a very low card failure rate. Its main problem is the unit 1 and unit 2 system cards are no longer being sold. All repairs to the integrated-circuit boards are being made on a discrete electronic component basis. If the circuit board is needed to operate a piece of equipment, the equipment will be unavailable for use until the circuit board is repaired. The preferred method of circuit board maintenance is to exchange the failed board for a new one which reduces down time and the chance for mistakes caused by trying to do a field repair.

The next major system examined for exchange was the burner management system. This system is responsible for the safe and reliable fuel burning associated with the boiler combustion system. This system is a digital transistor/transistor logic (TTL) system that can easily be replaced with programmable logic controllers. The main reasons for exchanging this system are the high cost of plant revisions and better plant safety associated with new standards, technology, and design philosophy.

Many advances have been made in the area of burner management control and many more will be coming in the near future. Several changes to field equipment associated with the burner management control system have caused plant personnel to realize how expensive it is to make the hard-wire changes necessary to modify the controls. A small digital logic permissive change for operating the oil igniters in a single igniter mode instead of a double igniter mode cost almost one-quarter of the cost of a new burner management control system.

The last major system to be added to the distributive process control system is the main turbine-generator and the auxiliary turbine controls. These controls do not have a high integrated-circuit board failure rate. Spare parts and qualified service personnel are difficult to find because of the limited number of new turbines that have been sold over the last ten years. The failure of the turbine manufacturers to sell new machines also has limited the number of control enhancements available to the customers. Only a small number of controls vendors have attempted to replace a complete turbine-generator control system because of limited personnel expertise and a small customer demand.

The first long-term plan developed by the Computer Modernization Task Force was mainly for budget purposes (Appendix F). This schedule is continually being changed as details of the controls upgrade are being revised.

There are many small control systems that are not included on the long-term plan schedule that may be exchanged during the same period of time. A decision must be made to either add these systems to the new distributive process control package or to buy less expensive stand-alone control systems. One of the major influences in this decision will be the necessity of the small systems to interface with other systems located on a plant-wide local area network (LAN).

A plant-wide LAN is a communications computer network, used to connect several different computers together for the purpose of sharing information. At Gibson Station the plant-wide LAN will be used to connect the individual plant computers together over a common communications network. The plant-wide LAN will allow information present on any of the plant computers to be accessible by any plant personnel using a terminal connected on the LAN.

Chapter 5

Economic Analysis

Defining analysis criteria. In March of 1989, the chairman of the Computer Modernization Task Force requested a meeting with station management to inform them about the progress of the task force. During this meeting, station management recommended that an economic evaluation be completed on the data acquisition and operator interface equipment necessary to establish a future plant-wide distributive process control system.

The economic evaluation was performed on phase one of the computer modernization project. This includes the addition of distributive-architecture data acquisition systems to unit 3 and unit 4, the modernization of the computer applications processor on unit 5 to allow a plant-wide local area network (LAN) link, the connection of all five units in a single plant-wide LAN, and a performance calculation package. The computers on unit 1 and unit 2 already have a distributive architecture.

An economic evaluation of a long-term project involving the upgrade of control equipment is difficult because the technology is changing at such a rapid pace. The original time frame established by the Computer Modernization Task Force was ten years, and even that period did not include all of the systems to be exchanged. Price fluctuations and equipment compatibility cause many uncertainties in the economic evaluation. The task force chairman decided to perform the economic evaluation on the first phase of the modernization project instead of the whole ten years.

If a savings from the performance calculations can be made to offset the cost of the data acquisition and plant-wide LAN, then the whole project could easily be justified. Phase two will be the controls portion of the project. This should be relatively inexpensive once the distributive-architecture and operator interface stations are installed. The cost of redundant microprocessor controllers to be added to the data bus purchased with the data acquisition system could have a payback time of one to two years for the control equipment. This payback for control equipment will come from generation that the station would lose when a single card failure occurs in an analog control system as compared with no loss of generation with redundant microprocessor controllers.

The economic model. The levelized fixed charge rate (LFCR) method was used for the economic evaluation of the phase one computer modernization project as illustrated in Table 1. This method is used to levelize the revenues necessary to cover the cost of capital expenditures over the expected life of the project. This fixed charge rate is also expressed as a fraction of the initial investment and results in a constant cost over the life of a project. The LFCR is a fixed cost that includes depreciation costs, rate

Table 1.

Computer modernization project costs

YEAR	LEVELIZED FIXED CHARGE RATE
1990	$528,240
1991	$528,240
1992	$528,240
1993	$528,240
1994	$528,240
1995	$528,240
1996	$528,240
1997	$528,240
1998	$528,240
1999	$528,240
2000	$528,240
2001	$528,240
2002	$528,240
2003	$528,240
2004	$528,240
Total cost	$7,923,600
PV 1990$	$4,029,504

of return, insurance and taxes[9].

The equipment for phase one of the computer modernization project will be installed in 1990. For purposes of the economic study, the economic life of the new computer equipment is estimated to be 15 years. The capital cost, excluding other constant costs used in the LFCR

"1989 Power Economic Evaluation Guide," Public Service Indiana Publication, 1989, p. 4-15.

method, for phase one is estimated to be $3,100,000. A discount rate of 12% was used for the study.

The $3,100,000 capital cost estimate used for the economic model came from a recent estimate for a computer installation at another Public Service Indiana generating facility. The estimate includes hardware, software, engineering and installation for the unit 3 and unit 4 data acquisition system, including input/output hardware, operator interface stations, historical data storage, sequence of events system and processors totalling $2,100,000. The upgrade to the unit 5 computer to make it compatible with the other distributive control systems is estimated to cost $400,000. This estimate was provided by one of the computer vendors. The cost associated with establishing the LAN is $350,000. The performance software and implementation will cost another $250,000.

The estimated maintenance savings is illustrated in Table 2, column 3. The maintenance cost savings are due to fewer component failures and less spare parts because standardization reduces carrying costs. Maintenance training costs also remain low because only one system must be learned by the instrument maintenance personnel which saves cost due to tuition, salary, and travel.

The impact on future developments is estimated at $50,000 per year. This impact on future developments is based on the costs associated with purchasing operator interfaces, data buses and other associated hardware and software for individual control systems instead of standardizing on a single distributive process controls manufacturer. Standardizing on a single system eliminates the need for expensive interface modules to connect the different control modules together.

The impact of the performance calculations is estimated to be an improvement of 25 British Thermal Units per Kilowatt Hour (BTU/KWH) per unit. The range of estimates for the benefits of performance calculations in the utility industry are very wide. A company Subject Matter Expert (SME) was used to establish these benefits for the economic study. The SME had experience in the results and analysis department at Public Service Indiana and was on several Electric Power Research Institute (EPRI) task force groups associated with generating station heat rates. Gibson Station currently does not utilize any performance calculation packages. The estimate of 25 BTU/KWH per unit is probably conservative.

The heat rate benefits in table 2 shows zero for 1990 because the equipment installation is in the fall and the performance calculation software will not be functional until the following year. The maintenance and future development benefits also reflect a fall installation date and are escalated at 5% per year.

Using the levelized fixed charge rate method shown in

Table 1, the present value (PV) for the cost of the new data acquisition system in 1990 dollars is $4,029,504. Table 2, columns 2, 3, and 4, show the annual benefits of the new data acquisition system, adjusted to reflect future inflation, the total benefits for each category, and the present value of the total benefits. The difference between the sum of the present value of the project benefits, $6,702,868, and the LFCR costs, $4,029,504, is the net present value (NPV) of $2,673,364.

Table 2.

Computer modernization project benefits

YEAR	HEAT RATE BENEFITS	MAINT. BENEFITS	FUTURE DEV. BENEFITS	TOTAL BENEFITS
1990	$0	$6,250	$12,500	$18,750
1991	$695,692	$26,125	$52,250	$774,067
1992	$723,279	$27,431	$54,863	$805,573
1993	$758,864	$28,803	$57,606	$845,273
1994	$812,785	$30,387	$60,774	$903,946
1995	$857,259	$32,058	$64,117	$953,434
1996	$904,590	$33,821	$67,643	$1,006,054
1997	$955,185	$35,513	$71,025	$1,061,723
1998	$1,004,148	$37,288	$74,576	$1,116,012
1999	$1,059,639	$39,153	$78,305	$1,177,097
2000	$1,134,409	$41,110	$82,220	$1,257,740
2001	$1,194,790	$43,166	$86,331	$1,324,287
2002	$1,258,065	$45,324	$90,648	$1,394,037
2003	$1,257,651	$47,590	$95,180	$1,400,422
2004	$1,336,109	$49,970	$99,939	$1,486,018
Totals	$13,952,465	$523,989	$1,047,977	$15,524,431
PV 1990$	$6,012,161	$230,236	$460,471	$6,702,868

The results of the economic model show that the new data acquisition system with performance calculations have a net present value of $2,673,364 over the fifteen-year period. The project has a benefit/cost ratio of 1.66:1 with a payback after 6.93 years. Figure 13 shows the total project cost for 15 years, the cumulative savings, and the cumulative costs. The break even point for the project occurs in 1997.

