CONTROLS MODERNIZATION AT Entergy's Louisiana Station Cogeneration Facility Baton Rouge, LA

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ABSTRACT

The primary objective of Entergy's Louisiana Station cogeneration facility is to provide a reliable source of process steam to the Baton Rouge, Exxon refinery. Megawatts are generated as a by-product by means of gas and steam turbines.

With more units being base loaded, today's cogenerators are being required to swing load (steam flow) just like a large megawatt-producing utility. In addition, management of today's Cogeneration facilities must recognize two broader constraints beyond simply meeting the load demand: first - the need for reliable operation with minimum personnel and minimum expenditure of equipment life; and second - the need to conform to environmental regulations including NOx and other environmental emission limits.

At this facility, boilers 1A, 2A and 3A supply a 1500 psig common header and are responsible for the automatic load following functions of this plant. Additional plant steam generation is base loaded.

A new distributed Control System was added to the station with three objectives in mind:

- NOx reduction from .33 lb/mmbtu to less than .20 lb/mmbtu for loads above 60%. This objective was to be met by the automation of air registers and by minimizing excess air through use of improved O2 and CO measurements for the on-line fuel/air ratio control.
- An increase in reliable loading rates and turndown ratios with less operator intervention. A "Direct Energy Balance Accounting" control strategy (see below) was installed to support this function across the multiple boilers regardless of loading.
- An easy progression to a future centralized control room.

INTRODUCTION

Background

Louisiana Station is an Entergy-owned cogeneration facility located in Baton Rouge Louisiana, and was originally built in 1930. The plant's primary purpose today is to provide reliable 135 and 600 psig steam to the adjacent Exxon Refinery as a supplement to Exxon's own steam capacity. Its secondary purpose is to generate megawatts. Boilers 1A, 2A and 3A which service the 1500 psig common header are responsible for the automatic load following functions of this plant. Additional plant steam generation is base loaded.

Previous control modernization work provided new distributed controls for the pressure reducing valves, gas supply and the steam turbine back pressure regulator systems. These systems, as well as a Heat Recovery Steam Generator Control System, were connected on an existing Data Highway. An additional boiler Control System was added on a second highway.

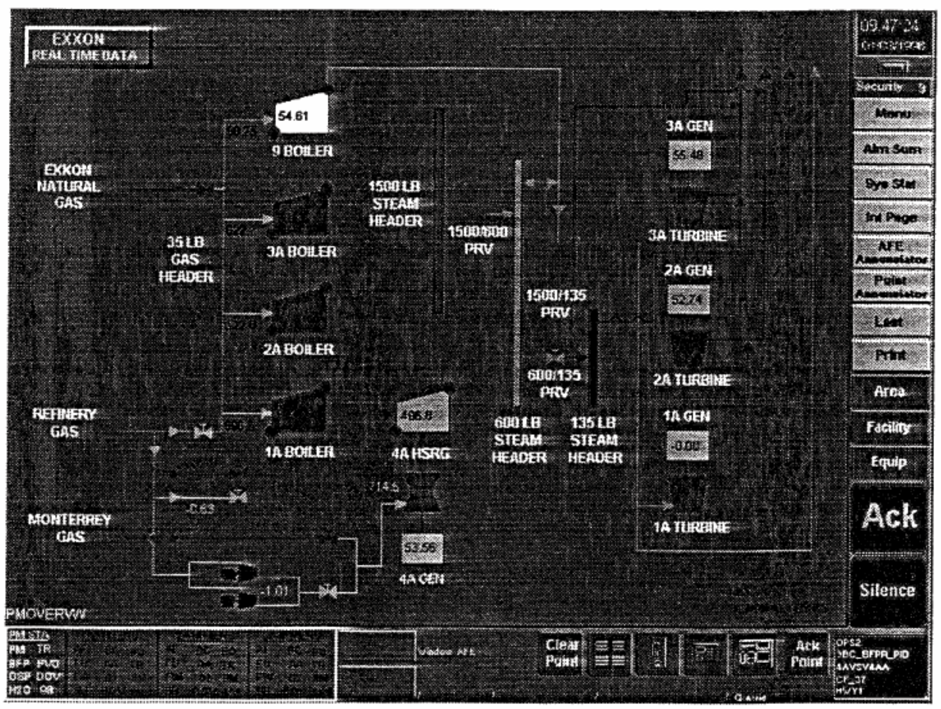


Figure 1

1A, 2A and 3A boiler are CE tangentially fired, balanced draft, drum boilers that operate at 1500 psig and 780 degrees F with a normal steam flow capacity of 55,000 pounds per hour. The original controls on these boilers were Bailey pneumatic combustion controls and L&N electric steam temperature controls. Both original control systems were placed in operations in 1951.