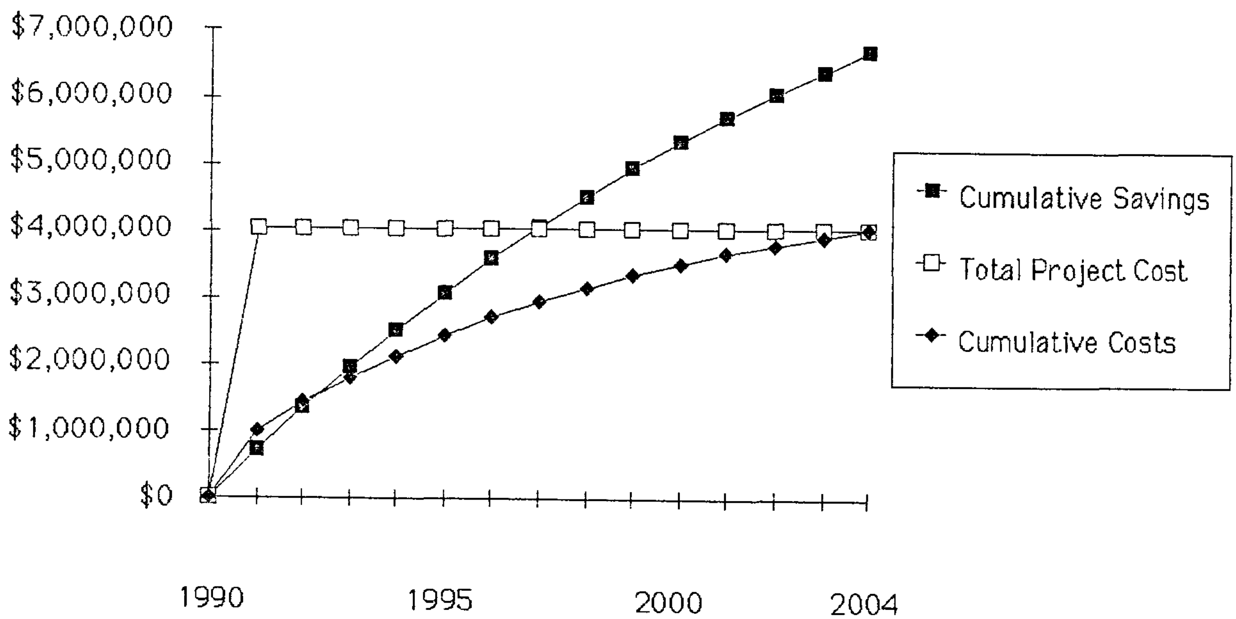


Figure 13. Benefit/cost comparison.

Chapter 6

Task Force Recommendations

Scope of work. A "scope of work" document was developed by the Computer Modernization Task Force to define the specific requirements necessary to complete phase one of the Gibson Station computer upgrade project. The scope of work describes the current data acquisition systems at Gibson Station and the data acquisition system boundaries, system architecture, functions, man-machine interface, application program options, engineering service requirements, and a project schedule.

The data acquisition system boundaries describe all of the current data acquisition and accessory equipment that must be replaced or modified on units 3, 4, and 5.

The equipment being exchanged on the data acquisition systems for unit 3 and unit 4 include the operator and engineer CRTs, consoles, printers, analog and digital input/output cabinets, the Central Processing Unit (CPU) and memory cabinets, and the spare CPU and memory cabinets.

The equipment being exchanged on unit 5 include the operator and engineer CRTs, consoles, printers, CPU, large core storage, magnetic tape cabinets, the moving head disk and the dual floppy disks. The unit 5 analog and digital input/output cabinets are compatible with distributive process control architecture and do not have to be replaced.

The system architecture of the data acquisition system will be an integrated system containing functionally distributed microprocessor subsystems. The systems requiring redundancy are the processors with the operator consoles, annunciator CRTs, internal power supplies, communications network processors and all future processors used for control.

The system architecture will also include communication capabilities that will enable information to be transmitted and processed on a data bus to be used in a plant-wide LAN. The plant-wide LAN will allow data, reports, and information to be transmitted and received from any man-machine interface connected to the data bus.

A Sequence of Events (SOE) system will be connected to the data bus. This SOE system will have one millisecond resolution for all digital points identified as SOE points. An SOE log will print the alarms in sequence of occurrence with respect to time.

The data acquisition functions section of the scope of work document, describes all the functions associated with the scan alarm and log functions of the data acquisition system. Some of the functions of the data acquisition system will include the following: Analog variable alarms; analog alarm cutouts; incremental re-alarming; operator logs; historical data storage and retrieval.

The man-machine interface is one of the most important aspects of the exchange of BTG board technology with the CRT distributive process control system technology. The new computer-driven CRT man-machine interfaces are designed as stand-alone consoles which causes problems when the system must be integrated with BTG board man-machine interfaces, as is the case at Gibson Station.

To gain the ergonomic advantages of the distributive process control systems, all control and data acquisition must be performed through the CRT man-machine interface. If the man-machine interface remains part-BTG board and part-computer CRT/keyboard the operator will interact between two separate interfaces causing loss of hand-eye coordination while adding unnecessary movement between tasks. To ultimately achieve complete CRT console operation, the Computer Modernization Task Force decided that in the first phase of the computer equipment exchange process alarm management should be handled entirely by the CRT console.

To obtain CRT console alarm management, the overhead annunciator display windows (Figure 14) will be eliminated and a combination of a computer-driven CRT touch screen and color graphic displays will be incorporated for alarm management.

Currently there are 300 annunciator alarm windows on each unit at Gibson Station. The number of alarm windows will be reduced to approximately 60 system alarms by internal processing using the system software package. All

Figure 14. Current overhead annunciator display.

annunciator alarms will then be sent to one annunciator alarm touch screen or a plant overview color graphic display screen. Each annunciator alarm will be directed to the proper alarm color graphic display when the operator touches the target that is blinking on the display screen. There will be different levels of display screens available to obtain detailed information on the events causing the alarm condition.

An example of a CRT console annunciator alarm system would be as follows: A boiler feed pump alarm is annunciated on a plant overview color graphic display screen (Appendix G). The operator acknowledges the yellow blinking alarm by touching the feed pump symbol in the lower center of the CRT screen (for this illustration the blinking alarms will be shown as the cross-hatched symbol on the black and white pictures); the feedwater system graphic appears showing the operator the entire system (Appendix H) involved in the alarm condition and showing which pump caused the primary alarm, again by blinking yellow. When the operator touches the blinking yellow pump this time, the individual pump color graphic screen will appear (Appendix I). This type of alarm hierarchy provides operators with graphic symbols and real time analog information in alphanumeric form to help the operator discover the system problem.

Another problem with the man-machine interface is the location of the controls on the BTG board with respect to the sequence in which the controls are to be exchanged. Combustion control is the first control system to be exchanged for distributive process controllers. When the combustion controls are taken from the BTG board and placed into the CRT console it will cause the operator to perform some control functions from the control board and some from the CRT console.

One particular problem for the unit operator would be starting or stopping a coal pulverizer. Currently, the operator manipulates the controls associated with the burner management system and the combustion control system to start or stop a coal pulverizer from the main control board. If the combustion controls are placed in a stand-alone CRT console away from the BTG board, two operators would be required to perform the task that previously only required one operator.

To avoid the problem of separating the operator from the CRT console and the BTG board, several CRT consoles will be integrated into the BTG board until all the essential control systems are converted to the CRT console (Appendix J).

The applications program options in the Scope of Work document outline a variety of software programs that are desirable but not a requirement of the new computer system. The applications program options include the following: Sootblower optimization; electric motor monitor; generator temperature monitor; turbine starting and loading program; rotating equipment vibration monitor; precipitator optimization packages.

The Computer Modernization Task Force decided to retain an outside consulting firm for the first phase of the computer modernization project. The cost of the expertise of outside consultants in a project of this magnitude is very small in comparison to the total project.

The outside consulting firm was retained for several reasons:

1. Phase one of the computer modernization project must be installed optimally because it is the foundation for entire control system exchange.
2. The complexities involved in writing the job bid

specification requires interfacing a variety of computers.

3. Engineering resources are limited because of a heavy work load and the current installation schedule (Appendix K).

Job bid specification. The scope of work document that was developed by Gibson Station personnel was used for technical reference by the outside consulting firm of Sargent and Lundy. The job bid specification was written to allow a competitive bid from each of the selected vendors. The job bid specification was sent to the bidders on August 30, 1989, to be completed and returned by October 27, 1989.

One of the key sections in the job bid specification was the section on performance calculations. A team of performance engineers from Gibson Station and Public Service Indiana's Corporate Offices developed the performance calculation section. The engineers directly responsible were: Edward Kramer, Senior Production Engineer, Gibson Station; Todd Muncy, Production Engineer, Gibson Station; and Ed Abbott, Supervisor Production Engineer, Corporate Offices.

The performance calculation section is the major factor in the economic evaluation that helped justify the computer modernization project. The emphasis for the performance calculation system was to help meet the corporate goals of being a low-cost producer of electrical power generation.

The performance calculation section includes complete boiler and turbine cycle monitoring, turbine cycle heat rate, turbine condition modeling, boiler condition modeling, boiler efficiency, boiler-pass cleanliness, operator controllable loss monitor, and maintenance controllable loss monitor.

New data acquisition implementation plan. After the Gibson Station data acquisition system contract is awarded, a team of engineers, operator training instructors, and instrument controls personnel will begin the task of developing the alarm management system and building an estimated 250 color graphic screens before the first computer installation date.

The color graphics will be designed on an operator work station that is to be shipped shortly after the award of the contract. This operator work station is to be an exact replica of the control room operator interface modules and will be a training simulator in the future. A room will be built in the Gibson Station training facility to accommodate the operator work station. Initially one training coordinator will be used to train operators on the new computer equipment. As controls and FGD systems are added to the plant, two more training coordinators will be added.

The team building the color graphic displays will design the displays with each priority alarm being displayed on an annunciator alarm screen, which is then linked to a secondary screen by a CRT touch screen. The graphics will be designed for alarm management and future control considerations. There is a time lag of approximately two years between the first data acquisition system and the first control system exchange. This time period will be used to train the operators on the new man-machine interface and color graphic alarm management system. By the time the first new control system is installed the operator should be familiar with the man-machine interface and the color graphics that he will use for control.

One of the advantages of using the new data acquisition system to do alarm management instead of the present annunciator is the elimination of a whole electrical equipment system. The elimination of the annunciator reduces the total number of electrical control equipment in the unit 3, 4, and 5 electrical equipment rooms by 19%.

All of the digital alarms in the plant currently are hard-wired to the annunciator input/output cabinets and then to the data acquisition system. This provides annunciator alarms and data acquisition alarms (Appendix L). To eliminate all of the annunciator cabinets, the wiring to the annunciator would have to be unwired and reterminated to the new data acquisition system. There are approximately 3600 digital points that would have to be rewired if the annunciators were to be removed. This would be very expensive because of extensive manpower requirements.

To eliminate the rewiring of all the digital points from the annunciator to the new data acquisition system, the task force decided to leave the existing digital field wiring and install plug connectors from the terminals to the new data acquisition cabinets.

The annunciator integrated-circuit boards would be removed from the annunciator cabinets, and termination blocks for the analog data acquisition points would be installed. The analog data acquisition points would also be terminated by plug connectors from the old annunciator cabinets to the new data acquisition system (Appendix M).

The old annunciator cabinets will now serve as a marshalling cabinet and provide wiring termination points for most of the data acquisition system. The advantages of using the annunciator cabinets in this manner are a large cost savings during installation, fewer wiring mistakes, and modularization of the data acquisition system by providing plug connections for all inputs to future data acquisition.

The Computer Modernization Task Force recommends standardization of all future controls to be of the same manufacturer as the data acquisition system whenever possible. If the standardization of equipment is not possible, the equipment will be interfaced to the existing operator interface. The standardization of equipment provides savings associated with fewer spare parts and less training needs. The single operator interface will reduce the cost of all future controls developments by reducing hardware and operator training costs.

The strategy of ultimately using the distributive process control computers to entirely replace the BTG board will reduce the maintenance and replacement costs associated with recorders, indicators, annunciators, hand switches, push buttons and so on. For each system eliminated, the associated spare parts are also removed from stock inventory.

The Computer Modernization Task Force recommends that only one maintenance group be responsible for the maintenance of the distributive process control systems. The single maintenance group seemed to work well at plants the Computer Modernization Task Force visited. The single maintenance group also requires less training expenditures and avoids problems associated with two maintenance groups being responsible for portions of the same controls hardware and software. This task could be accomplished by opening jobs in the instrument maintenance area to be filled by qualified personnel from the electrical maintenance area. The Electrical Maintenance Department would be used for high-voltage applications, switchyard, motor maintenance, and motor control centers. All of the distributive process control maintenance would be supplied by the Instrument Maintenance Department.

Human resource management techniques will be used to merge the two departments. When two groups of bargaining unit employees begin crossing established job duty boundaries, management must be careful to avoid conflict between the two groups. New job descriptions will need to be written and new job duty boundaries determined. The proper way to introduce this change in work scope to the employees would be to unfreeze the current way they envision their job duties by slowly introducing them to the need for change. Then to change their perceptions of their jobs and teach them new skills through training. When the changes have been made, the last stage of change is to refreeze their thoughts on the change to ensure their behavior is permanent.

The apparent manpower requirements suggest that during the installation check-out and start-up of the new distributive process controls, manpower requirements will be high. The manpower requirements after the systems are installed will be decreased on the computer-based systems and increased on the transducer input systems. This change in maintenance strategy is primarily because the new computer-based controls have less hardware maintenance, while the trend toward improving plant efficiencies will put added emphasis on data accuracy.

Chapter 7

Future Applications

Controls modernization. Phase one of the computer modernization project should be complete by July of 1991. Phase one includes complete new data acquisition systems on units 3 and 4, operator interface modules on unit 5 and a redundant data bus connecting units 1, 2, 3, 4, and 5 on a plant-wide LAN. Phase one also includes a performance calculation package for all five units, historical data collection/retrieval and CRT annunciators with 100 color graphic displays (per unit) for units 3, 4, and 5.

At the completion of phase one of the computer modernization project, all five units will have the foundation necessary to support redundant distributive process control systems. Phase two of the computer modernization project will involve adding new operator interface modules to units 1 and 2, and replacing existing control packages with new distributive process control systems.

The control modernization strategy at many plants is to use the existing control design in conjunction with new distributive process control systems. This strategy will improve plant generating availability because redundant microprocessors will prevent a control loop upset caused by a single point of failure in the system. The plant generating efficiency will also improve because of the ability of the distributive process controls to achieve better setpoint accuracies than the analog control systems.

The controls design philosophy at Gibson Station is to redesign any control loop that will improve plant generating efficiency, availability, safety or start-up capabilities. The Computer Modernization Task Force will start working on the combustion controls system in 1990 shortly after the phase one data acquisition system is purchased. The following topics have not been discussed in detail by the task force and are issues to be presented to the task force by the task force chairman.

Combustion controls. One of the first issues to be discussed on the new combustion control system design is the concept of a sliding pressure boiler ramp. Currently the boiler pressure ramp (Appendix N) begins with the throttle steam pressure at 1200 Pounds Per Square Inch Gauge (PSIG) with a temperature of 875°F and a load of 90 MW. As the throttle steam temperature increases from 875°F to 975°F the throttle steam pressure ramps from 1200 PSIG to 3550 PSIG. The throttle pressure ramp is complete at a load of approximately 180 MW. This throttle pressure ramp is considered a 25% ramp because full throttle pressure is reached at 25% of full unit load.

In a sliding pressure combustion control design, the throttle pressure ramp would be over a wider control area, probably 60% of the range of full unit load. The throttle pressure ramp would still start at approximately the same place as the 25% ramp. The throttle pressure would vary from 1200 PSIG to 3550 PSIG between the load range of 90 to 440 MW.

The advantage of sliding pressure is an efficiency improvement of approximately 180 BTU/KWH at low loads. The efficiency improvement is a result of less throttling of the four throttle steam admission valves to the turbine during the sliding pressure ramp as compared to the normal throttle pressure ramp. The cost of adding the sliding pressure design to the combustion control package would be very inexpensive. The expense involved would be due to boiler valve design modifications necessary to implement the sliding pressure revision.

A different control scheme will be implemented on the boiler feedwater system in the combustion control area because the current design causes boiler feed pumps to trip and damages the boiler feed pump thrust bearings. The current control system provides a boiler feed water master station that controls three individual boiler feed pumps, two one-half capacity steam-driven boiler feed pumps and a one-third capacity motor-driven boiler feed pump.

During normal operation the boiler feed pump master controls the two individual steam-driven boiler feed pumps. If one of the boiler feed pumps trips, a unit load run-back circuit will decrease output to one-half load; at the same time the boiler feedwater master increases the boiler feedwater flow of the remaining boiler feed pump to provide the boiler with the feedwater necessary to sustain one-half load on the unit. The problem with the current design is that the remaining boiler feed pump is loaded at such a fast rate it causes a thrust condition on the boiler feed pump resulting in a boiler feed pump trip, a unit trip and occasionally a damaged boiler feed pump thrust bearing.

The original induced draft fan design at Gibson Station incorporated two-speed fan operation for improved efficiency at low-load operation. The two-speed fan operation was removed because of the inability of the control system to measure the speed of the fans and switch from low-speed to high-speed operation effectively. The new speed control logic of the induced draft fans will be designed for two-speed operation on units 1, 2, 3, and 4 (unit 5's induced draft fan motors have only single fan capabilities).

The two-speed induced draft fan system provides unit efficiency improvements at low loads because the low-speed fan coils consume less power than the high-speed coils. The original fan controls used a speed generator tachometer mounted on the end of the induced draft fan shaft to determine speed of the fan. When the tachometer failed, a unit upset would occur and usually cause a unit trip. Highly reliable magnetic speed pickups in conjunction with some logic statements identifying the motor run contacts can be used to eliminate the unit disturbances caused by the original fan controls associated with the two-speed fan operation.

Burner management controls. The control design improvements associated with the burner management system will mostly involve redundancy and fail-safe operation to improve fuel safety at the plant. The current burner management controls use digital TTL logic to provide the permissives for burner management. The current control scheme needs electrical power to actuate solenoid devices to close dampers or trip electrical breakers.

In the event of a unit trip, it is important to remove all fuels from the boiler to prevent a boiler explosion. The current fuel management scheme could not provide the necessary actions to remove fuel from the boiler if it was unable to supply power to actuate field devices.