Reasons for Replacement

Corporate plans called for Louisiana Station to receive a new boiler to expand system capacity. This necessitated a new Control System in order to get environmental permits to meet existing and future plantwide NOx emission restrictions. In addition, an easy migration to a centralized control room was accomplished through the use of multiple Data Highways to a common human machine interface (HMI) as shown in the plant DCS highway layout diagram (see Figure 2). These controls interface to the rest of the plants existing controls on the second Data Highway.

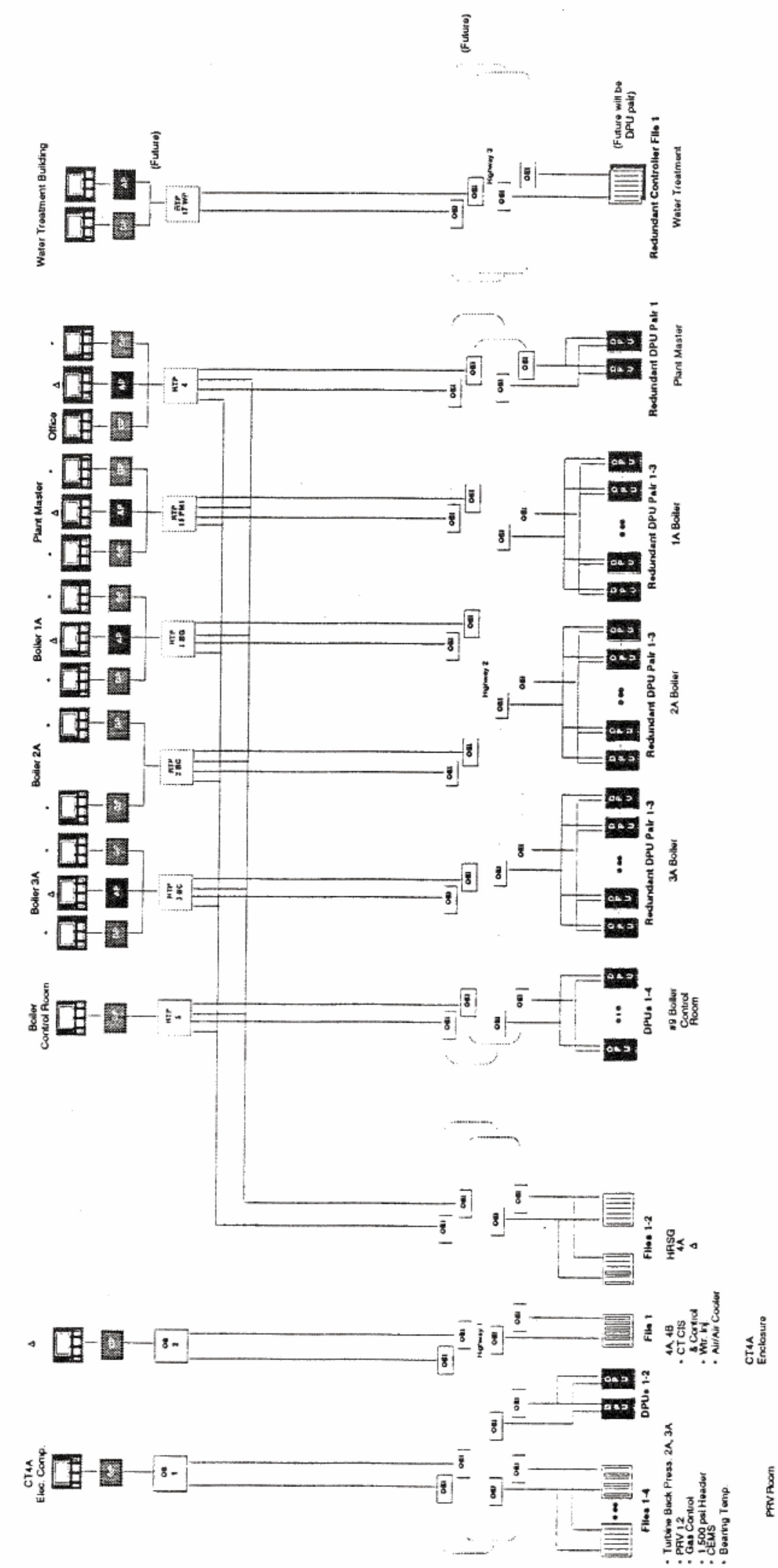


Figure 2

EXXON/ENTERGY Services Inc.
Louisiana Station
Baton Rouge Cogeneration Project
DCS Highway Layout

Δ = Cabinet Room
• = 1,500 Plant Control Room
PRV = Pressure Reducing Valve
CT = Combustion Turbine
Wtr. Inj. = Water Injection
HRSG = Heat Recovery Steam Generator
CEMS = Continuous Emissions Monitoring System

ENGINEERING, INSTALLATION AND START-UP

The Control Systems were delivered in three separate shipments. The first shipment contained the common 1500 psig Header Plant Master Control System and the 3A Control System. The Plant Master contained the front end logic and three boiler demand outputs with the appropriate bias and limits to the three individual boiler controls. The 2A system came in the second shipment and the 1A system in the last shipment.

Since the 1500 pound header cannot be taken out of service, the Control Systems had to be installed without disturbing the operation of the header. An outage was taken on the 3A boiler to allow the 3A equipment to be installed. Temporary logic and control functions were configured into the Plant Master to interface pulse to-pneumatic converters to the boiler demand of the 1A and 2A pneumatic fuel and air controls.

With the 1A and 2A boilers still operating on the pneumatic Plant Master Controller, the 3A boiler was put on-line. After the 3A boiler's fuel, air, water, heat release and steam temperature loops were tuned, header pressure control was switched to 3A, while 1A and 2A boilers were placed in manual mode of control.