In the event of a plant emergency, such as a fire, cables providing power to the burner management system may be damaged, preventing the trip signal from being delivered to the field device. A system will be designed to provide fail-safe actuation of field devices. Any loss of power will cause the field device to move to the safe position.

The current burner management system does not have redundant power supplies to the logic cards. One power supply feeds two pulverizer logic systems. A shorted field device could cause the loss of two of the five pulverizers necessary to accomplish full unit load. Since the digital logic needs power to actuate field devices, a power supply failure could cause equipment to operate in an unprotected mode. The new burner management system will have complete control redundancy. Some utilities are using triple redundant controllers instead of redundant controllers for burner management and turbine controls because of the importance of zero failures associated with these critical control systems. The issue of triple redundant controllers for critical control loops will be studied in depth during the evaluation process for the burner management and turbine control systems.

Coal handling controls. In 1987, the coal handling control system in the east and west track hoppers was replaced by a Programmable Logic Controller (PLC) distributive process control system that uses industrially hardened IBM consoles for operator interfaces. The installation of the system was initiated before the station had developed a philosophy on distributive process controls. The project consisted of exchanging many cabinets full of relay logic used for permissives to determine which coal belts could be operated and in which sequence they should operate.

The old relay control system was very costly to maintain as the price of the large relays and contacts steadily increased in price. The PLCs were a direct replacement for the relays, providing higher reliability at a lower price and greater operator awareness because of color graphic displays and diagnostic capabilities.

In 1990, the industrially hardened IBM operator interfaces will be exchanged with the standard operator interface determined by the computer task force. Each of the vendors bidding on the phase one computer modernization project can easily interface to the existing PLC controller located in the coal handling. The new operator interface will also make it possible to operate the east and west track hoppers from one operator interface console instead of two, providing potential manpower savings. The coal handling controls will probably be connected to the plant-wide LAN for easy access of coal weight scales and bunker usage information.

FGD controls. A preliminary plan is being developed by the Sargent and Lundy outside consultant firm for the development of additional FGD systems at Gibson Station. In the preliminary FGD system design, the new FGD controls will have the same vendor and system architecture as the system standardized by the Computer Modernization Task Force.

The control rooms will all be in the same building and consist of completely redundant distributive process control systems. Each unit will have one operator interface module in the control room. There will be no BTG boards. The FGD controls on unit 5 will be exchanged in conjunction with the addition of the new FGD control systems.

Artificial intelligence. Artificial intelligence and expert systems incorporate computers to help the operators make intelligent decisions about information provided to them about conditions in the plant. One system that will be incorporated at Gibson Station is intelligent alarm capabilities.

Most new data acquisition systems provide alarm capabilities for re-alarming at incremental analog value changes and contact cutouts. Contact cutouts provide a digital contact that shows the status of a piece of equipment to determine if any alarms should be in an alarm condition. The new data acquisition system at Gibson Station will have 1500 points per unit capable of utilizing digital logic statements to determine if an alarm should be in an alarm state.

"Smart targets" is another form of artificial intelligence that will be used at Gibson Station for control. In certain situations when conditions exist that require immediate operator action, a smart target may be used from the CRT touch screen. A smart target is an area that only appears on the CRT screen when certain abnormal conditions exist. The operator may choose to use the smart target to initiate an action to correct the current problem.

An example of a smart target would be an alarm statement that reads "Separator level high. Would you like to automate the "D" valve?" If the operator decides this would be the proper operator response, then touching the screen in the designated smart target area would put the "D" valve into the automatic operational mode.

An expert system is an intelligent computer software-hardware system that incorporates the intelligence of an expert into the decision making process. An example of an expert system would be: A thrust bearing metal temperature reaches an alarm level on a piece of rotating equipment. The computer has already been programmed to answer questions and ask other questions just as if an expert in rotating equipment were present. The operator would request information involving the thrust bearing metal temperature alarm. The computer may then ask for the operator to enter a variety of information such as the equipment speed, thrust bearing drain oil temperature, vibration reading, and so on. After the information is entered, the computer will give the operator an explanation of the problem or an action such as removing the piece of equipment from service.

Expert systems are being developed by many different groups. The drawbacks to an expert system are that the system is only as good as the expertise of the person or persons used to gather data about the equipment and the expertise used in writing the program. The other obvious problem is that all the possible combinations involved in solving the problems could never be entered into the computer. The best use of an expert system is to guide the operator in the right direction to solve reoccurring problems that have been previously diagnosed by the expert. The expert systems should be used as a training aid by the operators to help them expand their knowledge about the plant equipment and systems.

Chapter 8

Results

The Computer Modernization Task Force was established to determine the future computer and control needs for Gibson Generating Station. Since the Computer Modernization Task Force was formed, the station has a developed strategy for the next ten years for control modernization. A data acquisition system with redundant distributive process architecture and a performance calculation program for units 3, 4, and 5 is presently in the job bid evaluation process. The computer modernization contract will be awarded December 12, 1989.

The recommendations of the Computer Modernization Task Force meet the corporate goals of establishing Public Service Indiana as a low-cost producer in the electrical power industry. Cost savings will be realized by improving plant generating efficiency, availability, spare parts inventory, information flow, and reducing manpower requirements.

The reason the Computer Modernization Task Force was successful in attaining the goals it set out to accomplish is because of the following:

1. The proper personnel were utilized for the task.
2. The proper resources were utilized.
3. There was complete support for the project by the entire plant management.

4. The entire task force endeavor was a group effort instead of an individual effort.

Appendices

Appendix A

Definition of the terms hard and soft manual/auto stations. The term hard manual/auto station describes the operator interface device used by plant operators to control processes in an operator selectable mode of manual control or automatic control. The term hard manual auto/station began when computer-based control systems started using the cathode ray tube (CRT) screen as the operator interface via computer software. A hard manual/auto station would usually consist of several meters or light emitting diode displays that show the controlling process signal and the desired set-point signal. Several buttons associated with the manual auto/station would allow the operator to select manual operation to change the set-point signal, or automatic to let the control system control the set-point. The hard manual/auto stations are hard-wired to the control system and are often placed on a boiler turbine-generator (BTG) board.

A soft manual/auto station would be located on a CRT screen. The soft manual/auto station works exactly as the hard station except the operator selects the station using the computer-based operator interface and operates the soft manual/auto station via the touch CRT screen.

Appendix B

Definition of the term Unit Trip. A "unit" at a fossil-fired generating station consists of a steam supply, a turbine-generator, and auxiliary equipment that is necessary to generate electricity to an electrical distribution system. A "unit trip" is an event that causes a generator to be electrically disconnected from its electrical distribution system.

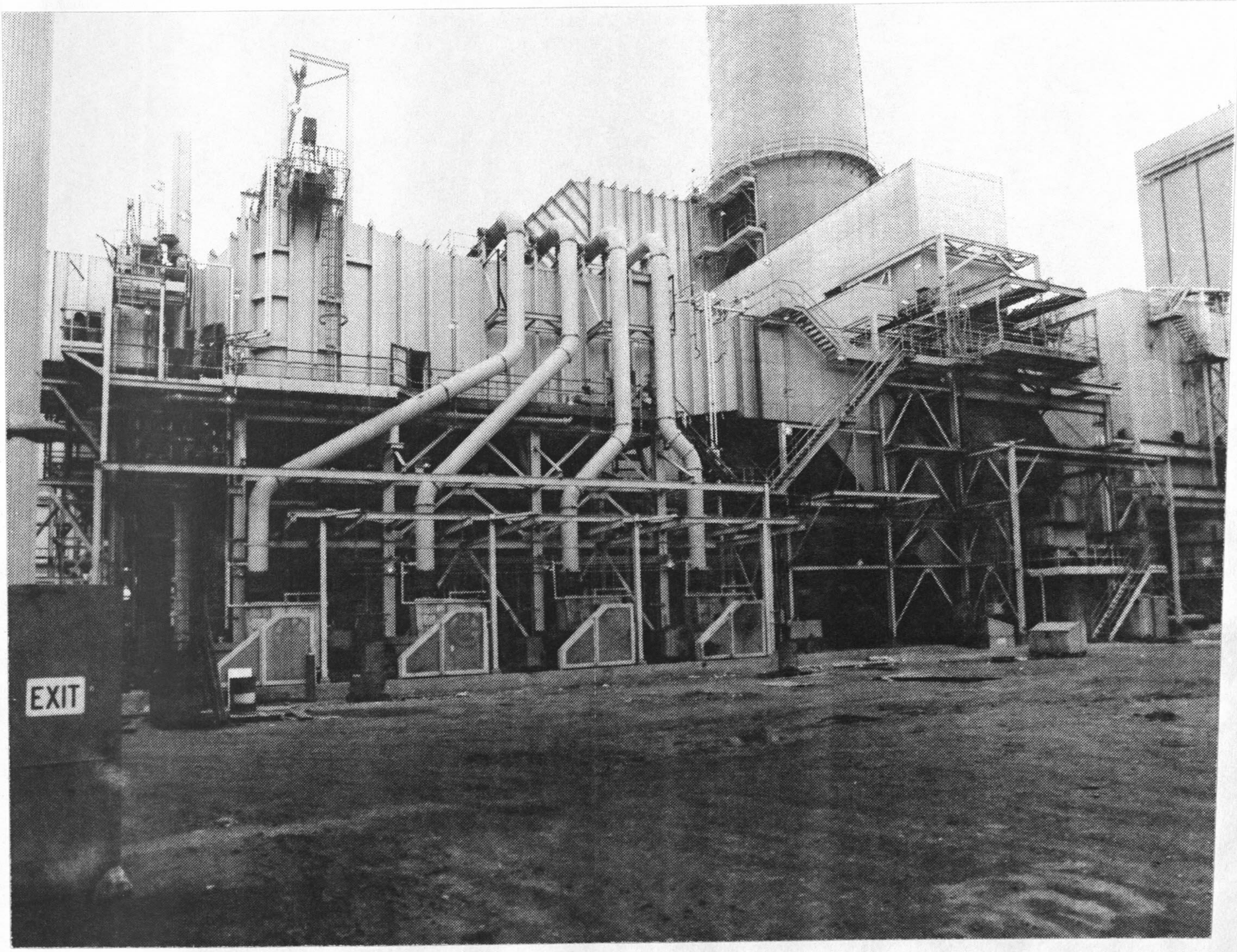
Many protective controls are added to these generating units to prevent injury to personnel or damage to equipment, when safe operating parameters are exceeded. A unit trip may occur automatically as programmed in instrument control devices or may be initiated by an operator. A typical unit trip would cause all of the steam admission valves on the turbine to close, taking the mechanical energy away from the generator. At the same time, the dampers or valves allowing fuel into the boiler would close, causing the flames in the boiler to extinguish. Bottled-up steam pressure would be relieved by venting it to the atmosphere or to a condenser. When the generator is no longer able to generate electricity, the main breakers that connect it to the electrical distribution system are opened.