The 2A and then the 1A boilers were transferred to the new Plant Master through the puls-to-pneumatic converter and placed on header pressure control. By making load changes to another boiler that was on the 600 pound header system of the plant, and biasing between 1A, 2A and 3A boilers, the tuning of the system could be checked and adjusted.

The outage for 3A and the Plant Master was from April 24 to May 30, 1994, 2A was from November 6 to November 22, 1994, and 1A was from March 21 to April 13, 1995. Meetings were held with the Control System vendor to approve wiring, functional, and logic drawings for the Control System. A full factory test was performed prior to the shipment to the plant site. This was done for each of the three systems with a check and adjust procedure to improve each succeeding Control System's Engineering and installation.

Checkout, startup and tuning functions were performed by Entergy plant and engineering staff. A local contractor pulled all cables and mounted as much equipment as possible prior to the outage under direction of the plant engineering staff. The first system start-up went well with little trouble. The second and third system start ups were even better. Ninety-five percent of the tuning parameters found in the first system were used on the subsequent boiler Control Systems.

All instrumentation at this site is maintained by Entergy's very talented Test Department staff, who also performed all loop checks and calibrations on these Control Systems and field equipment. Having the same people do this initial calibration and then be responsible for maintaining the equipment has worked well.

The Control System vendor was responsible for implementing function graphics of the Control System. All operational graphics were designed by the test shop with input from the operators. It is essential that operations be involved in this process. The graphics, while being quite easy to make on the DCS Workstation, are, in fact, very labor intensive because of the careful thought and development of plant operating philosophies which must be incorporated into the design. Figure 3, an overview graphic of 2A boiler, and figure 4, the Plant Master Station graphic are typical of the graphics developed for this project.