Appendix C

Unit 5 flue gas desulferization system.

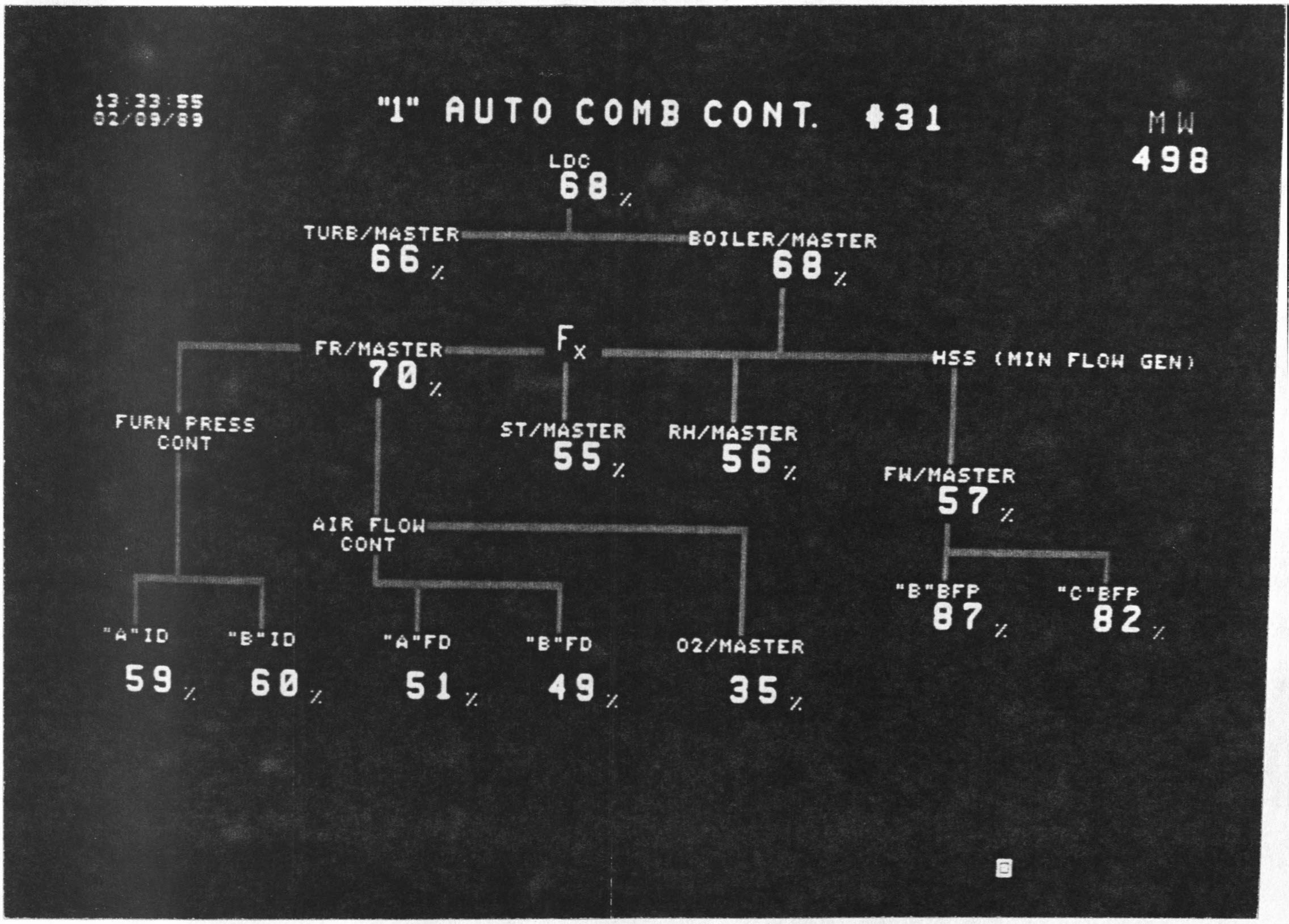
Appendix D

Unit 5 absorber/reactor module.



Appendix E

<u>Combustion control master stations</u>.



Long Term Computer Modernization Plan

Year	1990				1991				1992	
Quarter	1	2	3	4	1	2	3	4	1	2
Coal Handling Controls	*****	****	****							
System Devlopment Training	**	* *	**							
System Maintenance Training	*	****	*****	****						
System Operator Training		****								
Unit 5 Data Acquisition			**							
Unit 4 Data Acquisition				***						
Unit 3 Data Acquisition					*	**				
Unit 2 Combustion & Misc. Controls										
Controls Development Training										
Operator Controls Training										
Unit 1 Combustion & Misc. Controls										
Unit 4 Combustion & Misc. Controls										
Unit 5 Combustion & Misc. Controls										
Unit 3 Combustion & Misc. Controls										
Unit 4 FGD Control										
FGD Operator Controls Training										
Unit 2 Burner Management										
Unit 1 Burner Management										
Unit 4 Burner Management										
Unit 3 FGD Control										
Unit 5 Burner Management										
Unit 3 Burner Management										
Unit 2 FGD Control										
Unit 5 FGD Control										
Unit 1 FGD Control										

A

Long term com

			1993				1994				1995				1996			
2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4
				***														
			****															
			****															
					**													
						**												
							**											
								**										
									****									
								****										
									**									
											**							
												**						
														****				
														**				
														**				