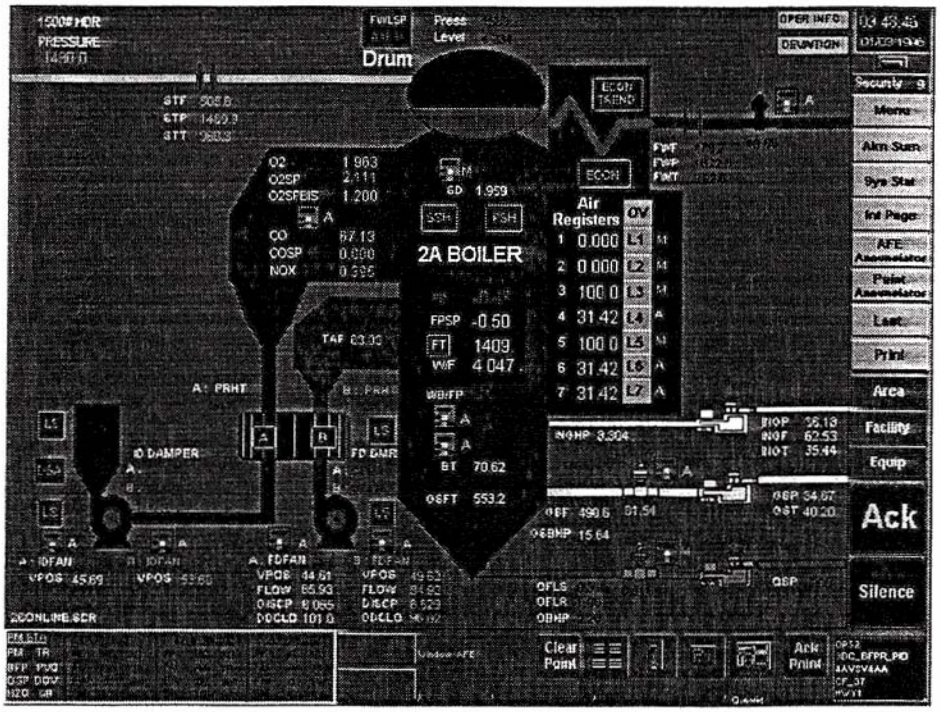


Figure 3

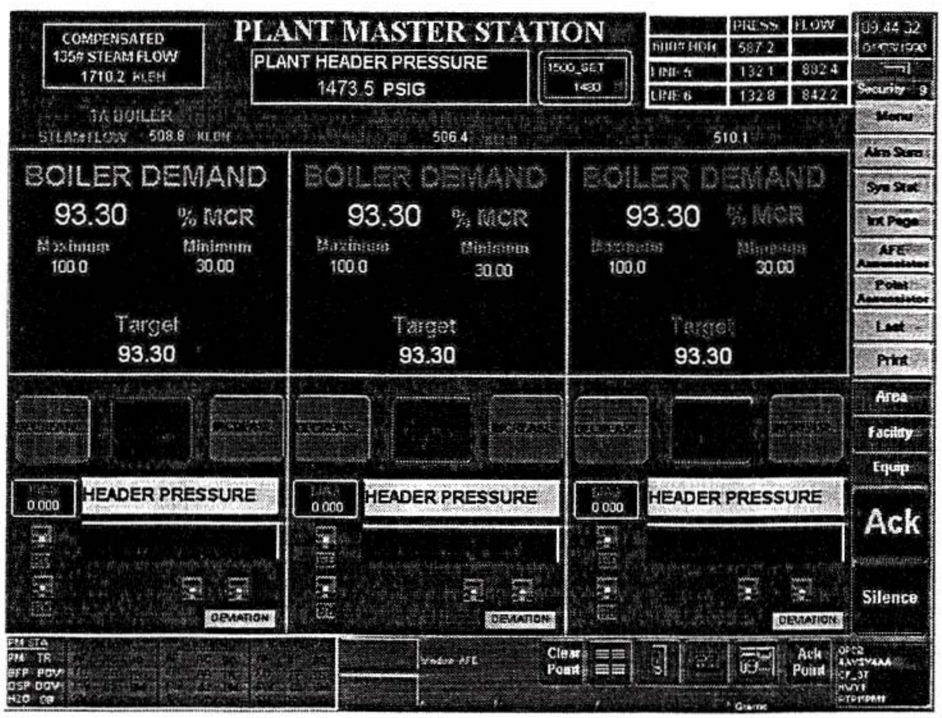


Figure 4

In addition to the Control System the following field devices were installed or modified on each boiler:

- Fourty-one (41) new pressure, flow, temperature and level transmitters were installed.
- New electrohydraulic actuators on the oil, gas and feedwater valves.