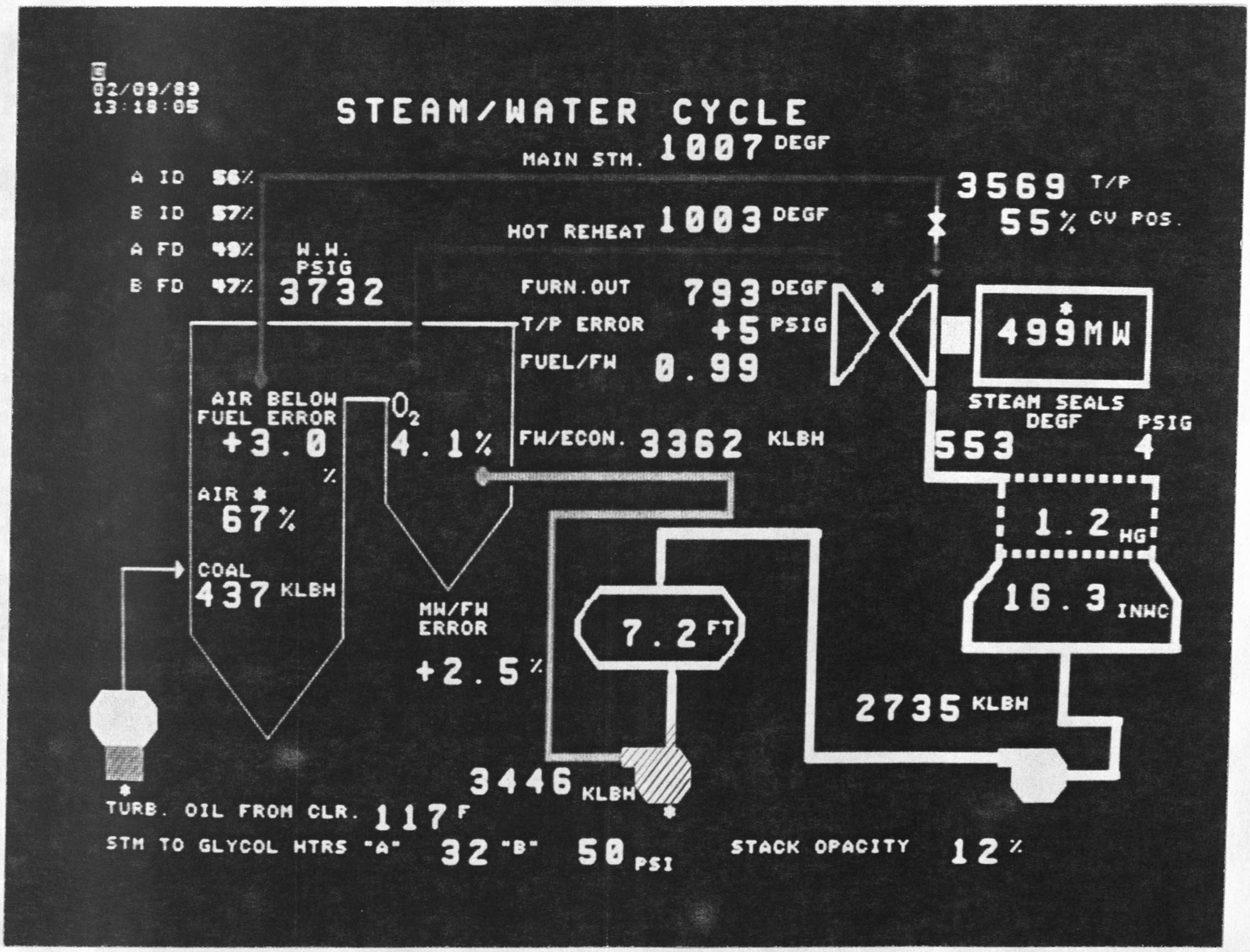
Appendix F

<u>Long term computer modernization plan</u>

			1995				1996				1997				1998			
	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4
	****																	
*																		
	**																	
			**															
				**														
						****												
						**												
						**												
											****							
														****				
																	****	

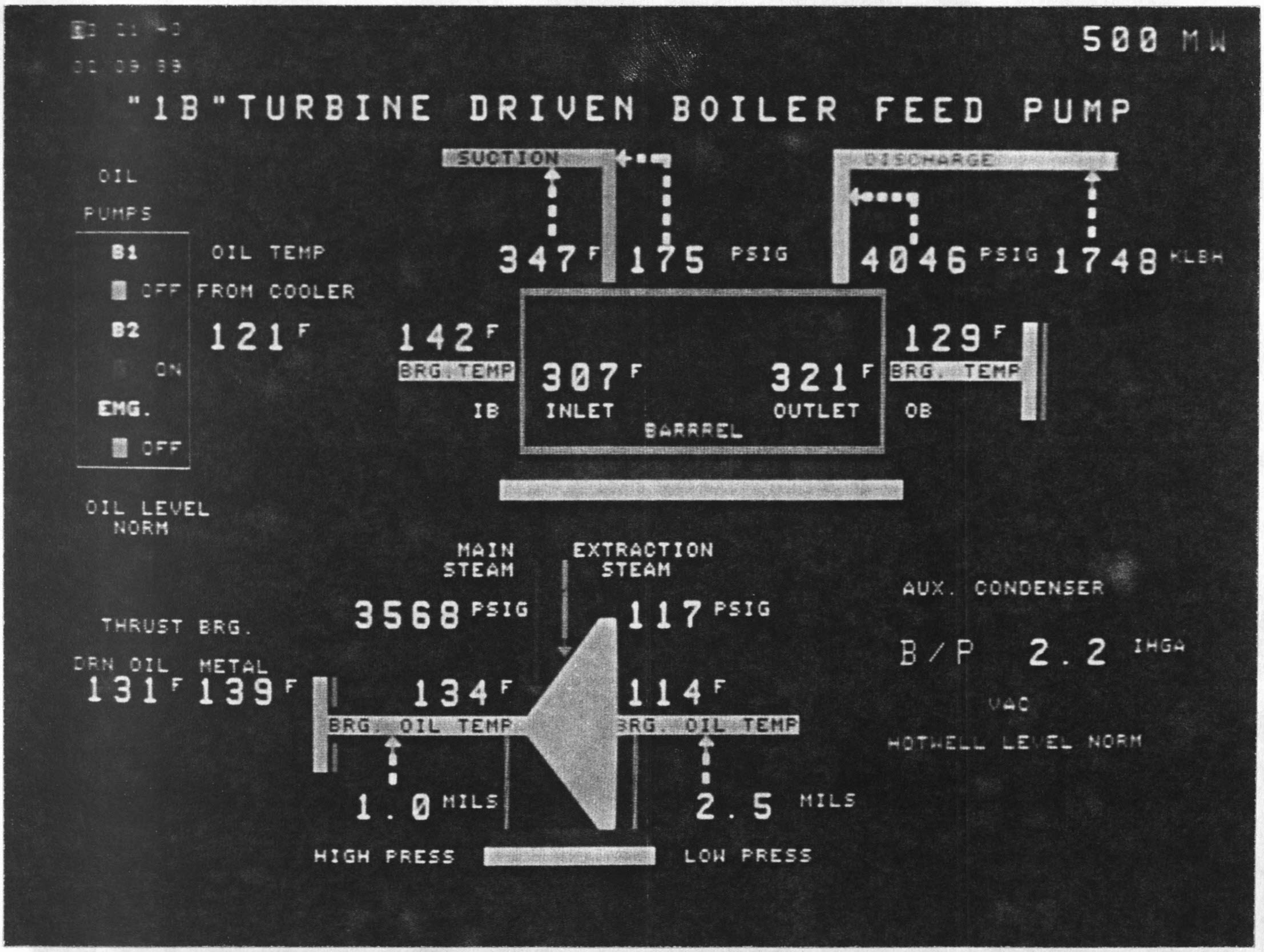
Appendix G

Plant overview CRT display screen.



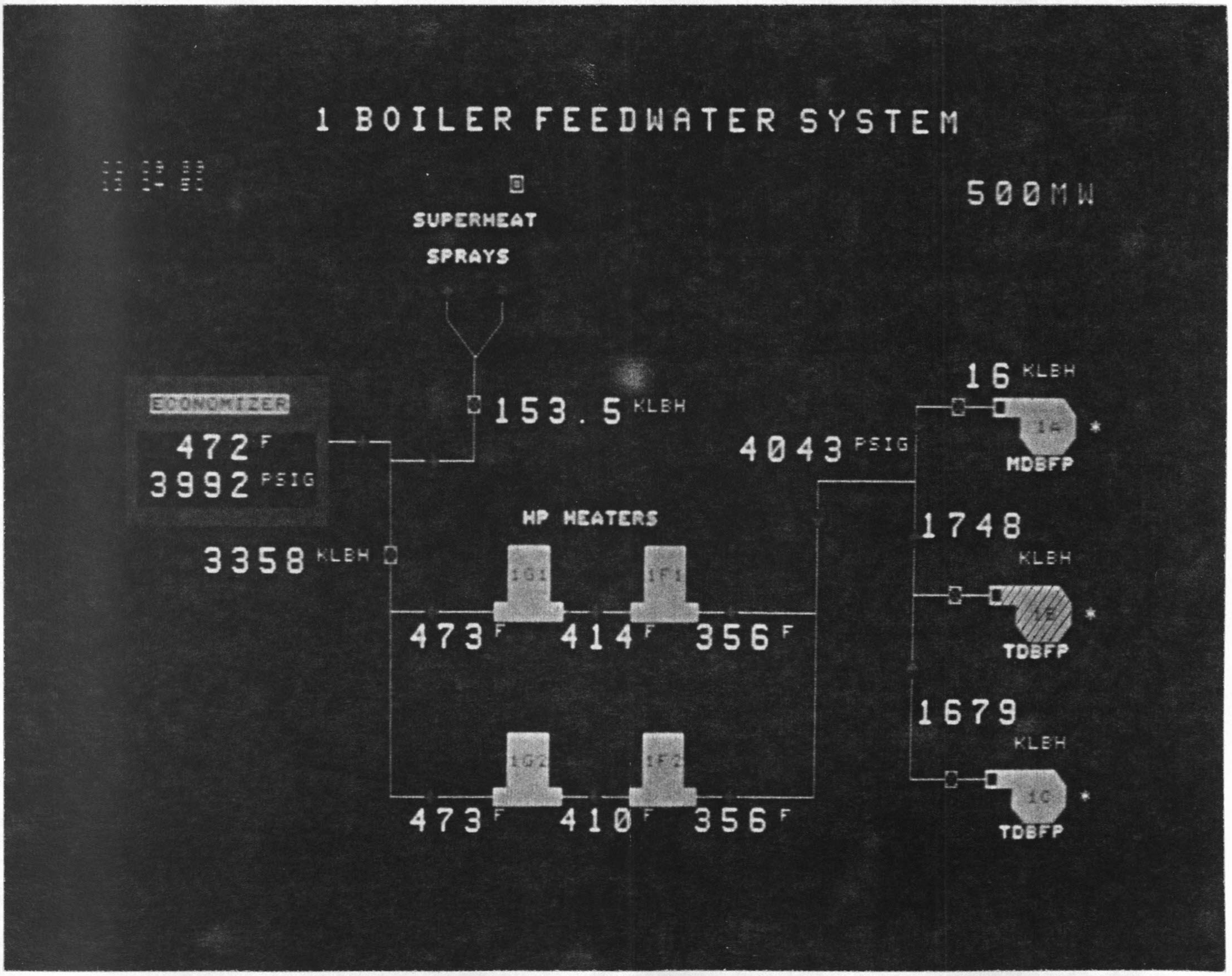
Appendix H

Boiler feedwater system color graphic display.