- Twenty-eight (28) electric actuators were installed on the air register dampers. To prevent binding, they were directly mounted using a slip coupling to allow for the expansion of the furnace.
- The four (4) electric ID and FD inlet vane actuators that had been previously installed and interfaced through pneumatic-to-current converters were modified to accept a PAT (pulse adjusting type) input from the Control System.
- Four (4) new in situ oxygen analyzers were installed in the high temperature region of the furnace.
- A new CO monitoring system was installed between the economizer and air preheater sections of a flue gas path.
- Four (4) existing 480 volt electric burner tilt actuators were interfaced into the system.

CONTROL CONCEPTS AND REQUIREMENTS

Demands on the new control system included stable header pressure control with increased loading rates, improved turndown rations with less operator intervention, as well as NOx reduction. This required the application of a "Direct Energy Balance Accounting" control strategy (shown in Figure 5) across the multiple boilers and multiple loads. "Direct Energy Balance Accounting" is a means of achieving a match between available Energy Supply and required Energy Demand for all sources and loads under all operating conditions.

The control strategy adopted for this project resulted in a series of improvements in plant operations:

Stable Header Pressure:

The front end (Plant Master) of the Control System uses the patented Direct Energy Balance method for control where the energy balance accounting for each boiler is accomplished at the fuel controller using the following relationship.

FUEL ERROR = ENERGY DEMAND MINUS HEAT RELEASE

Where Energy Demand is the demand for boiler output energy and Heat Release is the energy released by the fuel fired to a particular boiler.

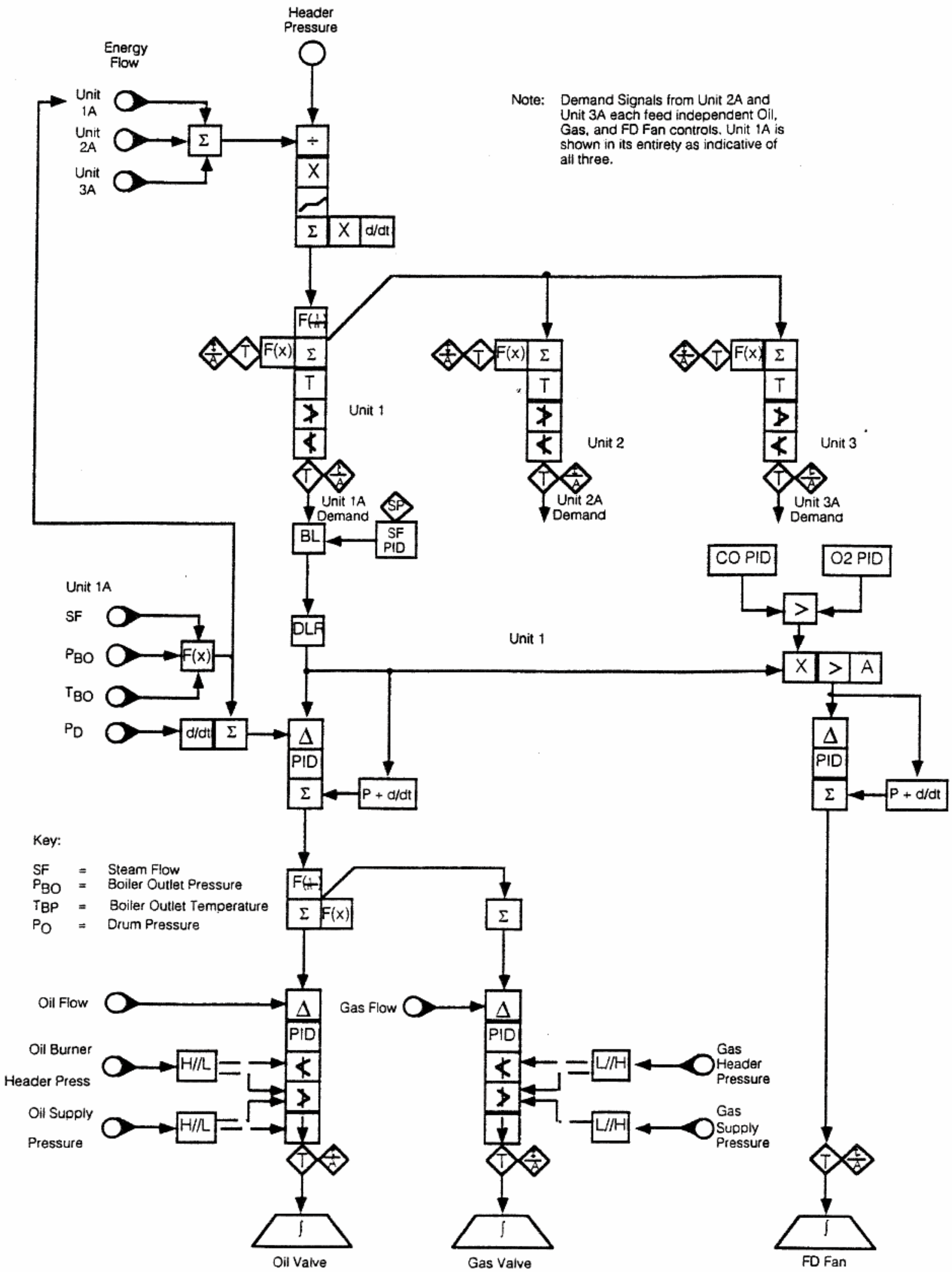
This relationship is used to generate the individual boiler demand signals. This has been applied successfully to single utility boiler turbine generator units for many years (see references 1 and 2). The special application in this case is the accounting for multiple energy sources (boilers) and multiple loads to maintain the appropriate energy balance between sources and loads under all operating conditions. The availability of steam property functions in the DCS vendors distributed processing unit greatly facilitated this accounting calculation.

ENERGY DEMAND is used in this Control System is the sum of the individual boiler energy flows (steam flows) divided by header pressure. This ratio is the effective Energy Demand at that header pressure. This ratio multiplied by the header pressure setpoint becomes the total Energy Demand (fuel demand) for the boilers. This signal is sent to the individual boiler's fuel demand after the appropriate boiler bias, ratio and limits adjustments have been applied by the Control System participation algorithms. The participation algorithm is a special algorithm provided by the DCS vendor to regulate multiple device/equipment in parallel.

HEAT RELEASE computes fuel input to each boiler based on the following relationship:

Fuel Input = Boiler output + Change in Stored Energy

Where Fuel Input = heat flow in BTU/minute, steam flow is the index of Boiler Output and the rate of change in drum pressure provides the indication of Change in Stored Energy. See reference 3.



Header Pressure
Energy Flow
Unit 1A
Unit 2A
Unit 3A
Note: Demand Signals from Unit 2A and Unit 3A each feed independent Oil, Gas, and FD Fan controls. Unit 1A is shown in its entirety as indicative of all three.
d/dt
Unit 1
Unit 2
Unit 3
Unit 1A Demand
Unit 2A Demand
Unit 3A Demand
SF PID
BL
DLR
CO PID
O2 PID
Unit 1A
SF
PBO
TBO
PD
PID
P + d/dt
Key:
SF = Steam Flow
PBO = Boiler Outlet Pressure
TBP = Boiler Outlet Temperature
PO = Drum Pressure
Oil Flow
Gas Flow
Oil Burner Header Press
Oil Supply Pressure
H//L
L//H
Gas Header Pressure
Gas Supply Pressure
Oil Valve
Gas Valve
FD Fan

Figure 5

The benefits of using the Heat Release signal for this application are:

- To provide a direct method of measuring all fuel input to the boiler independent of the source.
- To correct for any changes in fuel heating value, in particular refinery waste gas.
- To stabilize steam temperatures through a more uniform fuel-air ratio.
- To maintain uniform fuel-air ratio during load changes and at a steady state.