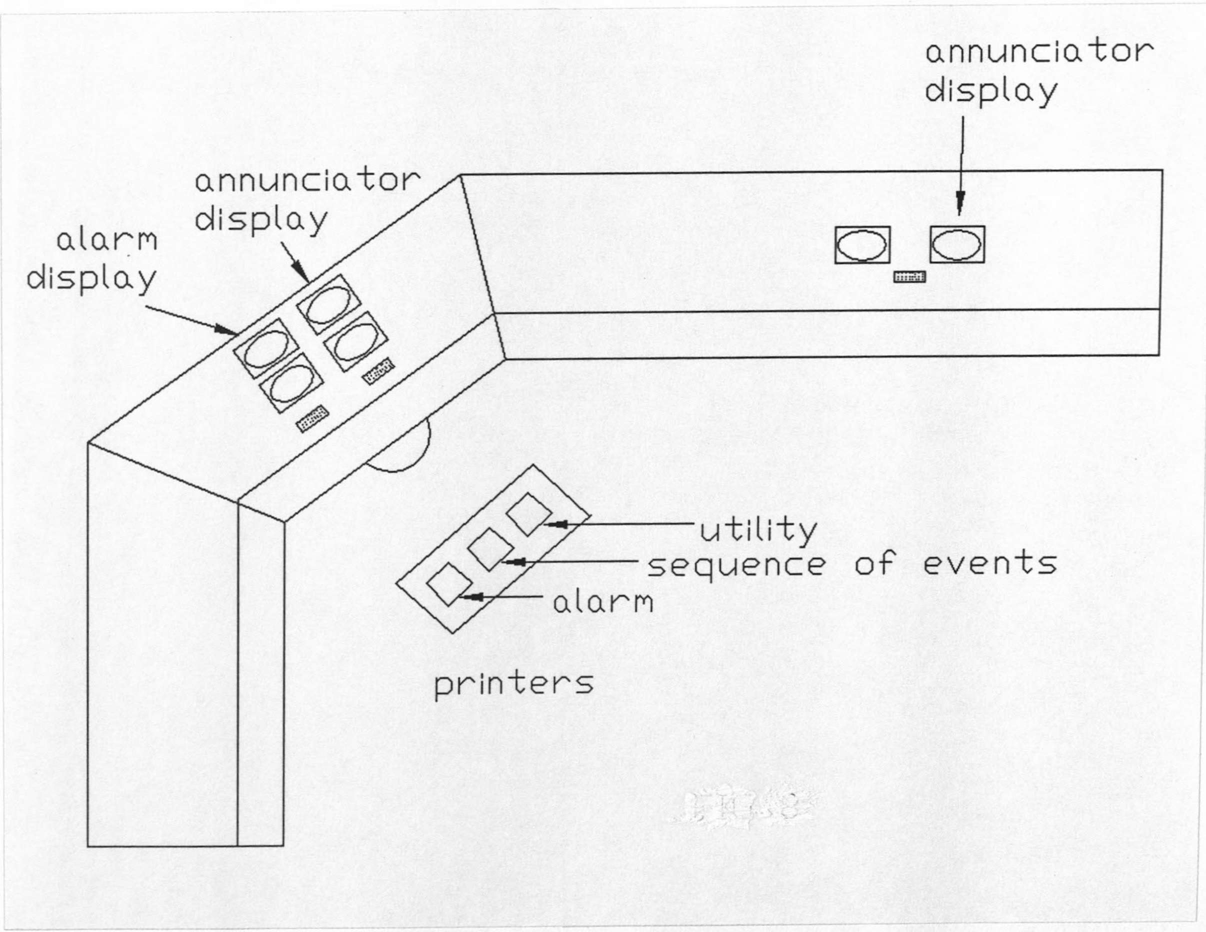
Appendix I

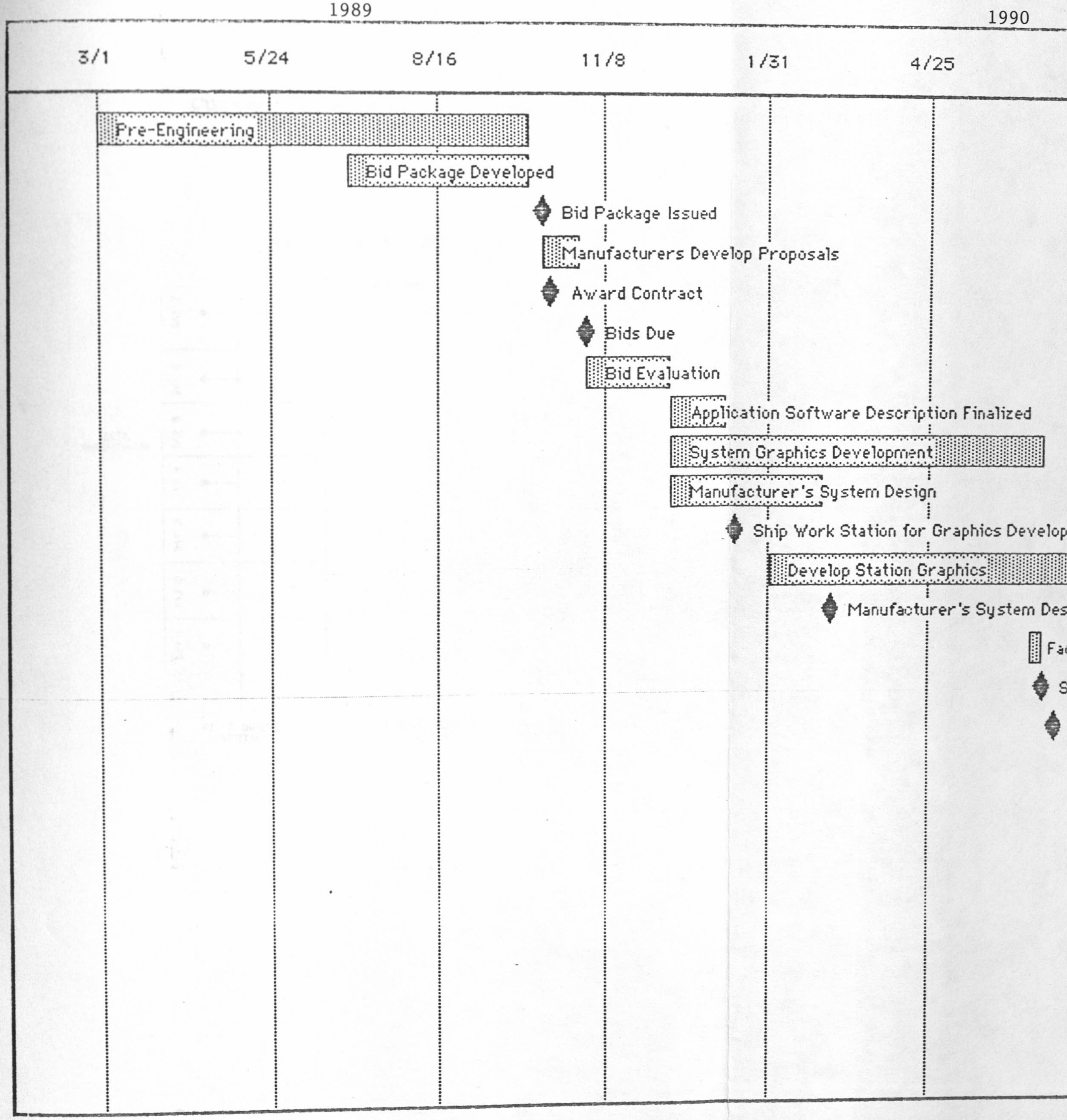
Individual boiler feed pump color graphic display.



Appendix J

Typical Gibson Unit boiler turbine-generator board.