Heat Release is computed individually on each boiler. When subtracted from the individual boiler demand, provided by the Plant Master, a precise fuel error is provided for the fuel controller. This fuel error is correct regardless of any BTU changes in the fuel.

This control strategy is shown functionally in Figure 5.

The Heat Release method has also been used very effectively on an existing HRSG (Heat Recovery Steam Generator) at this plant. The HRSG receives hot exhaust gases from a gas turbine. The Heat Release takes into account the heating value of these gases and generates the proper fuel error to the gas controls for the duct burners.

NOx Reduction:

A combination of air register and O2/CO automation is being used to achieve the reduction in NOx from over 0.33 to under 0.2 lb/mmbtu. This is required in order to obtain environmental permits for a planned new boiler.

Air Registers:

There are two levels of burners with the ability to achieve 100% load on natural or refinery waste gas.

There is a light oil capacity of 50%.

There are seven levels of air registers. Prior to automating they were left in the following positions:

Level 1: Overfire Air	-- Fully Closed
Level 2: Overfire Air	-- Fully Closed
Level 3: Fuel Air	-- Fully Open
Level 4: Overfire/Underfire	-- Fully Closed
Level 5: Fuel Air	-- Fully Open
Level 6: Underfire Air	-- Fully CLosed
Level 7: Underfire Air	-- Fully CLosed

During the individual boiler outages, new electric actuators were installed on each corner of each level, for a total of 28 actuators. Each one can be independently controlled and monitored from the Control System graphic displays. These new actuators are now controlled as follows:

Levels 1 and 2 (Overfire Air) are the primary means of reducing NOx. They are positioned from a load index to establish the proper damper position that will minimize the generation of NOx.

Levels 3 and 5 (Fuel Air) are controlled to maintain the proper windbox-to-furnace differential pressure.

Levels 4, 6 and 7 (Auxiliary Air are controlled to maintain the proper windbox-to-furnace differential pressure.

Previously the windbox-to-furnace differential pressure was allowed to rise to approximately eight inches at full load. After automating, a setpoint of 4 inches H_2O was maintained. This helped achieve the additional benefit of reduced FD and ID fan amps of approximately 12% at full load.

O_2 analyzers and Control:

The O_2 control is accomplished by using in situ analyzers mounted in the high temperature radiant region of the boiler (see reference 4).

This has two advantages:

1. A fast response time compared to mounting in the economizer or stack.
2. A truer O_2 reading by eliminating most of the error due to entrained or tramp air leakage into the negative pressure boiler. This tram air becomes more significant when low excess air operation is utilized.

CO analyzers and control:

The CO system, known as a Heuszometer, provides a single averaged CO sample to an infrared analyzer by drawing multiple representative samples from a grid of taps in the economizer outlet. These samples are drawn to a sample chamber at a controlled pressure by using the vacuum at the suction of the ID fans (see reference 5). This CO system provides an accurate stable signal and also a much shorter time constant when compared to a system mounted in the stack.

CONCLUSION

The Control Systems were installed and started up on schedule without any major problems. Increased loading rates and turndown ratios have been achieved. A relatively easy path for a migration to a plant centralized control room is proceeding.

Direct energy balance accounting across multiple boilers used in combination with Heat Release to develop the fuel error, provides a very stable and responsive header pressure control.

Operator acceptance is increased as they become more familiar with the equipment.

Continuing work is being done using the graphics and data collection capability of the distributed system to assist operators in getting information needed to solve operational problems while filtering out non-essential information.

More testing on the loading rates and boiler stability is being conducted on the units during the first quarter of 1996. During the same period, more testing is being done with the CO control and NO_x reduction. Results of both should be available by June.

Additional work is required to assist operators in coordinating the boilers, pressure reducing system and turbines during large load changes. There is a need to better allocate the steam flow between the pressure reducing valves and steam turbines to produce the maximum megawatts and still achieve reliable steam capacity to the refinery. A Plant Automation and Process Constraint Coordinator as described in Reference 6 is being considered to assist in achieving these objectives.

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