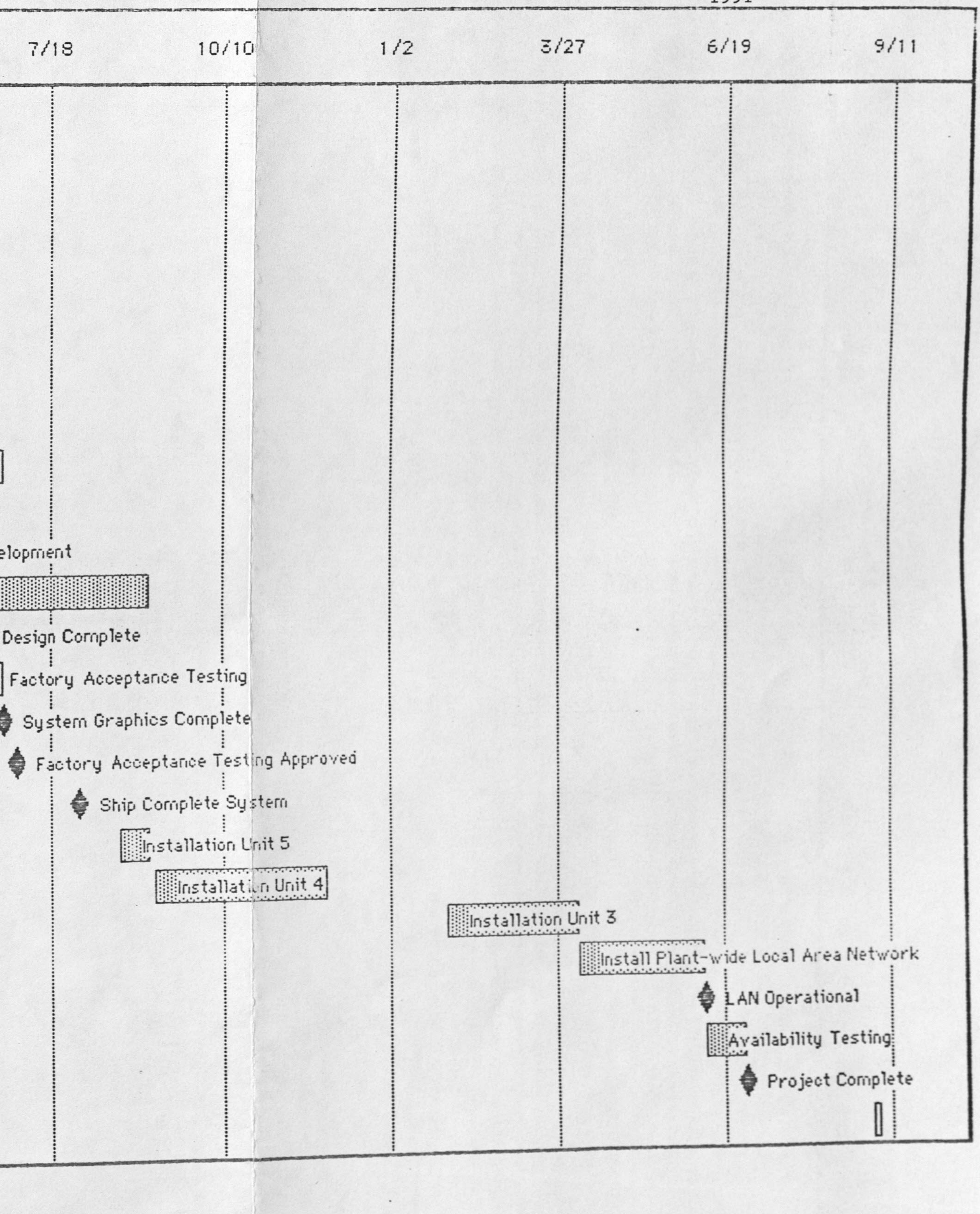




1989
1990
3/1
5/24
8/16
11/8
1/31
4/25
Pre-Engineering
Bid Package Developed
Bid Package Issued
Manufacturers Develop Proposals
Award Contract
Bids Due
Bid Evaluation
Application Software Description Finalized
System Graphics Development
Manufacturer's System Design
Ship Work Station for Graphics Develop
Develop Station Graphics
Manufacturer's System Des

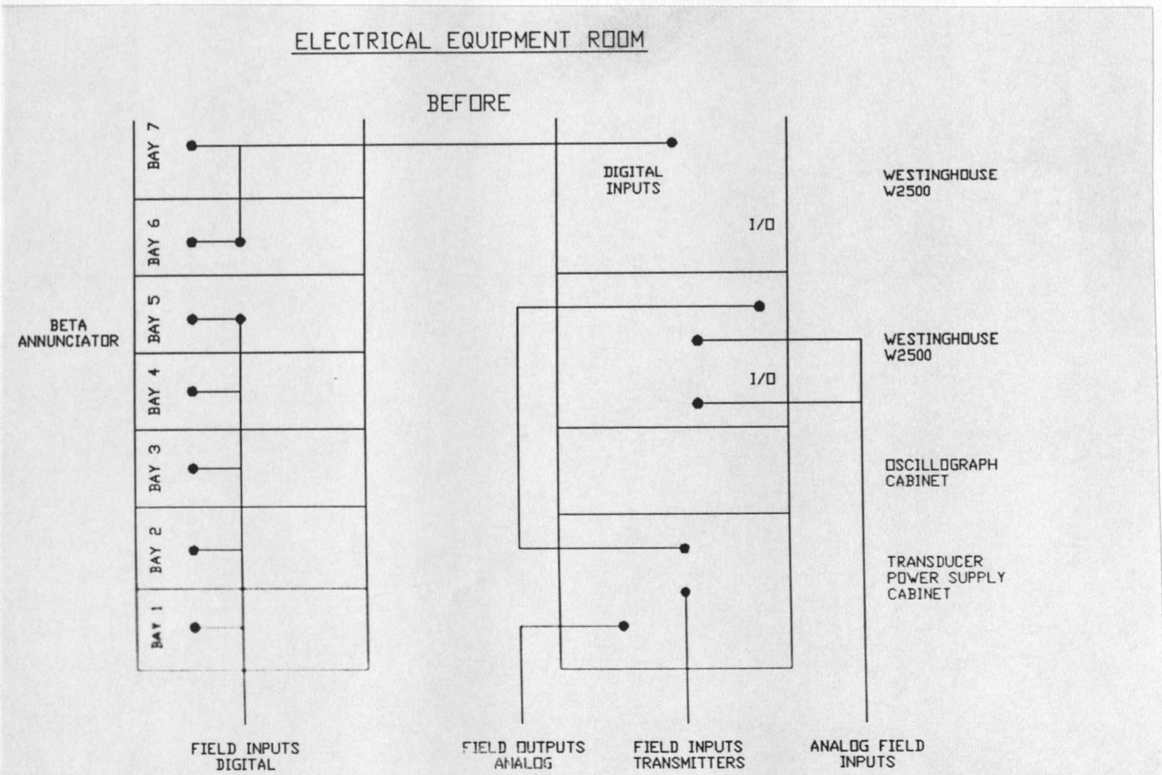
Appendix K

Units 3, 4, and 5 data acquisition schedule



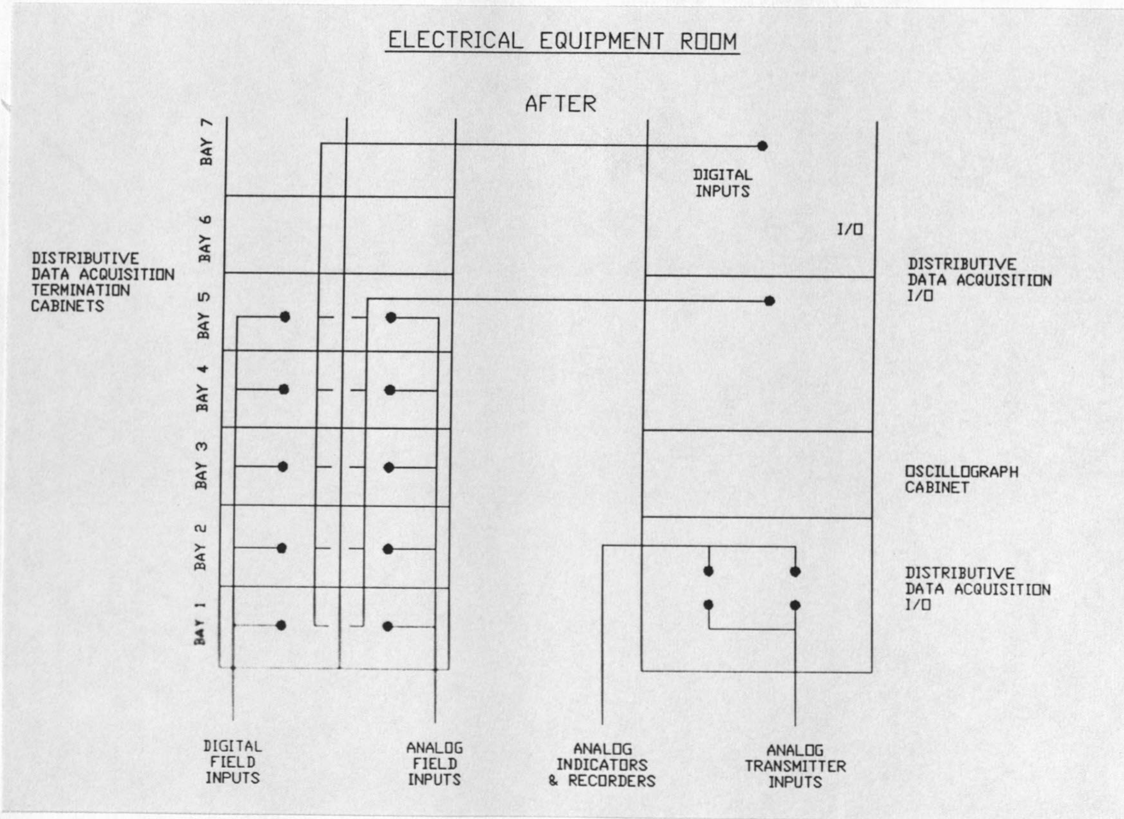
Appendix L

Current annunciator cabinet arrangement.



Appendix M

Proposed annunciator cabinet layout.



Appendix N

Definition of the term boiler pressure ramp. In the power industry the term "boiler pressure ramp" usually refers to the mechanical process used on supercritical boilers to increase the steam pressure (throttle pressure) that enters the turbine from minimum operating pressure to the desired operating pressure. During the time period the unit is in the start-up mode, the boiler operates on a bypass system at sub-critical pressures and temperatures. The boiler bypass system is used to increase the steam throttle pressure so the turbine can be started at a gradually changing rate of steam temperature and pressure. When the turbine throttle pressure steam reaches the supercritical condition the bypass system is shut off and the throttle pressure ramp is completed.